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“Underlying Technical Issues in Electricity Deregulation”

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Abstract

This paper reports on the results of a recent attempt by the Power Systems Engineering Research Center (Pserc) and EPRI to determine the technical tools missing in currently unfolding electric power restructuring scenarios.

1.0 Introduction

The business and regulatory environment of the US electricity enterprise is changing rapidly and these changes may prove to be radical. A workshop was organized to accomplish the urgent assessment of the potential extent of this change. The workshop was an internal joint effort of PSerc (The Power System Engineering Research Center) and EPRI (The Electric Power Research Institute) to anticipate the "end game" of the current trend towards electricity deregulation. The specific objective was to identify the engineering and economic tools that will be needed for the future environment. The vehicle for accomplishing this was through examining a range of alternative future scenarios and business structures.

This paper reports on the outcome of the workshop and sumarizes its findings. This paper is thus the collective work of the following workshop participants:

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2.0 A base case scenario - post FERC rules 888/889

2.1 Overall Scenario Description and Assumptions

The Base Case scenario represents a collective view of the structure of the electric power industry in the US in the short-term aftermath of the FERC 's Open Transmission Access rulings (i.e., Orders 888 & 889). We make a number of assumptions about the structure because final decisions have not been made on how Orders 888 and 889 will be fully implemented by utilities, state regulators, and other important players in the power industry. As a general approach, we choose assumptions that represent as small a change from the existing structure, policies, and market processes as possible while still complying with FERC Orders 888 and 889. The defining characteristics of this scenario are:

- There is no retail access.
- Most utilities remain largely vertically integrated as far as ownership of generation, transmission, and distribution is concerned.
- Transmission services are unbundled from all other services in terms of function and cost.
- Wholesale power marketing and transmission services are functionally separated from each other.
- Economic dispatch of utility generation will continue as it has in the past.
- Existing contractual or tariff mechanisms will be used for wholesale market transactions. Using those mechanisms, pricing will be market-based. However, utility power marketing must obtain transmission services on a comparable basis with other transmission service customers.
- Utilities will have an obligation to serve franchise retail customers. Terms and conditions of service will be state regulated.
- Transmission services will be provided through nondiscriminatory transmission services to all eligible wholesale customers under the FERC pro forma tariff.

- Utilities provide point-to-point and network transmission services. They compute and post Available Transfer Capability (ATC) on an Open Access, Same time Information System (OASIS).
- Utilities will provide information about their transmission systems and services to all potential customers on an Open Access, Same time Information System (OASIS).
- Scheduling and curtailments of transmission services are subject to protocols (e.g., service priorities) established in Order 888.
- Utilities are promised full recovery of stranded costs from departing customers.
- Utilities propose transmission rates to cover the cost of their transmission investments. (We recognize that opportunity costs and expansion costs may be proposed under Order 888.)

2.1.1 Generation

The Base Case scenario assumes that the internal power marketer of each utility will control the utility's generation assets and will operate them to maximize profit within the constraints imposed by the functionally separated transmission system operator. Presumably this implies the use of standard economic dispatch unless market conditions favor alternatives. The power marketer would serve the franchised native load plus any negotiated transactions, would contract to the transmission system operator to provide services such as spinning reserves and reactive power support and has the same rights and responsibilities as any other generating company in the market. The terms and conditions of sales to franchised native load are regulated by the state. The terms and conditions of sales in the wholesale market are determined by the market. New construction of generation would be subject to new state regulatory policies. Implicitly, the assumption is that new generation is regulated differently than existing assets and that decisions to build will not be subject to obtaining a certificate of public convenience and therefore the company is at risk for the investment.

2.1.2 Transmission

The Base Case scenario assumes that utilities will provide unbundled transmission services including six ancillary services to all eligible wholesale customers under comparable terms and conditions as it provides those services to itself. The six ancillary services are (1) scheduling and dispatch, (2) Var support, (3) frequency regulation, (4) spinning reserves, (5) supplementary reserves, and (6) energy imbalance. Transmission siting will be done according to state policies, but transmission planning will be under FERC access requirements. Regional transmission planning will be done under the auspices of a regional transmission group or will be coordinated among the transmission providers.

2.2 Essential tools required to support the Base Case scenario

Needed tools have been divided into the functional categories of Generation, Transmission and Distribution. In each category, there seems to be a common need to interface existing technical tools with the new economic unbundling.

2.2.1 Generation

The generation side of utilities have a need for improved monitoring and control equipment. These tools will consist of hardware to be used in the generation process, methodologies to evaluate their value, and algorithms to determine charges which will allow recovery of investment and encourage improvements in efficiency and reliability.

