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Utilization of Energy Efficiency and Demand Response as Resources for Transmission and Distribution Planning

Current Utility Practices and Recommendations for Increasing Opportunities as T&D Alternatives

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PRODUCT DESCRIPTION

EPRI began its Energy Efficiency Initiative in early 2007. Initiative research, which covers numerous topics associated with energy efficiency and demand management, is categorized into three areas: analytics, infrastructure, and devices. The project described in this report details the Initiative's analytics element, which deals with methods and tools for analyzing aspects of the use of energy efficiency as supply resource, including measurement and verification, inclusion in generation planning, emissions reductions, and economic impacts.

Results & Findings

The report describes the capabilities of various energy efficiency and demand response (EE/DR) initiatives that could potentially be used by system planners to address various system delivery capacity problems. Presented is current utility experience using EE/DR as a delivery capacity alternative. The report discusses existing barriers that are limiting use of EE/DR for transmission and distribution (T&D) planning purposes. In summary, the report categorizes delivery capacity scenarios for which EE/DR are and are not reasonable options based on existing data and suggests actions that could be pursued to potentially broaden the use of EE/DR for T&D planning.

Challenges & Objective(s)

This project's goals have been to identify

- the extent to which T&D planning engineers use EE/DR as a delivery capacity option when system deficiencies are identified,
- best practices in integrating EE/DR into T&D planning processes, and
- what actions, if any, can be taken to better position EE/DR as a T&D capacity alternative.

Applications, Values & Use

The effectiveness of EE/DR programs depends on how well utility needs are matched to the load response capability and how well the tariff or market rules accommodate both. While some EE/DR programs may adequately address a specific T&D capacity need, others may not adequately solve the problem. Characteristics of some T&D capacity needs also may be such that technical and/or economic limitations preclude any EE/DR solution. An analysis of current utility practices can provide insights and recommendations for increasing EE/DR opportunities as T&D alternatives.

EPRI Perspective

Many utility T&D planners are uncertain whether EE/DR can reliably provide sufficient delivery capacity when and where it is needed and feel that more quantitative data validating EE/DR capabilities as delivery resource is needed. Many utility planners who are confident that installed EE/DR can deliver utility-grade reliability response generally do not feel that EE/DR can currently be used as an alternative to T&D enhancement. While it is certain that EE/DR may not be an appropriate solution for some T&D needs, it is equally as certain that non-wires solutions should be viable for other needs. Many of the limiting factors/perceptions about EE/DR can be overcome with a better understanding of EE/DR capabilities and integration of this improved understanding into the planning process.

Approach

The authors summarize current utility practices for handling EE/DR within the T&D planning processes. First, they categorize general approaches, then they summarize examples of utility cases where specific EE/DR initiatives were evaluated as a solution to specific T&D needs. A summary of utility experiences with EE/DR initiatives that had a more generic impact on T&D planning is provided. The authors describe many of the obstacles and perceptions that limit the use of EE/DR as a T&D alternative, concluding with a description of efforts that might alleviate some of these limitations/perceptions and allow EE/DR to be more extensively used as a T&D resource.

Keywords

Transmission planning
Distribution planning
Energy efficiency
Demand response
Non-wires alternatives

CONTENTS

1 INTRODUCTION

In response to the electric power industry's growing efforts to reduce greenhouse gas emissions and develop sustainable supply portfolios, EPRI began its Energy Efficiency Initiative (Initiative) in early 2007. More than 40 utilities are participating with EPRI in this initiative which covers numerous research topics associated with energy efficiency and demand management. The research being conducted as part of the Initiative is categorized into 3 areas:

- Analytics – methods and tools for analyzing aspects of the use of energy efficiency as supply resource, including measurement & verification, inclusion in generation planning, emissions reductions, economic impacts, etc.
- Infrastructure –assessment tools and resources to enable enhanced communications and control infrastructure, including recommendations on protocol standardization
- Devices – identification of, and influence on, the design of new smart and efficient end- use devices and equipment

The project described in this report, "Integration of Energy Efficiency and Demand Response into Transmission and Distribution Planning," falls within the Analytics element of the Initiative. This project is unique among the projects being conducted in that it is the only project that addresses the utilization of energy efficiency and demand response as an explicit resource for the power delivery system.

The focus of this project has been three-fold:

1. Identify the extent to which transmission and distribution planning engineers are utilizing energy efficiency and demand response (EE/DR) as a delivery capacity option when system deficiencies are identified,
2. Identify best practices in integrating EE/DR into T&D planning processes, and
3. Identify what actions, if any, can be taken to better position EE/DR as a T&D capacity alternative.

Chapter 2 presents the capabilities of various energy EE/DR initiatives that could potentially be utilized by system planners to address various system capacity problems. Chapter 3 presents current utility experience in utilizing EE/DR as a delivery capacity alternative. Chapter 4 discusses existing barriers that are limiting the use of EE/DR for T&D planning purposes. Finally, Chapter 5 attempts to categorize delivery capacity scenarios for which EE/DR are and are not reasonable options based on existing data and suggests actions that could be pursued to potentially broaden the use of EE/DR for T&D planning.

2 BACKGROUND

EE/DR as a T&D Planning Alternative

Historically, interconnected power systems have tended to be designed, built, and operated to serve whatever loads customers presented. The power system reacts to customers needs; operational control is exercised over generation and transmission equipment. Broadly speaking, "energy efficiency and demand response" take the opposite approach. These terms refer to various methods of influencing the amount or timing of electric power consumption in response to power system conditions rather than exclusively in response to customer desires. Physically, there are five basic types of load response as shown in Figure 2-1 [1]. All of them have some impact on power system reliability and economics; some have a greater impact than others. Energy efficiency reduces consumption during all hours and typically reduces the need for generation and transmission. It is not focused on times of greatest power system stress and may not provide as cost effective reliability response to specific reliability problems as more directed alternatives. Price responsive load and peak shaving both target specific hours when response is desired: the former facilitates voluntary market response to price signals while the latter utilizes direct control commands. Both types can be used to address capacity inadequacy (local or system-wide) caused by a lack of generation or a lack of transmission. Reliability response (contingency response) and regulation specifically target power system reliability needs and offer the greatest reliability benefit per MW of load from loads that are capable of providing these types of response.

- **Energy Efficiency** programs reduce electricity consumption and usually reduce peak demand
- **Price Response** programs move consumption from day to night (real time pricing or time of use)
- **Peak Shaving** programs require more response during peak hours and focus on reducing peaks every high-load day
- **Reliability Response** (contingency response) requires the fastest, shortest duration response. Response is only required during power system "events" – *this is new and slowly developing*
- **Regulation Response** continuously follows the power system's minute-to-minute commands to balance the aggregate system – *this is very new and may have the potential to dramatically change production costs, especially for aluminum and chlor-alkali*

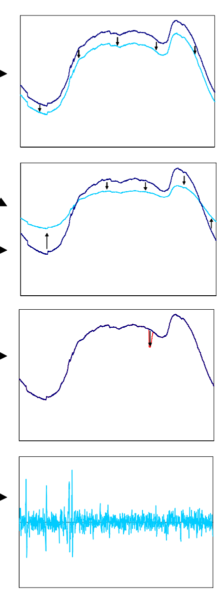

Figure 2-1
All Five Basic Types of Demand Response Impact Power System Reliability

Variations in actual implementation results in a large array of load response program types, each with unique characteristics. They can be used to potentially address an array of power system economic and reliability needs. Programs with appropriate characteristics can be implemented in the planning time frame as substitutes for generation or transmission capacity. Others can be used in the operating time frame to address more immediate problems such as equipment failure or fuel shortages. Load response programs can be geographically broad and designed to address system-wide generation shortages. They can also be geographically specific to address transmission or distribution inadequacies. In general, transmission and distribution concerns require the multi-hour load response capabilities offered by energy efficiency, peak shaving, and price response. While these same demand response types are utilized for generation inadequacies, some generation deficiencies such as spinning reserve shortages can often be addressed with the faster/shorter reliability and regulation responses.

The effectiveness of EE/DR programs depends upon how well the utility need is matched to the load response capability and on how well the tariff or market rules accommodate both. While some EE/DR programs may adequately address a specific T&D capacity need, others may not adequately solve the problem. Furthermore, the characteristics of some T&D capacity needs may be such that technical and/or economic limitations preclude any EE/DR solution. Industrial, commercial, and residential loads can all be used effectively if applied correctly.

Summary of EE/DR Program Implementations

Demand response (DR) refers to customers actively changing their consumption (demand) of electric power in response to price signals, incentives, or directions/intervention from grid operators. The changes in electricity use are designed to be short-term in nature, centered on critical hours during a day or year when demand is high or when reserve margins are low. Customer responses to high market prices, one type of demand response, can reduce consumption; this can shave wholesale market prices on a regular basis and thereby dampen the severity of price spikes in wholesale markets on extreme days.

Energy efficiency (EE) and conservation are not directly included in the definition of demand response programs. In fact, DR differs from energy efficiency in that the latter is improvement in efficiency that reduces electricity use with no change in the level of service (e.g. house still warm in the winter, lights still illuminating the room, etc.). DR, on the other hand, is a change in the level or quality of service that is chosen voluntarily by the consumer, which reduces electricity use or shifts it to a different time. If the change in service were imposed on the consumer involuntarily we would call it “curtailment” and it would be evidence of an inadequate or unreliable power system 2. Loads can also use technology and process control to provide DR without suffering a degradation in the quality of *effective* electrical service. This typically involves utilizing energy storage of some type within the process (or installing additional storage). Building thermal storage, for example, allows residential customers to provide 30 minutes of spinning reserve from air-conditioning without any user-noticeable impact on air-conditioning function.

Demand response mechanisms can be categorized into three major groups: time-based rate mechanisms, incentive payment mechanisms, and reliability response programs. Each category includes several options as summarized in the following sections.

Time-Based Rate DR Mechanisms

Time-based rate mechanisms include real-time pricing (RTP), time of use (TOU), and critical peak pricing (CPP) programs. These programs are based on the premise that by sending price signals to customers that reflect the underlying costs of electricity production, enough customers will reduce consumption during critical periods to ease power system capacity constraints and reduce prices for all customers. The differentiating characteristics of each of the time-based rate program types are summarized as follows:

Real-time pricing programs function by providing customers with a rate structure in which rates vary continuously (typically hourly) as the wholesale price of electricity varies. Variations in RTP programs in place across the United States include the following:

1. day-of versus day-ahead pricing – in day-ahead programs, customers are supplied with the hourly rates for the following day one day in advance as opposed to receiving hourly prices on the day the prices are effective
2. one-part versus two-part pricing – two-part pricing programs expose the customer to real-time prices only for their marginal use of electricity relative to a base-line usage determined from historical data
3. mandatory versus voluntary – some jurisdictions have established RTP structures as the standard rate structures for all customers (often of a certain size) , whereas other jurisdictions offer RTP programs as an option for customers to consider

Some jurisdictions have achieved significant MW reductions during peak periods through their RTP programs. Georgia Power has 1700 customers on real- time prices, representing approximately 80 percent of their commercial and industrial load (ordinarily, about 5000 MW). GP has seen these customers reduce their load by more than 750 MW relative to their baseline usage in some instances. 3.

Time-of-use (TOU) rate structures are a more course approximation of real-time pricing in that customers are exposed to different rates for peak versus off-peak periods. The rates are set and do not vary as the wholesale price of electricity varies, but they do reflect the general difference in electricity costs during high usage periods. This differentiation may be daily, weekly, or seasonally and may include not only peak and off-peak, but also shoulder periods. TOU prices are the most common time-varying rate structures, especially for residential customers.

Critical Peak Pricing (CPP) is relatively new and is a variation of TOU rates. CPP programs provide for very high, critical peak prices that are enacted during times that the utility defines as critical peak periods such as system contingencies or periods of high wholesale market prices. The CPP periods are not pre-specified and typically are communicated on short-notice. The number of hours that can be specified as critical periods is limited. CPP rates are relatively uncommon in the United States; the first major implementation occurred at Gulf Power in 2000. 3

Incentive Payment DR Mechanisms

Direct load control (DLC) programs are programs in which the utility has the ability to remotely disconnect customer electrical devices for reliability or economic reasons in exchange for an incentive payment or bill credit. These programs are often focused on air conditioning and/or water heating loads that utilities can either shut down entirely for a period of time or cycle off for some portion of each hour during the period. DLC is typically executed during periods of system peak demand, but most programs limit the number of DLC operations on a monthly and/or annual basis. DLC is more valuable to system planners and operators than other DR alternatives due to the higher degree of certainty that the required MW reductions will occur when needed. DLC is not 100% reliable, however, as most programs provide consumers the ability to override the shut down.

Demand bidding/buyback programs allow large customers to offer to provide load reductions for specific compensation 3. These alternatives offer customers payments for reducing their demand for electricity. In contrast with price mechanisms, which vary the cost of electricity to customers, these offers present the customers with varying prices they can receive as "sellers". When offered by ISOs/RTOs, these programs take the form of either demand bidding where large customers bid into day-ahead markets to reduce demand at specified price or price acceptance where the customer receives the market clearing price if demand is reduced when notified. Regulated utilities typically implement these types of programs as either short-term buybacks (load shifting for capacity reasons) or long-term buybacks (overall reduction for energy reasons).

Reliability Response DR Mechanisms

Reliability response programs are intended to provide system reserves from the demand side to withstand contingencies that rupture the generation/load balance (e.g. a generator outage or a transmission line failure which creates a generation shortage in one area and a generation surplus in another). Historically utilities used additional generating resources owned by the utility to meet these contingencies and their costs were simply included in the total costs to be recovered by the utility's regulated prices. The capability to reduce load can provide much the same reserve service as the capability to increase generation. The price at which the customer is willing to reduce load and other conditions of his participation will vary from customer to customer. While loads providing contingency reserve do not reduce transmission loading itself under normal conditions they can reduce the amount of transmission capacity that must be held in reserve to respond to contingencies. This both reduces the need for new transmission and increases the utilization of existing transmission to provide energy from low cost generation. These programs include curtailable/interruptible rate programs, emergency demand response programs, and ancillary service programs.

Energy Efficiency

Energy efficiency (EE) programs considered in this report are those programs designed to reduce electricity consumption through various means including altering consumer behavior, utilizing more efficient end-use devices, and improving the efficiency of the power system in delivering energy.

Conservation programs whereby utilities attempt to make consumers more aware of inefficient energy utilization are typically implemented as informational campaigns through advertising campaigns. The goal of such programs is to alter consumer behavior to reduce energy needs by turning off lights, adjusting thermostats, etc.

Many utilities implement programs to encourage consumer to utilize more efficient electrical devices or efficiency improving home alterations through incentive programs. Typical examples of such programs are compact fluorescent lighting programs and water heater, refrigerator, and heat pump exchange programs. Additionally, utilities also consider efficiency improvements when considering system designs and operational practices. Examples of such considerations include programs to replace retired transformers with high-efficiency transformers and conservation voltage reduction.

Load Response Characteristics and Viability as a T&D Alternative

The extent to which a specific EE/DR implementation represents a viable T&D alternative is dependent on whether or not the characteristics of the load response initiative meet the T&D need identified and on the cost of implementation. The technical characteristics of most concern to T&D planners include:

1. Speed of response
2. Duration of response
3. Frequency of response
4. Magnitude of MW reductions in specific locations
5. Magnitude of MW reductions over time frame of need (lead time and sustainability)
6. Certainty of obtaining MW reductions when required

Not all EE/DR implementations are created equal when it comes to their ability to meet T&D planning needs. For example, T&D planners would likely view estimated MW reductions obtained from a DLC thermostat program differently than reductions estimated from an energy efficiency initiative based on refrigerator magnets that remind consumer to turn off lights. The EE/DR alternative must be able to satisfy the technical requirements of the T&D need. Chapter 5 provides a more detailed consideration of how various EE/DR implementations match up with T&D capacity needs.

Utility T&D Planning Process

Purposes of T&D Planning

The power system must be designed so that the electric power consumption will be reliably met at the lowest cost. This means that the power delivery system must be planned, built and operated so that sufficient transmission and distribution capacity exist to deliver electricity from the available generation capacity reliably and economically. As load forecasts predict demand to exceed available capacity, T&D planners identify necessary system upgrades and expansions. Transmission planners also identify upgrades to reduce transmission congestion in order to lower electricity costs by providing access to lower cost generation and improving competition.

In general, planning goals that are within these two principal objectives can be identified as:

1. Improve system security and adequacy
2. Improve transfer (import and export) capability from different directions,
3. Accommodate load growth without delay,

4. Accommodate generation development without delay,
5. Provide flexibility to transmission customers to modify their transactions as market conditions change,
6. Reduce service denials and interruptions due to transmission constraints,
7. Reduce losses

Transmission and Distribution Planning Process

Transmission and distribution planning are complex and intricate processes in which many aspects and elements are to be taken into account when expansion projects are selected and designed. The main points to consider and develop are:

1. Planning period
2. Demand forecast
3. Demand Response and Energy Efficiency programs
4. Generation resources (Location, type, dating, etc.)
5. Reliability considerations
6. Congestion and power market issues
7. Economic and Financial constraints
8. ROW limitations
9. New and emerging technologies
10. Regulatory framework

Clearly, the planning process becomes more complex in unbundled industry structures and de-regulated markets, where different functions are carried out by different corporate entities. Transmission planning is more difficult where generation planning is no longer centralized and is left to the market to elicit opportunistic behavior in response to energy price signals that need to be locational if they are to be effective. Demand forecasting becomes more difficult, because the relevant data have to be collected from a number of different sources. A more detailed discussion of the intricacies involved in such planning processes is provided in Appendix B.

In very simplistic terms, however, transmission and distribution enhancement processes involve the following steps:

1. identification of delivery system needs to reliably and economically serve consumers
2. identification of possible solutions to needs
3. technical and economic evaluation of solutions
4. approval of recommended solution

Needs Identification

The needs of the power delivery system are driven by three primary factors: the level of load that must be served, the level of reliability that is required to adequately serve the load, and the locations of generators that can economically and reliably serve the load. These factors must be evaluated both in the near-term and long-term.

Demand Forecasting

Load forecasts are an essential part of transmission and distribution planning since demand changes are the driving force for resource adequacy requirements and delivery expansion plans. Projections must consider changes in electric power consumption related to seasons of the year, time of day, weather, available income, macroeconomic conditions, etc. Demand forecast are subject to a considerable level of uncertainty due to the number of variables. As noted in the subsequent section, EE/DR are often inherently considered in the planning process in that the underlying load forecast is directly or indirectly impacted by the load reductions achieved through such demand side programs.

Reliability Criteria

Transmission and distribution planning must provide a delivery system that allows produced electricity to be ***reliably*** delivered to meet forecast demand. As such, the definition of reliability that underpins the planning process impacts the decisions made to expand the system as load grows. The reliability criteria utilized by distribution planners to determine when system changes are required typically differ from the criteria utilized for the bulk transmission system. A distribution planner must be willing to accept curtailing the load on a radial feeder if that feeder is struck by lightning, for example. Conversely, a transmission planner can not accept the risk of not serving any load in the event of any single contingency.

Distribution planning has been typically done by projecting the load growth for several years and then estimating when a capacity limit will be exceeded at some peak loading condition. This is often done assuming the failure of one key circuit element, such as a substation transformer or a main feeder. Some utilities may design for two failures, but this option is too expensive for most utility customers at the distribution level. When the peak load power flow analysis predicts that the voltage will be too low or the current in a line or substation transformer will exceed limits, investment in new capacity is mandated.

NERC, the regional reliability councils, sub-regions, ISO/RTOs, power pools, Balancing Authorities, and their members have the primary responsibility for the reliability of bulk electric supply in their respective areas. These entities also have the responsibility to develop their own appropriate or more detailed planning and operating reliability criteria, and guides that are based on the NERC Planning Standards and which reflect the diversity of individual electric system characteristics, geography, demographics, regulation and politics for their areas.

Regional Reliability Councils like WECC also develop reliability standards and guidance for application in different kinds of studies. These standards are in accordance with NERC standards. In some cases transmission owners may develop company-specific planning criteria that, at a minimum, must conform to the NERC Reliability Standards and the criteria of the corresponding RTO. The NERC Planning Standards aim at preserving the reliability of the power system based on the two notions:

1. Adequacy: The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonable expected unscheduled outages of system elements.
2. Security: The ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

NERC standards (which are constantly evolving and are available in their full detailed form at www.nerc.com) are designed to enable the interconnected transmission systems to withstand probable and extreme contingencies and embody the following principles:

- S1: The interconnected transmission system shall be planned, designed, and constructed such that with all transmission facilities in service and with normal operating procedures in effect, the network can deliver generator unit output to meet projected customer demands and provide contracted firm transmission services, at all demand levels.
- S2: The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and contracted firm transmission services, at all demands levels, under the conditions of N-1 contingencies. These N-1 contingency conditions are featured by the loss of any single component and the credible simultaneous loss of any set of components.
- S3: The interconnected transmission systems shall be evaluated for the risks and consequences of a number of each of the extreme contingencies, featured by the loss of two or more components, or cascading events.

Planning Period

T&D planning is typically conducted on at least 2 planning horizons:

- *Long term planning*: The time horizon is usually 5-15 years. In this long term planning process the basic options for the transmission system expansion are determined. It permits consideration of many long-lead-time transmission options, like the definition of main transmission corridors, voltage levels, and technology options. Long-term planning addresses long-term load growth, the impacts of generation retirements, assessment of broad generation options as well as the possible use of demand response and distributed generation options.
- *Short term planning*: The time horizon is usually 1 to 5 years. Short term plans are intended to assess and define the transmission upgrades necessary to meet near term demand growth, generation interconnection requirements and reliability needs. It is within this short-term planning horizon that specific facility upgrades for alleviating specific constraints are evaluated.

Generally, as the length of the planning time horizon increases, the level of uncertainty in the projection of the future system and market conditions increases, and accuracy of the assessment of system performance in the long term decreases. Hence, the evaluation and design of system upgrades and measures for improving system operational security, like control systems of generation and transmission components, defense plans, protection systems, etc., can not be properly carried out on the long time period. On the other, it is necessary to consider a relatively long term period for the definition of the strategies for the transmission system expansion and future development.

Identification and Evaluation of Solution Options

Once planners determine that the existing system will not serve the forecast load at some point in the future within the accepted reliability criteria, potential solutions to the problem must be identified. This identification process differs depending on the characteristics of the situation and specific need identified -- transmission vs. distribution, regulated vs. deregulated, short-term vs. long-term need, etc.

For distribution, solution options are typically identified by the planning engineers. Investment options are usually restricted to substation or feeder expansion – options for which planners typically have considerable history. Planners then consider one or two feasible alternatives for solving the problem and select the one that best meets their performance and cost objectives and provides a comfortable margin for supplying future loads. This requires an established rule base. From experience, planners have learned that when the loading reaches a certain level, it is generally economical to build new capacity. The rules also dictate what capacity options to consider under which loading scenarios. This method works well when capacity options are limited to familiar choices (feeders, substations, etc.) and the economic environment is stable.

Today, the economic environment is rapidly changing for utilities and the capacity options are expanding. Distributed generation (DG) and EE/DR initiatives are examples of options that are being promoted for solving utility distribution system capacity problems. However, few utilities have experience in applying and evaluating these demand-side alternatives to establish planning rules for when they would be viable alternatives to new feeders and substations.

Potential transmission solutions may be identified by system planning engineers or proposed by other stakeholders. In deregulated jurisdictions, the process can be complicated as various entities have responsibility for various parts of the solution development process. Figure 2-2 depicts a general approach that can be followed for the development of a transmission expansion plan in which the different source of uncertainties as well as the extent of the uncertainty can be accommodated.

