BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

Application of Potomac Electric Power	**)**	
Company For Adjustments to Its Retail	**)**	**Case No. 9418**
Rates for the Distribution of Electric	**)**	
Energy	**)**	

SURREBUTTAL TESTIMONY OF
PAUL CHERNICK
RESOURCE INSIGHT, INC.

ON BEHALF OF THE OFFICE OF PEOPLES COUNSEL

SEPTEMBER 1, 2016

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Q: Are you the same Paul Chernick who filed direct and rebuttal testimony in this proceeding?

A: Yes.

Q: What is the subject of your surrebuttal testimony?

A: In this testimony, I respond to the rebuttal testimony of Pepco witnesses Karen Lefkowitz, Mario Giovannini and Ahmad Faruqui.

I. Responses to Lefkowitz Rebuttal

Q: To what issues in Ms. Lefkowitz's rebuttal do you respond?

A: Ms. Lefkowitz (Rebuttal at A74 at p. 41) attempts to defend her error in annualizing the T&D avoided costs.[1]

Q: What is Ms. Lefkowitz's position regarding her treatment of annual T&D costs?

A: Ms. Lefkowitz says that:

> Because the avoidance of transmission and distribution costs consists of the deferral or avoidance of new equipment/facilities for a period of time rather than a single project for the duration of the cost effectiveness period, it is necessary to apply an inflation rate to account for the increasing costs of deferred transmission and distribution projects over time. (Lefkowitz Rebuttal at p. 41)

In other words, her model of avoided T&D costs is as follows:

[1] She also criticizes my characterization of the magnitude of avoided costs that she reports (Lefkowitz rebuttal at A75 at p. 42). She simply misread my testimony; my point was that her analysis assumed that large projects had already been deferred, even though Pepco was unable to identify any projects deferred by the AMI programs.

- Project A would have been required in 2013, but is not needed in that year due to the load reduction.
- In 2014, Project A is built, but Project B is deferred, including another year's inflation.
- In 2015, Project B is needed, but Project C is deferred, with yet more inflation.
- This pattern repeats through at least 2023.

Ms. Lefkowitz's interpretation of avoided T&D costs is shown in Table 1.[2] The total savings are 9.9% of the cost of the first avoided project, rising at the 2.1% inflation rate.

Table 1: Pepco Annualization of Avoided T&D Cost (in thousands)

	Project	2013	2014	2015	2016
Avoided investment	Project A	$600	($600)		
Annual savings			$59.4	$0.0	
Avoided investment	Project B		$612.6	($612.6)	
Annual savings				$60.6	$0.0
Avoided investment	Project C			$625.5	($625.5)
Annual savings					$61.9
Total Savings	A+B+C		$59.4	$60.6	$61.9

Q: Is Ms. Lefkowitz's view realistic?

A: No. Ms. Lefkowitz ignores the inflation in the cost of deferred projects, when they are eventually built. Table 2 corrects this error, adding the inflation rate to the deferred cost and recognizing that the carrying cost of the deferred, inflated project will be higher than the carrying cost of the original project. Table 2 shows that this effect offsets the inflation in the new projects deferred in later years.

[2] For convenience, I assumed that each deferral lasts one year and that the deferred projects all have the same cost in constant dollars. Deferred T&D costs are lumpy and uneven, but this example puts Ms. Lefkowitz's assumptions in the best possible light.

Table 2: Realistic Treatment of Avoided T&D (in thousands)

	Project	2013	2014	2015	2016
Avoided investment	Project A	$600	($612.6)		
Annual savings			$59.4	($1.2)	($1.2)
Avoided investment	Project B		$612.6	($625.5)	
Annual savings				$60.6	($1.3)
Avoided investment	Project C			$625.5	($638.6)
Annual savings					$61.9
Savings	A+B+C		$59.4	$59.4	$59.4
Pepco Overstatement			—	$1.2	$2.5

In this example, the error starts at $1.2 million in the first year, rises to $2.5 million in the second year, and would continue to rise, to $10.7 million in 2023, totaling over $59 million.

Q: Are there any other problems with Ms. Lefkowitz's approach?

A: Yes. She ignores the effect of the end of the T&D deferrals in 2024, when the capacity avoided through 2023 would need to be built. In the example in Table 1 and Table 2, the replacement equipment would cost $739 million in 2024.

These errors result from her using the nominally-levelized avoided costs, rather than the real-levelized avoided costs that are standard practice in valuing deferral of investments.

II. Responses to Giovannini Rebuttal

Q: To what issues in Mr. Giovannini's rebuttal do you respond?

A: Mr. Giovannini responds to about a dozen of my corrections in Pepco's estimates of PJM market benefits.

Q: Please describe the errors in Mr. Giovannini's rebuttal that require only brief responses.

A: I describe each of Mr. Giovannini's claims below, with a brief response to each. I identify Mr. Giovannini's points using the numbering of his answers.[3]

A5: Mr. Giovannini expects "that PJM's load forecasts for Delivery Year 2020/21 and beyond will reflect the demand reduction capability of the dynamic pricing program due to the full scale pre-existing operation of the program since the summer of 2013."[4] Mr. Giovannini is free to expect whatever he wants, but the PJM load forecasts recognize only a couple percent of the dynamic pricing (DP) load reductions, as I demonstrated in my direct (Section V.B and VI.B.1) and rebuttal (12–13).

A6: Mr. Giovannini opines that a four-year delay between a load reduction and its reflection in the PJM load forecast is "conservative." The four-year lag reflects the fact that, for example, PJM used data through 2015 in its 2016 forecast that sets capacity obligations for 2019; the first potential effect of a load reduction in 2015 is on capacity obligations for 2019. Mr. Giovannini provides no evidence that the 2015 load reductions could affect obligations for any year before 2019.[5]

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[3] Mr. Giovannini does not identify the sections of my testimony to which he is responding, but I believe that I have determined what he is referring to.

[4] Mr. Giovannini supports his assertion by noting that the "U. S. Supreme Court issued Decision No.14-841 on January 25, 2016, permitted continuing DR participation in the PJM wholesale energy market." (fn 1) This fact is irrelevant to PJM's forecasting methodology, about which Mr. Giovannini is speculating in A5.

[5] Mr. Giovannini indicates that the savings claims that Pepco filed in Case No. 9155 may have been less realistic than those in this proceeding, including benefits before they could possibly been reflected in PJM's capacity obligations.

A7: Mr. Giovannini criticizes me for saying that “Pepco has claimed an equal percentage reduction over all hours for the CVR Program.” While that statement applies only to the energy computation, and excludes a few summer peak hours, it has no effect on any of my corrections.

A8: Mr. Giovannini repeats his agreement that the AMI programs produce capacity benefits on the demand side “only to the extent that they reduce PJM's forecast of peak load.”[6] He does not explain why he continues to claim benefits exceeding the extent to which the programs reduce PJM's forecast of peak load.

A9: Mr. Giovannini insists that Pepco’s error of inflating 2018/19 and 2019/20 capacity prices, as though they were in 2016 dollars, is reasonable.[7] Capacity suppliers will be paid in 2019 and 2020 dollars for delivering their 2019/20 capacity; there is no excuse for inflating that price by 11% for the last seven months of 2020. The same is true for Pepco’s decision to escalate the actual posted prices for 2019 by 8%.

A10: Mr. Giovannini attaches a paper I co-authored on price mitigation, apparently because he thinks he caught me in some inconsistency. I not only support the idea that price mitigation is a customer benefit in

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[6] Mr. Giovannini seems to believe that he is clarifying something, but both of us were referring to demand reductions, rather than cleared capacity.

[7] In addition, he does not explain why Pepco looked back to 2018/19 prices at all, rather than using actual prices in 2019/20 to start its forecasts. The 2018/19 capacity performance prices were higher than the 2019/20 prices, even though 2019/20 required more capacity performance. The opportunistic inclusion of 2018/19 prices increases Pepco’s price forecast by over 30%.

restructured electric market; I have been one of the leading proponents of accounting for those benefits, where they occur. In my direct, I said that “the categories of program benefits that Pepco claims from the AMI programs [are] all costs that can be avoided by some types of load reductions…The questions I address are whether Pepco has properly estimated the benefits…” (Chernick Direct at 6).

A11: Mr. Giovannini’s claims that the “DP Program does not increase the PJM capacity requirement for the Pepco Zone” demonstrate ignorance of PJM’s capacity market. As I show in my direct, adding low-priced supply to the capacity auction reduces the price but increases the amount of capacity purchased.[8] That is the objective of PJM’s Variable Resource Requirement (VRR) curve; as the price falls, more capacity is purchased. Table 3 shows PJM’s sensitivity-analysis results for the 2018/19 price and cleared capacity, with the actual bids, with 3,000 fewer MW of low-cost resources and with 3,000 additional MW. Removing resources raises the price and reduces cleared capacity, while adding resources reduces the price and increases cleared capacity.

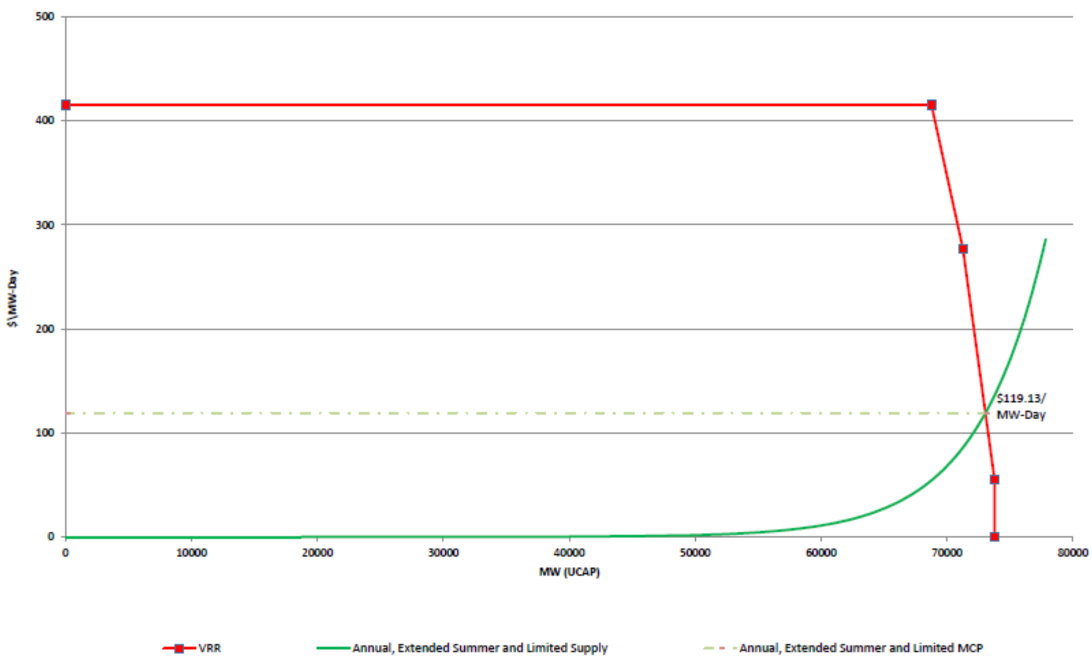
[8] Figure 3 of my direct shows how shifting the supply curve to the right reduces the RPM price but increases capacity purchases; such as the shift from S_1D_1 to S_2D_1, with the same demand curve but more low-cost supply. Figures 4 and 5 in my direct show PJM’s own reports on the results for two BRAs in which the DP program would have cleared at a lower price than Annual and Extended Summer resources. In each case, adding Limited capacity resources, such as the DP program, would reduce the clearing price for Limited resources but increase the capacity purchased.

Table 3: PJM BRA Sensitivity Results, RTO 2018/19

Auction Results	Actual	-3,000 MW in MAAC	Δ	+3,000 MW in MAAC	Δ
CP Price	$164.77	$179.33	$14.56	$150.00	-$14.77
Base Capacity Price	$149.98	$155.31	$5.33	$130.00	-$19.98
Cleared CP MW	140,600.4	140,071.0	-529.4	141,136.9	536.5
Cleared Base MW	26,236.5	26,236.5	0.0	26,236.5	0.0
Total Cleared MW	166,836.9	166,307.5	-529.4	167,373.4	536.5

Figure 1 provides a graph that PJM provided, showing the same effect graphically.[9] Moving the supply curve to the right would reduce the market-clearing price, but increase the capacity purchased.

Figure 1: 2016/2017 Base Residual Auction MAAC Supply Curve



A12: Mr. Giovannini responds to my statement “that DP load reductions not bid into the BRA have minimal effects on market prices” by discussing the fact that Pepco assumes only four years of effects. He failed to respond to my evidence that DP-style programs (with load

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[9] Supply Curves for Base Residual Auction, http://www.pjm.com/markets-and-operations/rpm.aspx for 2016/17.

reductions on just a few days each summer) have minimal effect on PJM's forecasts in any year, and thus cannot substantially affect market prices.

A13: Mr. Giovannini responds to my actual evidence regarding the relationship between increased capacity (or load reductions) and capacity prices with a cite to a Commission decision. He offers no substantive defense on this matter of fact, merely policy.

A15: Mr. Giovannini asserts that "Pepco DR programs reduce capacity prices for all supply-side resources because they increase the available supply-side resources above what they previously were, or if not in the capacity market, demand is reduced. In the absence of the Pepco DR resources, capacity prices would have been higher for all supply resources, including OPC Witness Chernick's premium supply-side resources. This is the manner that competitive markets function."[10] This may be the way that some competitive markets function, but not the PJM capacity market. Mr. Giovannini seems to be unfamiliar with the PJM capacity market, and even with the PJM data presented in my direct testimony (at 40–43). Table 9 in my direct shows PJM's conclusion that DP-like Limited resources in SWMAAC decreased RTO prices by about ⅕ as much as the same amount of generation and increased prices in SWMAAC and EMAAC.

[10] Just to be clear, I did not invent PJM's disaggregation of capacity into Annual, Extended Summer and Limited resources in earlier years, or Capacity Performance, Base Generation, and Base DR in later years. I used the term "premium" as shorthand for "Annual and Extended Summer or Capacity Performance and Base Generation, depending on the year."

A16: Mr. Giovannini claims that "Pepco has relied upon actual PJM energy market revenue through the summer of 2015" for its $200/MWh forecast of energy revenues from the DP program. The 2015 revenue from the DP program was $38/MWh, and the average over 2013–2015 was $57/MWh. He offers no reconciliation between the historic data and his $200/MWh forecast, other than the observation that shortage events could result in prices over $1,000/MWh in some hours.[11]

A17: Mr. Giovannini responds to my demonstration that Pepco ignored the effect of out-of-state load on Maryland energy prices by complaining that "there is a practical limitation to the quantity of data that is readily accessible for analysis purposes" and asserting that Pepco's estimate of the price effect was "conservative." In fact, hourly load by PJM zone is readily available on the PJM web site, and Pepco's assumption that loads in other states have no effect on Maryland prices is a gross overstatement, the opposite of a "conservative" estimate.[12] BGE, whom Mr. Giovannini likes to cite, agreed that my analysis was realistic (Case No. 9406, Pino Rebuttal at 22).

III. Responses to Faruqui Rebuttal

Q: To what issues in Dr. Faruqui's rebuttal do you respond?

[11] No such events have occurred since September 2013, and only four events have occurred since 2008.

[12] Pepco assumed that load in Washington, D.C. has no effect on prices in the Pepco zone, even though D.C. is in the Pepco zone, and that Delaware load has no effect on Delmarva zonal price, even though Delaware is in the Delmarva zone.

A: I respond to Dr. Faruqui's rebuttal on the treatment of the DP program incentives, and his claim that Pepco's biased analysis of DP load reductions is accurate.

A. The DP Incentives Reflect Real Participant Costs

Q: What is Dr. Faruqui's dispute with your testimony on the costs of the DP program incentives?

A: Dr. Faruqui claims that I contradict my argument that the DP rebates are costs "by accepting EE program incentives as transfer payments and rejecting DP program incentives as transfer payments." In order to reach this conclusion, he somehow interprets my direct testimony to mean the opposite of my intent.

My direct explained the difference between the incentives paid to customers in some EE programs and the bill credits paid to "participants" in the DP program. Since Dr. Faruqui claims to have not understood my testimony (perhaps because he does not understand the rationale for EE programs), I will repeat it here.

In such Pepco EE programs as the Appliance Rebate Program and the HVAC Efficiency Program, incentives are paid to customers to offset out-of-pocket costs (such as the incremental cost of a more efficient air conditioner), which are counted as costs in the cost-benefit analysis. In the process, the payment reduces or eliminates the customer's potential problems with financing (if the utility is paying the incremental costs, the participant does not need to seek financing), decision-making (the utility program makes most of the decisions, such as which models are eligible), regret (the participant does not face hard questions from a boss or spouse if the expected savings are not apparent), selecting contractors (which are usually trained and vetted by the EE program), and reviewing savings claims (the participant is not risking much money on the high-efficiency options, so even heavily discounted savings are sufficient to justify the participant's modest investment). The EE incentives do not pay the participants to accept a lower quality electricity service and bear the resulting burdens. The energy efficiency (EE) programs are designed to eliminate the customer's incremental costs.[13]

In contrast, the bill credit in the DP program does not eliminate any market barriers; the explicit purpose of the credit is to pay customers to accept a lower quality electricity service and endure discomfort and inconvenience that they would not experience without the credit. Unlike the EE analysis, Pepco's DP analysis does not include any cost to customers, such as cash participant costs, the cost of timers, or remote controllers or any other expenses the DP participants incur. Unlike EE program design, the DP program design does nothing to reduce the costs to customers of finding and evaluating the equipment, or the inconvenience and discomfort of participating.

Q: Has the Commission taken a position on whether program evaluation should reflect participant costs?

A: Yes. In Order 87082, the Commission directed the use of both the Total Resource Cost (TRC) test and the Societal Cost Test (SCT) (at 6) and found

[13] Some skeptics of EE programs assume that these costs cannot be eliminated and that EE incentives are payments to induce customers to accept burdens and reduced quality of life. I do not believe that Dr. Faruqui is taking that radical position.

that "the TRC test includes all participant costs" (at 15).[14] The Commission explicitly ordered the inclusion of non-monetary comfort benefits "in the TRC test and the SCT." (ibid)[15] Given the Commission's requirement that costs and benefits be symmetrical, including a comfort benefit for EE programs that increase comfort would require inclusion of discomfort costs for the DP programs which decrease customer comfort.

The only measure that we have of the monetary and non-monetary costs of participating in the DP program is the bill credit that Pepco has determined it must pay customers to bear those costs.

Q: Has Dr. Faruqui consistently rejected the treatment of incentives for load-management programs like the DP program?

A: No. In a January 2015 report prepared for Enernoc, Dr. Faruqui said that incentives should be included in demand-response program evaluation:

> In any valuation of a DR resource, the benefits should be weighed against the cost of the program. Examples of program costs would include equipment, marketing and customer outreach, participation incentive payments, and general program administration. (Hledik, R., and Faruqui, A., Valuing Demand Response: International Best Practices, Case Studies, and Applications, January 2015, attached as Exhibit PLC-S-1, at 3)

The category of "participation incentive payments" would include the DP bill credits.

[14] While the Commission did not explicitly require that "all participant costs" be included in the SCT, that test usually includes a broader group of costs and benefits than the TRC, not a narrow group.

[15] The Commission noted that "Pepco also advocated for the inclusion of known and quantifiable NEBs." (Order 87082 at 5)

A year later, Dr. Faruqui and his Brattle colleagues explained this point in more detail in a report for Portland General Electric:

> Treatment of participant incentives as a cost was given close consideration in the study. There is not a standard approach for treating incentives when assessing the cost-effectiveness of DR programs. In some states, incentive payments are simply considered a transfer payment from utilities (or other program administrators) to participants, and therefore are not counted as a cost from a societal perspective. Others suggest the incentive payment is a rough approximation of the "hassle factor" experienced by participants in the program (e.g., reduced control over their thermostat during DR events), and should be included as a cost.
>
> While there is some merit to the latter argument–that customers may experience a degree of inconvenience or other transaction costs when participating in DR programs–the cost of that inconvenience is overstated if it is assumed to equal the full value of the incentive payment. If that were the case, then no customer would be better off by participating in the DR program. For example, it would be unrealistic to assume that an industrial facility would participate in a curtailable tariff program if the cost of reducing operations during DR events (e.g., reduction in output) exactly equaled the incentive payment for participating. In reality, customers participate in DR programs because they derive some incremental value from that participation. Further, in some DR programs customers experience very little inconvenience. Some A/C DLC programs, for instance, can pre-cool the home and manage the thermostat in a way that few customers report even being aware that a DR event had occurred, let alone a loss of comfort.
>
> Given the uncertainty around this assumption, this study counts half of the incentive payment as a cost in the cost-effectiveness analysis.[16] (Hledik, R., and Faruqui, A., Bressan, L., Demand Response Market Research: Portland General Electric, 2016 to 2035, January 2016, attached as Exhibit PLC-S-2, at 12)

[16] The Brattle team also evaluated programs with "sensitivities" in which 100% and 0% of the incentives were treated as costs.

Q: What position did Dr. Faruqui take on this issue in the BGE proceeding, Case 9406?

A: Dr. Faruqui entirely reversed his position. Just three months after the Portland General Electric (PGE) report, his March 2016 rebuttal for BGE claimed that OPC's inclusion of rebate costs for BGE's peak-time-rebate program was a "plain error," because:

> The bill credits that participants in the…program receive in return for reducing load on ESDs do not result in an incremental cost or benefit to the Smart Grid Initiative. Rather, bill credits are simply transfer payments from all customers to participants. Therefore, the inclusion of the bill credits as a "cost" in the cost-effectiveness analysis by OPC makes no economic sense. (Faruqui Rebuttal, Case 9406, at p. 10)

In January 2016, Dr. Faruqui said that inclusion of the bill credits as a cost of programs that impose inconvenience was required by fundamental economic principles, as explained in Exhibit PLC-S-2 (at pdf p. 121–122, which are pages 142–143 of Appendix C: Cost-Effectiveness Adjustments); in March, he said that inclusion "makes no economic sense."

Q: Based on Dr. Faruqui's report to PGE, what proportion of the DP program bill credits should he have treated as a cost in this proceeding?

A: More than half the cost, but less than 100%. In the PGE report, Dr. Faruqui and his team treat half of the incentive payment as a cost for all demand-response programs, both direct load control (such as Pepco's EWR), in which they believe "customers experience very little inconvenience" and "AMI-enabled rate options" including the "Peak Time Rebate (PTR)" programs "being offered by BGE and Pepco to residential customers in Maryland" (Exhibit PLC-S-2 at 4–5). The DP program would fall in their high-inconvenience category; if half the incentive payment is a reasonable estimate of participant costs averaged over a variety of programs, the participant costs for the DP program would be more than half the bill credit.

