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Economically Correct Secure Economic Dispatch embedding UPFC Investment Cost in a Deregulated Power Market Scenario

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ABSTRACT

In a competitive power market scenario, the Independent System Operator (ISO) main problem is how to pursue its objectives taking into account generation costs, contractual clauses among the different market agents and insecurity costs related to the possible power system operating points. To face this problem, in previous papers, a model proposed by the authors, called Economically correct Secure Economic Dispatch (EcSED), is adapted to the new deregulated market scenario taking into account FACTS technology in order to reduce power system insecurity risk. Among FACTS devices, the Unified Power Flow Controller (UPFC) is the most flexible and versatile and its usage is under focus in this paper. But if, from one side, a UPFC installed in the transmission network can be exploited to minimize the insecurity risk, from the other side its use implies an expense, function of the size of the device itself. Then, in the paper an enhanced formulation of the EcSED model embedding the UPFC investment cost is proposed to support the ISO in its decision pertaining the choice of the UPFC size. Some numerical experiments on a 5-bus test system are also reported, to prove the effectiveness of the proposed enhanced EcSED formulation.

1. INTRODUCTION

The prevailing challenge nowadays in the electricity industry is to offer a product with a balanced mix of quality and price. These two features are conflicting: a higher supply quality level requires more investments, which in turns results in higher tariffs. It is recognized in power engineering that the system security level is a good translation of the quality attribute [1]. Let us so define the system security as the ability of the Electrical Power System (EPS) to supply loads demand, in terms of quality and quantity, even in case a possible outage (contingency) occurs.

Strictly bound to service quality and price is the concept of insecurity risk [1- 5], related to an operating state. In the paper, the insecurity risk is defined as an expected cost obtained as the sum, on all contingencies, of the product between the occurrence probability of each contingency and the minimum load curtailment [3, 4] needed to restore power system feasibility if the contingency really occurs.

As to contingencies, for sake of simplicity, only single line outages will be considered in the paper while, to respectively check the active and reactive security of the EPS, overloads and voltage limits violation will be accounted for.

Overloads, consequent to a contingency, may be prevented by means of opportune pre-contingency generation schedules. Also, they can be relieved in post-contingency state by means of phase shifters, tap transformers, reactive power supply, generation re-dispatch, Flexible Ac Transmission Systems (FACTS) devices [6- 8] and, as extreme measure, curtailment of loads. As to

FACTS devices, their presence in the network may be exploited to minimize the insecurity risk by acting on their controllable parameters [6]. In this paper, among FACTS devices, the most flexible and versatile, the Unified Power Flow Controller (UPFC) is under focus.

However the use of an UPFC presupposes a previous financial investment that have to be taken into account in a cost-benefit analysis.

In the paper, a model embedding the UPFC investment cost is then proposed to support the Independent System Operator (ISO) in its decision pertaining the choice of the UPFC size.

The paper starts recalling a previous proposal of Economically correct Secure Economic Dispatching (EcSED) model, already improved by the authors with an UPFC device embedded within its constraints [6]. An enhanced formulation of the improved EcSED is then here provided taking into account the UPFC investment cost. Finally, some numerical experiments on a 5-bus test system are reported to prove the effectiveness of the proposed enhanced EcSED formulation.

2. THE EcSED MODEL

With reference to the Italian market structure, two basic market items can be identified: the day-ahead and the day-after (or real-time) markets. During the day-ahead market, all participants make their bids yielding, for each h-th hour of the day after, the provisional power dispatching plan, $P_{Market(h)}$. No reference is made so far to network constraints, and only economic mechanisms (based only on the common financial profit and not on social aspects deriving from the security goal) guide the definition of the optimal power generation schedule.

