Bulk Power System Dynamics and Control IV – Restructuring, August 24-28, Santorini, Greece.

On the Cost of the Reactive Power Generation and Voltage Support Service

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Abstract.**—The cost of providing reactive power by the generation plants can be decomposed in two parts: a fixed part related to the required investment and a variable part related to the actual operation. The amount of the fixed part is quite difficult to evaluate and highly debated. On the other hand, the variable cost can be accurately computed. This cost is required if the generators are to be remunerated on an unbundled services basis. A way to compute this cost is shown, as well as some remarks on the typical results and a study case.**

1. Introduction

As new electrical sector regulations are implemented in Spain [1] and other countries [2,3,4], there is a growing need to quantify the cost of services formerly bundled. Among these services stand the ones associated to the reactive power supply and transmission network voltage control [5]. The focus of this paper is to identify and quantify the costs incurred by the generation facilities in order to provide these services.

These costs can be decomposed in two parts: one fixed and one variable. The fixed part is due to the difference between the plant building cost with and without a reactive margin, and to the cost of the equipment needed to use that margin. Although the precise amount of this cost is debatable, it does not affect the power system operation.

On the other hand, the variable cost should be taken into account in the system operation. Ideally, the operation should minimize the cost due to the losses in the network and in the generation units, while keeping the system safe. The correct quantification of generation unit variable cost is important in order to remunerate properly to the generators' owners.

The variable cost is mainly due to the active losses in the generator and in the step up transformer caused by the reactive power. These losses can be divided in Joule, eddy, hysteresis and stray losses, the generator mechanical losses and the losses of the excitation system. In the case that the reactive generation limit is reached, the opportunity cost of the non generated active power should be considered. This circumstance is, however, exceptional.

From the transmission network point of view the injected active and reactive power and the voltage in the high voltage bus characterize the generation plant. The generator operator tries to minimize the generation plant total losses while keeping the above constraints. The net result is that, for a given injected active power, high side voltage and transformer tap, the generation unit losses depends almost quadratically of the injected reactive power, with minimum losses for a slightly capacitive power factor.

The sequel is organized as follows: the next section deals with some general remarks on the nature of the service of reactive support and its associated costs. Section 3 explains the way of computing the reactive variable cost of a generation plant. In Section 4 a qualitative analysis of the usual results is done. A study case is shown in Section 5. Finally, conclusions are established in Section 6. There are also two appendices: the first one is a more formal exposition of the method used to compute the variable cost, and the second one includes the data of the study case.

2. Reactive support and voltage control services

The reactive power management and voltage control services in the transmission network can be decomposed into two main types:

a) *Voltage profile management and reactive dispatch:* This service is oriented towards the optimisation of the system active power losses costs while keeping steady-state system security in the face of possible contingencies (for instance, by keeping the voltage profile and the reactive power reserves within margins). It changes on an hourly basis or slower. Generators, capacitors, reactances and distribution load management provides this service.
b) *Voltage control:* also known as voltage regulation, it is the service provided to keep the network voltages in a dynamic time frame (seconds to minutes). Generators, SVCs, or other equipment capable of fast regulation can provide it. It is oriented towards the system dynamic security and the voltage quality. Although the

economic effect is undeniable, it is also difficult to evaluate.

To provide both kind of services; it is needed to incur in fixed and variable costs. The variable cost is mainly associated to the first kind of service, and it is extensively discussed below. The fixed cost is associated to both services. It is very difficult to evaluate, because most of the equipment required for these services is also needed for other purposes. For instance, an exciter is required for providing reactive power, but also to deliver variable quantities of active power (the field current is dependent on the injected active power even if the machine always works with unit power factor). The difficulty of evaluating these costs is, therefore, an unbundling one.

In the Spanish system and, likely, also in other ones, this kind of problems could be a cause of concern. For instance, as result of improvements in the energy efficiency of nuclear plants, the generators in these facilities cannot work up to the power factor initially rated (the MVA generators ratings have not changed, even when the plant can deliver a higher active power output). That shows that the power factor is, up to certain level, a design decision independent of the active power. It is not clear which part of the generator cost should be considered an “active power part” and which one a “reactive power one”, or even if such an unbundling is a sensible one or not.