Q: What do you conclude from the differences in the treatment of incentives between Dr. Faruqui's report for PGE and his testimony on behalf of Pepco?

A: Dr. Faruqui's abrupt, unexplained and frankly illogical reversal on this point suggests that little weight should be given to his current opinion.

B. Pepco Biased Its Estimate of DP Load Reductions

Q: Does Dr. Faruqui accurately describe the DP program analysis?

A: Not really. In his Answer 14 (Rebuttal at 5–6), Dr. Faruqui makes a series of claims, which I deal with in order:

- "Pepco chose to select a 'participant group' to gauge the effectiveness of the load-reducing capability of the program." Pepco did not select a group to participate in the program, nor did it engage in any analysis to determine whether customers who happened to have lower load on peak energy savings credit (PESC) days were participating in any meaningful sense.
- "Viewing the program from a participant perspective will most effectively capture the real impact of the program." This sentence is meaningless jargon, so long as it depends on a definition of "participant" that has little connection to actual behavior.
- "The program's success should be characterized as how effective it is in incenting customers to achieve a reduction in their electric consumption

behavior." I agree. Dr. Faruqui and Pepco have not measured the effectiveness of the program in incenting customers.

- "Therefore, it would be misleading to characterize the load-reducing capability of the program with the inclusion of non-participating customers….The non-participating customers are not engaged in the program, and therefore should not affect how the load-reducing success of the program is characterized." The fact is that many of the so-called participants are not engaged, but just happen to have lower usage on PESC days. Pepco makes no effort to account for these customers. Dr. Faruqui's position, that a corporation can count the results it likes and ignore the results it does not like, would be unacceptable in advertising, drug trials, environmental compliance, and almost every other context.

Q: Does Dr. Faruqui acknowledge that the "participants" include customers who did not respond to the DP program?

A: Interestingly, he does admit that the participants include load reductions unrelated to the program:

> Pepco's CBL approach identifies three types of customers as engaged in the program:
>
> i) customers who responded to the DP signal and intentionally reduced their load on the event day;
>
> ii) customers who did not respond to the DP signal but …reduce[d] their load on the event day due to reasons unrelated to the event day (i.e., being on vacation on the event days);
>
> iii) customers who did not respond to the DP signal but [had lower] load on the event day due [to] higher-than-usual consumption profiles on the baseline days (i.e., visiting in-laws during the baseline period)." (Faruqui Rebuttal A15, formatted for clarity).

Q: So does Dr. Faruqui admit that Pepco's reported results are overstated?

A: No. He claims that the second-stage analysis, extending the baseline to the entire summer, with a weather correction, would minimize "the influence of the random load variations" (Dr. Faruqui Rebuttal at 8, line 4) and "dampen the average load impact that is derived from the panel regression model" (ibid at lines 12-13).

Q: Is he correct that the second-stage analysis "minimizes" and "dampens" the error in Pepco's initial identification of participants in the DP?

A: If by "minimizes" and "dampens" he means "makes somewhat smaller," he is correct that using a larger baseline would catch some of Pepco's errors. On the other hand, the larger baseline may also increase the claimed savings from some customers in Dr. Faruqui's categories (ii) and (iii).[17]

Unfortunately, the second-stage regression cannot identify customers in categories (ii) and (iii), since the regression only accounts for weather.[18] Thus, the second-stage analysis does not "minimize" the error in the sense of making it vanishingly small or "dampen" the error in the sense of eliminating it. Even Ms. Lefkowitz recognizes that the DP program has free riders; that Pepco "has not performed" any analysis of free-ridership and the panel regression is limited to providing "some insight into customer behavior".[19] Pepco and Dr. Faruqui have no idea how badly they have overestimated the DP savings by selecting a biased sample of the customer base.

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[17] The weather-normalization may also increase apparent savings.

[18] Pepco Response to OPC DR 3-8 Attachment A, pp. 3–4, attached to my Direct Testimony at PLC-2.

[19] See Pepco Response to OPC DR 12-4(a) and (c), attached as Exhibit PLC-S-3.

Q: Does Dr. Faruqui have any response to your example of a drug company improving its test results by ignoring participants who do not get better?

A: He does. Dr. Faruqui goes off on a tangent, positing a particular experimental design, in which the drug company administers the drug to each subject, and hence knows who is taking their drug. This is a situation analogous to many EE programs, in which the utility knows exactly who is getting incentives and services.

As Dr. Faruqui admits, Pepco has no idea who is taking their medicine in the DP program. In other drug tests, subjects are handed a bottle of pills and are responsible for taking medication over weeks or months. Some will comply and get better, some will not comply and still get better; Dr. Faruqui would treat all those subjects as successes for the treatment.

It may be helpful to imagine the effect of applying Dr. Faruqui's approach to an EE program in which Pepco cannot identify the participants. For example, Pepco could pay retailers to display and discount LED light bulbs, and then claim all weather-adjusted usage reductions by residential customers as being due to the LED program, while ignoring all customers whose usage increased, on the grounds that they are not "engaged participants." I doubt that the Commission would accept that method for EE evaluation, and I hope it will not accept that biased method for DP evaluation.

If Pepco thought that the DP program was actually resulting in load shifts of the magnitude it claims, it could confirm that, by including all customers and eliminating its selection bias.

Q: Dr. Faruqui claims that "deeming customers as participants if they received a positive rebate in at least one…event day" and reporting the results for that group of customers "is conceptually consistent" with your "example." (Dr. Faruqui Rebuttal at 8, lines 22–23). Is that correct?

A: No. I am not aware of any example in which I propose this biased approach.

Q: Has Dr. Faruqui consistently considered the analysis of the DP program to be complete?

A: No. As recently as January 2016, Dr. Faruqui and his coauthors said that the "Opt-out deployments of PTR…being offered by BGE and Pepco to residential customers in Maryland [are] relatively new programs [that] will provide more information in the next few years as their impact evaluations become available." (Exhibit PLC-S-2 at p. 5)

Q: Does this conclude your surrebuttal testimony?

A: Yes.

Valuing Demand Response:

International Best Practices, Case Studies, and Applications

PREPARED FOR

EnerNOC

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THE Brattle GROUP

This report was prepared for EnerNOC. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients. Opinions expressed in this report, as well as any errors or omissions, are the authors' alone. The examples, facts, and requirements summarized in this report represent our interpretations. Nothing herein is intended to provide a legal opinion.

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1. Introduction

1.1. Background and Purpose

Demand response (DR) programs have been utilized around the globe for decades as a cost-effective resource for maintaining a reliable electrical grid. By reducing load during a limited number of hours per year, DR can defer the need for new peaking capacity, reduce peak period energy costs, and lessen transmission and distribution (T&D) infrastructure investment needs, among other benefits.

In the United States, for example, a five percent reduction in peak demand through DR programs could lead to $35 billion in savings over a 20 year period.[1] If anything, this is a conservative estimate. A 2009 study commissioned by the Federal Energy Regulatory Commission (FERC) found that, under certain market conditions, peak demand in the U.S. could be reduced by two to four times this amount, effectively eliminating the need for the equivalent of between 1,000 and 2,500 peaking units.[2]

The benefits of DR are not just limited to U.S. markets – they are applicable internationally. In Europe, the financial benefits of smart grid-enabled DR have been estimated at over 50 billion Euros over a 20 year period.[3] In the Middle East, an assessment of demand-side management potential in Saudi Arabia revealed that DR could significantly reduce the country's dramatically growing capacity needs at a benefit of nearly $2 billion over 10 years.[4] A study of the National Electricity Market in Australia found that reductions in peak demand could provide between $4.3 and $11.8 billion in benefits over the next decade.[5] In the United Kingdom, a recent study found that the financial benefits of DR could amount to over $160 million annually.[6] Globally, it is estimated that annual spending on DR will be over $5.5 billion by 2020, with more than 20 million customers participating in a DR program worldwide.[7]

Policymakers, regulators, and utilities that are considering introducing or expanding their portfolio of DR resources face an essential question: Will the benefits of the new DR program outweigh its costs? An accurate and defensible estimate of the value of DR must be developed in order to provide an answer. At the most basic level, the principles for estimating the value of DR programs are the same regardless of geographical region, regulatory structure, or market design. However, the nuances of the valuation approach will depend on these factors.[8] The purpose of this paper is to discuss best practices for establishing the value of DR while accounting for nuanced differences across a range of market and regulatory structures.

While there are many types of DR benefits, this paper focuses on quantifying the financial benefits that are derived from avoided costs. Our primary focus is on avoided generation capacity costs, as this benefit has driven the majority of the business case for most recent DR programs. That is discussed in Section 2. Section 3 addresses other avoided costs such as reduced peak energy costs, avoided investment in new T&D capacity, and ancillary services benefits. Harder-to-quantify benefits are discussed briefly in Section 4.

The focus of this paper is specifically on quantifying the benefits of DR. In any valuation of a DR resource, the benefits should be weighed against the cost of the program. Examples of program costs would include equipment, marketing and customer outreach, participation incentive payments, and general program administration.[9]

1.2. Defining DR

For the purposes of this paper, we define DR to refer to customer actions that are taken to reduce their metered electricity demand in response to an "event," e.g., a dispatch signal, whether in response to the high price of electricity, the reliability of the grid, or any other request for reduction from a grid operator, utility, or load aggregator. This definition of DR implies the following:

- DR must be "dispatchable." DR is event-based and we do not consider a program to qualify as DR if it entails a permanent (i.e., daily or seasonal) load reduction. This is an obvious distinction between DR and energy efficiency (EE), the latter of which involves technological or behavioral change that is static in nature. This also means that a time-of-use (TOU) rate - in which the retail electricity price is higher during peak hours than during off peak hours on every weekday – is not considered DR because the peak period price does not change dynamically in response to system conditions.

- DR can include behind-the-meter generation. As long as it is dispatchable, our definition of DR includes the use of behind-the-meter generation. One example would be a standby diesel generator or a cogeneration unit at an industrial facility that can also be used to reduce the facility's demand for electricity from the grid during DR activations. Non-dispatchable forms of self-generation, such as rooftop solar panels, however, do not fall within our definition of DR.

- DR can be price-based or reliability based. Our definition of DR includes programs and markets in which activations can stem both from energy prices and system reliability. Pricing programs, such as critical peak pricing (CPP) or real-time pricing (RTP) charge prices that are higher during hours when it is more expensive to generate and deliver electricity, and lower when it is less expensive to do so. Reliability-based programs, including DR participation in wholesale capacity markets, typically provide an incentive payment for automated or behavior-based load reductions – these programs clearly also fall under this definition of DR.

1.3. Recent Examples of DR Performance

To put the specifics of DR valuation into context, consider a few recent cases where DR has provided significant tangible benefits under a range of system conditions.

In most parts of the world, DR is typically utilized during months when temperatures lead to a rise in use of electricity. If temperatures are very high, particularly for several consecutive days, there is a risk that demand for electricity will exceed supply. This was recently observed during the summer of 2013, when a heat wave caused record demand for electricity in parts of the Northeastern U.S. such as the New York and the PJM Interconnection markets (comprising much of the Mid-Atlantic U.S.). In these markets, where DR had already been procured through a centralized wholesale capacity market, the resource provided significant load reductions. Peak demand in New York was reduced by over 1,000 MW in response to reliability concerns. In PJM, the market operator utilized around 1,600 MW of the over 9,000 MW of DR at its disposal.[10] The DR programs that were utilized spanned a range of customer groups, including residential, commercial, and industrial customers.

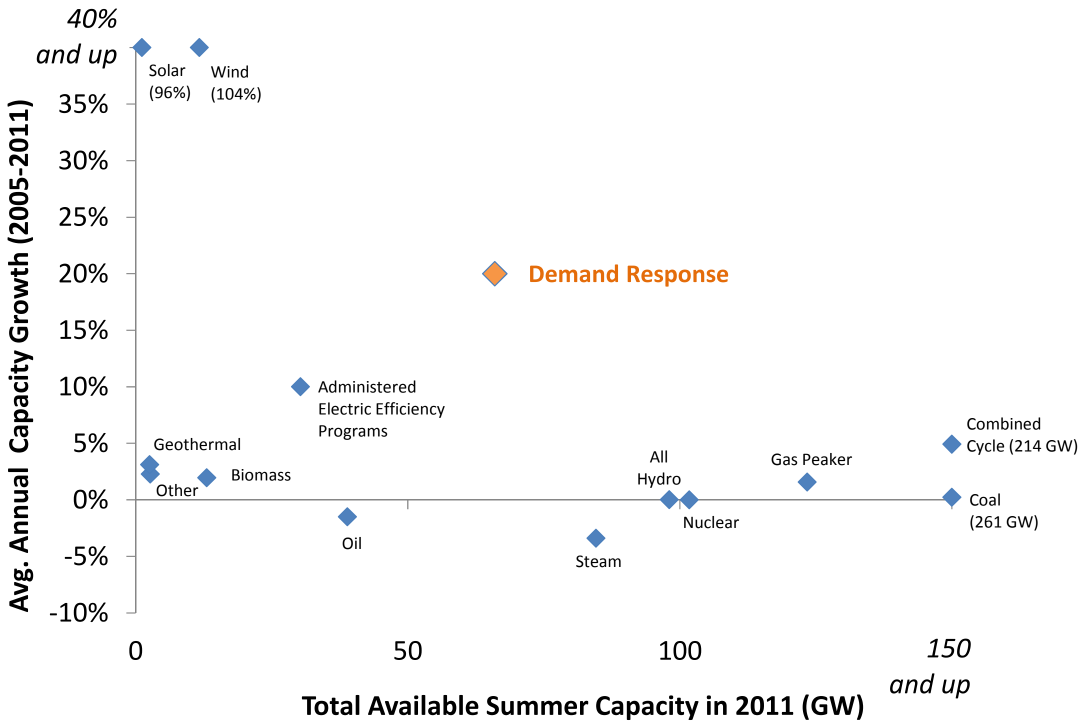
The value of DR is not just limited to hot summer months. The winter of 2013/2014 was one of the coldest in recent memory in parts of North America. Referred to as the "polar vortex," an Arctic cold front dropped temperatures to record lows in the Eastern and Southern U.S. This resulted in a sustained increased need for space heating, driving natural gas and electricity prices through the roof and raising serious concerns about maintaining grid reliability. This was particularly a concern in Texas, where the severe weather not only lead to a spike in demand but also caused outages at two major power plants. In response to these conditions, ERCOT (the grid operator) called on more than 600 MW of DR.[11] Within 45 minutes, the DR resources had reduced load to acceptable levels and the supply and demand balance had been stabilized, avoiding potential rolling brownouts.

Unexpected extreme weather conditions are not the only driver of DR utilization, or local reliability concerns. In 2012, Southern California Edison (SCE) was forced to take its San Onofre Nuclear Generating Station (SONGS) offline due to equipment reliability concerns. This led to the retirement of more than 2,200 MW of generation in a part of the Southern California electricity grid that was significantly transmission constrained. In response to a potential capacity shortage in the region, SCE has ramped up its efforts to procure DR capacity. SCE has announced that of the 2,200 MW that were lost after the retirement, 1,300 MW could be replaced with DR.[12] This highlights not only DR's value as a local resource, but also its potential to provide new capacity on shorter notice than would be required to install a new power plant or build new transmission capacity to the region.

While the three previous examples illustrate the use of DR in response to emergency conditions, it is a low cost resource that also provides economic benefits. In the 2017/2018 PJM capacity auction, for example, it was estimated that bids from DR and energy efficiency reduced total expenditure on capacity by $9.3 billion in the market for that year alone.[13] There has been a trend recently toward greater utilization of DR for reducing energy costs. Many energy markets in the U.S. and Europe have been revised to facilitate competition between DR and traditional supply-side resources. While participation has not been as high as in capacity markets, some U.S. regions like PJM, California, and the southern Midwest have seen up to approximately two percent of peak period energy participation coming from DR resources. Some ancillary services markets have also experienced a substantial amount of DR participation. In PJM, where DR is able to participate in the synchronized reserve market, DR has often come up against the current administratively-set cap of 25 percent of the total requirement, which is now being increased due to the levels of DR successfully participating in the market.[14] ERCOT also has a significant amount of participation in its ancillary services markets through its Load Resources program.[15]

Given the demonstrated value of DR in these examples, it is no surprise that DR has been growing quickly as a resource in the U.S. over the past several years. Next to wind and solar generation, which have been heavily subsidized at the federal and state levels, DR is the fastest growing resource in the country in terms of average growth rate. Between 2005 and 2011, DR has grown by 20 percent per year. Figure 1 summarizes the size and growth of DR relative to other resources.

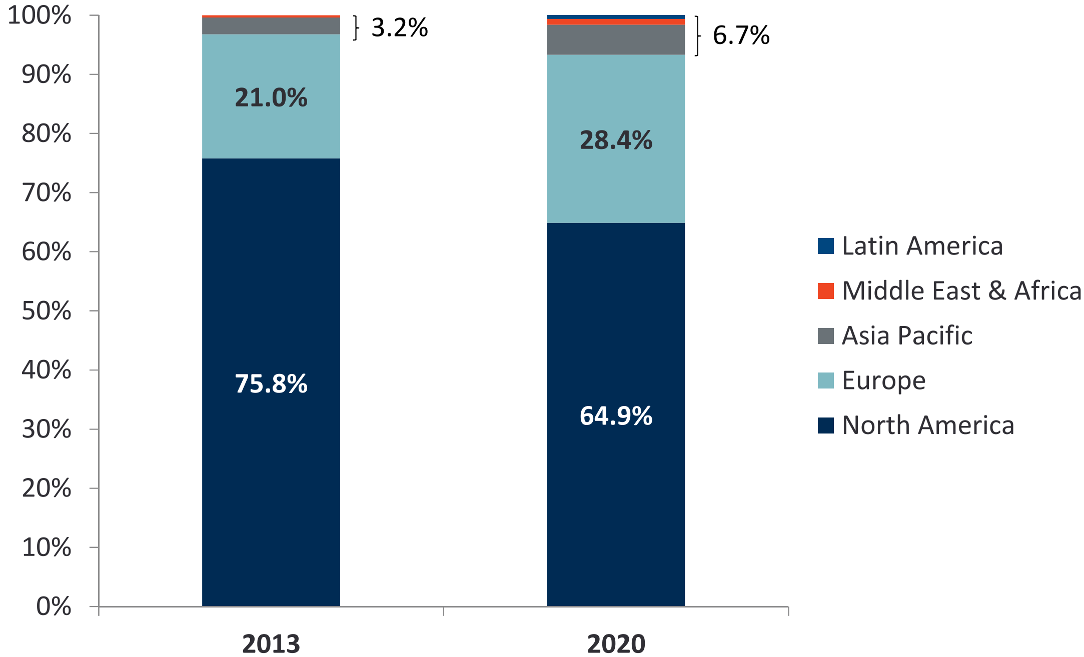
Figure 1: U.S. Available Capacity Resources and Growth in Resources



Notes:
Figure reproduced from Andy Satchwell and Ryan Hledik, "Analytical Frameworks to Incorporate Demand Response in Long Term Resource Planning," *Utilities Policy*, March 2014.
Source of generation capacity data is Ventyx Energy Velocity Database
Demand response data from FERC 2013 Assessment of Advanced Metering and Demand Response
Energy efficiency data based on actual peak reduction estimates from EIA-861
Summer capacity is total for generating units classified as "operating" with commercial online date before January 2012
Assumes 50% peak coincidence for solar and 25% peak coincidence for wind; all other types assume 100% availability for simplicity

This rapid growth in DR in North America is expected to be accompanied by even faster growth in DR in the rest of the world. Whereas North America represents around 75 percent of the worldwide DR market currently, this share is projected by Navigant Research to drop to approximately 65 percent by 2020.[16] Much of the international growth activity is expected to be in the commercial and industrial (C&I) sector, with the Asia Pacific region accounting for nearly 40 percent of all C&I DR participation by 2020. The projected growth in DR adoption outside of North America is illustrated in Figure 2.

Figure 2: Worldwide Share of DR Participation, 2013 and 2020



Source: Navigant Research, "Market Data: Demand Response," 2Q 2013.

2. Avoided Generation Capacity Cost

Avoiding or deferring the need for new generating capacity has long been the single largest source of value provided by DR. Often, this can comprise 80 to 90 percent of the value of a DR resource.[17] Since any electrical grid must have enough capacity available to serve load during the instantaneous time of highest demand (i.e., the coincident system peak), DR resources that are utilized to reduce the system peak lessen the need to invest in new generation capacity.

This basic calculation of the avoided generation capacity value of DR applies regardless of market structure, that is, whether in a traditionally regulated market or a restructured market. The computation requires determining the marginal cost of new capacity (i.e. the cost of serving a one kilowatt increase in system peak demand). In most regions, this is typically an open-cycle combustion turbine (OCCT), also referred to as a peaking unit. Relative to other sources of generation, peaking units have low capital costs and high operating costs, meaning they are cheap to build but expensive to run. For this reason, the units typically sit idle for most hours of the year and are only utilized during top peak load hours. Peaking units are typically the type of capacity avoided by DR because of their similar operational profile.[18]

Modifications to that installed cost of new capacity are then made to account for the energy and ancillary services value that the new generating unit would provide to the grid, as well as considerations for the availability and performance characteristics of the DR program. It is in these modifications that there are nuanced differences in the value calculation between restructured markets and regulated markets.

2.1. In Regulated Markets

In traditionally regulated markets where utilities own generation, transmission, and distribution and serve retail customers, all within a given territory, the utilities are responsible for planning to have enough capacity available to meet system peak demand. This is typically done through a resource planning process that is reviewed and commented upon by the regulator and stakeholders. Resource planning typically involves projecting peak demand over a multi-year period and then running sophisticated optimization models to determine the economically optimal timing and location of new generating capacity that would be needed to meet that peak demand.

While the economic valuation of DR would ideally be integrated into this process, most utilities assess its value outside of their resource planning modeling.[19] This is a two-stage process. They first determine the amount and cost of new generating capacity additions that would be needed to meet peak demand. Then, they use this result to assess the value of a reduction in peak demand attributable to demand response. In detail, this valuation process consists of the following six steps.

Step 1: Identify the marginal cost of capacity. The cost of new capacity will typically be based on quotes or bids from manufacturers. There are also often public sources of cost estimates that can be used as a proxy for a more region-specific estimate. Recently in the U.S., where gas-fired combustion turbines are often the marginal unit, the overnight cost of a conventional CT has ranged anywhere from around $700 to over $1,400 per kilowatt of installed capacity, depending on location and the type of technology.[20]

Step 2: Levelize the installation cost as an annual value. To properly account for differences in the useful life of a DR program relative to a generator, it is necessary to levelize the installation cost of the power plant. This will require establishing a lifetime of the unit (typically 20 to 30 years) and an appropriate discount rate. At a useful life of 20 years and a hypothetical utility's weighted average cost of capital (WACC) of seven percent, the annual value of a $900/kW peaking unit would be approximately $85/kW-year. Fixed operations and maintenance (O&M) costs should be added to this estimate. For a combustion turbine, those could be approximately between $5 and $10/kW-year.[21] Adding a fixed O&M cost of $5/kW-year to the levelized installation cost brings the total cost of the hypothetical marginal unit to $90/kW-year.