Within the day ahead and real-time markets, for each h-th hour, the ISO has then to check if $P_{Market(h)}$ causes any congestion or any other abnormal operating condition (i.e. any other active or reactive limit violation), in the intact system (N security). At the same time, it has also to verify the active and reactive N-1 security, always within $P_{Market(h)}$. For this aim, starting from $P_{Market(h)}$, the ISO has to determine the real time power dispatching plan, Pg_o , defined as $P_{Market(h)} + \Delta Pg_o$, in order to reduce the insecurity risk, preserving power system feasibility either in pre or in post contingency state, at the minimum cost.

Among all corrections, the ISO has at its disposal generation rescheduling in pre and post contingency state and load curtailments as extreme measure in post contingency state.

To take into account what has been described above, a model to solve the EcSED, detailed here in Eq. (1), has been provided by the authors in [6, 9].

$$H_{EcSED} = \text{Min } H(\Delta Pg_o, \Delta Pg_j, \Delta P_j) \quad (1)$$

Subject to:

$$\Delta Pg_o = Pg_o - P_{Market(h)}$$

$$\Delta Pg_j = Pg_j - Pg_o$$

$$\Delta P_j = P_j - P_o$$

$$H = F(\Delta Pg_o) + \sum_{j=1}^L p_j F^{post}(\Delta Pg_j) + \sum_{j=1}^L p_j G(\Delta P_j)$$

$$LF_o(Pg_o, U_o, X_o, P_o, Q_o) = 0$$

$$D_o(Pg_o, U_o, X_o, P_o, Q_o) \leq 0$$

For every dangerous contingency j

$$LF_j(Pg_j, U_j, X_j, P_j, Q_j) = 0$$

$$D_j(Pg_j, U_j, X_j, P_j, Q_j) \leq 0$$

In Eq. (1), LF , D , LF_j and D_j are, respectively, the Load Flow equations and the inequalities of the direct and functional constraints on the variables of the system, in pre and in post contingency state. ΔPg_o is the vector of the active generation powers corrections in pre-contingency state. ΔPg_j and ΔP_j are respectively the vectors of the active generation powers corrections and of the active load power curtailed, after contingency j .

In the proposed model [1], his objective function is composed by three terms:

- $F(\Delta Pg_o)$ represents the cost due to the variation of the generation schedule with respect to $P_{\text{Market}(h)}$ (rescheduling cost in pre-contingency);
- $\sum_{j=1}^L p_j F^{\text{post}}(\Delta Pg_j)$ represents the expected cost due to a post-contingency generation powers change with respect to Pg_o .
- $\sum_{j=1}^L p_j G(\Delta P_j)$ is the power system insecurity risk, where p_j is the occurrence probability of the j -th contingency, while G is the load curtailment cost function

The solution of (1), i.e. $(\Delta P^*g_o, \Delta P^*g_j, \Delta P^*_j)$ equal to the $\text{argmin}(H_{\text{EcSED}})$, just provides the ISO with the set of the “economically correct” actions it may undertake, taking into account all the economic aspects of a power system (rescheduling cost in pre-contingency state, expected cost due to a post-contingency generation powers change and power system insecurity risk, all referred to the h -th hour of the day).

In general, the cost coefficients of F are different from F^{post} ones. Indeed, always with reference to the Italian power market, to relieve congestion in the intact system, the ISO makes its purchasing and selling bids of energy in the so called *congestions relief market*. Conversely, to try to restore the system to non out-of-limit conditions after a contingency takes place, the ISO makes its energy provisions within the *reserve market* [10].

3. THE ECSED EMBEDDING AN UPFC IN A DEREGULATED POWER MARKET SCENARIO

As said before, power system security and performance can be improved also by controlling line power flows through the usage of an UPFC.

Basically, an UPFC consists of two voltage source converters (VSCs), operating from a common dc link provided by a dc storage capacitor (Fig. 1). One converter, in particular, is connected in series with the transmission line via a series boost transformer with a leakage reactance X_{se} , operating as a Static Synchronous Series Compensator (SSSC). The other one is connected in shunt with the transmission line via a shunt boost transformer with a leakage reactance X_{sh} , operating as a Static Synchronous Compensator (STATCOM).

