Determining the Cost of Dynamic Control Capacity for Improving System Efficiency

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***Abstract*— In this paper, we propose an approach to determining the cost of supplying the dynamic control capacity (DCC) necessary to ensure that the system operates without stability problems over a well-defined range of demand variations and system contingencies. This approach addresses the problem of finding an economically efficient combination of controllers and reserves to provide reliability and security economically and in a technically adequate way. In particular, we discuss the cost of providing DCC as a function of system dynamic performance (DP) metrics. The choice of performance metrics is critical for deciding the installation of controllers in power systems. In this paper, we illustrate the approach using the primary control problems of transient stability and primary voltage control.**

***Index Terms*— Power system control, Power system economics, Power system reliability, Power system security.**

I. INTRODUCTION

This paper is motivated by the need to assess the potential of enhancing performance of an electric power system by a variety of control techniques. The technologies vary significantly in type, rate of response, capacity, and the quality of their performance as operating conditions vary.

Of particular interest is the dependence of the system reliability and security on the amount of reserves and the type of control.

As electric power systems undergo major changes with respect to how they are utilized, it becomes essential to design for predictable, and well-understood dynamic performance (DP). The main reason for this re-assessment comes from several factors:

- The main objective of current automated control in an electric power system is to correct deviations around the nominal. The control is not intended to ensure automated system response during major equipment failures and/or excessive load variation. Instead, equipment failures are managed based on human decisions, that is, through the use of expert knowledge about the specifics of their utility, and/or off-line simulations concerning worst case scenarios.
- Today's practice of enabling the human operator to respond to failures critically depends on having reserves [1] [2].

In this paper, we observe that the actual stand-by capacity and reserve required, and their types, greatly depend on the specifics of dynamic problems that may take place when failures occur. For example, it has been known that the Western Electricity Coordinating Council (WSCC) is more prone to stability problems than the Northeast Power Coordinating Council (NPCC) in the United States. This is a consequence of system characteristics. The WSCC is a longitudinal system, and the NPCC is strongly meshed. Another particular case is the Argentinean system where, due to the relatively small inertia and connectivity of the system, the system is more prone to frequency stability problems when a generator failure occurs than other interconnected systems [2] [3].

Determining the most adequate type and amount of reserves necessary to ensure guaranteed performance is generally very complex. There are no methodologies in place for this purpose.

We propose in this paper that the total capacity/reserve amount depends on:

- The type of control present in the system; and
- The coordination of available control equipment

Therefore, it is important to evaluate the effect of the combination of controllers and reserves on the Dynamic Performance (DP) metrics of interest in order to arrive at adequate levels of power system reliability and security.

An important issue is how to define Dynamic Performance (DP) metrics in order to guarantee that the system variables stay within the security limits and the reliability is acceptable. Some examples of candidate performance metrics are given in Section II-B. However, system performance is a multidimensional property, and there are no single metrics that encompass all possible dynamic problems in power systems.

In general, the system DP depends on the possible disturbances and combination of reserves and controllers present in the system. That is, in order to improve it, better controllers (control hardware, logic, and coordination)

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combined with the use of reserves may be needed. Since unconditional improvements in DP are prohibitive in cost and system design, a trade-off between levels of DP acceptable by the system users and choice of controllers and reserves needs to be made. The levels of DP seen by the system users closely affect the levels of reliability and security provided to them and to the system as a whole. Examples of deciding the levels of reliability and security are discussed in reference [4], and it is also a part of our ongoing work [5].

In this paper, we consider the problem of determining the cost of supplying dynamic control capacity (DCC) and the costs necessary to ensure that the system operates without stability problems over well-defined ranges of demand variations and system contingencies. Our approach addresses the problem of finding an economically efficient combination of controllers and reserves to provide reliability and security economically and in a technically adequate manner. In particular, we discuss the cost of providing DCC as a function of system dynamic performance (DP) metrics. The choice of this function is critical for deciding the installation of new controllers in power systems. In this paper, we illustrate the proposed concepts using transient stability, and primary voltage control examples.

II. Background

A. The Power System Model

The power system can be described by equations (1), (2), (3) and (4). Equations (1) to (3) represent the machine dynamics, and are subject to the network equations (4)

$$\dot{\delta} = \omega - \omega_0 \qquad (1)$$

$$\dot{\omega} = f_1(T_m, E, i, \omega) \qquad (2)$$

$$\dot{E} = f_2(E, i, E_{fd}) \qquad (3)$$

$$\begin{cases} P = g_1(E, \delta, y_n) \\ Q = g_1(E, \delta, y_n) \\ V = g_1(E, \delta, y_n) \end{cases} \qquad (4)$$

Power system dynamics can be influenced by the primary controllers that generally respond to local measurements. These controllers can be modeled by the general equations (5), (6), and (7). Equations (5) and (6) represent the generator controllers (governor-turbine-machine controller (5), excitation controller (6)). Equation (7) represents an injection of reactive power that can be provided by FACTS devices, such as SVC.

$$\dot{T}_m = h_1(T_m, \omega_{local}) \qquad (5)$$

$$\dot{E}_{fd} = h_2(E_{fd}, V_{local}) \qquad (6)$$

$$\dot{Q}_{inj} = h_3(Q_{inj}, V_{local}) \qquad (7)$$

In this paper we simulate this system using the software Eurostag [6].