Step 3: Subtract the energy and ancillary services profit margin of the marginal unit. In the absence of DR, the peaking unit would be installed and it would generate electricity during hours when its variable costs (fuel and variable O&M) are less than the marginal cost of energy (i.e. it would run when doing so is profitable). The difference between the marginal cost of energy and the unit's variable costs are its "energy margin." Similarly, the unit could provide ancillary services and further increase its profit margin. This profit margin represents the incremental energy and ancillary services value that the unit would have provided to the grid. When estimating the net avoided cost of DR, this profit margin should be subtracted from the capacity cost (in other words, it is a benefit that is avoided by DR).[22]

Energy and ancillary services margins will depend heavily on the economics of the system that is being analyzed. For instance, in a region with tight reserve margins and a high dependency on fuels with volatile prices, there is a greater likelihood of energy price spikes and a new peaking unit would have a better opportunity to earn high energy margins than in a region with a large amount of excess capacity. For illustrative purposes, assume the peaking unit in our example has energy margins of $20/kW-year.[23] Subtracting this from the levelized cost of the unit gives a net avoided cost of $70/kW-year.

Step 4: Derate the resulting net avoided cost to account for DR availability and performance. Unlike the around-the-clock availability of a combustion turbine unit, DR programs are typically constrained by the number of load curtailment events that can be called during the course of a year. Further, there are often pre-defined limitations on the window of hours of the day during which the events can be called, and sometimes even on the number of days in a row that an event may be called. It is also often the case that hour-ahead or day-ahead notification must be given to participants before calling an event. All of these constraints can potentially limit the capacity value of a DR program.

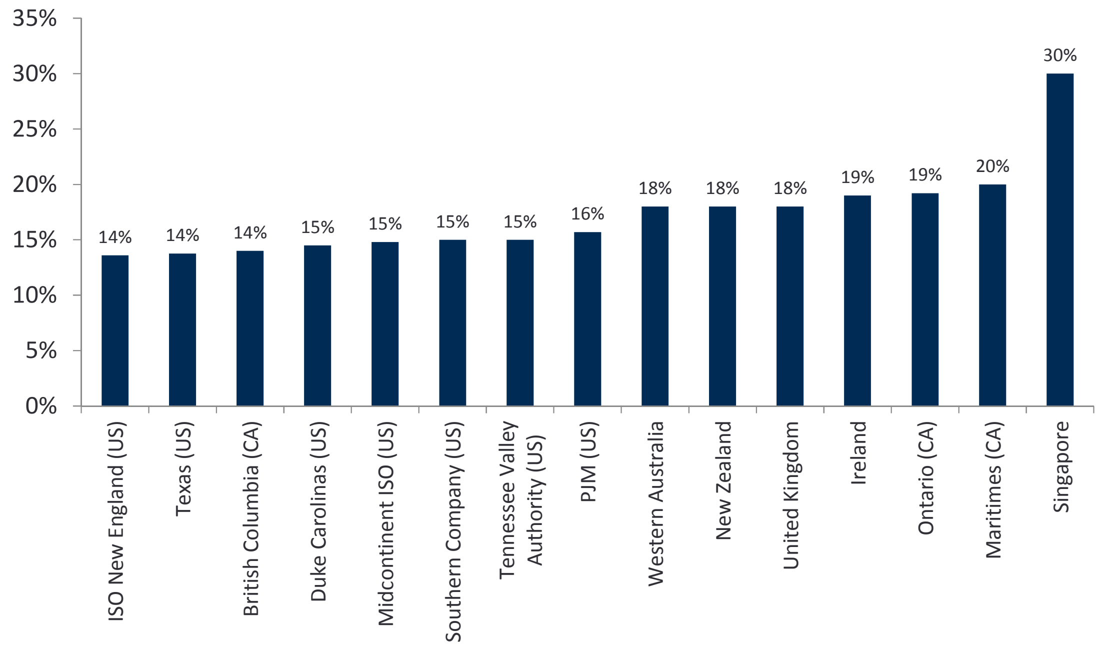
Some utilities account for this through a derate factor that is applied to the avoided capacity costs that are estimated for any given DR program. The derate factor is program-specific and is estimated through an assessment of the relative availability of DR during hours with the highest loss of load probability. Historically, depending on program characteristics and utility operating conditions, some derate factors have ranged from zero percent to roughly 50 percent of the capacity value of the programs.[24] The derate is program- and utility-specific. In California, programs with short response time and dispatch flexibility are derated by less than programs that do not have those characteristics. Historically in California, day-ahead programs with voluntary load reductions have been derated by as much as 60 percent whereas technology-enabled air-conditioning load control programs and aggregator-managed C&I programs with short response time could be derated by less than 20 percent.[25] In Colorado, Xcel Energy estimated that the capacity value of DR programs with a four hour dispatch limit per day and a 40 hour dispatch limit per year should be derated by around 30 percent, while unconstrained DR programs that could be dispatched up to 160 hours per year (a large number of hours for a DR program) should only be derated by five percent.[26] Very rough estimates by Portland General Electric (PGE) include derate factors of between five and 30 percent for direct load control programs and 50 to 60 percent for programs in which the load reductions are not automated. Many other utilities do not include any derate mechanism whatsoever, similar to DR valuations in wholesale capacity markets. While there is not a "typical" derate across markets due to the program-specific and system-specific nature of the adjustment, we find that 25 percent is a reasonable midpoint estimate to use as a representative value. Derating the $70/kW-year net avoided cost estimate in our example by 25 percent produces an adjusted avoided cost estimate of $53/kW-year.

Of course, the relative availability of peaking units should also be taken into account when establishing these derate factors. If rarely-used peaking units are found not to be reliable when needed during times of system emergencies, then the relative disadvantage of DR is not as significant as it may initially appear. For example, a recent analysis found that of 750 MW of peaking units in the San Diego area of Southern California, roughly 60 percent were available when called due to startup issues.[27] While DR resources have some dispatch limits, their availability and reliability during periods of system need could match or possibly exceed that of generation in some instances, enabling them to be comparably valued to a peaking resource by comparison in these instances.. ISO New England (ISO-NE) dispatched DR resources on July 19, 2013 for system reliability purposes and 95 percent of dispatched DR resources responded.[28] This also highlights the very system-specific nature of the derate calculation. It must be developed on a case-by-case basis with careful consideration for factors like the system load profile, DR program characteristics, and generating unit performance.

Step 5: Increase the avoided cost estimate to account for line losses and reserve margin. Demand response produces a reduction in consumption at the customer's premise (i.e. at the meter). Due energy losses on transmission and distribution lines as electricity is delivered from power plants to customer premises, a reduction in one kilowatt of demand at the meter avoids more than one kilowatt of generation capacity. In other words, assuming line losses of eight percent, a power plant must generate 1.08 kW in order to deliver 1 kW to an individual premise. Therefore, when estimating the avoided cost of DR, the avoided cost should be grossed up to account for this factor.

Similarly, most utilities incorporate a planning reserve margin into their capacity investment decisions. Reliability standards can be incorporated into planning decisions in a variety of ways (e.g., establishing a maximum target number of allowable reliability "emergencies" per year, or establishing a minimum amount of installed capacity in excess of peak load during a high load year due to unexpected weather). Figure 3 illustrates the range of reserve margins that are implied in the reliability standards of various markets around the globe.[29]

Figure 3: Implied Reserve Margin Requirement in Markets with Reliability Standard



Source: Sam Newell and Kathleen Spees, "Resource Adequacy in Western Australia: Alternatives to the Reserve Capacityi Mechanism," prepared for EnerNOC, August 2014.

A common target reserve margin is 15 percent, meaning the utility will plan to have enough capacity available to meet its projected peak demand plus 15 percent of that value.[30] In this sense, a reduction of one kilowatt at the meter level reduces the need for 1.15 kW of capacity. Combining the adjustments for both 8% line losses and a 15% reserve margin in our hypothetical example increases the avoided capacity cost from $53/kW-year to $66/kW-year.[31]

Step 6: Calculate the present value of avoided capacity over the lifetime of the DR program. The final step in quantifying the avoided capacity cost of a DR program is to account for the expected life of the program and the extent to which this aligns with new capacity needs. The life of a DR program will vary by program type and will be determined by the life of equipment that is being used (e.g., a switch on the compressor of an air-conditioner) and expectations about the amount of time that participants will choose to stay enrolled in the program. In our hypothetical example, assume that the utility's resource plan has determined that new capacity will first be needed three years from now due to a short-run capacity surplus. In valuing a DR program that would be offered today, the avoided capacity cost in years one and two would be near zero.[32] Assuming our hypothetical DR program has a 10 year life, it would have capacity value of $66/kW-year for the remaining eight years of its life.

Table 1 summarizes the six steps in determining the capacity value of DR for a vertically integrated utility in a regulated market.

Table 1: Steps to Calculate Avoided Generation Capacity Cost for Vertically Integrated Utility

Step	Description	Value	Calculation
[1]	Identify the marginal cost of capacity	$900/kW	Assumption
[2]	Levelize the installation cost (including O&M)	$90/kW-yr	(7% x [1]) / (1 - (1 + 7%)^-20) + $5/kW-yr
[3]	Subtract energy & ancillary services margins	$70/kW-yr	[2] - $20/kW-yr
[4]	Derate to account for DR availability and performance	$53/kW-yr	[3] x (1 - 25%)
[5]	Gross up for line losses and reserve margin	$66/kW-yr	[4] x (1 + 8%) x (1 + 15%)
[6]	Calculate present value over life of DR program	$344/kW	Present value over 10 years with avoided cost starting in year 3

Notes:
[1] Based on overnight cost of gas-fired combustion turbine
[2] Assumes discount rate of 7%, useful life of unit of 20 years, and fixed O&M cost of $5/kW-year
[3] Assumes energy & ancillary services margin of $20/kW-year
[4] Assumes derate factor of 25%
[5] Assumes line losses of 8% and reserve margin of 15%
[6] Assumes 7% WACC, 10 year life, and new capacity need in year 3

2.2. In Restructured Markets with Capacity Mechanisms

In restructured markets with centralized capacity mechanisms, there is a wholesale market that is designed to encourage investment in an economically optimal amount of capacity to meet the expected peak demand (plus a reserve margin). Capacity markets produce an annual marginal price of capacity that is paid to sellers in the market (i.e., generators and DR aggregators). This capacity price is the cost that is avoided if DR is procured in the market. Therefore, in a sense, it is simpler to assess the value of a new DR program in the context of a centralized capacity market – the price is published and does not require the multi-step computations that it would when valuing DR for a vertically integrated utility.

Capacity prices can be set in different ways depending on the specific mechanics of the capacity market, although most capacity markets share a basic set of common elements. First, the market operators will determine the gross cost of new entry (CONE).[33] Gross CONE is the marginal cost of new capacity, the same basic starting point that was discussed in Section 2.1 for vertically integrated utilities. Gross CONE is typically determined as a bottom-up engineering estimate or through a survey of recent power plant additions, and ultimately vetted through a public stakeholder process.[34]

Second, the market operators will subtract energy and ancillary services margins to produce Net CONE. Similar to the discussion in Section 2.1, and for the same reasons discussed in that section, an estimate of the likely profit margin that would be earned by the marginal generating unit is subtracted from Gross CONE to produce an estimate of Net CONE. In a state of perfect market equilibrium, Net CONE would be the marginal price of capacity.

Third, the market operators will establish a process through which to adjust the capacity price to balance the supply of and demand for new capacity. Due to the cyclical nature of power generation development, markets typically fluctuate between conditions of excess capacity and of tightened reserve margins. The pricing mechanism is designed to reflect these conditions. The price rises as the need for new capacity rises, and vice versa. The specific mechanism through which this happens is very specific to the market design. While a comprehensive detailed review of the nuances of the price setting process is beyond the scope of this paper, the following are examples of how it is done in a few existing markets.[35]

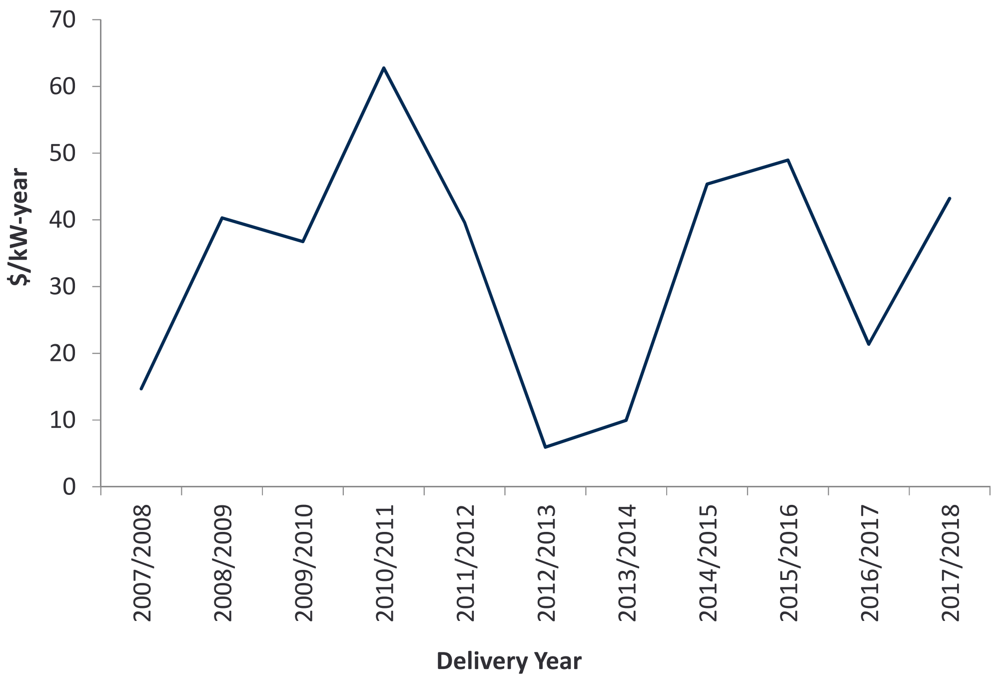
- **PJM:** A downward sloping "demand curve" is established to represent the price that will be paid for capacity at various reserve margin levels. When the reserve margin is low, supply is short and a high price would be paid for new capacity. The price progressively decreases for increasing amounts of capacity. The curve is anchored on a price that is equivalent to the Net CONE value, which would be paid for capacity that produces the target reserve margin level. PJM then conducts an auction into which participants bid their capacity. This creates a supply curve of capacity, and the intersection of the supply and demand curves determines the capacity price that is paid to all accepted bids. PJM conducts their auction annually on a three-year forward looking basis, meaning bids in the current year's auction are a commitment to provide capacity three years out.[36]

- **Western Australia:** As in PJM, Western Australia' Wholesale Electricity Market (WEM) starts with an estimate of net CONE and establishes this as a payment level that is associated with a target level of capacity procurement. Unlike in PJM, however, the capacity price is not ultimately set through an auction process. Rather, retailers and generators establish bilateral contracts for capacity, or sell to the market operator directly. If the amount of capacity procured through these bilateral transactions meets the target amount of capacity that is needed in the market, then the entities that are selling capacity are awarded a payment that is close to Net CONE. If the amount of capacity traded is higher than the target amount, then the payment level is progressively reduced from this price. Alternatively, if an insufficient amount of capacity has been procured, then the market operator would hold a supplemental capacity auction to procure enough capacity to meet the target. In Western Australia, procurement happens two years in advance of the delivery date.

- **Ireland:** In Ireland's Single Electricity Market (SEM), there is no auction process. Rather, pre-established capacity prices are paid to market participants for each half hour period of the year, depending on the participant's availability to provide capacity in each half hour interval. Depending on projected reliability conditions during each time interval, the capacity price can vary widely. In periods when supply and demand conditions are expected to be tight, the price is set higher. This allows the participants flexibility in the timing and duration of their commitment to provide capacity over the course of the year. All prices are derived from a common starting point, which is Net CONE. Unlike both the PJM and WEM markets, there is no forward procurement mechanism in the SEM.

These examples illustrate that there is likely to be fluctuation in the capacity price over time. In PJM, for example, prices have varied significantly over the decade that the capacity market has been in place (as well as across its various geographic zones). This annual volatility is illustrated in Figure 4.

Figure 4: PJM Capacity Prices[37]



Regardless of the specific price setting mechanics of the capacity market, the basic methodology for calculating the avoided capacity cost attributable to DR follows the same three steps:

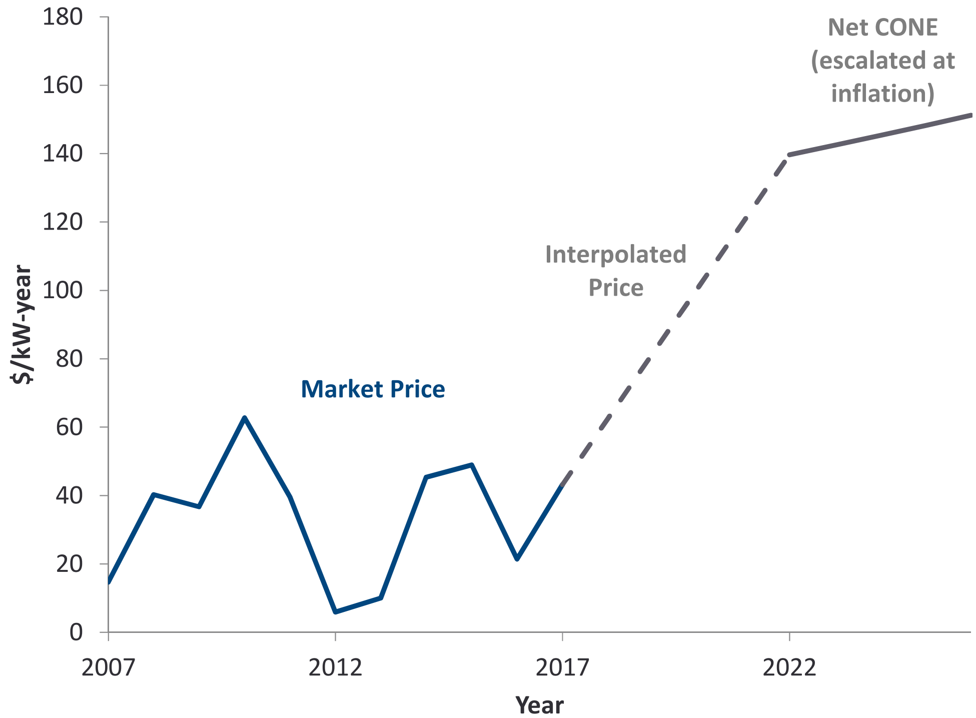
<u>Step 1: Identify the capacity price for all relevant years.</u> The market price for capacity should be used for all years available. For instance, since PJM is a three-year forward auction, there would be three years of capacity prices that would be used as the short-run avoided cost of capacity.[38]

Step 2: Establish Net CONE as the long-run equilibrium capacity price. Analysis of DR benefits in organized wholesale markets is sometimes short-sighted in the sense that it limits the evaluation to prices based on recent market results.[39] In the long-run, however, prices are likely to evolve and eventually would be expected to reach an equilibrium state. Economic theory suggests that, in the long run, supply and demand will equilibrate and the marginal cost of capacity will eventually stabilize at Net CONE. Thus, for the outer years of the forecast, Net CONE is used as the avoided capacity cost.

Step 3: Interpolate in intermediate years to create a smooth transition from market prices to the long-run equilibrium price. To account for a multi-year transition from the market price to the long-run equilibrium price, it is common practice to interpolate between the two prices over a three to five year period. Linear interpolation is sufficient.

Illustrative results of this three step process are summarized in Figure 5 using PJM capacity prices. In PJM, various economic factors and fluctuations in the market design have kept the capacity price from reaching Net CONE (for the 2017/18 auction, Net CONE was around $127/kW-year). In this specific case, if there is a belief among the evaluators of the DR program that these factors would continue to depress the capacity price, then the long run equilibrium price could be set below Net CONE. Some judgment is necessary when projecting capacity prices.

Figure 5: Capacity Price Forecast for PJM



Unlike in the previous discussion of DR valuation in regulated markets, no derating mechanism is used to account for operational constraints of the DR programs. Rather, these constraints are accounted for by the market rules that specify how a DR product must perform in order to be accepted as a resource in the market. For example, a market rule might specify a minimum number of hours for which the DR resource must available, a maximum lead time for notification, or specific technologies that must be used for communications and settlement purposes. Therefore, the market design includes a "screening" process that ensures that accepted DR bids will provide the same value to the market as a generating unit. As a result, in all of these wholesale capacity market constructs, DR receives the same remuneration for capacity as a traditional supply-side resource.

2.3. In Restructured Energy-Only Markets

Some restructured markets do not have a centralized mechanism for procuring capacity. These are commonly referred to as "energy-only" markets. The theory in these markets is that, as reserve margins tighten, energy prices will rise to a point that economically supports a sufficient amount of new entry of capacity into the market.[40] The Electric Reliability Council of Texas (ERCOT), the Ontario Power Authority (OPA) in Canada, and Australia's National Electricity Market (NEM) market are three examples of energy-only markets.

In these markets, since energy prices are intended to represent the cost of energy as well as capacity, there is no specific capacity price per se that is used to specifically evaluate the generation capacity value of DR. However, the operators of these markets will often create specific "products" that are designed to encourage DR resources to be available for capacity purposes. Payments are made to DR providers to be available for curtailment when needed and/or on a pay-for-performance basis. In this sense, the capacity value of DR programs in these markets is determined by the payment that is made to the DR providers.

These DR products exist in several energy-only markets. For example, in ERCOT's Emergency Response Service (ERS) program, customers are paid for providing load reductions on 10 or 30 minutes notice. Load reductions are procured for different time periods (varying by season and time of day). In the 30-minute ERS program (a pilot program at this point), prices are set through an auction process. Prices in the ERS program have cleared between $60 and $200/kW-year and are continuing to fluctuate as the product definition evolves.[41] In Canada, the Ontario Power Authority (OPA) has a mandatory, capacity-based DR program called "DR3".[42] Prices vary across the three programs and across locations on the OPA's grid. In Toronto, payments in the DR3 program, have been in the range of $100/kW-year to $170/kW-year.

To determine the capacity value of DR in these types of programs, the first step is to determine whether the DR program being evaluated meets the specific performance requirements of the market product (or, if multiple products are offered, as in the examples described above, determine which product, if any, is the best fit in this regard for the DR program being considered). The performance requirements are typically publicly available documents published on the market operator's website. Then, determine how much of a load reduction will be provided by the DR program. This load reduction is then multiplied into the published payment schedule to determine the overall monetizable value of the DR program.

