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Load control through smart-metering on distribution networks

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***Abstract*-- Recent developments of distribution systems take advantages of new technical issues and networks equipments such as: DG (Distributed Generation), Smart Grids, Smart Metering, etc.. The aim of the paper is to propose an approach for load/generation control in distribution grid based on the solution of an OPF (Optimal Power Flow). The OPF dispatch local generation (DG), power injected by feeders and assess the load that needs to be curtailed in emergency conditions (isolated system, lack of, transport capacity onto the feeders, etc.). The proposed approach investigates about the possibility for Distribution Companies to reduce customer load up to 50% using signals coming from smart meters.**

The analysis also considers compensation costs for customers' supply interruption based on the actual Italian regulation.

***Index Terms*-- Distributed Generation, Optimal Power Flow, Smart Grids, Smart Metering.**

I. Introduction

THE deregulation of energy markets and the new common policies on sustainable development are probably the main driving forces for the rise of the Distributed Generation (DG) issue. Very often Distributed Generation is associated with the production of energy from renewable sources. This is not necessarily true since DG systems can be constituted by generating units built with any technology and powered with conventional or renewable sources. DG technologies usually include photovoltaics, all-size wind generators, biomass, micro-turbines, mini and micro-hydro, internal combustion engines, etc. [1]. Nevertheless, the issues of renewables and Distributed Generation are strictly related since energy production by renewable sources is very often performed on small scale. This is due to the actual local availability of the specific source but also to the fact that most environmental policies provide incentives for small scale production oriented to energy self-supply. In addition, the presence of DG close to urban areas is justified only if environmental friendly technologies are utilized such as high efficient cogeneration plants and renewables. DG gives a chance for going beyond the usual generation-transmission-distribution scheme where electric energy is produced in centralized power plants that exploit conventional fossil fuels, hydro or nuclear power, and is then transferred over long distance and distributed to end-users [2].

If energy is commonly flowing unidirectionally from generating plants to end-users, Distributed Generation introduces a new paradigm where energy can be injected in any node of the distribution network by means of generators connected to the distribution network that are not subjected to centralized planning or generation dispatch. The issue of Distributed Generation is therefore dealing with installing and operating small electrical generators, most of time connected via power converters, to the distribution network [1].

Small generators connected to the distribution system did always exist. The novelty in the concept of the Distribution Generation is that with a high penetration level of small-scale generation, the distribution network cannot be considered anymore as the passive appendage of the transmission network and the entire system must be re-designed and operated as an integrated unit [3].

Finding the right answer to distribution system design and operation are probably the main issues in DG. Optimizing grid operation and optimizing the physical infrastructure constitute, for example, the first two deployment priorities in the European Strategic Deployment Document for Europe's Electricity Network of the Future [4]. The so-called Smart Grids are complex technology systems that incorporate distributed generation, storage units, automation, communication systems, automation, and that should be able to perform multiple innovative functions such as self-healing, energy management or real-time pricing of energy, Automatic Meter Reading (AMR).

The primary role of AMR (Automatic Meter Reading) systems is to provide energy consumption data to the utility, but the cost of retrofitting the existing energy metering system may not be justified without added value functions. Currently many utilities in Europe are setting up large-scale AMR-projects. So far, remote reading of energy measurements is the main focus of such projects.

Italy is the country in Europe that reached the highest degree of penetration of such technology (the AMR has been installed for 86% of customers). First implementations of advanced AMR systems allowed to overcome the basic function of energy meter, transforming this piece of equipment into a smart terminal unit and a gateway for many functions and multiple services, able to guarantee a real-time bidirectional communication between customers and utilities. Distribution Companies (DisCos), in addition to traditional use in billing and load settlement, can adopt AMR systems as support to normal operation (automatic LV-fault indication, isolation and location, accurate voltage and load data), grid and asset management (load profiling), power quality monitoring, customer service, and load control [5].