One possibility is pay to the generators at the marginal prices [6,7]. A claim often stated is that this kind of charging is economically optimal and that it avoids unbundling problems. In a system working in the economic optimum, it can be shown that the reactive power marginal price in a generator bus that works within limits (the usual situation) is just the total derivative of the cost with respect to the injected reactive power. That is, if for a given injecton of active power in the high voltage bus, the total cost of the generation plant is $C(Q,V)$, which depends on both the injected reactive power and the high side voltage, the reactive marginal price is

$$\sigma = \frac{\partial C(Q,V)}{\partial Q} + \frac{\partial V}{\partial Q}\frac{\partial C(Q,V)}{\partial V}$$

The sensitivity $\partial V / \partial Q$ is the variation in the generation plant voltage when the injected reactive power changes assuming that no other reactive power injection changes. Usually, the second term happens to be much smaller than the first one, although there might be exceptions.

3. Variable Cost

The variable cost is mainly due to the active losses in the generator and the step up transformer caused by the reactive power. From the transmission network point of view the injected active and reactive power and the voltage in the high voltage bus characterize the generation plant. From the generation plant point of view the main difference between a reactive power generation level or another one is the different magnitude of its active power losses. In a perfect market, these losses should be valued to the active power cost, i. e., the active power marginal price at the generator bus (see appendix A). In other regulatory settings, they can be still the basis for the service cost evaluation. Therefore, the chosen method for the evaluation of the variable cost has been:

1. Compute the generation plant losses, for a given active power injection, for different values of the injected reactive power, high voltage bus and transformer tap.
2. Compute the losses in the optimal operating point or in any other one taken as reference.
3. Compute the difference between these two values. As this difference is caused by operating in a suboptimal voltage/reactive power point it can be considered, when multiplied by the active power marginal price, the service cost.

The main causes of losses in the generation plant are [8]:

- Generator
    1 Stator
        - Joule losses. They are proportional to the current squared.
        - Foucault and hysteresis losses. They are considered to be proportional to the air-gap B induction field squared.
        - Stray losses. They are considered to amount the 10% of the Joule losses.
    2 Rotor
        - Joule losses. They are proportional to the excitation current squared.
        - Exciter losses. The exciter efficiency curve is modeled as a percentage of the rotor Joule losses.
        - Windage and friction losses.
- Step-up transformer.
    - Joule losses. They are proportional to the current squared.
    - Hysteresis and Foucault losses. They are proportional to the induction field squared. The induction field is proportional to the voltage.
    - Additional losses. They are considered to be a 10% of the Joule losses.

Some remarks can be made about this list:

1. Under the heading of stray and additional losses are listed several causes: eddy losses in the armature winding, losses in the structure due to the leakage flux around the armature winding overhangs, losses in the stator and rotor surfaces due to high-frequency flux variations, tooth pulsation, etc. The precise

computation of these losses is quite difficult. To model then as a percentage of the Joule losses is a standard approximation.
2. The mechanical (windage and friction) losses do not change so long as the machine speed does not change. Therefore, they are not longer considered in the sequel.
3. All the previous factors are static; that is, they do not depend on the history of the generator plant operation. However, if the operator changes the step-up transformer taps, there is an additional reliability cost due to the possibility of a failure.

In addition to the losses, it is needed to consider the machine operating limits. In order to simulate the possible operating points, the following restrictions were taken into account:

1. A stator current upper limit.
2. An excitation current upper limit.
3. An excitation current lower limit.
4. Lower and upper limits in the generator voltage.
5. Load angle limit.

Some remarks can be made:

1. There are some phenomena of complex analysis, such as the effect of the operating point on the cooling fluid pressure or the limitation due to the armature core end heating. These phenomena have not been considered in the sequel.
2. As changing taps, working close to the capability curve has a reliability cost. These reliability costs could be quantified by correlation analysis of failures and reactive power production from historical records

Formulae for the computation of the generation plant losses are given in the appendix A. Special care has been taken to propose a procedure that will use machine data easily available.