3. Other Avoided Costs

While avoided generation capacity costs have driven the bulk of DR benefits historically, there are other avoided costs that can also be attributed to DR. This section discusses other avoided costs, including T&D capacity costs, energy costs, and ancillary services costs.

3.1. Avoided Transmission and Distribution Capacity

Reductions in peak demand lessen the need to expand the T&D system. A portion of T&D investment is driven by the need to have enough capacity available to move electricity to where it is needed during peak times while maintaining a sufficient level of reliability. Geographic expansion of the system requires T&D investment, and that is often correlated to growth in peak demand. By reducing peak demand, DR reduces the need for new T&D capacity. In 2012, for example, the U.S. market of PJM cancelled plans for a new transmission line (the "PATH" line) that would improve import capability in its transmission-constrained eastern portion of the power grid, citing an increase in DR in the east as a reason for canceling the project.[43]

There are also aspects of T&D system expansion that are not driven by growth in peak demand. For example, some reliability-driven projects are built to ensure that enough capacity is available to address congestion during mid-peak and off-peak periods. Other projects are driven to integrate new generation additions which may be built as baseload resources rather than peaking generation. As a result, when calculating avoided costs for valuing DR programs, utilities will often calculate the total amount of expected T&D infrastructure investment and then derate it to account for the share of that investment that is driven by peak demand.

Utility estimates of avoided T&D costs vary significantly and are very system specific. In a review of utility DR filings and marginal cost studies, and interviews with utility engineers, avoided T&D costs typically ranged from $0 to $75/kW-yr. Table 2 summarizes avoided T&D cost estimates from recent DR studies. While the range is broad, we find that avoided costs of $20 to $30/kW-year are the most commonly accepted assumption in regulatory settings as well as in several unpublished studies for utilities.

Table 2: DR Avoided T&D Costs

Entity		State(s)	Avoided Cost ($/kW-year)
[1]	Pepco Holdings, Inc	DE, DC, MD, NJ	$0.00
[2]	Portland General Electric	OR	$18.00
[3]	Pennsylvania Statewide Evaluator	PA	$25.00
[4]	Connecticut Light & Power	CT	$29.20
[5]	Xcel Energy	CO, MN	$30.00
[6]	Southern California Edison	CA	$54.60
[7]	San Diego Gas & Electric	CA	$74.80
[8]	Pacific Gas & Electric	CA	$76.60

Note: Where multiple avoided cost scenarios were considered, the base case value was used
Sources: Utility DR potential studies, state regulatory decisions

In addition to avoiding system peak-driven T&D investment, DR can be deployed selectively in specific geographic locations to address local congestion issues on the transmission or distribution system.[44] For example, some utilities have used DR to manage loads at specific substations and transformers that were at or near capacity. Reflecting this location-specific value, Con Edison, a distribution utility in the U.S. state of New York, has developed its Distribution Load Relief Program (DLRP) which offers customers in congested parts of the grid incentive payments that are twice as high as those of customers in uncongested parts of the grid.[45]

Wholesale energy and capacity markets do not specifically address T&D system expansion needs. In both regulated and restructured markets, this is done through a centralized planning process. Therefore, there are not significant differences in the way T&D capacity benefits are estimated for DR in restructured and regulated markets. There are a few options for establishing the avoided cost of T&D:

Option 1: Rely on estimates from a recent marginal cost study. Many utilities will conduct marginal cost studies, primarily for the purpose of designing their retail rates. Among many calculations, these studies will include estimates of the portion of T&D costs that are driven by growth in the system peak. This estimate can be used as the basis for the avoided T&D cost of DR that is dispatched to reduce the system peak.

Option 2: Use an estimate from a review of assumptions in other utility filings. In the absence of marginal T&D cost estimates that are specific to the region or service territory being analyzed, an estimate of avoided T&D costs can be established based on a review of estimates in other regions, such as those summarized in Table 2 above. The results can be tailored to the service territory in question by restricting the survey to similarly situated utilities (e.g. similar geographic region, urban versus rural utility, etc.).

Option 3: Develop a bottom-up engineering estimate of the avoided cost of T&D. In instances where the utility is considering establishing a new DR program in a congested part of the grid in order to avoid or defer the expansion of the T&D system to that part of the grid, the specific cost of the T&D project in question should be taken into consideration. This will be a very project-specific estimate that most likely cannot be derived from other studies.

3.2. Avoided Energy Costs

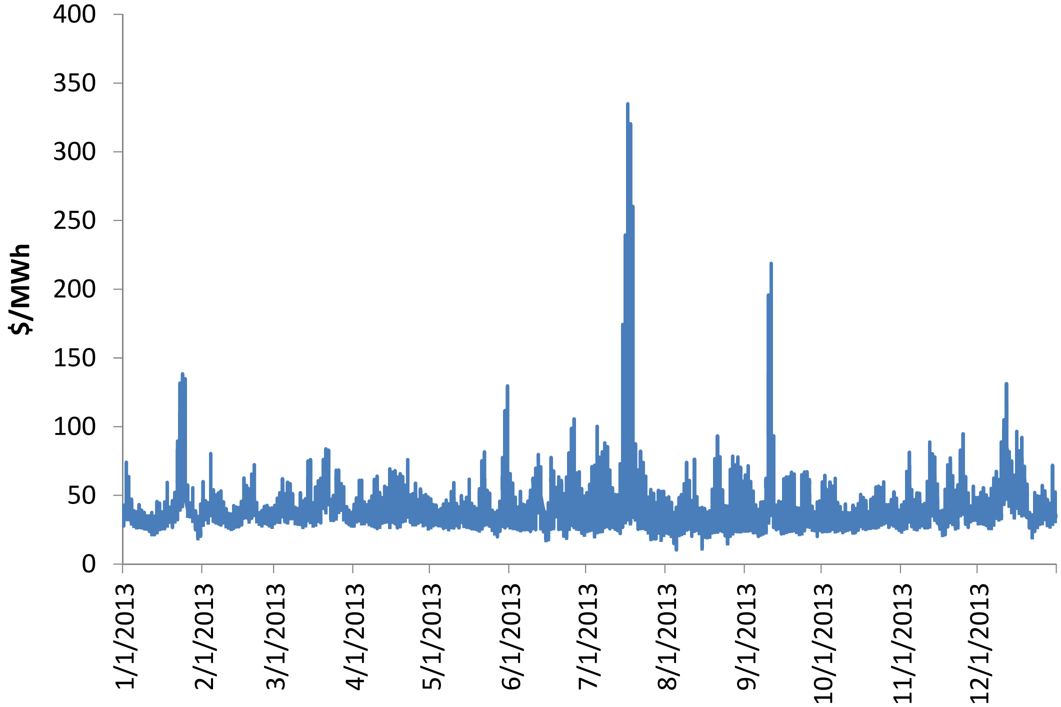
Reductions in consumption will avoid the marginal cost of generating electricity (primarily fuel costs, as well as variable O&M). This is typically a primary benefit of energy efficiency programs, which derive most of their value from overall reductions in consumption. For DR programs, avoided energy costs have historically made a relatively minor contribution to the total benefit, since consumption reductions are concentrated in a small number of hours in the year. However, when these reductions occur during hours of very high electricity prices – particularly in restructured energy-only markets – the benefit can be significant. There is a growing trend toward incorporating DR into wholesale energy markets in order to provide comparable opportunities to those of generating units, and to facilitate broader market participation and competition.

Avoided energy costs are a time-dependent source of value. Reductions during peak times avoid a higher marginal cost, because less efficient generating units are on the margin during these times. These costs also vary by season for the same reason – in the summer, when demand is often higher due to air-conditioning load, energy prices also tend to be higher.

The methodology for determining energy benefits is generally the same in restructured and regulated markets, with the only difference being the source of data for the marginal cost of energy. Steps for estimating the avoided cost are summarized below:

Step 1: Establish an hourly projection of marginal energy costs. In a restructured market, hourly energy prices – often referred to as the locational marginal prices (LMPs) - are established in the energy market. For a vertically integrated utility, marginal energy costs are simulated using a production cost model and represented by something referred to as a "system lambda." In either case, recent historical hourly marginal energy costs for a year with normal weather are typically used as the basis for estimating avoided costs. Figure 6 illustrates the hourly day ahead LMP in the Eastern Hub of PJM for each hour of the year 2013. The energy price exceeded $100/MWh in 89 hours in 2013.

Figure 6: Eastern PJM Hourly Energy Price (2013)



Step 2: Define the period when DR is likely to be utilized. The DR program will only be dispatched during a limited number of hours per year. A key question is whether the DR program is being dispatched for reliability purposes or economic purposes (or both). If it is being dispatched for reliability purposes, the demand reductions will likely coincide with the highest system load hours of the year. If it is being dispatched for economic purposes, the demand reductions will often coincide with the highest priced hours of the year.[46] In both cases, the top hours should be identified and restricted to the likely total number of hours that the program will be dispatched (typically 50 to 100 hours per year, primarily focused on the season of the system peak, which in the U.S. is typically the summer season). To illustrate, consider an economically-dispatched DR program that can be utilized up to 10 days per summer between the hours of 2 pm to 7 pm. In 2013, this program would have been dispatched during 10 days between the months of May and September in PJM (with the exception of one day in December during the Polar Vortex), as these were days with the highest average peak period prices. Table 3 identifies the top 10 days and the average day ahead LMP during the 2 pm to 7 pm window on those days.

Table 3: 10 Highest Priced Days in Eastern PJM, 2013

Date	Average Peak Period Price ($/MWh)
7/17/2013	297.30
7/18/2013	267.80
7/19/2013	214.04
7/16/2013	209.65
9/11/2013	185.11
7/15/2013	152.91
9/10/2013	148.64
5/31/2013	106.12
12/12/2013	101.37
5/30/2013	94.65
Average	**177.76**

<u>Step 3: Calculate the average energy price during the hours when the DR program is utilized.</u> The average marginal energy cost during the hours of dispatch represents the energy value of the DR program. In the example above, the average energy price during the 50 hours of dispatch was approximately $178/MWh.[47] This value would be multiplied by the total amount of energy reduced during that period to determine the total annual energy value of the DR program. Converted to a dollars-per-kilowatt-year estimate for comparability to the avoided capacity cost estimates discussed previously, this equates to approximately $9/kW-year. Thus, in this example, the avoided energy cost is a fraction of the range of avoided capacity cost estimates that have been discussed, but it is still a material financial benefit to be considered.

3.3. Avoided Ancillary Services Costs

The use of DR to provide ancillary services is becoming a topic of increasing interest in the industry due to growing concerns regarding the ability to reliability integrate large amounts of intermittent resources into the grid. Regardless of whether a utility is regulated or in a restructured market, DR could provide value by acting as a fast-response resource that would decrease or even increase load in response to unpredictable fluctuations in power generation. Specifically, there are four reliability-related problems that must be addressed when variable generation is adopted at high levels:[48]

- Increased intra-hour variability in supply

- Large magnitude of overall ramping requirements
- Over-generation concerns
- Near-instantaneous production ramps.

Newly emerging technologies and DR initiatives could eventually help to address some of these barriers. "Smart" appliances, home energy management systems (HEMS) and automated DR systems for the C&I sector are being developed and are becoming commercially available. These technologies can be programmed to respond to fluctuations in the real-time price of electricity. Initiatives are underway to open the market for these devices.

To be valuable in this new environment, ancillary services DR will likely need to be used in new and innovative ways. Specifically, it is likely that DR will need to be able to respond not just during peak hours, but during many of the 8,760 hours of the year. Additionally, there will be value not only in load reductions but also in the ability to *increase* load to maintain balance on the grid. The valuation techniques that have been discussed in this whitepaper are generally applicable in estimating the value of this type of "flexible" DR. For instance, to the extent that DR can be utilized in this environment to provide services that are comparable to those of an OCCT, then the same basic approach to estimating avoided capacity cost would be used. But if the operational characteristics of DR make it a unique resource that is not directly comparable to a generating resource in this environment, then a more sophisticated valuation approach may be needed. This could require a multi-step process, including:

1. Identify the customer segments and end-use loads that are the best candidates for participation in a "flexible DR" program, meaning those end uses that can be controlled with automating technology and used to both increase and decrease load (e.g., residential water heating);

2. Determine the total potential load increase/decrease in those end-uses and the cost associated with enrolling them in a DR program;[49]

3. Characterize the operational constraints of the portfolio of DR participants, such as the number of hours of allowable interruption per year and per day, and the response time;

4. Include this DR portfolio in a resource planning model with a level of granularity that accurately accounts for the volatility in electricity production from intermittent resources of generation;

5. Use the model simulations to determine the extent to which the inclusion of the DR portfolio reduces overall system costs.[50]

4. Other Benefits

It is important to consider additional benefits that are difficult to quantify but which certainly add to the overall attractiveness of DR programs. Qualitative factors such as these should be taken into consideration when conducting a detailed assessment of the benefits and costs of moving forward with a new portfolio of DR offerings.

4.1. Wholesale market price mitigation

When DR bids are accepted in a market, they displace bids from higher cost resources that otherwise would have been accepted. This serves to reduce the market price (a result that one would expect from increased competition in any market). This reduction in market prices can significantly benefit buyers in the market. As described earlier, DR and energy efficiency are estimated to reduce capacity expenditures by billions of dollars per year annually in the PJM capacity market.[51] In the energy market, a study found that a three percent reduction in peak demand through new DR programs could reduce energy prices by between five and eight percent, varying by geographic zone.[52]

However, whether wholesale price mitigation should be considered a benefit depends on one's perspective. While buyers in the market benefit from reduced prices, this represents a loss to suppliers. In this sense, wholesale price mitigation is simply a wealth transfer without a significant net benefit at the societal level. Additionally, the impact of wholesale price mitigation may only persist in the short run. In the long run, reduced prices could lessen the incentive for new market entry, and the market could return to equilibrium at prices similar to those prior to the introduction of DR. Finally, there is a tradeoff to consider between energy and capacity markets. The introduction of new DR will replace relatively efficient new generating capacity that would otherwise have entered the market. This will reduce capacity prices, but could put upward pressure on energy prices over time.

4.2. Possible environmental benefits

To the extent that a DR program results in a net reduction in energy consumption, there could be environmental benefits in the form of reduced greenhouse gas (GHG) emissions. Even in the absence of overall conservation, load shifting may lead to a small reduction in emissions, although this will depend on the emissions rates of marginal units during peak and off-peak hours.[53] For example, if DR causes load to be shifted from hours when an inefficient oil- or natural gas-fired unit is on the margin to hours when a more efficient gas-fired combined cycle unit is on the margin, one could expect a net decrease in GHG emissions. However, in a different service territory, there might be a gas-fired unit on the margin during peak hours and a coal unit on the margin during off-peak hours. In this situation, an increase in GHG emissions could arise.

Peak period load reductions could also reduce other types of generator emissions such as criteria and hazardous air pollutants. In the U.S., for instance, these reductions would be particularly valuable in designated "non-attainment areas" where pre-determined emissions levels cannot be exceeded.

To the extent that peak demand reductions result in avoided investment in new generation capacity or T&D capacity, the result would be a smaller geographical footprint of the grid. This would reduce the impact to wildlife habitat and sensitive ecosystems.

Finally, if DR is offered in the form of time-varying retail rates, this could facilitate the adoption of renewable sources of energy. For example, a strong time-of-use rate could improve the economics of rooftop solar by aligning the higher priced peak pricing period with the time of highest output from the system. To the extent that time-varying rates encourage adoption of technologies that automate load changes in response to prices, this could be valuable for integrating variable renewable energy resources (as discussed previously).

4.3. Option value

Assessment of DR value often relies on point estimates of factors like the peak demand forecast and generating unit availability. By limiting the analysis to a few discrete scenarios, the full spectrum of extreme events that could occur on a system is often underrepresented. In fact, it is in response to uncertain and extreme events that DR has been found to provide the most value; this is described as the "option value" of DR.[54] Studies have shown that being able to avoid blackouts in extreme reliability situations through the use of DR programs could justify investment in the programs even if they happen only once every five or ten years.[55]

4.5. Improved post-outage power restoration

After an outage, it is necessary to control the rate at which power is restored to the grid in order to avoid over-stressing the system. Some load control technologies have a feature which brings the controlled end-uses online in a staggered fashion in order to "spread out" the ramping of load over time.

4.6. More equitable retail rates

Demand response can be offered in the form of retail prices that are higher during peak periods and lower during off-peak periods (i.e., time-varying rates). By providing a price signal that more accurately reflects the cost of supplying electricity over the course of a day, time-varying rates are more equitable than a flat rate and reduces the cross-subsidization that currently exists between customers with “peaky” or “flat” load shapes.

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[2] FERC, "A National Assessment of Demand Response," prepared by The Brattle Group, Freeman, Sullivan, & Co., and Global Energy Partners, June 2009. 82 to 188 GW of demand reduction divided by an average 75 MW peaking unit results in the equivalent of approximately 1,000 to 2,500 avoided peaking units. http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf

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[7] Navigant Research, "Market Data: Demand Response," 2Q, 2013. http://www.navigantresearch.com/research/market-data-demand-response

[8] For instance, the specific mechanics of evaluating the capacity value of DR in a region with a centralized wholesale capacity market will be inherently different than those of valuing DR for a vertically integrated utility, despite the fact that the value is derived in both cases from the avoided or deferred cost of a new peaking unit.

[9] For further examples of DR costs, see EPRI, "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Projects," January 2010.

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[16] Navigant Research, "Market Data: Demand Response," 2Q, 2013. http://www.navigantresearch.com/research/market-data-demand-response

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[18] Depending on the specific economic conditions of the system, such as load shape and mix of existing generation resources, a different type of generating unit, such as a combined cycle (CCCT), could be the marginal unit. For simplicity, we use a combustion turbine as a proxy for marginal generation capacity cost throughout this report. System-specific modeling will reveal which technology makes the most sense, but generally the most "pure" form of generation capacity (lowest capital and highest operating costs) will be an open-cycle combustion turbine.

[19] Ideally, a supply curve of DR resources would be developed and incorporated into the modeling such that they are competing against conventional generation resources. For further discussion, see Andy Satchwell and Ryan Hledik, "Analytical Frameworks to Incorporating Demand Response in Long-Term Resource Planning," Utilities Policy, March 2014.

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[21] Ibid.

[22] Of course, DR would also potentially provide energy and ancillary services value that would offset some or all of this "avoided" benefit. The energy and ancillary services value of DR is discussed in Section 3.

[23] For instance, consider a new peaking unit with an average variable cost of $60/MWh. If the plant ran for 500 hours of the year and the average marginal price of electricity during these hours was $100/MWh, the energy margin would be ($100/MWh - $60/MWh) x 500 hours = $20,000/MW-year or $20/kW-year.

[24] For further detail on the derate factor, see the CPUC website. http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

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29 Derived from Sam Newell and Kathleen Spees, "Resource Adequacy in Western Australia: Alternatives to the Reserve Capacity Mechanism," prepared for EnerNOC, August 2014. http://www.brattle.com/system/publications/pdfs/000/005/070/original/WA_Resource_Adequacy_Spees_Newell.pdf?1408985223

30 If the system peak is projected to be 1,000 MW, the utility would have 1,150 MW of available capacity.

31 $53/kW-year x (1 + 8%) x (1 + 15%) = $66/kW-year.

32 It is possible that some old, inefficient, excess peaking capacity would be retired if DR is added to the system, in which case the fixed O&M associated with that capacity would be an avoided cost attributable to DR.

33 CONE is commonly accepted industry terminology, although various markets will use alternative terms for the same concept.

34 For an example of Gross CONE estimation, see Samuel A. Newell et al, "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," prepared for PJM Interconnection, May 15, 2014. http://www.pjm.com/~/media/documents/reports/20140515-brattle-2014-pjm-cone-study.ashx

35 For more detailed discussion, see EnerNOC, "Best Practices of Demand Response in Capacity-Based Markets and Programs," June 2014.

36 PJM also runs annual interim auctions.

37 RTO clearing prices for the Base Residual Auction. Other zones have cleared at higher prices to due transmission constraints. See PJM Website: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx

38 Note that PJM pays variations of the market clearing price for DR products with different performance characteristics. Similar to the derate that is applied in some regulated markets to account for the availability and flexibility of a DR program, PJM provides higher payments for more reliable and flexible DR products and lower payments for less flexible products. This type of price variation should be accounted for if it is a feature of the specific market being analyzed.

39 U.S. Department of Energy, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them," February 2006. http://energy.gov/oe/downloads/benefits-demand-response-electricity-markets-and-recommendations-achieving-them-report

40 These market constructs typically have a "scarcity pricing" mechanism through which energy prices are administratively increased during emergency conditions in order to encourage new entry into the market.

41 See Constellation website: http://www.constellation.com/documents/government%20case%20studies/ercot%20load%20response%20snapshot.pdf

42 IESO, "OPA Demand Response Programs," January 17, 2011. http://www.ieso.ca/Documents/icms/tp/2012/01/IESOTP_256_7b_OPA_Demand_Response_Programs.pdf. See also the Save ON Energy website: https://saveonenergy.ca/Business/Program-Overviews/Demand-Response.aspx

43 PJM letter to Transmission Expansion Advisory Committee, August 28, 2012 http://www.pjm.com/~/media/committees-groups/committees/teac/20120913/20120913-srh-letter-to-teac-re-mapp-and-path.ashx

44 At the distribution level, this may be a particularly valuable aspect of DR in the future if there is significant growth in electric vehicle adoption; direct control of charging could help to manage potential reliability issues on the distribution system.

45 ConEd website. Tier II customers receive payments of $6/kW-month and Tier I customers receive payments of $3/kW-month. Due to its very densely populated urban service territory in New York, ConEd is an

example of a utility with potentially very high peak-driven T&D costs. One study found that these costs could grow in excess of $200/kW-year over time. Josh Bode, Stephen George, and Aimee Savage, "Cost-Effectiveness of CECONY Demand Response Programs," November 2013. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BBE9E7304-DA3C-4C06-B18B-ADD0D4568E3F%7D

[46] This may not always be the case, as unplanned unit outages can lead to reliability concerns during mid-peak or even off-peak hours of the day.

[47] This is a weighted average, with the weights being the amount of energy reduced in each hour attributable to the DR program. In our example, we assume the same load reduction in each hour.

