Pricing and Control in the Next Generation Power Distribution System

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***Abstract*—Smart grid technologies are gaining acceptance and are being integrated into power distribution systems as a result of public and private investment and funding. However, costs of these technologies appear to be a clear obstacle in the widespread integration and maximal use of these technologies. In this paper, the utilization of dollar pricing signals is proposed and illustrated for power distribution engineering. A signal modeled after locational marginal pricing from transmission engineering is proposed to provide pricing data locally in distribution systems. The calculation, utilization, advantages, and shortcomings of the concept are presented. A main conclusion is that the use of a distribution locational marginal price signal fits well with an electronically controlled power distribution system.**

***Index Terms*—Direct digital control, distributed control, distributed resources, distribution engineering, locational marginal prices, power system control, solid state controllers, state estimation.**

I. Introduction and Motivation

SMART GRID technologies appear to be especially applicable to electric power distribution systems because there are a number of control and optimization possibilities near the point of end use. The smart grid as outlined implies that control and optimization should be used in all elements of power systems, and recently new initiatives have been put forth to control and manage energy and resources in power distribution systems. The essence of many of the newer technologies appears to be mainly on electronic controllers such as distribution class electronic switches. One example is the solid state transformer (SST) which is an electronic controller intended to replace or supplant distribution transformers in some applications. Recent advances in the use of sensory measurements and information processing to achieve smart grid objectives include [1]–[3]; pricing in distribution systems [4]; the utilization of electronic controllers in distribution systems [5]–[7]; and remarks on the next generation of power distribution systems [8].

In this paper, attention turns to the pricing infrastructure as a control mechanism to implement and encourage the utilization of renewable energy resources in distribution systems. The essence of the paper is that pricing signals may be developed to generate control signals for the electronic devices that are expected to appear in the power distribution system of the future. The reason for the use of pricing information is that the development of renewable resources requires economic soundness and motivation in addition to the innovative use of electronic controls.

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II. Envisioned New Features of the Distribution System of the Future

The main envisioned features of the distribution system of the future include: electronic controls for power at the customer level; high percentage of renewable energy penetration; storage of energy at some customers and perhaps at substations; a power distribution infrastructure that encourages renewable energy development, and customer loads that are capable of responding to changes in the grid. It is expected that these features will be implemented through the use of digital communication of signals including pricing information; electronic controllers capable of high speed control of power in some distribution circuits; direct digital control of some fraction of energy flows in distribution primary circuits and at customer sites; and the utilization of optimal strategies for the operation of storage devices. Several of these features and capabilities are discussed below.

A. A Distribution Class State Estimator

Power system state estimators utilize measurements to obtain the full state of the power system and are used for operations. Traditionally, this involves the minimization of the square of the 2-norm of a real valued residual vector r which represents the difference between an assumed process model $h(x)$ and measurements z ($h(x)$ is a nonlinear vector valued function of the vector valued argument x). It is assumed that the measurements are not exact, and are contaminated with noise η. When $h(x)$ is linearized the residual r,

$$r = z + \eta - hx$$

where hx denotes the process matrix h times the state vector x, i.e., the linearized formulation. Then,

$$\frac{\partial}{\partial x}(r^t r) = 0. \tag{1}$$

Solving for the 'least squares' estimate of x,

$$\hat{x} = h^+ z \tag{2}$$

where h^+ refers to the pseudoinverse of the real valued matrix h and the notation $\hat{x}$ refers to the estimate of x. This is the unbiased, least squares estimator. The details of this calculation, the inclusion of weights to bias the estimator, and many additional details will be found in [9]. Nominally, the measurements in transmission engineering applications include active and reactive power flows and bus voltage and line current magnitudes.

In the distribution engineering application, *synchronous measurements* could be used to acquire the z vector. The synchronous measurements are in fact synchrophasors that are time stamped using the global positioning satellite. The difference from the aforementioned transmission application is that voltage and current measurements in full phasor form are envisioned. These synchronous measurements are *phasors*, and hence the residual is a complex valued vector. Using the notation $(\cdot)^H$ to denote the Hermitian operation, the minimization of $r^H r$ entails the simultaneous solution of

$$\frac{\partial}{\partial x_r} r^H r = 0 \qquad \frac{\partial}{\partial x_i} r^H r = 0$$

where the x_i and x_r vectors are the real parts of the state vector x. In this distribution application, the estimator is

$$\begin{bmatrix} \hat{x}_r \\ \hat{x}_i \end{bmatrix} = \begin{bmatrix} h_r & -h_i \\ h_i & h_r \end{bmatrix}^+ \begin{bmatrix} z_r \\ z_i \end{bmatrix}. \tag{3}$$

A distribution state estimator is proposed in order to implement control features. That is, state estimates drive the calculation of pricing signals, and these signals drive distribution system controls. Fig. 1 (at the left) shows the proposed signal flow. Fig. 1 (at the right) depicts how sensors may be placed to develop the measurement vector z. The main issues in distribution state estimation are:

- High R/X ratio: tests reveal that a relatively high R/X ratio in distribution conductors does not degrade the state estimation. This is the case because real and imaginary parts of x and z are fully modeled as indicated above.
- Appearance of single phase laterals: distribution systems often include single phase subsystems. The approaches in this regard are to either model full three phase detail or to group buses such that positive sequence analysis is valid.
- The number and placement of synchrophasor measurements and the use of "smart meter" measurements generally total about $3n$ to $4n$ measurements for the case of n states to be estimated.
- Latency of measured signals is not a serious issue if the geographical extent of the distribution system is mainly limited to within 20 km. Also, since pricing signals are to be developed from the state estimates in the 5 to 60 min range, communication and latency issues are minimal.