The introduction of AMR is opening entirely new chances in energy and network management of DisCos. Centralized control of distributed resources is a possible application of AMR. It consists in controlling load, local generation and feeder power flows in order to match load demand with available generation. In the case of domestic users, several discounted special tariffs can be developed, aimed at compensating the reduced autonomy of end-users and giving the central system the right to control load demand. The customer accepts the risk of postponement or denial of use by the utility in return for a discount [6].

Although specific applications for load control have been already developed, the more general approach of exploiting AMR systems in network and electricity market management is still a rare application.

The present AMR meters offer the platform (i.e. the infrastructure and communication) to determine and develop new upper-level functions.

The possibility to control local generation and loads through the AMR technology provides the basic technology to design a new distribution grid (i.e. a smart grid). The possibility of dispatching generation and load gives the grid the necessary flexibility to manage price signals related to the energy bought through the feeders in ordinary operating conditions, load peaks and emergency conditions. Furthermore, control on interruptible (or dispatchable) loads and DG can be helpful to manage the system during emergency conditions (islanding of the distribution network, feeder overload, etc.) and to reduce the amount of curtailed load and the penalties due to load shedding.

II. Italian Regulation on Smart Grids and Smart Metering

The "Integrated Text of Authority for Electricity and Gas provisions for the delivery of the electricity transmission, distribution and metering services for regulatory period 2008-11" [7], issued by the Italian Authority (AEEG) for the period 2008-2011, has defined the regulation of a new tariff system for electricity transmission, distribution and metering services.

The new element introduced by this resolution, and relevant to this paper, is the introduction of a new mechanism that provides incentives to investments in distribution and smart grids. In particular, the cited document assesses the issue of distribution grid investments and their financial remuneration.

AEEG has formulated a compensation rate, defined according to WACC (*Weighted Average Cost of Capital)*, that is aimed at remunerating investments on grids, automation and metering. WACC has been set to 6.9% for transmission, 7% for distribution, and 7.2% for metering. In addition, AEEG has granted investments in automation systems, protections and control of smart grids a remuneration that raises with an additive 2% the WACC for 12 years [7].

Another important AEEG provision is Decision 202/2006 [8] which enforces the use of the automated meter reading (AMR) and smart meters in Italy. We recall that smart metering is a system that provides two-way communication, using the metering device as sender of time-series metering data and as receiver of control and price signals. This approach applies to several commodities (electric, gas, and so on) that are supplied to mass-market consumers (residential and small businesses consuming under a kilowatt threshold). Unlike AMR, smart metering takes advantage of communication channels with a bandwidth sufficient to deliver large quantities of data. Smart metering can receive communications for re-programming or appliance control.

Currently, 'smart' meters constitutes a very small percentage of installed meters in most of countries. This means that there is scarce knowledge on how customers may respond to time-based pricing structures and whether the potential benefits of this innovation (energy saving, market openness promotion, etc…) may be achieved. However, in the electricity sector, there are a number of frontrunner countries where the percentage of smart meters is already significant (86% in Italy). In particular, Italy and Sweden are planning to substitute 100% of the meters with 'smart' meters by 2011 and 2009 respectively. Denmark, Spain and Finland are planning to reach significant percentages of installations: Denmark 13% in 2010, Spain 65% in 2015 (and 100% by 2019, with no extra cost to electricity consumers) and Finland 60% in 2015 [9].

With the decision no. 292/06, December 18th 2006, (AEEG, 2006b), the Italian regulator established that the installation of smart meters, characterised by minimum functional requirements, for all household and non-household LV customers, is mandatory. The mandatory replacement programme will take place starting from 2008 and will last four years. It involves all DisCos, regardless of the number of the customers served [9]. The Italian Regulatory Authority is seeking to establish penalties for distributors failing to install smart metering. The Italian Regulatory Authority has also contributed government funds to the Project.

The Italian utility ENEL with ENEL's Telegestore Project is nearing completion of a project for the installation of 32 million smart meters that will enable tailored tariffs for residential customers. Another Italian utility ACEA proposed its own standard for smart metering.