[48] Kiliccote, Sila et al, "Integrating Renewable Resources in California and the Role of Automated Demand Response," Lawrence Berkeley National Laboratory, November 2010. http://poet.lbl.gov/drrc/pubs/lbnl-4189e.pdf

[49] For example, see EnerNOC Utility Solutions and The Brattle Group, "The Role of Demand Response in Integrating Variable Energy Resources," prepared for the Western Interstate Energy Board, December 2013. http://www.westernenergyboard.org/sptsc/documents/12-20-13SPSC_EnerNOC.pdf

[50] For further discussion, see National Renewable Energy Laboratory, "Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model," December 2013. http://www.nrel.gov/docs/fy14osti/58492.pdf

[51] Monitoring Analytics, "The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses," July 10, 2014. http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_Revised_20140826.pdf

[52] The Brattle Group, "Quantifying Demand Response Benefits in PJM," prepared for PJM and MADRI, January 29, 2007. http://www.brattle.com/system/publications/pdfs/000/004/917/original/Quantifying_Demand_Response_Benefits_in_PJM_Jan_29_2007.pdf?1379343092

[53] Ryan Hledik, "How Green is the Smart Grid?" *The Electricity Journal*, April 2009. http://sedc-coalition.eu/wp-content/uploads/2011/06/Hledik-09-04-01-Carbon-Emissions-Benefits-of-Smart-Grid.pdf Also see Pacific Northwest National Laboratory, "The Smart Grid: An Estimation of the Energy and CO2 Benefits," January 2010. http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19112.pdf

[54] Osman Sezgen, Charles Goldman, and P. Krishnarao, "Option Value of Electricity Demand Response," Lawrence Berkeley National Laboratory, October 2005. http://emp.lbl.gov/sites/all/files/REPORT%20lbnl%20-%2056170.pdf

[55] Daniel M. Violette, Rachel Freeman, Chris Neil, "DRR valuation and market analysis, volume II: Assessing the DRR benefits and costs." International Energy Agency (IEA) DRR Task XIII, January 6, 2006. http://www.demandresponsecommittee.org/id81.htm

Demand Response Market Research:

Portland General Electric, 2016 to 2035

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Opinions expressed in this presentation, as well as any errors or omissions, are the authors' alone. The examples, facts, results, and requirements summarized in this report represent our interpretations. Nothing herein is intended to provide a legal opinion.

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I. Introduction

Interest in demand response (DR) in the Pacific Northwest has grown considerably since Portland General Electric's (PGE's) first DR potential study was conducted in 2009 and subsequently updated in 2012.[1] A need to integrate growing amounts of intermittent resources (e.g., wind and solar) into the grid, increasingly stringent constraints on the operation of regional hydro generation, growth in summer peak demand, and an expectation of a capacity shortfall in the next five years have all driven interest in DR.

As a result of this growing interest from stakeholders, several new studies have explored the potential for DR to address these issues. For instance, in 2014 the Northwest Power and Conservation Council (NPCC) completed a study to assess the market for various flexible load resources.[2] In that same year, PacifiCorp completed a detailed DSM potential study spanning all of its jurisdictions, with considerable attention being paid to DR programs.[3] That study was noted for the considerable role that demand-side resources will play in future resource planning efforts. Several demonstration projects and pilot studies are now also underway in the region, including the involvement of the Bonneville Power Administration (BPA), Pacific Northwest National Laboratory (PNNL), and many regional utilities including PGE.

To better inform its own DR initiatives and to establish inputs to its integrated resource planning (IRP) process, PGE contracted with The Brattle Group to develop an updated DR potential study ("the 2015 study"). The purpose of this study is to estimate the maximum system peak demand reduction capability that could be realistically achieved through the deployment of specific DR programs in PGE's service territory under reasonable expectations about future market conditions. The study also assesses the likely cost-effectiveness of these programs.

The 2015 study includes several improvements over the prior studies commissioned by PGE, both in terms of the quality of the data being relied upon and the breadth of issues which it addresses. Specific improvements in the 2015 study include the following:

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1 The Brattle Group and Global Energy Partners, "Assessment of Demand Response Potential for PGE," prepared for PGE, March 16, 2009. Also, Ahmad Faruqui and Ryan Hledik, "An Assessment of Portland General Electric's Demand Response Potential," prepared by The Brattle Group for Portland General Electric, November 28, 2012.

2 Navigant, "Assessing Demand Response Program Potential for the Seventh Power Plan: Updated Final Report," prepared for the Northwest Power and Conservation Council, January 19, 2015.

3 Applied Energy Group and The Brattle Group, "PacifiCorp Demand-Side Resource Potential Assessment for 2015 – 2034," prepared for PacifiCorp, January 30, 2015.

- Market data was updated to account for changes in forecasts of the number of customers by segment, seasonal peak demand, the expected timing and cost of new capacity additions, and other key assumptions that drive estimates of DR potential and its cost-effectiveness.

- Assumptions about DR participation and impacts were updated to reflect emerging DR program experience in the Pacific Northwest. Ten regional studies conducted in the past five years in the region informed these updates.

- The findings of 24 new dynamic pricing pilots, conducted both in the U.S. and internationally, were incorporated to refine potential estimates for pricing programs. This allowed several important aspects of pricing potential to be accounted for, including seasonal impacts and differences in price response when programs are offered on an opt-in versus opt-out basis.

- A survey of market research studies and full-scale time-varying pricing deployments was utilized to improve assumptions around participation in dynamic pricing programs.

- The methodology for estimating the cost-effectiveness of the DR programs, while conceptually consistent with the prior PGE potential studies, was improved to address comments from the Oregon PUC regarding the derating of avoided costs to account for operational constraints of the DR programs. Accounting for incentive payments on the cost-side of the analysis was also refined.

- The menu of program options analyzed was significantly expanded to include several newly emerging options that have recently begun to generate interest among utilities around the country, such as smart water heating load control, behavioral DR, electric vehicle charging load control, and "bring-your-own-thermostat" programs.

A few key points should be kept in mind while reading this report:

1. The load reduction potential and cost-effectiveness of each DR option are evaluated in isolation from each of the other options; they do not account for potential overlap in participation that may occur if several DR options were simultaneously offered to a single customer segment. Therefore, the potential estimates of the individual DR options are not additive and the economics of the programs may change when the DR options are offered as part of a portfolio.

2. The analysis is based on typical program designs with illustrative yet realistic incentive payments. Rather than being the final word on the cost-effectiveness of these programs, findings should be used as a starting point for further exploring how different program designs would change the economics of the programs.

3. Unless otherwise noted, peak reduction potential estimates are reported for the year 2021. This was chosen as the reporting year of interest, because it is the first year in which PGE is projected to need new capacity.

4. Any options requiring a change to the rate structure could not be offered until 2018 or 2019 due to constraints with the current billing system.

5. In all cases, the cost of advanced metering infrastructure (AMI) is not accounted for in the cost-effectiveness analysis as the infrastructure is already in place regardless of whether or not a decision is made to the offer pricing programs.

6. As is discussed in the Methodology section of this report, the estimates of potential are not projections of what is likely to occur. Rather, they represent an estimated upper-bound on what is achievable under current expectations of future system conditions and reflect utility experience with successful DR programs around the country. Achieving this potential will require a significant customer outreach and education effort and will likely take time, given the relative lack of experience with DR in the Pacific Northwest relative to other parts of the country. Like energy efficiency, successful DR programs require active customer participation. DR in the Pacific NW is in a similar place to where energy efficiency was in the region in the late 1970s or early 1980s. The region – and PGE – has the potential to achieve a significant amount of DR, but there is an upfront investment in awareness and program design that will be required to meet this potential. Ultimately, PGE's ability to achieve significant impacts through DR programs will depend on customer understanding and acceptance of the programs.

The remainder of this report is organized as follows. Section 2 describes the various DR options that were analyzed. Section 3 summarizes highlights of the methodology for estimating potential and evaluating cost-effectiveness. Section 4 presents the key findings of the study. Section 5 concludes with a discussion of considerations for PGE's ongoing and future DR initiatives. The report is intended to be a concise summary of the highlights of the study; the appendices contain significantly more detail on methodology and assumptions.

II. The DR Options

Thirteen different types of DR programs were analyzed in this study. Eligibility for the programs varies in part by customer segment. PGE's customer base was divided into five customer classes. Customer class definitions were determined based on both applicability of DR programs and data availability.

- Residential: All residential accounts
- Small Commercial & Industrial (C&I): Less than 30 kW of demand
- Medium C&I: 30 kW to 200 kW of demand
- Large C&I: More than 200 kW of demand
- Agricultural: All agriculture accounts

Non-metered customers, such as street lighting, were excluded from the analysis, as were customers who have chosen direct access.

Accounting for the number of DR programs offered to each customer segment, a total of 28 different options were analyzed. For organizational purposes, the DR programs can be assigned to three categories: (1) Pricing options, (2) conventional non-pricing options, and (3) newly emerging DR options.

PRICING OPTIONS

AMI-enabled rate options include prices that vary by time of day. The potential in each pricing option was modeled both with and without the adoption of enabling technology. For residential and small C&I customers, the enabling technology is assumed to be a programmable communicating thermostat (PCT), also known as a smart thermostat, which would allow the customer to automate reductions in heating or cooling load during times when the price in the retail rate is high. For medium and large C&I customers, the enabling technology is Auto-DR, which can be integrated with a building's energy management system to facilitate a range of automated load reduction strategies.

<u>Time-of-use (TOU) rate:</u> A TOU rate divides the day into time periods and provides a schedule of rates for each period. For example, a peak period might be defined as the period from 3 pm to 8 pm on weekdays and Saturdays, with the remaining hours being off-peak. The price would be higher during the peak period and lower during the off-peak, mirroring the average variation in the cost of supply (including marginal capacity costs). In some cases, TOU rates may have a shoulder (or mid-peak) period, or particularly in the winter season, two peak periods (such as a morning peak from 6 am to 10 am, and an afternoon peak from 3 pm to 8 pm). Additionally, the prices and period definitions might vary by season. With a TOU rate, there is certainty as to what the prices will be and when they will occur.

<u>Critical peak pricing (CPP):</u> Under a CPP rate, participating customers pay higher prices during the few days when wholesale prices are the highest or when the power grid is severely stressed (i.e., typically up to 15 days per year during the season(s) of the system peak). This higher peak

price reflects both energy and capacity costs. In return, the participants receive a discount on the standard tariff price during the other hours of the season or year to keep the utility's total annual revenue constant. Customers are typically notified of an upcoming "critical peak event" one day in advance.

Peak Time Rebate (PTR): Instead of charging a higher rate during critical events, participants are paid for load reductions (estimated relative to a forecast of what the customer otherwise would have consumed). If customers do not wish to participate, they simply pay the existing rate. There is no rate discount during non-event hours. Customers stay on the standard rate at all hours. The program is analogous to the pay-for-curtailment programs that have been offered to large commercial and industrial customers in restructured markets for many years. Opt-out deployments of PTR are being offered by BGE and Pepco to residential customers in Maryland. These relatively new programs will provide more information in the next few years as their impact evaluations become available.

CONVENTIONAL NON-PRICING PROGRAMS

There is a long history of experience with conventional non-pricing programs in the U.S. These programs provide customers with incentive payments or bill credits in return for relatively dependable load reductions and do not require AMI.

Direct load control (DLC) for heating and cooling: With heating/cooling DLC the utility controls a customer's electric heating or central air-conditioning equipment on short notice. In exchange for participating, the customer receives an incentive payment or bill credit. Recent DLC programs have involved the installation of smart thermostats for customers, which allow remote adjustment of temperature settings, so the utility can remotely adjust the temperature to reduce demand from central air-conditioning (CAC) and central space heating units. After an event, load control is released, allowing the thermostat control to revert back to the customer's original settings.

Water heating DLC: Like DLC for heating and cooling, water heating DLC allows the utility to control the load of electric resistance water heaters. The water heating element is turned off during times when load reductions are needed, and turned back on before the average water temperature in the tank drops below a minimum threshold. In some applications, the water is superheated during nighttime hours to allow for longer periods of load curtailment during the day. One difference between water heating DLC and space heating/cooling DLC is that water heaters are used, on average, year-round and during all hours of the day, and can be interrupted without any detectable impact by the customer.

Curtailable tariff. This is similar to PGE's Firm Load Reduction program (Schedule 77).[4] Under a curtailable tariff, eligible customers agree to reduce demand by a specific amount or curtail their consumption to a pre-specified level. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (typically expressed as $/kW-month or $/kW-year) and are paid to be on call even though actual load curtailments may not occur. The amount of the capacity payment varies with the load commitment level and the amount of notice required (e.g., number of hour or minutes). In addition to the fixed capacity payment, participants typically receive a payment for energy reduction. Since load reductions must be of firm resource quality, curtailment is often mandatory and penalties can be assessed for under-performance or non-performance.

Third-party C&I DLC: This is similar to PGE's Energy Partner program. With Third Party DLC, an "aggregator" (also known as a "curtailment services provider") works with customers to establish protocols to automate load reductions at times when they are needed from PGE. PGE purchases the aggregated load reduction from the aggregator, who shares the revenues with the customers who participate in the program. With the Third Party DLC program, customer recruitment and certain operational aspects of the program are handled by the aggregator rather than the utility.

EMERGING DR OPTIONS

Several new DR options were analyzed in this study. These are DR options with which there is relatively limited experience to-date. However, the programs have garnered significant interest from utilities around the U.S. recently and are beginning to be tested through pilot programs and some full-scale rollouts.

Bring-your-own-thermostat (BYOT): In a BYOT program, customers who already own a smart thermostat are paid to participate in a DLC program. An advantage of this program over a traditional heating/cooling DLC program are that the customer already has the necessary equipment, so there are no equipment or installation costs associated with the program. Additionally, given that the customer has made the decision to invest in a smart thermostat, it is likely that participants are already more engaged in their energy usage than the typical customer. In PGE's service territory, the market penetration of central A/C is growing rapidly and the Energy Trust of Oregon (ETO) is promoting the adoption of smart thermostats for energy efficiency benefits, suggesting that the eligible customer base for such a program will grow considerably in the coming years. Even the low-end of the range of national studies on likely smart thermostat adoption suggests that 25 percent of households will be equipped with a smart

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4 Whereas PGE's Schedule 77 program has a specific design and incentive structure developed by PGE, our assessment of the Curtailable Tariff program in this study is based on average participation across a range of curtailable tariff program designs in the U.S. In this sense, our analysis is for a more generic design that is a hybrid of these programs.

thermostat by 2020.[5] Several utilities, such as Austin Energy, Southern California Edison, ConEd, and Hydro One have recently introduced BYOT programs. PGE is currently exploring this program option through a pilot program with Nest Labs.

Behavioral DR (BDR): In a BDR program customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. BDR can be thought of as a PTR without the rebate payment. Customers are typically informed of the need for load reductions on a day-ahead basis and events are called somewhat sparingly throughout the year. Customer response is driven by new information that they didn't previously have. BDR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, BGE, and four Minnesota cooperatives.

Smart water heating DLC: In contrast to the conventional water heating DLC program described above, smart water heating DLC accounts for an emerging trend toward the availability and adoption of "DR-ready" water heaters. These water heaters come pre-equipped with the communications capability necessary to participate in a DR program and have the potential to offer improved flexibility and functionality in the control of the heating element in the water heater. Rather than simply turning the element on or off, the thermostat can be modulated across a range of temperatures. Multiple load control strategies are possible, such as peak shaving, energy price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. This has the potential for facilitating the integration of intermittent sources of generation. Smart water heating DLC was modeled for electric resistance water heaters, as these represent the vast majority of electric water heaters in the Pacific Northwest and are the most attractive candidates for a range of advanced load control strategies.[6]

EV charging load control: EVs represent a potentially flexible source of nighttime load, and adoption of EVs is projected to grow in the future. This study focuses only on the potential to control home charging of personal EVs. It does not include, for example, load control at public charging stations or for commercial fleets.

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[5] Berg Insight, "Smart Homes and Home Automation," January 2015.

[6] It may also be possible to control the load of heat pump water heaters, though there is more uncertainty around the technical and economic effectiveness of this option.

III. Methodology

This study focuses on estimating "maximum achievable potential." This is founded in the assumption that enrollment rates in the DR programs reach the levels attained in successful DR programs being offered around the country. Therefore, while the assumed enrollment levels have been demonstrated to be achievable by other utilities, they represent an approximate upper-bound based on recent DR experience. In other words they represent some of the highest enrollment levels observed in DR programs to-date.

A few factors suggest that PGE may be able to attain levels of enrollment approaching what the very top programs have achieved nationally:

1. There has been a long history of success with energy efficiency programs in PGE's service territory, suggesting that customers are open to participating in energy management programs.
2. PGE has an environmentally conscious customer base.
3. There has been a trend toward the rising adoption of new energy management products, such as smart thermostats, in the region.
4. Growth in summer peak demand means that DR programs that were previously not applicable to PGE's service territory can now be productively offered to customers.

At the same time, it is important to note that it will likely take time for PGE to approach these levels of enrollment. PGE, like much of the rest of the Pacific Northwest, is starting from a point of limited experience with DR programs and low energy prices relative to utilities in other regions of the U.S., and customers will need to be educated about the benefits of the programs before having the confidence to enroll. To some extent, this appears to have been the experience thus far with the Energy Partner program. Nationally, the most successful DR programs often required years of promotion and experimentation by utilities and aggregators before achieving the high enrollment levels that are observed today.

DR potential is estimated using empirically-based assumptions about the eligible customer base, participation, and per-customer impacts. The fundamental equation for calculating the potential system impact of a given DR option is shown in Figure 1 below. Market characteristics (e.g. system peak demand forecast, customer load profiles, number of customers in each class, appliance saturations) were provided by PGE.

Figure 1: The DR Potential Estimation Framework

Potential DR Impact = Total Demand of Customer Base X % of Base Eligible to Participate X % of Eligible Customers Participating X % Reduction in demand per participant

PARTICIPATION

Two variations of maximum achievable potential were estimated for the pricing options (TOU, CPP, PTR), based on different assumptions about the manner in which these programs would be offered to customers. Opt-in deployment assumes that customers would remain on the currently existing rate and would need to proactively make an effort to enroll in the dynamic rate. Default deployment (also known as opt-out deployment) assumes that customers are automatically enrolled in a dynamic rate with the option to revert back to the otherwise applicable tariff if they choose. Default rate offerings are typically expected to result in significantly higher enrollment than when offered on an opt-in basis. Default deployment of dynamic pricing for residential customers is currently uncommon, although TOU rates have been rolled out on an opt-out basis across the province of Ontario, Canada and throughout Italy. PTR has been offered on an opt-out basis by Southern California Edison, Baltimore Gas & Electric (BGE), and Pepco Holdings in Maryland and Washington, D.C.

Participation in the pricing programs was based on a review of market research studies and full-scale deployments of time-varying rates. The market research studies used a survey-based approach to gauge customer interest in the various pricing options, while the full-scale deployments reflect actual experience in the field. Opt-in participation rates range from 13 to 28 percent, which varies by pricing option and customer segment. When offered on an opt-out basis, the participation assumptions range from 63 to 92 percent.

Participation in the conventional non-pricing programs is based on a review of DR program data collected by the Federal Energy Regulatory Commission (FERC).[7] FERC surveyed U.S. utilities to gather information on the types of DR programs they offer, the number of customers enrolled, the peak demand reduction capability of the programs, and several other variables. To establish a reasonable upper-bound on participation for this study, the 75th percentile of the distribution of participation rates in each program in the FERC database was used as the basis for enrollment. The resulting participation rates generally range from 15 percent to 25 percent, although they are higher in a few instances where significant enrollment has been observed (e.g., large C&I curtailable tariff enrollment of 40%).

Enrollment in emerging DR options (BYOT, behavioral DR, smart water heating DLC) was based largely on the experience of pilot programs, because by nature there is limited full-scale experience with the emerging options at this point. In instances where the programs have not been piloted, expert judgment was used to develop plausible enrollment estimates that were intuitively consistent with participation assumptions for other programs in the study.

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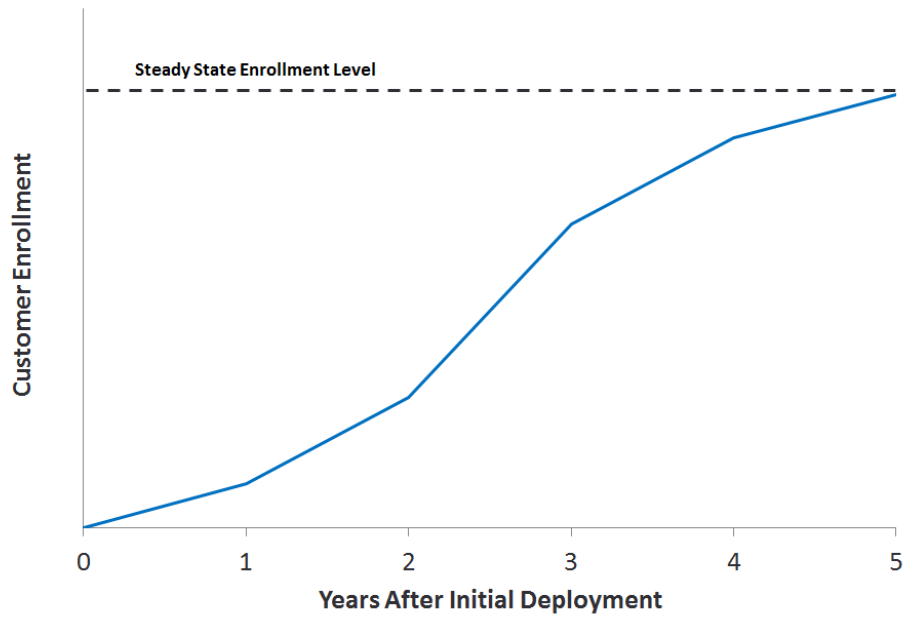
7 FERC, "Assessment of Demand Response and Advanced Metering," December 2012. Supporting database: http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp

Changes in participation are assumed to happen over a five-year timeframe once the new programs are offered. The ramp up to steady state participation follows an "S-shaped" diffusion curve, in which the rate of participation growth accelerates over the first half of the five-year period, and then slows over the second half (see Figure 2). A similar (inverse) S-shaped diffusion curve is used to account for the rate at which customers opt-out of default rate options. This reflects an aggressive ramp-up in participation for a utility with relatively limited DR experience like PGE. See Appendix A for more detail on the development of the participation assumptions.

Figure 2: Illustration of S-shaped diffusion curve



PER-PARTICIPANT IMPACTS

Per-participant impacts for the pricing options were based on the results of 225 different pricing tests that have been conducted across 42 residential pricing pilots over roughly the past 12 years.[8] These pilots have almost universally found that customers do respond to time-varying rates, and that the amount of price responsiveness increases as the peak-to-off-peak price ratio in the rate increases. The simulated impacts that were simulated for PGE in this study account for this non-linear relationship between a customer's price responsiveness and the peak-to-off-peak price ratio. The impacts also account for differences by season, across rate designs, and whether the rates are assumed to be offered on an opt-in or default basis. The study has assumed a price ratio of two-to-one in the TOU rate, four-to-one in the CPP rate, and eight-to-one in the PTR rate.

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[8] Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, August/September 2013.

These price ratios were provided by PGE based on rate designs that they would consider offering in the future.