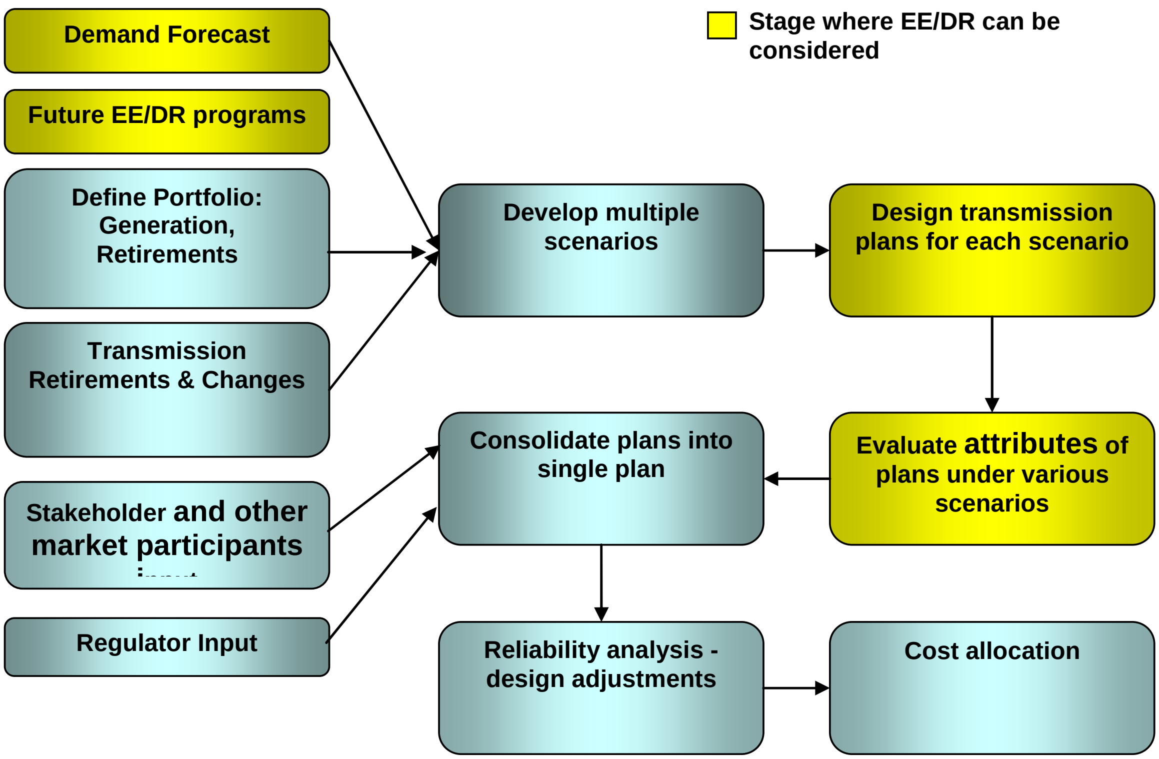

Figure 2-2
Overall Approach for Transmission Planning

The crux of this approach is to identify a single plan that is robust for the possible scenarios considered. Once the best plan is selected, it can be further improve by considering the attributes and performance of the other plans under different situations. It is also possible to design hedges (new options) to protect against adverse future developments.

DR and EE options can be taken into consideration in different parts of the process. In demand forecast, as is usually performed by planners, or in the development of the plan for each of the scenarios considered. In the later case, DR and EE would be in fact options for system upgrading that can compete with other traditional alternatives.

Trade-off analysis and other multiple goals optimization techniques could be used to define the optimal solution among the variety alternatives that arise when DR/EE are to be considered. DR/EE have peculiar characteristics that make them difficult to model or accurately quantify and compare the benefits and costs of different resources (i.e., avoided costs of energy and capacity). Chapter 4 of this report address obstacles that limit the utilization of DR/EE as resources for system upgrades.

3
PRESENT UTILITY PRACTICES IN INTEGRATING EE/DR INTO T&D PLANNING FUNCTIONS

This section provides a summary of current utility practices for handling EE/DR within their T&D planning processes. First, a categorization of general approaches is provided. Then, specific examples of utility cases where specific EE/DR initiatives were evaluated as an solution to specific T&D needs are summarized. Finally, a summary of utility experiences with EE/DR initiatives that had a more generic impact on T&D planning is provided.

Summary of the General Manner in Which Jurisdictions Currently Handle EE/DR Within the T&D Planning Function

Two activities were conducted in order to assess existing utility practices relative to consideration of EE/DR in the T&D planning processes:

- review of publicly available documents within power systems engineering publications, professional journals, and on the Internet
- solicitation of information from 40 utilities participating in the EPRI Energy Efficiency Initiative

These efforts show that current utility practices can be grouped into the following categories:

- indirect consideration of EE/DR through impact on load forecasts
- direct consideration of EE/DR as an option mandated for any facility upgrade proposed
- no consideration of EE/DR as a T&D capacity alternative

Indirect Consideration of EE/DR through Load Forecast

In most cases DR/EE are considered in demand forecasting. Different approaches are followed by planners to account for the effect of demand response programs on the demand forecast analysis for transmission planning purposes. In the case of PJM regional transmission planning, DR is implicitly included as a modifier to forecasted load. New England ISO uses historical DR energy data to estimate the long-run system energy requirements. Other RTOs do not directly include the effect of DR into the load forecast process. SPP for instance, does not itself explicitly include demand response in transmission planning studies. Individual load serving entities incorporate any current or expected demand response that is within their boundaries in their load forecasts. 3

In integrated planning in which DR and EE are considered within the range of options for system expansion and adequacy, the consistency between the demand forecast and the future development of the DR/EE options must be assured. Assuring consistency requires: 1) significant interaction between the forecasters and the DR/EE planners; and 2) a schedule that allows sufficient time for DR/EE analysis after the forecast is completed.

The major additional analytical requirements for load forecasting to support integrated resource planning include: 1) development of load shape forecasts; and 2) estimation of the net effect of DR and EE programs, including consideration of the actions that customers would have undertaken without utility programs and the efficiency rebound effect (i.e., customers tend to increase their comfort and/or level of energy functional use as their energy efficiency improves—for example, after insulating one's home, one may increase the thermostat setting).

It is extremely difficult to fully quantify the net effect of conservation and load-management programs using aggregate load forecasting models. Thus, the need to analyze the impact of DR/EE programs on the load forecast is a major driving force behind the increasing use of end-use load-forecasting models.

A range of forecasts reflecting uncertainty about load growth should be developed. This is usually done by developing a set of consistent assumptions concerning population growth and economic conditions for each possible load forecast scenario 4.

Mandated Consideration of EE/DR as Capacity Alternative

A few utilities/system operators indicate that they have either external or internal mandates to consider EE/DR options as alternatives to any proposed traditional facilities upgrade. BPA, through its Non Wires Solutions initiative, and MISO are examples of jurisdictions in which internal policy mandates that EE/DR alternatives be considered for any network upgrade. Nonetheless, these mandates have not yet resulted in identifying any specific EE/DR projects as a suitable alternative to traditional wires solutions.

Specific Cases Evaluating EE/DR as T&D Alternative to Specific T&D Investments

Four utilities provided detailed information concerning their demand response programs and how they are used to address T&D expansion needs.

BPA Non-Wires Solutions Initiative – Olympic Peninsula 56

BPA has a self directed obligation to examine non-wires demand response alternatives to every transmission enhancement project over $2 million. This was a key BPA focus in 2001 when it was embarking on a major transmission expansion program and it is still an important concern now that it has been integrated into BPA's normal transmission planning process. BPA has developed a screening process to identify if a particular transmission project is a good candidate for an EE/DR alternative and to determine which projects are best. Screening criteria examine the MW requirements and timing as well as the required response speed. Detailed site specific analysis is expensive and time consuming so screening analysis is helpful.

Since 2001 BPA has had pilot projects but no actual transmission deferrals based on non-wires alternatives have been implemented. Pilot projects using DR and EE have demonstrated the technical response capabilities and the reliability of the technology. A static VAR compensator has been used instead of upgrading a transmission line on the South Oregon coast but, while this is a non-wires solution it is not demand response. Interestingly, the SVC solution may delay the transmission upgrade for sufficient time to allow the development of a wave-generation based

DG solution. The network nature of transmission also complicates demand response effectiveness. One MW of demand response provides one MW of relief on a radial transmission system but it may take three MW of demand response to provide one MW of transmission loading reduction in a networked transmission system.

Demand response is still being considered as an alternative to further transmission upgrades on the Olympic Peninsula. Demand response was seriously considered as a transmission alternative previously but a change in the reliability criteria increased the response requirement too much for demand response to be effective.

BPA does not see technical or institutional barriers to the use of non-wires options. They work when called upon, they are reliable and they deliver. BPA developed special SCADA displays for system operators to show flows declining as demand response was called for on the Olympic Peninsula pilot project. Multiple demonstrations, with control room visibility for system operators, were successful in convincing operators of the viability of the technology. Adequate lead time is required to develop successful demand response projects and this complicates finding successful projects. BPA is actively trying to incorporate EE/DR options earlier in the transmission planning process.

The use of demand response for other applications may begin to make it easier to use demand response as a transmission alternative. Demand response projects that receive capacity payments will reduce costs to provide transmission response. This can be especially helpful for transmission needs which only occur a few hours a year.

CenterPoint Energy Share Initiative 7

The 2005 rules for the Texas PUC approved Energy Share program provide a $24/KW/year incentive for commercial and industrial demand reduction in transmission and distribution congested areas. The transmission planners, however, are not convinced the response will be sufficiently reliable or long lasting enough to justify changing transmission enhancement plans. Distribution planners identified several substations where demand response may help. The response incentive is not great enough to elicit daily response so locations with less frequent response needs were identified. Even 30 to 60 responses a summer were thought to be excessive. An industrial distribution substation was identified where contingency overloads exceed emergency capabilities if one of two parallel transformers trips. The substation has a 145MVA two hour rating and current load is 141MVA. CenterPoint sought 6-8MW of response from 24 customers but only received offers for 1.1MW total from two customers. The program was ended in July of 2006. As an alternative, CenterPoint began investigating the use of residential load response in January of 2007. Part of the investigation is to determine if new technology could be leveraged with advanced metering to increase customer acceptance. A pilot is planed for the summer of 2008.

Response incentives are established by the PUC and are based on 25% of the $78.50/kW/year avoided combustion turbine capital cost. Incentives are somewhat higher in congested areas and incentives for residential response can be up to 50% of the avoided generation cost. The low incentives are a deterrent to obtaining meaningful demand response. The PUC is considering raising the incentive to $80-$100/kW/year. CenterPoint is considering turning the program over to a third party with a performance based contract.

FPL Demand Response Programs 8

Florida Power and Light's (FPL) 1,400 MW of demand response is used to address supply concerns rather than T&D adequacy. Residential customers supply 800MW of response by allowing control of air conditioning, pool pumps, and water heaters. Pool pumps and water heaters were selected to minimize customer perceived impact. A direct thermostat control program is just starting. Commercial and industrial customers supply 600MW of response. Each customer must be able to drop 200kW in order to participate. Two way communications are used to assure the equipment remains functional. A lack of natural gas infrastructure limits the amount of distributed generation that is available.

FPL studies the use of demand response in place of T&D upgrades but rapid load growth and locational concerns make it difficult for this solution to succeed. Demand response and energy efficiency programs increase by 140MW per year while load is increasing by ~550MW per year at the same time as a result of 90,000 new customers per year. This is an increase of ~2.5%/year in the number of customers compounded by an increase in the use-per-customer. With a single new residential customer adding about 4kW to peak demand and residential load response offering about 1kW per customer, four customers need to sign up for demand response for each new customer connecting to the power system. This rapid load growth overwhelms the ability to recruit location specific demand response to address T&D upgrade requirements. DSM is credited with reducing the overall load growth impact, however, by calculating the typical cost-per-kw of load growth on the total system and valuing demand reduction for its ability to slow the general demand increase.

Demand response reliability is not a concern for FPL; demand response has proven to be a robust utility-grade resource. Planners and operators have enough experience with actual response to be confident that they know what response to expect under various conditions. Each time demand response is called upon the event is analyzed to verify that the expected response was realized. DSM programs are both popular and effective. Only the locational concerns and the rate of load growth prevent demand response from being used in place of specific T&D upgrades.

It is important to make sure all parties (customers and the utility) have the same expectations concerning how demand response programs will operate. Progress energy had 40% of customers participating in load control when they experienced an unusually hot summer. Response was called for twenty days in a row. Many customers subsequently left the program and reserve margins suffered. Responsive loads' contribution to reserve margins has now been limited as a result. Either customer expectations were not aligned with utility needs or the utility failed to understand the limits on customer endurance. In either case a better understanding is required to obtain the maximum reliability benefit from willing load response.

Snohomish PUD's CVR Program 9

Snohomish County PUD has a unique program of closely controlling customer delivery voltage in order to minimize energy consumption. The Customer Voltage Reduction (CVR) program objective is to cost effectively reduce energy consumption at the end-user and reduce distribution system losses. Both customer savings and reduced distribution system losses are valued when determining if a CVR project is economically justified.

Snohomish has tested the voltage response of numerous end-use loads over the last three years to determine the overall relationship between voltage and energy use. The research is expected to be published in early 2008. Snohomish calculates that on average load could be reduced by 200 MW if a 1% voltage reduction was implemented throughout the Pacific Northwest. Snohomish has used this research to design voltage control programs they are currently implementing.

Tightly controlling customer voltage requires careful control of the voltage drop along the distribution feeders. This is accomplished by reducing feeder lengths and reducing feeder loading. Switched capacitors and voltage regulators are used as are voltage sensors at both ends of the feeders.

The first phase of the CVR project cost $3.6 million to upgrade 36 substations. Fifteen minute demand VAR and watt meters were added to all feeders. Capacitors were added to flatten feeder voltage profiles. Voltages were reduced by 2.5% and a 1.75% energy reduction was achieved. In phase two $300K was invested to improve planning and optimization tools and $2.1 million was invested in upgrades for 36 substations achieving an average 2.4% voltage reduction. Phase three will spend an additional $5 million for line regulators, switching configurations, rephrasing, end-of-line voltage sensing and control, distribution transformers and secondary replacements, and MicroPlanet home voltage regulator installations at 70 substations.

Snohomish performed a detailed economic analysis of expected savings over a 30 year project life. Accounting for $252K/yr additional maintenance costs, a 3% cost of money, and a savings of 30,000 MWH/yr, the cost of saved energy is $21.73/MWH. With energy valued at $40/MWH the net consumer savings are $7.5 million over 30 years. Savings can be increased if the capacity that is released by the energy savings is also sold.

While the Snohomish County PUD CVR program is both economically and technically successful it is not used as an alternative to T&D upgrades. This is partly because the energy savings are dispersed throughout the power system. More importantly, Snohomish is investing in T&D enhancements in order to strengthen the T&D system to better control customer voltage and to reduce T&D system losses.

Integral Energy

Integral Energy is a state-owned electricity supplier and distribution utility in New South Wales, Australia, with a strong DSM program. 10 In New South Wales the state regulator now requires DSM to be fully integrated into the network planning process through a *DM Code of practice.* The code was drafted by industry and adopted by the regulator. The code requires demand response to be evaluated “when it would be reasonable to expect that it would be cost-effective to avoid or postpone the expansion [of a distribution system] by implementing such strategies.” 11 Development of the code was not easy or fast. It took six years from the time the government first established the requirement for utilities to evaluate DSM as a T&D alternative until the code was adopted and the code is still being updated and improved. Integral’s DSM program is based on the following principals 12:

- Pricing signals should be recognized as a legitimate demand management strategy
- Demand Management initiatives should focus on the reduction in peak demand

- The cost of network and non-network options, as identified by the distributor, should be used for evaluation purposes
- The cost recovery of non-network options should be on a similar basis as network options
- An effective demand management framework requires more customer education, as well as customer participation in reducing system load peaks in certain parts of the network. Distribution companies have a leading role to play in this education process

The fourth bullet, "The cost recovery of non-network options should be on a similar basis as network options" is particularly interesting given the regulated nature of network options and the often competitive nature of customer supply.

Integral's network planning process (summarized by bullets below) has been designed to accommodate DSM solution design:

- Annual development of a ten year plan detailing, by substation and zone:
    - Load forecast
    - Identification of system weaknesses
    - Identification of possible network solutions
- Evaluation of DSM potential to address specific identified system weaknesses
    - Overloading caused by load growth (rather than by aging equipment or Greenfield development)
    - The supply side solution costs at least $200,000/year (deferred investment of at least $2M – smaller projects do not have sufficient annual deferred cost to justify a DSM program)
- Public release of the annual DSM plan
    - Some DSM projects are specifically released requesting third party solutions
    - Other DSM projects are investigated directly by Integral
- Full assessment of all DSM alternatives and publication of results
- Selection and implementation of cost effective DSM solutions

Integral has found that sufficient time must be designed into the process to enable DSM solutions to be successful. Problems are identified well in advance so that third parties and Integral have ample time to evaluate potential solutions.

Integral actively seeks to understand why the DSM process has not been more successful. For example, they interview organizations that have expressed interest in one or more DSM projects but that subsequently did not submit proposals. Integral has also found that they must fully explain the constraints, timing, nature, MW amounts, and cost of the likely supply side alternatives to potential DSM providers to enable them to offer solutions. Further, Integral has found that they needed to reduce the requirements on initial DSM proposal details and may need to partially subsidize the proposal process. Developing detailed DSM proposals is time consuming and expensive. DSM project developers can not afford to do the required engineering, which is specific to each project, without at least partial compensation. Integral feels that this is comparable to how initial network solution design is internally compensated.

Integral found that 12 of the 28 network augmentation projects identified in 2002 and half of the 36 projects identified in 2003 were candidates for DSM solutions. Several projects were successfully implemented. Examples include:

Seven Hills – a single industrial load was able to provide 4.5 MVA peak reduction for four hours per day with 24 hour notice. This provided a five year delay of a $1.7 million substation augmentation.

Katoomba – Residential energy efficiency measures provided a ten year feeder and transformer deferral. The primary cost was for a full time energy efficiency advocate to provide advice to builders and developers along with publicity and education programs. The primary customer incentive was through lower energy consumption and bills.

Rooty Hill – High growth requires upgrading the substation. A $300,000/year DSM program that could deliver 2MVA would be effective. That translates into $600/MVAhr based on the expected required hours of response, clearly attractive for many responding loads.

Liverpool CBD – High commercial growth results in a need for 16MVA of load reduction for 20 hours a year. With substation augmentation deferral worth $400,000/year the DSM program would be valued at $1,250/MVAhr.

Use of emergency generation can show similar economic benefits. Although operating small generators is generally far more costly than the averaged cost of drawing electricity from the network, and there are often serious environmental concerns, it may be far cheaper than the cost of network system augmentation.

EE/DR Initiatives Generally Impacting T&D Investments

In addition to the cases provided in the previous section where specific assessments were made of EE/DR as alternatives to specific upgrades, this section describes other EE/DR projects that have characteristics that directly impact the need for transmission enhancement or they provide a reliability resource for use by the system operator which can reduce the dependence on transmission.

It is not possible to compile an exhaustive list of projects in which responsive load is having an impact on the need for transmission enhancement, there are too many transmission planning organizations to survey for that to be practical. Also, projects often have multiple impacts. However, the examples presented in this section provide good insight into the existing DR programs that have influence on the transmission system planning.

LIPA EDGE

LIPA Edge is a typical peak demand reduction project controlling residential and small commercial air conditioners using modern technology with several innovative features. It is particularly interesting because it has the technical ability to significantly increase its benefits by providing spinning reserves as well as peak load reduction.

Remotely controllable Carrier Comfort Choice thermostats coupled with two-way communication provided by Silicone Energy and Skytel two-way pagers allows the Long Island

Power Authority (LIPA) to monitor capability and response as well as to control load reductions. It also enables customers to control their individual thermostats via the Internet, a benefit that motivates participation 13. Currently controlling 25,000 residential units and 5,000 small commercial units provides 36 MW of peak load reduction. 14

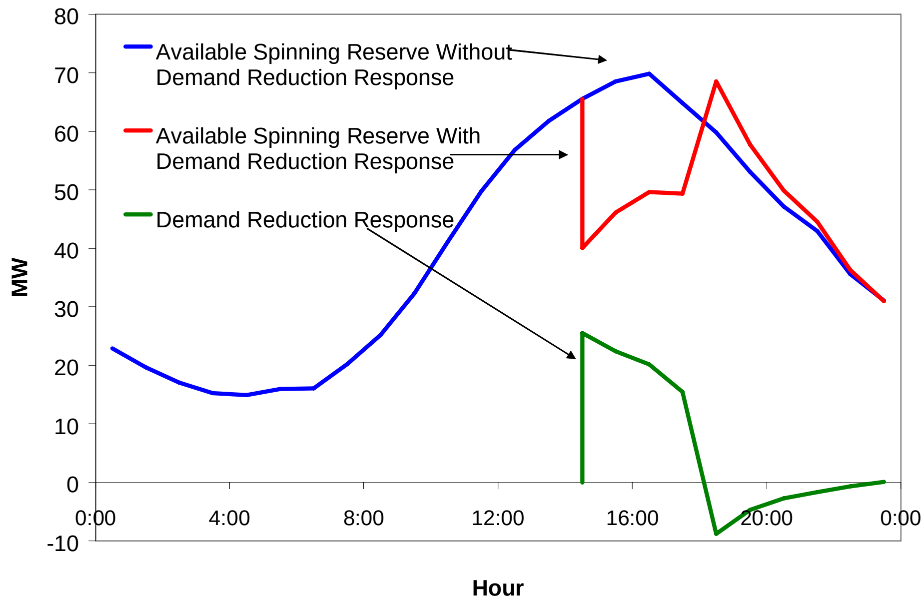

Figure 3-1
Significant Spinning Reserve Capability Remains Even When Demand Reduction is in Effect, as Shown in this 8/14/2002 Curtailment 1

Detailed discussions with Carrier in 2002 revealed that the technology is fast enough to provide spinning reserve and provides ample monitoring capability. Further analysis of test data revealed that the program can typically deliver 75 MW of 10-minute spinning reserve (when the peak reduction program only had 25 MW of capacity) at little or no additional cost at times of heavy system loading; this could be a significant benefit for capacity-constrained Long Island. Significant spinning reserve capability remains even if the system is being used for peak reduction as shown in Figure 3-2. 15 Spinning reserve capacity is now likely over 100 MW.

SCE FEEDER RELIEF

Southern California Edison (SCE), with California Energy Commission support, is conducting a Demand-Response Dispatch Verification Research and Demonstration Project in the summer of 2006, 2007, and probably 2008 to demonstrate the impacts of distributed resources both as a means to provide specific load relief at the substation and distribution feeder level, and as a spinning reserve resource. The system uses the public Internet, the SCE wide area network and various wireless technologies to provide two-way control and monitoring of the devices that control electric loads at approximately 450 sites in Southern California. Two specific objectives are to demonstrate that when load is curtailed by a dispatch signal, the available MW demand response of a specific circuit can be predicted with a 90% statistical confidence and demonstrate that the load can be curtailed reliably and quickly on the issuance of a dispatch signal. The load shed is expected to start within 10 seconds of the signal and be fully implemented within two minutes.

SCE is implementing a special contract for the test with 400 to 500 residential customers and 50 to 100 commercial customers. Various curtailment intervals are to be tested. The selected circuit has a peak load of 9 MW. SCE expects to curtail 2 to 3 MW depending on time of day, temperature, and day of week. A rigorous statistical analysis has been performed in planning the number of customers under test, the number of tests, and the data acquisition system to ensure the results provide a relative precision of 15% at the 90% level of confidence. SCE expects the test to provide a benchmark for repeatable, precise, rapid demand response used as a reliability service. 16

XCEL ENERGY PUMPING LOAD

WECC does not currently allow responsive load to supply spinning reserve. Xcel Energy wants to supply a portion of their spinning reserve obligation from their two 124 MW unit Cabin Creek pumped storage plant. Xcel is working with Oak Ridge National Laboratory to develop a test procedure to demonstrate the efficacy of load providing spinning reserve to WECC. Operator directed response will be provided by a fast but conventional shut down of the unit. This is expected to complete in less than one minute – much faster than the 10 minutes allowed for full generation response. The pumps will also automatically trip in respond to frequency deviations. The stability runs shown in Figure 3-2 were made in support of this project.