The smart metering systems adopted in Italy can implement different classical functions (metering, automatic LV-fault indication, isolation and location, accurate voltage and load data). The specific function addressed in this paper, relevant to load control, regards the possibility of curtailing load utilizing the circuit breaker power threshold that is electronically and remotely programmable.

In conclusion, smart metering technologies are technically feasible and mature, at least for the electricity sector. Many manufacturers can supply competitive solutions, based on different functionalities, architecture and telecommunication systems. Currently, Italy experiences the largest diffusion of smart meters [9].

III. OPF Analysis

OPF is one of the most useful tool in power systems at generation/transmission level. The OPF finds the optimal value of control variables minimizing an objective function typically related to generation and operating costs. This optimization method takes also into account security and operating inequality constraints in order to ensure the practical viability of the optimal solution.

In distribution systems, this tool has been usually adopted for voltage profile control, loss reduction network configuration, etc. [10]. The development of DG introduces uncertainty in the previously mentioned problems, but also voltage control and new control variables useful optimization [11].

In literature, distribution reconfiguration and OPF problems have been studied separately [10]. In this paper we adopt a classical OPF formulation, suitably modified for distribution systems. The proposed formulation is based on an objective cost function oriented to minimize costs for the DisCo.

The objective function takes into account costs for buying energy from the feeders and from the local generation (DG), costs for reserve, costs associated to penalties or load shedding and costs due to unserved energy.

Active power associated to DG and load at selected buses participating to load shedding or curtailment are the control variables. Security constraints are taken into account for all main components of the grid (transformer limits, capacity constraints for feeders and lines, etc.).

Power system research has widely developed OPF analysis in order to solve problems ranging from economic dispatch to loss minimization [12] and is a common feature in many power flow packages. Thus, in spite of many difficulties the OPF appears to be a logical approach to optimize operating conditions in distribution grids. The generator models traditionally employed in OPF are synchronous generators operating in voltage control mode. Hence, assuming that DG is generally operated at a constant pre-set power factor, it is possible to identify a specific need to find alternative models and keep power factor constant during optimization. In order to overcome this issue, methods, proposed in literature, take advantage of the commonly adopted technique of modelling steady-state DGs as negative loads.

In the proposed approach, load shedding (or curtailment), DG power adjustment and control of import/export flows from/to subtransmission lines are also taken into account.

In this paper we compare two different policies. The Strategy 1 consists in shedding the amount of load needed to balance generation and load, evaluated on the basis of an OPF-like procedure, at selected buses. It is assessed that the DisCo pays a penalty for this load to be shed under the hypothesis that the number of annual interruptions without penalties were exceeded for all customers in the area under study. In this case, the energy is also bought hour by hour across the interface with the subtransmission grid.

The Strategy 2 consists in utilizing the OPF to evaluate the amount of energy to be bought from local generation and feeders and to allocate the amount of load to be curtailed among the customers that accepted the possibility to have a curtailment not exceeding 50% of the load.

Consequently, we define two different objective functions:

$$C_1 = \sum_{i=1}^{n_{lsh}} \alpha_i \left(P_{L\,old_i} - P_{L\,new_i}\right)^2 + \sum_{j=1}^{n_{\mathrm{int}}} \beta_i P_{\mathrm{int}_j}^2 \qquad (1)$$

where:

α_i is the penalty paid by the DisCos for load to be shed;

β_i is the hourly cost of energy bought from the subtransmission grid;

n_{lsh} and n_{int} are the number of selected nodes for load shedding and interface subtransmission lines respectively;

$P_{L\ old}$ is the active power at i-th node before load shedding;

$P_{L\ new}$ is the active power at i-th node after load control.

$$C_2 = C_1 + \sum_{i=1}^{n_{G_{DG}}} \gamma_i P_{DG_i}^2 \qquad (2)$$

where γ_i is the hourly cost for DisCo of the distributed generated power.