Impacts for conventional non-pricing programs remained relatively stable relative to PGE's 2012 DR potential study, given the long history of experience with these programs in the U.S. In this updated study for PGE, those impact assumptions were refreshed based on a review of ten DR pilot programs that have been conducted in the Pacific Northwest. For the emerging DR options, impacts were based on the findings of pilots where available and otherwise calibrated to the impacts of other DR programs in the study to ensure reasonable relative impacts across the programs. While estimates of impacts associated with all of the programs have some degree of uncertainty, there is less uncertainty in the impacts of the conventional and pricing programs due to significant experience with these programs through both a full-scale rollouts and scientifically rigorous pilots. There is a higher degree of uncertainty in the impacts of the emerging DR programs as, by nature, they are newer and less tested. See Appendix B for more detail on the development of the per-participant impact assumptions.

COST-EFFECTIVENESS

The cost-effectiveness of each DR option was assessed using the total resource cost (TRC) test. The TRC test measures the total benefits and costs of a program, including those of both the utility and the participant. The TRC test is the cost-effectiveness framework that is commonly used by the Oregon PUC to assess the economics of demand-side programs. The present value of the benefits is divided by the present value of the costs to arrive at a benefit-cost ratio. Programs with a benefit-cost ratio greater than 1.0 are considered to be cost-effective. [9]

Benefits in the cost-effectiveness analysis include:[10]

- Net avoided generation capacity cost ($145/kW-yr)[11]
- Avoided peak-driven T&D cost ($31/kW-yr)
- Avoided peak energy cost ($32/MWh, growing over time)

9 For further information on cost-effectiveness analysis of DR programs, see Ryan Hledik and Ahmad Faruqui, "Valuing Demand Response: International Best Practices, Case Studies, and Applications," prepared for EnerNOC, January 2015.

10 Avoided cost estimates were provided by PGE and reviewed by The Brattle Group for reasonableness.

11 The total cost of a peaking unit is reduced by an estimate of the unit's expected energy margins to arrive at a net avoided cost that would be roughly equivalent to the net cost of new entry (CONE) in an organized capacity market.

Costs in the cost-effectiveness analysis vary by program type and include:[12]

- Program development
- Administrative
- Equipment and installation
- Operations and maintenance
- Marketing and recruitment
- Incentive payments to participants

Treatment of participant incentives as a cost was given close consideration in the study. There is not a standard approach for treating incentives when assessing the cost-effectiveness of DR programs. In some states, incentive payments are simply considered a transfer payment from utilities (or other program administrators) to participants, and therefore are not counted as a cost from a societal perspective. Others suggest the incentive payment is a rough approximation of the "hassle factor" experienced by participants in the program (e.g., reduced control over their thermostat during DR events), and should be included as a cost.

While there is some merit to the latter argument – that customers may experience a degree of inconvenience or other transaction costs when participating in DR programs – the cost of that inconvenience is overstated if it is assumed to equal the full value of the incentive payment. If that were the case, then no customer would be better off by participating in the DR program. For example, it would be unrealistic to assume that an industrial facility would participate in a curtailable tariff program if the cost of reducing operations during DR events (e.g., reduction in output) exactly equaled the incentive payment for participating. In reality, customers participate in DR programs because they derive some incremental value from that participation. Further, in some DR programs customers experience very little inconvenience. Some A/C DLC programs, for instance, can pre-cool the home and manage the thermostat in a way that few customers report even being aware that a DR event had occurred, let alone a loss of comfort.

Given the uncertainty around this assumption, this study counts half of the incentive payment as a cost in the cost-effectiveness analysis. Two sensitivity cases were also analyzed, exploring how the findings change when the full incentive is counted as a cost as well as when it is entirely excluded from the calculation.[13] This is similar to the approach adopted by the California Public

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12 Costs of the programs were typically annualized over a 15-year life in this study. Fifteen years is an illustrative but plausible assumption. While the life of individual appliances and technologies will vary around this number, the impact of that variance is well within the magnitude of other uncertainties in the analysis such as projections of marginal costs and load growth. In future research, sensitivity analysis could be conducted around uncertain variables such as these to develop a better understanding of the key drivers of the findings.

13 See Appendix C for the results of the sensitivity cases. Relative to the case where half of the incentive is included as a cost, when none of the incentive is included as a cost, water heating load control for

Continued on next page

Utilities Commission, which considers a range of treatments of the incentive payment when evaluating DR cost-effectiveness.

Another important consideration in the cost-effectiveness analysis is how to derate avoided capacity costs to account for operational constraints of the DR programs. Unlike the around-the-clock availability of a peaking unit, DR programs are typically constrained by the number of load curtailment events that can be called during the course of a year. Further, there are often pre-defined limitations on the window of hours of the day during which the events can be called, and sometimes even on the number of days in a row that an event may be called. It is also often the case that hour-ahead or day-ahead notification must be given to participants before calling an event. All of these constraints can potentially limit the capacity value of a DR program.

Some utilities account for these constraints of DR programs through a derate factor that is applied to the avoided capacity costs that are estimated for any given DR program. The derate factor is program-specific and is estimated through an assessment of the relative availability of DR during hours with the highest loss of load probability. Historically, depending on program characteristics and utility operating conditions, some derate factors have ranged from zero to roughly 50 percent of the capacity value of the programs. The derate factor is program- and utility-specific.

In California, a methodology for establishing these derates has been codified by the CPUC in its DR Cost-Effectiveness Protocols.[14] There are effectively three factors that are used to adjust the avoided costs attributable to DR programs:

1. The "A Factor" represents the "portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted." In other words, it accounts for limitations on the availability of the DR program, when DR events can occur, and how often.

Continued from previous page

small C&I, agricultural pumping load control, and technology-enabled PTR for residential and small C&I become moderately cost-effective. When the full incentive is counted as a cost, several DLC programs for residential and small C&I customers become slightly uneconomic. Across these cases, through the changes in the economics are relatively modest, with benefit-cost ratios that remain close to 1.0.

14 California Public Utilities Commission, "2010 Demand Response Cost-Effectiveness Protocols," December 16, 2010. http://www.cpuc.ca.gov/NR/rdonlyres/7D2FEDB9-4FD6-4CCB-B88F-DC190DFE9AFA/0/Protocolsfinal.DOC. An Energy Division Staff Proposal to update the protocols, dated June 2015, includes additional information on the derate factors and changes that are being considered: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=94268875

2. The "B Factor" accounts for notification time. Programs requiring day-ahead notification are less likely than programs with hour-ahead or real-time notification to coincide with system peak or reliability conditions due to forecasting uncertainty.

3. The "C Factor" accounts for limitations on any triggers or conditions that would permit the utility to call a DR event. For example, a DR tariff might only allow an event to be called if the outdoor air temperature exceeds some predetermined threshold.
4. Additionally, the CPUC defines two factors used to adjust T&D costs and energy cost, but those are specific to avoided assumptions in California and not directly applicable to this analysis for PGE. The CPUC is currently examining the possible modification and expansion of these factors.

To develop derate factors for PGE, the derate factors applied by the California investor-owned utilities (IOUs) to their extensive portfolio of DR programs were compiled.[15] Based on a review of these derate factors, the values were calibrated to capture the appropriate relative relationships across the programs evaluated for PGE. Expert judgement was used to develop estimates for those programs for which there is not a clear example in the California data. This approach – starting with approved utility estimates from a nearby jurisdiction and modifying them to better reflect the programs that could be offered by PGE – ensures that the estimates are based on actual DR program experience and reasonably well tailored to PGE's system conditions. As a result, the avoided capacity costs were derated anywhere between 19 and 47 percent. A summary of the portion of avoided capacity cost attributed to each DR program is presented in Table 1.

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15 See the links for the utility programs at the CPUC website: http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

Table 1: Share of Total Avoided Cost Attributed to DR Program

Class	Program	A) Availability	B) Notification	C) Trigger	Combined
Residential	TOU - No Tech	65%	100%	100%	65%
Residential	CPP - No Tech	60%	88%	100%	53%
Residential	CPP - With Tech	60%	88%	100%	53%
Residential	PTR - No Tech	60%	88%	100%	53%
Residential	PTR - With Tech	60%	88%	100%	53%
Residential	DLC - Central A/C	70%	100%	95%	67%
Residential	DLC - Space Heat	70%	100%	95%	67%
Residential	DLC - Water Heating	85%	100%	95%	81%
Residential	DLC - BYOT	70%	100%	95%	67%
Residential	Behavioral DR	70%	88%	100%	62%
Small C&I	TOU - No Tech	65%	100%	100%	65%
Small C&I	CPP - No Tech	60%	88%	100%	53%
Small C&I	CPP - With Tech	60%	88%	100%	53%
Small C&I	PTR - No Tech	60%	88%	100%	53%
Small C&I	PTR - With Tech	60%	88%	100%	53%
Small C&I	DLC - Central A/C	70%	100%	95%	67%
Small C&I	DLC - Space Heat	70%	100%	95%	67%
Small C&I	DLC - Water Heating	85%	100%	95%	81%
Medium C&I	CPP - No Tech	60%	88%	100%	53%
Medium C&I	CPP - With Tech	60%	88%	100%	53%
Medium C&I	DLC - AutoDR	75%	100%	95%	71%
Medium C&I	Curtailable Tariff	75%	88%	100%	66%
Large C&I	CPP - No Tech	60%	88%	100%	53%
Large C&I	CPP - With Tech	60%	88%	100%	53%
Large C&I	DLC - AutoDR	75%	100%	95%	71%
Large C&I	Curtailable Tariff	75%	88%	100%	66%
Agriculture	DLC - Pumping	75%	100%	95%	71%

Notes: A-factor estimates for dynamic pricing (PTR and CPP), residential DLC, and curtailable tariffs are derived from values estimated by the California utilities. A-factor estimates for other programs are based on intuitive relationships to those programs. B-factor estimates follow a general assumption observed in California that day-ahead programs have an 88% value and day-of programs have a 100% value. C-factor estimates in California tend to assume 100% for all programs except DLC, for which the assumption is 95%.

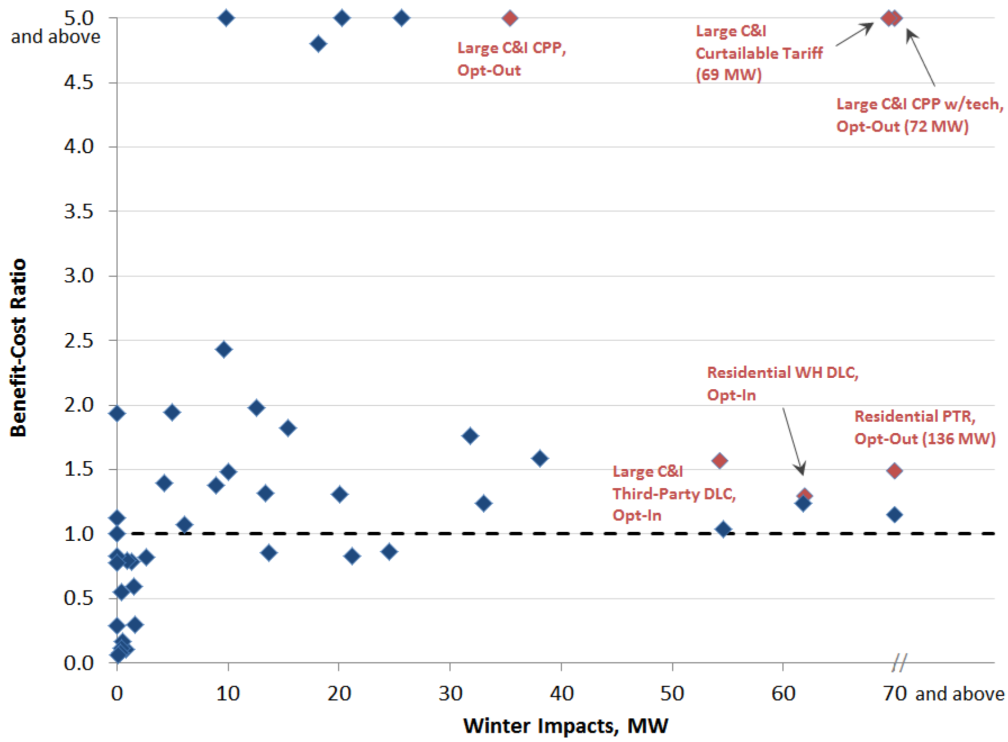
IV. Findings

The result of the analysis is an estimate of the maximum achievable peak reduction capability of each DR program for each year from 2016 through 2035, as well as a benefit-cost ratio for each program. These annual results are provided in Appendix D as a Microsoft Excel File. The results can be organized around 10 key findings:

1. The largest and most cost-effective DR opportunities are in the residential and large C&I customer segments
2. Residential pricing programs present a large and cost-effective opportunity to leverage the value of PGE's AMI investment
3. The incremental benefits of coupling enabling technology with pricing options are modest from a maximum achievable potential perspective and perhaps best realized through a BYOT program
4. BYOT programs offer better economics than conventional DLC programs but lower potential in the short- to medium-term
5. Residential water heating load control is a cost-effective opportunity with a broad range of potential benefits
6. EV charging load control is relatively uneconomic as a standalone program due to low peak-coincident demand
7. Small C&I DLC has a small amount of cost-effective potential
8. DR is highly cost-effective for large and medium C&I customers and the potential can be realized through a number of programs
9. Agricultural DR programs are small and uneconomic
10. The economics of some programs improve when accounting for their ability to provide ancillary services

Finding #1: The most cost-effective DR opportunities are in the residential and large C&I customer segments. In fact, nine of the ten programs with the largest potential are in the residential and large C&I sectors. Those also tend to be the sectors with the most cost-effective programs. Figure 3 below illustrates each program's cost effectiveness relative to its peak reduction potential. Those programs in the top-right portion of the chart provide the biggest "bang for the buck" whereas those in the bottom-left corner are small and uneconomic. The largest and most cost-effective programs tend to be pricing programs for residential and large C&I customers.

Figure 3: Winter Potential vs. B-C Ratio by Measure



Finding #2: Residential pricing programs present a large and cost-effective opportunity to leverage the value of PGE's AMI investment. If offered on an opt-out basis, residential PTR and CPP programs could potentially provide over 100 MW of peak reduction capability.[16] Offered on an opt-in basis, the potential is smaller but still in excess of 40 MW for both of these options. Impacts from TOU rates are smaller than those of PTR and CPP due to the lower peak period price in the TOU. However, the TOU impacts would represent a permanent shift in the daily system load profile due to the daily price signal embodied in the rate's design.[17] Based on the experience of recent pilot programs an opt-out BDR program could lead to peak demand reductions of close to 60 MW. However, given limited experience with BDR programs on a large scale, there is uncertainty around the extent to which the impacts would persist across multiple

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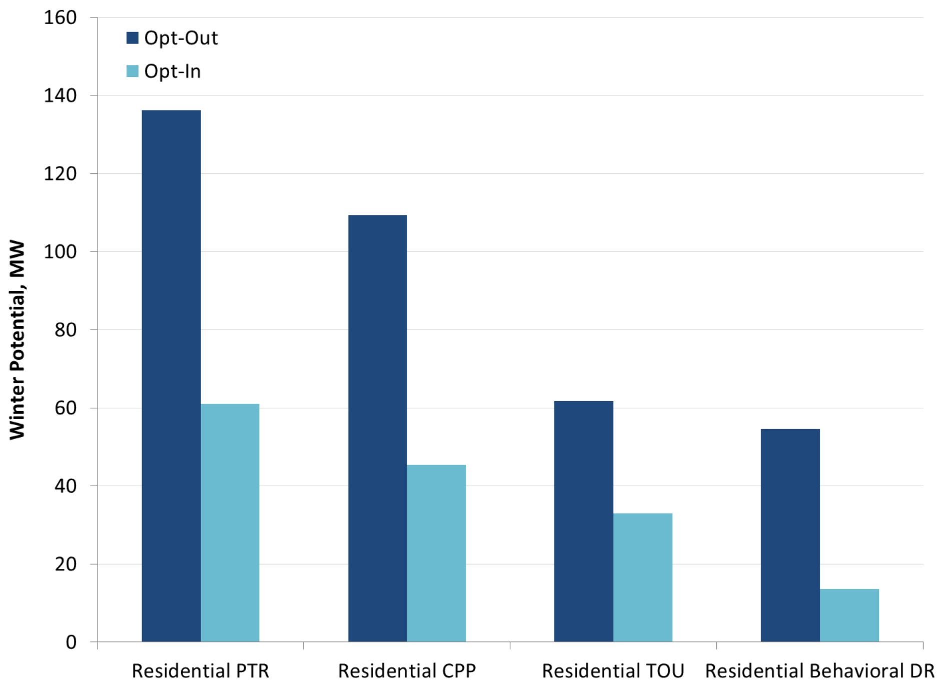
16 In this analysis, the higher potential in PTR relative to CPP is driven by the assumption that the PTR would have a significantly higher price ratio, and therefore produce larger per-participant load impacts. If the PTR and CPP were assumed to have the same price ratio, there would be more potential in a CPP rate offering.

17 It is also important to note that a TOU design could be coupled with a CPP or PTR rate. The TOU rate would apply most days of the year, with the CPP or PTR peak price (or rebate) applying on a limited number of days. This would provide both the daily load shifting benefits of the TOU rate and the advantages of a dynamic CPP or PTR price signal that can be dispatched in response to changing system conditions.

events and when deployed to all customers in PGE's service territory. There is significantly more certainty and reliability in the impacts of the pricing programs.

Figure 4 summarizes the potential estimates of residential pricing programs. All of these impacts are in the absence of enabling technology – they are purely based on behavioral response to the new prices and information. Additionally, it should be noted that the pricing options likely could not begin to be rolled out to customers on a full-scale basis until 2018 or 2019 due to constraints with the current billing system. While this would still leave time to reach significant enrollment levels by 2021, it means that the pricing options will not be available to address immediate needs for load reductions.

Figure 4: Winter Peak Reduction Potential for Residential Pricing and BDR



The programs are cost-effective in all cases except opt-in BDR.[18] For conventional pricing programs the opt-in offering has a slightly higher benefit-cost ratio than the opt-out offering due to marketing and education costs that are lower on a dollars-per-kW basis. However, opt-out offerings provide greater net benefits in absolute dollar terms. In all cases, the cost of AMI is not accounted for in the cost-effectiveness analysis as the infrastructure is already in place regardless of whether or not a decision is made to the offer pricing programs.

18 It is unlikely that BDR would be offered on an opt-in basis in any case. These programs are typically based on mass appeals to customers to reduce load, and customers could elect to opt out of the notifications if they desired.

Finding #3: The incremental benefits of coupling enabling technology with residential pricing options are modest and perhaps best realized through a BYOT program. The provision of enabling technology such as smart thermostats only modestly increases the potential of pricing options in the aggregate. On its surface, this appears counterintuitive because recent studies have found that enabling technology provides a 90 percent boost over the impact of price alone for a given customer, almost doubling their price responsiveness. The reason for the low incremental potential is that the eligible market for the technology is limited. We have assumed that only customers with both electric heat and central A/C would be eligible for pricing with enabling technology, as these are the only segment for which it is likely to be cost-effective given PGE's dual peaking nature and the need for load reductions in both the summer and winter seasons. Less than 10 percent of residential customers have both electric heat and central A/C. As a result, in the aggregate, potential increases only by about 5 MW for opt-in offerings and 10 MW for opt-out offerings.

Further, the provision of enabling technology by PGE does not appear to be incrementally cost-effective. Assuming there is already a plan to roll out dynamic pricing to customers, the incremental load reduction capability provided by enabling technology, above and beyond the impact that would be achieved in the absence of the technology, is not enough to justify the cost. This is a different outcome from some other jurisdictions, where a summer peak and significant air-conditioning market penetration can help to justify the investment.

This conclusion changes when customers already own a smart thermostat; a BYOT program coupled with a dynamic pricing program could be highly cost-effective. In the future there may also be additional value in a "prices-to-devices" concept with real-time pricing and end-uses that provide automated response to changes in the price with short notification, as these programs could provide significant energy and even ancillary services benefits, in addition to avoided capacity costs. Additionally, the provision of enabling technology has the potential to improve customer satisfaction and participation in the programs by automating load reductions and allowing customers to "set it and forget it."

Finding #4: BYOT programs offer better economics than conventional DLC programs but lower potential in the short- to medium-term. As is illustrated in Figure 5, A/C load control is a particularly large summer resource, representing over 100 MW of peak reduction capability. Potential is significant but smaller in the BYOT program, because it will take time for adoption of smart thermostats to materialize in the market. However, BYOT programs offer better cost savings than conventional DLC because there is no associated equipment cost. Whereas the benefit-cost ratio of conventional A/C DLC is around 1.1, the benefit-cost ratio of a BYOT A/C program is close to 2.0.[19] A program design consideration, therefore, will be whether to pursue the larger potential in the conventional DLC program versus the most cost-effective potential in

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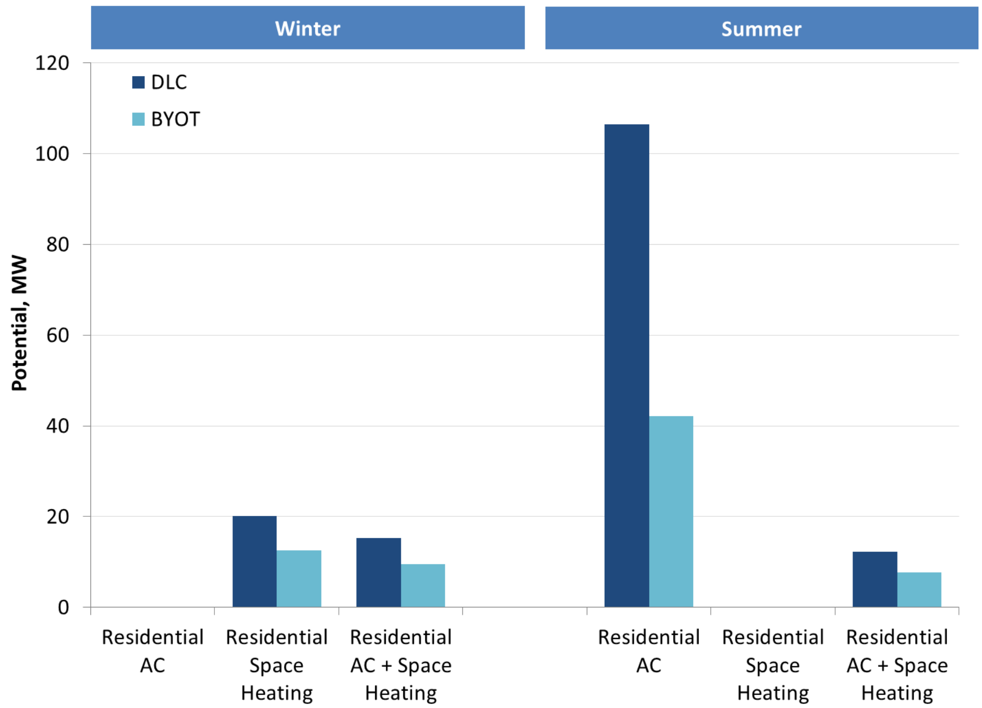
[19] Note that A/C load control in either form will become increasingly cost-effective as summer capacity needs escalate in PGE's service territory.

the BYOT program. The potential for differences in customer satisfaction with the programs is also an important consideration – this could be tested further through primary market research.