B. Dynamic Performance (DP) Metrics

An important issue is how to define Dynamic Performance (DP) metrics in order to guarantee that the system variables stay within the security limits and that the reliability is acceptable. Some candidate performance metrics are:

- Frequency deviations;
- ACE deviations (frequency and inter-area power transfer) [7];
- Voltage deviations;
- Voltages at a strategic set of buses, and reactive power generated in some units [8] [9];
- Critical Clearing Time CCT (transient stability) [10];
- Based on energy functions [11];

In this paper, we propose a systematic approach to defining adequate dynamic performance (DP) metrics for a) a given system topology, type of generation, and given load characteristics for normal operation; b) the range of demand variations around normal, and the class of contingencies for which DP metrics are defined; c) technical system user specifications, such as acceptable frequency and voltage deviation around the nominal; as well as the rate of acceptable interruptions; and d) economic system user specifications, such as the basic willingness to pay for reliability and security. We first outline our basic framework. This is followed by an illustration on a simple 3-bus system (see Fig. 1) and a specific set of disturbances, where the cost of providing dynamic control capacity (DCC) as a function of a chosen DP metrics is also addressed. Tradeoffs between the DCC cost and the economic implications of points c) and d) indicated in this paragraph, should be analyzed. This analysis is the objective of our ongoing research [5], and it is not going to be addressed in this paper.

The disturbances of interest are a step increase in reactive power load; this disturbance can be interpreted as the failure of reactive power compensation equipment, such as a bank of capacitors. The acceptable voltage and frequency deviations are ΔV_1 and Δf_1.

A DP metrics consisting only of ΔV is not sufficient in this case because step disturbance also causes frequency oscillations. In order for Δf to be within the pre-specified threshold Δf_1 it is necessary to monitor both frequency dynamics and steady state voltage off-set due to this disturbance.

Moreover, we observe that the choice of adequate DP metrics also depends on the type of controllers in place. When an automatic voltage regulator (AVR-generator) and a static Var compensator (SVC) are used, see Fig. 2 (a). It can be seen in Fig 2 (a) that SVC has a better dynamic performance (DP) than the AVR-generator as measured by the voltage deviation ΔV during the first 10 seconds of simulation. However, an SVC introduces more frequency oscillations between G1 and G2 than an AVR-generator does (as seen by comparing Fig. 2 (b) and (c)). This comparison reveals that we cannot only care

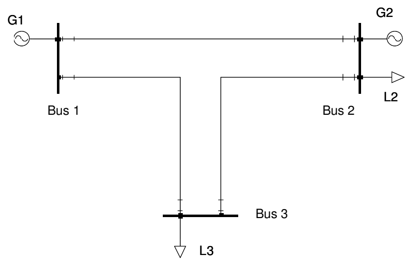

Fig. 1: A simple 3-bus power system

about ΔV when measuring dynamic performance (DP). Instead, we also need to view DP as a multidimensional property, and more work on defining an adequate DP needs to be done.

In this particular case, frequency oscillations can be damped by using supplementary control, such as power system stabilizers (PSS) at G1 or G2. Again, ΔV alone does not give an appropriate dynamic performance indication.

Even in this simple example one can see that the choice of adequate DP metrics for ensuring acceptable service to the system users is a difficult and not uniquely defined problem. The system operators play a major role in the effective use of reserves and controllers

C. *The Role of Control in Ensuring Reliable Operations*

The current approach to a reliable system operation is to ensure sufficient generation spinning reserve in order for the system to remain stable during critical equipment failures and load variations.

However, when the equipment failure causes extremely fast instabilities, such as transient instability created by a short circuit of a system transmission line, generally there are not many fast controls available for stabilizing the system. To illustrate this, consider the system shown in Fig. 1, subject to a three-phase short-circuit fault in the transmission line 1-2. This system (Fig. 1) consists on 2 groups of thermal generators, G1 and G2, and two loads, L2 and L3 are modeled as constant impedances. Without any fast control, the critical clearing time (CCT) for the transmission line protection is 139ms. The system response for this case is shown in the *Base Case* curve in Fig. 3, implying that if the over-current, or distance protection system responds slower than the CCT, the overall power system will lose synchronism and a full-blown blackout will occur.