In order to represent a single objective function for both purposes, let us define:

$$C_0 = C_1 + k \sum_{i=1}^{n_{G_{DG}}} \gamma_i P_{DG_i}^2 \qquad (3)$$

where k has been introduced to take into account both objective functions. The variable k=0 applies to the objective function (1). If k=1 the C_2 function results active.

A. Control variables

When the cost function C_1 is minimized, the control variables are $\mathbf{P}_{L\ new}$ and $\mathbf{P}_{int\ j}$; in addition, when C_2 is the objective function variables $\mathbf{P}_{DGi}$ are controlled too.

The control vector *u* is in this case:

$$\mathbf{u} = [\mathbf{P}_{L_{new}}, \mathbf{P}_{\mathrm{int},j}, \mathbf{P}_{DG}] \qquad (4)$$

B. Equality Constraints

As usual in OPF formulations, equality constraints are constituted by load flow equations synthetically expressed as

$$\mathrm{f}(\mathbf{V},\mathbf{u}) \qquad (5)$$

where **V** denotes voltage in 2n- dimensional vector in polar coordinates and **u** is the control vector and n+1 is the number of the bus bars.

C. Inequality Constraints

Voltage magnitude are usually constrained between maximum V_i^M, and minimum V_i^m values:

$$\mathrm{V}_i^m \le \mathrm{V}_i \le \mathrm{V}_i^M \quad (i = 1,\ldots,n) \qquad (6)$$

as well as power flows are constrained by capacity limits of the power system components (lines, transformer, etc.);

$$\mathrm{T}_i^m \le \mathrm{T}_i \le \mathrm{T}_i^M \quad (i = 1,\ldots,b) \qquad (7)$$

where b denotes branches.

Furthermore, since usually distributed generation is operated at constant power factor (it is not usually voltage controlled) we impose a constant power factor on operated units:

$$Q_{G_i} = tg\varphi \, P_{G_i} \quad (i = 1,..., n_{PF}) \tag{8}$$

and

$$[P_{G_i}, Q_{G_i}] \in \Omega_i \tag{9}$$

where Ω_i denotes the capability curve of a specific generator.

The whole set of inequality constraints can be synthesized as:

$$\mathbf{h}(\mathbf{V},\mathbf{u}) = 0 \tag{10}$$

Finally, trivial constraints on control variables are:

$$0 \leq P_{L_i}^{new} \leq \delta \, P_{L_i}^{old} \tag{11}$$

where δ=1 for load shedding in Strategy 1 and δ=0,5 for load curtailment in Strategy 2.

D. The overall optimization algorithm

Under the previous illustrated assumptions, the optimization problem can be formulated as:

$$\min_u C_0(\mathbf{u}) \tag{12}$$

k = 0, 1 depending on the chosen policy;

$$\mathbf{f}(\mathbf{V},\mathbf{u}) = 0 \tag{13}$$

$$\mathbf{h}(\mathbf{V},\mathbf{u}) \leq 0 \tag{14}$$

In addition, we introduced inequality constraints through a penalty functions:

$$C_P(\mathbf{V},\mathbf{u}) = \begin{cases} 0 & if \quad \mathbf{h}(\mathbf{V},\mathbf{u}) \leq 0 \\ k \; \mathbf{h}^2(\mathbf{V},\mathbf{u}) & otherwise \end{cases} \tag{15}$$

In this case, the optimization problem in constrained by equality constraints only that is:

$$\min_u C_0(\mathbf{u}) + C_p(\mathbf{V},\mathbf{u}) \tag{16}$$

$$\mathbf{f}(\mathbf{V},\mathbf{u}) = 0 \tag{17}$$

An approach to the minimization of a function, in presence of equality constraints, consists in incorporating the inequalities in the objective functions by adopting the "penalty factor method". We treat the whole problem as a minimization in presence of the sole equality constraints by use of Lagrange multipliers [13].

