NORTH AMERICAN UTILITY DEMAND RESPONSE SURVEY RESULTS

Randy Gunn, Summit Blue Consulting[a]

Introduction

This paper summarizes the results of a survey conducted of utility demand response (DR) programs in the United States and Canada. The focus of this survey is the demand response programs that individual North American utilities are conducting. The results complement data that the project team has already collected on demand response programs offered by North American regional transmission organizations.

The objective of this paper is to examine the "state of the practice" regarding demand response programs in North America. The survey results are intended to inform demand response market potential benchmarks, as well as program valuation and technology documentation. The most immediate aim of the survey results is to develop demand response benchmarks for "best-in-class" programs that have been in operation for 10 years or more. A more aggressive goal is to determine the "market potential" (i.e., attainable MWs) for these types of programs in given settings. However, developing such market potential benchmarks would require more information than could be reasonably be collected in this survey.[b]

Methodology

Interviews were conducted with demand response program managers or other staff involved with their utilities' demand response programs at 40 utilities across North America. The utilities surveyed range from companies with peak demands of 700 MW to 35,000 MW. About 90% of the utilities surveyed are American, while 10% are Canadian. Approximately 90% of the utilities surveyed are investor-owned utilities, while 10% are municipal or cooperative utilities.

The targeted utilities of interest for this survey are those that are conducting or considering at least one demand response program, including some type of time-differentiated pricing. However, about 10% of the utilities surveyed are not currently conducting any DR programs or offering any type of time-differentiated pricing.

The data that was collected on both residential and commercial/industrial utility demand response programs through this survey include:

- The specific demand response programs that utilities are currently conducting, how long the programs have been operating at each utility, program eligibility requirements, and how utilities market the programs to their customers.
- Program pricing structures or rate discounts.

---

[a] Mr. Gunn can be contacted at: Summit Blue Consulting; 150 North Michigan Avenue, Suite 2700, Chicago, IL 60601 and via E-mail at rgunn@summitblue.com.

[b] This effort was conducted for the International Energy Agency Demand Side Programme – Task XIII: Demand Response Resources. A number of the participating countries requested estimates of the market potential for DR programs in their countries, and some attempt was made to bracket this potential, but meaningful market potential estimates can not be developed through this type of survey. Key baseline work would need to be conducted in the countries desiring such an estimate.

- Relevant general utility information, such as their standard rates, their number of residential and commercial/industrial customers, and peak demands.

- Any load control equipment that utilities provide to customers as part of their programs, how customers' loads are monitored through the programs, and how their load monitoring or billing information is processed.

- Program performance information, including the number of customers participating in each program, the peak demand reductions that utilities realize from each program, and how utilities calculate the latter. Also, whether the programs are expanding, in maintenance mode, or declining, and the reasons for their status.

- Planning and analysis that utilities conduct regarding these programs. This information includes the extent to which they conduct market potential studies for the programs and how they do so, the type of benefit-cost analysis they conduct for the programs, and how they incorporate the programs into their long-term system planning.

- The utilities' satisfaction with various aspects of their programs, and which program elements they would like to change.

Staff experienced with demand response experience were used to conduct the telephone surveys. A 47 question survey instrument was used to collect data for the project. Most often residential DR program managers and commercial/industrial DR program managers were interviewed separately. In some cases utility rate department staff were interviewed instead.

The data are generally self-reported by the utility staff surveyed. In several instances utilities provided regulatory reports that documented the status of their programs at the time, but such reports were usually unavailable.

Residential Survey Results

This section summarizes the residential survey results and focuses on:

- The prevalence of different types of residential DR programs.
- Program eligibility requirements, marketing, and pricing.
- Program participation and performance.
- Planning and analysis activities.

Prevalence of Different Types of Residential DR Programs

Throughout this survey, the focus is on four types of demand response programs that utilities offer to residential customers:

1. **Direct load control (DLC)**: Through these programs, customers allow their utility to directly control their central air conditioner, water heater, or other types of major electrical equipment. Utilities cycle this equipment on and off during peak demand periods, usually in alternating 15 minute cycles. Utilities usually offer customers some type of rate discount as a participation incentive.

2. **Time-of-use (TOU) rates:** The most common type of TOU rates are "two-part" rates that charge customers a higher "on-peak" price than the standard flat utility rate during daytime hours, and a