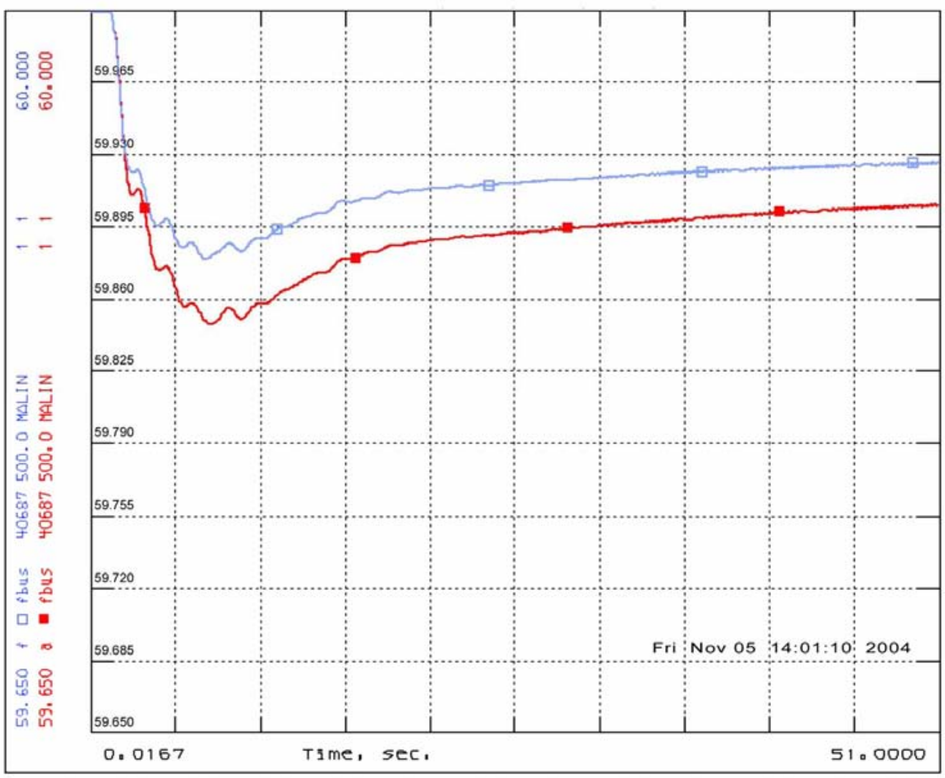

Figure 3-2

WECC Analysis Shows That Responsive Load (blue) Can Increase Power System Stability When Used Instead of Generation (red) to Provide Spinning Reserve (Analysis done by Donald Davies)

ONCOR ELECTRIC DELIVERY COMPANY (TXU)

Oncor offers a Residential and Small Commercial Standard Offer Program in response to a 2002 Texas law requiring a 10% reduction in demand growth. The program consists of incentive payments for the installation of a wide range of energy savings and demand reduction measures. Oncor purchases peak demand reductions from energy efficiency service providers who market and install the measures.

COMMONWEALTH EDISON

As part of the 1992 franchise renewal negotiations Commonwealth Edison agreed to invest $1.25 billion in transmission and distribution improvements and $100 million for the Chicago Energy and Reliability Account program which defers distribution investment by energy efficiency and distributed generation.

CONSOLIDATED EDISON

Consolidated Edison provides an example where demand response is being explicitly sought as an alternative to transmission and distribution expansion. Consolidated Edison issued a request for proposals in April 2006 seeking at least 123 MW of demand side management in targeted areas of New York City and Westchester County in order to defer transmission and distribution capital investment. Multiple proposals will be considered; each proposal must be for at least 500kW of aggregated peak summer load reduction. Consolidated Edison provided detailed information and maps for each geographic area to help project developers. Materials include:

- Numbers and types of customers (residential, commercial, small commercial, types of business, types of residential, numbers of central air conditioners, numbers of room air conditioners, …)
- Sizes of individual customer loads (10-300+KW)
- Total required load reduction (2-25 MW)
- Need date (2008-2011)
- Minimum project duration (2 to 4 years)

Clean distributed generation may be proposed as well as energy efficiency measures. Distributed generators can reduce customer load but they may not export to the grid to be considered for this program. Energy efficiency measures are allowed (compact florescent lights, energy efficient motors, efficient air conditioning, and steam chillers for example).

Unfortunately, direct load control and measures that "temporarily curtail or interrupt loads" will not be considered. Neither will operating and maintenance improvements nor improved new construction measures. 17

MAD RIVER VALLEY PROJECT

In 1989 Green Mountain Power (GMP) needed to enhance the distribution system feeding Sugarbush Resort in the Mad River Valley in central Vermont. Load was expected to grow and a $5 million parallel 34.5 kV line was needed. Instead, Sugarbush installed an energy management system to enable it to monitor and control its load and keep the total feeder load below 30 MW. Snowmaking was the major controlled load.

GMP also engaged in an energy efficiency program for other customers on the feeder. GMP largely abandoned the follow-on demand side management work once the network problems were resolved. 18

THE ENERGY COALITION

The Energy Coalition was formed in 1981 by end users to aggregate load response to help alleviate generation and network capacity shortages in southern California. The Coalition develops load response capabilities that are sensitive to both the utility needs and the needs of the individual load. Since its inception The Energy Coalition has aggregated loads in the service territories of Pacific Gas & Electric, the Long Island Power Authority, Boston Edison, and Commonwealth Edison.

Interest in the Coalition declined in the 1990s as California went from having electricity shortages to capacity surpluses. Interest revived when the situation turned around again in the 2000s. The Business Energy Coalition is a specific project in the San Francisco area that specializes in short-term network relief. A 10 MW pilot project is based on the area’s 200 largest customers with day-ahead and same-day response. Response is limited to five hours/event, one event/day, five events/month, one hundred hours/year. Response can be called upon for CAISO Stage 2 emergencies, spinning reserve shortfalls, forecasted San Francisco temperatures above 78 degrees, local emergencies, and total CAISO load forecast to exceed 43,000 MW.

4 CURRENT OBSTACLES TO BROADER UTILIZATION OF EE/DR AS T&D RESOURCES

There are a number of obstacles, and perceived obstacles, to the broader use of EE/DR as T&D resources. These obstacles can be grouped into four broad categories: technical, reliability rules, regulatory, and market. Some of the obstacles span more than one category. In addition to providing a description of each of these potential limitations, this section also provides a summary of survey results obtained as part of this project providing insights as to utility perceptions of EE/DR in T&D planning.

Technical Obstacles

The first set of obstacles relate to the current inability of EE/DR solutions to solve the T&D needs as reliably or economically required. Energy efficiency and demand response solutions may currently be unable to provide the desired function, or obtaining the desired response may currently be too expensive. Improvements in technology may be needed before the full potential of EE/DR can be realized.

Communications

While energy efficiency projects typically do not require communications (with the possible exception of performance verification), communications are required to send response commands or price signals from the system operator to responsive loads. Communications are also required to monitor response capability (readiness), willingness/commitment (when loads are given a choice) and actual response. Expenses are related to the number of communications channels needed and the required speed. Consequently communications are not typically a concern for energy efficiency projects which do not require real-time data transfers. Communications are not typically a problem for large loads either because the expense for each communications channel is spread over a large number of MW. The largest loads may already be monitored by the utility SCADA system, reducing any incremental communications cost.

Communications can be especially problematic for demand response from large aggregations of small loads. It is impractical, for example, to provide utility grade AGC control and SCADA monitoring for every residential air conditioner. Technology can help by lowering the cost and broadening the reach of communications networks.

Careful consideration of the actual communications requirements in both directions is needed. There are at least five distinct types of communications that must occur between responsive loads and the power system operator. While the utility industry has tended to address all of these requirements by using the dedicated high-speed communications systems when dealing with conventional generators that may not be necessary or desirable when dealing with large aggregations of small loads. Considering the actual requirements for each type of communication may help increase the functionality and reduce the cost:

1. Price or advanced event signal: The utility may supply a price signal or an announcement of an upcoming peak reduction event to customers. In either case the signal is broadcast to all customers, or all customers within a specific geographic region. The signal is also relatively slow. In one extreme the signal may be an announcement of time-of-use rate publicized a year in advance. Even “fast” price or peak reduction signals are typically sent at least minutes and often a day in advance. Real-time, individual communications are typically not needed.
2. Participation election: Some responsive loads may have the option of deciding if they will be available to respond to power system needs. It may or may not be necessary for the load to inform the utility of each decision. If a response is required the needed communications speed is relatively low (minutes to hours).
3. Capability monitoring: It is important for the system operator to be aware of the current response capability. This can include monitoring of environmental parameters that correlate with load levels (monitoring outdoor air temperature as an indication of air conditioning load level and available fleet response, for example). It can also include direct monitoring of the resources themselves. The required communications speed needs to be evaluated for the specific application. Real-time monitoring may not be required.
4. Operational response monitoring: Aggregate response must be monitored in real-time to provide the system operator with situational awareness. Monitoring must be fast but it need not be specific to the individual. Statistical sampling or monitoring at an aggregation point may be adequate.
5. Verification response monitoring: Individual response must be monitored to assure continued quality of service and reliability of the power system. Monitoring speed is not particularly important.

The nature of the demand response resource and the possible failure modes also impact communications requirements. No technology is perfect and the power system is designed to accommodate the failure of resources to respond. When a large power plant or large load fails to respond the system operator needs to know immediately so that alternative actions can be taken. Failure of a single residential air conditioner to respond when expected does not have similar reliability consequences for the power system; failure of the entire load response system does. It may be appropriate to treat individual failures of small loads statistically, changing the monitoring and communications requirements. Monitoring of common resources such as the communications network might be done through SCADA. Monitoring requirements for individual loads might allow slower monitoring, monitoring only a statistical sample, monitoring at less frequent intervals, or using a less robust communications network.

Control

The inability to control loads quickly, accurately, or automatically may limit the usefulness of EE/DR for T&D and other power system applications. Technology may be able to improve the ability and/or reduce the cost of actually controlling load response. Automation should increase the certainty and accuracy of response. It may also help in providing locational control which is necessary for T&D applications. The need to control large numbers of smaller loads means that control technologies need to be inexpensive. Retrofit technologies may also be required until remote control of end use devices becomes universal and control technologies are built into the devices as a standard feature. Control and communications issues are often intertwined.

Sustainability of Response

There are two technical aspects to the sustainability of load response. One involves the power system while the other involves the load itself. Power system engineers are used to dealing with generators which typically incur cost when they turn on: unit commitment decision and startup costs. Once operating, the generator's costs are steady and typically dominated by the fuel cost: constant $/MWH cost. The generator is typically able to run as long at the power system needs it.[1] Consequently, there is normally little need to carefully evaluate response duration requirements. Unlike generators, responsive loads often have response duration limitations. Evaluating the actual response duration becomes important for the system planner to be able to gain maximum advantage from the responsive load. Response duration needs will vary depending on the specific application the planner is trying to meet. Larger response is typically available for shorter durations. This can be akin to the distinctions made in normal and emergency ratings for T&D equipment.

A responsive load's ability to sustain its response is a technical issue that basically relates to the amount of storage available at the load. Storage can take many forms. Thermal storage may be inherent in the thermal mass of a house, building, or freezer. Thermal storage in the form of chilled water tanks can also be built specifically to provide load response. Storage may also be in the form of pre-produced product that allows a manufacturer to curtail manufacturing for a time. The product may be final product ready for shipment or it may be various intermediate products within a manufacturing or chemical process. Storage may be in the form of pumped water or gas held in a tank. Storage can also be more directly in the form of useable electricity based on pumping water, flywheels, or batteries. Examination of the customer's energy use can determine how much response (both MW amount and duration) a load can provide at reasonable cost. Studying the customer's energy use can also determine what process changes and/or investments could be made to increase the amount of storage available and lengthen the response duration or increase the response amount.

Reliability of Response

The type of problem and the available alternative operating solutions being addressed determine how reliable the demand response must be. EE/DR might be considered as an alternative to a transmission upgrade to alleviate congestion, for example. If ample flexible local generation is available down stream of the congestion the EE or DR solution need not be highly reliable. The objective of the EE/DR solution may be to alleviate economic congestion most of the time and continue to utilize the local generation when still needed. Broad averages concerning availability or energy price impacts may be adequate metrics to assess success.

Use of EE or DR resources in place of T&D upgrades when there is no alternative operating solution requires a more rigorous assessment of reliability. No power system equipment is 100% reliable so availability and failure probabilities must be compared. Data on load response

[1] There are exceptions. Hydro generators with pond limitations can have limitations on their run times. Fossil fueled plants with emissions limits can also have run time limitations.

reliability may not be available and studies may be needed to quantify response. Since available load response is generally correlated with load itself the quantification may be somewhat complex. Increasing outside temperature may reduce the available transmission line and transformer capacity while it may increase the response available from some loads, for example.

The reliability nature of response from large aggregations of small loads is also fundamentally different than the reliability response of large discrete resources. This difference in reliability nature must be evaluated differently. Figure 4-1 demonstrates this difference when comparing aggregate load response with conventional generator response to a contingency event. In this simple example, response from six generators that can each provide 100 MW of response with 95% reliability is compared with response from 1200 small loads that can each provide 500 kW of response with 90% reliability. Interestingly the less reliable loads provide a more robust overall response than the individually more reliable generators. There is a 74% chance that all six generators will respond to an event and a 97% probability that at least five will respond, which implies a nontrivial chance that fewer than five will respond. This can be contrasted to the performance from an aggregation of 1200 responsive loads which typically delivers 540 MW (as opposed to 600 MW) but never delivers less than 520 MW. As this example illustrates, the aggregate load response is much more predictable and the response that the system operator can “count on” is actually greater.

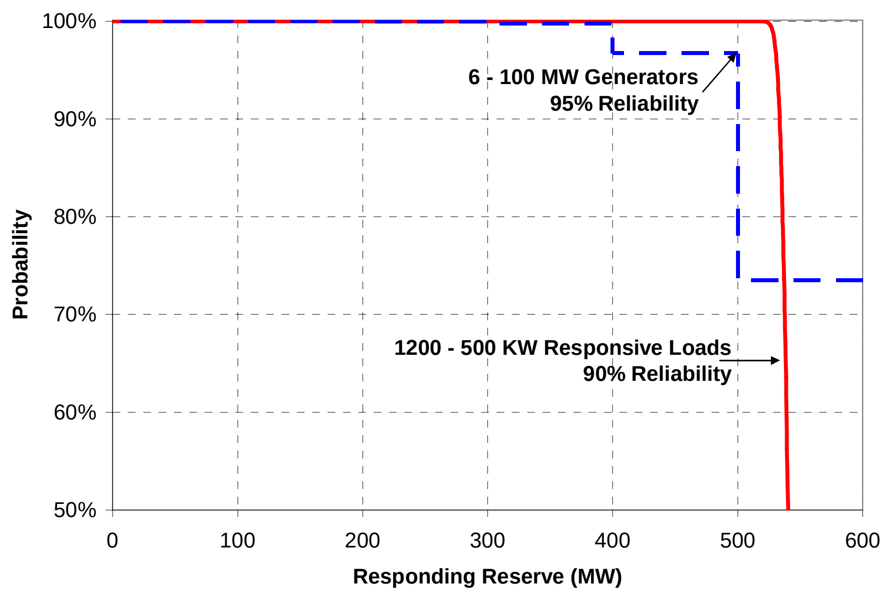

Figure 4-1
Larger Numbers of Individually Less Reliable Responsive Loads Can Provide Greater Aggregate Reliability Than Fewer Large Generators

Any analysis of demand response reliability must carefully consider which elements of the system are independent and which may be correlated. Clearly the demand response communications system is a point of potential common failure. If the response signal does not go out there will be no response at all. The communications system must have the utility grade monitoring and redundancy included in other large utility resources. Individual load’s mechanical failures are likely statistically independent but the response from the load operators may not be. Some types of customer overrides, for example, will likely be independent and based upon individuals' unique daily needs. Other types of customer overrides, such as response to the third day of an intense heat wave, may be highly correlated. As the correlation in the probability of lack of expected response increases, the gains in aggregate reliability depicted in Figure 4-1 erode. Accurately characterizing the load response capabilities and performance is an important technical challenge.

Planning Process Time Frames

The time lines associated with T&D planners identifying short-term needs may impact whether sufficient EE/DR program development and marketing can be completed to achieve required acceptance/subscription rates to potentially meet the capacity need. For example, planners may not actually begin the solution identification process until the need is 1-3 years away. Such a short time line may be too short for achieving sufficient EE/DR capacity. If, however, the process were altered such that the planners could inform EE/DR marketers of a potential need 3-5 years before solutions are required, there might be sufficient time for achieving EE/DR reductions that would allow further upgrades to be deferred or precluded.

Planning and Operations Tools

Lack of knowledge concerning demand response and energy efficiency capabilities is a major technical barrier to increased use of the resource. Tools are needed to assist planners in determining what response capability is potentially available for future use and operators to know the capability of the existing installed system.

Planners need tools that characterize the potential load response (amount, response speed, response duration, control requirements, cost, etc.) by location under the full range of loading and environmental conditions. Operators need similar tools that characterize the response available a day ahead and in real-time. Typically aggregate locational response will be of interest rather than individual load response. Tools are also needed that monitor and assess actual performance to help establish the correct level of confidence in the resource.

Planning tools are important for the potential responding loads as well. It is important for the loads to have an accurate forecast of the number of times and the durations that they are likely to be asked to curtail. Without realistic expectations on both the utility and load sides demand response programs can not be successful over the long term.

Reliability Rules

Reliability rules can present another obstacle to the appropriate use of EE and DR for T&D applications.

Reliability rules are often, understandably, written around the capabilities of the dominant supply resources. There is little point in asking for response that is simply unavailable. This has little adverse impact when there is a uniform pool of resources to draw from and when the resources have little control over their response. It does have an adverse impact, however, when a new type of resource (demand response) tries to enter the mix. When multiple types of resources become available with varying capabilities and limitations the system requirements need to be reevaluated and specified in terms of the basic power system reliability needs rather than in terms of the capabilities of one type of resource. It is particularly important to separate familiarity and comfort with past performance from genuine system requirements.

There are many examples of features of reliability rules that accommodate generator limitations that do not increase system reliability. They are necessary to enable generators to provide the desired reliability response but they are not themselves directly related to that desired reliability response. A partial list includes:

- Minimum run times
- Minimum off times
- Minimum load
- Ramp time for spinning reserve
- Accommodation of inaccurate response
- Limiting regulation range within operating range to accommodate coal pulverizer configuration

It is not that these accommodations should be revoked. They are necessary to elicit the reliability response the power system requires. Similar accommodations should be examined for demand response technologies to determine if they can and should be included in reliability rules. A partial list might include:

- Maximum run time
- Value capacity that is coincident with system load
- Value response speed
- Value response accuracy
- Match metering requirements to resource characteristics

Regulatory Obstacles

Regulatory obstacles can deter EE and DR in a number of ways. Regulatory rules can be so narrowly crafted that they limit the types of response loads are allowed to provide. Price caps based on generator fuel costs may not be appropriate for responding loads which incur higher production losses. EE and DR project costs can be difficult to recover. Regulatory treatment of T&D investments generally differs from regulatory treatment of EE and DR. Prohibitions on independent system operators' involvement with EE and DR programs can restrict EE and DR success.

Load Response Limitations

Some regulators narrowly craft demand response rules to protect loads from abuse and assure that customers do not get dissatisfied with their electric service. Utilities may be limited in the number of times they can interrupt a customer during a day or a season, for example. This laudable goal can have the unintended consequence of limiting the types of response loads can provide. Limiting the number of curtailments, for example, drives the utility to only use load response for multi-hour peak reduction rather than for more frequent but faster and shorter reliability response. It is often difficult to get regulatory restrictions changed, especially for limited term testing to determine if a different type of load response would be preferable.

Price Response Limitations

Regulators and market designers sometimes place price caps on energy markets. With known fuel costs it is possible to calculate generator production costs. Prices will only rise well above the production cost if supplies are limited. Allowing prices to rise far above the generators' production cost does not bring additional generation into the market, at least in the short run. Price caps prevent generators from unfairly exploiting supply shortages.

Load response prices are not tied to fuel costs, however. Load response costs typically depend on the load's opportunity costs which are in turn related to the business the load is in and can be very high. Calculating load opportunity costs can be very difficult. While legitimate generator price caps protect customers from excessive prices they can block load response and limit available energy supply when applied to responsive loads.

Cost Recovery and Market Participation Limitations

Restructuring of the electric utility industry has required the separation of regulated and competitive entities. Regulated transmission or distribution companies can find themselves unable to continue recovering the costs associated with demand response programs if those programs are seen as more properly participating in the competitive energy market. Some successful, long standing, demand response programs are withering because the distribution company that historically hosted the program has no way to recover costs. Similarly, some Independent System Operators state that they are prohibited from promoting any form of demand response because they can not favor any individual participant in the competitive energy markets that they are charged with facilitating.

Rather than treating all energy efficiency and demand response programs as competitive participants in the energy markets it may be more appropriate to treat some as regulated resources, similar to the way the transmission and distribution assets that they are complementing are treated. While customers generally benefit through lower electricity bills as a result of participating in energy efficiency and demand response programs that is often not the primary motivation or the primary value. Often customers participate in an effort to help increase power system reliability and reduce overall power system costs. Similarly, all customers benefit when enough load responds to offset the need for a T&D enhancement. Program costs, especially the supporting communications and control infrastructure costs incurred by the host transmission or distribution company, may better be treated as regulated investment costs and provided with a regulated rate of return. Quite often it is much more efficient for the local transmission and distribution company to facilitate demand response programs than it is for third parties to establish a parallel support structure.

Assured Multi-Year Response

Regulated transmission and distribution solutions continue to receive preferential treatment throughout their lives. T&D assets are maintained and paid for even if their usefulness temporarily declines. A 161 kV transmission line would not be decommissioned when a 500 kV line was overlaid in order to alleviate congestion on the 161 kV line, for example. Instead the 161 kV line would be maintained as part of the integrated transmission system. It would contribute to the robustness and reliability of the power system even if actual line loading was greatly reduced.

Demand response programs are typically not treated the same way. If a program is initiated to alleviate a generation capacity problem or a transmission congestion problem the program is typically discontinued as soon as the problem is alleviated. This is not unreasonable but it does have important implications in terms of capital cost recovery. A demand response program risks incurring stranded costs if conditions change and it is no longer required. A transmission solution that was built in response to the same problem would not be exposed to a similar financial risk. This is another reason that it may be appropriate to treat some demand response and energy efficiency programs as regulated resources.

Survey Results Measuring Present Perceptions of EE/DR as T&D Resource

In order to gain guidance in understanding utility perspectives on EE/DR as T&D capacity options a brief questionnaire was submitted to each of the 40 member that participate in this Initiative.

This survey was motivated from the fact that a preliminary literature investigation surprisingly uncovered few reports on successful EE and/or DR projects that have been designed and deployed to either delay or replace transmission and distribution upgrades or new projects. FERC's August 2006 staff report "Assessment of Demand Response & Advanced Metering", for example, contains a chapter on the "Role of Demand Response in Regional Planning and Operations". FERCs report documents what projects and processes they found, but considering the number of conventional transmission and distribution projects that are underway there are extremely few alternative projects being implemented.

Therefore, this questionnaire was aimed to capture information from utility planners and other technical staff about the most relevant issues that prevent EE/DR from being seriously considered as transmission and distribution expansion alternative. It is intended to answer two main questions:

- Why are there apparently so few EE and DR projects to offset T&D expansion?
- What can be done to increase EE and DR project use for T&D?

The survey instrument consisted of 7 statements with a total of 18 sub statements. Responders were asked to indicate their response on a 5 point agree-disagree scale.

Twelve responses to the questionnaire were received from the forty project utilities to whom they were distributed. Responses were processed to obtain statistics on the sample responses. Complete survey results are presented in Appendix A.

A work shop about current practices on using energy efficiency and demand response as potential alternatives to specific T&D investments was held in Dallas in August 22, 2007. Eleven professionals from ten different utilities participated in the event. The project was aimed at providing the project team with insights as to how to proceed to complete the project in manner that would bring maximum value to the participants.

Survey results were first presented and discussed with the attendees. It is worth noting that not all the meeting attendees had answered the questionnaire, so that the conclusions of the survey were further enriched by additional responses from the attendees.

In this section, the results for the most relevant points as well as a summary of the main conclusions are provided. These conclusions are drawn from both the answers to the questionnaire and the input from workshop participants.

One of the main issues is to what extent the EE and DR are currently used for T&D, and what are the main obstacles that prevent them from further utilization. Figure 4-2 depicts the responses profile for the Statement A of the questionnaire: "EE and DR are being fully and properly utilized". It is observed from these responses that only a few percentage of the responders really considered that EE and DR are being fully utilized.