By applying the optimization method of Lagrangian multipliers to the evaluation of the minimum of the function $(C_0 + C_P)$ it is possible to determine the solution of the problem above:

$$\mathrm{L} = C_0(\mathbf{u}) + C_P(\mathbf{V},\mathbf{u}) + \lambda^T \mathbf{f}(\mathbf{V},\mathbf{u}) \tag{18}$$

$$\frac{\partial \, \mathrm{L}}{\partial \, \mathbf{V}} = \lambda^T \frac{\partial \, \mathbf{f}}{\partial \, \mathbf{V}} + \frac{\partial \, C_P}{\partial \, \mathbf{V}} = 0 \tag{19}$$

$$\frac{\partial \mathrm{L}}{\partial \mathbf{u}} = \frac{\partial C_0}{\partial \mathbf{u}} + \frac{\partial C_P}{\partial \mathbf{u}} + \lambda^T \frac{\partial \mathbf{f}}{\partial \mathbf{u}} = 0 \tag{20}$$

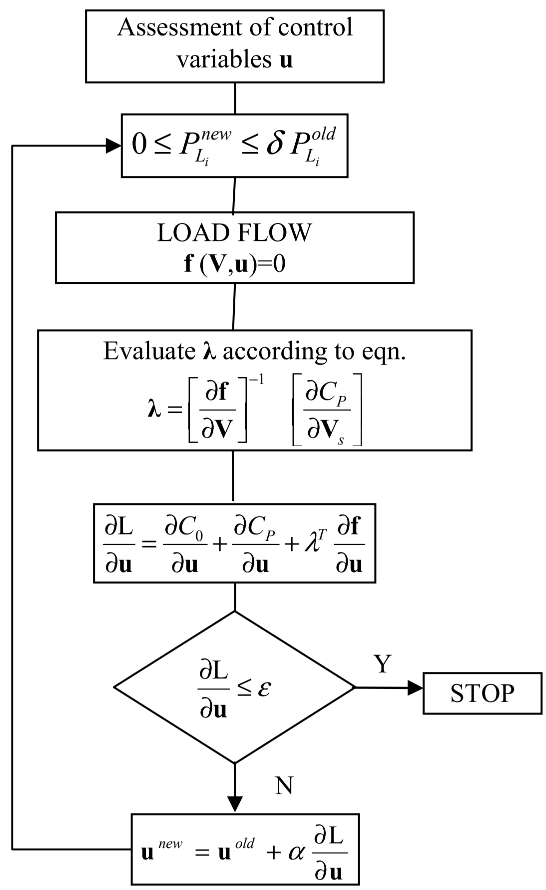

Fig. 1 Flow chart of the algorithm

To solve the set of the first order necessary conditions for optimization, we adopted the Generalized Reduced Gradient method (GRG) [13-14]. This choice derives from the simplicity of the method, which involves only first derivatives without computing Hessian matrices as in Newton-like methods, which would increase significantly the algorithmic complexity of the problem.

The flow chart of the proposed approach is shown in Fig.1, where α denotes a convergence acceleration factor. It should be remarked that assuming a constant cosφ during load shedding, the reactive power is updated through:

$$Q_{\mathrm{L}}^{new} = P_{\mathrm{L}}^{new} \tan\varphi \qquad (21)$$

As usual in the GRG method, Equation (11) are directly taken into account constraining control variables during the iterative process.

IV. Test Results

The proposed approach was tested on the "IEEE 34 Node Test Feeder" [12], suitably modified for the implementation of a distribution system with embedded Distributed Generation. The test system included 4 wind turbines producing 1 MW each, 2 photovoltaic plants producing 800 kW each and one gas-turbine generator (24 MW) associated to a CHP (Combined Heat and Power). The maximum transport capacity of the feeder was assumed to be 40 MW.

Different generation costs were assumed for each source. Costs were fixed at 110€/MWh for wind turbines, 550€/MWh for photovoltaic and 95 €/MWh for the gas turbine. It was assumed that distributors are buying energy from the subtransmission system tariff at 140 €/MWh (during peak hours). For the simulated scenario the overall load was estimated in 49 MW (at the peak). The unserved energy was assumed to have the value of 200€/MWh.

