CAPACITY COST PAYMENTS

COMMENTS OF THE ELECTRIC UTILITY GROUP
DOCKET NO. E999/CI-01-1023

I. INTRODUCTION

Following are the consolidated comments of Minnesota Power, Alliant Energy, Xcel Energy, Otter Tail Power and Dakota Electric (the "Electric Utility Group") justifying our position on the payment for avoided capacity to a distributed generation customer when no capacity is needed by the utility.

At the October 30, 2002 distributed generation meeting, the Department of Commerce (the "Department") proposed a methodology for pricing avoided capacity costs. Under their proposal, marginal capacity cost is defined as the cost per kW of adding the next capacity unit (e.g., combustion turbine, combined cycle, or power purchase) to the utility's electric system. The proposal ties this capacity addition to the next marginal unit called for in the utility's integrated resource plan.

Although there seemed to be general agreement by the Electric Utility Group on this pricing approach; much of the ensuing discussion focused on how to recognize factors that impact the value of marginal capacity, including the value of avoided capacity when the utility is not capacity deficit. The Electric Utility Group believes:

> *If capacity is not needed by the utility, the utility should not be required to provide a capacity payment to the distributed generation customer.*

As shown below, this position is supported by the rate principles and scope established by the Distributive Generation Rate Workgroup (the "Workgroup").

II. DISTRIBUTIVE GENERATION RATE WORKGROUP

A. Rate Principles

At the September 18, 2002 distributed generation meeting, the Workgroup agreed on the following overall principle to be used in discussions for setting rates for the power purchased from a distributed generation customer:

> *Rates should reflect the value of the distributed generation to the utility, including any reasonable credits for emissions or for costs avoided on the generation, transmission and/or distribution system.*

Furthermore, in pricing the value of energy and capacity service from a distributed generation facility to the utility for any purchases the utility must make, the Department proposed the following principle at the October 9, 2002 meeting:

> *Rates should reflect the costs the utility expects to avoid (including as appropriate any purchases the utility avoids having to make in the wholesale market to meet the needs of retail customers).*

These rate principles lay the groundwork for establishing the use of avoided costs to price services provided from a distributed generation customer to the utility. Following the intent of these rate principles, it is clear that if capacity is not needed by the utility, the utility should not be required to provide a capacity payment to the distributed generation customer. That is, if the utility's avoided capacity is zero, the value to the utility of capacity from the distributed generation customer is zero, and therefore the rate paid for such capacity should be zero. Note that at the November 18, 2002 distributed generation meeting, distributed generation customers similarly stated that they do not wish to pay for services from the utility that are not required (e.g., standby).

At the September 18, 2002 meeting, the Workgroup also agreed that promoting distributed generation means removing barriers rather than requiring other customers to subsidize distributed generation. If the utility's avoided capacity cost is zero, current utility customers should not be required to pay now for future capacity additions. Levelizing capacity payments to account for a purchase of capacity from a distributed generation customer before there is an established need for capacity by the utility does not address the fact that current customers are paying for future capacity additions. Many factors support whether basing a current payment for a forecasted capacity addition is just and reasonable. These factors include the uncertainty of a long-term forecast (e.g., load loss) and whether the distributed generation customer, when not under a must-sell obligation, could decide to sell elsewhere, scale back or get out of the business all together.

Finally, at the October 9, 2002 meeting, it was noted that the value of capacity during peak periods should be recognized as being more valuable than the value of capacity at off-peak times. At a minimum, prices paid should reflect differences in summer and winter (seasonal) costs and, preferably, peak and off-peak period costs. Avoided costs should include the costs of purchases the utility avoids making in the wholesale market to serve retail customer's needs. The Workgroup generally agreed that costs of getting information becomes prohibitive at some point, but the better information available, the more efficient the system becomes in terms of encouraging distributed generation to produce power when it is more valued in the utility's system. Following that pricing logic, providing capacity payments when the utility's capacity need is zero sends the wrong price signals to distributed generation customers. The capacity should be priced based on its value to the utility. The utility or its ratepayers should not simply subsidize the business interests of the distributed generation customer.

B. Docket Scope

As established through the Workgroup process, the scope of this docket is limited to services provided between the utility and a distributed generation customer. However, other parties have argued that a utility should be required to act as a marketer and purchase and then resell unneeded capacity.

At the September 18, 2002 distributed generation meeting, the issue was raised whether this Workgroup is discussing sales of power from distributed generators to the wholesale market in general (i.e. selling power to entities other than the electric utility of which they are a customer.) The Department clarified that the scope of the Workgroup, as indicated in the Commission's June 19, 2002 Order, is focused on two aspects of distributed generation: utilities providing interconnection and backup service to distributed generation customers, and utilities buying power services from distributed generation customers.

At the October 9, 2002 meeting, the Department restated that the scope of the Workgroup does not extend to sales by distributed generation owners to the wholesale market in general. The appropriate venue for such sales is through federal rules and regulations as an exempt wholesale generator. At the meeting, the Workgroup appeared to agree that merchant power plants (e.g. no retail load and dispatchable) are outside the scope of this proceeding. Since they are not native load customers, such plants would likely be exempt wholesale generators under federal regulations.

Finally, at the November 18, 2002 meeting, it was noted that Minnesota law allows qualifying facilities to wheel power through their incumbent utility to another Minnesota utility that needs power (Minnesota Statute 216B.164, subd. 4, part. c). In addition, wheeling power produced from all other sources is a required service for which the utility shall charge a distribution wheeling fee. The Department also stated that any distributed generation owner that wanted to negotiate with the utility to have the utility act as an agent to sell their power on the open market could do so. However, the Department stated that such transactions would be at the wholesale level, beyond the jurisdiction of the Commission and subject to federal regulation.

III. CONCLUSION

The Electric Utility Group believes that the rate principles and scope established by the Workgroup in this docket support the position that if capacity is not needed by the utility, the utility should not be required to provide a capacity payment to the distributed generation customer. That is, if the utility's avoided capacity is zero, the value to the utility of capacity from the distributed generation customer is zero, and therefore the rate paid for such capacity should be zero.