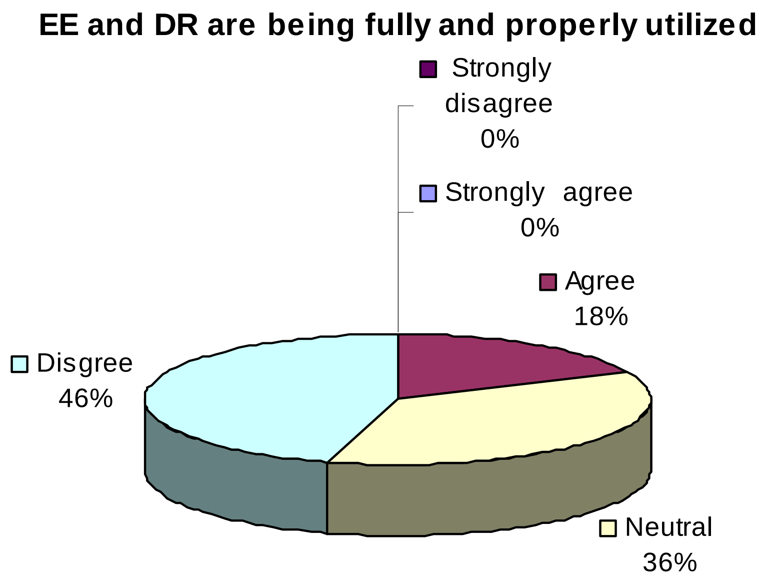

Figure 4-2
Response for the Statement A of the Questionnaire

Questionnaire and meeting responses provided further insights concerning how utilities view EE and DR:

- EE and DR are usually imbedded in the load forecast and so are not explicitly considered for T&D planning.
- Not enough dependable capacity can be garnered when and where needed to defer the proposed wires project at a cost that would be less than the project itself.
- EE & DR programs have typically been addressed at reducing overall energy and capacity demand and not focused on regional or local T&D issues.
- DR programs often need substantial investment in a communications infrastructure and/or recruiting efforts to maintain the capacity contributions necessary to avoid the investment in infrastructure.

- Planners are not fully aware of EE and DR capabilities and may have misunderstandings about current capabilities.
- The separation of transmission planning from all other planning options limits planners ability to consider options other than new transmission equipment.
- DR programs are treated as dispatchable resources for generation, but they are not considered as resources for T&D because using them in that manner would greatly increase the number of hours they are invoked, increasing cost and making customers less likely to participate.
- Traditional T&D planning philosophy has been reluctant to consider EE/DR based on uncertainty of demand response performance.
- Interrupting load goes against the nature of the power supply industry.
- While it is possible to count on mandated direct load control, it uncertain how demand response to voluntary or price response.
- Customer interruption tolerance is not known
- Load response tends to fall off when loads are asked to respond too often or for too long.
- Much more data is needed to characterize customer response and give planners and operators confidence.

Both the questionnaire responder and meeting participants stated that EE and DR can at best delay the need for a T or D project but they can never replace the T or D investment. Figure 4-3 shows that 80% of responders strongly agree or agree with this statement, and none of them disagree. That is strong conclusion that should be considered in the development of further stages of this project.

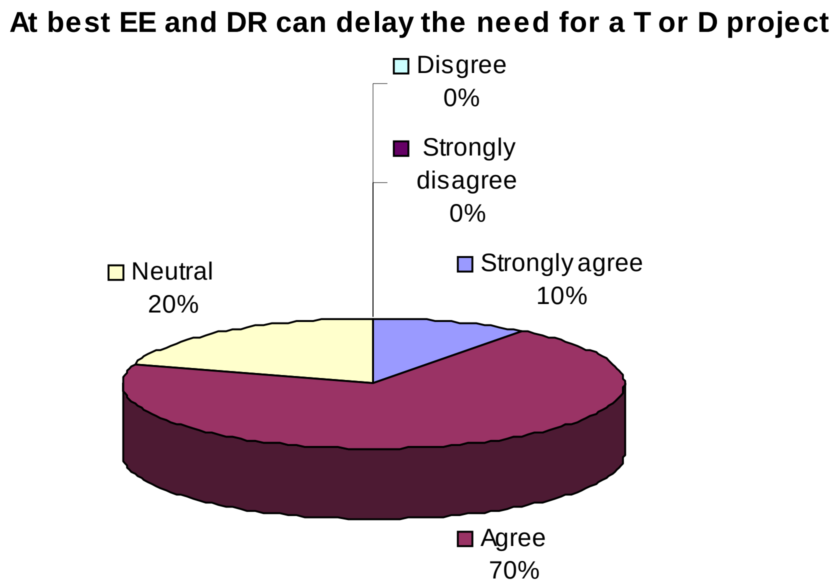

Figure 4-3
Response for the Statement C of the Questionnaire

Other comments and conclusions include:

1. The percentage of load reduction needed to avoid most T&D upgrades would be to large and to quick to be practical.
2. Possibly consider T&D benefits as additional benefits to the primary purpose of a EE/DR project rather than as project justifications themselves

Further issues other than the specific points addressed in the questionnaire were discussed at the work shop. One of these topics related to the locational specificity of the T&D needs. It takes significant effort to know the locational response of EE/DR though some good programs do know the locations. Targeting locations for new EE/DR programs is particularly difficult. The group expressed the concern that EE/DR programs are better targeted more broadly and locational benefits should be considered and exploited only as they occur.

Another important point treated the characterization of needs and capabilities of the EE and DR programs. Specific T&D technical needs can be characterized in terms of the required response duration, speed, frequency, lead time, and risk. EE/DR solutions can be similarly characterized. By characterizing both the needs and possible solutions for a specific project an optimal solution can be selected. Without such characterization general problem and solution descriptions make it difficult to select successful alternatives.

A participant from Snohomish County PUD discussed that, while usually the primary focus in this kind of projects is it to identify how EE and DR can be integrated into the T&D planning process to help reduce the need for or delay T&D enhancements, Snohomish has followed an alternative approach where additional T&D resources are installed to minimize T&D energy losses and also reduce customer energy consumption. He expressed that Snohomish County PUD has done extensive work on Conservation Voltage Regulation (CVR), and that a report detailing five years of work studying 60,000 loads’ voltage response will be available from the Northwest Energy Efficiency Alliance.

5
REQUIREMENTS TO INCREASE UTILIZATION OF EE/DR AS T&D ALTERNATIVE

As detailed in Section 3, although more utilities are attempting to consider EE/DR as a T&D capacity resource, at the present time, EE/DR options are seldom, if ever, implemented in place of traditional wires alternatives. Section 4 describes many of the obstacles and perceptions that limit the utilization of EE/DR as a T&D alternative. This section describes efforts that might alleviate some of these limitations/perceptions and allow for EE/DR to be more extensively utilized as a T&D resource.

Increase T&D Planner Understanding and Ability to Quantify EE/DR Options

As part of the effort to better understand how utilities are utilizing EE/DR as a T&D resource, we conducted several information gathering exercises:

- Literature review
- Utility survey
- Utility workshop
- Detailed phone interviews

Although not a consensus opinion, the overwhelming majority of utility feedback consistently identified T&D planners' lack of confidence in EE/DR capabilities or reliability as the driver for the limited utilization of EE/DR as a T&D resource. The first step to increasing consideration of EE/DR as a T&D option is to provide planners with hard data as to the capabilities and characteristics of various EE/DR initiatives.

Assimilation of Existing Data in Useable Format

Although not necessarily intended to provide T&D capacity, numerous utilities have implemented various EE and DR programs that could provide data as to performance characteristics of the programs. For example, Georgia Power's real-time pricing program has been in place since 1992 and provides significant historical data that should provide valuable insights as to how quickly certain MW reductions might be achieved, probabilities associated with MW reductions at different subscription rates and under various conditions, etc. The LIPA Edge direct load control program is another example of a DR program with a historical record that can be examined to extract quantitative data useful for evaluating DLC as a T&D alternative.

In addition to on-going programs with historical track records, shorter-term EE/DR pilot programs and demonstration projects that have been conducted by utilities also provide valuable data as to some of the characteristics/capabilities that are often questioned. Some of these projects provide data specifically applicable to EE/DR as a T&D option. The BPA Olympic Peninsula irrigation DLC program was specifically designed to determine MW reductions in an area for which new transmission was being considered. Similarly, Kansas City Power & Light's

Energy Optimizer (thermostat DLC) Program and CenterPoint's Energy Share Program (load curtailment) were pilots specifically aimed at achieving demand reduction in delivery constrained areas.

These programs, even when not economically successful, provide valuable data that can be utilized by planners to better evaluate the technical capabilities of specific EE/DR programs against specific T&D requirements. The data from the various programs, however, are not currently aggregated into a central location and arranged in a format that can be extrapolated to new applications.

Identification and Execution of New EE/DR Demonstration/Pilot Projects

While assimilation and manipulation of existing data into a central, applicable format provides a basis for more informed planning decisions, it is very likely that additional data will be required before planners are able to confidently quantify EE/DR capabilities for evaluation. Planners may feel that sufficient data may not be available for a particular tenant of a particular EE/DR program. Perhaps planners are uncomfortable extrapolating results from other regions as customer behavior or regional climates may impact program performance. As such, additional demonstration/pilot programs must be identified and executed to fill in the gaps in the existing data record to build confidence in the EE/DR options.

Characterizing Utility Requirements and Load Capabilities

Once planners obtain resources that allow them to quantify the relevant characteristics of EE/DR as a delivery capacity resource, this data must be evaluated against typical T&D planning requirements. Transmission and distribution planning is a broad field. No single resource, and especially no demand response or energy efficiency resource, can address all of the T&D needs. Specific T&D needs must be characterized in such a way that the requirements can be compared with the capabilities of specific EE and DR resources. Responsive loads must be similarly characterized so that their capabilities can be matched with utility needs. A common set of metrics is needed to facilitate this matching of needs and resources.

Characterization metrics for load response are similar but not identical to the metrics already used to characterize conventional transmission, distribution and generation solutions. For example, the peak loading requirement some years in the future may be the primary consideration when specifying a transformer addition to a distribution substation. Once it is determined that a transformer addition is needed, considerations of how many hours a year the transformer will be heavily loaded are secondary at most[2] In fact, transformer sizing considerations are often dominated by estimates of possible loading many years in the future since upgrade costs are themselves dominated by installation costs: it is impractical to regularly "adjust" transformer sizes. The number of times a year the transformer will see high loads, the number of hours a day, high load predictability, high load warning time, loading variations from year to year; none of these are overly important when specifying a conventional T&D solution as the additional capacity provided by the transformer is not dependent on the frequency of the

[2] This discussion is overly simplistic and is only trying to illuminate the conceptual differences between T&D and demand response resources.

need. All are important, however, when considering energy efficiency and demand response. One DR solution, for example, might be able to deliver sufficient load reduction to alleviate the transformer overload for the peak hour but be unable to sustain that response for additional hours that the total load is still above the existing transformer rating. Or the load response may be perfectly adequate and reliable if called upon a few times a summer but beyond customer tolerance if needed twenty days n a row.

Ideally a system of metrics for characterizing requirements and capabilities would be exhaustive (completely covering all needs) and exclusive (metrics would not overlap). The following classification of characteristics strives to meet those goals but is neither completely exhaustive nor are individual metrics exclusive.

- ***MW Needs*** **–** the most basic metric concerns the total amount of real-power response required. In some cases any amount of response will be useful in reducing size of the T&D upgrade alternative. More typically a minimum amount of response is required to eliminate the need to upgrade. Similarly, excess response may have little value. An individual load does not have to provide all the response but there must be enough aggregate responsive load to meet the requirement.
- ***Timing*** – timing is a broad category covering planning and operations.
    - o **Installation, first need, annual needs –** knowing when capacity is first needed determines the amount of time available to implement a solution. Annual needs are not critical for conventional T&D solutions but they are for EE and DR solutions which can meet initial installation requirements at one level and continue to grow as needs increase.
    - o **Response speed, predictability, and warning –** can response requirements be accurately predicted a day or more in advance? Is response required instantaneously or can the system operator provide some advanced warning?[3]
    - o **Response duration –** will response required for multiple hours in a row or for a few minutes at a time?
    - o **Response frequency –** will response be required 10, 100, or 1000 times a year?
    - o **Coincidence with load –** is the response need tied to system or feeder load or is it driven by another need? Can the timing of the need be characterized (time of year, time of day, etc.)
- ***Location*** **–** some utility needs (dealing with generation capacity deficiencies, for example) are locationally flexible. Others (substation transformer relief, for example) are locationally specific.
- ***Response certainty:*** alternatives and consequences – a T&D enhancement may be needed to alleviate economic congestion or to eliminate the need to operate a local reliability-must-run (RMR) generator. Alternatively it may be needed to simply supply load during

[3] Common wisdom holds that advanced warning is necessary or preferred for demand response. This is not always the case. Some loads can respond very rapidly and without warning. They are willing to trade faster response speed for shorter response durations.

peak times. A solution that works most of the time may be the best choice to solve the first problem but may be inadequate for the second.

- ***MVAR Needs*** – while load currently seldom provides power system voltage control or reactive power resources this may be changing. Static and dynamic reactive power requirements and voltage control needs can be quantified and compared with load capabilities, especially the capabilities of loads with large power electronics based inverters.

These nine characteristics can provide a common ground to compare utility needs with various types of load response capabilities. Initial screening will immediately exclude some types of response. Screening can also direct further analysis along potentially fruitful lines by helping to specify what types of load response to look for and where.

One of the most important characteristics, "Response type", does not appear explicitly in the above list because it is captured with other information. "Response type" (needed to regularly deliver energy versus needed to respond to contingencies) impacts the required response speed, duration, frequency, and response certainty. Consequently it is not included as a separate characteristic though the importance of the distinction is very great.

Characterizing the Utility Need

Each utility project has a unique set of requirements dictated by the specific situation. Each project must be characterized individually. For situations where a deficiency in required delivery to serve load is identified, specific location and high response certainty are required for all situations. The nature of the overload (specific situation), however, determines many of the timing metric requirements. Two factors in particular are critical – the area load growth rate and the shape of the area load (or overload).

Impact of Area Growth Rate

The technical and economic viability of any incremental capacity solution such as EE/DR or distributed generation (DG) as an alternative to investment in wires-based power delivery solutions is greatly dependent on the growth rate of the planning area. In general, the lower the growth rate, the higher the likelihood the incremental solution can provide the required capacity and the longer a new investment in bulk wires capacity can be avoided. While incremental solutions may better match the capacity deficiency at a given point in time, a growing load requires more and more capacity to cover the deficiency. If the load growth continues, bulk power delivery by wire eventually becomes the more economic alternative. This factor determines the first need and annual need metrics defined above.

Figure 5-1 shows the results of an analysis of a planning area bounded by three substations 1920. Deferral of a new, fourth substation by locating incremental DG at customer locations was being considered. The sensitivity of the planning decision to the assumed growth rate was evaluated by plotting the year in which each capacity option becomes economic as a function of load growth rate. If the growth rate was only 0.5%, it would have been economical to invest in DG in year 1 while for such a low growth rate it would not have been economical to invest in the large capacity achieved by a new substation for more than 10 years. The break-even point occurred for a growth rate of 1.5%. For higher growth rates, the substation option was more economical than the DG option.

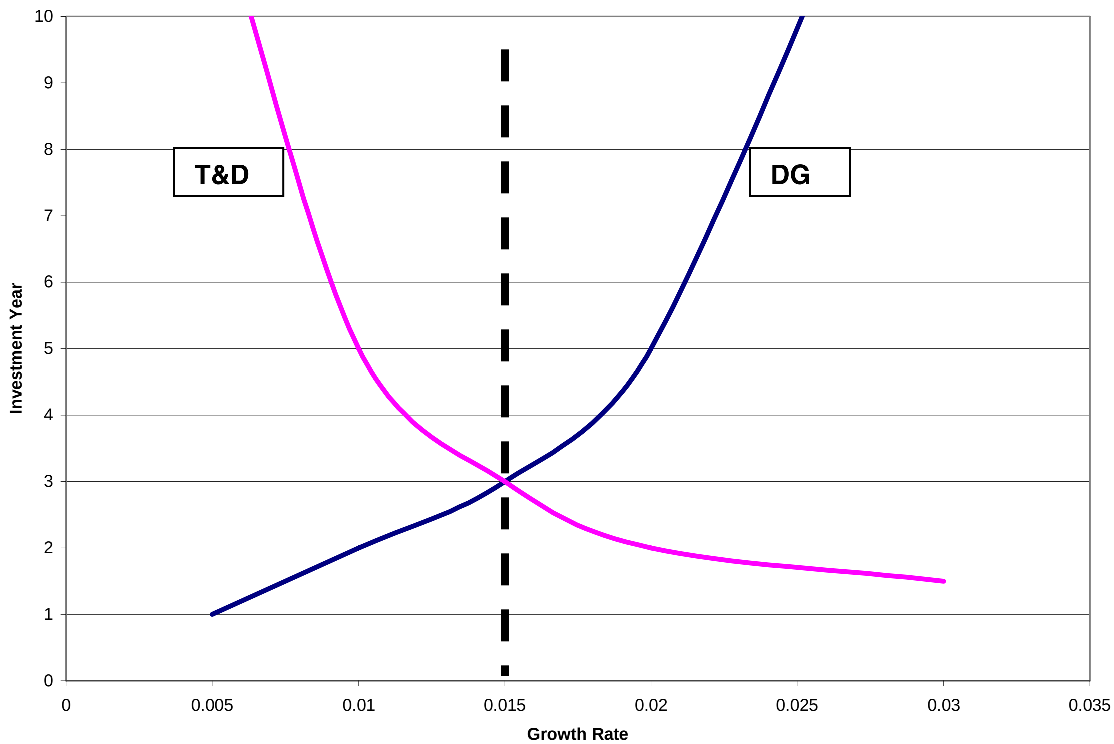

Figure 5-1
Example Cost-Effective Investment Year vs. Growth Rate

Impact of Overload Shape

Besides annual growth rate, another factor that significantly influences the match between system need and EE/DR solution is the shape of the overload for which relief is sought 21. Basically, the fewer hours the overload exists, the more likely an incremental solution will prove more economical and feasible than a large capacity option such as a new substation and transmission line. This factor determines the frequency of response and duration of response metrics defined above.

Figure 5-2 shows an annual plot of the energy exceeding capacity aggregated per hour of the day per month of the year. This particular overload shape is an example of an overload for which an incremental solution such as DR may prove feasible and economical. Some planners may refer to this characteristic as a “needle peak.” This overload is expected to develop in mid-afternoon and has a relatively short duration – in terms of both hours of the day and days of the year. In contrast, Figure 5-3 shows another summer peaking shape where DR will likely be less viable. The overload can occur for many hours of the day from May to September. This generally represents enough energy at risk to justify large capacity additions over incremental capacity additions.

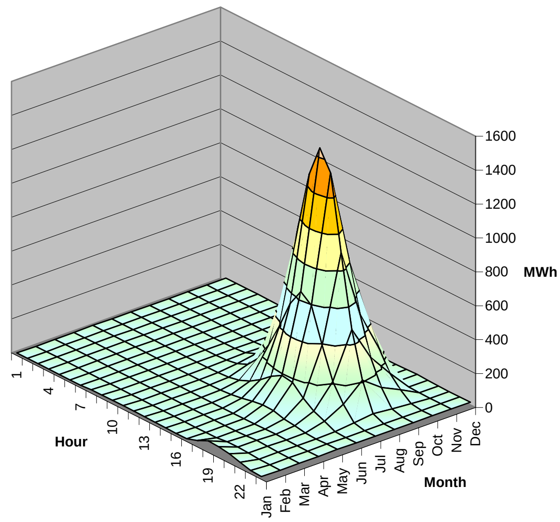

Figure 5-2
Annual Overload Characteristic Due to Sharp Summer Peak That is Often Amenable to Solution by DG Options

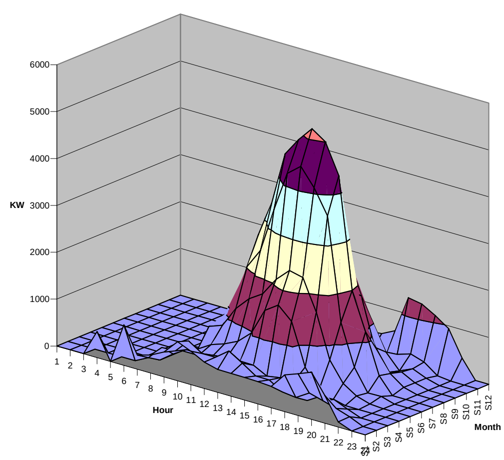

Figure 5-3
Annual Overload Characteristic Due to Broad Summer Peak for Which DG Options are Difficult to Justify

The following sections examine a few general types of utility needs to develop an understanding of how the characterization process can be conducted and what type of results is provided.

Distribution Transformer Upgrade

Consider an example from a planning study conducted in 2003 where future year annual load flows showed that load growth at a distribution substation with radial feeders were expected to exceed the substation transformer firm capacity within three years (2006). Figure 5-4 shows the growth of the expected overload. Although the overload in the first year is small and only present during a limited number of hours, the load growth rate is such that the magnitude of the overload and the number of hours per day and months during which additional capacity is needed increases each year. When selecting a replacement transformer the system planner might consider the expected load growth for the next ten or fifteen years to assure that the selected replacement did not itself have to be replaced prematurely.[4] The new transformer is needed prior to the old one being loaded to failure. Table 5-1 provides additional information needed to evaluate energy efficiency and demand response alternatives.

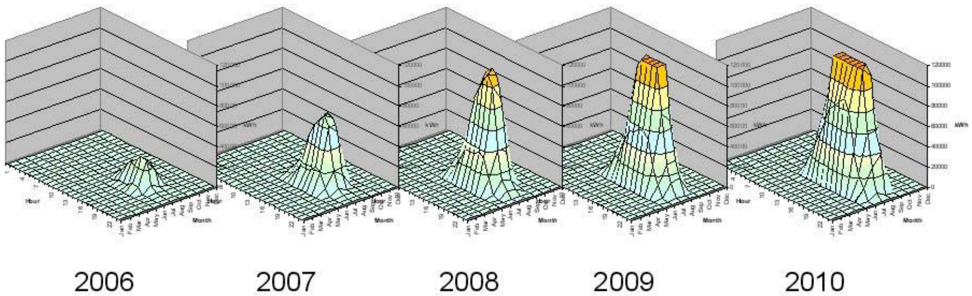

Figure 5-4
Example Distribution Transformer Excess Load Growth Forecast 22

Table 5-1
Example Distribution Transformer Upgrade Project Requirements

Characteristic	Requirement
First and continuing need	2 MW in 3 years growing to 10 MW in 10 years
Response speed, predictability, and warning	Peak loading requirement, hours warning, predictable, fast response not needed
Response duration	4 hours growing to 8 hours
Response frequency	20 days per summer growing to 100 days per year
Coincidence with load	Coincident with summer peak residential load
Location	On 4 feeders fed by the transformer
Response certainty	Radial load, no alternative feed, high certainty needed
MVar	Not a consideration

Congested Path Transmission Line Upgrade

Planning studies and energy market performance might show that a transmission path has become congested. Energy prices in one region exceed prices in an adjacent region because there is insufficient capacity on the interconnecting transmission lines. Transmission path ratings are often limited by contingency concerns (loss of one line in a multi-line path, for example) rather than because of line flows exceeding the normal capacity of the line themselves. Sizing an additional transmission line would only require knowing the expected peak requirements in ten to twenty years. Table 5-2 provides the additional information needed to evaluate energy efficiency and demand response alternatives.

[4] The system planner will, of course, take into consideration many other factors including other conditions on the power system that might present alternative opportunities. This example is deliberately oversimplified for illustrative purposes.

Table 5-2
Example Transmission Congestion Upgrade Project Requirements

Characteristic	Requirement
First and continuing need	50 MW now growing to 400 MW in 15 years
Response speed, predictability, and warning	Contingency response requirement, hours warning to be ready to respond, immediate response when called on
Response duration	Typically 20 minutes but occasionally up to 90 minutes
Response frequency	Typically several times a week
Coincidence with load	Coincident with high power transfers
Location	Within a large congested region
Response certainty	Contingency response must be certain when promised but high price local generation is available with hours warning if demand response is unavailable
MVar	Not a consideration

Characterizing the Load Response Capability

Each energy efficiency and demand response technology has a unique set of capabilities and limitations. Capabilities and limitations are further refined when the technology is applied to specific loads in specific locations. Similar to the evaluation required when assessing specific utility needs, each load response project must be characterized individually. But here too it is still useful to examine a few general examples of energy efficiency and demand response technologies.

Residential Energy Efficiency

Residential energy efficiency programs can take many different forms. Many utilities offer compact fluorescent lighting (CFL) programs. Some offer subsidies for replacing residential air conditioning units with more efficient units. Others provide subsidies for improving insulation, replacing windows, adding storm doors, etc. Regardless of the programs, the end result is that the total energy consumed by the customer decreases without reducing the level/quality of service received. Table 5-3 provides the additional information needed to evaluate energy efficiency and demand response alternatives.