B. Storage Devices

Contemporary power distribution systems generally do not include energy storage except perhaps the thermal storage in the form of water heaters and heating, ventilating, and air conditioning systems might be viewed as storage. However, in distribution systems of the future, one might envision distributed electrical storage. At the residential level, this might be in the range of 5 to 10 kWh; at the industrial level, energy storage might reach 1 MWh or more. At the low end of this range, batteries are envisioned, while at the high end, thermal energy storage seems to be more appropriate (and this has already been commercialized in connection with utility scale concentrated thermal energy storage).

The scheduling of energy charge and discharge cycles involves multiobjective optimization [10]–[12]. A multiobjective optimization problem (MOP) is the quantitative assessment of

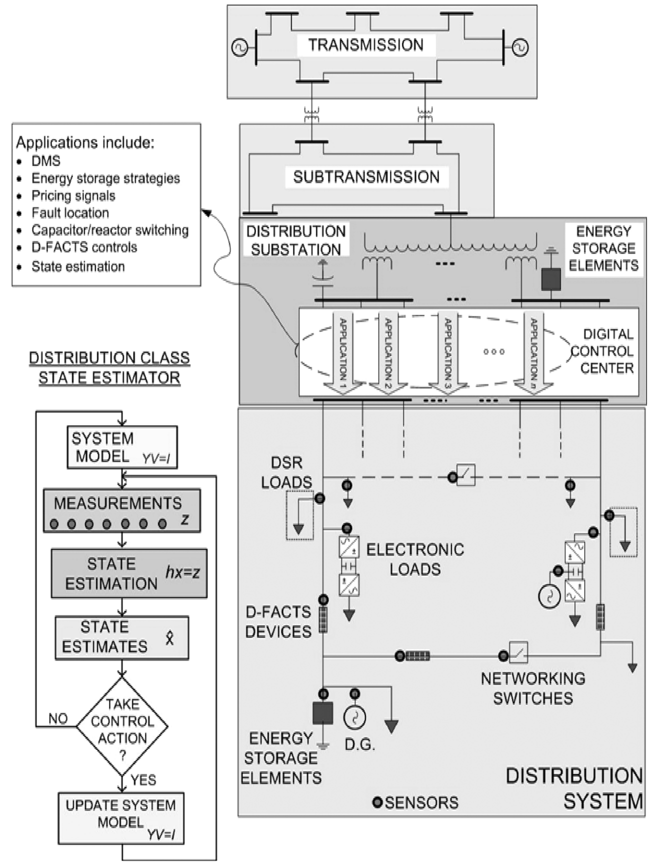

Fig. 1. Utilization of a distribution class state estimator: a new feature in distribution systems.

a control variable X in simultaneous view of p objective functions. The p objective functions can be united into a single objective vector f as follows:

$$f(\Re^n \rightarrow \Re^p) \equiv \left\{ X \mapsto f(X) = (f_1(X), f_2(X) \ldots f_p(X))^T \right\}. \tag{4}$$

Since an individual function could contradict another and be incommensurable, it is necessary to formulate f in a meaningful form, accommodating all functions in f. This necessitates the need for an appropriate optimality criterion called Pareto optimality. Hence, it is possible to find an optimal frontier (called the Pareto optimal front) of Pareto optimal solution points for a given problem, which also describes the trade-offs between the objective functions considered in the formulation. In the forthcoming sections, the objectives considered for one such multiobjective formulation for distribution system control has been depicted in detail. The normal boundary intersection method has been utilized for solving the multiobjective optimization problem.

C. Line Flow Controls—D-FACTS

Flexible ac transmission (FACTS) controllers have been proposed for large scale power flow control and modulation. This is a solid state electronic technology that uses converters to effectuate power flow control. This approach has been used in distribution engineering with a limited range of applications (so-called D-FACTS, e.g., [13]). While congestion management in transmission systems has been in place for several years, this concept has not been deployed to the same extent in distribution engineering because distribution systems are not usually networked and also distribution systems are often so robustly designed that most credible power flows can be readily accommodated. It is likely that with a higher percentage of networking of the primary distribution system, and the conversion to higher primary voltages (e.g., 35 kV class), over-robust designs will be less common. Thus power flow control would be more attractive. This is the envisioned increase in proliferation of D-FACTS.