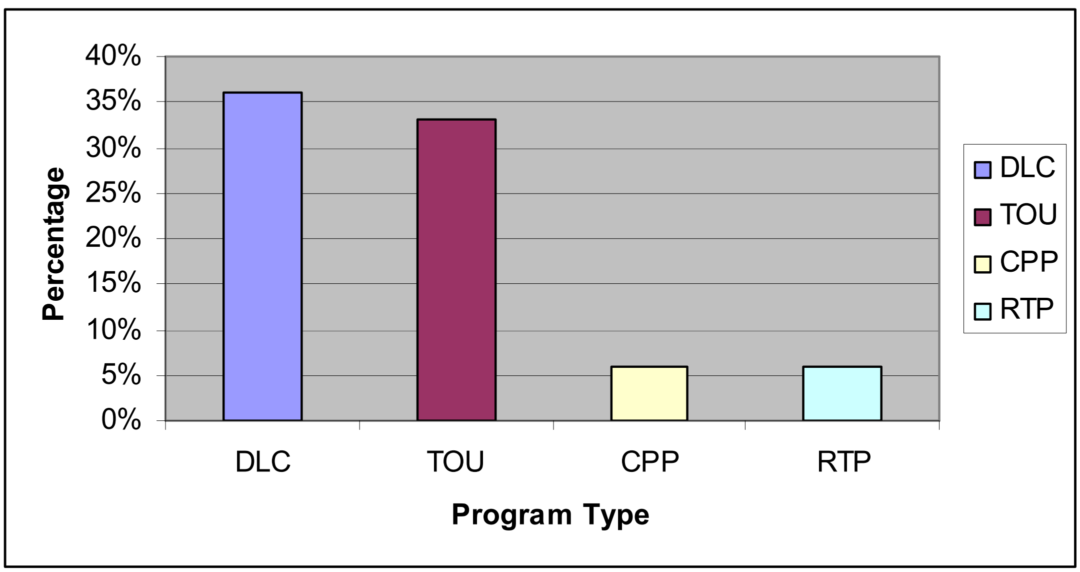
lower “off-peak” price during nighttime hours and weekends. Some utilities offer a “three-part” TOU rate, in which both the on-peak and off-peak periods are shorter than the typical two-part TOU rate periods. In addition, the three-part TOU rate includes a “shoulder” period between the on-peak and off-peak hours, during which time prices are between the on-peak and off-peak prices.

3. **Critical peak pricing (CPP) rates:** These are similar to TOU rates, but add a “critical peak” period and rate. The “critical peak” period is typically 1% or fewer hours throughout the year, during which time the utilities’ production or power purchase costs are highest. Electric prices during this period are higher than the regular TOU on-peak prices. These rates are only offered to residential customers by two utilities surveyed.

4. **Real-time pricing (RTP):** Prices offered through these programs are tied to some type of hourly pricing benchmark, such as the PJM RTP rate, or a utility’s commercial/industrial hourly pricing rate. These rates are only offered to residential customers by two utilities surveyed.

Approximately two-thirds of the utilities surveyed are conducting at least one type of DR program for residential customers. The most prevalent residential DR programs are two-part TOU rates and DLC programs, each conducted by about one-third of the utilities surveyed. Figure 1 shows the percentage of utilities conducting each type of residential DR program.

Figure 1. Percentages of Utilities Offering Different Types of Residential DR Programs



Most utilities started their DLC programs in the early 1990s, but about one-third started their programs in 2002 or 2003. For TOU rates, the starting dates varied widely, from 1980 until 2002. CPP and RTP programs all started in 2001 or later.

Program Eligibility Requirements, Marketing, and Pricing

Two-thirds of the utilities’ DLC programs cover central air conditioners only, while the other third also cover electric water heaters or other types of electrical equipment. Most utilities allow any residential customer to participate in TOU rates, but a few utilities require TOU participants to have a minimum amount of electric use (approximately 1,000 kWh) or a good electric bill payment history to qualify.

Half of the utilities offering CPP or RTP programs require a minimum amount of electric use in the summer – roughly 1,500 kWh – to qualify for the program, while the other half allow any residential customer to participate.

Direct mail is the most common method that utilities use to market residential DR programs to customers, followed by bill inserts and telemarketing, while a few utilities use media advertising. One utility primarily promotes its TOU rates to new customers, which has been a very successful approach for them.

All utilities surveyed offer rate discounts as incentives for customers to participate in their DLC programs. The discount amounts offered are most commonly $4 to $8 per month for each of the four summer months. One utility offers a programmable thermostat instead of rate discounts to new program participants.

For utilities that offer fixed, time differentiated pricing, the following range of prices are offered for each different pricing period:

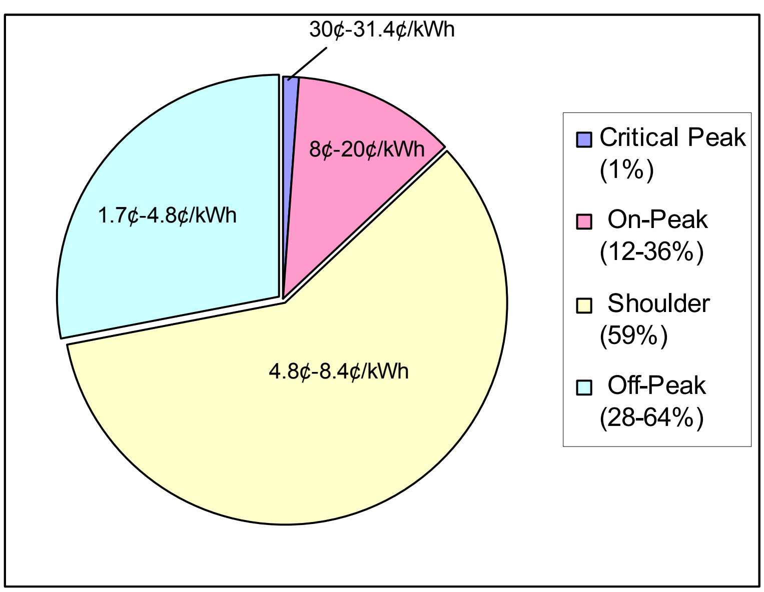
- Critical peak prices, which are only generally in effect about 1% of the time or less: prices are very similar between the two utilities surveyed that offer these programs – 30¢/kWh and 31.4¢/kWh.

