Demand Response (body of Plan)

<u>What is Demand Response?</u>

Demand response is a change in demand for electricity corresponding to a change in the power system's cost of electricity. The problem is that while the region's electricity <u>supply</u> is generally responsive to conditions in wholesale power markets, its electricity <u>demand</u> is not. This situation has a number of adverse effects. It's widely recognized as one of the factors contributing to the high and volatile electricity prices experienced on the West Coast in 2000-2001.

How did this situation arise? As described earlier, the electricity market is currently a mix of competition and regulation. Producers of electricity, who sell into the competitive wholesale market, generally see prices that reflect the marginal cost of production. When supplies are short, prices rise and producers expand supply. In the short-term, supply expands through operation of more expensive units. In the long-term, supply expands through the building of new power plants. When supplies are ample, prices moderate, and producers cut back the operation of their most expensive units and review their plans to invest in new generating units.

But most consumers of electricity see retail market prices that are set by regulatory processes. These retail prices do not follow wholesale market prices except over the long run. It may take a year or more for high wholesale prices to be reflected in retail consumer prices. The good news is that retail customers are buffered from the volatility of the wholesale market. The bad news is that retail customers have little immediate incentive to respond to shortages and high wholesale prices (e.g. caused by extraordinary weather, poor hydro conditions, by temporary generating or transmission outages or even market manipulations) by reducing demand for electricity.

In the absence of such response, overall system costs are increased. More expensive generators are dispatched and eventually, when there are no additional supplies available, prices can become extremely high as load serving entities bid against one another for power. As the experience of the last couple of years has shown, higher costs to load-serving entities eventually make their way into retail rates and customers' bills. Without demand response,[1] the electricity market lacks one of the mechanisms that moderate prices in most other markets.

In the traditional world of regulated monopoly utilities, poor retail market signals led to a power system that was inefficient but tolerable. Without much demand response, we probably built more generation, transmission and distribution facilities than would have been necessary otherwise. However, utilities were able to build the extra facilities and to make returns on their investments so they stayed in business. The lights stayed on, but average costs were higher than they needed to be. Even in that world demand response would have offered cost savings , by reducing the need for generating and distribution capacity that was used only rarely.

[1] In fact we have had some limited demand response mechanisms in the past. For example, in the past Bonneville had the right in their contracts with the Direct Service Industries to reduce power deliveries under certain conditions. However, under current contracts this right is much more limited. The significance of this right is further diminished if DSI load declines long term, which seems quite possible.

But in the electricity industry we have now, and many believe we will continue to have in the future, the potential benefits of demand response are even greater. We now rely on a mix of regulated and unregulated power producers to build many new generating plants. The unregulated producers have no obligation to build, and no assurance of making a return on investment. Regulated producers, too, may regard construction of a new generating plant as a risky investment, because of uncertainty regarding their ability to recover costs for regulatory and other reasons. There is no guarantee that either group will find it worthwhile to build to the same reserve margins as we have enjoyed in the past.

The region needs to maintain the reliability of the system and moderate the volatility of wholesale prices, without giving up the potential benefits of a competitive wholesale market. In our current situation, demand response can reduce the overall cost of the system, and play a critical role in ensuring reliability and price stability as well.

How is Demand Response Different from Conservation?

The distinction between "demand response" and "conservation." needs to be clear. "Conservation," as the Council uses the term, is improvement in efficiency that reduces electricity use while providing an unchanged level of service (e.g. a warm house in winter, cold drinks, light on the desktop). "Demand response," as the term is used here, is a change in the service (level, quality or timing) 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 it would be "curtailment" and it would be evidence of an inadequate or unreliable power system.

Demand response could result from rescheduling an industrial customer's production, resetting a commercial customer's heating system thermostat, or a utility's direct control of a residential customer's water heater. Demand response could also be a customer's substitution of self-generated electricity for electricity provided by the power system (e.g. the use of a backup generator for a few hours at the system's peak load).

