

LOAD MANAGEMENT STRATEGIES TO SUPPORT THE GRID-INTEGRATION OF INTERMITTENT RENEWABLE RESOURCES

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Wind and solar are intermittent energy sources; as a result there are times in which these resources do not generate power. Storing energy for use at a later time is a potential solution to the intermittency problem. An alternative solution is turning non-essential load on and off to match the availability of energy supply that results from intermittent generation resources. Several operators have implemented customer load management programs, which generally offer two separate functions in the electric system. The first type of load management programs have been designed to minimize spikes in electricity prices. The second type have been designed to support grid stability. In the U.S., several Independent System Operators (ISOs) have developed programs of both types. The California ISO, for example, has recently developed a proxy demand response program in which a load (or an aggregation of loads) capable of reducing its electricity demand is allowed to participate in the day-ahead or real-time market and be dispatched by the ISO (1). New York ISO (NYISO) offers four load control programs (2). Two of these programs (the Emergency Demand Response Program and the ICAP Special Case Resources program) pay large electricity consumers to reduce their consumption at NYISO's request. A third program, the Day-Ahead Demand Response Program, allows large-scale consumers to bid their load reduction capabilities in the day-ahead market. Finally, a fourth program, the Demand Side Ancillary Services Program, allows consumers that meet certain requirements to provide regulation and reserve services. ERCOT, similarly, has a Load Acting as a Resource program (3), which enables qualified interruptible loads to participate in the ancillary service market.

In addition to ISO-operated load control programs, which target large-scale electricity consumers, some utilities have attempted to smooth demand in the past with interruptible tariffs or direct load control. Under direct load control programs (DLC), customers are offered a monthly reduction in their electricity bill or some other benefit, such as a smart thermostat, if they allow the utility to interrupt part of their electric load temporarily, e.g., they allow their air conditioner to be interrupted for up to 10 minutes each half-hour. DLC has been employed by many utilities with varying results. Often the utility realizes a load reduction far less than what they expected because a portion of the DLC controls have been interrupted for one reason or another. With smart meters, DLC is likely to be more uniformly successful, unless the customer is given the ability to override the utility signal.

A number of pricing plans have also been used to reduce peak demand, including: Time of use (TOU) rates, critical peak rebates (CPR), critical peak pricing (CPP) and real time pricing (RTP).

- In TOU programs, electricity rates vary throughout the day to reflect the average daily usage pattern over a season. TOU rates do not vary from day to day or over a given season. Thus, TOU rates are a general approximation to the time varying cost of generating a kWh. For example, TOU rates would be the same for a stormy, cold summer day as for a hot, humid summer day. Thus, TOU rates generally motivate reduced demand during peak hours but give no specific incentive for when peak load is close to system capacity. Implementation of TOU rates has varied among utilities. In some programs, the peak is continuous for several hours of the day. This is the case in the Salt River Project (which serves Phoenix) between May and October, when high cost hours occur between 1:00 p.m. and 8:00 p.m. In other cases, the high cost hours are in effect only for a few hours at a time. For example, between November and April, the high cost hours in the Salt River Project program occur between 5:00 a.m. and 9:00 a.m., and

between 5:00 p.m. and 9:00 p.m (4). In addition, the ratio between peak and off peak rates has differed a great deal. Generally, the TOU experiments have found some reaction to prices, although the price elasticity has been found to be small.

- CPR and CPP programs specify certain hours, a day in advance, when customers can reduce their bill by reducing consumption (CPR) or when they will face very high prices (CPP). For CPP, the customer is offered a reduction in non-CPP hours in return for agreeing to pay high prices during critical peak hours. CPR and CPP are aimed at fewer hours per year, specifically at the days and hours when demand threatens to overwhelm the generation capacity. Generally the time period is specified a day before and the price is fixed. Thus, the price reflects the average wholesale price of electricity during critical peak hours, but not the price during these specific hours. As a result CPR and CPP programs allow for scheduled load reduction, but offer limited support in times of crisis.
- RTP exposes customers to the real-time wholesale price of electricity plus a delivery charge. As a result, the price of electricity for a customer varies from hour to hour, or even from minute to minute. The local utility is not at risk by wholesale price fluctuations since price changes are immediately passed on to the customer. RTP can provide price signals to customers that a crisis, such as a generator tripping offline, has occurred and quick reductions in load are needed to maintain system stability. Several RTP field trials have been conducted and found that customer reaction to changing prices is small. A seven-year long program in Illinois showed little or no customer reaction to higher prices, even during the hottest days with the highest prices. From an implementation point of view, two devices could support RTP. The first device gives customers easy access to current prices. The second device is an energy manager that adjusts the setting on appliances to carry out a customer's preprogrammed instructions to respond to utility price signals.