Figure 5: Seasonal Peak Reduction Potential for Residential DLC

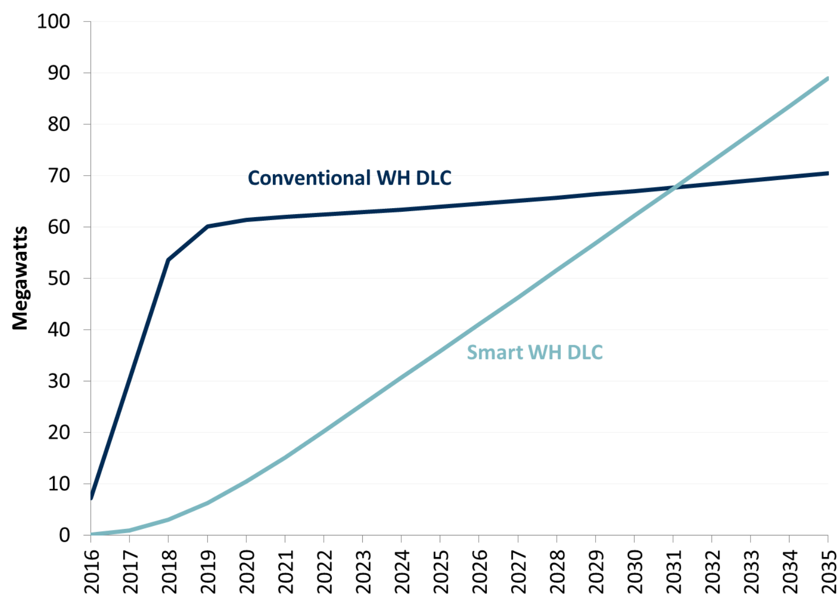


DLC programs are typically offered as part of a bundled package targeting multiple end-uses. Customers could receive different incentive payments based on the number of end-uses (A/C, space heating, electric water heating) they enroll in the program. Both the conventional DLC approach and the BYOT approach are cost-effective as bundled packages, with the conventional approach having a benefit-cost ratio of 1.3 and the BYOT approach having a ratio of 2.0. Additionally, for customers with an electric vehicle, EV charging load control could be added to the portfolio. In this case, the conventional approach would still be cost-effective, with a ratio of 1.2.

Finding #5: Residential water heating load control is a cost-effective opportunity with a broad range of potential benefits. As described in Section 3, two types of water heating load control programs were modeled. The first is conventional water heating DLC. With this type of program, it is assumed that the control technology is a retrofit on existing or new water heaters. The typical equipment and installation costs would amount to approximately $300 per participant.[20] The second type of program is "smart" water heating DLC. This assumes that DR-ready water heaters continue to gain market share. In this scenario, costs are lower, with roughly $40 for equipment and installation (a communications module) and an incremental manufacturing cost to build in the DR capability of $25 per water heater.

Smart water heating DLC potential is low in early years of the forecast horizon due to limited market penetration of "DR-ready" water heaters. However, if these water heaters gain market share, potential in the program will increase. Eventually, due to likely higher participation rates among customers who invest in DR-ready water heaters, the potential could exceed that of a conventional DLC program. Figure 6 illustrates the annual winter peak reduction potential estimate based on one plausible trajectory of smart water heating market penetration.[21]

Figure 6: Winter Peak Reduction Potential for Water Heating Load Control



Both program options are cost-effective, although the smart water heating DLC program has a considerably higher benefit-cost ratio of 2.2, compared to 1.3 in the conventional program. This is because DR-ready water heaters offer a number of cost saving opportunities relative to conventional DLC, primarily in the form of reduced equipment and installation costs. Smart water heaters could also incorporate more sophisticated load control algorithms that provide

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20 Cost assumptions for the water heating DLC analysis were derived from EPRI, "Economic and Cost-Benefit Analysis for Deployment of CEA-2045-Based DR-Ready Appliances," December 2014. Some costs were modified to be consistent with assumptions for other DR programs in this study.

21 Assumes 6% annual replacement of the existing stock of electric resistance water heaters, the assumed annual share of new water heaters that are DR-ready reaching 60% by 2022, and 25% of those customers participating in a water heating DLC program.

harder-to-quantify benefits. These algorithms could facilitate larger load reductions than a conventional on/off switch in the long run by anticipating the water heating needs of the owner and responding accordingly. This technology could also reduce the risk of insufficient hot water supply following a DR event relative to the conventional technology.

Ultimately, with water heating load control programs, benefits will vary depending on the load control strategy and the characteristics of the electric water heater. For example, if equipped with the appropriate control technology, electric resistance water heaters can provide significant increases and decreases in average load with very little notification, making them an ideal candidate to offer ancillary services.[22] Alternatively, or possibly in conjunction with this strategy, water heaters could be used as a form of thermal energy storage. Large tanks equipped with a mixing valve can super-heat the water at night and then require little to no additional heating during the day. This would be beneficial in a situation where the marginal cost of generating electricity is low or even negative at night (e.g., large amounts of nighttime wind generation coupled with inflexible baseload capacity) or when energy prices are high during the day; it provides an energy price arbitrage opportunity. The potential to provide this type of energy price arbitrage is highly dependent on the size of the water heater and the number of hours over which the load shifting is occurring.

Finding #6: EV charging load control is relatively uneconomic as a standalone program due to low peak-coincident demand. Most residential charging occurs during off peak hours. Figure 7 illustrates the average EV charging load profile across many EV owners. While any individual owner's charging load would likely be concentrated in a smaller number of hours, the average load profile is the relevant profile to use in this study, because it represents the load shape that would be associated with a number of DR program participants with naturally diverse charging patterns across the service territory. As shown in the figure, the average amount of peak-coincident load available to curtail on a per-participant basis is less than 0.2 kW. As a result, even if most or all of the charging load can be shifted away from the peak hours, the low peak reduction potential translates into small benefits relative to the cost of the charging control equipment and the program is not cost-effective on a standalone basis. Total load reduction capability in the program is less than 2 MW by 2021 and less than 8 MW by 2035.[23]

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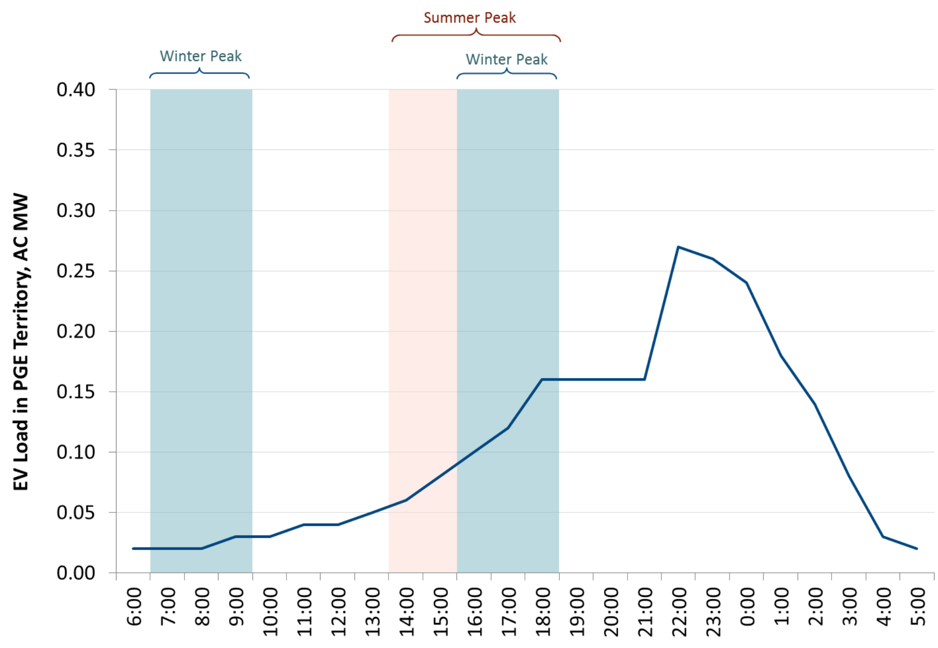
22 The technology that would facilitate this type of operation is in development and has been proven through a number of demonstration projects. It would include a potentially significant additional incremental cost beyond the costs modeled in this study.

23 Assumes roughly 140,000 personal EVs in PGE's service territory by 2025.

Figure 7: Average Hourly Home Charging Profile of EV Owner



Source: EV Project, October-December 2012

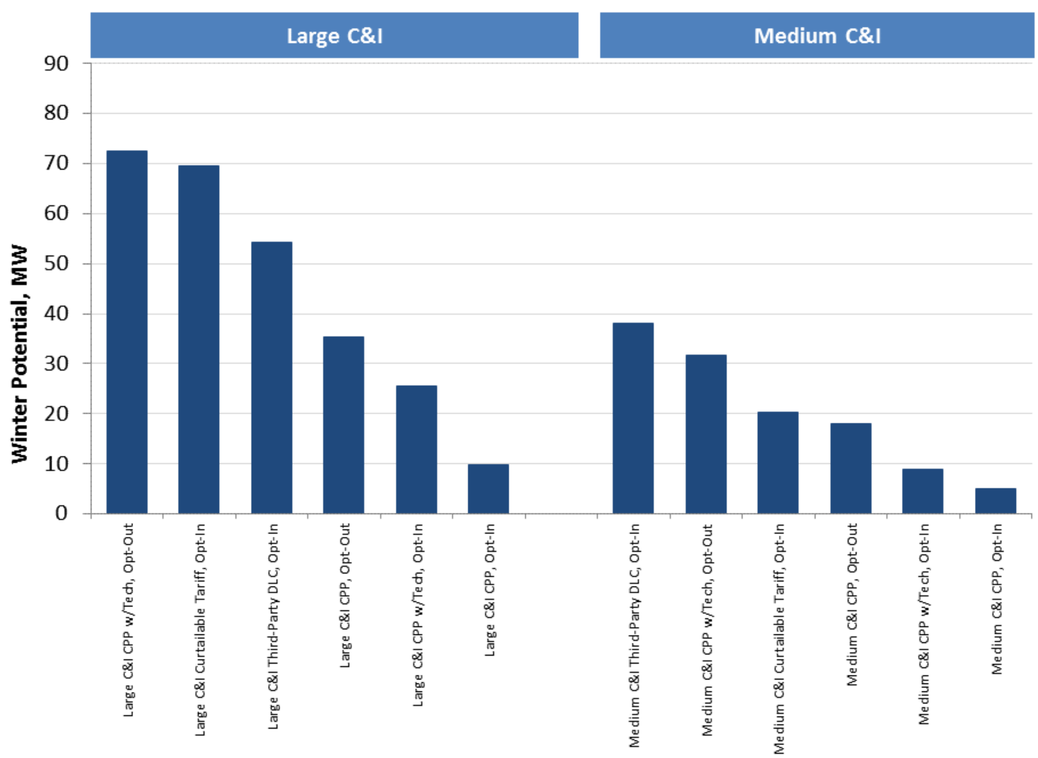
There are several important considerations to be aware of when interpreting these results, however. DR potential would be higher if targeting the late evening period with the most charging load; his time period could in fact eventually be the target of future DR programs that are designed to address distribution feeder-level constraints that are peaking at that time. The potential could also be higher in the future if EV owners adopt high-speed chargers that concentrate a larger amount of load in a smaller number of hours. It is also possible that there is more potential in programs focused on charging load outside the home. For example, the economics of load control at public charging stations might be more cost-effective. Control of commercial vehicle charging could also be cost-effective as part of a broader load control strategy, perhaps integrated with an Auto-DR program. Finally, as noted earlier in this section of the report, when EV charging load control is included as part of a broader DLC program, the package as a whole is cost effective.

Finding #7: Small C&I DLC has a small amount of cost-effective potential. Space heating DLC is the only cost-effective measure identified for the small C&I segment and its potential is small (around 6 MW in the winter). This is partly because small C&I customers tend to be unresponsive to time-varying rates unless equipped with enabling technology. Generally, electricity costs are a small share of the operating budget for these customers and they lack the sophisticated energy management systems of larger C&I customers. Further, while there is some potential in technology-enabled options, these customers have historically tended to be less likely to enroll in a DR program and generally represent a small share of the total system load.

Finding #8: DR is highly cost-effective for large and medium C&I customers and the potential can be realized through a variety of programs. All of the analyzed DR programs are cost-effective for medium and large C&I customers. Customer acquisition costs tend to be lower on a dollars-per-kilowatt basis for these segments, leading to improved economics for DR. The large C&I segment accounts for the majority of the DR market in other regions of the U.S. for this reason.

In addition to being highly cost-effective, several large/medium C&I programs have large peak reduction potential. Figure 8 summarizes the potential in each DR option. There is significant potential in a curtailable tariff and a third-party DLC program. A CPP rate would provide similarly large impacts. In general, these programs could be considered the "low hanging fruit" of the available DR options.

Figure 8: Winter Potential for Medium and Large C&I DR Programs



Finding #9: Agricultural DR programs are small and uneconomic in PGE's service territory. There are large irrigation load control programs in the Pacific Northwest, such as Idaho Power's Irrigation Peak Rewards program. However, PGE has little irrigation pumping load. Relative to other options, programs focused on agricultural customers are small and not cost-effective in PGE's service territory. While pumping load control could become slightly cost-effective if PGE were to become a more heavily summer peaking utility, it is still too small to be considered a top priority given the other DR opportunities that exist.

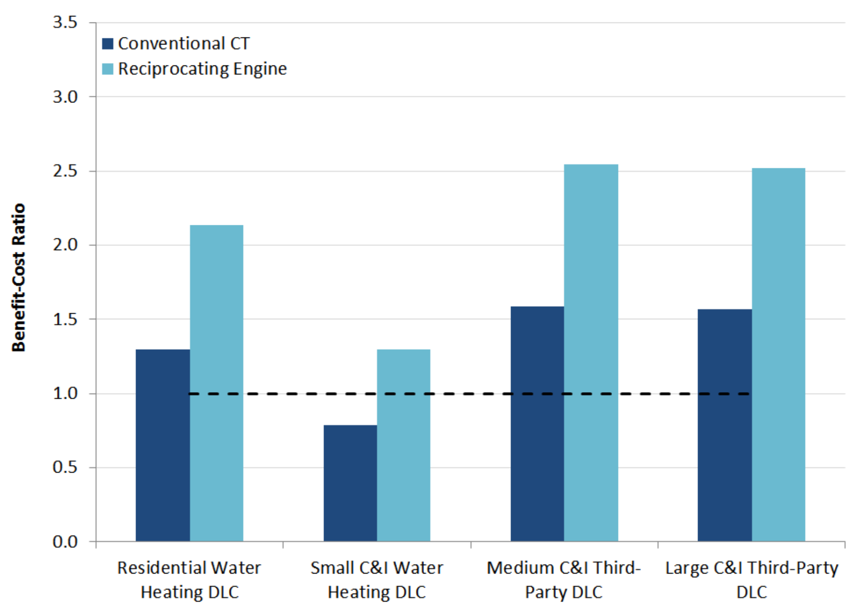
Finding #10: The economics of some programs improve when accounting for their ability to provide ancillary services. There is emerging interest in the Pacific Northwest in DR programs that can provide load reductions on very short notice in response to fluctuations in supply from intermittent generation resources like wind and solar. DR options that can provide both load decreases and increases provide even more value to the grid as ancillary services.

Since there is not currently an ancillary services market in the Pacific Northwest, the avoided cost of a reciprocating engine was used as a proxy for the value associated with these "fast" DR options. Reciprocating engines are more expensive than a conventional combustion turbine, but also have more operational flexibility and are better suited to address some of the reliability challenges posed by intermittent sources of generation.

Benefit-cost ratios were recalculated for those options capable of providing fast response (i.e., only DR options relying on automating technology). While the reciprocating engine is a good first-order approximation of this additional value, there are limitations to this approach and more granular analysis of the ancillary services value of the DR options would be informative in future research activities. Further, it should be noted that this cost-effectiveness analysis is based on the full coincident peak reduction capability of the programs; in practice, they would not be able to provide a reduction of that magnitude at regular intervals as an ancillary service, and the economics could change accordingly.

With a reciprocating engine as the basis for avoided costs, the economics improve for all programs and small C&I water heating DLC becomes cost-effective. Mass market water heating load control and medium and large C&I load control could provide fast ramping capability in the form of load increases and decreases, and would be particularly valuable as sources of ancillary services. Figure 9 illustrates the cost-effectiveness of these DR programs.

Figure 9: Cost-effectiveness for measures with "fast" load decrease and increase capability



V. Considerations for Future DR Offerings

This study utilized a detailed bottom-up approach to estimating PGE's peak demand reduction potential through DR programs. These estimates were carefully tailored to PGE's system conditions through research on likely adoption rates, per-customer impacts that are consistent with the experience of utilities around the country including the Pacific Northwest, and market conditions that are consistent with PGE's projections. The market potential for a variety of DR options and the economics of these options were assessed under a range of assumptions. The findings of the study suggest several considerations for future DR offerings by PGE.

Run a new dynamic pricing and behavioral DR pilot. A new pilot could provide insight about relatively untested issues such as the impact of a PTR in PGE's service territory, persistence in behavioral DR impacts, the relative difference in seasonal impacts of these programs, and even the difference in impacts when the rates are offered on an opt-in versus default basis. A pilot could also be designed to test a "prices-to-devices" concept involving real-time prices and automated response from specific end-uses, to address fluctuations in supply from renewable generation.

Develop a water heating load control program. There is a clear economic case for water heating load control and the potential benefits are diverse. Piloting or even a larger scale program would help to identify optimal load control strategies and further test the technical feasibility.

Continue to pursue opportunities in the large and medium C&I sectors. DR potential in the large C&I sector can be cost-effectively achieved through curtailable tariffs, third-party programs, and pricing options. Which of these programs to pursue is largely a strategic question, as each have their advantages and disadvantages. To maximize the participation from this customer segment, it may be beneficial to eventually pursue all of the program options through a portfolio-based approach.

Establish well-defined cost-effectiveness protocols. There does not appear to be a well-established approach to analyzing the cost-effectiveness of DR programs in Oregon. For example, the appropriate treatment of incentives as costs and the methodology for establishing derate factors to account for operational limitations of DR programs are two areas in need of further discussion. Reviewing the approaches being used in other states and tailoring these to the specific needs of the Oregon utilities would be a productive starting point. Well-defined protocols should be established while developing utility DR portfolios and strategies.

Develop a long-term rates strategy enabled by PGE's AMI investment. The strategy should address important considerations such as whether to offer new rates on an opt-in or default basis, the advantages and disadvantages of CPP versus PTR, whether a demand charge or increased customer charge is needed to address emerging inequities in cost recovery due to growing market penetration of distributed energy resources, how to transition customers to the new rate options, and other such considerations.

Explore the distribution system value of DR. Recent initiatives in other states have highlighted that the distribution-level value of DR may be understated in current practices. Additional analysis of distribution system constraints and the potential to deploy DR locally to address these constraints would be a useful research activity.

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Opower, "Using Behavioral Demand Response as a MISO Capacity Resource," June 4, 2014.

PG&E, "PG&E's SmartRate Program Tops 100,000 Participants," PG&E Currents, May 28, 2013.

Rocky Mountain Power, "Utah Energy Efficiency and Peak Reduction Annual Report," June 26, 2013 and May 16, 2014.

Appendix A:
Participation Assumptions

Exhibit PLC-S-2

Estimating Maximum Achievable Enrollment in DR Programs for PGE

PRESENTED TO

Portland General Electric

PRESENTED BY

The Brattle Group
Applied Energy Group

THE Brattle GROUP

In this presentation

This presentation summarizes the methodology and assumptions behind estimates of enrollment in potential new DR programs in PGE’s service territory

The presentation is divided into three sections

- Pricing programs
- Non-pricing programs included in prior PGE studies
- Non-pricing programs that are new to this study

Participation rates shown in this presentation are “steady state” enrollment rates once full achievable participation has been reached; they are expressed as a % of eligible customers

Pricing Programs

We developed enrollment estimates based on an extensive review of pricing participation studies

The enrollment estimates are derived from a review of 6 primary market research studies and 14 full scale deployments:

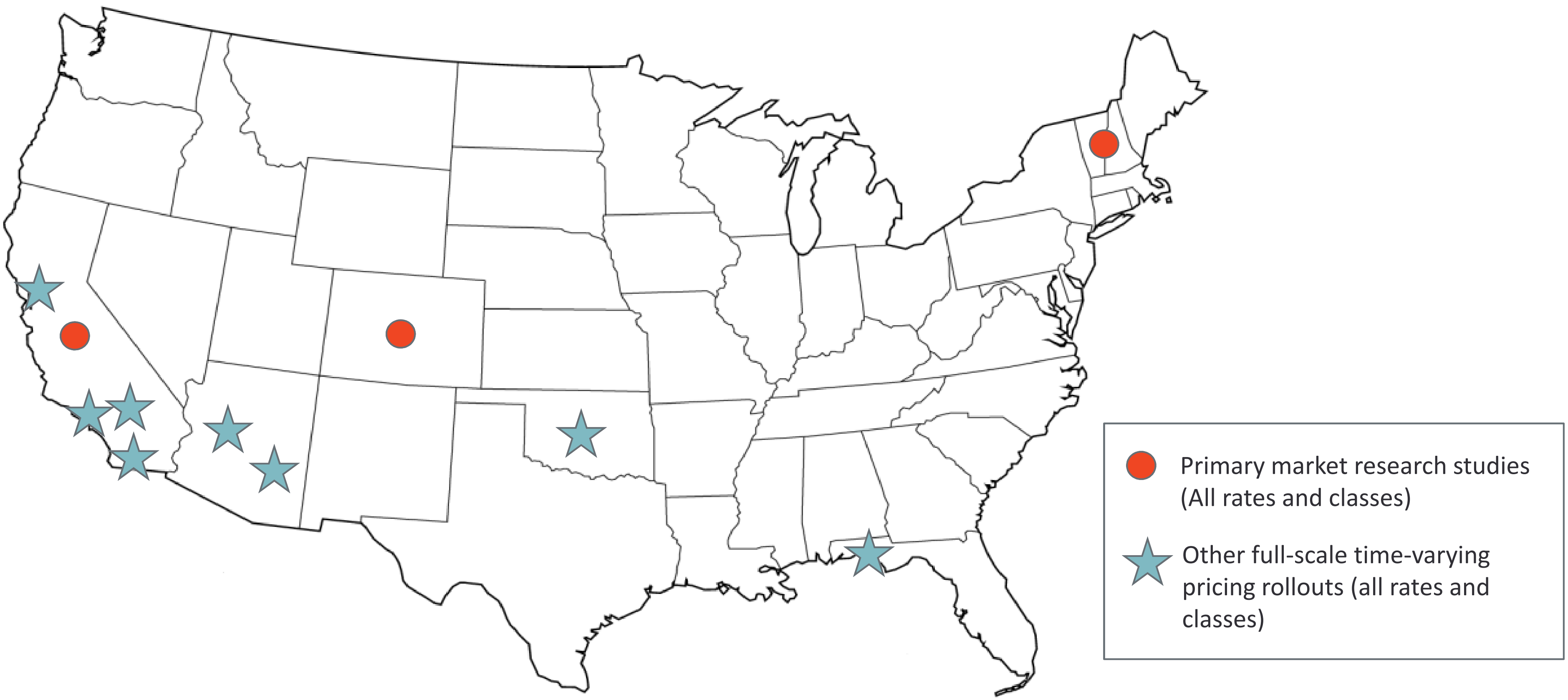
Primary market research studies

- A survey-based approach designed to gauge customer interest
- Adjustments were made to account for natural tendency of respondents to overstate interest in survey responses
- Respondents were randomly selected from utility customer base and confirmed to be representative of entire class
- Samples were large enough to ensure statistical validity of findings

Full-scale deployments

- Based on enrollment levels reported by utilities and competitive retail suppliers to FERC and other sources
- Restricted to programs with significant enrollment
- Focus on well marketed deployments

The market research studies and full-scale rate deployments span many regions of the U.S.