As long as utilities have an obligation to serve their franchise customers, there will be a continuing need for load forecasting. A tool for reactive power forecasting will also be needed to allow maximum utilization of resources. Forecasting of market prices and wholesale transaction opportunities will be needed for making investment decisions. There will be a need for tools which use these forecasts to evaluate alternative generation mix plans, operating practices, and fuel investments.

New environmental policies concerning issues such as global warming and ozone pollution will be developed and these will require emissions monitoring. Forecasting of combustion emissions is needed together with forecasting prices for emissions trading to ensure compliance with federal regulations and efficiency. Models that support the development of emissions trading strategies will be important.

Generation suppliers will need tools to assess the risk of investment and expansion of services. This will be true for utilities as they build into the wholesale market. These tools would be methodologies and algorithms for forecasting and system modeling. Given the functional separation of transmission and generation, the generation business will need tools for assessing the system condition and its implications for trading, and for verifying transmission capacity, pricing, and costing calculations provided by the transmission provider.

2.2.2 Transmission and Operations

The following existing tools will still be needed in transmission:

a. Load flow

b. Optimal power flow
c. Maintenance scheduling
d. System monitoring
e. State estimation
f. Control determination
g. Contingency analysis
h. Steady-state security assessment
i. Dynamic security assessment
j. Available Transfer Capability (ATC)

These tools will continue to be the basis for maintaining reliable service and flexible interchange but will evolve in response to the industry restructuring.

The most significant need for improvement of these tools is in the Available Transfer Capability tool. Traditional algorithms are based on a few worst case conditions and require massive computational efforts. More accurate determination of the available transfer capability is needed to operate the system efficiently and securely.

Advances in computing, algorithms and data acquisition will generally cause tools to evolve from a planning tools to operational tools. The advances in real time phasor measurements will open opportunities for real time control. Operational tools can take advantage of system measurements and knowledge of the system configuration but are required to be fast enough. Methods and tools for better display and visualization of status and results are needed.

Tools for monitoring the power system and evaluating system security online are needed. The tools should offer suggestions to the operators for corrective actions.

Tools to relieve congestion in a fair, justifiable and economic manner are needed. These tools would run in real time and would supply responses to overloading or contingencies. Methods of settling congestion costs are needed.

Ancillary services must be defined in detail, quantified and costed. The tradeoffs in supplying different mixes of ancillary services must be analyzed. Methods of monitoring and verifying delivery of the services should be developed.

New tools are needed to forecast generation and demand.

There is increased incentive for more flexible and active control of the power system, including control of flows, voltages and stability margins. The roles of the various FACTS technologies will emerge as restructuring proceeds. Increased power system control will improve efficiency but must inevitably make maintaining system stability much more challenging. For example, as controls are added, the possibility of adverse interactions increases. Nonlinear effects which are not addressed by present tools will become more important. Advances in analysis and design tools will be needed to ensure system stability. The new devices will require a range of validated device models which can be used for studies at several levels of detail and addressing dynamic as well as steady state issues. The specific economic impact of a FACTS device in operating a power system should be better quantified.

3.0 CENTRALIZATION OF AUTHORITY OR MAXIMUM ISO SCENARIO

3.1 Overall Scenario Description

This scenario assumes centralized operation of the power system and a centralized market for power. This scenario places the maximum informational, control, and computational load on a centralized entity -- the independent system operator (ISO). Participants submit bid curves for supply (including uptime and downtime constraints, minimum and maximum generation, and startup and shutdown costs) and demand for various time frames, and a schedule (unit commitment) is selected based on solving the "global" unit commitment by the ISO. The unit commitment decision occurs one day ahead. In real-time, the ISO selects a dispatch, which may be different from the schedule for a variety or reasons. The ISO also sets nodal prices, including a transmission congestion component. This organization corresponds closely to the well known "PoolCo" concept. Because of subtle differences we refer to it as the Centralization of Authority (COA) scenario or centralized for short. The role of the ISO in this scenario includes system operations and security in addition to system economy. Thus, transactions will only take place if security permits. All physical transactions are determined by the ISO. The ISO has complete control of the transmission (although it may or may not have ownership of the transmission system). All energy is sold and purchased through the pool.