There is an important implication of the difference between demand response and conservation. Since conservation leaves service unchanged, the costs of alternative ways of providing the service can be compared (e.g. conservation and generation) and a cost-effective level of conservation in kilowatt-hours estimated. The estimate will be somewhat uncertain because of the quality of data, but the conceptual process is straightforward -- that is, start with the cheapest conservation measures and add more measures until saving another kilowatt-hour costs as much as generating and delivering another kilowatt-hour. The total conservation measures at that point represent the cost-effective level of conservation. The Council's plans have used this level as the basis for efficiency standards and implementation targets.

But this approach can't be used to set a kilowatt-hour target for demand response. To estimate a cost-effective level of demand response in kilowatt-hours would require putting a value on the changes in service levels for the whole range of services that might be affected, which is unfeasible.[2] But it is reasonable to assume that each consumer's choice of service level is best for him given the prices he faces, and would be best for the region as well if the consumer saw

[2] The cost of a changed level of service can be calculated, but to calculate the value it would be necessary to see into each consumer's head.

the region's cost of electricity. Instead of a policy goal specified in kilowatt-hours, we can adopt a goal of identifying incentive mechanisms (e.g. prices paid or payments received) that will lead each consumer's chosen level of service to be best for the region as well. To the extent consumers see these incentives, their demand response to changing conditions will be appropriate for them and for the region as a whole.

There are a number of approaches available to develop greater demand response, each with its own advantages and disadvantages. No one of these mechanisms will be the best for every situation – it seems more likely that some combination of mechanisms will be a sensible strategy, particularly while the region is still learning about their strengths and weaknesses. At the most general level, the approaches can be categorized as price mechanisms and payments for reduced demands. This chapter examines these approaches very briefly, with more detailed examination in Appendix X.

Price Mechanisms

Real-time prices

The goal of price mechanisms is the reflection of actual marginal costs of electricity production and delivery, in retail customers' *marginal* consumption decisions. One variation of such mechanisms is "real-time prices" -- prices based on the marginal cost of providing electricity for each hour. This does not mean that every kilowatt-hour customers use needs to be priced at marginal cost. But it does mean that consumers need to face the same costs as the power system for their *marginal* use. The "two-part" real-time prices used by Georgia Power and Duke Power provide the needed marginal cost signal without charging real-time prices for all usage. The "two-part" tariff charges customers the traditional average-cost based rate for the customer's typical usage, and applies real-time prices to deviations from the typical usage level.

Real-time prices offer significant advantages, including low transaction costs, broad reach, and a very close match of market conditions and customer incentives. Real-time prices also face significant disadvantages, including a requirement of more sophisticated metering and communication equipment than most customers[3] have now, and concern about the volatility and fairness of real-time prices. Real-time prices have not been widely adopted as yet -- because of their problems (more detail in Appendix X), the pace of future adoption may be gradual at best.

Time-of-use prices

"Time-of-use prices" -- prices that vary with time of day, day of the week or seasonally -- could be viewed as an approximation of real-time prices. Time-of-use prices are set a year or more ahead and are generally based on the expected average costs of the pricing interval (e.g. 6 a.m. to 10 a.m. and 5 p.m. to 8 p.m. winter weekdays). Time-of-use prices have many of the same metering requirements as real-time prices. Compared to real-time prices, they have the advantage of more predictable bills and they do not require the same ability to communicate constantly changing prices. On the other hand, time-of-use prices cannot communicate the effects of real-time events on the cost to the system of providing electricity. Compared to real-time prices, time-of-use prices trade a degree of efficiency in price signals for greater

[3] Although many large customers already have the metering equipment.

acceptability to customers and regulators, but have nonetheless achieved only limited adoption as yet.

"Critical peak pricing" is a variant of time-of-use pricing that could be characterized as a hybrid of time-of-use and real-time pricing. This variant leaves prices at preset levels, but sets the price of a small number of hours (e.g. 1% or 87 hours per year) at a relatively high price (e.g. 4-5 times average price). The hours these prices apply to are not set until conditions warrant, and customers are notified 24 to 48 hours in advance. Utilities are able to match the timing of highest-price periods to the timing of shortages as they develop, providing improved incentives for demand response at times when it is most valuable.