- On-peak prices, which are generally in effect from 12% to 36% of the time: prices range from 8¢/kWh to 20¢/kWh.

- Shoulder prices, which are in effect up to 59% of the time: prices range from 4.8¢/kWh to 8.4¢/kWh.

- Off-peak prices, which are in effect from 28% to 64% of the time: prices range from 1.7¢/kWh to 4.8¢/kWh.

Figure 2. Fixed, Time Differentiated Pricing: Annual Price Period Frequencies and Price Ranges

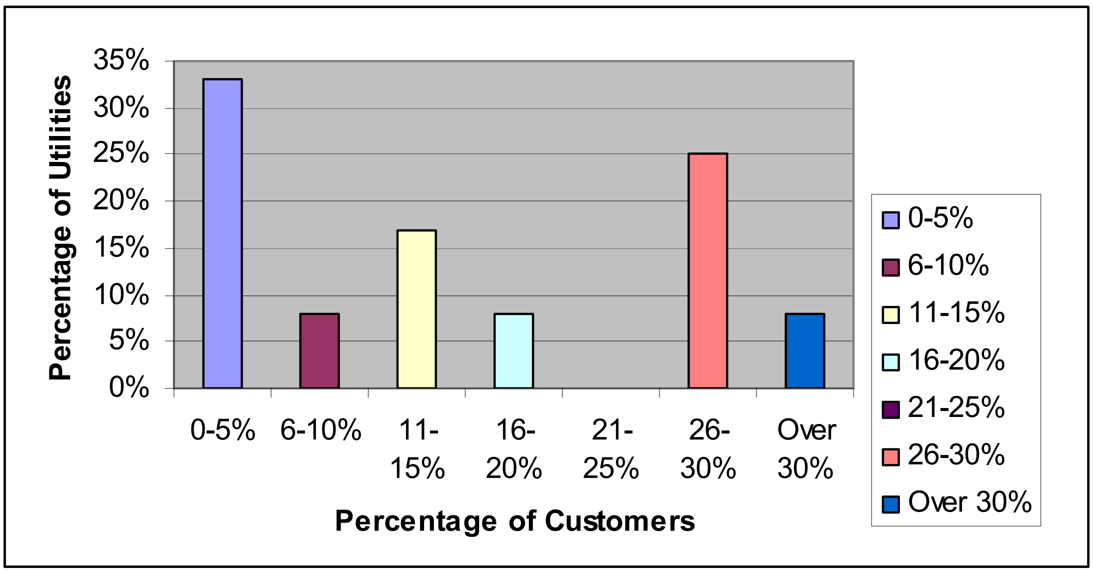


Residential Program Participation and Performance

Participation

The number of residential customers participating in DR programs varies widely between utilities, and from program to program at any given utility. Generally, DLC programs draw more customer participation than other types of DR programs, with several utilities enrolling 20% or more of their eligible customers in these programs. However, about one-third of the utilities surveyed reported DLC program participation rates of 5% or less. DLC program participation rates for the utilities surveyed are portrayed graphically in Figure 3 below.

Figure 3. Percentages of Eligible Customers Participating in Residential DLC Programs



Participation in TOU rates and other types of residential DR programs is generally low, usually ranging from almost zero to 3% of eligible customers. However, one utility has made a significant effort over the last decade to enroll new customers in its two-part TOU rates program, and now has almost 40% of its residential customers on those rates. Given their customers' load characteristics, most customers with new homes will reduce their electric bills on TOU rates compared to standard residential rates.

DLC programs generally provide the largest peak demand reduction impacts for the utilities surveyed. However, several northern winter-peaking utilities report the largest peak reduction impacts from interruptible space heating ("Dual Fuel") programs. Several utilities surveyed only offer TOU or CPP programs, and so realize all of their residential DR program impacts from those programs.

