CPS1-compliant Economic Dispatch for a Single Balancing Authority System

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***Abstract*—The integration of variable generatio to power systems has led to a revision of ancillary service definitions. In the case of secondary frequency control, these concerns are related with the dimensioning of reserves to cope with variability and uncertainty, and, ultimately, with the compliance with performance standards. One of such a performance standards used in North America is the Control Performance Standard 1 (CPS1), that measures the contribution of a balancing authority to frequency control within an interconnection. This paper proposes an Economic Dispatch formulation that ensures CPS1 compliance in the case of a single balancing authority. The formulation assumes that the ramping capability of units and generation variability and uncertainty are given, and determines the optimal procurement of secondary reserves to comply with CPS1. An explanatory example will be presented.**

I. Introduction

Secondary frequency control is defined by the North American Reliability Council (NERC) as the "control that maintains the minute-to-minute [demand-generation] balance throughout the day [1]." In that context, CPS1 is defined as a "frequency-sensitive evaluation of how well its [balancing authority] demand requirements were met [1]." Consistent with these definitions, Secondary Reserves (SR) will be considered in this work as the system capacity and ramping capability dimensioned and procured for secondary control operation to comply with CPS1.

Variable generation (VG) establishes an increment in the requirement for SR. The Variability and Uncertainty (V&U) of these resources (wind and solar power, for example) is significantly larger than that of traditional generation or load per unit of power [2], so the integration of VG increases the intra-day overall V&U. This increment in V&U leads to new requirements for SR to both cope with the incremental V&U and comply with control performance Standards [3].

In general, the dimensioning SR represents a problem that can be seen as three sub-problems:

- to estimate the V&U from VG in function of VG installed capacity,
- to estimate SR to cope with such V&U, and
- to comply with CPS1.

The estimation of V&U per unit of VG installed capacity has been intensely treated in the literature. Most studies model VG as a stochastic process and obtain the standard deviation of the intra-dispatch forecast error to model V&U [4], [5], [6]. The forecasting error does not vary significantly amongst different algorithms [2], [7], suggesting that appropriate models to estimate V&U per unit of VG capacity have been developed. This work will assume that the standard deviation of the intra-dispatch forecast error modeling V&U, namely σ_{VG}, is known for the analysis.

The estimation of SR to cope with VG has also being treated in various works, and the majority of such works consider that the amount of SR to cope with σ_{VG} is equivalent to $n\sigma_{VG}$, for some $n > 0$. The criterion is based in the symmetrical shape of the histogram of load and VG forecast error, so the standard deviation is a valid measure of dispersion [8], [9], [10]. Normally, n is determined to be 3 to cover a significant amount of the deviations (99.73% of the samples in the case of a normal distribution), which is known as the "3-sigma rule." [11]. However, these dimensioning criteria does not consider the performance of frequency control that involves frequency response dynamics and indexes of performance, such as CPS1 that considers samples of system frequency. The performance of frequency control will depend not only on a capacity constraint, but also on how fast such a capacity can be deployed.

Compliance with CPS1 is not currently considered in a systematic manner into SR dimensioning. The 3-sigma rule is based on satisfying the capacity requirement to cope with VG, but the ramping capability of units is not taken into account [12]. For example, the ramping capability of SR depends on the number of units that provide such a reserve; the more units share the requirement, the faster the response is. In the Electric Reliability Council of Texas (ERCOT), a capacity constraint is being associated with a ramping capability requirement, which may limit the amount of capacity that a generator can offer into the Ancillary Service (AS) market [3].

The dimensioning of SR does not consider CPS1 compliance, so the various formulations including SR in dispatch frameworks do not ensure CPS1 compliance as well. SR dispatch constraints have been developed in various ways: the consideration of fast-starting units in SR [13], the inclusion of ramping capability [14], or the market valuation of SR in terms of the actual, real time contribution of SR providers to frequency control [15]. However, none of these works have developed a formulation including performance standards compliance into system dispatch.

This paper will first develop a constraint to ensure CPS1 compliance through an Economic Dispatch formulation. The formulation considers that the standard deviation representing VG V&U is known, as well as the ramping capability of units participating in the SR market. The proposed formulation will determine the optimal dispatch satisfying CPS1. An illustrative example will be presented to test the proposed formulation.