D. Additional Features and Characteristics of Future Distribution Systems

The core discussion in this paper relates to distribution system control. Contemporary distribution systems have a dearth of controls, but future distribution systems may have additional opportunities for operational control. These additional control features may be able to appeal to distribution energy pricing signals to effectuate their control. Also, some features of the next generation of power distribution systems may use alternative signals to assist in control features. Solid state energy management control devices both at the point of end use and in series with distribution lines are examples of future control devices. The characteristics of the future system area matter of conjecture, but surely intelligent fault interruption may play a role [14], [15]. The distribution system of the future may also embody advanced technologies in the form of:

- higher primary distribution voltages (e.g., to and above the 35 kV class);
- more widespread utilization of both primary and secondary networking to enhance reliability;
- standardized connection voltages for distributed generation, for example direct connection to 35 kV circuits for generation above 50 kVA;
- development of self-healing strategies to remove failed circuit components.

III. Alternative Control Architectures

Fig. 2 shows the control architecture of two alternative approaches to control. The figure labeled Gen I at Fig. 2(a) is based on a *centralized control* approach. In a centralized control approach all power, voltage, and frequency measurements are sent to a centralized optimization routine that incorporates the pricing signals to determine the SST settings to provide the desired outputs. In the centralized control the inputs signals to the optimization routine scale linearly with the number of SSTs in the system. In Fig. 2(b) (labeled Gen II), the control is *decentralized*. In this approach, the optimization is performed locally and pseudo-optimality is obtained through message passing and coordination between the intelligent energy management (IEM) nodes. Each IEM node consists of the physical SST and the coordinating software ("agents") that incorporate the pricing signals to determine the output.

If no delay, error, or noise existed in the system, the decentralized control will approach the outcome of the centralized control as each IEM develops its own state representation of the system. The time frame in which each of these controls operates is indicated on the left axis of Fig. 2(a). Local control of the SSTs (such as gating controls) operates in the subsecond timeframe. Frequency regulation will operate in the second time frame to maintain load and distribution balance. Economic control will occur in the range of (sub-) minutes to hours depending on the frequency of the available pricing signals.

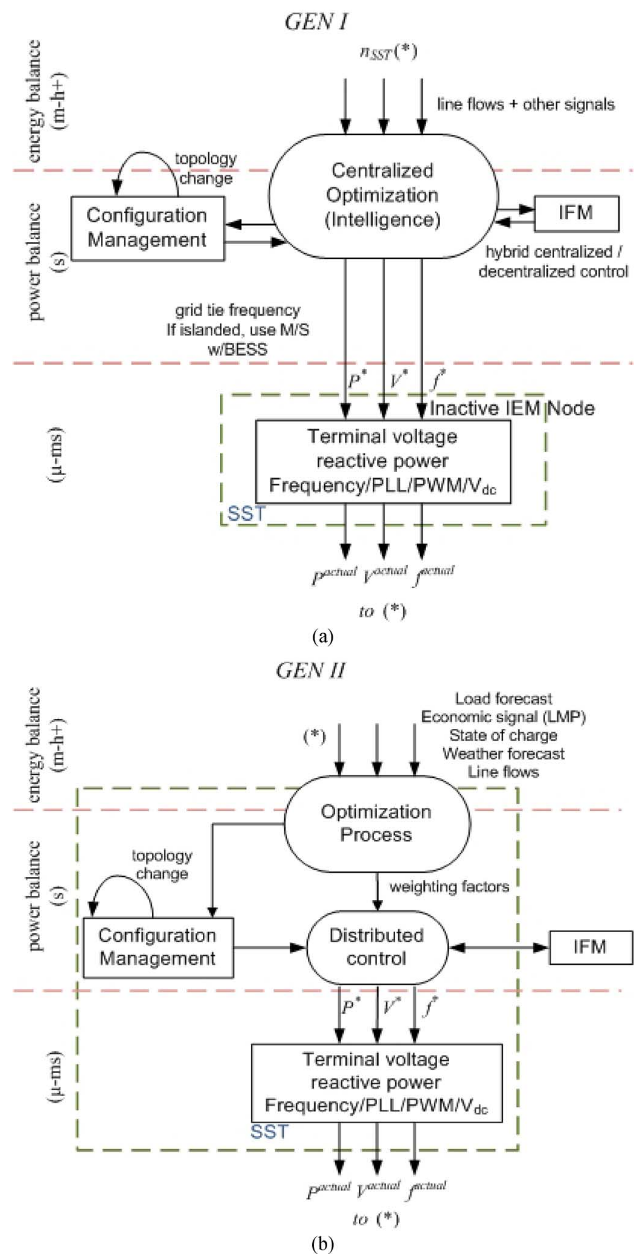

Fig. 2. (a) Generation I (centralized control) and (b) generation II (decentralized control) of a control infrastructure for future distribution systems. The objective is to introduce pricing for control in distribution systems. Intelligent energy management (IEM) and intelligent fault management (IFM) is implemented in these designs. (a) Centralized control. (b) Decentralized control.

