Demand Response

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 supply is generally responsive to conditions in wholesale power markets, its electricity demand 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. This chapter describes the analysis of the potential benefits of demand response and proposes steps to confirm and secure this resource for the region.

Potential Value of Demand Response

The region has not tried to stimulate demand response to any significant extent in the past. In some respects demand response is like conservation was 20 or 25 years ago; it seems to be a promising resource, but our experience is too limited to make confident estimates of the size and cost of the resource and the value it could provide the region.

We have approached the question of the potential value of demand response in several ways. The first was to look at its avoided cost – what costs are avoided by having demand response available. It is cost-effective to pay for demand reductions up to the marginal cost of serving demand. But since avoided costs vary with circumstances, no single value is appropriate for all utilities and all times. As pointed out earlier the short term avoided costs, which include the variable costs of operation of existing generators, can be much lower than long term avoided costs, which also include the cost of construction of new generating plants.[1] This plan focuses on the latter category, long run avoided costs, and the following discussion includes construction costs in estimates of avoided cost.

To start a regional examination of this issue, Council staff have estimated avoided costs using three contrasting approaches (see Appendix X for detailed description of these estimates). The first two approaches focus on the costs of meeting peak loads of a few hours' duration ("capacity problems"). Each approach has shortcomings; they should be seen as initial cuts at the problem rather than final solutions.

[1] 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 the avoided cost estimates described here. If it were possible to include distribution and transmission in the calculations avoided costs would be higher.

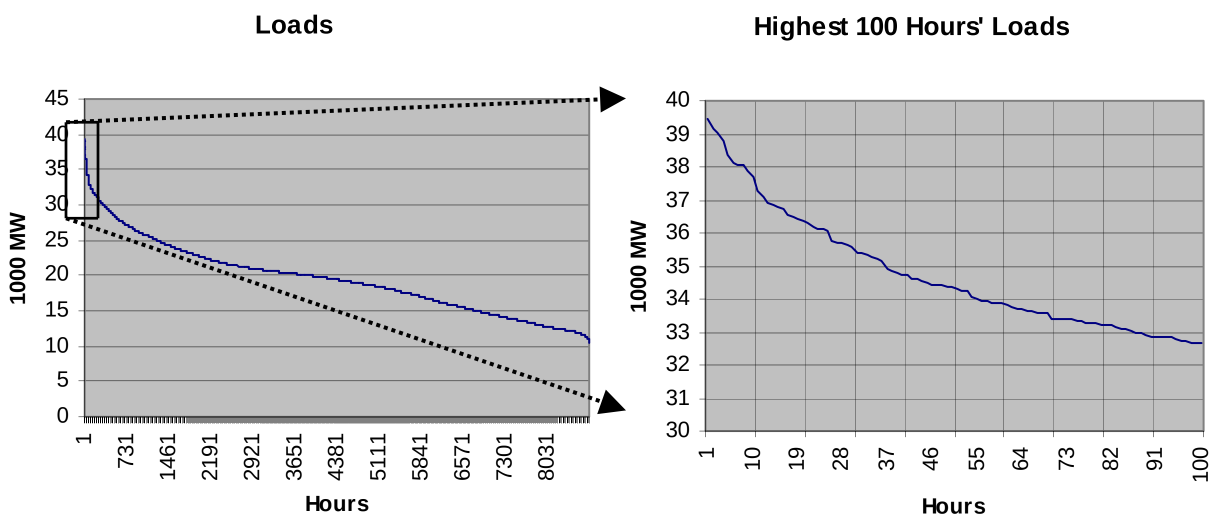

Figure XX

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 megawatts, while the load in the 10th highest hour is about 37,800 megawatts. In other words, about 1,700 megawatt 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 $6,489/megawatt-hour ($6.49/kilowatt-hour) for duct burner attachments on combined cycle combustion turbines, and $11,442/megawatt-hour ($11.44/kilowatt-hour) for simple cycle combustion turbines[2].

Per megawatt-hour costs decline as the number of hours per year of operation increase. Based on Figure XX, about 6,000 megawatt 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/megawatt-hour ($0.68/kilowatt-hour) for duct burners and $1,179 ($1.18/kilowatt-hour) for simple cycle combustion turbines (about one tenth the cost of running 10 hours per year).

These figures mean that the avoided cost (i.e. value) of an incremental megawatt-hour 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[3] $6,489 to $11,442 per incremental megawatt-hour, 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 $1,179/megawatt-hour 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

[2] Assumed costs for new generators are taken from the Council's new resource database.
[3] Most of this load is served even fewer than 10 hours per year and therefore has an avoided cost that is even higher.