4. Qualitative analysis

The figure 1 shows generator losses curves for the study case in function of the injected reactive power for a given nominal active power, high side voltage and transformer tap. The shape of the curves is quite typical.

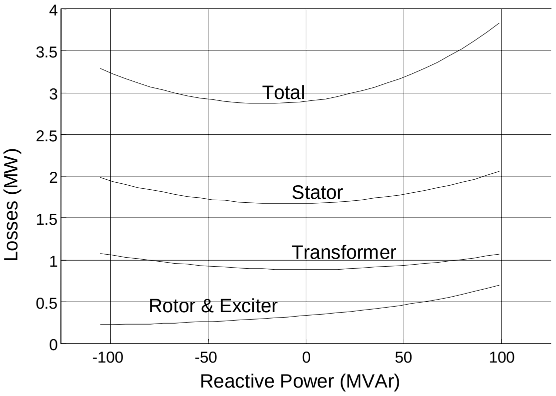

Fig 1.Losses curves.

It can be noted that:

1. The transformer and the stator have similar losses curves. This is because in both cases the losses are due to the same reasons: Joule effect, Foucault and hysteresis losses, and the stray losses, which are modeled as a percentage of the Joule losses.
2. The hysteresis and Foucault losses are almost constant, as they depend on the almost constant internal voltages. On the other hand, the Joule losses show considerable variation. Therefore, the stator and transformer losses are almost quadratic with respect to the reactive power (the Joule losses are quadratic with respect to the current, and the power lineal with the power assuming constant voltage).
3. As the generator voltage is not constant, the stator Joule losses curve are slightly displaced towards the left.
4. The rotor losses are mainly due to the excitation winding Joule losses. The Foucault and hysteresis losses are very small, because the rotor spins synchronously respect to the field. The excitation current is minimal when the machine is subexcited. The losses curves is roughly quadratic with respect to the reactive power.
5. The quadratic character is modified due to saturation effects and the variable exciter efficiency.
6. The total losses, therefore, are minimal for a certain amount of absorbed reactive power. Thus, the reactive cost curve is highly asymmetrical for absorbed or generated reactive power.
7. If the reactive support and voltage control service is paid through marginal prices, the generation plant could pay to the system. In fact, in the zone of negative injected power right to the optimal point, the marginal price (the derivative of the cost) is positive, the injected power positive, and thereof its product negative. This product is the income to be received by the generation plant; that is, the generation plant must pay to the system.

5. Study case

The proposed losses estimation method has been applied to the generation plant whose characteristics are shown in the appendix B.

Figure 2 shows the total losses when the transformer tap is the nominal one, and different high side voltages, as function of the injected reactive power. Figure 3 shows the total losses when the high side voltage is the nominal one for different transformer taps. In both cases the active power generation is assumed to be 204 MW. Finally, figure 4 represent the total losses for nominal high side voltage and transformer tap and different injected active power.

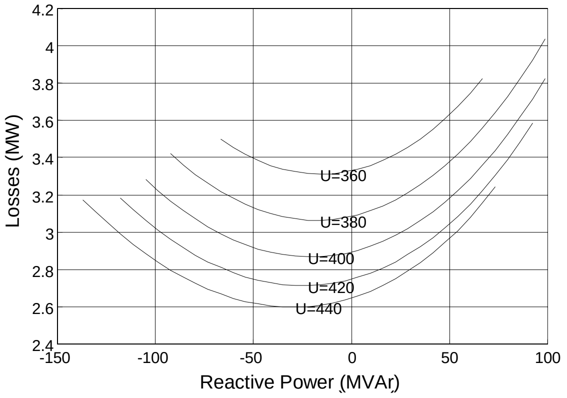

Fig 2. Losses curves. *P* and *t* constant.