3.2 Existing and new tools required to support the centralized scenario

3.2.1 Transmission planning

Existing planning tools such as load forecasting must be modified and extended. An important question is in how the transmission infrastructure will be planned or developed in this scenario. Is the ISO responsible for anticipating the need for new transmission? There could well be conflicts between generators who want congestion to promote higher revenues and those who want more capacity for transactions. Market simulation models will be important to examine the implications of transmission investments for market prices, transactions, etc. so that informed discussions can occur on the need for investments. The coupling between transmission pricing and decisions to expand the network are necessary so that the prices set for perceived public benefit do not create unnecessary expense.

3.2.2 Reliability

New tools are required to calculate the increase in reliability produced by an investment or change in operating policy so that a cost can be assigned to increasing reliability. Simulation techniques or theory for rare events may be required in order capture major power system disturbances. Given that providing reliability is an ancillary service, there will be pressure to quantify the benefits of improvements made to allow the system to survive events whose probability of occurrence is imprecisely known.

3.2.3 Economic Dispatch, OPF, Unit Commitment

Economic dispatch and unit commitment are two of the main functions which distinguish the COA scenario from the Minimum ISO scenario discused in the next section. Here, the ISO is assumed to receive bids from generators, and, in some versions of the scenario, from consumers. The generators' bids will include information on startup/shutdown costs, minimum up/down times, etc. The ISO must then perform unit commitment and announce the generation commitment schedule for the next several days. From hour to hour, the ISO must also perform economic dispatch according to the announced schedule.

It is important to recognize that the centralized model may require the ISO to perform a unit commitment. If the ISO were to simply perform economic dispatch at each hour, without taking into account generator constraints, these constraints would often be violated. On the other hand, if the ISO were to perform economic dispatch by myopically taking into account these constraints (based on which generators were up/down during the last few hours), the resulting outcome would likely be inferior to a centralized unit commitment.

Another large technical challenge is to integrate optimal power flow (OPF) which takes into account lineflow and voltage constraints and reactive dispatch with unit commitment. A unit commitment algorithm which uses a standard economic dispatch at each time point in the schedule is obviously simpler than one in which an OPF has to be done at each time point instead, and so the latter would be much more computationally intensive. The question arises of how large of a system could be reasonably scheduled given this increased complexity. Incorporation of security (security constrained OPF) into the unit commitment problem would increase the complexity still further.

3.2.4 System control

Existing control techniques, including generation rescheduling, voltage adjustments, capacitor switching, operating reserves, etc., must be for this scenario to “play out”. Again, increased system size is an issue. The issue of ancillary services such as voltage support is also an important problem. New tools must be developed to control power flow using FACTS devices in a coordinated and centralized fashion. Real-time phasor measurements and improved communications can be exploited to produce improved damping of dynamics and faster reaction to transient events, although algorithms for rapid control of system dynamics need continued development. VARS, and other ancillary services from generators, to the extent that they affect the behavior of the whole grid and do not affect only specific users, could be a factor in the setting of prices for gird access and transmission.

3.2.5 Security/contingency analysis

Tools for security assessment that produce operating limit boundaries for both static and dynamic contingencies must continue to be developed. The increased size of the system implies much larger lists of contingencies , for example. Contingency selection algorithms and corrective action strategies for loss of lines, generation, and load rejection based on line flow and voltage magnitude limits must be extended. Limits on operating states determined by dynamic and transient events must also be considered.

Tools for determining the ISO actions before the contingency occurs are also required. Presumably the ISO has little or no resources with which to provide system security other than possibly preventive redispatch. Any additional resources required (spinning reserve, etc.) would have to be purchased as a service. The ISO would need tools to determine which resources might be desired and what it should be willing to pay for them. Only by being able to compute a value for these resources can the utility determine whether to purchase individual ancillary service at a given price. Only by determining the values of these ancillary services and trading these off against the market prices of these services, could the ISO could operate the system at the minimum cost while still maintaining an appropriate level of security.

3.2.6 ISO Incentives/Performance Evaluation

The ISO is an agent of the various stakeholders: generators, transmission owners, consumers, the state. The ISO will have a major influence on the power systems operations. The ISO will have more information about the power system and about costs and benefits than anyone else. Thus two questions take on major importance. First, how should the ISO organization be designed so that it will tend to favor the public interest as a whole? Second, how would the public monitor, evaluate and correct the ISO's performance?