Payments for reductions

Given the obstacles to widespread adoption of pricing mechanisms, utilities have set up alternative ways to encourage load reductions when supplies are tight. These alternatives offer customers payments for reducing their demand for electricity. In contrast to price mechanisms, which vary the cost of electricity to customers, these offers present the customers with varying prices they can receive as "sellers". Arrangements can vary widely in the degree of control given to the utility in exercising the demand reduction, and in the demand reduction's required duration.

Short-term buybacks

Short-term programs are primarily directed at reducing system peak demand (e.g. by reducing loads on a hot August afternoon or a cold January morning). The total amount of electricity used may not decrease, and may even increase in some cases, but the overall cost of service is reduced mostly because of reduced investment in generators and the moderating effect on market prices. Short-term programs can be expected to be exercised and have value in most years, even when overall supplies of energy are adequate.

Utility payment for load reductions

One variant of this approach is a utility offer of compensation for short-term demand reduction (e.g. for a 4-hour period the next day), giving the customer the choice whether or not to accept the offer and reduce load. Generally the customer is not penalized for not responding to the offer, but if he accepts the offer there is usually a penalty if he doesn't deliver the load reduction. Other variants of this approach are described in Appendix X.

Such programs require that customers have meters that can measure the usage during buyback periods. The programs also require that the utility and customer agree on a base level of electricity use from which reductions will be credited. The base level is relatively easy to set for those industrial customers whose use is usually quite constant. It's more difficult to agree on base levels for other customers, whose "normal" use is more variable because of weather or other unpredictable influences.

Demand side reserves

Another mechanism for achieving demand response is "demand side reserves," which can be characterized as options for buybacks. The power system needs reserve resources to respond to unexpected problems (e.g. a generator outage or surge in demand) on short notice. Traditionally these resources were generating resources owned by the utility, but increasingly other parties provide reserves through contracts or an “ancillary services” market. In such cases, the reserves are paid for standing ready to run and usually receive additional payment for the energy produced if they are actually called to run.

The capacity to reduce load can provide much the same reserve service as the capacity to generate. The price at which the customer is willing to reduce load, and other conditions of his participation (e.g. how much notice he requires, maximum and/or minimum periods of reduction) will vary from customer to customer. In principle, customers could offer a differing amount of reserve each day depending on their business situation.

The metering and communication equipment requirements, and the need for an agreed-upon base level of use, are essentially the same for demand side reserve participants as for short-term buyback participants. Compared to stand-alone buyback programs, demand side reserve programs may have an advantage to the extent that they can be added to an existing ancillary services market.

Payments for reductions -- interruptible contracts

Interruptible contracts give the utility the right to interrupt a customer’s service under certain conditions, usually in exchange for a reduced price of electricity. Utilities have negotiated interruptible contracts with some customers for many years. An important example of these contracts was Bonneville Power Administration’s arrangement with the Direct Service Industries, which allowed BPA to interrupt portions of the DSI load under various conditions.

In the past, these contracts have usually been used to improve reliability by allowing the utility to cut some loads rather than suffer the collapse of the whole system. In practice, service was rarely interrupted. Now these contracts can be seen as an available response to price conditions as well as to reliability threats. We can expect that participants and utilities will pay close attention to the frequency and conditions of interruption in future contracts, and we can imagine a utility having a range of contract terms to meet the needs of different customers.

Payments for reductions -- direct control

A particularly useful form of interruptible contract gives direct control of load to the utility. Part of BPA’s historical interruption rights for DSI loads was under BPA direct control. Not all customers can afford to grant such control to the utility. Of those who can, some may only be willing to grant control over part of their loads. Direct control is more valuable to the utility, however, since it can have more confidence that loads will be reduced when needed, and on shorter notice. The adoption of advanced metering and other technologies can be expected facilitate the use of direct control.