In order to prevent this from happening, possible alternatives including fast control (see Fig. 3) are: *Alternative A*- fast valving in generator 1; *Alternative B*- an a priori limited power transfer in line 1-2 during normal operation of an amount that would not cause transient instability in the case of line failure [1]; *Alternative C*- novel high-gain control of generator excitation (such as FBLC-ODSS [12], or others [13]); *Alternative D*- high-gain controllers of transmission line flows (FACTS devices [14]); and *Alternative E*- FACTS + energy storage (ES) devices, an example being superconducting magnetic energy storage (SMES) [15] [16] [17] [18].

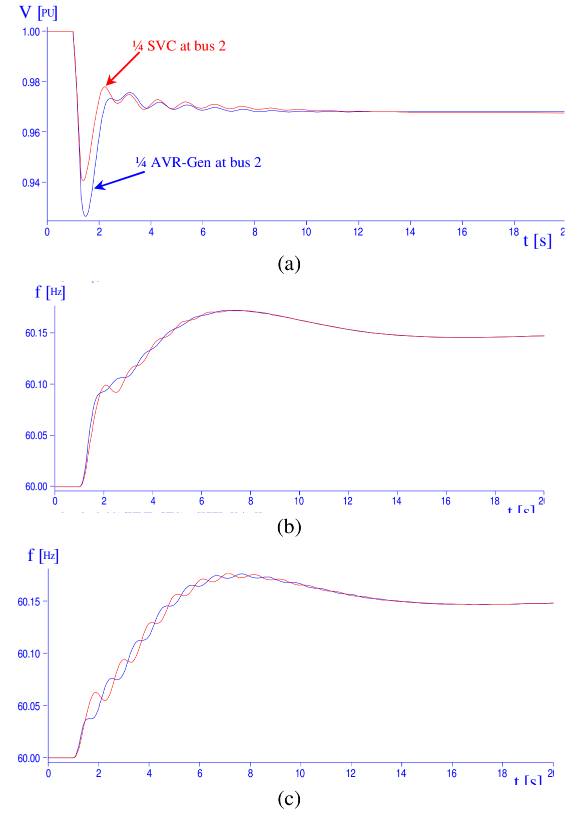

Fig. 2: (a): Voltage at bus 2 for cases with AVR-Gen at bus 2; and with SVC at bus 2; when there is a step change reactive power at bus 3. And machine speeds for the cases with AVR-Gen at buses 1 and 2 (b); with AVR-Gen at bus 1 and SVC at bus 2 (c)

We believe that *Alternative B* is the most common practice of avoiding transient stability for the worst-case scenarios in today's industry. In our illustration, *Alternative B* is achieved by dispatching 50MVA more capacity at bus 2, and 50MVA less at bus 1, as is shown in Tables I and II. Notice that we are not modifying the amounts of spinning reserves present in the system; we are just shifting some capacity committed at bus 1 to bus 2. The economic implications of *Alternative B* are discussed in section II-D.

For illustration purposes, we show in Fig. 3 the effects of having *Alternatives A, B* and the *Base Case* in the system response. The values of critical clearing time (CCT) for these alternatives are shown in Table III. We observe that system-wide response greatly depends on three main factors: (a) controller logic; (b) the type of controller used (compare *Alternatives A, and the Base Case*); and (c) the a priori power transfer limits (compare *Base Case, Alternative A, and B*). As we can see in Fig. 3, Alternative B stabilizes the system faster than Alternative A; this is coherent with the CCT values shown in Table III. Then, we can argue that the CCT is a dynamic performance (DP) metrics relevant for transient stability. How good this DP metrics is for measuring transient instability is an open question.

In summary, we have illustrated that there exist several technically equivalent alternatives to deal with dynamic problems in power systems.

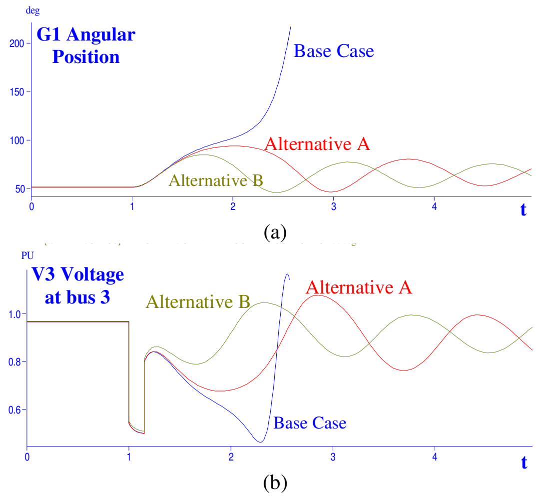

Fig. 3: Angular position generator group 1 (a), and the voltage of bus 3 (b) for the Base Case and Alternatives A, B; when the short circuit in line 1-2 is cleared 150ms after.