There exist no tools at present that address questions of organizational design and performance evaluation. Indeed there is hardly any research that can provide the foundation for building such tools. We suggest the need for the following tools:

1. A means of simulating different forms of ISO’s.
2. A facility run by an academic or other expert group that can serve as a forum where challenges to ISO's decisions could be brought.
3. A facility that can test the software and other procedures that the ISO uses in order to certify their robustness, efficiency, etc.
4. A forum that can propose changes to the ISO's structure.
5. A facility to simulate the behavior of the various markets.
6. A facility to collect data on the several regional and local markets that will develop as the process of deregulation gains momemtum. It is an important question to design such a database. (These facilites should be set up very soon, so that the initial history of the deregulation experience is recorded and there is an opportunity to learn from that experience.

3.2.7 Costing

One of the tasks of the ISO would be to distribute jointly incurred costs/benefits to the system participants. New tools would be required to compute these allocations. The theoretical basis for such allocations is also needed.

The British experience is that up to 50% of the price consists of "uplift" charges. These are administratively computed and account for a variety of "fixed" costs and "ex post" prices including: transmission fixed charges, transmission congestion charges, generation fixed charges such as startup costs, capacity charges, ancillary services, etc. Tools are needed to compute these costs.

3.2.8 Bid preparation

Regardless of the exact details of the mechanism for coordination between the ISO and individual generators or generation owners and individual consumers, generators (and possibly consumers) would need tools to enable them to prepare their bids. On the generation side, a bid preparation tool could be based on (local) unit commitment (assuming a distributed unit commitment method) or local economic dispatch.

3.2.9 Risk Management/Forecasting

In any scenario being contemplated here, it is likely that prices will be more volatile than they have been historically. In the centralized scenario, all participants pay or are paid the spot price as determined by the ISO, which, by their nature, will vary considerably from period to period. Two types of tools will be required as a result of these volatile prices. Forecasting tools will be required in order either to forecast price directly, or at least to predict supply and demand in the future. Risk management tools will also be required.

3.2.10 Power Quality

The issue of power quality and the ability to provide different levels of power quality to the end user will impact all scenarios. Control over the quality of power at the load interface will be a most difficult task for a central dispatching system to achieve since it will have little practical control (unless negotiated) on the local sources of quality reduction. In theory, price/cost penalties could be used, but this implies good local sensors and exception transmission. Remote correction, that is correction applied remotely from the problem source, would seem to be the least effective method. The "best" arrangement might be the development of new tools/equipment to detect and correct problems locally with an automatic billing to the organization that caused them. The basis of the bill might be for the losses that were incurred because of a deteriation in power quality.

3.1.11 Protection

The existing protection system has evolved over generations and is appropriate for a vertically integrated utility. The underlying principle is that the protection system should never fail to clear a fault. To provide this dependability, multiple primary and redundant back - up systems are used. The effect is that the existing protection system errs on the side of false trips. A survey of the annual disturbance reports from NERC indicates that the protection system exacerbated the situation in approximately 66% of major disturbances. The philosophy of protection appropriate for an ISO must be reconsidered given the consequences of false trips on transactions.

4.0 MINIMUM INDEPENDENT SYSTEM OPERATOR (MIN ISO)

4.1 Overall description of the scenario

The structural organization of this scenario involves an ISO that plays a minimalist role in the marketplace and that is concerned primarily with network security, unregulated suppliers of generation, an (either regulated or quasi-governmental) overseer of transmission services (a Regional Transmission Authority, Transmission Access Provider or similarly named organization), marketing entities, and unregulated customer service groups.

The objective of this scenario is to maximize flexibility and the capability to accept new technology in either generation or customer use by limiting the role of the independent system operator to maintaining system security. In this scenario, the operation of the system is in the hands of the ISO, but the ISO has no authority over prices. A minimal ISO may, however, be permitted to use price signals in an attempt to reach secure and viable operating points. The ISO will also be in a unique position to determine system losses and to attribute these losses to individual contracts or to individual market participants.

In this scenario generation must be separated from transmission. The ISO will not own any generation or transmission facilities. In the Min ISO scenario generation can be anything -- from residually regulated large central-station facilities (e.g. nuclear), to privately constructed suppliers supported by the spot market and/or bi-lateral contracts, to local distributed generation built primarily for own-use, quite possibly designed for independent operations, but able to interconnect to the grid. Electric energy storage facilities would, able to act as loads at times and generators at other times, are also permitted within this category.

Transmission facilities will be built and owned by a Regional Transmission Authority. In addition to its role as provider of transmission facilities (including siting and construction of new facilities), the RTA will set other incentives for market participants, such as environmental surcharges. RTA's will probably be multi-state entities akin to the existing Reliability Coordinating Councils, probably encompassing one or more ISO. These entities are responsible for all remaining quasi-public functions, including approving wheeling fees and compensation to ISOs, assessing network externality fees and environmental fees on market transactions, and arranging for the siting of needed new transmission lines, either through actual construction or by contracting for private construction and maintenance through performance based bids on pre-approved routes. The Authority is comprised of federal and state representatives, and functions in accordance with accepted administrative and engineering standards and criteria as well as accepted law practices.