According to these hypotheses, the energy bought from transmission is always more expensive than the one locally produced during peaking periods.

Figure 2 shows the test grid used in the simulation. Data in table 1 and table 2 are referred to Load and Generation at each node.

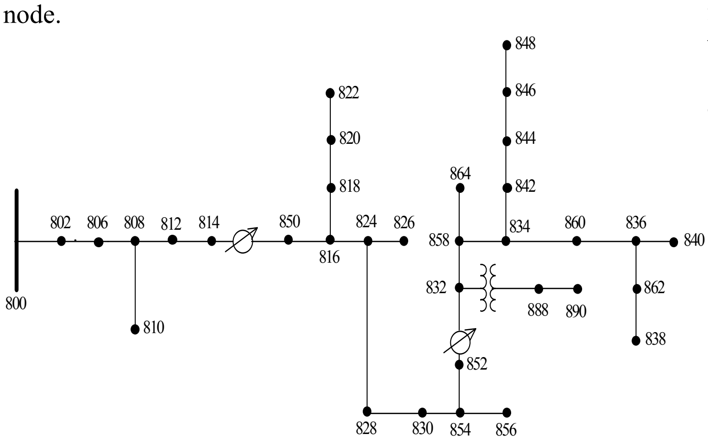

Fig. 2 Representation of the modified IEEE 34 Node Test Feeder

In our test, to fix the penalty value for the interruption of loads we adopted the current Italian regulation.

The text was formulated in consideration of the observations submitted by operators with respect to the three consultation documents and on the basis of the guidelines that emerged from the regulatory impact analysis.

TABLE I
POWER LOAD PER NODE

Node	Load (MW)	Node	Load (MW)
800	-	856	0.60
802	1.91	852	0.85
806	1.90	832	0.44
808	0.53	888	2.21
810	4.91	890	2.70
812	0.59	858	1.00
814	0.84	864	0.52
850	0.15	834	2.60
816	0.02	842	0.30
818	1.13	844	0.85
820	1.18	846	0.75
822	8.00	848	1.00
824	0.15	860	4.65
826	6.20	836	1.31
828	0.20	862	0.92
830	0.12	838	0.10
854	0.12	840	0.88

TABLE II
POWER GENERATION PER NODE

Node	Gen. (MW)	Type
800	-	-
806	2.00	Wind
810	0.80	PV
822	0.80	PV
840	2.00	Wind
856	24.00	Turbine

The AEEG has defined the continuity levels in supplying medium voltage loads.. These levels are defined in terms of the number of long interruptions per year and depends on the geographical area they refer to. The maximum number of long interruptions per customer should not exceed a specific threshold between 3 and 5 depending on the particular area.

Moreover AEEG has fixed penalties for DisCo in failure to comply continuity of service and compensations for users.

Equation (21) defines the penalty (*P)*:

$$P = \sum_{i=s+1}^{\min(w \times s;n)} (\mathbf{V}_P \times PMI_i) \qquad (21)$$

where:

- w is the threshold for long interruptions;
- n is the number of interruptions for which the specific levels of service continuity are not respected
- s is the specific level of continuity
- PMI_i, is the average interrupted power (kW) of a specific customer referred to the *i*-interruption;
- V_p depends on the interrupted power and is equal to 2,5 €/kW for loads less than 500kW and 2 €/kW for loads exceeding 500kW.

Equation (22) shows the compensation (*I*)for each user:

$$I = \sum_{i=s+1}^{\min(w \times s; n)} (V_P \times PMI_i) \qquad (22)$$

where w, n, s, PMI_i and Vp have been previously defined.

We assumed that this compensation is adopted to evaluate the interruption costs in our tests, i.e. loads are compensated with an amount of money between 2 and 2,5 €/kW if the number of annual interruptions is exceeded for a particular customer [16].