Longer-term buybacks

Longer-term reductions in load, from buybacks or other incentives, are uncommon in most parts of the world but have been a useful option in the Pacific Northwest, given the year to year variability of hydroelectric production. Such programs, in contrast to short-term buybacks, generally result in an overall reduction of electricity use. They are appropriate when there is an overall shortage of electricity, rather than a shortage in peak generating capacity.

Most utility systems, comprised mostly of thermal generating plants, hardly ever face this situation. The Pacific Northwest, however, relies on hydroelectric generating plants for about two-thirds of its electricity. In a bad water year we can find ourselves with generating capacity adequate for our peak hours, but without enough water (fuel) to provide the total electricity needed over the whole year.

This was the situation in 2000-2001, an unusually bad supply situation for our region. The longer-term buybacks that utilities negotiated with their customers were reasonable and useful responses to the situation. Even though these longer-term buybacks might not be used often, there will be other bad water years in the future, and it's prudent to preserve long-term buybacks as an option for those years.

Relative Advantages of Price Mechanisms and Payment for Reductions

Generally, buybacks avoid some of the problems of price mechanisms, and they have been successful in achieving significant demand response. Utilities have been able to identify and reach contract agreements with many candidates who have the necessary metering and communication capability. The notification, bidding and confirmation processes have worked. Utilities have achieved short-term load reductions of over 200 MW. Longer-term reductions of up to 1,500 MW were achieved in 2001 when the focus changed from short-term capacity shortages to longer-term energy shortages because of poor water conditions.

But buybacks have limitations relative to price mechanisms, even though the marginal incentives for customers to reduce load should be equivalent in principle. Buybacks generally impose transaction costs by requiring agreement on base levels of use, contracts, notification, and explicit compensation. The transaction costs mean that they tend to be offered to larger customers or easily organized groups; significant numbers of customers are left out.

Transaction costs also mean that some marginally economic opportunities will be missed. There may be times when market prices are high enough to justify some reduction in load, but not high enough to justify incurring the additional transaction cost of a buyback.

Potential benefits of demand response

The benefits of demand response depend on: 1) the cost avoided by an incremental megawatt-hour of demand response, 2) the total amount of demand response that can be achieved, and 3) the cost of achieving that amount of demand response. This section will describe approaches to estimating the first two factors. While experience with the cost of achieving demand response is beginning to accumulate, it is not yet practical to translate that experience into a "supply curve" of demand response.

Avoided cost

The cost avoided by an increment of demand reduction is the cost of generating and delivering the extra electricity that would have been needed otherwise. The avoided cost is the value of demand reduction to the power system. The system could afford to pay up to the avoided cost for demand reduction and still reduce the system's total cost.

It's important to understand that the short-run avoided cost can be substantially different than the long-run avoided cost. In the short run the power system may have adequate peak capacity, so that the cost of meeting peak load is simply operating the already-existing generators and using the already-existing transmission and distribution system to deliver the energy. In the long run, with growing demand for electricity, the cost of meeting peak includes the construction and operation of new generating plants and perhaps the expansion of the transmission and distribution system. These extra construction costs can increase avoided cost by multiples of 5 to 20. <u>The real value of demand response is in avoiding construction of unnecessary generators in the long run</u>. Accordingly, this Plan is concerned with long-term avoided cost and the following discussion includes construction costs in estimates of avoided cost[4].

The avoided cost varies widely across the hours of the year as supply and demand for electricity are affected by season, weather and other conditions. The avoided costs will be highest when demand is highest and/or supply is tightest. Estimates of these costs depend on assumptions regarding availability of imports, the degree of flexibility available in the hydroelectric system, the cost of peaking generators, and others.

These estimates can be compared to the rates paid by most retail customers, which are based on average costs. These rates vary by utility but average about $60/MWh over the Pacific Northwest. To the extent that avoided costs and retail rates diverge, retail customers lack incentive to adjust their electricity usage appropriately, and demand response programs are worth pursuing.