In order to perform these functions, the Regional Transmission Authority must have access to all records on physical flows from the ISO and any pertinent information about the network, including information about congestion, prospective congestion leading to imperfectly completed transactions, congestion charges, and disputes on the actual use of the transmission network. The Regional Transmission Authority may also resolve disputes between marketing entities and the ISO

An ISO's predominant responsibility is to carry out contracted power exchanges while maintaining system security over the existing transmission facilities. It's focus is on physical flows, with most prices set elsewhere. The ISO will be compensated by the Regional Transmission Authority, and its performance will be evaluated based upon how well it performs its dispatching and emergency response functions -- as well as conveying these operating parameters rapidly to all market forces. Institutionally, therefore, the ISO could either be a quasi-public entity, or a private firm whose compensation is related to performance criteria.

A minimal ISO may or may not be responsible for ancillary services. To the extent that some ancillary services can be provided by available market mechanisms (such as, for example, reserve services) there would be no need for the ISO to be directly involved in these services. On the other hand, in many models of a quasi-minimal ISO, ancillary services would either be provided or coordinated by the ISO. It is likely, for example, that reactive power services and voltage control, because of their highly regional nature, will be the responsibility of the ISO. On the other hand, the ISO may be in a position to use market mechanisms to assure the provision of these services.

In most cases an ISO, although not participating in the marketplace, would need information about the type and nature of the transactions in effect or projected. Without a sufficient knowledge of these it will be impossible for the ISO to perform its security functions.

In this scenario, the obligation to serve is replaced by contractual arrangements and willingness to pay. It is conceivable that customers seeking guaranteed service will contract accordingly with distribution companies or through bilateral contracts. Failure to provide a guaranteed service is treated as a breach of contract and is subject to damage payments and litigation.

4.2 Description of the physical system structure

This section describes four general time frames in which tools are needed.

4.2.1 Long time ahead

Within this time frame, there is opportunity to add components to the system and to establish long term contracts and agreements. Because of their interconnected nature, power system interactions are the norm. In particular, careless equipment design or inappropriate requirements will undoubtedly lead to subsequent operational problems. Thus, minimum engineering criteria need to be established for generators (and perhaps loads) intending to connect to the system. For example in order to do transient stability studies the Regional Transmission Authority needs dynamic information from the intended generators. This information may include electrical characteristics, such as exciter settings, and other information such as minimum/maximum MW ramp rates.

4.2.2 Some time ahead
Within this time frame, there is opportunity for markets to respond and for potential technical problems to be resolved. An ISO can establish criteria for transaction approval, and markets can work within these restrictions. It is probably not essential for a Min ISO to be an active participant within this time frame, but undoubtedly security issues that pertain to the ISO need to be addressed. This section reviews unresolved or significant technical and market-related questions that need to be addressed.

4.2.3 Real-time
The key real-time responsibility of the ISO is system security. During normal system operation the ISO will be charged with maintaining system frequency through AGC control. ISO will also be charged with maintenance of adequate system voltage through reactive power control (LTC transformers, generator set point voltages and capacitors).

In order to perform its security functions, the ISO needs knowledge of all transactions within the region, as well as information about the complete status of the system (this would include real-time device status and flows, and results from near real-time state estimation), projections for change in the immediate future, and the probability of outages and events as a result of weather or other conditions. Load forecasts could be provided by the distribution entities.

4.2.4 Settlement period
Metering and control imperfections and delays, unforeseen events and other such occurrences will result in actual fact deviating from agreed upon conditions. There is likely a need to settle and verify system operations, contracts and costs after the fact.

In the pre-dispatch period, various types of contracts, including forward, futures, options, insurance, and other risk management devices, will be traded in an open market (which may be facilitated by a power exchange) and submitted to the ISO as the pre-dispatch schedule for the next day. Changes to this schedule, or re-dispatch, may be needed in the actual dispatch due to unexpected contingencies (e.g. a contingency such as a line or generator trip) and security considerations. Settlement rules will serve the important function of settling financial payments between contract holders and the ISO for any real time deviations of the actual dispatch from pre-dispatch contracts cleared by the ISO. Except in the unlikely event that pre-dispatch markets completely cover all the contingencies, settlement rules will entail settlement payments. Ideally, these rules should be designed to ensure the financial integrity of pre-dispatch contracts and, at the same time, provide the ISO incentives to re-dispatch efficiently. As a possibility, the ISO may be required to provide a menu of contract performance insurance offerings in which the insurance premium varies with the coverage. The ISO will have financial incentives to make changes efficiently so as to result in the smallest compensatory payments.