IV. The DLMP

Much of the electric power industry has been cost/benefit driven for many years. This suggests that there shall be a focus on distribution engineering to realize benefits of future investments in the overall power system. Drivers may include the public impetus for disbursed generation that does not produce greenhouse gases, allocation of costs where they are warranted, maintaining high levels of reliability appropriate for a digital society, and compliance with a view to modernization. In transmission systems, one signal that effectuates some of these drivers is the locational marginal price (LMP) defined as the cost to deliver the next megawatt hour to a given transmission bus.

Electric market theory suggests that real-time pricing at the distribution level will provide increased economic efficiency, delivering the fairest prices to both the buyer and the seller [16]. Extending Schweppe's ideas on the LMP, that spatial and temporal spot pricing of electricity reflects the truest cost [17], a LMP for the distribution system can be developed as a form of accurate real-time pricing for the customer. Such a distribution level LMP would lower the customers' average monthly bill, mitigate the need to build further peaking capacity, and decrease CO_2 emissions [18]. System reliability would also benefit as the increased prices during times of network congestion would reduce the demand on the constrained lines. A distribution locational marginal price appears to be a promising instrument for modernizing and deregulating the electric distribution system. Three alternative formulations of the distribution class LMP signal are described below.

The concept of an LMP may be translated to a distribution system milieu by adopting the basic concept of cost of energy at the substation, i.e., the transmission LMP, and inclusion of distribution objectives and costs. There are several alternative formulations offered for the distribution LMP. One such reformulated LMP is the distribution LMP (DLMP) defined as

$$\begin{aligned} DLMP &= w_1 \sum_{i \in sources} \pi_i LMP_i + w_2 \sum_{k \in lines} (|I_k + \Delta I_k|^2 - |I_k|^2) r_k \\ &+ w_3 \sum_{\gamma \in renew\ gen} P_\gamma + w_4 \sum_{k \in lines} \frac{|I_k|}{I_k^{rating}}. \end{aligned} \tag{5}$$

In this formulation, the DLMP differs from its transmission counterpart in that added terms are inserted to capture conceptualized objectives such as renewable resource encouragement. In this formulation, the various terms are defined as: (1) the DLMP is the transmission LMP at the supply substation and π_i denotes the generation participation factor at connection bus I; (2) a term that captures the cost of losses in the distribution system in each line k (r_k denotes line resistance) using $(|I+\Delta I|^2 - |I|^2)r$ to obtain the *incremental* line active power lost (3) a term that captures the objective of encouragement of the use of renewable resources at the given load point; and (4) a term that relates to the circuit loading represented as a fraction of the circuit rating, and this is a cost associated with reduction in congestion in a networked distribution system.

In (5), the four disparate terms are observed to respectively reflect the cost of energy at substation; a term that captures the energy losses in the distribution lines evaluated as the $|I|^2 r$ losses over an hour; the value of renewable generation P_γ over one hour; and a heuristically formulated term that penalizes high circuit current loading. Each of the four terms is weighted by a w_i parameter to render the DLMP in consistent units ($/MWh). In the case of the fourth term which captures the circuit current loading ($|I_k|/I_k^{rating}$), w_4 is selected to produce the desired penalty for high loading. The selection of the w_i is heuristic and involves experience with the system and the desired control objective.

A distributed methodology for calculating the DLMPs without the presence of a centralized entity to oversee transactions is developed and compared against the centralized LMP concept. With the distributed DLMP scheme, each load and generation element can communicate with one another directly and determine locational marginal prices. Just as some customers' electric bills are itemized it is possible to include a breakdown of component costs as per the term in (5).

A. Alternate Formulations of a DLMP

An alternate formulation of the DLMP, denoted δ_k at any distribution node k

$$\delta_k = w_5 \sum_{i=1}^{N} \pi_i LMP_i + w_6 \sum_{l=1}^{m} \frac{\partial P_{loss,l}}{\partial P_k} + w_7 \sum_{l=1}^{m} \frac{\partial P_l}{\partial P_k}. \tag{6}$$

As an example, w_5 might be 1.00, and w_6 and w_7 in the range $\{5.0 \text{ to } 10.0 \text{ cents/kWh}\}$. For the sake of simplicity, the component relating to the encouragement of renewable generation use has been ignored here. In (6), the first term is a summation of the transmission LMP component with generation participation factors, where N is the total number of supply connections. The second term in (6) is the loss component of the DLMP. This term is the rate of change of active power losses in a feeder segment l with respect to the load at node $k(P_k)$. This second term is calculated as a sum over all feeder segments in the network. Assuming the voltage magnitude at node k to be a constant,

$$\sum_{l=1}^{m} \frac{\partial P_{loss,l}}{\partial P_k} = \sum_{l=1}^{m} \frac{2 I_l R_l}{|V_k| \, \phi_k} \frac{\partial I_l}{\partial I_k}. \tag{7}$$

The rate of change of line current (I_l) with load current (I_k) is computed by calculating the power transfer distribution factors for the distribution network. The third term in (6), takes into account the cost of congestion of the distribution network,

$$\sum_{l=1}^{m} \frac{\partial P_l}{\partial P_k} = \sum_{l=1}^{m} f_{l,k}. \tag{8}$$

As indicated for (5), the w_i in (6) are selected using an assumed one hour time interval, and a heuristically obtained penalty for losses in the circuit loading.