Avoided costs were estimated using two contrasting approaches (see Appendix X for detailed description of these estimates). Both approaches focus on the costs of meeting peak loads of a few hours' duration ("capacity problems").

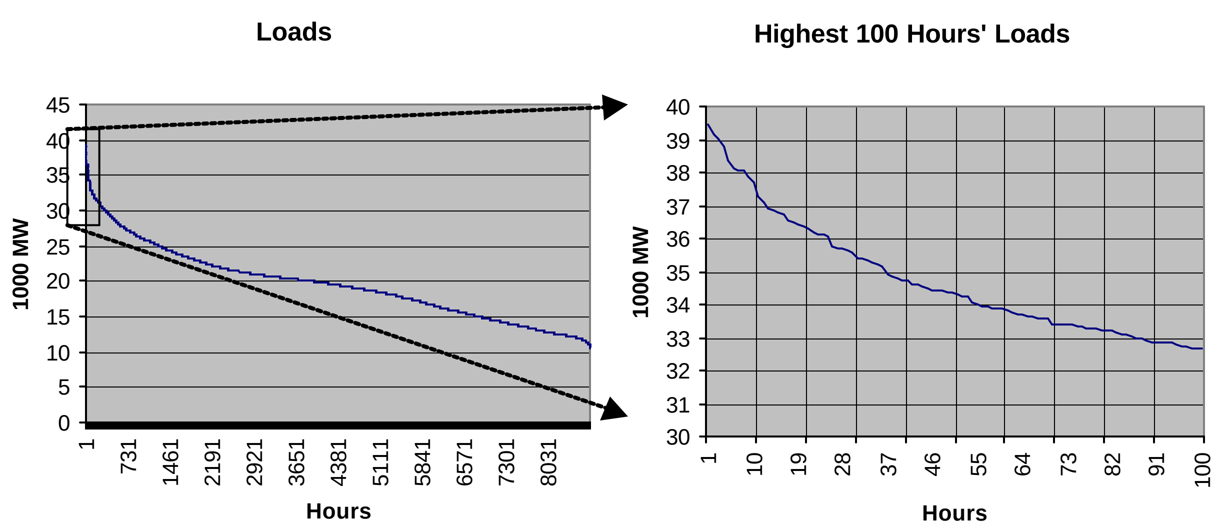

Figure XX

[4] In some cases costs of construction of distribution and/or transmission could also be avoided by demand response. These costs are location specific and are not included in these avoided cost estimates. If it were possible to include distribution and transmission in the calculations avoided costs would be higher.

Approach 1. The first approach is to estimate the avoided cost of serving the peak loads of a power system served entirely by its own thermal generation, with loads distributed through the year similarly to the Pacific Northwest's loads. By arranging hourly loads from highest to lowest, a "load duration curve" is created -- shown on the left in Figure XX. The highest 100 hours are highlighted in the segment on the load duration curve shown on the right in the figure. The load in the highest hour is about 39,500 MW, while the load in the 10^{th} highest hour is about 37,800 MW. In other words, about 1700 MW of generating capacity are needed to meet loads that occur no more than 10 hours in an average year. The cost of building and operating a peaking generator for only 10 hours a year would be $6489/MWh ($6.49/kWh) for duct burner attachments on combined cycle combustion turbines, and $11,442/MWh ($11.44/kWh) for simple cycle combustion turbines.

Per megawatt-hour costs decline as the number of hours per year of operation increase. Based on Figure XX, about 6000 MW of generating capacity are needed to satisfy loads that occur 100 hours or less per year. A generator running for only 100 hours per year would cost $677/MWh ($0.68/kWh) for duct burners and $1179 ($1.18/kWh) for simple cycle combustion turbines (about one tenth the cost of running 10 hours per year).

These figures mean that the avoided cost (or value) of an incremental MWh of load reduction declines as we achieve more of it. If demand response allows us to avoid serving the highest 10 hours of load, we save at least[5] $6489 to $11,442 per incremental MWh, depending on the generator technology. But if the power system is able to achieve enough demand response to avoid serving the highest 100 hours of load, the minimum avoided cost drops to the $677 to $1179/MWh range.