New types of network-based software system are needed to facilitate the settlement process. This software system is to be connected to the databases maintained by the ISO and the power exchange in real time. It translates the pre-dispatch contracts and the actual dispatch into comparable terms and compute the differences. The results are transmitted to individual market participants and the ISO for billing purposes.

A set of incentive compatible settlement rules based on sound economic principles need to be developed to promote efficiency and equity. These rules could directly affect the ISO's re-dispatch behavior. They could also affect the formation of market expectation and thus indirectly the market performance. Markets will play no active role in the settlement period.

4.3 New tools required to support the MinISO scenario

A new tool that is needed is a way of assigning system loses to individual transactions. This method should have a good theortical foundation for fairly assigning these values, and should be correct in that it does not over or under assign losses. Other needed tools are:

-Commercial transaction tools:
- evaluation of contract economics
- risk assessment and mitigation tools
- liability and enforcement issues
-antitrust: identifying existence of market power,

While the present tools can function a day ahead; improvements are needed in order to operate the system less conservatively and to be able to defend the restriction or curtailment of transactions (in the worst case in court)]

Transmission planning and economics tools will be needed. If transmission capacity rights are used, then tools supporting them will have to be developed. If transmission is simply infrastructure, then planning and compensation techniques will be needed.

Following a disturbance, control actions often must be taken within a time frame of minutes. New tools are needed for providing sufficient real-time information to market participants so that the market can respond even within this short time frame. To the extent possible, the market mechanisms for correcting these very short time problems should be identical to the mechanism in the longer time frame. It is recognized, however, that the number of available market alternatives diminish as the time frame shortens.

Dynamic security assessment tools are also important. Present tools for dynamic security assessment (including transient stability), and in particular, assessment of sensitivities of dynamic security to actions and transactions is still needed. Even a real time transient stability capability is insufficient to satisfy this requirement.

Uncertainty and the handling of uncertainty in network situations is still a need. The key is the characterization "ex-ante" of the costs and incremental costs of transactions, including expected values, standard deviations, and other statistical parameters that would permit proper risk management decisions to be made by all transacting parties.

Contracts are needed that include provisions for load following. The ISO would then monitor the load associated with these contracts and send the necessary AGC signals to the brokers (i.e., to their AGC control center).

Tools for handling, measuring and quantifying ancillary services are needed. In many cases these tools will be the same as other tools, just used in a different way. As an example, a tool for the quantification of the value of reactive power on system security. Another example is pricing the setpoint voltages for generators. The speed of response of the reactive power also needs to be priced and valued.

Congestion Management tools for ISO.
-Protocols and algorithms that will enable fast iterative feasibility assesment and provision of information to traders to modify or suplement transactions.
-Tools to dynamically evaluate trading rules

Tools for Power Exchange:
Mutiarea unit commitment algorithms.
Sequential bidding procedures allowing self-commitment
Scheduling tools that allow self-commitment and and integrated demand side resources

Tools for market analysis
- Tools supporting use of price risk management and futures trading
- Long-run market price forecasting tools for investment decisions and contracting
- Transaction evaluation tools that enable players to evaluate their own costs

A new network-based software system is needed to facilitate the settlement process. This software system is to be connected to the databases maintained by the ISO and the power exchange in real time. It translates the pre-dispatch contracts and the actual dispatch into comparable terms and compute the differences. The resutls are transmitted to individual market participants and the ISO for billing purposes.

A set of incentive compatible settlement rules based on sound economic principles need to be developed to promote efficiency and equity. These rules could directly affect the ISO's re-dispatch behavior. They could also affect the formation of market expectation and thus indirectly the market performance. This case suggests that the public information on the availability of the transmission system and the bidding for acquisition of transmission rights needs to be done in parallel with sale or purchase of generation.

Tools for better dealing with dynamic problems and dynamic limits in the system are so computationally intesive and/or so inaccurate at present that further developments in these tools will continue to be required. In particular, sensitivity of dynamic problems to various market actions are needed.