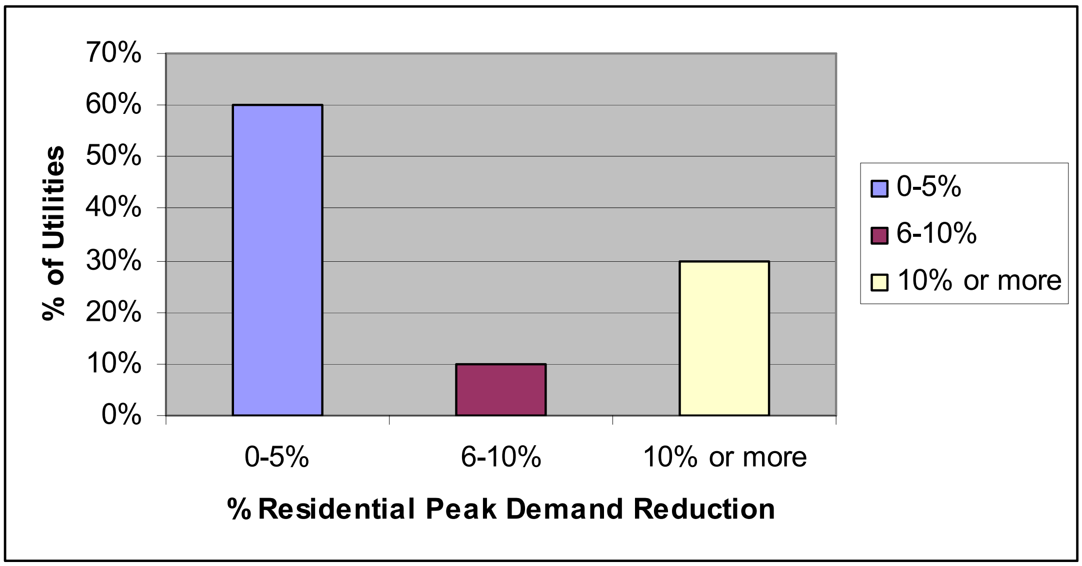
Performance

Over 80% of the utilities surveyed that are conducting at least one residential DR program were able to provide estimates for their programs' peak demand reduction impacts as well as their system peak demands. Utilities were also asked to provide the percentage of demands that are attributable to their residential customers, which most were able to do. The data provided by the utilities was checked for reasonableness, but generally could not be independently verified, given the limited scope of this project.

The most common method for estimating peak demand impacts is load research metering of the total electric loads for a sample of participating customers. However, utilities whose DR efforts are focused on TOU, CPP, or RTP rates tend to estimate program impacts primarily by analyzing all program participants' hourly load data that is collected through interval data recorders or automatic meter reading (AMR) systems.

The largest number of utilities, about 60% of those surveyed, report total peak demand reductions from their DR programs that are less than 5% of their residential peak demands. The second largest group, about 30% of the utilities that reported DR program impacts, can reduce their residential system peak demands by slightly more than 10% through these programs. The remaining 10% of utilities surveyed report total DR program impacts of between 5% and 10% of their residential peak demands. These results are portrayed graphically in Figure 4 below.

Figure 4. Residential DR Program Impacts as Percentages of Residential Peak Demands



Variations between utilities in the magnitude of their residential DR program impacts are largely attributable to their program selections and the length of time that their programs have been operating. All of the utilities whose DR program impacts are 10% or more of their residential peak demands have been conducting their programs since the early 1990s or earlier.

In addition, all of these utilities are conducting DLC programs, and most of these utilities' DLC programs account for almost all of their total residential DR program impacts. It is also interesting to note that the utilities conducting the largest impact DLC programs are all located in northern states that border Canada. So, large summer cooling loads are not required for these programs to have significant peak demand impacts. Variations in the utilities' DLC rate discounts do not contribute significantly to rates of program participation or magnitudes of program demand reduction impacts. For the group evaluated, program participation averaged 15% and ranged between 1-29%. Meanwhile, peak load reduction realized from DLC programs averaged 70 MW, with residential DLC impacts as a percentage of resident peak demands ranging from 0.5% to 12%.

On the other hand, most of the utilities whose total residential DR program impacts were less than 10% of their residential peak demands had either started their DR programs in 2000 or later, or did not include a DLC program as part of their residential DR program portfolio. The largest demand reduction impact from TOU, CPP, or RTP pricing programs came from the previously mentioned utility that enrolls most of their new customers on TOU rates. This company estimates that their TOU rate program reduces their residential peak demand by about 6%.

Peak demand reduction impacts per participating customer average about one kilowatt each. Utilities with significant interruptible space heating programs and one utility conducting a CPP program report impacts per customer of about two kilowatts each.

Most utilities report that their DLC programs are still expanding due to the programs' benefits or regulatory requirements. Most utilities' TOU rates programs are not expanding, due to lack of customer interest or changing regulatory circumstances. Utilities' CPP programs are expanding, as these are newer efforts that still have significant remaining market potential. Utilities' RTP programs are of mixed status, with one expanding and one in maintenance mode pending a program evaluation.

Utility Residential DR Planning and Analysis

About one-third of the utilities conducting residential DR programs have made long-term market potential estimates for their programs. None of these studies were publicly available and therefore could not be reviewed in depth. These utilities reported using a variety of methods to develop such estimates, including:

- Comparing their program's impacts to the results of other utilities' programs.
- Making future projections based on their recent program experience.
- Econometric analyses.
- Analyzing the results of their residential appliance saturation surveys.

Most utilities that conduct benefit-cost analyses for their DR programs do so in the same manner as for their energy conservation programs. These analyses most often follow the California standard practice manual approach that evaluates cost-effectiveness to program participants and utilities, the impact on rates, and the total resource cost or societal perspective. Several other utilities' benefit-cost analysis method is to compare their DR program costs per kilowatt of demand reduced to the costs of a new combustion turbine and/or to spot market electric prices. Several utilities conduct very limited or no DR program benefit-cost analyses.

About half of utilities explicitly include their residential DR programs in their long-term system planning through integrated resource planning (IRP) processes. The other half of utilities surveyed either do not include these programs in their long-term system planning, or do so through certificate of need processes for new generating facilities.