Approach 1 neglects a number of significant features of the Pacific Northwest's power system: There is a large component of hydroelectric generation in the region's power system, which can generally meet peak loads more cheaply than a thermal system. Further, there are large transmission links with California and the Southwest, which facilitate sharing of generators, including peakers, with other regions and should generally reduce the cost of meeting peak loads. The western power system includes a number of older, less efficient power plants that could be displaced by new peaking generators, with the operating cost savings offsetting part of the investment in the new units. The region also faces significant variation in the energy supplied by the hydroelectric system from one year to another, which changes the economics of thermal peaking generators (in poor water years the new peakers may run many more hours than usual).

Approach 2. To reflect these features more realistically, the second estimation approach used AURORA©, an electric price forecasting model, to simulate the West Coast electricity system. This model takes account of interaction between hydro and thermal generators, trade among the various regions, and the operational interaction among plants of different generating efficiencies. The cost of a power system built to provide a given level of service was compared to the cost of a power system that could avoid serving about 5 per cent of its load during the most expensive hours (about 250 hours in an average year). The difference is the avoided cost of service in those hours, or the value of demand response in those hours. Our estimate of avoided cost using this

[5] Most of this load is served even fewer than 10 hours per year, and therefore has an avoided cost that is even higher.

approach is $1029/MWh in an average water year. In dryer than average water years the marginal generators would run more hours, reducing the cost/MWh of their production.[6] In wetter than average years they would run fewer hours, resulting in a higher cost/MWh.

Both approaches lead to estimates of avoided costs that are several times the average rates paid by retail customers for electricity, and well above the incentives offered by regional utilities in their demand response programs in 2000-2001.

Potential size of resource

Since short-term demand response affects customers differently than does long-term demand response, it is to be expected that different amounts of each will be available. Some of the limited historical experience with short-term demand response has been translated into a range of short-term price elasticities[7]. By using elasticities from the lower end of that range, modest avoided costs, and modest peak loads,[8] it was estimated that short-term demand response of at least 1800 MW could be developed in the Pacific Northwest.

Any estimate of longer-term demand response must be based on the region's recent experience using demand response to respond to the tight supply and high prices that persisted for weeks and months in 2000-2001. In that case, load reductions varied from month to month but totaled over 2000 MW for significant periods. However, many of these reductions came from the aluminum industry, which has unique characteristics that made it particularly attractive to reduce loads in the economic environment of 2000-2001. Similar reductions could be difficult or impossible to repeat if, as seems possible, the aluminum industry's presence in the region does not recover in the future.

These very rough estimates could be refined, although the basic conclusion to be drawn seems clear – even if they are wrong by a factor of 2 or 3, the potential is significant.

Experience

Programs to stimulate demand response are gaining experience, in our region and nationally. In our region, a number of utilities have run short-term buyback programs; Bonneville, PGE and Pacific Power have the most experience in this area. Longer-term buyback programs were run in 2000-2001 by these utilities and others, including Avista, Chelan County PUD, Grant County PUD, Idaho Power and Springfield PUD. While this region has no significant experience with real-time prices, several utilities, including Tacoma Power, Puget Sound Energy and Montana Power (now Northwestern Energy) have offered service to customers at prices that followed the wholesale market on a daily or monthly basis. Puget Sound Energy, Portland General Electric and Pacific Power and Light have experience with pilot programs in time-of-day pricing. Milton-Freewater Light and Power has a program that allows the utility to control residential water heaters directly, and Puget Sound Energy ran a pilot program in which it directly controlled thermostats of residential heating systems. More detailed information about this experience is presented in the Appendix X.

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[6] We repeated the experiment with critical water and estimated an avoided cost of $519/MWh.
[7] Price elasticity is a measure of the response of demand to price changes – the ratio of percentage change in demand to the percentage change in price. A price elasticity of –0.1 means that a 10% increase in price will cause a 1% decrease in demand.
[8] Our estimation process is described in more detail in Appendix X.