5.0 Distributed generation scenario

Until recently, the traditional working assumption has always been that transmission investment is small relative to generation. However, for the first time in history, recent T&D investment has exceeded that in generation. Moreover, in the past there have been significant economies of scale associated with central station generation. There have also been reliability/security benefits to central-station generation with large-scale interconnection. Technological changes in the nature of available generation and the growing potential of several distributed storage technologies suggest that the system structure could change dramatically. If current trends continue, it may make more (economic) sense to site generation to avoid installing new T&D

instead of the other way around. This observation suggests the scenario to be examined here: that of a very distributed utility environment, with many small scale generating units operating at the distribution system level. We envision that entities on the scale of current distribution systems will evolve to provide some coordinating services on this scale, and to serve a role (as necessary) of intermediary to the transmission backbone.

As one part of this scenario we anticipate the existence of a "base-load backbone" from which distributed (local) suppliers can draw fixed amounts of power. Local distributors could coordinate various sizes of local generation and storage. These units may be held by the distributor itself, or held by individual customers. Clearly, the placement of such units will be greatly influenced by developments at the bulk power level. If wholesale wheeling remains the predominant transaction scenario, it will tend to favor generation placement at the distribution substation level. Should retail wheeling become successful and widespread, there will be stronger motivation to place units at the customer level. In this scenario, the number of units could approach the number of loads. In either case, these storage and generation units can serve the peaks and smooth the valleys through contractual arrangements with the backbone.

Clearly, as more local generation is installed there may be a less reliance on the backbone and the movement towards a distributed utility may leave overcapacity and stranded investment in transmission. However, local users with a distributed power source still find the grid a valuable resource for reliability and a careful balance will need to occur between growth in local generation and a decreased need for backbone power.

The dominant distrbuted technologies are small generation and storage systems with short investment recovery cycles, in the 3 - 5 year range.In addition the open access to wholesale power market is a positive force by providing a possible competitive source of electrical power. This has a down side if stranded cost recovery fees are to high. This could create regions where wholesale power is not competitive with local generation, encouraging large customers to separate from the system, or at least find ways to reduce overall energy cost.

Some emerging generation technologies seem to have no significant scale economies, but they may have economies of mass production. These include, micro-turbines, photovoltaic cells, wind-turbines, fuel cells and internal combustion engines.Lower rates of load growth and higher variability favor smaller scale plants.

Today best available central station technology is modular combustion turbine (CT) and combined cycle combustion turbine (CCCT), see Figure 6-1. The typical optimal size of the CCCT is in the 200-500 megawatt range. This technology is now offered with a 60% efficiency and capital costs in the $400-600 range. Fired on natural gas these systems are dominating the current new generation market in the US. Being modular, highly efficient and far cleaner than coal fired station, this technology marks a return to more distributed generation (so long as natural gas is plentiful and low cost. If natural gas prices rise or scarcity develops, the CCCT technology can be integrated with goal gasifiers and suffer only a modest (4-5%) reduction in efficiency.

The choices in size and efficiency that are available in today's combustion turbine and combined-cycle gas turbine technology introduces the opportunity for affordable distributed generation. But today the economic sizes are still relatively large in comparison with all but large industrial users. New technology emerging from decades, of research may alter the situation and create the opportunity for affordable generation at the point of the user or on a local commodity basis.

5.1 Essential tools required to support the distributed generation scenario

5.1.1 Modified tools

The local distribution utility with dispersed generation and storage may be able to adopt some of the existing system design and operation tools which now exist to the new dispersed utility. Where the local distribution company owns generation and can purchase off a transmission system, there may be interest in evaluating interactions with the traditional utility utility, suggesting a need for
(1) unit commitment and economic dispatch tools as they may evolve in an ISO structure, (2) load flow forecasting and load growth forecasting as well as existing market research tools and (3) load flows which include three phase unbalanced operation.

However, it is important to note that these needs are predicated upon the assumption of a synchronous link to the larger transmission system. It is also important to consider whether these smaller networks with distributed storage and generation might instead choose asynchronous links to the larger transmission network (e.g., back-to-back dc, or other FACTS technology).

Distribution network design, relaying and breaker specification will be radically different in this environment. The individual customer is now a potential source, and the distribution grid will migrate from largely radial design to a true coupled network design. Protection will be dramatically changed in this scenario, and will require both new tools for design, and new relay types. The costs of development of special purpose interfaces and energy management systems will be excessive at these scales. Standard interfaces and control systems based on "appliance" scale microprocessor control will need to be developed from the current experimental and custom installations. A particular challenge exists in the evaluation of stability for such interconnections (to the extent that these remain based on synchronous rotating machines).