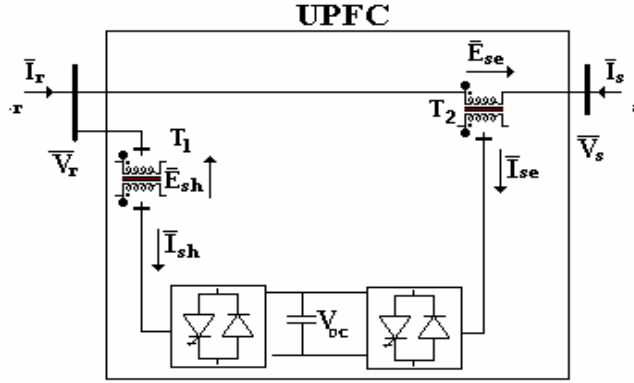


Fig. 1 UPFC scheme

It is noteworthy to underline that the main objective of the series converter is to control the active and reactive power flows on the transmission line, by regulating phase and magnitude of its output voltage. Conversely, the shunt converter can independently supply/absorb reactive power, in order to provide a voltage regulation at the connection point. Besides, it can provide the eventually required active power by the series converter through the dc link terminals. In this way, the active power freely flows between the shunt and the series converters ac terminals, via the common dc link, and the net active power interchange between UPFC and power system is zero in steady state (neglecting converters losses).

Representing the effect of the two VSCs in terms of voltage sources, controllable in magnitude and in phase, $\bar{E}_{se} = m_{se} e^{j\varphi_{se}} \bar{V}_r$ and $\bar{E}_{sh} = m_{sh} e^{j\varphi_{sh}} \bar{V}_r$ respectively, an equivalent circuit of UPFC can be obtained, as depicted in Fig. 2.

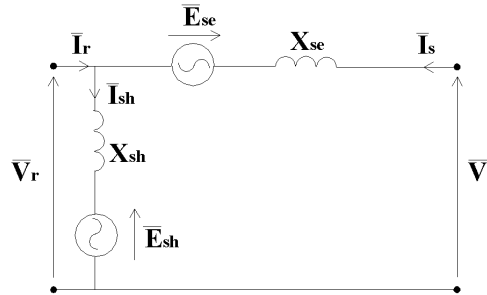


Fig. 2 UPFC equivalent circuit

Using the UPFC representation of Fig. 2, a model for the UPFC device can then be derived and easily incorporated into the steady state power flow model. The UPFC can be modeled either by means of its transmission matrix model, then deriving the relating admittance matrix, as described in [6], or by a classic injection model [11, 12], as it will be shown in the following.

Since the series voltage converter carries out the main function of the UPFC, let us discuss the modeling of a series voltage source converter first.

Let us suppose a series connected voltage source is located between nodes r and s in a power system. The series voltage source converter can be modeled with an ideal series voltage, \bar{E}_{se} ,

in series with a leakage reactance, X_{se} . As in Fig. 3, the injection model is so obtained by replacing the voltage source \bar{E}_{se} by the current source $\bar{I}_{se} = (-jb_{se})\bar{E}_{se}$, in parallel with the reactance leakage X_{se} , with b_{se} equal to the inverse of the reactance X_{se} .

The current source \bar{I}_{se} corresponds to the injection powers $\dot{S}_{r_se} = \bar{V}_r (-\bar{I}_{se})^*$ and $\dot{S}_{s_se} = \bar{V}_s \bar{I}_{se}^*$, while the shunt side absorbs from bus r a complex power $\dot{S}_{r_sh} = P_{r_sh} + jQ_{r_sh}$. The total injections at buses r and s as well as the UPFC functional constraint are then:

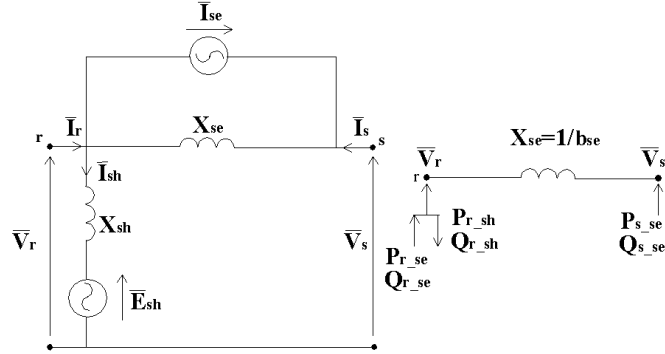


Fig. 3 Shunt and series sides of the UPFC converted into two power injections at buses r and s

$$P_r = P_{r_se} - P_{r_sh} = -V_r V_s m_{se} b_{se} \sin(\varphi_{se} + \delta_r - \delta_s) \quad (2)$$

$$Q_r = Q_{r_se} - Q_{r_sh} = -V_r^2 m_{se} b_{se} \cos \varphi_{se} + V_r^2 b_{sh} (1 - m_{sh} \cos \varphi_{sh}) \quad (3)$$

$$P_s = P_{s_se} = V_r V_s m_{se} b_{se} \sin(\varphi_{se} + \delta_r - \delta_s) \quad (4)$$

$$Q_s = Q_{s_se} = V_r V_s m_{se} b_{se} \sin(\varphi_{se} + \delta_r - \delta_s) \quad (5)$$

$$Re\{\bar{E}_{sh} \cdot I_{sh}^*\} = Re\{\bar{E}_{se} \cdot I_s^*\} \quad (6)$$

By incorporating the UPFC power injections Eqs. (2), (3), (4) and (5), the load flow equations of (1) in pre and post contingency state, denoted LF_o' and LF_j' respectively, can be updated and rewritten as in Eqs. (7) and (9). Moreover, the active power balance constraint described by Eq. (6) has to be taken into account within Eq. (1). Constraints M_o and M_j can then be formulated in compact form as in Eqs. (8) and (10), for the pre and post-contingency state respectively. Each set of post contingency constraints (M_j and LF_j') has to be replicated for every contingency detected dangerous by the ISO from its knowledge of the network.

$$LF_o'(Pg_o, U_o, X_o, P_o, Q_o, m_{seo}, m_{sho}, \phi_{seo}, \phi_{sho}) = 0 \quad (7)$$

$$M_o(m_{seo}, m_{sho}, U_o, \phi_{seo}, \phi_{sho}) = 0 \quad (8)$$

$$LF_j'(Pg_j, U_j, X_j, P_j, Q_j, m_{sej}, m_{shj}, \phi_{sej}, \phi_{shj}) = 0 \quad (9)$$

$$M_j(m_{sej}, m_{shj}, U_j, \phi_{sej}, \phi_{shj}) = 0 \quad (10)$$

4. OPTIMAL SIZING OF AN UPFC BY MEANS OF AN ENHANCED EcSED FORMULATION EMBEDDING ITS INVESTMENT COST

The strategic benefits provided by the use of FACTS devices can be translated into financial benefits such as:

- Additional sales due to increased transmission capability.
- Additional wheeling charges due to increased transmission capability.
- Avoiding or delaying of investments in new high voltage transmission lines or even new power generation.

On the other hand, the use of such a device implies an investment cost.

The investment costs of FACTS devices can be broken down into two categories: (a) the devices' equipment costs, and (b) the necessary infrastructure costs. Equipment costs depend not only upon the installation rating but also upon special requirements such as:

- Redundancy of the control and protection system or even main components such as reactors, capacitors or transformers.
- Seismic conditions.
- Ambient conditions (e.g. temperature, pollution level).
- Communication with the Substation Control System or the Regional or National Control Center.

Infrastructure costs depend on the substation location, where the FACTS device should be installed. These costs include e.g.