II. AGC, ACE, AND CPS1

For simplicity, only one balancing authority will be considered. One balancing authority is equivalent to one AGC system operating one single interconnection. In general, several balancing authorities with different AGCs are defined over large interconnections, such as the Western Interconnection or the Eastern Interconnection in North America. For example, the Western Interconnection consists of 37 balancing authorities as shown in [16] (Fig.1).

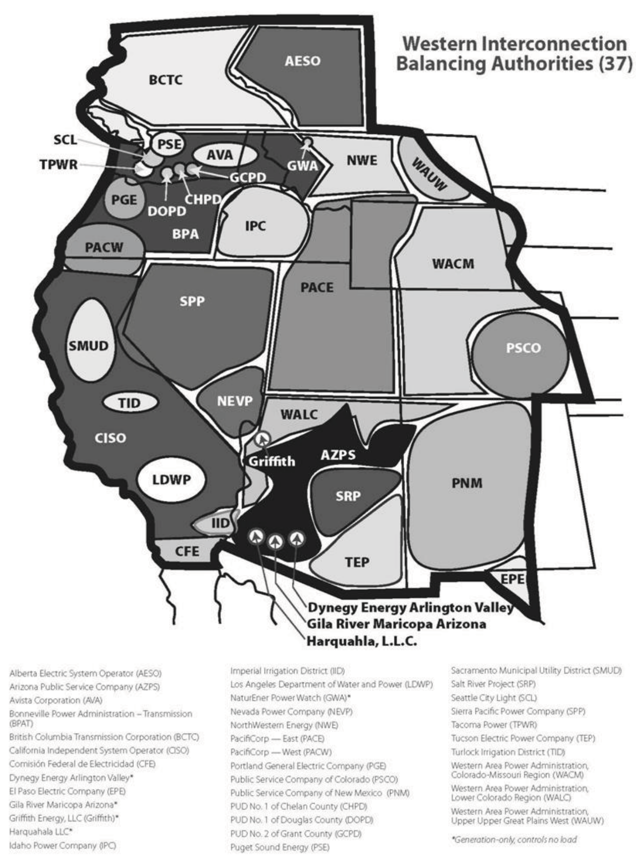

Fig. 1. Western Interconnection balancing authorities

CPS1 definitions are also simpler in the case of a single balancing authority, because there are no tie-line flows. ERCOT, for example, is the interconnection of the state of Texas, which is not synchronously interconnected to any other interconnection and has only one AGC system.

A. Definition of CPS1

Several definitions are needed to formulate the CPS1 criterion. The Area Control Error (ACE) is a measurement of power imbalance:

$$\mathrm{ACE} = I_A - I_S - 10B(\overline{\Delta f}_{1m}). \tag{1}$$

I_A and I_S are the actual and scheduled tie-line flows respectively, $\overline{\Delta f_{1m}}$ is the one-minute average of 4-second samples of system frequency deviations , and B is the frequency "bias" (the expected MW/Hz response from a balancing authority).

CPS1 is defined as:

$$\mathrm{CPS1} = \left(2 - \frac{\mathrm{ACE}}{-10B}\frac{\overline{\Delta f}_{1m}}{\epsilon^2}\right) \cdot 100\%, \tag{2}$$

where ϵ represents the historical performance of regulation defined by the NERC [1].

In a single-balancing authority $I_A - I_S = 0$, so CPS1 can be simplified as follows:

$$\mathrm{CPS1} = \left(2 - \frac{\overline{\Delta f}_{1m}{}^2}{\epsilon^2}\right) \cdot 100\%. \tag{3}$$

The NERC requires that the one-year average of CPS1 be larger or equal to 100% for the area to comply with the requirement, which is equivalent to

$$\overline{\left(\overline{\Delta f}_{1m}{}^2\right)_{1year}} \leq \epsilon^2. \tag{4}$$

This is the CPS1 compliance criterion in a single balancing authority.

B. Dynamic and Dispatch Variables

The Automatic Generation Control (AGC) system is the control system that regulates minute-to-minute frequency deviations. General AGC schemes [17] require steady state error to be zero and integral terms to compensate for inadvertent tie-line flows; in the case of a single balancing authority, integral terms are not required as there are no tie-line flows. An AGC structure is depicted in Fig. I.