The DC-OPF model [19], [20] is commonly used in the calculation of LMPs in the transmission network. Based on the DC-OPF model, the branch flow in branch l of the network as a function of the change in load at node k of the network (denoted by f_{lk}) is computed as the element on the l^{th} row and k^{th} column of matrix T,

$$f_{lk} = [T]_{(l,k)} = HA \begin{bmatrix} (B')^{-1} & \vdots \\ \cdots & 0 \end{bmatrix}. \tag{9}$$

Note that H ($m \times m$) is primitive line admittance matrix, A ($m \times n$) is the bus-line incidence matrix, and B' ($n-1 \times n-1$) is the modified susceptance matrix; where m is the number of lines and n is the number of buses.

The application of marginal pricing concepts in the distribution system can also be seen as increasing the capability of control in a distribution system. Controls in the area of voltage regulation and protection already exist in the distribution systems. With the increased advent of distributed infrastructure, (i.e., distributed sources and storage capability) control of the distributed resources can be effectuated by means of the DLMP. At this juncture, it is also imperative to understand the inherent differences between traditional LMPs used in a market environment, and the conceptualized DLMPs presented here. Traditionally, LMPs are calculated system-wide across an interconnected transmission network as the optimal cost of delivering the next megawatt-hour of energy at each node of interest. The DLMPs are built on the traditional LMP framework, i.e., using the transmission LMP component with participation factors at each supply node. Further they have been designed to include the incremental losses and congestion in the branches, which will be incurred in the distribution feeder to deliver the next kilowatt-hour at a load node. In the next section it will be shown how this signal is then utilized to control the distribution system, and optimize several different objectives therein.

B. Alternate Formulation II Based on OPF: Inclusion of Renewable Energy Incentives

Considering the AC-OPF model, the DLMPs at each bus could be calculated using a similar formulation as (5). The DLMP is decomposed into marginal energy cost component (MEC); marginal loss component (MLC); and marginal congestion component (MCC). The AC-OPF objective function is to minimize the total energy cost to supply demand in a distribution system with security constraints (e.g., voltage limits and line flow limits) and generation constraints. The AC-OPF formulation and DLMP derivation can be simplified as

$$\min : F(x, u)$$

subject to constraints

$$G(x, u) = 0 \qquad H(x, u) \leq 0 \tag{10}$$

where x is a vector of dependent variables (the bus voltage magnitudes and angles); u is a vector of generation from renewable DGs, the energy storage elements and the legacy grid; $F(x, u)$ is the objective function (the total cost of power generation). This approach is offered as an alternate formulation of the DLMP. Note that the costs of renewable DGs and energy storage are multiplied by incentive factors in a fashion similar to the third term in (5); the function $G(x, u)$ is the set of equality constraints (the real and reactive power balance equations); and $H(x, u)$ is the set of system constraints (line flows, bus voltage and generation limits). The constrained minimization posed in (10) is solved using Lagrange multipliers in (11). And the DLMP at bus k is computed by differentiating the lagrangian with respect to P_k.

$$\mathcal{L} = F(x, u) + \sum_{k=1}^{N} \lambda_k G_k(x, u) + \sum_{l=1}^{M} \gamma_l H_l(x, u). \tag{11}$$

The DLMP at bus k is derived in this formulation as

$$\delta_k = \frac{\partial \mathcal{L}}{\partial P_k} = \lambda_k + \lambda_k \sum_{l=1}^{m} \frac{\partial P_{loss,l}}{\partial P_k} + \sum_{l=1}^{m} \gamma_l \frac{\partial P_l}{\partial P_k}. \tag{12}$$

This formulation is an alternative to (6). The first term in (12) is MEC; the second term is MLC; the last term is MCC. The values of λ_k and γ_l can be found from OPF results.

C. Illustrative Tests and Results

The above algorithms have been individually implemented on a 12-bus distribution test bed indicated in Fig. 3, and a comparison of results obtained is shown in Fig. 4. The system configuration is listed in Table I and system data in Table II.

