Modeling Primary Frequency Response for Grid Studies

Jennie Jorgenson and Paul Denholm

National Renewable Energy Laboratory

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Abstract

For the electric power grid, maintaining nearly constant frequency is an important measure of system reliability and stability. Primary frequency response (PFR) is one of the important reserve services used by grid operators to uphold steady frequency. Modeling PFR has historically been rare in grid integration and planning studies, but it could become more important with greater deployment of nonsynchronous generators. In this work, we illustrate how a PFR constraint can be implemented in production cost models, which are a key component of grid planning studies. We also discuss the complexities and nuances associated with PFR modeling, and we provide results of a case study implementing PFR in a section of the western U.S. power grid. Like previous analysis, the case study finds that the impacts of such a constraint are generally small, but highly dependent on underlying assumptions.

Introduction

A key element of renewable integration studies and utility resource planning is grid modeling using a production cost model (PCM). These tools, which are also known as unit-commitment and economic dispatch models, evaluate many aspects of grid operations, including estimating generation costs, emissions, and metrics related to system reliability. One such element PCMs can simulate is the provision of operating reserves. Traditionally, integration studies model several operating reserve products including some combination of contingency, regulating, and flexibility reserves. Most grid studies using commercial PCMs have not considered primary frequency response (PFR), also known as governor response. PFR is a non-market but important reserve that helps the grid maintain frequency stability [1]. Historically, synchronous generators such as steam or combustion turbines have provided frequency response on the sub-minute timescale with rotating inertia and governor[1] control, which require no human intervention [1, 2]. However, growing deployment of inverter-based generators and removal or disabling governors from existing generators have led to concern about how some grids may respond to a disturbance in grid frequency caused by an unexpected generator or transmission line outage [2-5].

Modelers and system planners are beginning to consider an explicit PFR constraint both in commercial models an in academic formulations of the unit commitment and economic dispatch problem [6-9]. Typically, these analyses demonstrate that including PFR has a small impact but may become more important as synchronous generation resources are replaced with inverter-based solar and wind generators [6, 10]. There have also been proposals for new PFR (or fast frequency response) market products, which provides additional motivation to understand the costs and potential revenues associated with this service [2].

In this work, we detail a method to include PFR in a commercial PCM. We discuss the many complexities involved with modeling PFR, including the need to consider which generators have governor response, their ramp rates, and the possible provision of PFR from inverter-based generators. We then provide results of a case study of PFR simulations in the California grid. These results demonstrate that, as with other reserve products, including PFR generally has a small impact on overall dispatch results and costs. However, these impacts can be highly dependent on many assumptions, and including PFR in grid studies will likely increase in importance as power systems continue to evolve.

[1] A governor is a piece of equipment on turbines that acts to regulate the flow to the turbine.

Overview of Operating Reserves and Primary Frequency Response

Operating reserves are defined as "that capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection" [11]. It is important to emphasize there are no uniform definitions for individual operating reserves and ancillary services. U.S. independent system operators and utilities use different terms, with different product definitions, and different terms are used within the United States and internationally. Wherever possible, we use terms and definitions used by the North American Electric Reliability Corporation (NERC) [11].

Figure 1 shows the approximate role of different operating reserve products in response to a system contingency that leads to a decline in frequency. This diagram is simplified; in some cases, not all types of reserve are needed to return the grid to its normal state (depending on severity and length of an event), and timescales for each reserve service illustrate general trends as opposed to precise definitions. In this illustration, upon loss of a large generator, frequency will decline, and the rate of change of frequency is slowed by the inherent physical inertia in the rotating mass of generators. Decline in frequency is detected by generator governors, which respond by increasing plant output to further slow and arrest the decay in frequency. This stage is the primary focus of this analysis. This governor response, here also referred to as PFR, occurs within seconds of a contingency event, and requires no intervention. Frequency is then restored by deploying additional reserves, including regulating reserves and contingency reserves (both spinning and non-spinning[2]). Every reserve product is itself restored, generally by a slower responding but longer-duration product.