Table 5-3
Example Residential Energy Efficiency Response Capability

Characteristic	Capabilities
First and continuing need	Residential energy efficiency might reduce consumption by x%/year until y% reduction is achieved
Response speed, predictability, and warning	Response is continuous and automatic
Response duration	Continuous
Response frequency	Continuous
Coincidence with load	Coincident with load
Location	Coincident with residential load
Response certainty	Some uncertainty in the planning time frame concerning sufficient program participation. Highly certain in the operations time frame once customers switch appliances
MVar	Not a consideration

The amount of response needs to be ratioed with the available residential load for each year and in each location in order to determine available MW amounts. It also may be appropriate to separately estimate the highest potential efficiency gain and a practical achievable penetration. It may be desirable to separately estimate gains for subcategories such as lighting, heating, air conditioning, water heating, plug loads, etc.

Industrial Response – Aluminum Production

The response available from an industrial process is specific not only to the industrial technology but also to the specific plant being considered. This example hypothesizes a 400 MW aluminum smelter with 4 - 100 MW pot lines that normally operate continuously. Short interruptions of up to 3 hours are possible but longer interruptions are not. Consequently, response characteristics depend upon the application being considered. Two response tables are presented. Table 5-4 presents the peak reduction response the plant can provide essentially continuously by rotating a curtailment among its 4 pot lines.

Table 5-4
Example Aluminum Plant Peak Reduction Response

Characteristic	Capabilities
First and continuing need	100 MW available immediately
Response speed, predictability, and warning	Several hours warning desirable to prepare the plant to respond
Response duration	12 hours or longer
Response frequency	Daily
Coincidence with load	Always available
Location	Specific plant location
Response certainty	Highly certain
MVar	Possible

Table 5-5 presents the response the plant can provide for infrequent, fast, short, contingency-type events.

Table 5-5
Example Aluminum Plant Contingency Response

Characteristic	Capabilities
First and continuing need	400 MW available within 3 months (communications and control equipment installation)
Response speed, predictability, and warning	Several hours warning to be ready to respond, immediate response when called on
Response duration	2 hours max
Response frequency	Daily
Coincidence with load	Always available when required
Location	Specific plant location
Response certainty	Highly certain
MVar	Possible

Residential and Small Commercial Air Conditioning Response

Residential and small commercial air conditioning response shares characteristics with both residential energy efficiency and with industrial response. As with the residential energy efficiency response, determining the MW response available for a specific T&D project depends on determining the response that is potentially available from the typical residence and then determining what penetration is likely to be achieved from a promotional program. Air conditioning demand response is similar to industrial response in that the amount of response available depends on how long the response is needed for and how often it will be called upon.

Figure 5-5 shows a typical daily load profile for a single residential air conditioner on a hot summer day. The figure also shows the total system load for a mid-sized utility demonstrating that for this utility the total system load peaks at the same time the air conditioning load peaks. Individual transformer and feeder loading might exhibit the same loading behavior.

With the appropriate communications and control equipment air conditioning can be curtailed completely for a few minutes with little customer impact if this is done infrequently making residential air conditioning a good candidate for contingency response. Peak consumption can also be reduced either by adjusting the thermostat set point up a few degrees or by cycling the unit off for a fraction of each hour. The amount the temperature can be raised and therefore the amount of peak reduction that can be achieved depends upon the customer's comfort tolerance and must be ascertained as part of any estimation of the potential size of the resource. In this example it is assumed that the air conditioning load can be reduced by about 33%. The peak reduction resource potential is characterized in Table 5-6.

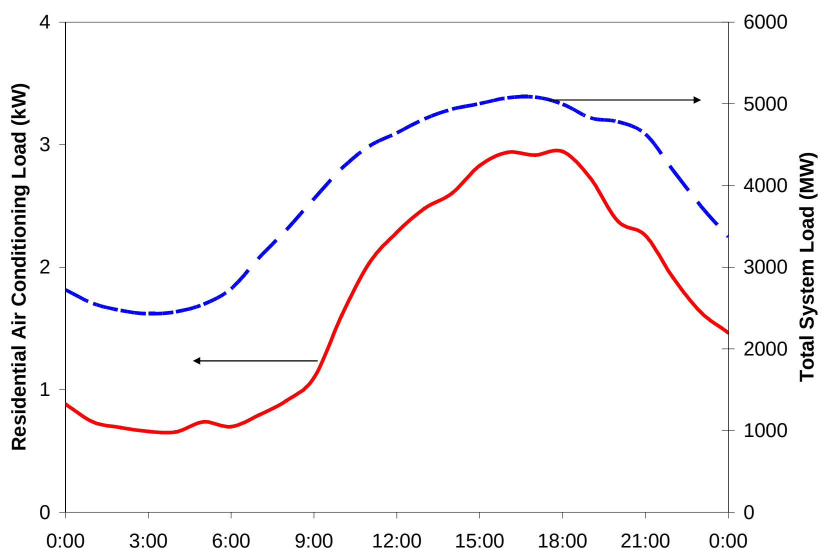

Figure 5-5
Typical Individual Residential Air Conditioner Energy Consumption Compared With the Total System Load of a Mid-Sized Utility

One complication when dealing with residential customers is that response limitations are often established in the tariff. Non-technical considerations may limit the planners' and operators' flexibility.

Table 5-6
Example Residential Air Conditioning Peak Reduction Response Capability

Characteristic	Capabilities
First and continuing need	Peak consumption can be reduced by 1kW per customer with x%/year penetration until y% reduction is achieved
Response speed, predictability, and warning	Response is fast and automatic, no warning is required though it may be desirable
Response duration	6 hours
Response frequency	40 times per year
Coincidence with load	Coincident with load
Location	Coincident with residential load
Response certainty	Highly certain – de-rate by a %
MVar	Not a consideration

The same residential air conditioning resource will exhibit different characteristics when it is considered for contingency response. The response size may triple because all air conditioners can be completely curtailed simultaneously but the use (duration of each event and number of events per summer) must be limited. Communications and control requirements are not typically more difficult but they must be considered during system design to assure that a fast immediate curtailment signal can be delivered to every air conditioner. Each unit may also be required to be autonomously responsive to system frequency.

Table 5-7
Example Residential Air Conditioning Contingency Response Capability

Characteristic	Capabilities
First and continuing need	Peak consumption can be reduced by 3kW per customer with x%/year penetration until y% reduction is achieved
Response speed, predictability, and warning	Response is fast and automatic, no warning is required
Response duration	30 minutes
Response frequency	Multiple times per month
Coincidence with load	Coincident with load
Location	Coincident with residential load
Response certainty	Highly certain – de-rate by a %
MVar	Not a consideration

There are two additional differences between these example residential and industrial load responses. First, the industrial load operates continuously so response is also continuously available. The residential air conditioning load does not operate continuously but does exhibit the same load shape as the overall system and as the feeder or transformer loading. Response needs and resource capability need to be carefully evaluated to assure that the resource will really be available at the time of system need. Secondly, it may be appropriate to de-rate the residential load response to account for the statistical nature of the large aggregation of loads. Individual pieces of equipment may fail or communications signals may not always get to every load every time. Experience can provide an appropriate de-rating factor. The industrial load, on the other hand, exhibits behavior more like that of a large generator. It may fail to perform on occasion (no equipment is 100% reliable) but it is not likely to exhibit continuous reduced behavior.

Matching Utility Needs With Load Response Capabilities

Once the T&D need and various EE/DR mechanisms are characterized on a common basis, an initial screening can be performed to determine which, if any, of the EE/DR options can meet the technical requirements. Matching requirements and capabilities can be examined from at least three perspectives. First, a specific load at a specific location and with specific characteristics can match its capabilities with the power system needs. Second, an aggregator or technology provider can examine the types of loads that are available within a region, along with their inherent capabilities and limitations, and look for opportunities to facilitate matching those resources with the power system's needs. Third, a power system planner faced with a specific reliability concern can seek demand response solutions within the regional or local mix of loads. All three analysis processes are similar.

Table 5-8 provides an example of screening potential demand response options for the generic distribution substation transformer upgrade example described above. Six alternative load response solutions are compared. The energy efficiency alternative is marked as questionable because it is uncertain if enough energy efficiency opportunities exist within the load pool served from the substation. If sufficient MW reductions could be achieved within the required timelines then it meets the rest of the requirements. The price response solution probably does not meet the requirement because response is not certain. This "price response" solution envisions providing customers with a local time-of-use or real-time price signal. The nature of the transformer overload is such that a guaranteed means is required to limit transformer load and the price response solution can not meet the requirement. The residential air conditioning peak load reduction program is the only load response resource that can meet the requirements, though that too depends on if enough responsive air conditioners can be found. The residential air conditioning contingency response program is not an option because the required response duration is too long. Neither of the industrial response solutions is viable because the load is not served by the substation transformer.

For this generic example, two load alternatives were found to have response characteristics that potentially meet the utility response requirement. Either one or a combination of both might be practical. It is still necessary to determine if sufficient resources of each type can be committed in the time frame required. Once the resource alternatives are known the costs can be compared.

Table 5-8
Load Response Alternatives Requirements Evaluation for a Distribution Transformer Upgrade Project

Characteristic	Requirement	Energy Efficiency	Price Response	Residential AC Peak Reduction	Residential AC Contingency Response	Aluminum Smelter Peak Reduction	Aluminum Smelter Contingency Response
Overall		?	☒	☑	☒	☒	☒
First and continuing need	2 MW in 3 yr 10 MW in 10 yr	?	☑	2,000 to 10,000	700 to 3,500	☒	☒
Response speed, predictability, and warning	Peak loading requirement, hours warning, predictable, fast response not needed	☑	☑	☑	☑	☑	☑
Response duration	4 hours growing to 8 hours	☑	☑	☑	☒	☑	☒
Response frequency	20 days per summer growing to 100 days per year	☑	☑	☑	☑	☑	☑
Coincidence with load	Coincident with summer peak residential load	☑	☑	☑	☑	☑	☑
Location	On 4 feeders fed by the transformer	?	☑	☑	☑	☒	☒
Response certainty	Radial load, no alternative feed, high certainty needed	☑	☒	☑	☑	☑	☑

Looking at another case, the high-level screening results are somewhat different for the previously described example of transmission congestion where the transmission line rating is limited by contingency requirements. Table 5-9 repeats the alternatives analysis but all alternatives are found to be potentially viable. There are three important differences in the cases which explain the difference in results. First, in the second example local generation alternatives are available to supply the load at higher cost. A solution is needed which reduces costs but response does not have to be available every time, so the price response solution may be viable. Second, the facility upgrade is required to alleviate contingency loading rather than continuous loading so faster, shorter contingency response can be useful. Third, a larger geographic area is impacted so a larger potential resource pool is available, though a larger MW response is required as well. As in the previous case, multiple load response programs could be combined in an effort to achieve the required response.

Table 5-9
Load Response Alternatives Requirements Evaluation for a Transmission Congestion Upgrade Project

Characteristic	Requirement	Energy Efficiency	Price Response	Residential AC Peak Reduction	Residential AC Contingency Response	Aluminum Smelter Peak Reduction	Aluminum Smelter Contingency Response
Overall		☑	☑	☑	☑	☑	☑
First and continuing need	50 MW now 400 MW in 15 years	☑	☑	50,000 to 400,000	17,000 to 133,000	100 MW	400 MW
Response speed, predictability, and warning	Contingency response requirement, hours warning to be ready to respond, immediate response when called	☑	☑	☑	☑	☑	☑
Response duration	Typically 20 minutes but occasionally up to 90 minutes	☑	☑	☑	☑	☑	☑
Response frequency	Several times a week	☑	☑	☑	☑	☑	☑
Coincidence with load	Coincident with high power transfers	☑	☑	☑	☑	☑	☑
Location	Within a large congested region	☑	☑	☑	☑	☑	☑
Response certainty	Contingency response must be certain when promised but high price local generation is available with hours warning if demand response is unavailable	☑	☑	☑	☑	☑	☑

The contingency nature of the congestion limit has an important implication for the size of the potential load response resource. The problem itself can be addressed by preemptively reducing area load and therefore line loading whenever loading is expected to be high. This may require multi-hour curtailments several times per week. Alternatively, fast responding loads could continue to operate but be ready to curtail immediately if a contingency actually occurs. This triples the response available from each residential air conditioner and quadruples the response available from the industrial load examples provided earlier. Response costs will be reduced by using a contingency response program but, more importantly, this may make an otherwise infeasible project viable simply by providing sufficient response resources.

Setting Reliability Rules

Utility needs and load response capabilities should also be examined when setting reliability rules. This is a similar process to the utility evaluation of demand response alternatives for specific projects but the conditions and resources are more generalized. Required response characteristics for a specific service (frequency responsive reserve, for example) can be characterized in terms of response speed and duration (full response within 30 seconds, sustainable for ten minutes, for example) rather than in technology specific terms (generation that is on line and unloaded with an active governor, for example). Functional specifications can be tested against both the available generation and load response technologies to assure that the utility reliability requirements can be met at reasonable cost with realizable technology. This will maximize reliability while minimizing costs by maximizing the number of reliability resources available to the system operator.

Development of a Systematic Planning Process that Includes EE/DR

Once planners obtain resources that allow them to quantify the relevant characteristics of EE/DR as a delivery capacity resource, this data must be utilized as part of a planning process that allows for an equitable consideration of EE/DR options along side traditional capacity options. Perhaps an initial high-level screening phase is added to the process that utilizes a generic needs/capabilities match matrix similar to that suggested above. If certain EE/DR options are found to provide reliable capacity when and where needed so long as implementation of the programs begins 3 years prior to when needed, for example, the timeline for identifying transmission needs may need to be slightly altered. The process may need to be altered to include additional value streams when conducting economic or reliability evaluations. Regardless of the needed modifications identified, the intention will be that the resulting process provides for an equitable evaluation of EE/DR along side wires solutions where all benefits and limitations of all options are accurately represented.

6 CONCLUSIONS AND RECOMMENDATIONS

Summary of Current Practices for Use of EE/DR in T&D Planning

Presently, EE/DR options are not generally considered by transmission and distribution planners as potentially viable alternatives to traditional system upgrades. There are a few jurisdictions in which EE/DR are considered as a matter of protocol any time significant system upgrades are considered – BPA in the United States and Integral Energy in Australia are two of the more visible examples. Even for those domestic utilities that are considering EE/DR in their normal planning process, there are very few examples where EE/DR options have been selected as an alternative to specific T&D build-outs. In most jurisdictions, EE/DR is at best reflected in load forecasts that may have an indirect impact on T&D planning.

In general, utility T&D planners are still uncertain as to whether EE/DR can reliably provided sufficient delivery capacity when and where it is needed. A majority of utility personnel queried, however, feel that more quantitative data validating EE/DR capabilities as delivery resource is needed. The predominant concerns that form the basis of this uncertainty include:

- Ability to control load response when required
    - Need for direct control by system operators
    - Concern that control can be overridden by customer
- Lack of sufficient data verifying effectiveness of EE/DR programs specifically designed for addressing T&D concerns

Surveys and interviews conducted with utility planners and EE/DR experts show that this uncertainty is not universally true -- some utilities that have long histories of utilizing EE/DR for supply capacity and at least some experience in considering EE/DR indicate that reliability is not a limiting factor for EE/DR as a delivery option. Even these utility planners that are confident that installed EE/DR can be counted on to deliver utility-grade reliability response generally do not feel that EE/DR can currently be used as an alternative to T&D enhancement. They do not believe sufficient EE/DR response can be recruited in the necessary locations within the required time to be effective for specific T&D projects. In addition to the perception among planners that the reliability of EE/DR options is uncertain, other factors that were identified as reasons EE/DR have seen limited use for T&D purposes include:

- *Inability to sign up sufficient response in the needed location.* While utilities that use DR regularly typically find that the response is robust and effective they also feel that it is difficult to recruit enough response in a specific location to completely counter high load growth or to alleviate specific delivery constraints.
- *Limited communication between EE/DR experts and planners*. In many instances, the customer service/marketing groups that have experience with EE/DR implementation do not directly communicate with the T&D planners. In such cases, any data that exists that might provide more certainty as to achievable subscription rates and reliability of response is not

being communicated to or considered by planners. Furthermore, the built-in timeline for the planning process may not lend itself to consideration of EE/DR options. For example, the planning process may only identify some capacity deficiencies 1-3 years in advance of the need. This timeline may not allow for initiation and execution of demand side programs such that sufficient capacity can be obtained through the programs.

- *Perception that EE/DR can only provide for deferral of wires solutions.* Many planners and EE/DR program marketers state that the demand-side options can at best only defer the need for new infrastructure investments for a few years into the future. Many further believe that whatever apparent savings might be derived from deferring the investment are mitigated by increased permitting issues and associated costs in the future. The common sentiment among those voicing this viewpoint is that "it isn't getting any easier to obtain permits." Further, many believe that the economic benefits of the deferral would be significantly reduced if appropriate cost factors for future permitting efforts and costs of right of way attainment are included in the economic calculations. The implications of this deferral-only concern would be alleviated, however, if planners were convinced that EE/DR could actually preclude the need for new wires investments rather than only defer the need.
- *EE/DR is simply not appropriate for some T&D needs.* As discussed extensively in Chapter 5, some delivery capacity deficiencies do no lend themselves to resolution through incremental solutions such as EE/DR. For high-load growth areas, the economics simply favor bulk capacity solutions.

Integral Energy in Australia has had success using EE/DR as a T&D alternative but it has taken considerable time to get the institutional processes to work. They find that EE/DR solutions must be identified very early in the planning process to allow sufficient time (generally years) to develop effective solutions. They also use both internal and external providers of EE/DR solutions and have adapted their proposal process to accommodate the needs of the DSM project developers' less detailed initial proposals accepted and partial compensation for proposal development provided. This accommodation is based on the regulator's, as well as the utility's, belief that customers are best served by aggressively pursuing EE/DR solutions when they can lower overall costs.

Recommendations for Closing Gaps

While it is certain that EE/DR may not be an appropriate solution for some T&D needs, it is equally as certain that non-wires solutions should be viable for other needs. Nonetheless, there is only limited consideration being given to these options for the reason identified above. Many of these limiting factors/perceptions can be overcome through development of a better understanding of EE/DR capabilities and integration of this improved understanding into the planning process. The following three efforts are recommended to facilitate accomplishing this goal:

1. *Assimilation of Existing EE/DR Performance Data.* A thorough investigation of previous and existing EE/DR programs at utilities world-wide needs to be conducted and relevant data extracted to develop an EE/DR capabilities database. Cataloging data such as the time line for achieving specific acceptance/subscription rates, verified MW reductions over time, customer tolerance for the length and frequency of curtailments, and execution

rates for opt-out/overrides provisions should reduce the uncertainties that planners currently associate with EE/DR options.

2. *Development/Execution of Additional EE/DR Pilot/Demonstration Projects.* Because most of the available historical data on EE/DR performance is associated with programs implemented for supply capacity reasons, it is expected that some specific additional data/research will be needed to adequately address some of the uncertainties associated with EE/DR as a delivery capacity resource. Based on the assimilated data from #1 above, a limited number of additional demonstrations should be defined to address gaps in EE/DR capabilities/performance. Hosts for these projects would then need to be identified and the projects executed over a reasonable period of time.
3. *Modification of Planning Methodologies/Processes.* Once EE/DR capabilities are better understood and confirmed through the assimilation of actual performance data from #1 and #2, T&D planning processes will need to be altered to allow for an equitable evaluation of these options along side traditional wires solutions. As noted in Chapter 5, these changes may be procedural such as adjusting need assessment time lines or adding preliminary screening processes, or they may be analytical such as adding new revenue or cost items to the evaluation. The most effective way of identifying the exact changes may well be to identify 2-3 case studies where EE/DR options are evaluated as part of actual utility T&D planning projects. Engaging both planners and EE/DR marketer resources will help to ensure that any process changes would not be such as to favor the EE/DR options, but rather allow for a full, fair consideration of them based on their defined capabilities.
4. *Identification of Alternative Financing Arrangements. EE/DR solutions are currently* typically financed as limited duration programs designed to defer T&D upgrades rather than as permanent resources. It may be appropriate to consider some EE/DR projects as long-term investments, similar to the way T&D enhancements are financed. Alternative methods for valuing EE/DR projects as regulated assets should be considered, especially for residential programs where responding loads are often not motivated exclusively by payments they receive.

7
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A
SUMMARY OF SURVEY RESULTS/INTERVIEWS OF UTILITY ADVISORS

Question #1: Why Are There Apparently So Few EE and DR Projects To Offset T&D?

Statement A: EE and DR are being fully and appropriately utilized

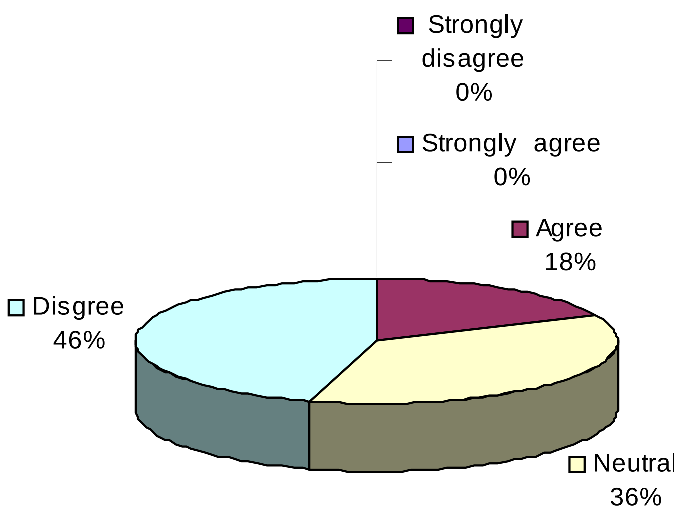

Figure A-1
Responses for Statement A

Sub-Statements	Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree
Utility planners are aware of the capabilities of EE and DR.	9%	45%	9%	36%	0%
Programs are implemented that exploit these resources for T&D benefit.	0%	9%	9%	45%	36%
EE/DR Solutions do not appear in T&D programs because they are treated as demand modifiers.	9%	27%	18%	36%	9%
While T&D plans do not appear to explicitly include EE & DR they do fully incorporate both because the load forecast is adjusted downward.	0%	36%	27%	18%	18%

Opinion by the Dallas Work shop attendees: Though the survey found that planners feel they are already fully aware of EE and DR capabilities the group felt that planners may not be fully aware and may have misunderstandings about current capabilities.

Statement B: EE and DR are always considered but they are usually eliminated, often in the very early planning stages before inclusion in the formal process such that consideration is not typically documented

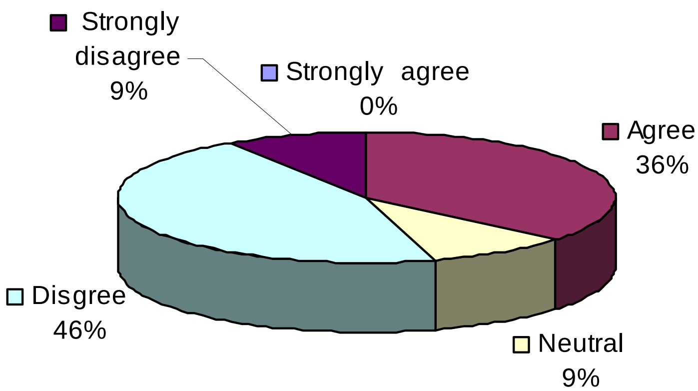

Figure A-2
Responses for Statement B

Sub-Statements	Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree
This is appropriate because EE and DR solutions are so non-competitive that utility planners do not need to conduct formal studies.	0%	27%	27%	27%	18%

Opinion by the Dallas Work shop attendees: Some in the group felt that EE/DR solutions are too expensive and inadequate so they are appropriately dismissed early in the planning process.

Statement B1: EE and DR technology is simply not yet up to the task.