The first test is aimed at studying the behaviour of a smart distribution grid in the presence of distributed generation and interruptible supply contracts when the feeders and the local generation are not able to supply the full load. It has been assumed that the gas turbine (GT) unit was unavailable and the feeders were overloaded.

Simulations are based on the hypothesis that specific interruptible supply contracts allow the Distribution Company (DisCo) to curtail the load up to 50% rate through remote control. This is actually possible according to Italian installed AMD which can reduce the circuit power threshold of 15% for customers in arrears. For each interrupted MWh, it was assumed that the DisCo has to pay a fee. If customers are equipped with an Automatic Metering Device, the equipment permits to control the maximum supplied demand of each customer by remote control.

The OPF analyses were performed considering as objective function the overall cost of energy for the Disco. This cost takes into account: energy bought from the subtransmission network and the local distributed generation, load curtailment costs and the lack of revenues for the unserved energy. Due to the formulation of the overall objective function, the energy cost of power losses are also kept into account.

Two policies were compared here. The first one consists in shedding the amount of load needed to balance generation and load, evaluated on the basis of an OPF-like procedure, at selected buses (bus # 826 and bus # 822). It was assessed that the DisCo pays the penalty of 2,5 €/kW for this load to be shed under the hypothesis that the number of annual interruptions without penalties were exceeded for all customers in the area object of the study. In this case, the overall hourly cost of the bought energy, the cost of the penalties and the cost due to the unserved energy is equal to: 24,200 €/h. Losses are equal to : 2.45 MW.

The second policy consists in utilizing the OPF to evaluate the amount of energy to be bought from local generation and feeders and to allocate the amount of load to be curtailed among the customers that accepted the possibility to have a curtailment not exceeding 50% of the load. The fee recognized by the DisCo to the customer has been assumed to be 100€/MWh. In this case, the overall cost is equal to 8750 €/h and losses are equal to: 2.33 MW. It can be observed that the choice operated by the OPF reduces the overall cost and losses with regard to the first policy.

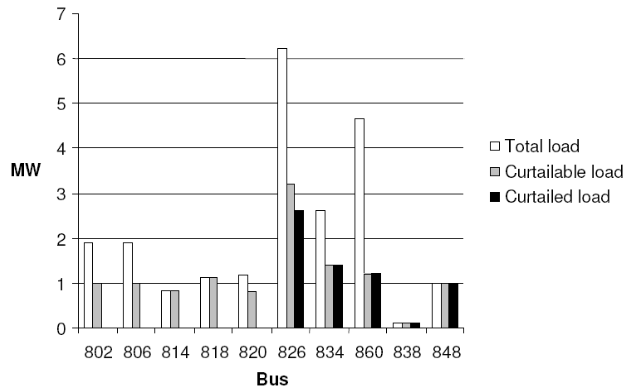

Fig. 3 OPF loads allocating procedure

In Fig. 3 it is shown how the OPF procedure allocates the load curtailment on the basis of the assumed fee paid to the customers by the DisCo. In Table III fees for each selected node are presented. It can be observed that the algorithm chooses loads far from the feeder and the local generation since the reduction of the load allows a reduction of power losses.

The second test case deal with another interesting application of the Distribution OPF and smart grids consists in utilizing these tools for selecting the buses and assessing the amount of load to be shed to guarantee the supplying of energy to the maximum amount of load when the system operates isolated (i.e. with a lack of power flow coming trough the feeders).

In this case, we assumed that the compensation adopted by the Italian regulation is utilized to evaluate the interruption costs i.e. loads are compensated with an amount of money between 2 and 2,5 €/kW if the number of annual interruptions is exceeded for a particular customer.

Furthermore, we assumed, in this test, there are some buses for which the penalties are zero since they are supposed not to have experienced a number of long interruptions exceeding the Italian regulation threshold for a particular year. Test results are shown in Fig. 4.

Figure 4 shows that the OPF can operate a choice in selecting the most appropriate buses where the load need to be shed minimizing the overall cost which takes into account economical parameters such as the cost of local generation, penalties and the cost of the energy bought trough the feeder but also power losses which are taken into account on the basis of the cost of the extra energy which need to be bought for them.