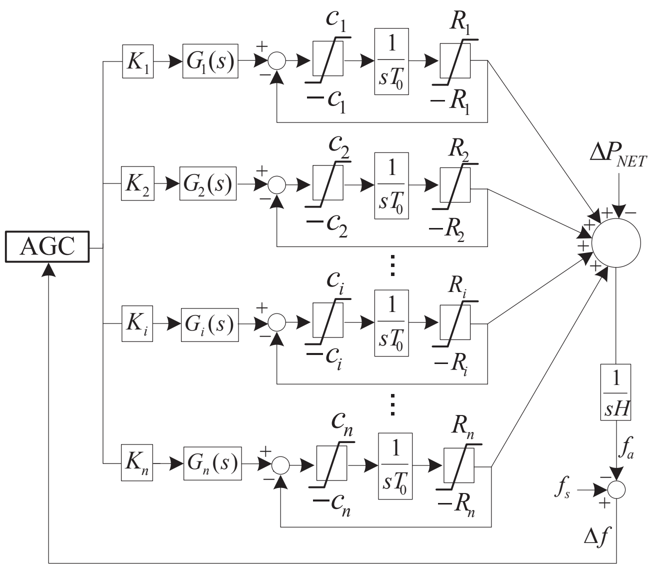

Fig. 2. AGC block diagram

In Fig. 2, f_a and f_s are the actual and scheduled system frequency, ΔP_{NET} (MW) is the power imbalance caused by the intra-dispatch deviations between actual generation and actual load, $G_i(s)$ represents the dynamics of generator i, H (MWs/Hz) represents the inertia of the system, and T_0 is a small number. Also, c_i (MW/min) is the ramping capability of generator i and R_i (MW) is the capacity for regulation available from generator i.

In real time operation, the AGC system defines a controller that sends commands to generator providing regulation, which respond to the command according to its inner dynamics and its physical capabilities R_i and c_i. There is a gain K_i that distributes the AGC responsabilities to generators according to the procured capacity R_i. System dispatch determines R_i, and takes c_i into account to make sure that the total ramping capability is enough for the total generation capability to follow forecasted demand. However, it is not ensured that the remaining ramping capability is enough at all times to also allow for the AGC system to operate.

III. CPS1-COMPLIANT AGC

This section summarizes the findings of [18] defining the AGC dynamics that lead to CPS1 compliance. For the analysis, ΔP_{NET} is divided into two components, one from the load, ΔP_{LOAD}, and another from the generation ΔP_{VG}. Let σ_{VG} and σ_{LOAD} the standard deviation of the variability from generation and load respectively. The expression for CPS1 compliance in a single balancing authority determining the AGC proportional gain is given by:

$$K_{AGC} \geq \frac{1}{\epsilon B}\sqrt{\sigma_{VG}^2 + \sigma_{LOAD}^2}, \tag{5}$$

where K_{AGC} is the AGC gain, ϵ is the CPS1 requirement of the interconnection given by the authority and B is the expected frequency response from the balancing authority.

In [19], the capacity REG (MW) and ramping capability RREG (MW/min) needed to operate under (5) are shown and considered as follows:

$$\text{REG} = 3\sqrt{\sigma_{VG}^2 + \sigma_{LOAD}^2} \ \text{(MW)}. \tag{6}$$

$$\text{RREG} = \frac{3\sqrt{2}}{\Delta T}\sqrt{\sigma_{VG}^2 + \sigma_{LOAD}^2} \ \text{(MW/min)}. \tag{7}$$

where ΔT is the economic dispatch interval. These relationships are fundamental to determine a dispatch that complies with CPS1.

IV. CPS1-CONSTRAINED ECONOMIC DISPATCH

This section analyses the CPS1-compliant AGC to formulate a constraint suitable to be included in the OPF to guarantee CPS1 compliance. The analysis is focused on determining the minimum capacity and ramping capability needed to establish the CPS1-compliant AGC functioning, and then constraints are formulated.