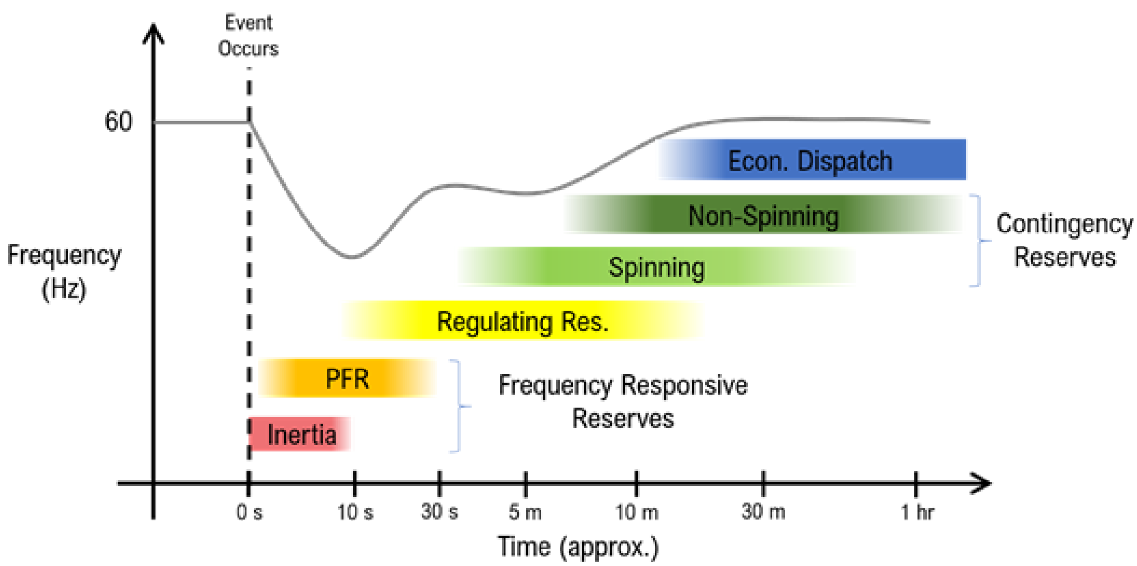

Figure 1. Sequence of reserve deployments in response to a contingency event

[2] "Spinning" reserves are those of generators already online, and "non-spinning" generators are offline generators that can turn on within minutes.

Regulating and contingency reserves are market products in regions with restructured markets, and the amount procured is set by the local balancing area (BA) authority. Regulating reserve quantities are based on expected net load variability—they respond to normal random fluctuations in demand as well as events.[3] Contingency reserves are often based on the size of the largest contingency event and include spinning and non-spinning generators [11].

PFR is not a market product. Because frequency is shared across each interconnection, frequency response obligation is set at the interconnection level. Table 1 summarizes primary frequency response obligation by region as recommended by NERC. Each interconnection has a frequency response obligation, which is defined as the amount of increase in generation that must occur per unit of frequency decline (megawatts [MW]/hertz [Hz]). Also established is the maximum delta frequency (MDF) or the decline in frequency that results in full frequency response. The product of these two factors is the PFR obligation by interconnection. This interconnection frequency response obligation (IFRO) is further divided by BA in proportion to demand so that each region "shares" its obligation to the entire interconnection. We include the PFR obligation for the California Independent System Operator (CAISO) as an example.

Table 1. 2017 Recommended Frequency Response Obligation

Interconnection	Region	IFRO (MW/0.1Hz)[4]	MDF (Hz)[5]	Requirement (MW)
Electric Reliability Council of Texas (ERCOT)	ERCOT	381	0.405	1,543
Western	Western Total	858	0.28	2,402
	CAISO	196.5		550
	Non-CAISO	661.5		1,852
Eastern	Eastern Total	1,015	0.42	4,263

PFR can be provided by any generator that is partially loaded with the ability to increase (or decrease) output and has a governor. PFR requires rapid response. Traditionally, it is provided by a variety of generators, including hydro and thermal plants, but only a limited subset of the fleet is equipped properly to sustain primary frequency response [13]. Both wind and solar plants can provide PFR, and wind turbines in ERCOT are now required to have this capability [14-18]. However, using variable generation to provide frequency response also has a downside. If an *increase* in grid frequency is required when a generator is lost, the affected plants must have been partially loaded in the first place to increase their output. Operating at a partially loaded