Nationally, the best-known real-time price programs are at Duke Power, Georgia Power and Niagara Mohawk. Gulf Power has a voluntary residential time-of-day price program that incorporates a critical peak price for no more than 1 percent of all hours. Finally, there are a number of short-term buyback programs, run by utilities or independent system operators; some of the best-known are those run by PJM Interconnection, ISO New England, New York ISO and by several utilities and agencies in California.

Next Steps

To realize the potential savings of demand response, the region needs to take a number of steps in the next few years:

Fully Incorporate Demand Response into Utilities' Integrated Resource Plans

As mentioned earlier, the greatest part of the potential benefit of demand response is due not to the avoidance of operating peaking generators, but to the avoidance of building them. After a generator is built, demand response allows the system to avoid only the operating cost of the generator. Before the generator is built, demand response can avoid not only the operating cost, but the construction cost as well. Depending on the hours of operation of the new unit, the total avoided cost of construction and operation may be 5 to 20 times the avoided cost of operation alone.

To take full advantage of the potential savings from demand response, planners need to take it into account from the beginning of their planning process, before they've committed to building new peakers.

Refine Estimates of the Size of the Resource

In order to fully incorporate demand response into resource plans, planners must have an estimate, in which they have confidence, of the size of the resource. As mentioned earlier, estimation of the size of the demand response resource faces the same problems as sizing the conservation resource, and more. Nevertheless it is necessary if planners are ever to rely on a significant amount of demand response instead of building new generation. This requires that load serving entities develop inventories of demand response capability in their service territories.

Preserve and Expand Options

The need for demand response may have seemed to decline since the spring and summer of 2001, but if the events of the last few years have taught any lessons, one should be that conditions can change, and quickly. Maintaining and expanding the responsiveness of the region's demand to changing conditions is a cheap and attractive complement to building new generation capacity. Utilities should be able to offer programs to more participants. Participants should be able to identify more actions that will reduce load, given adequate incentive. We have a chance to build on recent experience and be able to respond quickly the next time conditions warrant.

Refine Buyback Programs to Reduce Transaction Costs

Much of the demand response enlisted in the 2000-2001 experience was the result of one-to-one negotiation, which was effective but relatively costly on a per-transaction basis. Utilities should be able to streamline some or all of these transactions (e.g. establishing many contract terms in advance, converting some negotiated deals to offers such as the Demand Exchange, etc.). Simplifying transactions will reduce the cost of making deals for both utilities and customers, which will make more deals and more load response possible.

Resolve Regulatory Issues

Cost-effectiveness: So that utilities can pursue demand response with confidence that regulators will allow them to recover costs, a clear standard of cost-effectiveness for the resource is needed. Avoided cost is the appropriate conceptual basis for cost-effectiveness, but since avoided costs vary with circumstances, no single value is appropriate for all utilities and all times. The estimates of avoided cost described earlier are reasonable starting points, but further work is needed before the avoided costs of utilities in the region are fully understood.

Retail access: Giving customers the ability to choose their electricity suppliers might have the effect of reducing access to demand response. Assume, for example, that Supplier 1 serves industrial customers, whose loads are mostly constant, while Supplier 2 serves residential and commercial customers, whose loads are peakier. Supplier 1 needs little peaking generation to serve its load, while Supplier 2 needs significant peaking resources.

There is a potential regional benefit in Supplier 2 being able to obtain voluntary load reductions (demand response) not only from its own customers, but from Supplier 1's customers as well. Such transactions are likely to involve all three parties (i.e. the customer and both suppliers), and could need explicit approval from regulators. It would be unfortunate if suppliers, regulators and customers can't overcome any extra complexity to complete transactions that are in the regional interest.