A. Current Formulation

The classical Economic Dispatch formulation is as follows:

$$\min \left(\sum_{k\in\mathcal{K}} \sum_{i\in\mathcal{I}} e_{i,k}(P_{i,k}) + \sum_{k\in\mathcal{K}} \sum_{i\in\mathcal{I}} s_{i,k}(R_{i,k}) \right) \tag{8a}$$

$$\text{s.t.} \sum_{i\in\mathcal{I}} P_{i,k} = \sum_{j\in\mathcal{J}} d_{j,k}, \quad k \in \mathcal{K} \tag{8b}$$

$$\sum_{i\in\mathcal{I}} R_{i,k} \geq \text{REG}, \quad k \in \mathcal{K} \tag{8c}$$

$$\left| \frac{P_{i,k} - P_{i,k-1}}{\Delta T} \right| \leq c_i, \ k \in \mathcal{K}, \quad i \in \mathcal{I}, \tag{8d}$$

$$R_{i,k} \leq \overline{R}_{i,k}, \quad k \in \mathcal{K}, \quad i \in \mathcal{I}, \tag{8e}$$

$$P_{i,k} + R_{i,k} \leq \overline{P}_i, \quad k \in \mathcal{K}, \ i \in \mathcal{I}, \tag{8f}$$

$$P_{i,k} - R_{i,k} \geq \underline{P}_i, \quad k \in \mathcal{K}, \ i \in \mathcal{I}, \tag{8g}$$

$$P_{i,k}, R_{i,k} \geq 0, , \quad k \in \mathcal{K}, \ i \in \mathcal{I}, \tag{8h}$$

where

- $i \in \mathcal{I}$: set of generators,
- $j \in \mathcal{J}$: set of loads,
- $k \in \mathcal{K}$: set of dispatch intervals,
- P_i : generator i dispatch (MW),
- $e_i(P_i)$: generator i energy cost function ($/h),
- R_i : generator i secondary reserve (MW),
- $s_i(R_i)$: generator i R cost function ($/h),
- c_i : generator i total ramp rate (MW/min),
- $\overline{P}_i$: generator i total capacity (MW),
- $\underline{P}_i$: generator i minimum output (MW),
- $\overline{R}_i$: generator i maximum R (MW),
- d_j : load j (MW),
- ΔT : dispatch time interval,

The objective function (8a) represents the total dispatch cost that is minimized. Constraint (8b) is the power balance at all periods, constraint (8c) represents the total reserve constraint that must be larger or equal to the required reserve REG, (8d) is the ramping capability constraint that prevents two consecutive dispatch instructions to be faster than the ramping capability of each generator, constraint (8e) represents an offered reserve constraint if any, constraint (8f) represents total capacity constraint for the upper limit and regulation up, constraint (8g) represents total capacity constraint for the lower limit and regulation down, and constraint (8h) are non-negativity of the variables.

Note that this formulation does not ensure that enough ramping capability is placed for the AGC system.

B. Proposed formulation

The proposed formulation includes a restriction on the ramping capability needed to maintain AGC operation.

Let $\frac{\mathrm{d}P(t)}{\mathrm{d}t}{}^{AGC}_{i,k}$, $t \in \Re$ the ramping capability contribution of unit i during period k to the AGC operation. This contribution may not be constant as the generator response to the AGC system is dynamic. However, one can consider that the ramping capability of unit i can be approximated by a constant $c^{AGC}_{i,k}$, assuming worst case scenario conditions:

$$c^{AGC}_{i,k} t \leq \int_0^t \frac{\mathrm{d}P(t)}{\mathrm{d}t}{}^{AGC}_{i,k}, t \in [0, \Delta T],\ k \in \mathcal{K},\ \ i \in \mathcal{I} \tag{9}$$

This worst case approximation can be seen in Fig. 3.

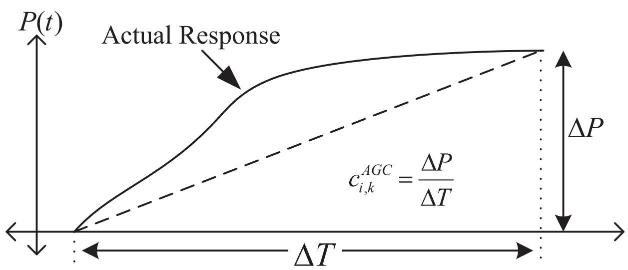

Fig. 3. Worst case definition for $c^{AGC}_{i,k}$

Then, a necessary condition can be formulated using the definition of $c^{AGC}_{i,k}$:

$$\sum_{i \in \mathcal{I}} c^{AGC}_{i,k} \geq \text{RREG},\ k \in \mathcal{K}. \tag{10}$$

Note that (10) is a stronger than necessary condition as (9) holds.