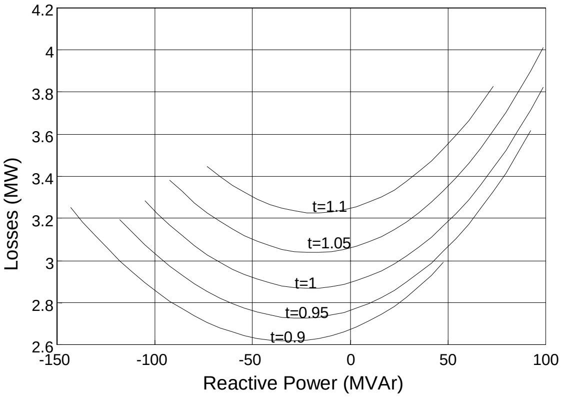

Fig 3. Losses curves. *P* and *V* constant.

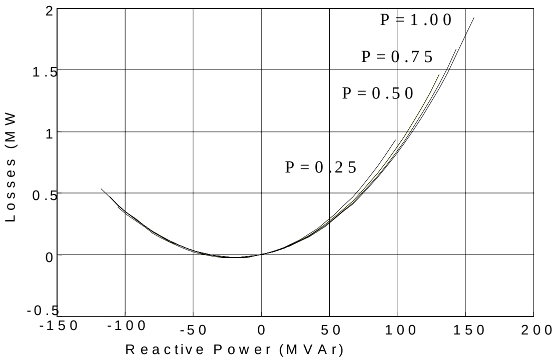

Fig 4. Losses curves. *V* and *t* constants.

Note that, if it is desired to work with minimal losses, there should be tap changing when generating more than 50 MVAr. This is because, for tap ration equal to 0.9, the maximum field current limit is reached for this value. However, changing taps has realibity risks. Therefore, it is not clear if the optimal policy is to keep the tap fixed to some "optimal" value.

Note also that the losses are almost independent of the injected active power. That is, the active and reactive power are effectively decoupled.

6. Conclusions

A method to compute the reactive power cost curves of a generation plant has been shown. The obtained curves happen to be asymmetrical ones, with a minimum when working in subexcited conditions. Therefore, if generation units are remunerated by marginal prices, they could be paid by, as well as pay to, the system.

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Appendix A

The purpose of this appendix is to show the procedure used to compute the generation plant losses. In the sequel, the magnitudes when given in S.I. units are denoted with high-case letters, and the same magnitudes in p.u. are denoted with low-case letters.

The total losses have been computed according the formula:

$$\text{Losses} = \left[\frac{u_{Fe}^2}{r_{Fe}} + 1.1\frac{r_{sc}}{2}i_{high}^2 + 1.1\frac{r_{sc}}{2}i_{low}^2\right]_1 + \left[\frac{1}{\eta}r_{rotor}i_{exc}^2\right]_2 + \left[k_{Fe}e_{rot}^2 + 1.1r_{est}i_{est}^2\right]_3$$

The first term is the transformer losses, the second one the rotor and exciter losses, and the last one the stator losses. Each term shall be now considered.

The electrical model is shown if the figure 2. The value of the different parameters is dependent on the tap position *t*, according the formulae

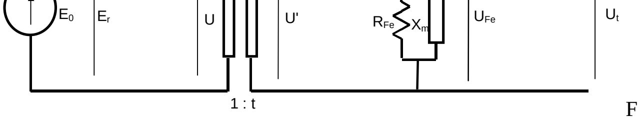

Fig 5. Electrical model.