- land acquisition, if there is insufficient space in the existing substation.
- modifications in the existing substation, e.g. if new HV switchgear is required.
- construction of a building for the indoor equipment (control, protection, thyristor valves, auxiliaries etc.).
- yard civil works (grading, drainage, foundations etc.).
- connection of the existing communication.

The total investment costs, which are exclusive of taxes and duties, may vary due to the described factors by -10% to +30%. Including taxes and duties, which differ significantly between different countries, the total investment costs for FACTS devices may vary even more [13].

Starting from these two categories, it is then possible to further distinguish among costs varying with the size of the device and costs constant with it.

According to this final assumption, a formulation can be given of the UPFC investment cost as it will be described in the following:

$$C_{UPFC} = C_{UPFCu} \times A_{max} + FC \quad (11)$$

where, C_{UPFCu} = The UPFC unitary cost coefficient (M.U./MVA), and
 FC = The UPFC fixed cost.

Assuming that FC is constant with the size of the UPFC, and that, as such, it can be neglected in the minimization problem, we can then define c as [15]:

$$c = \frac{\alpha}{8760} C_{UPFCu} \left[\frac{M.U.}{MVAh} \right] \quad (12)$$

where, $\alpha = \frac{i(1+i)^n}{(1+i)^n - 1}$ = The capital recovery factor, with i the interest rate and n the capital recovery plan.

Let us assume that the ISO has already perceived the need for an UPFC to lessen the insecurity risk in the power system management.

As in [14], it is reasonable to assume the two VSCs of the same size, A_{max} : hence both the apparent powers of the series and of the shunt VSCs can be limited by the same upper bound, as described in Eqs. (13) and (14).

$$\left| \overline{E_{sh}} \times I_{sh}^* \right| \leq A_{Max} \quad (13)$$

$$\left| \overline{E_{se}} \times I_{rs}^* \right| \leq A_{Max} \quad (14)$$

In [6] the upper bound A_{max} is considered constant. In this paper, A_{max} is instead held variable.

Weighting A_{Max} through the capitalized UPFC unitary cost coefficient c and summing the term so obtained up to the objective function of Eq. (1), the last will then become:

$$H = F(\Delta P_{g_o}) + cA_{Max} + \sum_{j=1}^L p_j F^{post}(\Delta P_{g_j}) + \sum_{j=1}^L p_j G(\Delta P_j) \quad (15)$$

Let us assume that the ISO has at its disposal the “history” of the power system and that it is able to choose an opportune operating state.

With reference to this operating state, the size of the UPFC can be so determined by minimizing Eq. (15), while meeting all the constraints of Eq. (1) with LF equations modified as in Eqs. (7) and (9) and with Eqs.(8), (10), (13) and (14) in addition.

It is worth to underline that the greater is the UPFC capacity, A_{max} , obtained by the EcSED optimization, the heavier is its relating cost, whilst the lower is the insecurity risk and the higher are the consequent savings pertaining to generation rescheduling.

5. NUMERICAL EXPERIMENTS

In order to illustrate how the proposed enhanced EcSED model works, some numerical tests have been carried out on a 5-bus test power system, whose data in p.u. are shown in Fig. 4. In particular buses 1 and 2 are generation nodes, while buses 3, 4 and 5 are load nodes.

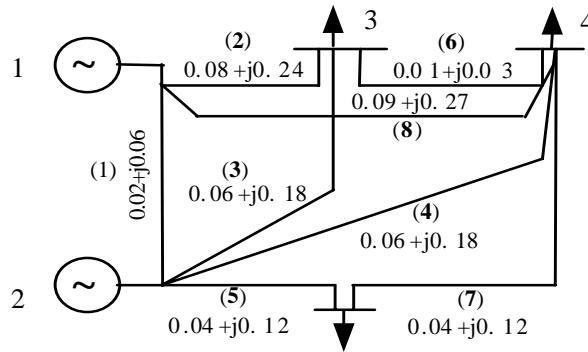


Fig. 4 Test power system (1 to 5: buses, (1) to (8): lines, base power= 100 MVA)

Subsequent to a brief description of a possible operating state chosen by the ISO, a first experiment is carried out with opportune load shedding costs and no UPFC installed in the network. This first test is useful to justify the need for an UPFC able to reduce the insecurity risk of the power system.