It is assumed that each DG consists of a commercially located 100 kVA photovoltaic array and a 250 kVA wind turbine. The hourly renewable generation may vary with weather conditions, and thus may not follow the demand changes. It is also assumed that the energy cost from renewable DGs and storage devices are more competitive than that from the legacy grid because of the "encouragement factors." Fig. 4 shows simulation results in which the upper trace is the DLMP (read the right scale); the middle two traces are the total DG and total load (read the power scale at the left); and the lower two traces are the generation at bus 1 (read the left scale) and the storage energy expressed in per unit kWh at the left scale (1.0 per unit power is 1.0 MW and 1.0 per unit energy is 1.0 MWh). The control used for the energy storage device is an OPF which simply minimizes operating cost. It can be observed from the simulation results in Fig. 4. A different control concept based on multiobjective optimization will be introduced and discussed in Sections V-B and V-C. The renewable generation replaces the legacy grid as the main supply source, and the legacy grid can be considered as reserved supply during peak demand hours. The DG harvesting

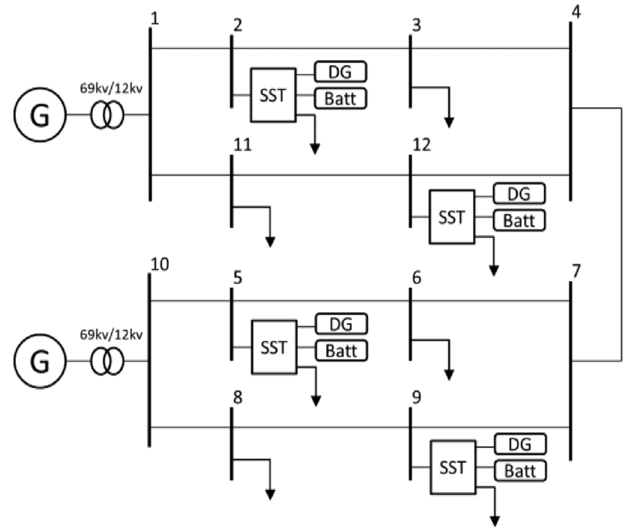

Fig. 3. 12-bus microgrid test bed with 12 kV distribution primaries.

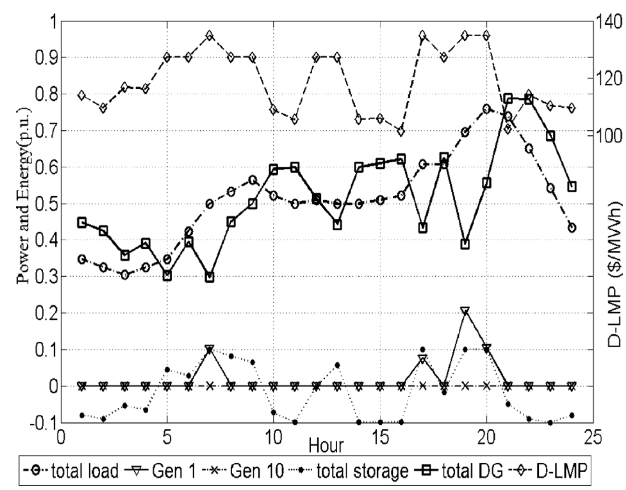

Fig. 4. Test results on 12-bus distribution system using the algorithm indicated in Section IV-B: the per unit power base is 1.0 MW and the per unit energy base is 1.0 MWh. The DLMP is calculated using the OPF formulation described in Section IV-B.

TABLE I
12-BUS DISTRIBUTION SYSTEM CONFIGURATION

Voltage base (kV)	$V_B = 12$
MVA base (MVA)	$S_B = 1.0$
Feeder characteristics (Ω/mile)	$Z = 0.896 + j\ 0.7743$
Feeder length (mile)	$L = 0.5$
Feeder thermal limit (A)	$I_{max} = 270$

TABLE II
12-BUS DISTRIBUTION SYSTEM DATA

Bus	Load specifications	Generation capacity (kVA)	Energy storage (kWh)
1	No load	$P_{G1} = 500$	*None*
2,5,9,12	$P_B = 50$ kVA, p.f.= 1.0	$P_{DG} = 350$	$P_E = 50$
3,6,8,11	$P_B = 200$ kVA, p.f.= 0.7 lag	--	None
10	No load	$P_{G10} = 500$	None

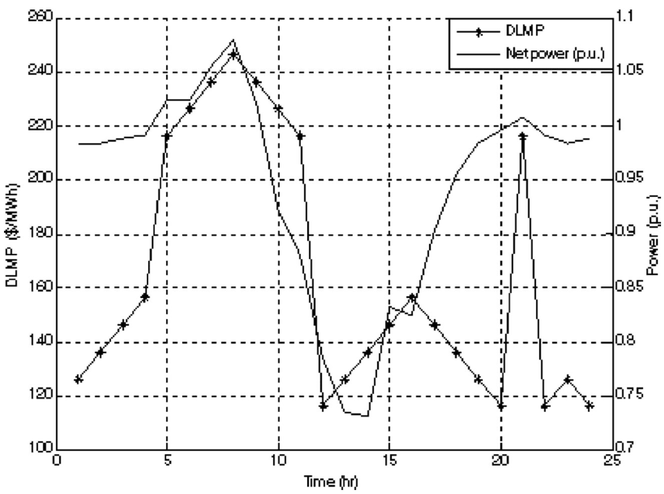

Fig. 5. Test results obtained using algorithm developed in Section IV-A. The DLMP is calculated using (6) with $w_5 = 1.0$, $w_6 = w_7 = 10\ \mathrm{cents/kWh}$, and net power is calculated using a multiobjective control algorithm described in Sections V-B and V-C.

and load factor are improved through energy management control by utilizing energy storage.