Among the tools to be developed are integrated customer information/communications services. These will provide electronically supplied information relating to the customers interactions with the distribution system, with pricing information, power quality, imbalance, and other system condition summaries. These may use text, video, and audio, and interactive communication systems. Tools include (1) real-time communications systems, (2) service options, (3) energy efficiency options, (4) customer decision-support tools, (5) customer assistance requests and (6) customer usage and bill history.

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5.2.2 New tools

Quality of Power

The issue of quality of power and the ability to provide different levels of power quality to the end user are important. To accomplish this differentiation in power certain tools and methods are required. These are : (1) Decision methods to activate fast switching on multi-infeeds, (2) Analysis tools to study harmonic flow, interaction and methods of harmonic control, (3) Decision methods on which noncritical load to drop to protect critical loads., (4) Smart, automatic metering methods, (5) Methods to detect the source of unbalance loads and take action based on local informationand (6) Planning tools to target optimal system locations for load balancing devices

The vision of the distributed utility, operating on a geographic scale comparable to existing distribution networks, makes integrated, high speed data communication between participants in this network a natural concept. Therefore, taking the presence of high speed data communications as a given, we wish to consider the control and communications options which this opens.

This scenarios brings at least two major needs for tools development. First is the identification of communication protocols to distribute the necessary information. The design of these data protocols should be versatile, such that they can be communicated through a variety of lower level computer networking standards, and hierarchical, such that various levels of data exchange can be accommodated, depending on the speed of data link.

The second major tool development will be that of the distributed control itself. Traditional power systems have long operated in a fashion in which the central control entity sends out set point information to local controllers, who in turn have faster time scale local feedback loops. Some elements of this structure may be replicated in the scenario here, but with greatly expanded interaction between the central entity and local control agents. The control that must be developed to meets these needs will likely return to a form very close to the "homeostatic" concepts first introduced in the late 1970's.

Protection coordination

It is likely that as a range of new generation from 50kW to 100MW is installed by a distribution company, the distribution system will become interconnected beyond the radial configurations that dominate today's design. It is also likely that the most economical way to manage loads will be to tolerate phase imbalances, a practice that is severely discouraged in the transmission system. This high level of distribution system interconnection plus phase imbalance will require non-standard tools for system protection.

Fault Protection

Most current distribution system protection practices revolve around overcurrent. Thus, the zone of protection for a line is simply based on whether or not the line current is exceeded for a specified time period and not whether a fault actually exists on the line. This practice avoids the cost of measuring voltage needed to compute impedance and if the line is radial, the existence of a large current means the existence of a line fault. If complex interconnections exist, large line currents may or may not indicate the existence of a fault. Moreover, if distribution is essentially non-radial, conventional overcurrent relay coordination is not possible

What is needed is the equivalent of a symmetrical component relay that can identify and independently trip one, two or three phases of an unsymmetrically loaded line. Since a symmetrical component distribution relay must be an intelligent device, other communication and control functions can be bundled in such as metering, reconfiguration, and perhaps, compliance and diagnostic information

Network Reconfiguration
System reliability may be severely degraded if lines are allowed to remain out of service for any significant period of time. A substantial reconfiguration of the distribution system topology may be needed in response to emergencies. Also, local wheeling of power may become commonplace as the new operators attempt to balance the distribution flows at least cost. All of this points to the need for new hardware and software to more effectively manage distribution system resources.

Economic Tools
Economic tools fall into two categories: strategic and tactical. Strategic tools address investment decisions and tactical tools address operating decisions. Economic tools in this case range from development of new tools for interacting with wholesale power suppliers and making the most profitable buy/sell decisions and purchase/sale contracts.

Need for tactical economic tools will depend upon whether DR operates primarily in base-load or dispatchable mode. Operating decisions for base load operation are minimal, so no new tools should be needed here. Operating decisions for dispatchable operation involve scheduling. In a world of spot electricity prices, DR dispatch will depend upon price and local load forecasts, so tools will be needed to predict them. Also, real-time communication of the spot price will be required. In many industrial and some commercial facilities, local load forecasting will be part of or interact with production scheduling or energy management systems. Real-time dispatch decisions for DR would then be optimized as part of the production or energy management schedule. Hardware, software and algorithms for these functions needs to be developed.

Need for strategic economic tools will differ between customers and discos. Customers will evaluate DR investments in a similar fashion as they do other investments in end-use energy devices. Central system electricity prices will have to be forecast as will utilization factors for the DR equipment; however, the economic analysis presents no unusual challenges.