[3] An additional reserve product is sometimes used to address longer-term variability of net load. It has a variety of names including flexibility, following, or ramping [12].
[4] 2017 NERC BA-level Frequency Response Obligation in MW/0.1Hz, https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/BA%20FRO%20Allocation%20for%20OY%202017.pdf
[5] Maximum Allowable Delta Frequency, https://www.nerc.com/comm/OC/BAL0031_Supporting_Documents_2017_DL/2017_FRAA_Final_20171113.pdf

level (or alternatively, curtailing energy) incurs a cost, as curtailed energy cannot be sold into the market. Thus, proper incentives must exist for variable generation to provide frequency response [2, 6].

Operating Cost of Reserves

Maintaining operating reserves imposes a cost to grid operations from two primary sources: opportunity cost and movement cost [12]. Provision of operating reserves requires grid operators to keep a subset of the fleet partially loaded, increasing the number of plants online and reducing overall system efficiency, as partially loaded plants are not operated at their optimal output. This incurs an opportunity cost for individual generators that could be operating at full output and receiving greater energy revenue. Movement cost represents the fact that plants providing some operation reserve types, such as regulating reserves, are constantly adjusting output to respond to grid conditions. This increases wear and tear costs, and it reduces the efficiency of the generator, requiring additional fuel per unit of generation for thermal generators. In restructured markets, generators “bid in” the movement costs, and opportunity costs are calculated by the market operator, with the clearing price being the sum of the two (co-optimized with energy to generate the least-cost overall dispatch).

Reserve costs are often expressed in terms of capacity over time as opposed to energy. For example, a 500-MW plant providing 400 MW of real power and holding back 50 MW of headroom for reserves would provide in each hour 400 MWh of energy and 50 megawatt-hours (MW-hr) of reserves. Therefore, reserves may be priced in MW-hr units. As shown in Figure 1, resources with different technical characteristics are deployed at different times—typically, they are deployed in order from very fast to slow. This generally corresponds with costs that range from more to less expensive.

Modeling Reserves and PFR in Grid Studies

Using production cost models (PCMs) is an inherent part of grid planning. Though open-source and academic PCMs are available, most grid studies use commercial tools. Because the code of these tools cannot be examined (and documentation sometimes does not include explicit model formulation), validation comes primarily by comparing results to historical data, and the tools’ widespread acceptance by utilities and planners.

The basic formulation of a PCM is well documented, with the overall objective function of minimizing operating cost of the system (mainly variable costs associated with the generator fleet). These costs are shown in a simplified form in Equation 1, where $e_{g,t}$ is electricity produced by generator g at time point t, $C_{g,t}$ is the incremental generation cost for g including fuel, variable operation and maintenance, and any emissions cost, C_g^{su} is the cost of starting generator g, $y_{g,t}^{su}$ is a binary variable denoting startup of generator g at time $t,$ and τ is the set of all time points within the optimization horizon.

$$\sum_{t\in\tau}\sum_{g}\left(C_{g,t}e_{g,t}+C_g^{su}y_{g,t}^{su}\right) \qquad (1)$$

This cost minimization objective will be subject to many constraints, including the requirement to provide reserves. As an example, Equations 2–5 provide the formulation for a generic spinning reserve product (r_t) required as percentage (η) of load (d_t) in every timestep and specifying some response period (μ). This formulation will constrain only online generators to provide an amount of reserves at time t ($R_{g,t}$) within their maximum capacity (C_g^{max}) and ramp rate (R_g^{max}). The reserve product (r_t) can also be set as a fixed value (e.g., the value of the single largest continency) or as a time-varying value calculated regulation reserves might be calculated based on net-load uncertainty, such as the method described in [20]. Thus, the optimization is to minimize Equation 1, subject to Equations 2–5:

$$r_t \geq \eta\, d_t, \forall t \in \tau \tag{2}$$

$$\sum_g (R_{g,t}) \geq r_t \tag{3}$$

$$e_{g,t} + R_{g,t} \leq C_g{}^{max} \tag{4}$$

$$R_{g,t} \leq \mu R_g{}^{max} \tag{5}$$

Most commercial tools can represent operating reserves based on parameters described in Equations 2–5. For each reserve product, each generator will have several parameters describing its ability to provide the product. These parameters include:

1. Generator Ability: A binary variable associated with whether a generator can provide the service. For example, this might be based on whether the generator has the necessary telemetry equipment to receive an automatic generation control signal for the provision of regulating reserves.
2. Synchronization Requirement: A binary variable indicating whether the reserve requires the generator to be online or synchronized
3. Headroom: Capacity available between a generator's current dispatch point and its maximum capacity or minimum generation level
4. Response Rate: The amount of generation that can be provided based on response time and ramp rate. For example, if a reserve product has a 10-minute response time, and a generator has a 2%/minute response rate, the generator can provide up to 20% of its capacity for that reserve product, assuming sufficient headroom.
5. Movement Cost: Providing reserves, especially regulating reserves, sometimes requires that plants follow a reserve signal, which requires the plant to operate in a non-steady state mode. This serves as a "bid cost" in restructured markets that is above and beyond the lost opportunity cost associated with providing reserves [12].
6. Actual Movement and Energy Provision: PCM simulations consider the impact of "holding" reserves, but they do not simulate the actual dispatch of reserves.[6] However,

[6] Different models are used to simulate reserve deployments. As an example, contingency events can be captured by power flow models, which captures the physics of the power system including inertia and PFR [21]. Regulating reserves requires a model that captures the deployment of automatic generation control [22].

the actual movement and associated provision of real energy should be considered, in combination with a movement cost (item #5 above). This movement can be captured by applying an estimate of typical amount of actual energy provided for provision of a service, referred to as the "regulation energy use ratio" [23] or the "dispatch to contract ratio" [24]. For example, one study of regulation reserves uses a dispatch-to-contract ratio of 14%, meaning each MW-hr of upward regulating reserves requires 0.14 MWh of actual additional energy [25]. However, both upward and downward movement are required for PFR and regulation, and because these services are responding to random and uncorrelated variability, when coupled, these services are ideally net energy neutral. This means provision of PFR and regulation should require no net change in total energy provided.[7]

The multiple constraints and binary variables associated with additional reserve products can add considerable computation time, so simplifications are often made. As an example, grid integration studies by the National Renewable Energy Laboratory (NREL) often ignore non-spinning contingency reserves, as the constraint rarely changes the dispatch or overall system costs.[8] Downward reserves have also historically not been modeled in NREL studies, assuming downward ramping requirements are less binding than upward requirements. Furthermore, systems with significant amounts of wind and solar can often rely on these generation sources to curtail (or reduce) their output with little notice, making the downward ramping requirements less binding. As with nearly all previous studies, NREL integration studies have also historically ignored PFR because run times are challenging and most analysts agree the normal dispatch and reserve provision offer sufficient quantity of frequency-responsive generators online. However, as discussed previously, ignoring PFR as a modeling constraint may be inappropriate as inverter-based variable generation penetration increases, and efforts to improve solve times via spatial and temporal decomposition techniques [27] allow greater modeling fidelity.

Adding a PFR constraint to a PCM can be imposed by implementing a system of equations such as those presented in Equations 2–5 and involving the constraints outlined in the list above. Implementing PFR would be most similar to regulating reserves in that it requires both upward and downward flexibility, and be fast ramping and highly variable, but it does not require continuous duration (and is therefore suitable for provision by energy storage). The PFR signal should also likely be energy neutral over reasonable timescales. Key differences include uncertainty regarding how many and which types of generators have the equipment needed to provide PFR, and the actual provision of real energy, which is important for estimating mileage costs.[9]

To provide an example of how these constraints might be implemented into a PCM, we next describe a case study that illustrates the effect of adding a PFR constraint, as well as the specificities of the PFR constraint itself.

[7] This is not the case when these services are provided by energy storage where efficiency losses will require an increase in net energy demand and "make-up energy" in both reality and in simulations of energy storage providing PFR or regulation [26].

[8] This is also reflected in the very low and often zero prices for non-spinning reserves in ISO/RTO markets.