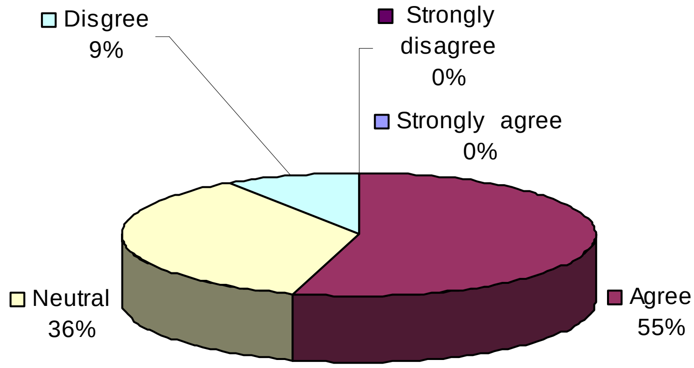

Figure A-3
Responses for Statement B1

Sub-Statements	Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree
While in principal EE or DR could provide an economically attractive alternative, these solutions are limited in the following ways:					
i) too expensive	11%	33%	44%	11%	0%
ii) not reliable enough - lack sufficient data as demand reductions	10%	50%	0%	40%	0%
iii) sustainability - customers get annoyed/stop responding when needed	20%	40%	30%	10%	0%
iv) not there when you need it	0%	50%	30%	20%	0%
v) unverifiable	0%	30%	30%	40%	0%
vi) unattractive for customers	10%	20%	40%	30%	0%
vii) timing does not work out - EE and DR take too long to implement	10%	30%	30%	20%	10%
viii) inability to be spatially targeted to alleviate specific T&D	30%	10%	50%	10%	0%

Statement C: At best EE and DR can delay the need for a T or D project, they can never replace the T or D investment

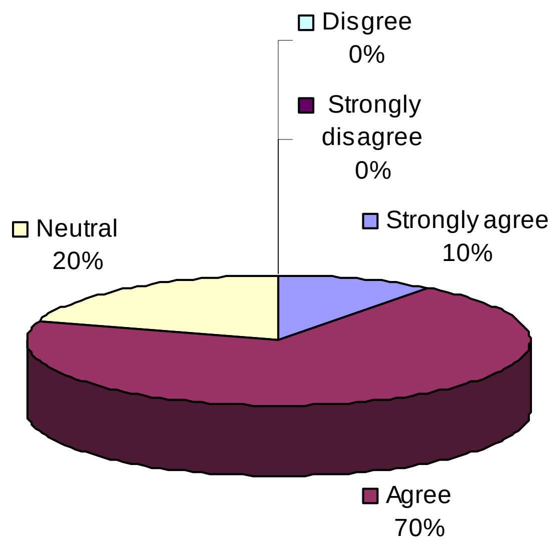

Figure A-4
Responses for Statement C

Sub-Statements	Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree
You might as well do the T or D project as soon as possible because it is not getting any easier to build.	0%	30%	30%	30%	10%
In one sense EE and DR actually hurt because they may delay needed T or D investment and make it harder to build later.	0%	20%	30%	30%	20%

Opinion by the Dallas Workshop attendees: The group identified a number of factors that make T&D project delay unattractive (rising land and material costs).

Statement D: EE and DR are commercial solutions just like generation. Commercial entities are free to propose EE and DR solutions when transmission needs are identified. If EE and DR solutions are not being implemented that is because the commercial providers are not offering them

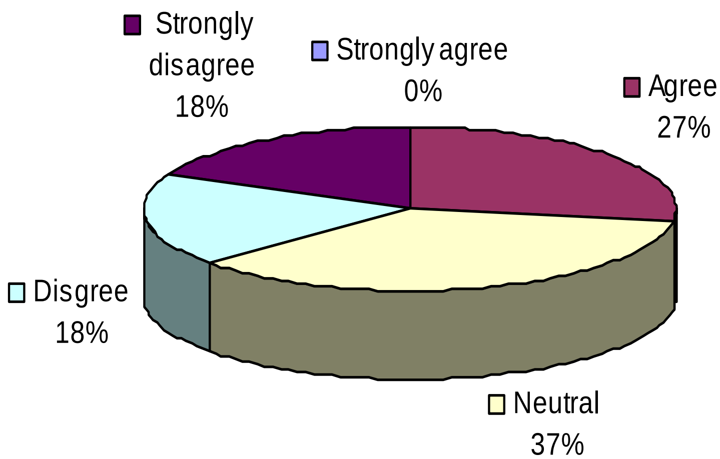

Figure A-5
Responses for Statement D

Opinion by the Dallas Workshop attendees: While some ISOs/RTOs expressed the concern that they are legally forbidden from preferring one commercial solution over another it was pointed out that this thinking shows a flawed understanding of how customers treat EE/DR projects

Statement E: EE and DR are underutilized

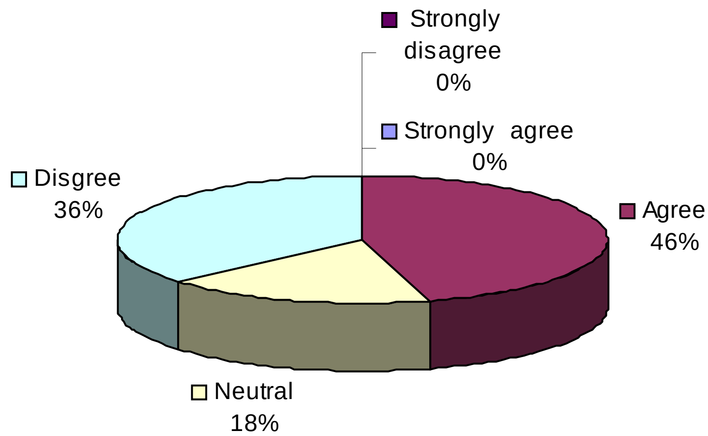

Figure A-6
Responses for Statement E

Sub-Statements	Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree
There are technical and/or regulatory and/or commercial barriers to implementation. These barriers should be removed and we will then see lots of EE and DR solutions implemented. Barriers might include:	0%	29%	14%	57%	0%
i) ISOs/RTOs being barred from favoring one technology over another so can not actively promote EE and DR in stead of T&D.	0%	10%	30%	60%	0%
ii) commercial incentives are not in place to reward EE and DR investment like there are to reward T&D investment.	30%	20%	30%	20%	0%
iii) others	0%	0%	100%	0%	0%

Opinion by the Dallas Workshop attendees: The group felt that EE/DR is underutilized for T&D.

Statement F: There are a lot of EE and DR projects underway. The literature simply does not reflect them

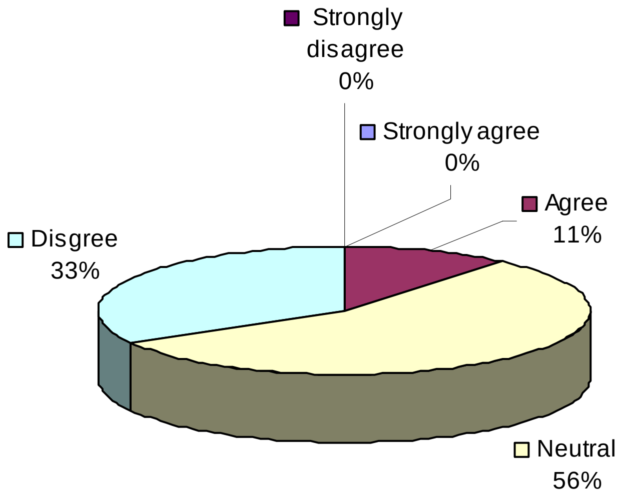

Figure A-7
Responses for Statement F

Opinion by the Dallas Workshop attendees: The group felt that there are numerous EE/DR projects but not for T&D.

Some expressed that there is a wealth of information on numerous EE/DR programs that have been largely successful for peak reduction.

Question #2: What Can Be Done To Increase EE and DR Project Use For T&D?

Statement	Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree
Technology: Identify the shortcomings and improve the technology.	10%	60%	20%	10%	0%
Demonstration: Get more example projects with high visibility to demonstrate high reliability and low cost.	22%	56%	11%	11%	0%
Regulatory: Fix the commercial and regulatory rules to make EE and DR profitable.	33%	11%	33%	11%	11%
Nothing: Things are fine as is.	0%	11%	22%	56%	11%
Education: Educate the regulators as to why EE and DR are not currently appropriate for T&D>	10%	40%	30%	20%	0%
Education: Educate the regulators as to how EE and DR are being fully considered and being used when and where appropriate. Tell the good news.	0%	44%	22%	33%	0%
Education: Educate T&D planners as to how their EE and DR concerns are unwarranted and why EE and DR should be more equitably considered.	0%	44%	33%	22%	0%

B
DETAILED DESCRIPTION OF TRANSMISSION PLANNING PROCESSES

One of the key issues in transmission expansion planning is defining who is responsible for developing expansion plans and what is the geographic scope and the grid level that a specific plan must cover. This definition is closely related with the reliability needs and the market issues that have to be addressed in each case.

FERC Order 2000 issued in December 1999 established the authority of an RTO to perform regional planning and gives it the ultimate planning responsibility within its region. FERC wrote that each regional transmission organization (RTO) “must be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable, and nondiscriminatory transmission service and coordinate such efforts with appropriate state authorities.” FERC included transmission planning as one of the eight minimum functions of an RTO.

Clearly, the planning conducted by RTOs is focused on meeting the needs of regional electricity markets. This type of planning can be considered “top down” since it addresses the general requirements of the transmission system itself. RTOs conduct long-term regional planning to identify system upgrade and expansion needs for reliability and, increasingly, for economic benefit.

These expansion plans are developed through a collaborative process that includes transmission utilities, state and provincial authorities, and other stakeholders. Usually the transmission utilities perform the majority of the technical analyses for their respective systems and jointly participate in development of longer-term assessments. The RTO reviews and approves transmission utilities’ plans and assessments based on applicable planning standards and criteria, and technical and economic feasibility.

In most cases Stakeholders are involved in a coordinated planning process and review to ensure needs identified by various market participants can be addressed through system upgrades and system expansion, including interconnection of new generation, and through demand side programs, where appropriate.

Regional electric system planning is evolving. In the early days of an RTO planning effort, transmission expansion plans often represented a compilation of the member utilities local transmission plans 23. Some RTOs, like CAISO and PJM, have recently implemented integrated planning methodologies which include the identification of economic and reliability needs of the transmission system, and analysis of risk due to uncertainties in the expected future system conditions.

In most cases, the overall system expansion plans are coordinated with the ISO/RTO participants as well as with neighboring areas. The ISO/RTO Council (IRC) members have all registered as NERC planning authorities and are active members in their Regional Reliability Councils. RTOs have open planning processes with participation of stakeholders, market participants, state or provincial as well as local governmental authorities, and other interested parties, such as consultants and manufactures. Proper communication and collaboration between developers, transmission owners, and the regulatory community is essential to facilitate the development of optimal plans that are more widely accepted.

In some cases there are sub-regional planning groups that actively participate in the regional planning process lead by the corresponding RTO. These groups mainly perform studies to identify problems and upgrading needed within their specific sub-areas. In the ERCOT Region for instance, there are three Regional Planning Groups (RPG), North, South and West, that directly participate with ERCOT in the development of the transmission plan for the entire region. In the Western Interconnection, geographic scale imposes an inherent sparsity on the transmission network, and there is a wide diversity in both climate and resource concentration across the West. Five sub-regional planning groups (NTAC, Columbia Grid, NTTG, West Connect and California) have been organized to address common issues on a more localized basis. These organizations are much closer to the loads being served and to smaller load serving organizations, such as municipal or rural electric cooperative systems, thereby increasing participation of such organizations in transmission planning.

Transmission utilities commonly develop their transmission expansion plans focusing on the reliability needs within their own areas. This is usually a “bottom-up” planning process since it starts with the specific needs of specific customers. These plans are used as input in the development of the transmission plan for the entire region developed by the corresponding RTO.

Each RTO has created its own transmission planning process with the objective to achieve an integrated, open participatory and transparent process for the development and shaping of the regional transmission plan. The process of the different RTOs differ in: the structure, the responsibilities assigned to each of the participating entities and the way each contributes to development of the plan, the time line associated with each part of the process, the approval procedure and criteria for evaluation and decision. Nonetheless, it is possible to identify common components and objectives among the different process that RTOs follow in the development of the regional transmission expansion plans. Figure B-1 depicts a general procedure for regional planning, in which the participation of the different entities and their interrelation is emphasized.

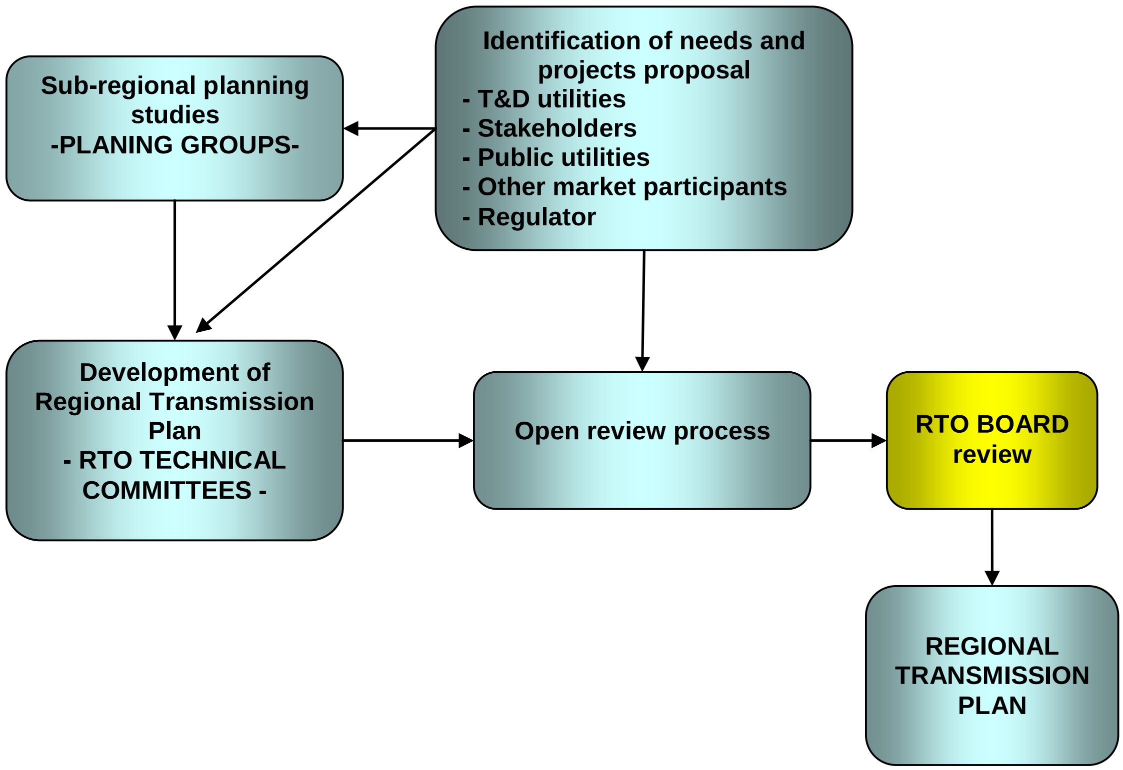

Figure B-1
General Process of Regional Transmission Planning

Generation Resources

With the new power station technologies, such as gas turbines, installation lead times are much shorter than with traditional types of power stations such as thermal or nuclear. Power stations can also be quickly removed from the generation mix because they are no longer profitable in relation to new technologies. A system operator has to face far greater uncertainties in network planning studies than before as far as the location of power stations is concerned.

Transmission planners consider requests for interconnection of new generating resources a key component for defining the future generation portfolio. Unfortunately, while interconnection queue requests provide insight into the new generation for the short term they do not address the extended time horizon required for the long term planning. Thus system planners have to speculate on what future generation commercial entities will choose to build and what generators they will choose to retire.

A well-established measure to quantify adequate installed generation capacity is the loss of load expectation (LOLE) criterion. The LOLE is a measure of the likelihood that system load (or demand) will exceed available generating capacity. A common LOLE requirement is set so that demand exceeds capacity on average no more than one day in 10 years on average. The installed capacity (ICAP) required to meet this criterion includes an Installed Reserve Margin (IRM), expressed as the percent reserve above the forecasted annual peak load net of Active Load Management (ALM) 24. The calculation is based on the load forecast developed for the time horizon of the analysis.

Regulatory Framework

Regulations may also change rapidly and this introduces additional uncertainty to be considered in transmission planning. Transmission pricing rules also impact generator dispatch strategy. Congestion pricing is designed to influence the location of generators. Environment-related decisions also have considerable influence on the structure and location of generation facilities. Requirements to limit CO2 emission may lead to significant changes in the future generation mix.

Approaches to Transmission Planning Under Uncertainty

Uncertainty and decision making 4 26, 27, 40

Uncertainty in the future generation mix leads to the possibility of defining a multiplicity of future conditions that in turn affect the definition of the transmission plan. Several rational strategies can thus be candidates in the resolution of a constraint, with different strategies performing better under different assumed conditions. The "best" strategy may prove to be either the most profitable on average (i.e. the one that minimizes the expectation of network costs for all the scenarios) or the one that minimizes the risk related to the diversity of scenarios.

There are a number of analytical methodologies that can be used in a decision making process to address multiple alternatives. They differ in the criterion considered for the decision and the approach followed to achieve the best decision under such criterion. Minimum average cost techniques can be applied if the main objective is to obtain a transmission plan that is the most economic for all the considered scenarios, considering the relative importance of each scenario in the decision making (weighted average). However, if this is the sole criterion applied for making the decision, the risk associated with the probability of occurrence of the envisaged condition is not taken into account.

Risk can be defined as being the degree of exposure to strategy performance variance due to uncertainty. The risk can be measured by assessing the "regret" associated with a strategy for a scenario which corresponds to the strategy performance variance between the scenario in question and the scenario where it turns out to be the most favorable. Different analytical methods have been developed to deal with risk. In the so-called "mini-max regret" method, the strategy to adopt is the one that minimizes the maximum regret for all the scenarios. In other words, this is the choice which limits the harm done when the worst scenario occurs. Alternatively, the traditional method, based on the maximization of expectations, increases exposure to risk if an adverse scenario occurs.

The following example illustrates the "mini-max regret" method 4. In this example, we would like to compare 2 strategies with 3 possible futures. The following table gives the cost of each strategy and the associated regrets. It is assumed that the cost of each strategy depends both on the investment and on the operating cost (redispatch costs, for example) to obtain the same level of reliability.

		Future 1	Future 2	Future 3
Strategy 1	cost	$10M US	$15M US	$20M US
	regret	$0M US	$0M US	$8M US
Strategy 2	cost	$19M US	$16M US	$12M US
	regret	$9M US	$1M US	$0M US

For future 1, the best strategy is strategy 1 because it is the cheapest. The regret would be $9M if strategy 2 was chosen ($19M cost for strategy 2 vs $10M cost for strategy 1). For future 2 the best strategy is still strategy 1, with a regret of $1M if strategy 2 was chosen. And for future 3, strategy 2 becomes the best. If strategy 1 was chosen, the regret value would be $8M. The "mini-max regret" method will select strategy 1 which gives the minimum regret for all the possible futures ($8M compared to $9M with strategy 2). The minimum average cost methodology would also select strategy 1 if all three future scenarios were considered equally probable since the average cost of scenario 1 is $15.0M compared with an average cost of $15.7M for scenario 2.

Criteria of minimum average cost and mini-max regret lead to complementary solutions in terms of cost and vulnerability or risk. The criterion of minimum cost (min-cost) allows the system planner to determine the most economic plan, which however can be vulnerable under the occurrence of one or more scenario. On the other hand, the mini-max regret criterion allows the planner to determine the least vulnerable plan, which nevertheless can lead to higher costs of investment and operation under specific scenarios. These plans are in fact Pareto-optimal, that is, they are superior to other alternatives in some aspects but worse with regard to the other aspects.

Trade-off risk analysis can be applied to these conflicts. When conflicts arise reasonable compromises are necessary. Trade-off risk analysis is a mathematical technique which allows robust strategies to be identified in a multi-criteria planning problem. The purpose of the methodology is not to solve an optimization problem but to evaluate the relations between criteria and uncertainty in an orderly fashion by eliminating inferior strategies. Figure B-2 is an example taken from 26. The stars represent the different strategies studied. The bold line is called the trade-off curve, the strategies on this curve are considered the best compromises especially those near the knee. In this case the best strategies are those with the lowest investment costs and that create the least loss of loads. This configuration is a favorable one, depending on the problems studied, we can have trade-off lines called "non attractive compromise" or "lose-lose possibilities" where there are no ideal strategies.

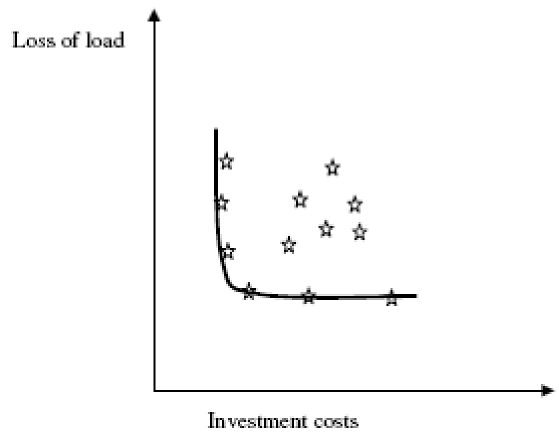

Figure B-2
Trade-off Curve

Current Planning Practices for Selected Jurisdictions

This section provides a general survey of the transmission planning perform by different organizations country-wide. The analysis is focused on the aspects that are the most relevant for discussing the consideration of DR/EE options into T&D planning. The principal topics addressed in each case are:

- Overview of the process
- Time lines associated with the process
- Criteria for project justification
- Reliability criteria
- Data sources including: demand forecast, new generation project, fuel future prices

Although it was not possible to conduct an exhaustive survey of planning process of all the organizations with transmission planning responsibility in North America for this report, various organizations were selected for inclusion in order to span the geographic scope as well as the range of organizational structures.

CAISO

The California Independent System Operator (CAISO) is a state chartered (state mandated), nonprofit corporation that controls the transmission facilities of all Participating Transmission Owners (PTOs) serving approximately 75% of the load in the state. The remaining load is mainly served through the independently operated and planned systems of Sacramento Municipal Utility District (SMUD), Los Angeles Department of Water & Power (LADWP) and the Imperial Irrigation District (IID).

CAISO provides electric transmission and related reliability services under both State and federal authority. The power system operated by CAISO contains more 25,000 miles of transmission lines and a peak load of over 47,000 MW.

Process Overview

Until year 2007, the CAISO transmission planning process consisted of reviewing the transmission expansion plans submitted by the PTOs to assure that they solved identified problems, were the best alternatives, and were the most economical from a system point of view. CAISO performed a comprehensive review to assure that nothing was missing. Management approved projects costing less than $20 million and referred larger projects to the CAISO board for approval. Studies were performed to establish Reliability Must Run generation requirements. CAISO has approved 337 transmission enhancement projects costing over $3 billion. Both the CAISO and the California Public Utility Commission have authority to require transmission enhancements to meet regulatory obligations 29.

In the summer of 2005, CAISO began the process to transform its existing Transmission Planning Process to the "New ISO Transmission Planning Process". The new planning process is intended to be more centralized and proactive. A five year project-specific plan and a ten year conceptual plan is now produced to address reliability and economic needs. Identified projects are submitted to the transmission owners. PTOs are then expected to submit transmission plans that incorporate the CAISO plan. The transmission plan is designed to eliminate congestion and reliability must run requirements as well as to provide economic signals for generation siting. As an integral component of its coordinated Transmission Planning Process, the CAISO is determined to actively eliminate congestion and Reliability Must Run generation contracts where economical to create a robust transmission system to benefit all CAISO ratepayers.

The 2007 CAISO Transmission Plan (Plan) 28 is the first annual plan report of the new plan. It contains the outline of key issues that the CAISO believes are important for inclusion in future Plans. The entities that participate in the development of the annual transmission plan are: CAISO, PTOs, Load Serving Entities (LSE), Publicly Owned Utilities (POU), California Energy Commission (CEC), California Public Utilities Commission (CPUC), Stakeholders and affected customers, Regional and subregional planning groups.

The Transmission Plan

The Transmission Plan provides details on all proposed future transmission facilities and is updated annually. The Transmission Plan also contains information on other issues related to transmission planning such as congestion analysis, Local Capacity Requirement (LCR), resource deliverability and operational issues based on experiences learned from real-time operations, as well as proposed transmission facilities that would address these issues.

The main elements contained in the Transmission Plan are as follows: 28

- *Long-Term Transmission Plans*: Lists and describes significant long-term projects that are addressed by the Transmission Plan and the progress on various studies.
- *PTO Transmission Plans*: Provides an overview of the projects proposed or being evaluated by each PTO and describes reliability and economic justifications of such projects.
- *Regulatory Transmission Plans*: Lists and describes the projects that are required to meet the State of California's RPS.
- *Merchant Transmission Plans*: Describes individual merchant transmission projects, project sponsors, estimated costs and benefits and expected on-line dates.