One can assume that $c^{AGC}_{i,k}$ is defined to be the ramping capability that allows generator i to ramp to the reserve capacity $R_{i,k}$ within a dispatch interval:

$$c^{AGC}_{i,k} \geq \frac{R_i}{\Delta T}\ i \in \mathcal{I}\ k \in \mathcal{K},\ \ i \in \mathcal{I}. \tag{11}$$

This relationship express that $\frac{R_i}{\Delta T}$ is the lowest constant ramp that can occur while dispatching R_i, as shown in Fig. 3

Then, considering (11) and (10),

$$\sum_{i \in \mathcal{I}} c^{AGC}_{i,k} = \sum_{i \in \mathcal{I}} \frac{R_{i,k}}{\Delta T} \geq \text{RREG},\ k \in \mathcal{K}. \tag{12}$$

Then, this ramping constraint has to be included in the general ramping constraint (8d). As $c^{AGC}_{i,k}$ is associated to a particular unit i, this ramping capability constrain must be added to the other constraint on the ramp:

$$\left| \frac{P_{i,k} - P_{i,k-1}}{\Delta T} + \frac{R_i}{\Delta T} \right| \leq c_i,\ k \in \mathcal{K},\ \ i \in \mathcal{I}, \tag{13}$$

Thus, the CPS1 compliance-constrained economic dispatch is shown below:

$$\min \left(\sum_{k \in \mathcal{K}} \sum_{i \in \mathcal{I}} e_{i,k}(P_{i,k}) + \sum_{k \in \mathcal{K}} \sum_{i \in \mathcal{I}} s_{i,k}(R_{i,k}) \right) \tag{14a}$$

$$\text{s.t.} \sum_{i \in \mathcal{I}} P_{i,k} = \sum_{j \in \mathcal{J}} d_{j,k},\ \ k \in \mathcal{K} \tag{14b}$$

$$\sum_{i \in \mathcal{I}} R_{i,k} \geq \text{REG},\ \ k \in \mathcal{K} \tag{14c}$$

$$\left| \frac{P_{i,k} - P_{i,k-1}}{\Delta T} + \frac{R_{i,k}}{\Delta T} \right| \leq c_i,\ k \in \mathcal{K},\ \ i \in \mathcal{I} \tag{14d}$$

$$\left| \frac{P_{i,k} - P_{i,k-1}}{\Delta T} - \frac{R_{i,k}}{\Delta T} \right| \leq c_i,\ k \in \mathcal{K},\ \ i \in \mathcal{I} \tag{14e}$$

$$R_{i,k} \leq \overline{R}_{i,k},\ \ k \in \mathcal{K},\ \ i \in \mathcal{I} \tag{14f}$$

$$P_{i,k} + R_{i,k} \leq \overline{P}_i,\ \ k \in \mathcal{K},\ \ i \in \mathcal{I} \tag{14g}$$

$$P_{i,k} - R_{i,k} \geq \underline{P}_i,\ \ k \in \mathcal{K},\ \ i \in \mathcal{I} \tag{14h}$$

$$P_{i,k}, R_{i,k} \geq 0,,\ \ k \in \mathcal{K},\ \ i \in \mathcal{I}, \tag{14i}$$

$$\sum_{i \in \mathcal{I}} \frac{R_{i,k}}{\Delta T} \geq \text{RREG}\ k \in \mathcal{K}. \tag{14j}$$

V. Example

The example consists on four generators and one load connected to a single bus as shown in Fig. 4.

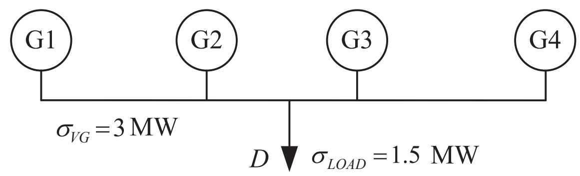

Fig. 4. Simulation Diagram

The parameters of the generators are given in Table I.