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 peaking units 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 percent 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 approach is $1,029/megawatt-hour in an average water year. In drier-than-average water years the marginal generators would run more hours, reducing the cost/megawatt-hour of their production. Critical water conditions resulted in an estimated avoided cost of $519/megawatt-hour. In wetter than average years they would run fewer hours, resulting in a higher cost/megawatt-hour.

While this approach captures the interaction between new and existing generators and trade between regions, it fails to reflect fully the flexibility in meeting peak loads that the hydroelectric system provides. Further, the analysis does not capture the unpredictability of loads and output from the hydroelectric system.

Approach 3. Portfolio analysis in support of this plan also demonstrates the potential for substantial benefits from including demand response in the region's power plans. The available demand response assumed in each case of the analysis is shown in Table XX. Compared to a portfolio with no demand response, the "base" portfolio makes 2,000 megawatts of demand response available over a twelve year period. This very rough estimate is based on estimates of price elasticity from time-of-day and real-time pricing experience elsewhere in the nation. We have further estimated that demand response could be maintained for a fixed cost of $5,000/MW for the first year and $1,000/MW for each year thereafter and could be dispatched for a cost of $150 per megawatt hour. In the case where there is no demand response, the portfolio model deploys additional combined cycle and single cycle combustion turbines while reducing somewhat the amount of wind generation.

Table XX: Available Demand Response by Case in Portfolio Analysis (megawatts)

	12/03	12/07	12/09	12/11	12/13	12/15	12/17	12/19

No DR	0	0	0	0	0	0	0	0
Base Portfolio	0	500	750	1000	1250	1500	1750	2000

The portfolio analysis concluded that available demand response makes it possible to reduce expected cost, risk or both. As Table XXX shows, the expected cost of the least cost portfolio declines from $17,519 million with no demand response, to $17,490 million with base case demand response assumptions. As the table also shows, including demand response in the portfolio allows a reduction in the lowest possible expected risk from $29,384 million to $28,820 million.

The "Risk ~ 29,800" category at the right of Table XXX lets us focus on changes in expected cost, while holding risk essentially constant. Introducing demand response at the base level allows the reduction of expected costs by $319 million, with no increase in expected risk.

Table XXX: Expected Costs, Risks of Demand Response Portfolios
($Millions, Net Present Value)

	Least-cost Portfolio		Least-risk Portfolio		Risk ~ 29,800	
	Expected Cost	Expected Risk	Expected Cost	Expected Risk	Expected Cost	Expected Risk
No DR	17519	31661	18440	29384	18184	29781
Base DR	17490	30696	18478	28820	17865	29744

Confirming and realizing the potential

The results described above are dependent on the assumptions. Can 2000 megawatts of demand response be developed and done so at the costs we have estimated? What is the avoided cost? While this analysis clearly indicates that the potential benefit of demand response is very significant, there are a number of steps that the region needs to take to confirm and realize that potential:

Preserve, Refine 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.

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 five 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. Regulators should require utilities to incorporate demand response fully into utilities' integrated resource plans.

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. Estimation of the size of the demand response resource presents many of 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, both long-term and short term, in their service territories.

Agree on Cost-Effectiveness Methodology

All the approaches we have used to estimate the value of demand response have significant limitations. Nevertheless, all the 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.

Another element of a cost-effectiveness methodology is the allocation of cost of metering and communication equipment necessary to demand response mechanisms. This equipment provides other benefits, such as automatic meter reading, to utilities and customers, and its cost is continuing to decrease. Cost-effectiveness evaluations should use the net cost of this equipment, after other benefits have been taken into account, to compare to demand response benefits.

Utilities, regulators, the Council and others from the region should work to develop a method of evaluating cost-effectiveness of demand response that gains general support.

Use Demand Response for Ancillary Services

Demand response is an alternative to generation in the provision of ancillary services, particularly reserves, and should be able to compete with generation to provide these services. The control and operation of the transmission system may well change in the next few years, and if a formal ancillary services market is part of that change, demand response should be able to participate on an equal basis with generation.

Transmission operators and their regulators should work to make this participation possible.

Resolve Regulatory Issues

The region's regulators will need to be involved in the regional discussion of avoided cost methodology, of course, since they will need to approve utilities' acquisitions of demand response. But there are other regulatory issues that need to be resolved as well.

For example, to the extent that states move toward giving customers the ability to choose their electricity, the effect could be to reduce 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 exhibit daily and seasonal peaks. 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.

The region's regulators will need to be alert to such issues and to be prepared to resolve them to remove obstacles to the fullest appropriate use of demand response.

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.

The Council, utilities, regulators and others should engage in a serious consideration of alternative forms of price mechanisms to meet valid concerns while achieving some of the advantages of these mechanisms.

---

j:\power committee\2004_07\drnextsteps(kcdw)070704.doc