D. Economic Implications

There are two major economic implications directly dependent on the choice of dynamic control capacity (DCC) in power systems: using out-of-merit generation, and missed-opportunity cost due to the use of generation reserves. The former is mainly used due to constraints created by the need for generation reserves and limits on power transfer. The use of out-of-merit generation usually results in an increase of the price of energy. The second implication is the missed-opportunity cost incurred by the generators that cannot sell energy in the energy market, because they supply spinning reserves to the system. The cumulative costs of these two effects need to be considered with new control hardware, or when assessing control coordination and enhanced logic. In this section, we first illustrate the cost of using out-of-merit generation to avoid transmission line congestion. The missed-opportunity costs incurred by generators are discussed here and then illustrated in Section IV.

In Section II-C, we illustrated the technical implications of setting an a priori limit in power transfer in line 1-2 to account for transient stability problems (*Alternative B*), and using fast valving control (*Alternative A*). Limiting power transfer in line 1-2 implies the use of out-of-merit generation in bus 2 and not committing cheaper generation at bus 1 (assuming that the *Base Case* dispatch is the optimum unconstrained one). Therefore, *Alternative B* has a higher price of energy on the energy market.

For illustration purposes, we assume that the price of energy for the *Base Case* is 46$/MWh; and for *Alternative B*, the price of energy is 48$/MWh. Assuming that this situation is repeated for 5 hours every day, and every day in one year, the cost of *Alternative B*, and the cost of using out of merit generation can be calculated with equations (8) and (9). Equation (8) formulates the cost of energy for one day assuming an hourly energy market.

TABLE I
GENERATION DISPATCH FOR BASE CASE AND ALTERNATIVE A

	Pg [MW]	Pmax [MW]		PL [MW]	QL [Mvar]
G1	550	600	L2	500	100
G2	550	600	L3	600	100
	PL1-2 [MW]			p [$/MWh]	
	251.7			46	

TABLE II
GENERATION DISPATCH FOR ALTERNATIVES B

	Pg [MW]	Pmax [MW]		PL [MW]	QL [Mvar]
G1	500	550	L2	500	100
G2	600	650	L3	600	100
	PL1-2 [MW]			p [$/MWh]	
	223.2			48	

TABLE III
CRITICAL CLEARING TIME (CCT) FOR THE ALTERNATIVES SIMUATED

Alternative	CCT [ms]
Base Case	139
A (fast valving at G1)	155
B (L1-2 transmission limit)	212

$$C_{T-1day} = \sum_{i=1}^{24} P_{TLi} \cdot p_i \cdot 1h \qquad (8)$$

Where $C_{T\text{-}1day}$ is the total cost of energy for one day in [$/day], $i=1:24$ is an index for each hour of the day; P_{TLj}: is the total system load in [MW]; p_i: is the price of energy for each hour in [$/MWh]

Then, the cost of *Alternative B* for one day can be calculated as the difference between the total cost of energy with and without the limit on power transfer. This calculation is formulated in equation (9), taking into account the assumptions already made.

$$C_{TaltB} = \left(C_{T-1day-AltB} - C_{T-1day-BaseCase}\right) \cdot 365 days \qquad (9)$$

Where $C_{T\text{-}1day\text{-}AltB}$ is the total cost of energy for one day in [$/day] when the *Alternative B* dispatch is repeated for 5 hours in one day; and $C_{T\text{-}1day\text{-}BaseCase}$ is the total cost of energy for one day in [$/day] when the *Base Case* dispatch is repeated for 5 hours in one day.

This calculation results in C_{AltB} = *8.03 M$/year*.

This cost is the breakeven point to compare with the cost of *Alternatives A, C, D, and E.* The cost calculation for these alternatives is described in section IV-A.

A simplified formulation to calculate the missed-opportunity cost of generators due to the need of keeping spinning reserves is given in equation (10). For this equation, the following assumptions have been made: (a) the total amount of spinning reserve in the generator is used exclusively for primary voltage control, (b) there exists only a market for energy, therefore the only generator misses the opportunity of selling in the energy market, (c) the generator incurs on missed-opportunity costs for a fixed amount of hours a day every day for one year with the same amount of reserve, (d) the capability curve of the generator is not considered to calculate the amount of spinning reserve. Then the missed-opportunity cost can be calculated with the simplified formula in equation (6) [19]:

$$\sum_{year} C_{Opportunity} =$$

$$= \underbrace{\underbrace{\left(p_M - p_{bid}\right) \overbrace{\left(CAP - S_G\right)}^{Approx-Spinning-\mathrm{Re}serve} T_{op}}_{1day} \cdot 365 days}_{1year} \tag{10}$$

where $\Sigma C_{Opportunuty}$ is the cumulative missed-opportunity cost in [$] of not selling energy on the energy market and keeping spinning reserve instead; T_{op} are the hours when the generator incurs missed-opportunity costs; p_M is the price of energy in the energy market for the period T_{op},; p_{bid} is the bid that the generator made in the energy market for the period T_{op}; CAP is the capacity of the generator in [MVA]; and S_G is the apparent power generated for the generator.