TABLE I
GENERATION PARAMETERS

Gen.	Marg. cost ($/MW)	$\overline{P}_i$ (MW)	$\underline{P}_i$ (MW)	c_i (MW/min)
G1	1.5000	105	10	3.5
G2	4.9000	80	20	0.3
G3	10.0000	50	20	0.1
G4	19.6000	160	10	0.1

The simulation will consider 3 periods, the offer for reserves to be null ($s_{i,k}(R_{i,k}) = 0$) and ΔT = 10 min. The reserve requirement for σ_{LOAD} = 1.5 MW and σ_{VG} = 3.5 MW, is REG = $3\sqrt{\sigma_{VG}^2 + \sigma_{LOAD}^2} \approx$ 10 MW, and RREG = 1.4 MW/min. The demand profile is given in Table II.

TABLE II
DEMAND PROFILE

Period	0	1
Demand	155	176

The first period is the initial condition of the dispatch, and period 1 will show the dispatch instruction.

The dispatch results with and without the CPS1-compliance constraint is shown in Table III.

TABLE III
DEMAND PROFILE

	Without CPS1 constraint				With CPS1 constraint		
gen	P_0 MW	P_1 (MW)	R_1 MW		P_0 MW	P_1 (MW)	R_1 MW
G1	88	105	0		83	100	5
G2	37	40	$\frac{10}{3}$		42	45	3
G3	20	20	$\frac{10}{3}$		20	20	1
G4	10	10	$\frac{10}{3}$		10	10	1
Price	—	4.9	0		—	4.9	3.4

For the dispatch without the CPS1 constraint, the energy price is consistent with the marginal unit, which is unit 2 (the other units operate at minimum output). The price for reserves is zero, consistent with the fact that reserve offers are zero as well. Generator 1 is fully dispatched in period 1 because its ramping capability (3.5 MW/min) is enough to ramp from 88 MW to 105 MW. to satisfy demand, generator 2 has to be dispatched, setting the price.

For the dispatch with the CPS1 constraint, unit 1 is prevented from being fully dispatched, because it is needed to satisfy the ramp rate constraint associated with the AGC operation. The other units are not fast enough to satisfy the ramp constraint, and for the 10 min period unit 3 and 4 can only increase output power by (0.1 MW/min)(10 min) = 1 MW, which is the dispatched reserve quantity for both units 3 and 4. Unit 2 can increase output power by (0.3 MW/min)(10 min) = 3 MW, which is the dispatched reserve quantity of unit 3. The rest (5 MW) are provided by unit 1 that has a ramping capability of 3.5 MW/min.

Note that the price for reserves is not zero in period 1, even if reserve offers are null. For reserve prices to be consistent with the profit maximizing behavior of generators, such prices must ensure that generators are indifferent between being dispatched to produce energy or to provide reserves. In such an scenario, reserve prices should increase if an inexpensive generator is necessary for reserve provision, even though reserve bids are all assumed to be zero. In the dispatch case in Table III, period 1, generator 1 has a constant marginal cost of 1.5 \$/MWh, and the energy price is 9.8 \$/MWh, so generator 1 would maximize its profit if it were fully dispatched. In the example, generator 1 increases its profit by 4.9 - 1.5 = 3.5 \$/h for each additional MW of dispatched capacity, so if the price for reserves is set to 3.4\$/MW, the generator would be indifferent between producing energy at 4.9\$/MWh or providing reserves at 3.4\$/MW. This representation of the opportunity cost is intrinsically defined into the formulation.

VI. CONCLUSIONS AND FUTURE WORK

The proposed formulation ensures CPS1 compliance by dispatch instruction within a single balancing authority. The results are consistent with economic principles of economic dispatch.

Future work is proposed to expand de formulation to a multi balancing authority system as the one depicted in Fig. 1. The representation of multi balancing authority systems is not unmediate as tie-line flows are different from zero and the AGC controller must include integral gains to ensure tie-line flows consistent with system dispatch. Also, balancing authorities in multi balancing authority systems must also comply with the Control Performance Standard 2 (CPS2) that limits the net deviations of ACE from zero within a balancing authority.

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