- *Resource Adequacy and Related Issues*: Provides an overview of the state mandatory requirements for LSEs to procure sufficient capacity to meet their demand during peak hours.
- *Local Capacity Assessments*: Addresses local capacity requirements to ensure that local areas meet CAISO's Local Reliability Criteria and potential transmission alternatives to reduce those requirements.
- *Short-Term Plans:* The CAISO generally addresses short-term planning requirements as part of PTO Transmission plans. These requirements include operational or reliability concerns that must be mitigated during an interim period until evaluation, approval, and completion of permanent, long-term solutions (approximately a three year time frame). These short-term planning solutions may include the use of Special Protection System (SPS), re-conductoring or re-rating of a transmission facility (i.e., transformer bank re-rate by installing additional cooling equipment). The time horizon of the short-term plan is three years.
- *Operating Guide*: Provides early warning and guidelines to CAISO's grid operations division regarding the possible impact of new transmission projects and the need to revise existing operating procedures or develop new ones.

Timelines Associated With the Process

The CAISO's Transmission Plan consists of three major stages of development and is updated annually as shown in Figure B-3. Each stage has specific tasks, objectives and timeline. The CAISO conducts at least three stakeholder meetings annually to achieve the intended objectives of the various stages. The specific objectives and deliverables of each stage of the Transmission Plan development are as follows:

- **Stage 1: Development of Unified Planning Assumptions**

Determine the goals of, and agree on study assumptions for, the upcoming Transmission Plan studies. Input is collected from various entities such as CEC-IEPR (Integrated Energy Policy Report), subregional planning groups such as California Subregional Planning Group, PTOs, CAISO, CPUC, and POUs. The timeframe for Stage 1 development is January to April of each year.

- **Stage 2: Performance of Technical Studies**

Perform technical studies and present the study results to stakeholders. The studies follow the Study Plan using the Unified Planning Assumptions. The time frame for this activity is May – October of each year. The CAISO and PTOs perform technical studies according to the Study Plan. At the end of Stage 2, the CAISO and PTOs present the preliminary study results to stakeholders during the 2nd stakeholder meeting (around October of each year) and seek stakeholder input and comments.

- **Stage 3: Development of Transmission Plan**

Develop the CAISO Transmission Plan report in coordination with PTOs, and other stakeholders, and to present it to the CAISO Board of Governors. The timeframe for this activity is November – January. Within Stage 3, the CAISO develops a draft annual CAISO Transmission Plan report based on the final study results.

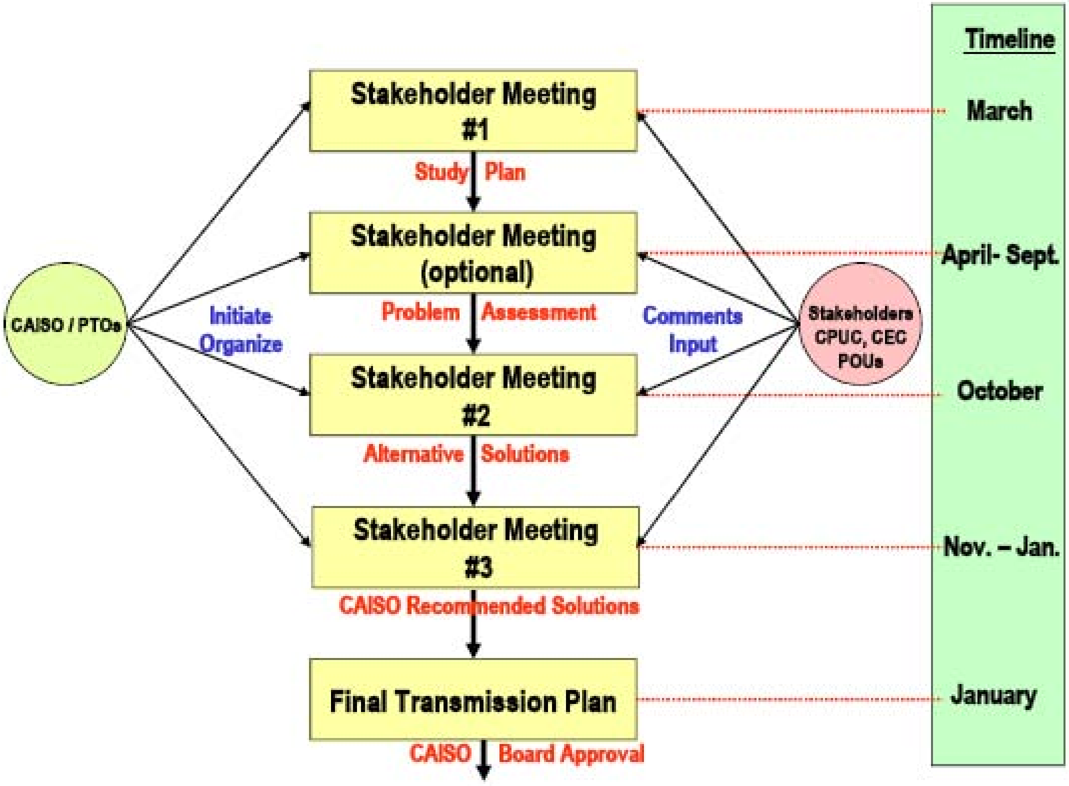

Figure B-3
Overview of the Transmission Plan Development 30

Criteria for Project Justification

Currently, CAISO justifies the needs of transmission projects based on at least one of the following basis:

- *Reliability*: In order to ensure that transmission system in CAISO control area is being planned to a level that meets or exceeds regional/national reliability standards, a transmission project can be justified if it mitigates or eliminates potential problems as identified by the violation of WECC/NERC or other applicable reliability criteria.
- *Economics*: Beside transmission projects that will reinforce the system to meet reliability criteria, a transmission project proposal can be justified if it provides reasonable economic benefits. This is done by showing that the benefits of a project outweigh its costs.

Data Source (demand forecast, new generation and gas prices)

The CAISO and PTOs utilize WECC as a primary source of data, including models, base cases, and tools for both the CAISO and PTOs. They also use data from California Energy Commission's (CEC) and the manufacturer of electric equipment. 30, 31

The CEC also is used as the key source of data for newly planned and approved generation. The CAISO and PTOs rely on WECC and DOE for economic data such as forecasts of the price of natural gas.

Demand Forecast 30, 31

The CAISO and PTOs rely on the CEC for demand and supply forecast information. The method and assumptions the CEC uses for demand analysis and long term forecast are as follows: The commercial, residential, and industrial sector energy models are structural models that attempt to explain how energy is used by process and end use. The forecasts of agricultural and water pumping energy demand are made using econometric methods. After adjusting for historic weather and usage, the annual consumption forecast is used to forecast annual peak demand.

The last demand forecast report (California Energy Demand 2008-2018 - CED 2008) includes electricity and natural gas system assessments and analysis of progress toward energy efficiency, demand response, and renewable energy goals. However, the possible impact of demand response is actually not accounted for in the demand forecast analysis. The report by CEC (CED 2008) stated the following as regards of this topic: 'The term "demand response" encompasses a variety of programs, including traditional direct control (interruptible) programs and new price-responsive demand programs. A key distinction is whether the program is dispatchable. Dispatchable programs, such as direct control, interruptible tariffs, or demand bidding programs, have triggering conditions that are not under the control of and cannot be anticipated by the customer. Energy or peak load saved from dispatchable programs is treated as a resource and therefore not accounted for in the demand forecast. Nondispatchable programs are not activated using a predetermined threshold condition, but allow the customer to make the economic choice whether to modify its usage in response to ongoing price signals. Impacts from committed nondispatchable programs should be included in the demand forecast. At this time, all of the existing demand response programs have some form of triggering condition. Although the utility or California ISO may not have direct control, the customer only has the opportunity to participate in the program when the program operator has called an event, either because of high market prices or resource scarcity. Therefore, in this forecast, no demand response impacts are counted on the demand side.'

Midwest ISO

The Midwest Independent System Operator (MISO) manages the transmission system and operates electricity markets for a region that covers all or part of fifteen states and one Canadian province. Peak load is ~132,000 MW; 16% of the total US/Canadian load and 21% of the Eastern Interconnection load 34.

Transmission Plan Objectives 33, 34

The MISO regional transmission expansion planning process has as its goal the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. Thus, the MISO Transmission Expansion Plan (MTEP) process has been bifurcated into two distinct areas for assessment: the first being reliability and the second being economic.

The first objective is to document and validate the need and sufficiency of all planned and proposed transmission projects provided by the member Transmission Owners to make sure they: i) are required to address a system need; ii) are sufficient to address reliability standards; and iii) form an efficient set of expansions to meet identified needs.

The second objective is the development of economic projects to supplement or replace as appropriate, the reliability projects proposed to the MISO. The effort to identify economic expansions has required several years of foundational work including development of the tariff provisions for cost allocation, the extension of the planning horizon beyond the typical five-years associated with reliability needs assessment, and the establishment of practices and policies for developing planning models representative of these longer horizon futures.

Process Overview 33, 34

The MISO has adopted a planning process approach that incorporates both a top-down and a bottom-up perspective. The top-down, or regional, perspective addresses the need to look beyond the least-capital-investment solution and to develop transmission expansion plans that maximize long-term value and that are supported by a wide range of economic benefits. The bottom-up perspective ensures that near-term and localized reliability needs are addressed.

Developing a process that simultaneously addresses the short-term and the long-term more efficiently allows for higher voltage solutions that meet multiple lasting needs. When planning is only near-term and reliability focused (i.e. the next five years) the resulting plans tend to involve facilities of a lower voltage, with low initial investment costs, but that generally do not enable significant improvements in market efficiency and the expected benefits to customer prices. High voltage transmission lines tend to provide longer-term solutions and need to be analyzed over a ten to twenty-year time horizon in order to recognize their full value.

The movement of the planning horizon beyond 5 years to 15 years is complete within the MISO and this will be a fundamental component of the MTEP08. The overall process is depicted in Figure B-4. The steps comprising the process are briefly described in the sequel:

- *Step 1 - Define Future Generation Portfolios:* The MISO generation Interconnection Queue provides initial insight into the new generation being proposed within the footprint, but does not provide the extended time horizon required. Currently, the Strategist model performs this function on a regional basis. Generation portfolio assessments are being developed for each of the three planning areas within MISO. These areas conform to the areas encompassed by the Regional Study Groups.
- *Step 2: Site Future Generation in Planning Models*: Once the future generation from the portfolio assessment process is developed it must be sited. The generation type and timing required to meet future load growth requirements must be sited within all the planning models to provide an initial reference condition. Potential generation siting locations are identified by using a defined set of criteria, and then engineering judgment is used in selecting the actual injection point chosen. Stakeholders provide feedback to the process for siting the proxy or future generation into the power flow and production cost analysis.
- *Step 3: Preliminary Transmission Plan Development for Four Futures:* Step 3 is the development of an extra high voltage (EHV) transmission plan which enables the economic delivery of energy for each of the four Futures scenarios being investigated (scenarios defined in steps 1 and 2). The primary analytical tool in this step is a security constrained economic dispatch production cost model. MISO uses PROMOD® for this purpose. Using results from the PROMOD analysis of each scenario, a transmission upgrade plan is developed for each of the four futures in collaboration with stakeholders in an open planning

process. Step 3 determines transmission upgrades required to deliver new generation resources and mitigate existing system constraints. Results of this step allow identifying transmission which is valuable to the energy markets and also identify regionally beneficial projects.

- *Step 4 - Economic Assessment of Preliminary Transmission Plans:* The outcome of the MTEP study process in Step 3 is the development of transmission plans for each future being studied. Step 4 is economic analysis of each plan under the other scenarios. The value of transmission upgrades required to deliver new generation resources and mitigate existing system constraints is determined in this step. Stakeholders are involved and have access to the information used to evaluate the transmission plans. A robustness test is performed to evaluate the performance of each of the plans defined, under the uncertainty conditions associated with the development of each of the other plans. A set of output attributes for making the value comparisons are used for this purpose. Step 4 determines the value of transmission upgrades required to deliver new generation resources and mitigate existing system constraints. Stakeholders are involved and have access to the information used to evaluate the transmission plans.
- *Step 5 - Consolidation of Preliminary Transmission Plans*: Step 5 uses the economic and value information from Step 4 to consolidate the transmission plans from the four scenarios into a single preliminary transmission plan. The output of Step 5 comprises the transmission upgrades required to deliver new generation resources and mitigate existing system constraints. Stakeholders are involved and have access to information used to consolidate the transmission plan scenarios into a single consolidated transmission plan.
- *Step 6 - Reliability Analysis of Transmission Plan*: Step 6 develops the transmission plan to meet reliability criteria, economic criteria, and test the simultaneous feasibility of the transmission plan with neighboring plans. Stakeholders are involved and have access to system issues which must be addressed by the transmission plan; they may participate in the development of solutions and the review of transmission upgrades recommended for approval.

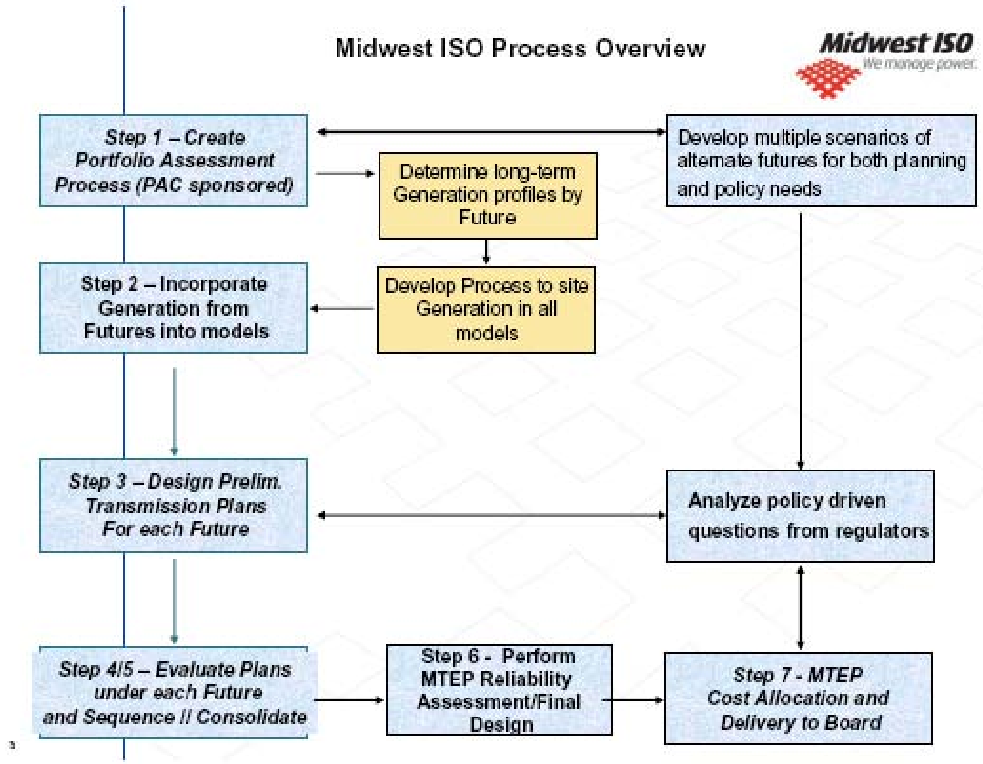

Figure B-4
Midwest ISO Process Overview

Criteria for Project Justification 33

As mentioned before, MISO Transmission Expansion Plan (MTEP) is intended to meet reliability and economic expansion needs:

- *Reliability*: Baseline Reliability Projects are Network Upgrades identified as those required to ensure that the Transmission System is in compliance with applicable reliability requirements of NERC, regional reliability councils, or successor organizations. Baseline Reliability Projects include projects that are needed to maintain reliability while accommodating the ongoing needs of existing Transmission Customers.
- *Economic*: Economic projects are Network Upgrades that are proposed by the Midwest ISO or by Market Participants as beneficial to one or more Market Participants but that are not determined to be Baseline Reliability Projects or new Transmission access projects. Economic projects may benefit Market Participants by supporting competition in bulk power markets, by expanding trading opportunities, or alleviating congestion beyond that achieved by Baseline Reliability Projects or New Transmission Access Projects.

Data Source

Demand Forecast

MISO does not currently prepare a long-term load forecast. Load projections are reported by Network Customers under the tariff, and are represented in planning models developed collaboratively between the MISO and its transmission-owning members. Members also provide load forecasts through the NERC regional reporting processes.

Demand Response

Recently, the MISO has put a stakeholder Demand Response Task Force (DRTF) in place. This DRTF will work to coordinate the appropriate market design elements for demand response. In addition, MISO has initiated efforts to incorporate demand response in its markets. These efforts include:

- *Energy Markets*: Price sensitive demand bids in both DA/RT markets. MISO projects LMPs for price transparency & discovery.
- *Ancillary Services Markets*: Reliability response demand bids – response required only under power system contingencies.
- *Resource Adequacy Construct*: Allow demand response to qualify as capacity credits.
- *Planning Process*: Integrate demand response into resource planning and as possible alternatives to transmission expansions.
- *Emergency Procedures*: Provide more rigorous emergency protocols to enhance reliability and promote demand response.

MISO used an estimated 3,000 MW of Demand Side Management during the 2006 Summer Peak period. The estimated total amount available was 3,400 MW. The DSM used was about 2.6% of the MISO Summer Peak load.

DSM is controlled by the MISO members. Most of the programs involve controls on the distribution system or to large industrial services.

Generation and Resources

Resource adequacy is evaluated under the tariff by requiring load serving entities to report their Network Resources that will be used to meet state and Regional Reliability Organization (RRO) resource adequacy guidelines. MISO generation interconnection queue is considered for the five years period.

Southwest Power Pool (SPP)

The Southwest Power Pool (SPP) is a NERC Regional Reliability Council and a FERC approved RTO for all or parts of Arkansas, Kansas, Louisiana, Mississippi, Oklahoma, New Mexico, and Texas. SPP serves 4 million customers and ~39,000 MW peak load with 33,000 miles of transmission lines.

SPP identifies the region’s transmission expansion needs through an open stakeholder process. Coordinating with the region’s 45 electric utilities, SPP identifies the best overall regional transmission expansion plan. SPP then directs or arranges for the necessary transmission expansions, additions, and upgrades including coordination with state and federal regulators 23.

Transmission Plan Objectives

The main objective of the SPP RTO Expansion Plan is to create an effective long-range plan for the SPP footprint which identifies NERC, SPP and local planning criteria violations and develops appropriate mitigation plans to meet the reliability needs of the SPP region. In addition, projects which may produce an economic benefit to the stakeholders in the SPP footprint are also evaluated.

The SPP Transmission Expansion Plan consolidates the transmission needs of the SPP Region into a single plan which is assessed on the basis of maintaining the reliability of the SPP Region and takes into account economic considerations 23, 41.

Process Overview 23

The planning process consists of the following steps:

- Identification of the reliability based problems (NERC, SPP and local criteria violations);
- Comprehensive assessment of known mitigation plans, and
- Development of additional mitigation plans to meet the needs of the region and maintain NERC, SPP and Local reliability/planning standards, and
- Identification of other projects that may provide economic benefit to the system.

The process is an open process and allows for stakeholder input. All study results through the planning process are coordinated with other entities/regions responsible for transmission needs assessment/planning.

Stakeholders participate in the development of the SPP Transmission Expansion Plan through the SPP planning process briefly outline below:

- *Commencement of the Process*: Each year, SPP initiates the stakeholder process to develop the annual SPP Transmission Expansion Plan.
- *Preparation of Assessment*: SPP prepares an assessment of the Transmission System on the basis of maintaining the reliability of the SPP Region and taking into account economic considerations, including congestion and integration of new resources or load on an aggregated basis.
- *Analysis of Transmission Alternatives*: Incorporating the feedback from the stakeholders on the reliability and economic assessments, SPP performs the required studies to analyze the potential alternatives for improvements to the Transmission System.
- *Development of the Recommended SPP Transmission Expansion Plan*: Upon completion of the analysis and studies and stakeholder review of the results, SPP prepares a draft SPP Transmission Expansion Plan for review by the stakeholders and invites comments to be submitted to SPP.
- *Approval of the SPP Transmission Expansion Plan:* The annual SPP Transmission Expansion Plan, or any modifications made to the SPP Transmission Expansion Plan throughout the year, are posted on the SPP OASIS. Approval of the SPP Transmission Expansion Plan by the SPP Board of Directors certifies a regional plan for meeting the transmission needs of the SPP Region and constitutes approval of cost allocation pursuant to the provisions of the Tariff.

The Transmission Plan 23, 42

SPP Transmission Expansion Plans include the following:

- Upgrades required to maintain reliability in accordance with the NERC Reliability Standards, SPP Criteria, and more stringent individual Transmission Owner planning criteria;
- Upgrades associated with executed Service Agreements;
- Upgrades that have potential economic benefit to the SPP membership for which project sponsors have committed to the projects;
- Upgrades associated with filed Interconnection Agreements; and
- Upgrades developed with neighboring transmission providers to meet interregional needs, including results from the coordinated system plans.

The SPP Transmission Expansion Plan covers ten year planning horizon

Reliability Criteria

The SPP Transmission Expansion Plan conforms to the NERC Reliability Standards and the SPP Criteria. It also addressed Local Planning Criteria as requested by Transmission Owners (TO). The NERC Reliability Standards and the SPP Criteria are the basis for determining whether a regional reliability violation exists for which Base Plan Upgrades are needed. Individual Transmission Owners within the SPP Region may develop company-specific planning criteria that, at a minimum, conform to the NERC Reliability Standards and SPP Criteria. The individual planning criteria of each Transmission Owner are the basis for determining whether a reliability violation exists for which a need for a new Zonal Reliability Upgrade should be considered. SPP provides oversight to assure that each Transmission Owner applies its local planning criteria comparably to all load in its service territory.

Data Source

Transmission Owners are responsible to provide SPP detailed power system models of their transmission systems and provide updates to their models via a web based application. Generator Owners are responsible to provide to SPP modeling data for power flow, short circuit and stability analysis. Also, they have to provide to SPP modeling data for economic analysis.

Demand Data

Transmission customers with existing and planned demand resources are required to submit information on such resources and their impacts on demand and peak demand. Stakeholders with demand resources must provide details concerning proposed demand response resources if they wish to have them considered in the development of the SPP Transmission Expansion Plan.

Demand Response

SPP does not itself explicitly include demand response in transmission planning studies. Individual load serving entities incorporate any current or expected demand response that is within their boundaries in their load forecasts. Individual transmission owners could investigate demand response solutions as alternatives to transmission expansion projects but they are not required to do so by the region. SPP does require 30% of the load to be interruptible on under frequency load shedding relays in three blocks of 10% each.

PJM Interconnection

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM encompasses major U.S. load centers from Illinois' western border to the Atlantic coast, including the metropolitan areas in and around Baltimore, Chicago, Columbus, Dayton, Newark and northern New Jersey, Norfolk, Philadelphia, Pittsburgh, Richmond and Washington D.C. It serves approximately 51 million people. Collaborating with more than 390 members, PJM dispatches more than 164,000 megawatts of generation capacity over more than 56,000 miles of transmission lines. It has a peak demand of ~135,000 MW; roughly 16% of the total US/Canadian load and 22% of the Eastern Interconnection load. PJM has a long history, starting in 1927 and developed as a tight power pool. In 1997 it became fully independent and started its first bid-based energy market. It became an RTO in 2001. (PJM 2006A).

Transmission Plan Objectives 24, 25

PJM's Regional Transmission Expansion Planning (RTEP) process identifies transmission system upgrades and enhancements to preserve the reliability of the electricity grid. Transmission planning in the PJM region has been accomplished through the Regional Transmission Expansion Planning Protocol which annually generates a Regional Transmission Expansion Plan (RTEP) covering the next fifteen years. RTEP determines the best way to integrate transmission with generation and load response projects to meet load-serving obligations. The RTEP recommends transmission upgrades to address near-term needs within five years and assesses long-term needs that require a planning horizon of 15 years or more.