III. Determination of the Cost of Supplying Dynamic Control Capacity

The approach for determining the cost of supplying dynamic control capacity (DCC) as a function of the choice of DP metrics is illustrated in the diagram of Fig. 4. Blocks in Fig. 4 and their interdependencies are discussed in this section.

This function is constructed by selecting the minimum cost of the controller for each value of DP metrics. This result is important for deciding the installation of system controllers.

An important part of the determination of the Cost of Supplying Dynamic Control Capacity is the definition of the set of disturbances (with a probability ρ_i) based on information from expected variation of load in normal conditions in magnitude ΔPi ΔQi and rate of change |d|ΔPi|/dt|, |d|ΔQi|/dt|, and a set of equipment outages that are going to be translated into ΔPi ΔQi, normally with a high rate of change |d|ΔPi|/dt|, |d|ΔQi|/dt|. This is represented in block 2, Fig. 4.

It is proposed that controllers are compared through an adequate system of DP metrics. Then, for the defined set of disturbances (load variation and equipment outages), the system dynamic performance becomes a function of reserve and controller quantity and location in the network. This function is a result of dynamic simulations (block 4, Fig. 4).

A critical part in the DCC cost definition is the choice of the DP metrics by which the controllers are going to be evaluated. Examples of dynamic performance are: voltage and frequency deviations and their persistence [2], and critical clearing time (CCT) [10]. As is mentioned in section II-B, the dynamic performance (DP) metrics is a multidimensional property and more work needs to be done in order to better define the choice of DP metrics.

The cost of supplying dynamic control capacity (DCC) as a function of DP is determined by using dynamic-simulation results from block 4 (Fig. 4), and the cost information from block 1 (Fig. 4).

A. Determination of Dynamic Control Capacity Costs

In this subsection, we first classify the actions that contribute to improving the specific DP metrics. Next, we describe the DCC costs.

Typical candidate contributors to improving the dynamic performance, as measured by proper parameters, are classified as:

1) Generator-based controllers: generation reserves controlled by the excitation control (e.g.: AVR, PSS), and mechanic torque control (e.g.: governors, fast valving). The operation of these controllers is subject to the energy market dispatch and unit commitment.

2) Non-generator-based controllers: Reactive power injections (e.g.: SVC, STATCOM, etc), active power injection (e.g.: FACTS + energy storage), transformers automatic tap changers, etc.

3) Out-of-merit generators: As mentioned in sections II and III, use of out-of-merit generation can have an impact on dynamic performance. Due to the fact that this is related with the energy market, it is considered that using out-of-merit generation to account for dynamic problems should be considered by the (I)SO in the clearing mechanism.

4) Automatic Load interruption: Loads automatically adjusted to improve DP metrics.

Costs from generator-based control are different than the costs of non-generator-based control. The costs of generator-based control have a component of missed-opportunity cost of keeping reserves and not selling energy on the energy market. Besides, they have capital and O&M costs that should be separated from the cost of capital and O&M for producing energy for the energy market. On the other hand, the cost of non-generator-based controllers is mainly based on capital costs, as is shown in reference [20] for the cost of SVC.

In general, the costs of a controller can be formulated as

$$C_{Gen-based,T} = C_{capital,T} + \sum_T C_{O\&Mi} + \sum_T C_{Opportunity} \tag{11}$$

, and

$$C_{Non-Gen-based,T} = C_{capital,T} + \sum_T C_{O\&Mi} \tag{12}$$

for generator- and non-generator-based control, respectively; where T is the DCC evaluation period (long term, e.g. one year), $C_{Gen\text{-}based,T}$ is the cost of generator-based controller for the period T, $C_{Non\text{-}Gen\text{-}based,T}$ is the cost of non-generator-based controller for the period T, $C_{capital,T}$ is the capital cost of the controller for the period T, $\Sigma C_{O\&M}$ is the accumulated O&M cost of the controller for the period T, and $\Sigma C_{Opportunuty}$ is the accumulated missed-opportunity cost of the controller for the period T.

In order to obtain the cost of DCC as a function of DP, we choose the minimum cost controllers as a function of the (DP).