Further two experiments are then conducted to show how the EcSED model works in correspondence of other two different load shedding cost configurations, respectively higher and lower than the previous case. In the last two experiments an UPFC is installed on line (1) as depicted in Fig. 5.

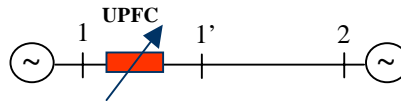


Fig. 5 Line (1) scheme with UPFC installed in correspondence of node

Table 1 Pre-contingency generators and loads data in p.u.

Bus	$P_{Market(h)}$	Bus	P_o	Q_o
1	2.0	3	-0.6	-0.3
2	0.275	4	-0.8	-0.1
		5	-0.8	-0.2

Table 2 Generators and loads data

Bus	$\Delta P_{g_0}^{max}$	$\Delta P_{g_j}^{max}$	rc_o	rc_j	Bus	ΔP_j^{max}	sc_j
1	20%	15%	10	10	3	50%	70
2	50%	40%	10	10	4	50%	70
					5	0%	-

The operating point to be used to determine the most proper UPFC size has to be chosen by the ISO taking into account the critical characteristics threatening the EPS security.

For example, let us suppose that bus 1 covers the greatest amount of the loads demand, as reported in Table 1. Furthermore, it is assumed that bus 1 participates to the reserve and congestion relief markets with a limited flexibility with respect to bus 2, as shown in Table 2. The pre-contingency reserve capacities, $\Delta P_{g_0}^{max}$, of buses 1 and 2 are indeed respectively limited to 20% and 50% of the provisional power dispatching plan $P_{Market(h)}$. The post-contingency reserve capacities, $\Delta P_{g_j}^{max}$, of buses 1 and 2 are instead respectively limited to 15% and 40% of the real-time power dispatching plan, P_{go} .

The operating state has been chosen so as to highlight the benefits coming from the use of an UPFC on the reduction of the insecurity risk, already within intact system, current on line (1) is indeed close to 90% of its thermal limit.

For sake of simplicity, the cost coefficients vectors of the functions F and F^{post} (pre and post contingency generation rescheduling unitary costs (reserve costs)), rc_o and rc_j (both in M.U./h) respectively, are assumed equal.

As reported in Table 2, loads at buses 3 and 4 are supposed curtailable up to 50% of their loads demand, while bus 5 is supposed not curtailable. In the same table, the load shedding unitary costs vector in M.U./h, sc_p , is provided.

As shown in Table 3, referring to the (N-1) security, as consequence of contingencies (2) and (8), due to the reduced reserve flexibility of bus 1, load curtailments are needed within buses 3 and 4 to constraint current on line (1) to its thermal limit.

It can be noted that the correspondent expected insecurity cost is greater than 70% of the total management cost (H_{EcSED}).

Table 3 First test Results without UPFC

Bus	$\Delta P_{g_2}^*$	$\Delta P_{g_8}^*$	Bus	ΔP_2^*	ΔP_8^*
1	-0.40	-0.37	3	0.28	0.018
2	0.11	0.11	4	0.0	0.23

$F(\Delta P_{g_o})$	$\sum_{j=1}^L p_j G(\Delta P_j)$	$\sum_{j=1}^L p_j F^{post}(\Delta P_{g_j})$
0.0 M.U./h	0.37 M.U./h	0.1 M.U./h.
$H_{EcSED} = 0.47$ M.U./h.		