The results obtained with the use of the algorithm developed in Section IV-B are compared with that obtained using the Section IV-A formulation for an identical test bed. These results appear in Fig. 5 which depicts the net load and the DLMP calculated at Bus 2 using (6), and the net load calculated using a multiobjective control algorithm discussed in Sections V-B and V-C. In Fig. 5, note that the wind energy data has been excluded from the simulations performed using the Section IV-A model. The salient observation is that both the DLMP at Bus 2 and the power demand from the subtransmission system are reduced during the peak demand period of the day.

V. CONTROLS AND CONTROL INTERACTION

In legacy distribution systems, controls are minimal. Controls are predominantly characterized by shunt capacitor switching, and tap changers at the distribution primary feeder. Several projected distribution control initiatives propose smart control possibilities taking into picture, innovative metering strategies, and the use of measurements to facilitate control; but these may be constrained by the radial nature of distribution feeders. The high penetration of distributed generation and storage devices that has been projected for the future implies that innovative and 'smart' options of controls are envisioned, e.g., the distribution system being networked at the primary distribution level.

The time horizons of controls for the distribution system are varied. Some system states such as voltage magnitude are controlled in real time, whereas energy demand of a system can be controlled in a wider time horizon. It is assumed that the above mentioned controls are completely decoupled due to the disparate nature of their time resolutions. Fig. 6 depicts the time horizon of distribution system operations.

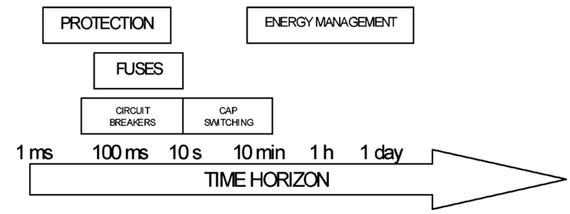

Fig. 6. Time horizon of distribution system operations.

A. Distribution System Control

In the economic market, each generation or load in distribution system is represented by an independent agent locating at intelligent energy management nodes. These agents could submit bids/offers to buy/sell energy to the optimization process; they also send local measurements of system states, e.g., voltage magnitudes.

The system control is determined through optimization process with objectives as:

- maximize the total benefits in economic market;
- encourage power penetration from renewable distributed generations and energy storage devices;
- reduce transmission stress to supply distribution system from the legacy grid;
- improve environmental benefits and reduce overall greenhouse gases emission caused by energy supply;
- reduce system losses and congestion risk.

In this optimization process, the DLMP is adopted as a new control signal to determine power dispatch from DGs, energy storage devices, and legacy grid. The dispatch schedule will be distributed to agents, which afterwards pass control signals to devices directly.

Since most renewable generation is weather dependent and may not follow the demand change through every hour, it is envisioned that future distribution systems will be networked and the interaction between several systems would improve renewable energy harvesting as well as supply reliability. This interaction is illustrated in Fig. 7. The optimization process of each distribution system would firstly find local DLMPs and power dispatch based on offers/bids and system states, then it may communicate with other peer systems if the renewable generation and energy storage has surplus/shortage energy against demand. If any other systems could answer the request by absorbing/supplying the additional power, the involved systems may exchange energy as long as it is allowed in the distribution network with security constraints. The DLMPs may be used to determine the most economical interaction.

The foregoing indicates that the legacy grid energy consumption and transmission stress may also be reduced since the overall efficiency of renewable energy harvesting and the reliability index is improved through such control interactions. Although this goal can also be achieved by increasing the installation of energy storages, but it is discouraged by the high cost and limited life cycles of current storage devices.

B. Multiobjective Optimization and Pareto Optimality

Traditional distribution systems are radial systems that feed the end use customers through three phase primary feeders and single phase laterals [21]. In a conventional understanding, load

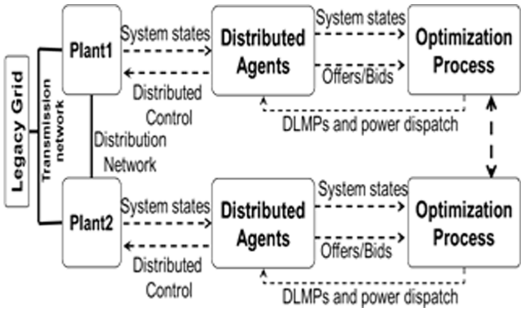

Fig. 7. Distribution system control diagram.

management [22] refers to the management of the end-use load shape to satisfy a number of objectives including: reduced demand during peak system load periods, acceptable system reliability, acceptable customer convenience and incentives, and compatibility with existing system designs. In general, the energy management problem can be represented as a multiobjective minimization problem.