Utilities are satisfied with the billing and payment processes for their DR programs, as well as the ease of signing customers up for the programs and the customer relations aspect of the programs. Utilities are generally either neutral or satisfied with their programs' rates or discounts and their program peak demand reduction estimates. Utilities report interest in modifying their program prices or enabling technology more frequently than any other type of potential program modifications.

Commercial/Industrial Survey Results

This section summarizes the commercial/industrial (C/I) program survey results focusing on:

- The prevalence of different types of C/I DR programs.
- Program eligibility requirements, marketing, and pricing.
- Program participation and performance.
- Planning and analysis activities.

Prevalence of Different Types of Commercial/Industrial DR Programs

Throughout this survey, the focus is on six types of demand response programs that utilities offer to commercial/industrial customers:

1. **Interruptible rates (IRs):** Through these programs, utilities offer customers generally fixed price discounts for reducing their loads to certain levels during peak demand periods. Customers are usually given one to two hours notice before the start of a control period to reduce their loads to the agreed upon levels. Utilities often require multi-year contracts with customers as a condition of program participation, and usually penalize customers if they fail to reduce their loads to the levels specified in their contracts.

2. **Demand "Bidding" or "Buy-back" (DBB):** These programs are similar to interruptible rate programs, but are newer vintage programs that are designed to be more flexible and give customers more options. The rate discounts offered to customers are typically linked to spot market electric prices in some manner. Customer participation and the amount they reduce their loads during peak periods are usually optional.

3. **Direct load control (DLC)**: Through these programs, customers allow their utility to directly control their central air conditioner, water heater, or other types of major electrical equipment. Utilities cycle this equipment on and off during peak demand periods, usually in alternating 15 minute cycles. Utilities usually offer customers some type of rate discount as a participation incentive.

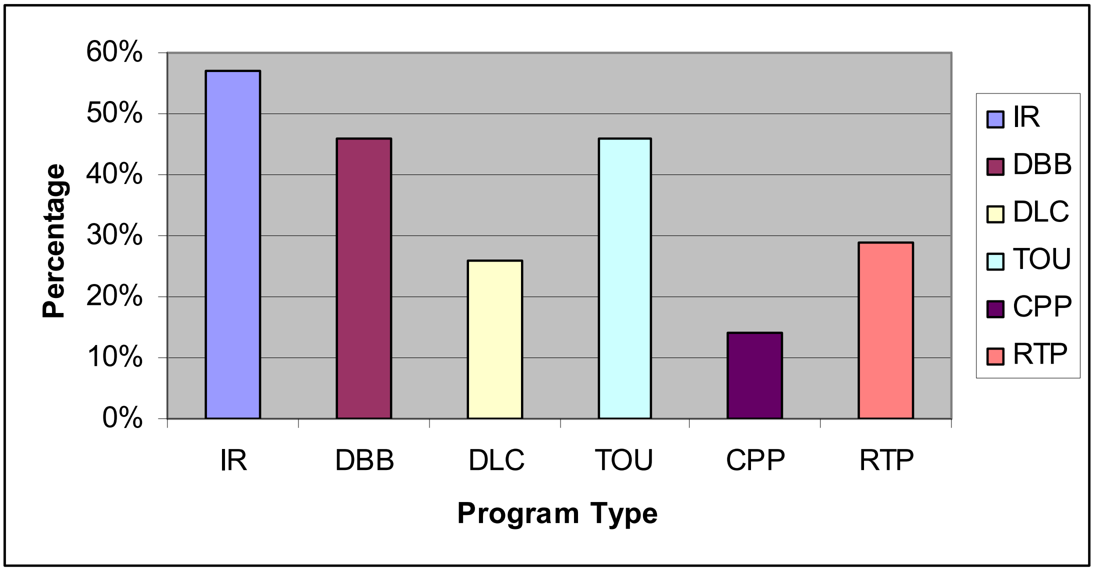
4. **Time-of-use (TOU) rates:** The most common type of TOU rates are "two-part" rates that charge customers a higher "on-peak" price than the standard "flat" utility rate during daytime hours, and a lower "off-peak" price during nighttime hours and weekends. Some utilities offer a "three-part" TOU rate, in which both the on-peak and off-peak periods are shorter than the typical two-part TOU rate periods. In addition, the three-part TOU rate includes a "shoulder" period between the on-peak and off-peak hours, during which time prices are between the on-peak and off-peak prices.

5. **Critical peak pricing (CPP) rates:** These are similar to TOU rates, but add a "critical peak" period and rate. The "critical peak" period is usually 1% or fewer hours throughout the year, during which time the utilities' production or power purchase costs are highest. Electric prices during this period are higher than the regular TOU on-peak prices.

6. **Real-time pricing (RTP):** Prices offered through these programs are tied to some type of hourly pricing benchmark, such as the PJM RTP rate, or are based on the utilities' internally calculated short-term marginal costs.

Almost 90% of the utilities surveyed are conducting at least one type of DR program for C/I customers. The most common C/I DR programs, offered by about half of the utilities surveyed, are interruptible rates, two-part TOU rates, and DBB programs. The next most common types of C/I DR programs, each offered by about one-fourth of the utilities surveyed, are DLC and RTP programs. CPP programs are only offered by about 10% of the utilities surveyed. Figure 5 below shows the percentage of utilities conducting each type of C/I DR program.