Process Overview 24

PJM's RTEP process integrates transmission, generation and demand-side resources to address transmission system constraints involving reliability and persistent congestion. The RTEP addresses the following issues in an integrate fashion procedure:

- Forecasted load growth, demand-side-response efforts and distributed generation additions
- Interconnection requests by developers of new generating resources and merchant transmission facilities
- Solutions to mitigate persistent congestion and forward-looking economic constraints
- Assessments of the potential risk of aging infrastructure
- Long-term firm transmission service requests
- Generation retirements and other deactivations
- Transmission-owner-initiated improvements
- Load-serving entity capacity plans

The planning process considers two time frames for the development of the plan

- *Five-Year Planning to Meet Near-Term Load Growth*: This short-term plan enables PJM to assess and recommend transmission upgrades to meet near-term demand growth for customers' electricity needs. This includes electricity from both existing generation and new resources arising from interconnection requests by developers.
- *15-Year Planning*: Addressing Long-Lead Times for Backbone Facilities A 15-year planning horizon permits consideration of many long-lead-time transmission options. This type of planning addresses long-term load growth, the impacts of generation retirements and the delivery needs of '"clustered"' generation development emerging in PJM. This includes large base load Midwest coal projects, nuclear generation in Maryland and Northern Virginia, Appalachian Ridge wind farms, and natural gas pipeline access projects.

Load Forecast 24

PJM's load forecast model produces a 10-year monthly forecast of unrestricted peaks. The PJM Load Forecast Model incorporates three classes of variables: 1) calendar effects such as day of the week, month, and holidays 2) a forecast economic conditions and 3) weather conditions across the RTO. Specifically, PJM uses Gross Metropolitan Product (GMP) in the econometric component of its forecast model, which allows for a localized treatment of economic effects within a zone. PJM has contracted with an outside economic services vendor to provide economic forecasts for all areas within the PJM footprint on an ongoing basis. To account for weather conditions across the RTO, PJM calculates a weighted average of temperature, humidity and wind speed as the weather drivers. PJM has access to weather data from approximately 30 weather stations across the PJM footprint. The projection of peak demand is weather normalized. The PJM RTO summer peak is forecasted to grow at an average rate of 1.6% annually over the next 10 years – from 133,500 MW in 2006 to 156,893 MW in 2016.

Demand Response

The EDCs and Load-serving entities (LSEs) are required to provide estimated load drops, of which DSR may be a part, for the development of the forecast. From an operational perspective, DSR has both day-ahead and real time components. Demand response is implicitly included in PJM regional transmission planning as a modifier to forecast load. PJM typically assumes that the current level of demand response will continue into the future when evaluating any specific transmission area.

Generation Resources 24

Future generation scenarios are based on the request for interconnection of new generating resources, the PJM's interconnection request queues. Future generating capacity is calculated by adding the projected capacity additions to the current level of installed capacity within the PJM footprint. Generation that has formally announced retirement is removed. In order to make system models representative of the systems conditions that will actually exist in future years, PJM only adds those new generating resources that have a completed System Impact Study.

Criteria to Determine When New Investment is Needed

- *Reliability consideration*: PJM's analytical processes, which include thermal and voltage analysis, system stability, short circuit and other studies, yield recommendations to upgrade transmission facilities to maintain safe and reliable system operations in compliance with established reliability criteria. This remains the case regardless the upgrades are driven by load growth, generation interconnection requests, merchant transmission interconnection requests, unhedgeable congestion, generation deactivation requirements or operational performance issues.
- *Economic criteria – Congestion mitigation*: In 2004, FERC approved changes to the RTEP Process that allow PJM, in certain narrowly defined circumstances, to order transmission upgrades needed to enhance competition, in addition to those needed to resolve reliability criteria violations. PJM identifies transmission upgrades needed to address congestion that is deemed to be "unhedgeable." Rather than immediately ordering such upgrades, however, the economic planning process incorporates a "market window," i.e., a period of time for competition among alternative solutions to come forward voluntarily and resolve the congestion issue. Only if market forces do not resolve such congestion within the window will PJM order construction of transmission upgrades.

ISO New England

ISO New England Inc. (ISO-NE) is the private, nonprofit entity that serves as the RTO for New England. ISO-NE has the responsibility to protect the short-term reliability of the control area. ISO-NE works with stakeholders throughout New England to develop fair and efficient wholesale electricity markets and to plan a reliable bulk power system. Stakeholders include, but are not limited to wholesale market participants, state public utility commissions, and other interested representatives from state agencies in Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. The six-state New England electric power system serves 14 million people living in a 68,000 square-mile area. The system is fully integrated, using all regional generating resources across state boundaries. Over 350 generating units produce electricity, representing approximately 31,000 MW of generating capacity, connected to approximately 8,000 miles of high-voltage transmission lines. Most of these lines are fairly short and networked as a grid, resulting in close interrelationships of electrical performance in all corners of the system. Twelve transmission ties interconnect New England with neighboring electricity systems in the United States and Canada, including New York, New Brunswick, and Québec; these lines carry power into or out of New England depending on system needs.

ISO-NE's main responsibilities include: operation of New England's bulk electric power system, providing centrally dispatched direction for the generation and flow of electricity across the region, administration of New England's wholesale electricity marketplace, and management of the comprehensive planning processes for the bulk electric power system and wholesale market 23.

Process Overview 23, 33

As the RTO, ISO-NE leads the annual planning effort through an open stakeholder process. In order to ensure that system modifications made to one part of the system, including newly interconnected generating units, will not have an adverse impact on another part of the system, ISO-NE considers in the planning process inputs from the Planning Advisory Committee (PAC) and other stakeholders, and technical assistance from the transmission owners. ISO-NE develops the Regional System Plan (RSP). The plan identifies system improvements needed over the next 10 years and provides information on what infrastructure improvements are needed and when and where they are needed to meet the system's peak demands in conformance with planning criteria.

ISO-NE works with stakeholders in New England's wholesale electricity markets including the NEPOOL Participants Committee and the technical committees (Markets, Reliability, and Transmission). ISO-NE also works with state representatives through the New England Conference of Public Utilities Commissioners (NECPUC). ISO-NE conducts an open and ongoing stakeholder process for development of the Wholesale Markets Plan (WMP) and the Regional System Plan. The Planning Advisory Committee provides regular opportunities for stakeholder input to the development of the RSP. The RSP identifies projects based on both reliability and economical criteria.

The process to determine system additions and improvements needed to meet the applicable reliability criteria comprised three main steps:

- **Determining the Amount of Resources Needed**

ISO-NE conducts loss-of-load expectation (LOLE) and operable capacity (OC) analyses to determine the amount of resources the system will require to serve load for the long term period (10 years). The loss-of-load-expectation analysis is a probabilistic measure of resource adequacy. It uses the probability of generator forced outages and load levels to calculate the amount of loss, or disconnection, which can be expected of the system during weekday peak-demand periods under various weather conditions and a range of resource availabilities. ISO-NE uses the "1 day in 10 years" (or 0.1 day per year) criteria.

Operable Capacity Analysis is a deterministic analysis of resource adequacy that accounts for both the 50/50, and 90/10 load forecasts. This analysis reviews the ability of the bulk power system to serve load using a specific scenario. It compares the expected peak loads plus the requirements for reserve capacity to the amount of operable capacity the system is expected to have available during these peak loads. This method essentially provides a day-to-day "look" at operational requirements by identifying the operable capacity requirements for the total system and by load pockets, which recognize the specific characteristics of each area.

- **Analyzing Resource Location and Operating Characteristics**

Several analyses provide information on the desired location and operating characteristics of generating resources needed to supply load. These analyses include those that assess reliability, the diversity of the New England mix of fuels, environmental air emission issues, and the requirements for Renewable Portfolio Standards (RPS).

- **Conducting Transmission Studies**

Transmission studies are necessary to ensure that system reliability can be maintained in conformance with NERC, NPCC, and ISO-NE criteria, procedures, and guidelines. These studies are also conducted to evaluate the performance of economic, elective, and merchant transmission upgrades. ISO-NE uses a comprehensive model of the power system for conducting transmission studies that includes data on all generators, transmission facilities, and loads. Simulations address physical issues, such as thermal loading, minimum voltage, voltage regulation, transient stability, dynamic oscillations, harmonics, and short-circuit interrupting capability.

Criteria to Determine When New Investment is Needed 33

The needed transmission upgrades are determined base on both, reliability and economic criteria:

Reliability: The plan identifies projects required over the next 10 years to ensure local-area and systemwide reliability in accordance with NERC, NPCC, and ISO-NE planning criteria and to facilitate the future operation of the system.

Economic: ISO-NE's planning process also proposes transmission improvements needed to minimize congestion costs on the system. An open stakeholder process advises on the need for market efficiency upgrades.

Generally, transmission projects that provide benefits to the region are eligible for cost support through the tariff, while projects, or elements of projects that do not provide regional benefits, are not eligible for regional cost support.

Reliability Criteria

The Regional System Plan is developed to comply with the NERC, NPCC, and the ISO-NE reliability requirements. These criteria and procedures include prescriptive guidelines for resource adequacy and transmission performance necessary for ensuring a reliable electric power system design.

Data Source (demand forecast, new generation and gas prices) 33

ISO-NE load-forecast process creates energy and peak-load forecasts for the ISO-NE Control Area and the New England states. These forecasts integrate the historical demand for each state, economic and weather data, <u>and the impacts of utility-sponsored conservation and peak-load management programs on the forecasts </u>38. The primary factors applied to determine energy use, which serve as proxies for overall economic and demographic conditions, include average income per household and total number of households. The information regarding the average residential electricity prices is taken mainly from the DOE and the EIA. The peak forecast is based on applying a load factor to the long-run energy forecasts.

<u>Demand Side Management</u>

The ISO-NE Control Area and state long-run forecasts of energy use and peak loads are explicitly adjusted to reflect the reductions in energy use and peak loads from utility-sponsored Conservation and Load Management programs. New England utility companies provide this data annually based on utility-initiated customer rebate and shared-savings programs for installing energy efficient appliances, lighting, and electrical machinery and for subsidized weatherization programs. Historical DSM energy savings are added into the historical energy data used to estimate the long-run energy models. The resulting energy forecast excludes the impacts of these utility-sponsored programs, but captures any naturally occurring conservation trends. The forecasted DSM energy reductions then are subtracted from the energy forecast. The load-factor methodology used to forecast the long-run seasonal peaks explicitly incorporates the DSM reductions in a similar manner 38.

DSM is treated differently, however, in the last Forecast Report of Capacity, Energy, Loads and Transmission (CELT), for 2007, and future years, than how it was treated in the past. In anticipation of the Forward Capacity Market (FCM), in which DSM will be treated as a generation-equivalent resource, DSM effects are no longer explicitly incorporated into the state models, but are considered to be embedded within the historical data and the subsequent forecast 39.

ERCOT

The Electric Reliability Council of Texas (ERCOT) is state chartered (state mandated), nonprofit corporation that controls and operates most of the transmission facilities in the State of Texas. The ERCOT Region is one of the four North American grid interconnections. The ERCOT grid covers 75% of Texas and serves 85% of Texas load. Assets are owned by transmission providers and generators, including municipal utilities and cooperatives. As the ISO for the region, ERCOT schedules power on an electric grid that connects 38,000 miles of transmission lines and more than 500 generation units. ERCOT also manages financial settlement for the competitive wholesale bulk-power market and administers customer switching for 5.9 million Texans in competitive choice areas. The peak demand for 2006 was 62,339 MW and the estimated increase growth rate for the upcoming years is about 2.3 percent.

Since 1999, over 4,400 circuit miles of transmission lines and 24,600 MVA of autotransformer capacity have been added in ERCOT. The estimated capital cost of these transmission improvements is approximately $2.2 billion. Fifty nine power plants totaling 24,000 MW were added in ERCOT during the same time period. Approximately 3,750 miles of new transmission and 23,600 MVA of new autotransformer capacity have been identified as needed over the next six years with a cost of $2.8 billion 23.

Process Overview 35

ERCOT works directly with the Transmission and Distribution Providers (TDSPs), stakeholders/market participants through the Regional Planning Groups (RPGs). Each of these entities has responsibilities to ensure the appropriate planning and construction occurs. ERCOT supervises an open, non-discriminatory planning process that considers and balances the impact of transmission system additions on stakeholders. The main characteristics of the process are:

- Projects or studies can be proposed by any Market Participant, Transmission Owner or ERCOT Staff
- Stakeholders have the opportunity to comment on proposals and offer alternative solutions through the RPGs.
- ERCOT Staff performs independent review
- ERCOT Staff makes independent recommendation to the Board of Directors for major projects
- ERCOT leads and facilitates three Regional Transmission Planning Groups (North, South and West)

- ERCOT Board endorsements are considered by the Public Utility Commission of Texas (PUCT) for approval of Certificate of Convenience & Necessity
- Information about planned transmission projects is distributed to and among members of these groups
- These groups provide the means for stakeholders to participate, express concerns, share alternatives, and provide input to the ERCOT staff independent recommendation.

The overall process is outlined in the following figure.

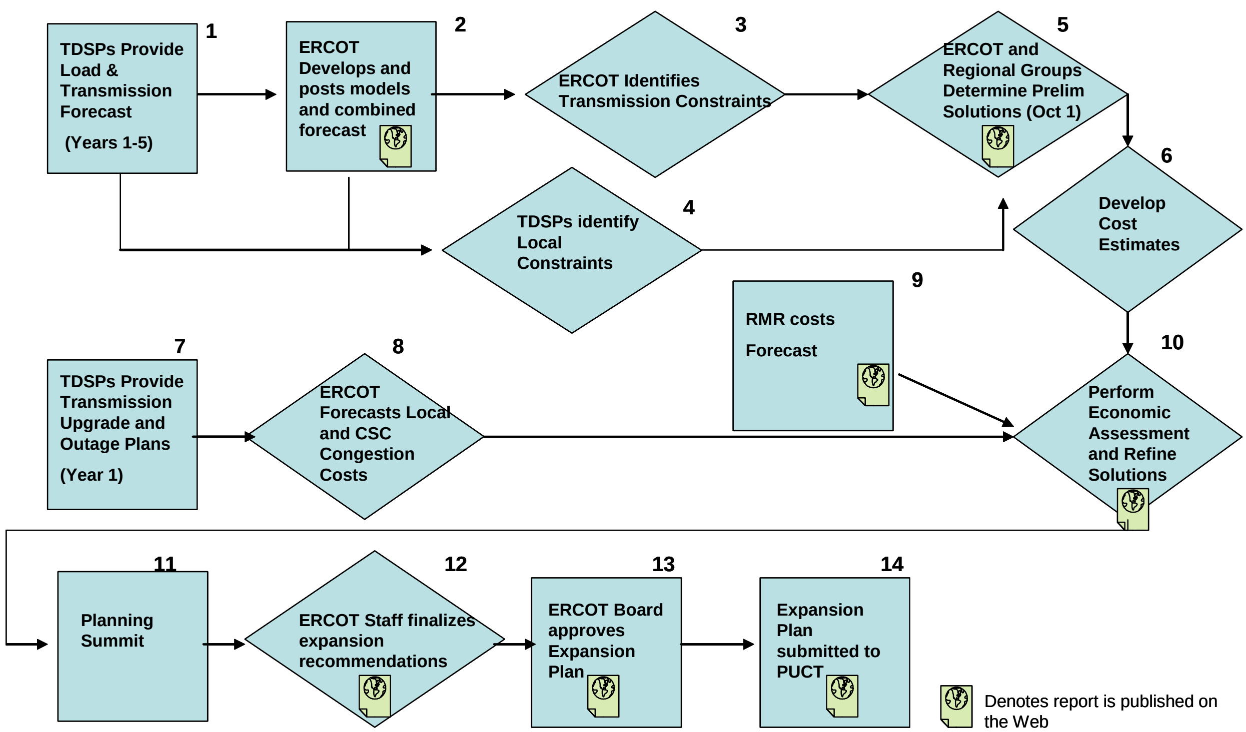

Figure B-5
ERCOT Transmission Planning Process 35

Methodology for Planning Studies

Planning studies begin with computer modeling studies of the generation and transmission facilities and substation loads under normal conditions. Contingency conditions, along with changes in load and generation that might be expected to occur in operation of the transmission grid, are also modeled. To maintain adequate service and minimize interruptions during facility outages, model simulations are used to identify adverse results based upon the planning criteria and to examine the effectiveness of various problem-solving alternatives.

To determine the most favorable of the identified transmission enhancement alternatives, the short-range and long-range benefits of each must be considered including operating flexibility and compatibility with future plans. The software UPLAN is used for economic evaluation. This model calculates the security-constrained, least cost unit commitment and economic dispatch of all generation to serve forecasted system load assuming cost-based dispatch of generation.

ERCOT primarily uses UPLAN to predict which transmission lines are likely to be congested and to forecast production costs savings that will result from proposed transmission system improvements. UPLAN also inherently calculates the marginal cost of electricity at each bus in each hour.

Main Responsibility of the Different Entities in the Planning Process

TDPs must provide their annual report of all planned transmission projects to ERCOT. The RPG process is used as the forum for ERCOT Staff, PUCT Staff, consumers and stakeholder/market participant review of all proposed transmission projects.

With the implementation of retail competition in the ERCOT market and the associated changes in market design and operations, more market participants and stakeholders have a financial stake in the development of a reliable and cost-efficient transmission system. Stakeholders and Market Participants must actively participate in the ERCOT transmission planning process to encourage efficient, reliable, and cost-effective long-term transmission system development. They have to review proposed projects and provide timely comments about projects submitted to the RPGs for their review that address reliability and/or economic deficiencies of the transmission system. They also review and submit proposed projects fro review.

The PUCT participates in the RPG process. It monitors the TDSPs and the RPGs to assure their activities are non-discriminatory. PUCT reviews and approves or rejects applications from TDSPs for any amendments to their Certificate of Convenience and Necessity (CCN) for the construction of transmission facilities. The PUCT also resolves disputes between ERCOT, TDSPs, consumers, and other market participants concerning transmission projects.

The Regional Planning Groups: ERCOT leads three regional planning groups (North, South, and West) in the consideration and review of proposed projects to address transmission constraints and other system needs. Participation in these regional planning groups is required of all TDSPs and is open to all market participants/stakeholders, consumers, and PUCT staff personnel. An RTG coordinates transmission planning and construction to ensure that the ERCOT and NERC planning standards are met, that a proposed project addresses ERCOT planning criteria requirements, and that transmission upgrades address needs. They are also committed to preventing inefficient solutions to regional problems through a coordinated effort and resolving the needs of the interconnected transmission systems while ensuring a reliable and adequate network.23

Criteria to Determine When New Investment is Needed

Reliability consideration: Transmission constraints and problems are noted when any one of the following conditions is reached in simulations 35:

- Flow of a circuit is at or above the thermal limit for post-contingency loading
- Voltage on a bus is at or below the minimum post- contingency limit
- A portion of transmission system reaches a state of voltage instability leading to voltage collapse
- A portion of the transmission system is not dynamically stable if a disturbance were to occur

ERCOT determines when constraints need to be addressed with transmission facility additions. This determination is based on the following considerations:

- Transmission additions are considered when studies show that a contingency on the transmission system will result in one or more of the four conditions listed above.
- Transmission additions are considered when significant excess generation is constrained inside an area where forecast load fails to materialize as anticipated or where load growth cannot be met by sufficient new generation.
- Transmission additions may be indicated when the studies show a disproportion in the amount of transmission capacity to load into a load area.

A reliability-justified project designated as “without generation re-dispatch options” indicates that the binding constraint(s) driving the need for the project does not have any generators whose dispatch can be altered to eliminate an ERCOT Planning Criteria reliability violation.

Economic consideration: Projects intended to reduce congestion and losses can be economically justified. Economic Projects are defined as system improvements intended to resolve current or projected levels of reliability criteria violations that could instead be solved by redispatching of existing generation but have been initiated because they are projected to result in a net economic benefit to the market based on ERCOT-wide impacts. ERCOT has recommended several major and numerous minor projects since 1996 to reduce the impacts of congestion, there has been an increased emphasis on identifying and evaluating such projects during the last years 35.

ERCOT considered different solutions for network constraints. If a non-transmission upgrade alternative is available, a comparative economic evaluation is warranted to determine the most economically efficient energy delivery option. Non-transmission alternatives include, but are not limited to, load interruption (DSM), Out of Merit Capacity (OOMC), Out of Merit Energy (OOME), Local Balancing Energy (LBE), and Reliability Must-Run (RMR) services. These components contribute to local congestion costs currently “uplifted” or socialized, in a similar manner to wires charges, and therefore fall into the desired optimization mix necessary to minimize energy delivery costs. Demand response may also be considered an option, if it can be feasibly evaluated as a reliable option 23.

Reliability Criteria

ERCOT is its own Reliability Council as well as an ISO. For transmission planning and operation it follows NERC criteria and its own protocols that are more stringent.

Data Source (demand forecast, new generation and gas prices)

The different entities involved in the planning process have responsibility in the provision of the necessary data and information:

TDSs:

- Provide accurate and appropriate load data via the ALDR process;
- Provide data necessary to allow RPG members to replicate studies of project proposals and feasible alternatives.

Stakeholders/Market Participants

- Provide accurate, appropriate and timely data including performance characteristics and limitations upon request by ERCOT and TDSPs for their simulations and analysis
- Provide data necessary to allow RPG members to replicate studies of project proposals.

The table on the following pages presents a summary of the analyzed ISO/RTO planning processes.

	CAISO	MISO	SPP	PJM	New England ISO	ERCOT
Transmission planning	A 5 years short-term and a 10 years long-term plan is developed	An integrated plan considered 5 years short-term and a 15 years long-term plan is now developed	10 years transmission plan that cover the needs of the entire SPP region is developed.	5-years planning to meet near-term needs. 15-year planning to consider many long-lead-time transmission options	10-year Regional System Plan elaborated by the ISO.	A transmission plan for the entire area control by ERCOT, based on the regional transmission plans elaborated by Regional Planning Groups.
Participants involved	Transmission owner, Public owned utilities, CEC, stakeholders and affected customers	Transmission utilities, market participants. Open stakeholders process Regional study groups	The process is open to stakeholders with RTO approval Regional study groups	The process is open to stakeholders with RTO approval	The process is open to stakeholders with RTO approval Regional study groups Planning Advisory Committee	T&D providers, stakeholders, Public Utilities, Regional Planning Groups, PUCT
Reliability criteria	NEC, WECC Planning standards and more stringent CAISO specific standards	NERC, MRO,RFC, SERC and TO Criteria and Procedures.	NERC, SPP and TO Criteria and guidelines Transmission owners may develop company-specific criteria	NERC, RFC, SERC and RTO Criteria and Procedures.	NERC, NPCC and RTO Criteria and Procedures	NERC Criteria and more stringent ERCOT Protocols
Criteria for project justification	Reliability and economic	Reliability and economic	Reliability and economic	Reliability and economic	Reliability and economic	Reliability and economic
Economic planning	Transmission Economic Assessment Methodology established through stakeholder and regulatory process	Analyze projected congestion to identify opportunities for economic transmission solutions to provide market efficiencies.	Economic planning is a key part of the SPP RTO Expansion Plan. Cost recovery associated with Economic Upgrades is a key provision of the SPP Tariff.	Analyzes all congestion to identify opportunities for economic transmission solutions to relieve unhedgeable congestion costs.	Information provided to Market participants. An open stakeholder process advises on the need for market efficiency upgrades.	ERCOT leads annual reviews of economic transmission upgrades to reduce expected congestion costs
Future generation portfolio	CEC is the key source of data for newly planned and approved generation	ISO generation interconnection queue is considered for the short-term period Strategic model is used for the entire period.	Mainly from generation interconnection queue	From generation interconnection queue Only those that have completed the system impact study are considered.	Several analyses are conducted to provide information on the desired location and operating characteristics of generating resources needed to supply load.	Mainly from generation interconnection queue
Demand forecast	Developed by CEC: end use energy model	Members provide load forecast through the NERC regional reporting process. New customers provide load		Load forecast econometric model is used. The model is weather normalized.	ISO-NE conducts long-term forecast that consider economic and weather data.	Based on load data provided by transmission and distribution providers.

		projections				
Consideration of DR/EE	No DR impact are accounted for in the demand forecast	A new implementation of DR options is underway. It Includes integration of DR into the planning process.	SPP does not itself include demand response into transmission planning studies. Load serving entities may incorporate into their own forecast.	DR is implicitly included into PJM planning process as a modifier to load forecast	Load forecast is adjusted to reflect the reduction on energy and peak load from utility-sponsored Conservation and Load Management programs.	Demand load response can be considered as a solution for network constraint if it can be feasible evaluated as a reliable option.

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