[9] Provision of actual energy from regulating reserves is sometimes expressed as the "dispatch to contract" ratio [11].

Case Study

We use the PLEXOS Integrated Energy Model [28-32] to demonstrate the effect of adding PFR to a commercial PCM and evaluate the effect of various assumptions about PFR provision on total system costs. We evaluate the impact of implementing a PFR constraint in the CAISO BA. Though we focus on this single BA, given the interconnected nature of the region, we performed simulations for the entire Western Interconnection of North America, which is especially important considering California is historically a net importer of electricity. The geographic footprint of this model encompasses the western portions of the United States and Canada, as well as a small amount of northwestern Mexico. The model database is derived from the California 2030 Low Carbon Grid Study, which examined a variety of scenarios that achieve a 50% reduction in emissions from California's electricity sector by 2030 compared to 2012 [29].

The California 2030 Low Carbon Grid Study examined dozens of scenarios, but we focus on its central Diverse Enhanced Flexibility scenario, with sensitivities examined later. This case achieves 56% penetration of renewables in California, including 21% PV, 18% wind (much of it out of state), and 17% other non-variable renewable energy. It also includes about 2.2 gigawatts (GW) of storage, in addition to the 1.5 GW of storage built or under development as part of the California Public Utilities Commission's storage mandate.

The model database includes every generator in the Western Interconnection of North America, with details about part-load heat rates, start costs, and transmission network topology derived from the Western Electricity Coordinating Council's Transmission Expansion Policy Planning Committee [30].[10] Optimal DC power flow inside California is represented at the nodal level but at a less-resolved zonal level outside the state. So, nodal power flow is simulated, but individual line constraints are not enforced; only the 129 Western Electricity Coordinating Council paths are constrained within the modeling. We also initially include the six types of reserves considered in the Low Carbon Grid Study, which include Spinning Contingency, Flexibility, and Regulation [29].

In the 2016 iteration of its Long Term Procurement Plan, CAISO established a new constraint in its operational modeling to consider PFR [33-35]. This constraint attempts to ensure each BA can supply sufficient frequency response in accordance with NERC standard BAL-003-1. The standard, along with CAISO's stakeholder process, states that California's frequency response obligation is 258 MW/0.1 Hz [34, 36][11]. NERC calculates the allowable deviation in frequency before load-tripping will occur at 0.292 Hz [36]. Thus, multiplying California's obligation by the allowable deviation leads to the requirement of 752 MW of headroom [34].

CAISO assumes, based on operating experience, that 50% of the 752-MW PFR obligation will be met by hydro, which has historically been able to respond to under frequency conditions, and is thus not modeled. The balance (376 MW) of PFR is modeled and must come from eligible

[10] Details about the formulation of this model are available [29]. Relevant to this study, however, are the fuel costs. Natural gas averages $6.96 per million British thermal units (MMBtu) in California but varies by location and month of the year. Coal averages $2/MMBtu, with less variation in cost. The carbon price in California is $32.4/metric ton, and carbon outside California has no cost.

[11] Note that the California frequency response obligation used here (258 MW/0.1 Hz) from 2016 is slightly different than the more up-to-date 2017 frequency response obligation from Table 1.

resources, include battery storage (excluding pumped hydro storage resources) and online gas combined-cycle (CC) generators. Battery storage generators can provide headroom on a MW-for-MW basis, meaning each unused MW of capacity can count toward the requirement. Gas CC units, however, can provide only 8% of their online capacity, assuming sufficient headroom. The constraint for PFR at time t ($r_{PFR,t}$) being provided by only online gas CCs ($R_{c,t}$) and batteries ($R_{b,t}$) providing some amount of PFR at time t ($e_{PFR,t}$), varying the initial equations shown in (2) – (5), becomes:

$$r_{PFR,t} \geq 376, \forall t \in \tau \tag{6}$$

$$\sum_{c,b} \left(R_{c,t} + R_{b,t}\right) \geq r_{PFR,t} \tag{7}$$

subject to:

$$e_{PFR,t} + R_{c,t} \leq (C^{max}) \tag{8}$$
$$e_{PFR,t} + R_{b,t} \leq (C^{max}) \tag{9}$$
$$e_{PFR,t} \leq (C^{max}) \times 0.08 \tag{10}$$

Where Equation (10) only applies to the online gas CCs. CAISO does not model a variable mileage (movement) cost, so therefore only calculates the opportunity cost associated with provision of PFR. Following the CAISO methodology, we only consider holding the upward (more challenging) component of PFR, and we do not model a PFR constraint outside CAISO.