$$p'_0 = \frac{p_0}{t^2}$$

$$p'_{sc} = \frac{p_{sc}t(1+t)}{2}$$

$$x'_{sc} = x_{sc}t^2k_d$$

$$i'_0 = i_0$$

$$r_{Fe} = \frac{1}{p'_0}$$

$$x_{Fe} = \frac{1}{\sqrt{i'^2_0 - p'^2_0}}$$

$$r_{sc} = p'_{sc}$$

$$x_{sc} = \sqrt{u'_{sc} - p'_{sc}}$$

p_0 denotes the open circuit power, p_{sc} the short-circuit power, x_{sc} the leaking inductance, r_{sc} the winding resistance, u_{sc} the short circuit voltage, x_{Fe} and r_{Fe} the magnetizing inductance and resistance, and i_0 the open circuit current. t denotes the tap position ($t = 1$ is the nominal tap). The unprimed quantities are those when the tap position is the nominal one, and the primed quantities when the tap position is *t*. The parameter k_d embodies the distortion effect in the leakage field when the tap is changed, and it is computed by interpolating the data in the following table:

100 (1-t)	0	2	3	4	9.5	16
100 k_d	0	0.8	2	3.1	10	17.2

The Foucualt and hysteresis losses are proportional to the square of the air-gap induction field. This field is assumed to be proportional to the voltage behind the leakage reactance E_r. Therefore, if $P_{Fe,0}$ are the nominal-voltage open-circuit losses, it is assumed that:

$$k_{Fe} = \frac{P_{Fe,0}}{U_n^2}$$

$$p_{Fe} = k_{Fe}e_r^2$$

The rotor losses are the rotor Joule losses ($r_{rotor}i_{exc}^2$) affected by the exciter efficiency (η). The last parameter depends on the excitation current. Usually, exciters are designed for a maximum efficiency when $i_{exc} = 0.7$. The maximum efficiency is different for each exciter, but the dependence of the efficiency with the excitation current is remarkably similar. After analyzing typical values for Spanish generation plants, it is proposed to use the expressions

$$\frac{\eta}{\eta_{max}} = 1 - \left[(i_{exc} - 0.7)^2 + 1.225 (i_{exc} - 0.7)^{2.526} \right]$$

for DC generator exciters and

$$\frac{\eta}{\eta_{max}} = 1 - \left[(i_{exc} - 0.7)^2 + 2.6692 (i_{exc} - 0.7)^{4.6404} \right]$$

for static exciters.

The computation of the excitation current (i_{exc}) and the voltage behind the leakage inductance (e_r) is done in a standard way [9] from the generator terminal complex voltage $\overrightarrow{u_g}$ and injected complex power $\vec{s}_g = p_g + jq_g$. Then,

$$\vec{i}_g = \left(\frac{\vec{s}_g}{\vec{u}_g} \right)^*$$
$$\vec{e}_r = \vec{u}_g + (r_{est} + jx_l)\vec{i}_g$$

To compute the excitation current the following equations are used:

$$i_{f0} = \frac{e_r}{x_{ad}} (1 + S(e_r))$$
$$S(e_r) = Ae_r^x$$
$$i_{exc} = i_{f0} + \alpha i_g$$

The parameters A and x are computed from two points in the saturation open circuit characteristic corresponding to terminal voltages $u_g = 1$ and $u_g = 1.2$, which are provided as input data. α is computed from the short circuit ratio. These formulae are valid if the machine is a round rotor one.

Appendix B

The following table shows the study case generation plant data.

Generator (round rotor)	
Nominal Power	240 MVA
Nominal Power Factor	0.85
Nominal Voltage	17 kV
Short Circuit Ratio	0.64
Synchronous Reactance (unsaturated)	167 %
Stator Leakage Reactance	8 %
Field Current for Rated Voltage on OCC	607 A
Rated Voltage Saturation ($S(1.0)$)	0.114
1.2 Rated Voltage Saturation ($S(1.2)$)	0.496
Stator Resistance (25ºC)	0.007225 Ω
Rotor Resistance (25ºC)	0.21675 Ω
Open Circuit Iron Losses	0.0012 p.u.
Maximum Field Current	1425 A
Maximum Exciter Efficiency	95 %
Stator Working Temperature	75ºC
Rotor Working Temperature	85ºC
Step-up Transformer	
Nominal Power	240 MVA
Nominal Voltage	400/17 kV
Short Circuit Voltage	14 %
Short Circuit Power	0.4 %
Magnetising Current	0.3 %
Open Circuit Power	0.05 %