Explore Ways to Make Price Mechanisms More Acceptable

Some of the advantages of price mechanisms over the alternative means of stimulating demand response were discussed earlier. Price mechanisms avoid transaction costs. They can reach more customers. They provide appropriate incentives when prices are low as well as when they are high. They can provide appropriate incentives for every hour of the year.

However, there are significant obstacles that hinder the adoption of price mechanisms. These obstacles may prove to be intractable, at least for now, but serious efforts are needed to identify ways to make price mechanisms more practical and acceptable. Such options as two-part real-time prices and time-of-use prices with critical peak prices deserve close examination and testing.

Northwest Power and Conservation Council

Demand Response in the 5th Power Plan

NW Power and Conservation Council

March 10, 2004

Helena, Montana

What is Demand Response?

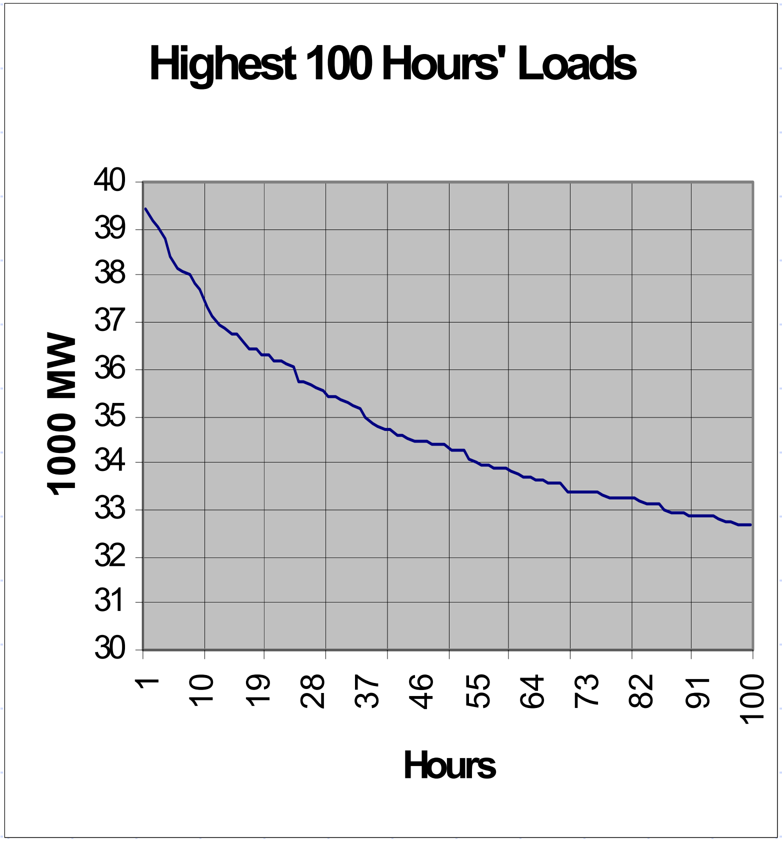
- Change in demand that corresponds to change in power system cost
- DR often missing because consumers don't see power system cost
- In most cases, we've got "half a market"

Northwest Power and Conservation Council

Why Does Demand Response Matter?

- Without DR, loads are "too high" at peak
- More generation built, operated
- Increased vulnerability to market power

Illustration of Peak Load Costs



- More than 1700 MW served 10 hours/yr or less - $6.49 to $11.44/kWh
- Nearly 7000 MW served 100 hours/yr or less - $0.68 to $1.18/kWh

Northwest Power and Conservation Council

DR Is Not Conservation

- May or may not reduce energy use
- Unlike conservation, DR changes service

DR Mechanisms

- Price mechanisms
- Payments for reductions

Relative Advantages

- Price mechanisms
  - Pro - low transaction cost, broad reach, flexibility
  - Con - require meters & communication equip, unpredictable bills
- Payment for reductions
  - Pro - more predictability
  - Con - higher transaction cost, fewer participants

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Next Steps

- Bring DR into utilities' IRPs
- Refine estimates of size of resource
- Preserve & expand options
- Regulatory issues
- Explore ways to make price mechanisms more acceptable.

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