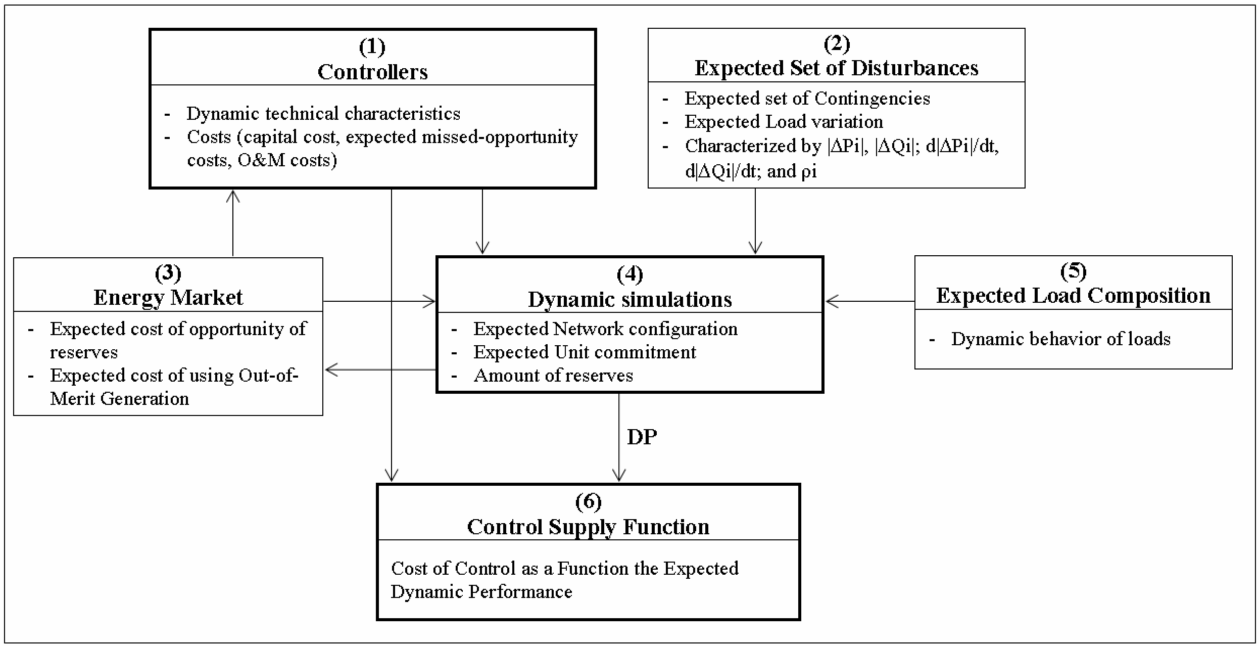

Fig. 4: A possible framework for assessing dynamic performance of candidate controllers.

B. *Interdependences with the Energy Market*

The interdependence with the energy market (block 3, Fig. 4) is evident by the use of out-of-merit generation to deal with dynamic problems (interaction between blocks 3 and 4 in Fig. 4), and the missed-opportunity costs incurred by generation-based controllers (interaction between blocks 3 and 1 in Fig. 4). Their accumulated costs over long periods of time are relevant when compared to the cost of other control alternatives with equivalent dynamic performance (DP).

Using out-of-merit generation to increase transmission and generation reserves is an alternative to improve dynamic behavior, as was illustrated in section II-C to improve transient stability (increase CCT).

IV. ILLUSTRATION EXAMPLE

In this section, a simple example is used to illustrate the methodology for determining the cost of supplying DCC. The three-bus power system used in this illustration is shown in Fig. 1. Dynamic simulations are performed with the software *Eurostag* [6]. The dynamic problem illustrated is the primary voltage / reactive power control.

This system consists of 2 groups of thermal generators, G1 and G2, and two loads, L2 (500MW, 100Mvar) and L3 (600MW, 100Mvar).

Load L3 is modeled as a constant power load in order to have the same change in reactive power at L3 (disturbance simulated) for all the cases simulated, while the load in bus 2 is modeled as a constant impedance. Controllers used in this illustration are:

Controllers in generators: To control the mechanical power of generators, generic turbine-governor control is used [6]. Excitation control of G1 is an automatic voltage regulator (AVR) [6], while in G2 the excitation control alternates between automatic voltage regulators (AVR) [6] and constant excitation (Efd = constant). Using constant excitation is equivalent to the situation when the limits on excitation are hit.

SVC: is connected at bus 2. The model used here is a generic model [6].

To simplify the illustration the set of disturbances is reduced to two contingencies: step increases in reactive power at loads L3 (ΔQL3), and step increases in reactive power at loads L2 (ΔQL2). The dynamic performance measurement chosen here is voltage deviation. First, we analyze ΔQ3, the controllers at bus 2, and voltage deviations (ΔVss, and ΔVt) at bus 2. Then, we compare the results with the simulations for ΔQ2, the controllers at bus 3, and the effects ΔVt on bus 3.

The evaluation period for DCC costs is taken as 1 year.

A. *Dynamic simulations*

Dynamic simulations are performed for several primary voltage controllers at bus 2. The cases simulated are listed in the first column of Table IV.

The dynamic performance (DP) of the system is measured through voltage deviations, steady state voltage deviation (ΔVss) and transient voltage deviation (ΔVt) defined through the typical voltage response shown in Fig. 5. The time frames in Fig. 5 depend on the system operation policies, and primary control action responds immediately to local measurements. Secondary control action can be the result of manual or automatic coordinated actions changing the voltage reference at some nodes in the network.

Dynamic simulation results are shown in the third and fourth column of Table IV.

B. *Determination of Dynamic Control Capacity Costs*

SVC, and AVR-Generator costs are illustrated for an evaluation period of one year.