To examine the impact of adding PFR, we add the constraint described in Equations (6) – (10) to the California grid model. For each sensitivity, we model first a case with no PFR constraint and then a case imposing PFR constraints. The difference in the optimized production cost of the two cases gives the additional cost as a direct result of the PFR constraint.

Base Case Study Results

Adding the PFR constraint results in additional operating costs. If, in a given time step, the requirement from PFR comes from online CCs, CCs are required to operate below their maximum capacity to provide upward headroom. Gas CCs are often less efficient operating at part load than at full load, thus requiring more fuel per unit of energy produced. Furthermore, turning down gas CCs to part load may require turning on additional, higher-cost generators, which also increases total system cost. Generally, after adding a PFR constraint, costs from the gas fleet (gas CCs and gas combustion turbines [CTs]) increase by a small amount. Again, this occurs due to the requirement to, at times, keep gas CCs at a lower generation level to acquire PFR reserves. This results in less efficient operation of gas CCs and slightly increased use of gas CTs to make up the difference.

The impact of adding PFR can be measured in terms of total cost as well as cost per unit of PFR provided. In the base case (without PFR) the total Western Interconnection-wide system annual operational cost was $17.379 billion, while the cost in the case with PFR was $17.392 billion, which represents a difference of about $13 million. (We compare the total Western

Interconnection-wide costs because changes in dispatch in CAISO can affect plant operation outside CAISO, particularly because CAISO imports a significant portion of its power.) This adds a total of 0.07% to the cost of energy production in the model footprint. Although the change is small, the effect is observable, as 0.07% is outside the numerical tolerance of the optimization (0.05%).

The total operational costs in CAISO are about $7.52 billion, so adding PFR adds about 0.2% to total operational costs, or about $4/MW-hr of PFR. The latter number is similar in magnitude to the costs of the spinning reserve product in many independent system operator (ISO)/regional transmission operator (RTO) markets. Table 2 summarizes average spinning contingency costs, showing most in the range of $3–$5/MW-hr. Exceptions include CAISO in 2017 and ERCOT. The rise in costs in CAISO are due to tight supply conditions resulting in scarcity pricing [37]. This reflects a capacity need that is not captured in our modeling, which assumes a resource-adequate system. (High prices in ERCOT are also due to scarcity pricing, which can result in very high reserve prices.[12])

Table 2. Spinning Contingency Reserve Requirement Prices

Market Region	2017 Average Price ($/MW-hr)
CAISO	$10.13[13] ($5.65 in 2016)
PJM	$3.73[14]
ERCOT	$9.77[15]
ISO-NE	$2.96[16]
NYISO	$5.00[17]
MISO	$2.94[18]
SPP	$5.25[19]

A more appropriate comparison of costs might be with regulating reserves. These costs are generally higher due to the inclusion of mileage payments. A more sophisticated treatment of PFR would include these "mileage costs," which would increase the cost and may result in costs that are more comparable to regulation costs.

[12] This is due in part due to ERCOT's energy-only market, which requires capacity costs to be recovered in energy and ancillary service prices.
[13] Weighted average day-ahead market clearing price [37].
[14] 2017 weighted average clearing price for Tier 2 synchronized reserve for all cleared hours in RTO zone [38].
[15] Average Annual Ancillary Service Price [39].
[16] Annual average TMSR price [40].
[17] Day-ahead 10-minute spinning price for Southeast NY Zone; 10-minute spinning price equals the sum of 10-minute spin component, 10-minute non-spin component, and 30-minute component [41].
[18] Average RT Spinning Reserve Price [42].
[19] Average real-time market clearing price for spinning reserve in 2017 [43].