Smart metering can ensure the technology to send the right control signals to selected customers to shed or curtail the load. OPF technology is the right tool to allocate the load to be shed and assess, in real-time, the right amount of load which need to be shed.

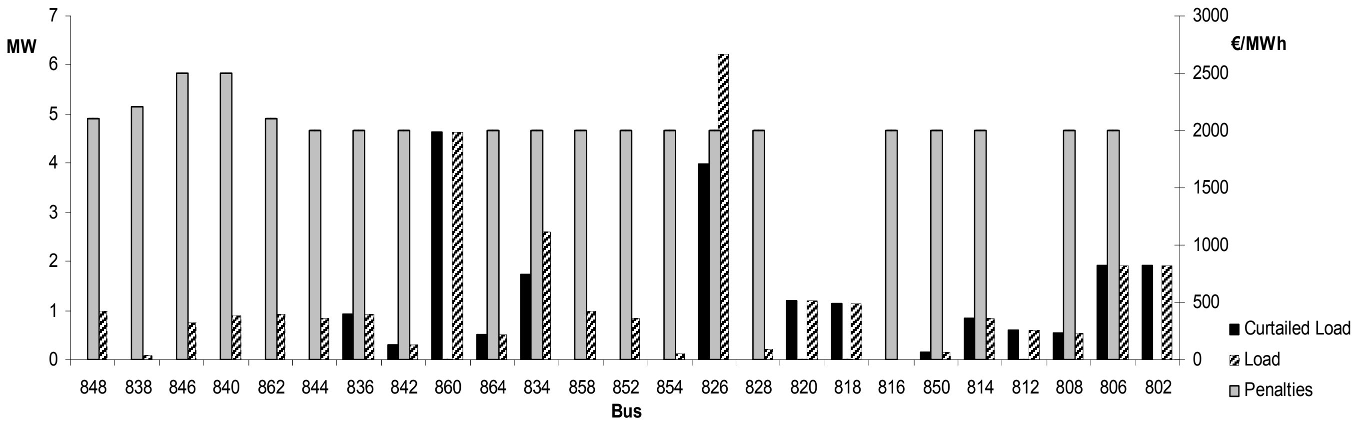

Fig. 4 Curtailed loads minimizing the overall cost due to penalties

TABLE III
POWER GENERATION PER NODE

Bus	Fee [€/MWh]	Bus	Fee [€/MWh]
848	2500	854	2000
838	2100	826	2000
846	2200	828	2000
840	2500	820	2000
862	2500	818	0
844	2100	816	0
836	2000	850	2000
842	2000	814	2000
860	2000	812	2000
864	0	808	0
834	2000	806	2000
858	2000	802	2000
852	2000		

The computational complexity of the approach is typical of OPF problems. In this case under investigation, no convergence problems were experienced. In Table IV the CPU time and the number of iterations for the two tested strategies is reported. We stress here that algorithmic features of the OPF problem were not optimized since the focus of the paper was basically on testing the feasibility of adopting smart metering to improve distribution operations in a more market-oriented fashion.

TABLE IV
COMPUTATIONAL TIME

Strategy	k	Iterations	CPU time [s]
Optimize C_1	0	15	525
Optimize C_2	1	22	770

For our test we used a DEC ALPHA SERVER 800-8/333 characterized by a CPU of 333MHz, 256 RAM and 4 GB disk space.

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VI. Biographies

Sergio Bruno was born in Bari, Italy, in 1975. He received the degree in Electrical Engineering from Politecnico di Bari (Italy) in 2000 and his Ph.D. in Electrical Engineering from Politecnico di Bari in 2004. He has been involved in research activities with the Politecnico di Bari and is currently consultant for energy and environment for the Strategic Plan of the Bari Metropolitan Area. His recent studies deal with Power System Dynamics and Control, FACTS technologies and Energy Markets.

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