The annual cost of these alternatives is going to be based on their capital cost, O&M costs, and missed-opportunity cost.

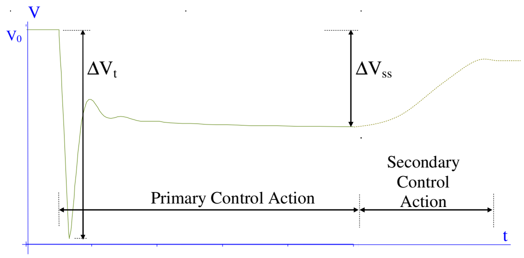

Fig. 5: Illustration of parameters ΔVss and ΔVt for a typical bus voltage evolution after a step change in reactive power load.

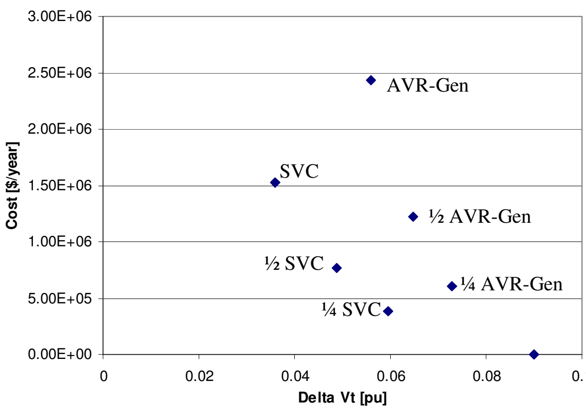

Fig. 6: Yearly cost of dynamic control capacity as a function of a DP metrics

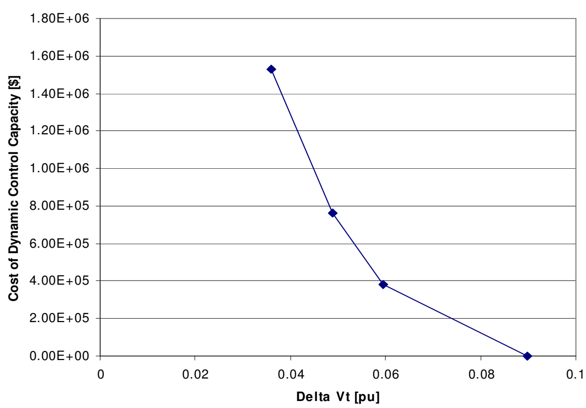

Fig. 7: Cost of DCC as a function of DP

Typical costs are shown in table V. These costs are taken from reference [20].

The capital, and O&M costs of an AVR-generator are only a portion of the total costs of the power plant, because the power plant is used also for other purposes, such as generating energy, providing spinning reserve for frequency control, etc. The AVR-generator incurs missed-opportunity cost because the generator has to keep spinning reserve in order to provide primary voltage control.

Then, the costs of these options for one year can be calculated with equations (4) and (5).

The variables of these equations are defined similarly to the variables of equations (1) and (2). Here $C_{capital}$ is the main component of SVC cost, while $\Sigma C_{O\&M}$ and $\Sigma C_{Oportunuty}$ are important components of the cost for the AVR-Generator alternative.

TABLE IV

DYNAMIC SIMULATION RESULTS FOR SEVERAL CONTROLLERS

Controllers at bus 2	Capacity and Response time [Mvar, s]	ΔV_{ss} [pu] (*)	ΔV_t [pu] (*)
None	---	0.0899	0.0899
¼ AVR-G2	(175, 2.9)	0.0306	0.0728
¼ SVC	(100, 1.4)	0.0313	0.0595
½ AVR-G2	(350, 2.9)	0.0187	0.0647
½ SVC	(200, 1.4)	0.0187	0.0489
AVR-G2	(700, 2.9)	0.0106	0.0559
SVC	(400, 1.4)	0.0106	0.036

(*) Voltage deviations, as defined in fig. 3. Result of dynamic simulations.

TABLE V

TYPICAL COST OF CONTROLLERS

Cost component	SVC	AVR-Generator
Capital cost	45 $/kvar	30 $/kvar (*)
O&M	moderate	high
Oportyunity Cost	No	Yes

(*) This value is assumed to be the same as the capital cost of a synchronous compensator. The rest of its capital cost is assigned to the active power generation.

TABLE VI

YEARLY CONTROL COST CALCULATION

Case	Capital Cost [M$/year]	O&M costs [M$/year]	Opport. Costs [M$/year]	Total costs [M$/year]
SVCB2	1.489	0.040	0	1.529
AVRG2	1.737	0.419	0.280	2.438
½ SVCB2	0.744	0.020	0	0.7647
½ AVR-G2	0.868	0.209	0.140	1.219
¼ SVC B2	0.372	0.010	0	0.382
¼ AVR-G2	0.434	0.104	0.070	0.609

Only fixed O&M costs are considered, 0.1$/kvar-year for the SVC, and 0.6$/kvar-year for the AVR-generator.