Sensitivities

We examined several sensitivities, including (1) the amount of PFR required (essentially examining the CAISO assumption that 376 MW of headroom can automatically be provided by hydro generators, indicated as 1.5x and 2x in Table 3), (2) the impact allowing renewable generators to provide PFR (indicated as RE in Table 3), and (3) the assumption that batteries can provide PFR (Only Gas CCs in Table 3).

The results of the base and sensitivity case are provided in Table 3 and summarized below.

Table 3. Base and Sensitivity Results

Scenario	Total Cost (M$)	Cost per unit of PFR ($/MW-h)
Base	13.0	3.93
1.5x	18.4	3.72
2x	28.4	4.31
RE	12.2	3.66
Only Gas CCs	66.2	20.09

A main assumption about CAISO's PFR constraint is that hydro will be available to provide 50% of the requirement. Based on CAISO's operating experience, hydro is a sufficiently flexible and dependable resource that this requirement is not actually modeled—the requisite PFR requirement is simply halved. However, recent droughts have impacted the hydroelectric generation in the state, and during the 2014 drought, hydroelectric generation dropped in California by roughly 50% [44]. The impacts that a sustained drought may have on hydro contributions to ancillary services are unclear. In this sensitivity, we examine the impact of a reduced ability of hydro to provide PFR; we increase the PFR requirement from the base case (376 MW) by 150% (to 564 MW) and 200% (to 752 MW). We assume this PFR must be derived from other eligible resources (gas CCs and battery storage). The results show a roughly linear increase in total costs, with relatively small changes in per unit cost.

In our base case, we do not allow renewables to provide frequency response. But, both wind and PV are technically capable of providing this service, and wind turbines are now required to have this capability in ERCOT. So, we evaluated a case where renewables are allowed to provide PFR. It is important to emphasize that to provide upward reserve capacity, these generators must be able to increase their output, meaning they were dispatched below their available capacity to begin with (pre-curtailed). This inherently limits the economics of providing PFR (or any reserve) from wind and solar. This only occurs economically when curtailment must occur for some other reason, or when the price of reserves is greater than the price of energy, which is rare. As a result, due to the limited amount of curtailment in the base case (enabled in part by the additional storage), we see somewhat limited value in allowing curtailed renewable energy to contribute to frequency response. Overall, PFR costs drop by about 7%.

Finally, we examine the impact of disallowing batteries to provide PFR by allowing only CCs to provide PFR. In the base case, over 95% of the PFR requirement is provided by battery storage. Unsurprisingly, requiring the gas fleet to provide the required capacity for PFR leads to a significant increase in the cost. This increased cost is caused by greater part-loading of CCs providing reserves as well as increasing use of higher heat rate units.

Conclusions

Modeling ancillary services is important for a full understanding of the reliability aspects of power system operations. Furthermore, the importance of understanding these services will only increase as nonconventional (and often nonsynchronous, or inverter-based) generation continues to grow on the system. Historically, economic dispatch was often enough to ensure sufficient capacity for certain types of reserves on the system, although these products will soon need to be considered explicitly. For example, primary frequency response (PFR) is a service conventionally provided by online units with functioning governors on their turbines to ensure the system can adequately respond to changes in frequency. However, this service can be provided by other forms of generation as well, but the implications of changing generator mixes on PFR is not yet well studied or understood. Many modern commercial production cost models can incorporate multiple types of ancillary services, so including PFR in future grid studies should be possible. To this end, we discuss a method for incorporating PFR into grid systems models and the many complexities associated with it. Then, we incorporate our methodology into a large and realistic power system (the U.S. Western Interconnection) to observe the impacts of a PFR constraint on dispatch and costs. Like other studies, we find that the impacts of such a constraint are generally small, but dependent on underlying assumptions. One major underlying assumption is which generators are enabled to provide PFR. Real-world data have indicated that the number of generators that can actually provide this essential service are limited [13], and therefore the impact of the PFR constraint may be slightly understated here. Furthermore, the role of PFR will continue to evolve as renewable generation increases beyond the levels studied here, meaning that proper markets and incentives must eventually exist for PFR to be a valued service. The work presented in this report presents a framework for other modelers and analysts to consider the relative importance of modeling PFR in other systems.

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