Figure 5. Percentages of Utilities Conducting Different Types of C/I DR Programs



Most utilities started their interruptible rates programs in 1990 or earlier, as is the case for TOU rates. DBB and CPP programs all started within the past 5 years. C/I DLC and RTP programs are about evenly divided between those that started since 2000 and those that started in the mid-1990s or earlier.

Program Eligibility Requirements and Marketing

Eligibility requirements for interruptible rate and DBB programs vary widely between utilities. Several utilities require customers to be able to reduce their loads by 5-10 MW or more to be eligible for their programs, while several other utilities only require customers to reduce their loads by 50 kW or more to participate. TOU rates have among the fewest eligibility requirements of any type of C/I DR programs, as about half of the utilities allow any C/I customer to participate. In some states, all customers with demands above a given size such as 200 kW are required to be on a TOU rate. DLC program eligibility criteria are also generally minimal, usually ownership of qualifying equipment such as central air conditioners or electric water heaters that are covered by the utilities' programs. Utilities' CPP programs most often require customers to have average demands of 100 kW to 200 kW to qualify. Some utilities' RTP programs also require such relatively small customer peak demands, but more than half of RTP programs require customers to have minimum peak demands of 1,000 kW or more.

Almost all utilities primarily promote their C/I DR programs through their account reps. Several utilities also use other methods, such as direct mail or their web site.

Program Participation, Performance, and Pricing

The highest total overall C/I DR program participation rates reported by the utilities surveyed were about 20% of their total C/I customer population, which was achieved by about 8% of the utilities reporting. This overall DR participation rate is calculated as the total number of C/I customers participating in a utility's DR programs divided by their total number of C/I customers. About 25% of the utilities report that 2-9% of their customers participate in at least one of their DR programs. The largest group of utilities, about 67% of the total reporting, have overall rates of C/I customer participation in their DR programs of 1% or less.

The utilities in the highest customer participation group have large numbers of participating customers in their C/I DLC programs, which these companies have been operating for 10 years or more. However, these companies also have at least 3% or more of their customers participating in at least one other type of DR program as well. The utilities in the medium participation group generally have the largest numbers of customers participating in their TOU rates programs, often due to state requirements that customers with demands of 100 kW-500 kW or more enroll in the utilities' TOU rates.

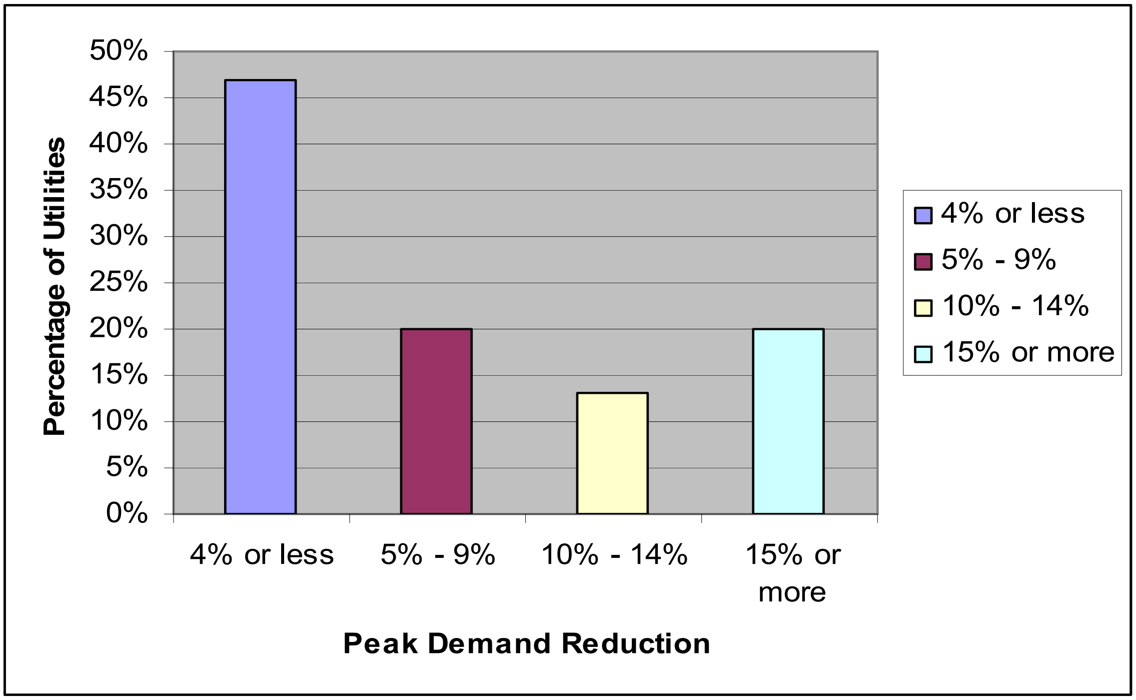
About 80% of the utilities surveyed were able to provide peak demand reduction impact estimates for their C/I DR programs, as well as information on their system peak demands. Utilities were also asked to provide the percentage of their system peak demands that are attributable to their C/I customers, which most were able to do. The data provided by the utilities was checked for reasonableness, but generally this data could not be independently verified, given the limited scope of this project.