To reduce the aforesaid insecurity risk, it could be useful installing an UPFC on line (1) (see Fig. 5). This should allow moving the line (1) power flow to less loaded lines, such as line (2), on the occurrence of contingency (8) and vice versa. Such lines (2) and (8), in the intact system, are indeed loaded less than 50% of their thermal limits.

The capitalized UPFC unitary cost, c in p.u., is assumed equal to 2.7 M.U./h [13], while the interest rate, i , and the capital recovery plan, n , are respectively equal to 10% [13] and 10 years [15].

The question now is of which size the UPFC has to be installed. The following two experiments show how the proposed enhanced EcSED model can be used to suggest a proper UPFC size.

Let us consider two different load shedding costs configurations. The first configuration, higher than the previous one, is reported in Table 4.

Table 4 Reserve and load shedding costs configuration in test 2

Bus	rc_o	rc_j	Bus	sc_j
1	10	10	3	80
2	10	10	4	80

From the EcSED solution, an UPFC of 8 MVA has to be installed. As reported in Table 5, it can be noted that load sheddings are zero and the insecurity risk is consequently null. Furthermore, the total management cost results less than in the first test, even if the load shedding costs has been increased.

Table 5 Second test results with UPFC

Bus	$\Delta P^*_{g_2}$	$\Delta P^*_{g_8}$	Bus	ΔP^*_2	ΔP^*_8
1	-0.09	-0.06	3	0.0	0.0
2	0.11	0.09	4	0.0	0.0

$F(\Delta P_{g_o})$	$\sum_{j=1}^L p_j G(\Delta P_j)$	$\sum_{j=1}^L p_j F^{\text{post}}(\Delta P_{g_j})$	cA_{max}
0.0 M.U./h	0.0 M.U./h	0.035 M.U./h.	0.216 M.U./h.
$H_{\text{EcSED}} = 0.25 \text{ M.U./h.}$			

In the third test the load shedding cost is decreased with respect to the value used in the first test, as reported in Table 6.

Table 6 Reserve costs configuration in test 3

Bus	rc_o	rc_j	Bus	sc_j
1	10	10	3	40
2	10	10	4	40

From the EcSED solution an UPFC of 4 MVA has to be installed. As reported in Table 7, as expected, the UPFC size decreases while, conversely, the insecurity risk is different from zero.

Table 7 Reserve and load shedding costs configuration in test 2

Bus	$\Delta P^*_{g_2}$	$\Delta P^*_{g_8}$	Bus	ΔP^*_2	ΔP^*_8
1	-0.18	-0.12	3	0.08	0.0
2	0.11	0.10	4	0.0	0.02

$F(\Delta P_{g_o})$	$\sum_{j=1}^L p_j G(\Delta P_j)$	$\sum_{j=1}^L p_j F^{\text{post}}(\Delta P_{g_j})$	cA_{max}
0.0 M.U./h	0.07 M.U./h	0.05 M.U./h.	0.1 M.U./h.
$H_{\text{EcSED}} = 0.22 \text{ M.U./h.}$			

6. CONCLUSIONS

In the paper, an enhanced formulation of the EcSEC model embedding the UPFC investment cost is proposed to support the Independent System Operator (ISO) in its decision pertaining the choice of the UPFC size.

Some numerical experiments have proved the validity of the proposed model embedding the UPFC investment cost in the choice of the UPFC size, reaching a trade-off among all the costs accounted within the objective function.

As next steps of research, the authors are going to investigate on the optimal UPFC sizing, taking into account both the “load duration curve” and the possibility of considering the generation and load shedding costs variability.

7. NOMENCLATURE

P_g	=	vector of the active generation powers
P	=	vector of the active powers delivered to loads
Q	=	vector of the reactive powers delivered to loads
U	=	vector of the decision variables
X	=	vector of the other variables of the load flow equations
o	=	subscript denoting the intact state
j	=	subscript denoting the state after the j -th contingency
M.U.	=	monetary unit

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