The solution to traditional linear optimization problems is faciliated through the use of linear programming tools (e.g., the *simplex* method). In the case of multiple objectives to be optimized simultaneously, with the functions themselves not strictly linear, the use of alternative techniques is nessecitated. The calculation of a global optimal solution for the multiobjective optimization problem which is also the global optimal solution for each of the individual objective functions is generally impossible because different objective functions might be at conflict. This leads to the development of a *Pareto optimal approach* [23], [24]. Pareto optimality is defined thus [25]:

"A control vector $X^* \in S$ is Pareto optimal, if there does not exist another control vector $X \in S$, such that $f_i(X) \leq f_i(X) \leq f_i(X^*)\ \forall\, i = 1, 2, \ldots, m$, and $f_j(X) < f_j(X^*)$ for at least one index j, where S is a nonempty subset of R^n called the *feasibility region*."

C. Energy Management Objectives

As an example of multiobjective optimization, consider the following objectives and their mathematical formulation denoted by functions $f_1(X) - f_4(X)$:

1. The entire time horizon over which the optimization is carried out is split into n equally spaced time intervals of duration ΔT. The objective relating to peak power demand from the distribution system is captured by f_1
$$f_1(X) = \max_i(x_i). \tag{13}$$
2. The peak period energy supplied from the distribution network is
$$f_2(X) = \sum_{i=p}^{p+k}(x_i \Delta T), \tag{14}$$
where the peak period is user defined as the interval in which the index i ranges from $p, \ldots, p+k$.
3. The total cost of energy taken from the distribution supply for the entire duration of the time horizon is expressed as
$$f_3(X) = \sum_{i=i}^{n} \delta_k x_i \Delta T, \tag{15}$$
where δ_k is the cost of energy in \$/kWh, or the DLMP at the node at which optimization is performed.

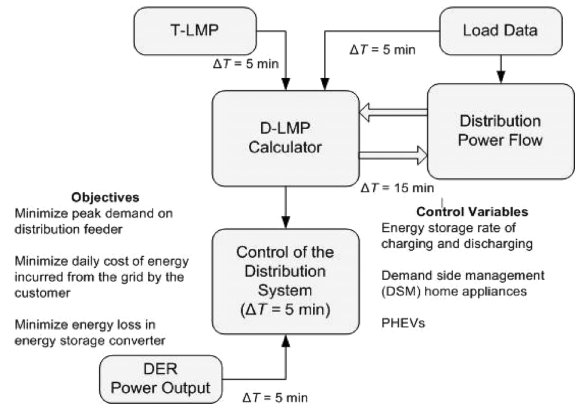

Fig. 8. Distribution system energy management control architecture (used in the control signal calculation e.g., energy storage). The DLMP calculator is separate from the multiobjective control algorithm.

4. The total power loss in the power converters for the DESD is a function of the square of the current. As $|V| \approx 1$ p.u., f_4 can be approximated by
$$f_4(X) = \sum_{i=1}^{n} \frac{(1-\varepsilon)|x_{S,i}\Delta T|}{\varepsilon} \tag{16}$$
where ε is the efficiency of the power converter and battery combined, X_s is the rate of charging (kW) of the energy storage element.

One solution approach to the multiobjective optimization employs a robust algorithm called the *normal boundary intersection* (NBI) method. A detailed handling of the NBI formulation of the solution subproblems for the above mentioned problem can be found in [25], [26]. The integration of the DLMP and optimization for distribution system control is depicted in Fig. 8. Note that the proposal is to use multiobjective optimization for *control* (e.g., control of storage devices and other energy flow controllers) but *not* for the calculation of the DLMP discussed earlier. Note further that in Fig. 5, the DLMP indicated is not the result of multiobjective control, but the net power indicated is a result of the application of NBI. [25] shows some of the details of the mathematics (e.g., separable programming) used to calculate net power.

VI. Conclusions

The main conclusion of this work is that the use of pricing information to drive distribution system controls is feasible in a system that employs electronic controls. One way to encourage the use of renewable resources in power distribution systems is via these pricing signals. While no proof is offered, and no actual experience is at hand, alternative pricing signal formulations shown in this paper may effectuate smart grid objectives in energy management. A candidate pricing signal, denominated a distribution locational marginal price (DLMP) has been proposed and illustrated. In order to drive the control, a multiobjective optimization has been proposed and illustrated. Possible controls include: the schedule of energy storage; the power flow in selected lines (using electronic controllers); and possible controls at solid state distribution transformers. One set of multiobjectives is: the reduction of the peak power demand in the distribution system; the reduction of energy delivered during a specified peak demand period; the reduction of cost to deliver energy over a specified time horizon; and the reduction of the distribution system active power losses. Achieving these controls may entail the use of additional distribution system measurements, and a new formulation of a distribution class state estimator has been illustrated to obtain these measurement signals. The distribution state estimator used synchronized fundamental system measurements.

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