Interruptible rate programs provide the largest demand reduction impacts for three-fourths of the utilities surveyed. About 20% of the utilities surveyed reported program impacts that amount to 15% or more of their C/I peak demands. However, most of these utilities report that the majority of their IR demand reduction impacts come from steel plants, which comprise a significant portion of these utilities' C/I peak demands.

An additional 13% of utilities surveyed are able to reduce their C/I peak demands by 10-14% through their IR programs. These utilities have a broader base of program participation than most of the utilities with the largest program impacts.

By contrast, the largest group of utilities surveyed, about half of those providing data, can realize peak demand reductions of 4% or less of their C/I peak demands from their interruptible rate programs. The median IR program impact as a percentage of C/I peak demand for the utilities surveyed was 6%, while the corresponding mean was 8%. IR program impacts as a percentage of C/I peak demand for the utilities surveyed are shown in Figure 6 below.

Figure 6. IR Program Demand Reduction Impacts, Percentage of Utilities' C/I Peak Demands



The most common characteristic of the top-performing IR programs was long program operating histories. The mean length of program operation for these programs is 24 years, and varied between 14 and 37 years.

The number of customers participating in the surveyed utilities' IR programs varied widely, but the highest participation rate reported was about 2% of the utilities' total number of C/I customers. The somewhat low participation rates are primarily due to the utilities' IR program eligibility requirements. Almost all utilities surveyed limit program eligibility to the utilities' larger customers. At the high end, a few utilities require participants to have a minimum peak demand of 5 MW or more, which has limited participation to 10-20 customers even for some of the top-performing programs. On the low end, several utilities allow customers who can reduce their peak demands by as little as 50 kW to participate in their IR programs. These utilities have hundreds or thousands of program participants. The median number of IR program participants for the utilities surveyed is 20, while the mean number of program participants is 212.

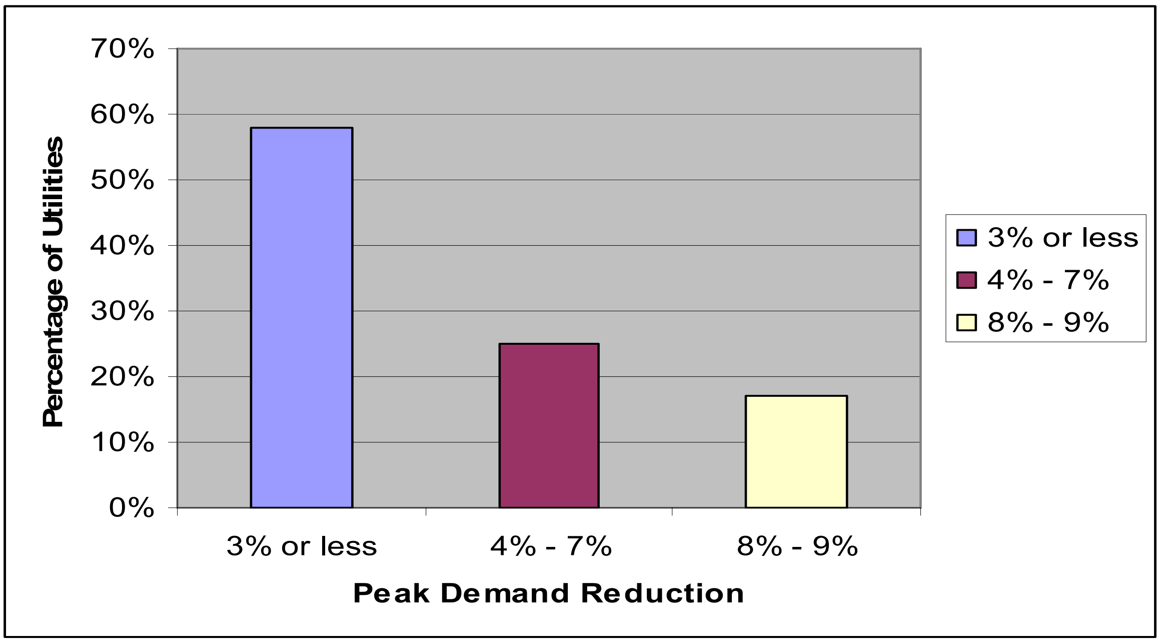
Given the wide variation in program eligibility requirements, there was also a wide variation in program impacts per participating customer. Program impact per participating customer varied from 187 kW/customer for the utility with the largest number of program participants, up to 26,000 kW/customer for one of the utilities that restricts program eligibility to its largest customers.

DBB programs are estimated to provide the largest peak demand impacts for about one-fourth of the utilities surveyed, and several additional utilities also estimate significant demand reduction impacts from their DBB programs. The top-performing programs have impacts that amount to 8-9% of utilities' C/I peak demands. Utilities achieved the reported magnitude of impacts several years ago when spot market electric prices were higher than they have been in recent years.