An important consideration when designing load management programs is the customer's willingness to participate. In the U.S., customers may be resistant to DLC programs, even if these are shown to be a cost-effective mechanism for load management. In addition, two critical issues regarding all load management programs are the response time associated with each mechanism and the duration of the response. Direct load control of residential consumers, for example, may allow for an instantaneous response to a generation or transmission constraint. Direct load control of industrial consumers, on the other hand, should be scheduled hours in advance. Programs like NYISO's Demand Side Ancillary Services Program allow demand side response to provide regulation and reserve services, and as such, participants may need to be able to respond to the ISO's instructions in short time frames (seconds to 10s of minutes). Reductions in demand over longer time frames of hours to days are more difficult to achieve and none of the programs previously described are suitable to accomplish this even though systems will need this capability due to the strong growth in intermittent resources. Energy Efficiency programs or direct mandates are better suited to reduce demand over longer time frames (weeks to years).

Interest in load management strategies has increased in recent years as a means to reduce the need to construct new power plants and transmission lines, which require a significant up-front investment and have extensive permitting requirements. Little attention has been given, however, to the role of load management strategies in supporting the integration of intermittent renewable resources.

The preceding discussion has focused on load management strategies designed to reduce load, which could be beneficial at times of low renewable generation. It is possible, however, that load

management strategies could also be used to schedule loads at times of high renewable generation. The current way of handling too much power is to lower the locational marginal prices (LMP) of electricity – even to a large negative number. Under the current system, this seems to be sufficient in the sense that there are no reports of frequency or voltage changes that caused problems. However, as state RPS mandates put more wind and solar into the system, the problem of generation exceeding demand at certain hours will grow. The question is whether there are other mechanisms that can help the LMP manage the overage.

One policy instruments might include DLC for electricity use rather than reduction. As the RPS force more wind and solar online, there are likely to be more electric vehicles (EVs) in the system. One approach would be to save recharging the EVs until there is excess generation. The same could be done with electric hot water heaters and other large electricity consumers that store energy (in that case, hot water rather than electricity, as is done in France). The load serving entity (LSE) could offer customers monthly payments to allow utility control of the hot water heater, EV charging etc. Similarly, pricing schemes could support strategies to increase electricity demand at times of large renewable generation.

In a world of perfect foresight, we could charge the EVs and heat the water when there is excess generation – subject to constraints on rate of charging, etc. However, the transmission and distribution lines cannot handle a huge increase in flow and the batteries and heater can absorb electricity only so fast, so other options to manage excess generation may be needed and should be compared to the effectiveness of load management.

Within the context of load management and renewable generation, an analysis of the types of load management strategies better suited to support renewable integration should be performed. Are ISO level strategies better suited than utility-based strategies? What is the role of load reducing and load dispatching strategies? Under which circumstances are market mechanisms, like time-of-use pricing, suitable as means to support renewable integration? What role should direct load control strategies play in supporting renewable integration? If direct load control strategies are to be used, load characterization studies may be required. In addition, it may also be important to identify how these load management strategies may affect grid reliability when paired with renewable energy generation. Finally, it is necessary to understand how load management strategies compare to other strategies designed to deal with the intermittency associated with wind and solar power. As part of the RenewElec project, we hope to work on these areas of research in order to identify load management strategies that can better support the integration of wind and solar power.

References:

- (1) CAISO: “Process for Participating Load Program.” Available on-line at <http://www.caiso.com/17e5/17e5997039720.pdf>
- (2) NYISO: “Demand Response Programs.” Available on line at http://www.nyiso.com/public/markets_operations/market_data/demand_response/index.jsp
- (3) ERCOT: “Load Acting as a Resource.” Available on-line at <http://www.ercot.com/services/programs/load/laar/>
- (4) Salt River Project: “SRP Time-of-Use Price Plan.” Available on-line at <http://www.srpnet.com/prices/home/tou.aspx>