The missed-opportunity costs for the AVR-Generator controller are calculated using the simplified equation (--). Where T_{op} (hours when the generator incurs missed-opportunity costs) is 1h for this example; p_M (price of energy in the energy market for the period T_{op}) is 46$/MWh ; and p_{bid} (the bid that the generator made in the energy market for the period T_{op},) is 40$/MWh for this example.

Considering a life cycle of 20 years and an interest rate of 5%, the numerical values obtained for this illustrative example are shown in Table VI and Fig. 6.

In order to obtain the cost of DCC as a function of DP, we choose the minimum cost controllers as a function of the ΔVt (DP). As a result of this process, we obtain Fig. 7.

C. Controller and Disturbance Location. Effects of Interactions

Here we compare the effects of disturbance 1 (ΔQ3), the controllers at bus 2, and voltage deviations (ΔVt) at bus 2; with simulations for ΔQ2, controllers at bus 3, and effects ΔVt on bus 3.

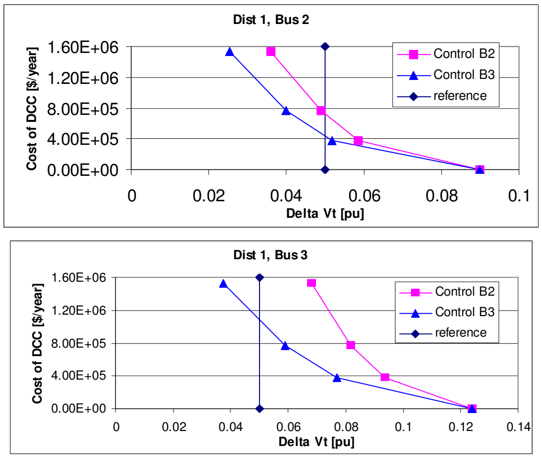

Fig. 8: Interactions for two different locations of control actions, disturbance 1 (ΔQ3)

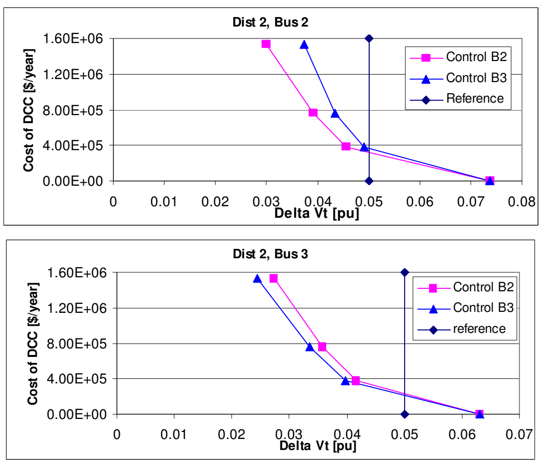

Fig. 9: Interactions for two different locations of control actions, disturbance 2 (ΔQ2)

These results are shown in Fig.8 and Fig. 9. In these figures there is a line at ΔVt = 0.05pu only to be used as a comparative reference.

V. Conclusions

In section II, an approach to evaluating DCC is defined. Important issues for defining the basis for DCC evaluation are: (a) a well-defined set of disturbances with associated probability and rate of response, (b) a long-term evaluation period, and (c) an expected load composition that has influence on the risk of load interruption and its expected cost, and on the dynamic behavior of loads to be used in dynamic simulations.

In order to define the costs of supplying control, the cost components of these controllers and the DP metrics chosen to compare them play a critical role. The costs of the controllers are described and classified in section II-A, and illustrated in section III-B. These controllers are evaluated as a function of their impact on the dynamic behavior of the system.

Further, we compare the effects and interaction of controller and disturbance locations. We conclude that the curves of the costs of controllers as a function of DP are very useful for making decisions about the controller location in the network. These curves combined with the system-user requirement will help find the optimum amount and location for DCC; this is part of our ongoing research [5].

In section III-A (dynamic simulations), it is shown that if voltage deviation only is considered as a DP metrics, frequency oscillation becomes an issue. This fact shows that the DP metrics is a multidimensional concept. More research needs to be done in the technical field in order to better define DP metrics in order to assess dynamic problems and characteristics such as system robustness.

In section II-D, the influence of the use of out-of-merit generation on improving DP metrics is illustrated and compared to the action of a fast valving controller. Interdependence of designing controllers and their costs with the energy market should be coordinated by the (I)SO in order to evaluate tradeoffs between the controllers and the costs of out-of-merit generation. Another aspect of this interdependence is the estimation of the costs of missed-opportunity for reserve; it is proposed in section II-A that the suppliers of control should evaluate these costs, and include them in their bids.

Further research is needed to define adequate Dynamic Performance (DP) metrics for capturing the multidimensional aspects of dynamic problems in power systems, while providing an appropriate comparison tool for the combination of controllers and reserves.

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