It should also be noted that most of the utilities conducting DBB programs have not used them much or at all in the past several years given the low spot market electric prices of this time. So DBB program impacts are more uncertain than those for other DR programs that have been used more regularly. Since the load reduction incentives that utilities offer customers through DBB programs are usually tied to spot market electric prices, high spot market electric prices are needed to achieve the demand impacts reported by the utilities.

The top-performing programs are run by 17% of the surveyed utilities that conduct such programs. By contrast, almost 60% of the utilities surveyed that are conducting DBB programs report demand reduction impacts of 3% of their C/I peak demands or less. The mean and median program impacts are 3% of the surveyed utilities' C/I peak demands. The DBB program impacts as a percentage of the utilities' C/I peak demands are shown in Figure 7 below.

Figure 7. Demand-Bid or Buyback (DBB) Program Impacts, Percentage of Utilities' C/I Peak Demands



The largest impact DBB programs have few common characteristics, other than having less than one-tenth of one percent of their C/I customers participating in the programs. It is interesting to note that all of these utilities achieve larger DR impacts from their IR programs than they do from their DBB programs. Since DBB programs are of relatively recent vintage, the oldest having been introduced in 1998, utilities may achieve larger impacts from these programs in the future, especially if the high spot market electric prices that gave rise to DBB programs return on a regular basis.

C/I DLC programs provide significant demand reduction impacts for one-fourth of the utilities surveyed, but these programs did not provide the largest demand reductions for any of the utilities surveyed. Only one utility surveyed, Otter Tail Power Company, reported DLC program impacts that were larger than 1% of their C/I peak demands. Otter Tail's DLC program impacts total about 9% of their C/I peak demand. Otter Tail operates several C/I DLC programs, as they do for their residential customers, but about two-thirds of their total DLC program impacts come from their controllable space heating program. Otter Tail has been conducting its C/I DLC programs for 25 to 60 years, and currently has almost 20% of its C/I customers participating in its C/I DLC programs.

Utilities reported very limited demand reduction estimates for TOU, CPP, and RTP rate programs. Only one utility surveyed, Georgia Power, reported demand reduction impacts from these programs that were greater than 1% of the utilities' C/I peak demands. Georgia Power offers two related RTP programs to its customers. Their total combined RTP peak reduction impacts are approximately 8% of the company's C/I peak demand. Other utilities that the project team was not able to survey as part of this project also report significant program impacts from RTP programs[c].

Georgia Power's success with its RTP programs illustrates what is possible to achieve through these types of programs. However, what is not yet clear is the replicability of its success at other utilities. The project team will collect additional information on other utilities' experience with these programs in the near future to better address this issue.

Utility C/I DR Planning and Analysis

About one-fourth of the utilities conducting C/I DR programs have made long-term market potential estimates for their programs. None of these studies were publicly available and therefore could not be reviewed in depth. These utilities reported using a variety of methods to develop such estimates, including:

- Based on in-depth program evaluations.
- Making future projections based on their recent program experience.
- Analyzing the results of C/I customer surveys.

For conducting benefit-cost analyses of their DR programs, utilities are divided approximately evenly between those that do so in the same manner as for their energy conservation programs, those that primarily compare their DR program costs per kilowatt of demand reduced to the costs of a new combustion turbine and/or to spot market electric prices, and those that conduct very limited or no program benefit-cost analyses.

About half of utilities explicitly include their C/I DR programs in their long-term system planning through integrated resource planning (IRP) processes. The other half of utilities surveyed are evenly divided between those that do not include these programs in their long-term system planning, and those that do so through certificate of need processes for new generating facilities.

Utilities are satisfied with the customer relations aspects of their DR programs and their billing and payment processes for them, as well as the ease of signing customers up for the programs. Utilities are on average neutral about their programs' rates or discounts and their program peak demand reduction estimates. Utilities report interest in modifying their program prices or enabling technology more frequently than any other type of potential program modifications.

Summary and Conclusions

The primary purposes of this survey are to document the "state of the practice" for DR programs in North America, and to develop simple market potential benchmarks for various types of DR programs. Survey findings were more insightful for some types of programs than for others:

---

[c] See, for example, Goldman et al, "A Survey of Utility Experience with Real Time Pricing", Lawrence Berkeley National Laboratory, December 2004.

- Several utilities that have been conducting residential DLC programs for 10 or more years have enrolled 20% or more of their customers, and achieved peak demand reductions of slightly more than 10% of their residential peak demands.

- Several utilities that have conducted C/I interruptible rate programs for a decade or more can reduce their C/I peak demands by 10% or more through these programs. Utilities rarely have more than 2% of their C/I customers participating in interruptible rate programs, and often much smaller percentages of their customers participating. A subset of these utilities with significant steel plant loads can reduce their C/I peak demands by about 20% through these programs.

- Participation rates and peak demand impacts for other types of residential and C/I DR programs (TOU, CPP, and RTP rates and DBB programs) are generally low, with several exceptions. CPP and RTP rates and DBB programs have only been introduced to most utility customers in the last five to seven years or less, so insufficient operating experience with these programs have been established to develop market potential benchmarks for them. Experience to date with TOU rates either indicates that they have generally limited market potential as voluntary programs, or that new program designs or marketing approaches are needed to achieve significant market impacts.