Additionally, our analysis includes the Ontario, Canada TOU rollout and three non-public market research studies in the Upper Midwest, Central Midwest, and Asia

Full-scale rate offerings have mostly been for residential and large C&I customers

Utility/Market	State/Region	Applicable class	Rates	Offering type	Approx. years offered
Arizona Public Service (APS)	Arizona	Residential	TOU	Opt-in	30+
Ontario Power Authority (OPA)	Ontario, CA	Residential	TOU	Opt-out	2
Salt River Project (SRP)	Arizona	Residential	TOU	Opt-in	30+
Gulf Power	Florida	Residential	CPP	Opt-in	14
Oklahoma Gas & Electric (OGE)	Oklahoma	Residential	CPP	Opt-in	2
Pacific Gas & Electric (PG&E)	California	Residential	CPP	Opt-in	3
Oklahoma Gas & Electric (OGE)	Oklahoma	Large C&I	TOU	Opt-in	?
Pacific Gas & Electric (PG&E)	California	Large C&I	CPP	Opt-out	3
San Diego Gas & Electric (SDG&E)	California	Large C&I	CPP	Opt-out	3
Southern California Edison (SCE)	California	Large C&I	CPP	Opt-out	3
Los Angeles DWP (LADWP)	California	All C&I	TOU	Opt-in	?
Progress Energy Carolinas	North/South Carolina	All C&I	TOU	Opt-in	15+

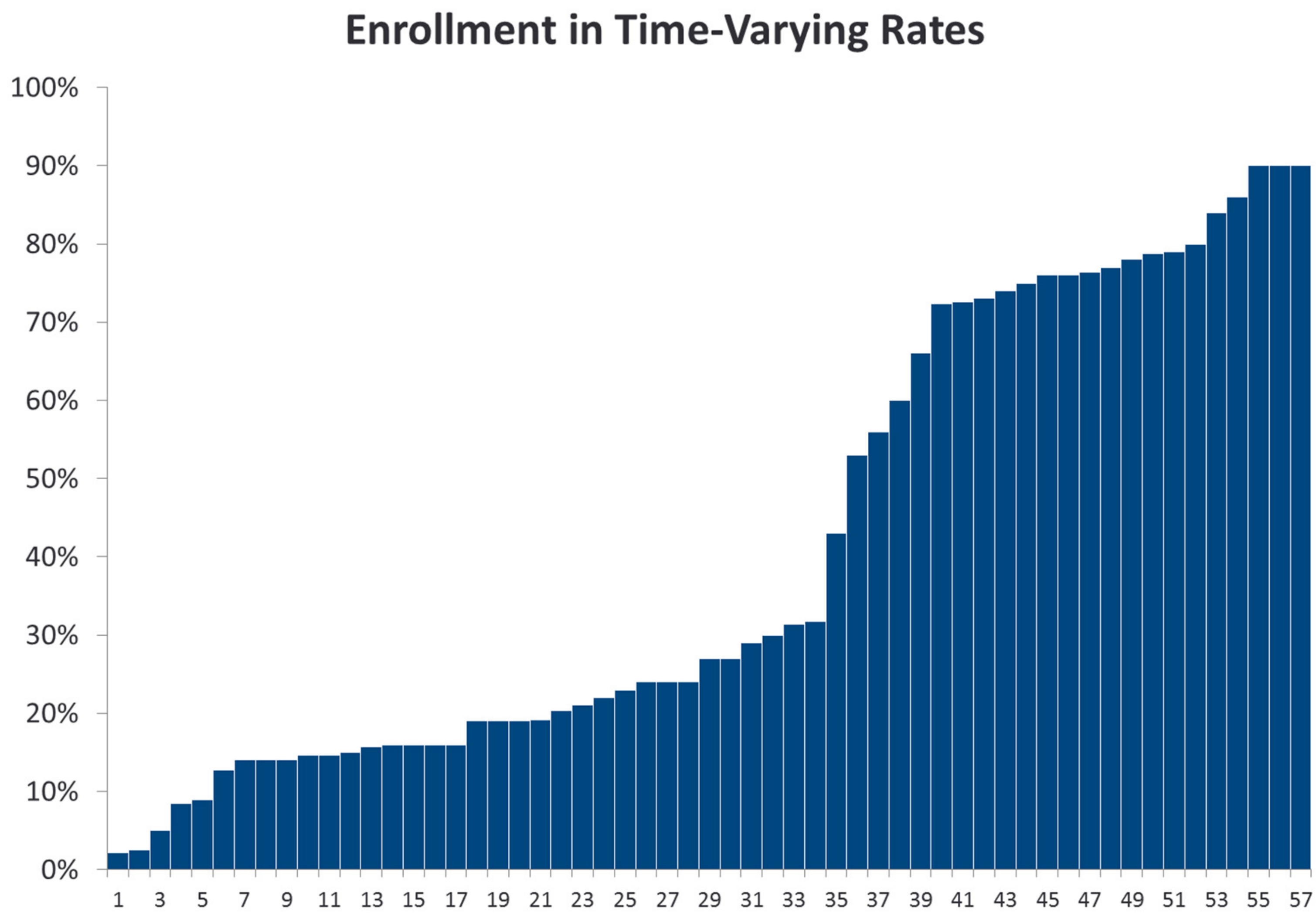
Notes:
BGE, Pepco, SDG&E and SCE have rolled out default PTR to their residential customers, but enrollment data is not available. Results are forthcoming.
The OPA TOU deployment is considered opt-out rather than mandatory because customers can switch to a competitive retail supplier.

The six market research studies primarily surveyed residential and small/medium C&I customers

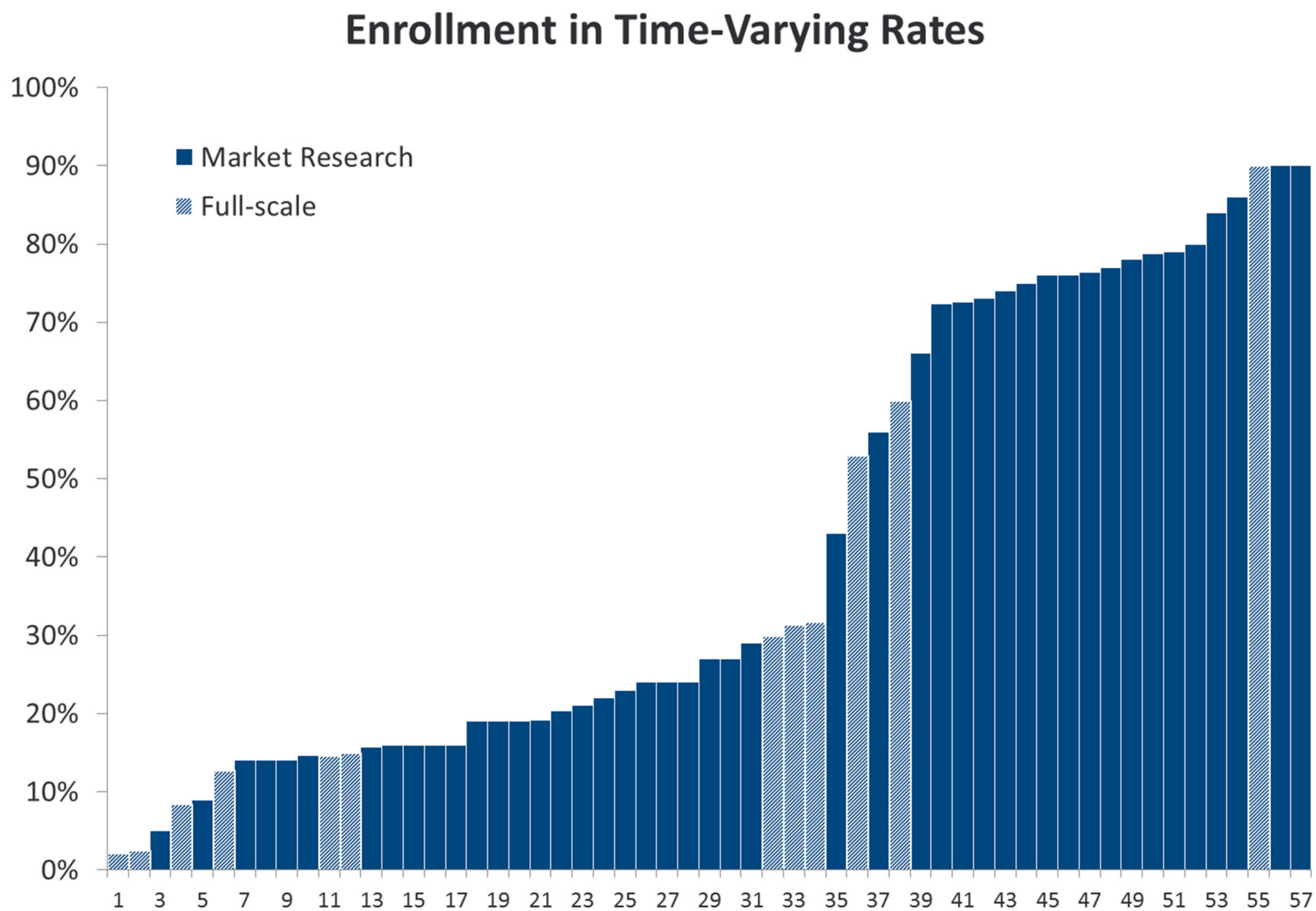
Utility/Market	Year of Study	Applicable classes			Rates	Deployment type	
		Res.	Small/Med	Large C&I		Opt-in	Opt-out
California IOUs	2003	X	X		TOU, CPP	X	X
ISO New England	2010	X	X		TOU, CPP, PTR, RTP	X	
Asian Utility	2013	X			TOU, PTR	X	
Large Midwestern IOU	2013	X	X	X	TOU, CPP	X	X
Mid-sized Midwestern Utility	2013	X	X		TOU, CPP	X	
Xcel Energy (Colorado)	2013	X	X	X	TOU, CPP, PTR	X	X

- These market research studies were conducted in order to form the basis for utility AMI business cases or DSM potential studies
- They were led by Dr. David Lineweber and a team of market researchers who are now with Applied Energy Group (AEG)

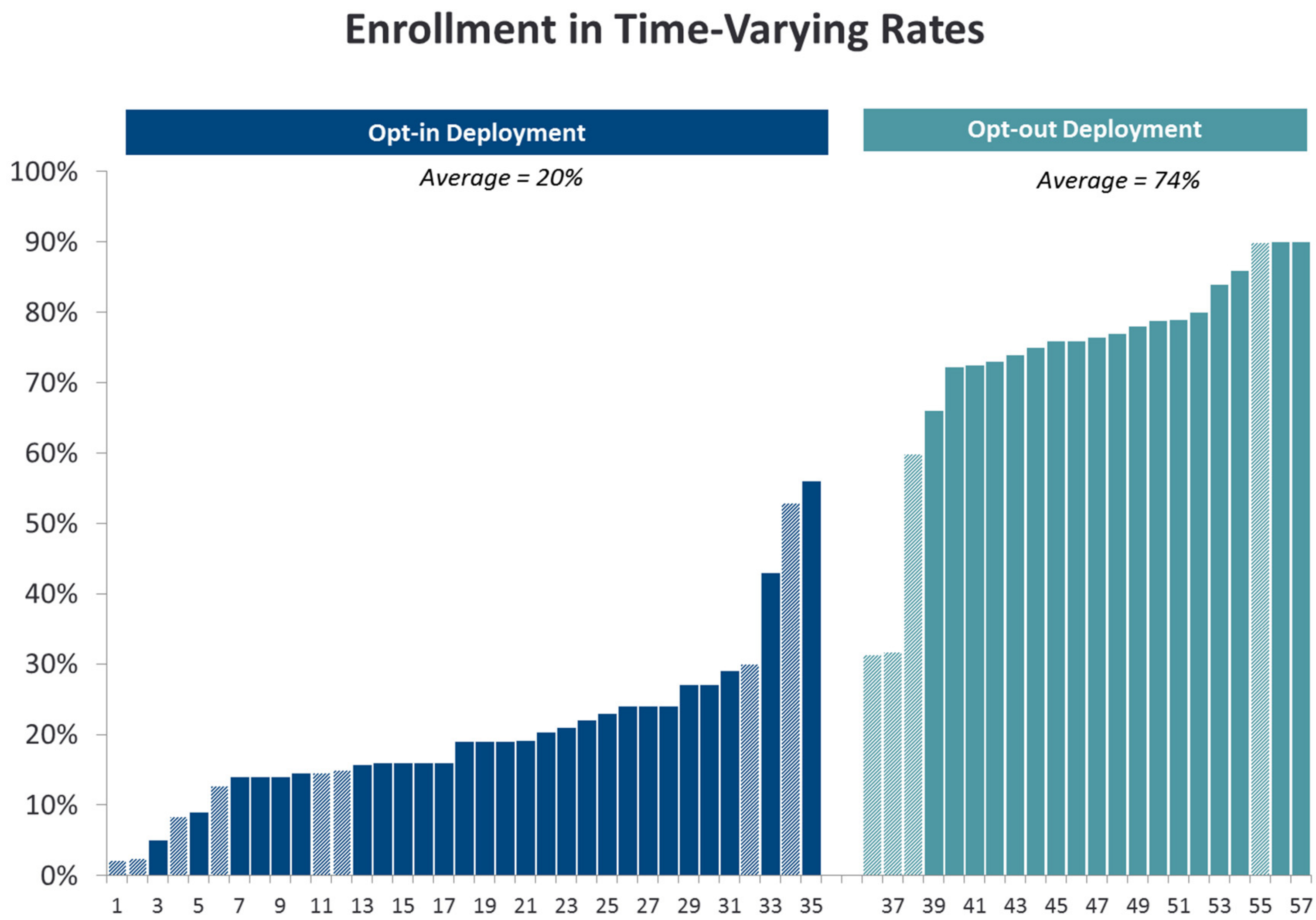
There are 57 enrollment observations across all of the studies (sorted low to high)



There is no obvious bias in market research results relative to full-scale deployments



Opt-out offerings result in significantly higher enrollment on average



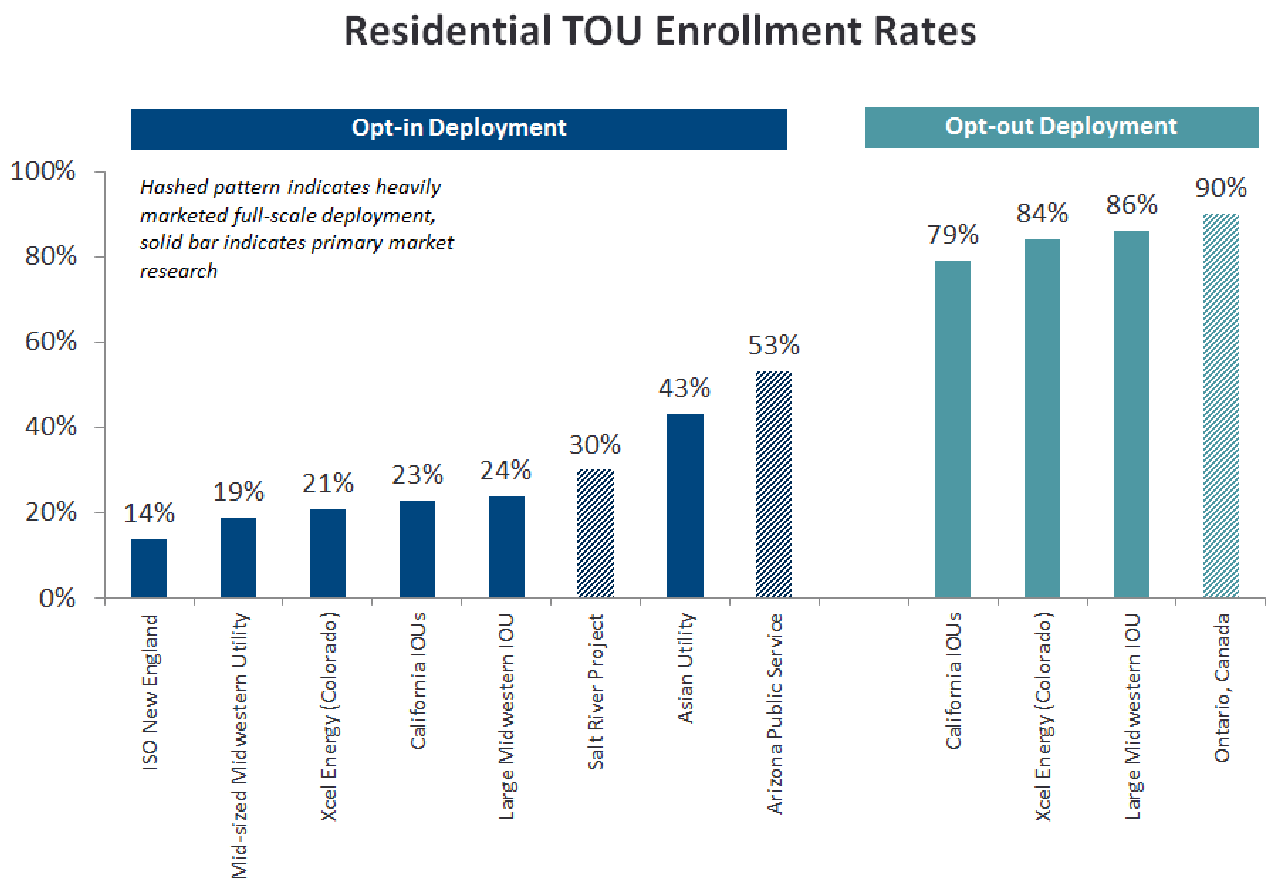
The enrollment data can be further organized with additional granularity

We have organized the data across the following elements

- Customer class (residential vs non-residential)
- Rate (TOU, CPP)
- Offering (opt-in vs opt-out)

We summarize the key findings of this comparison in the slides that follow

The results of our residential TOU analysis are summarized below

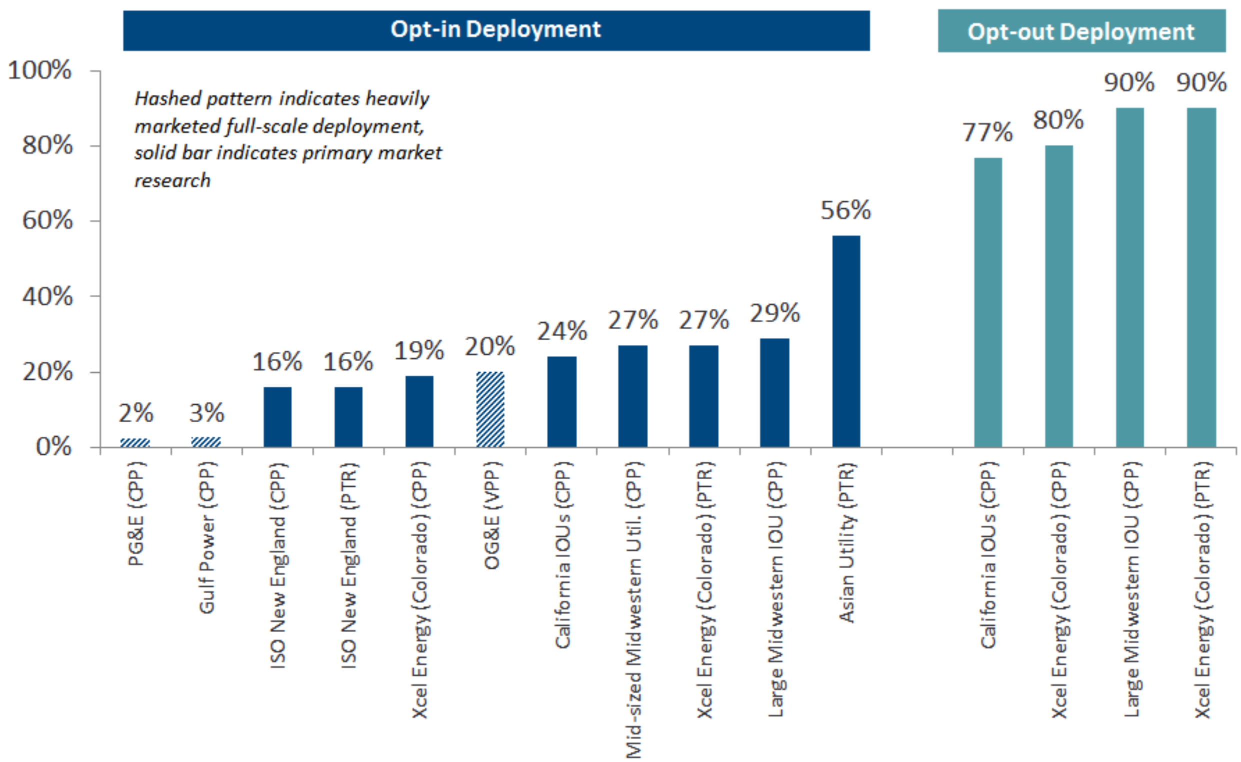


Comments

- Opt-in average = 28%
- Opt-out average = 85%
- Opt-out rate offerings are likely to lead to enrollments that are 3x to 5x higher than opt-in offerings
- Arizona's high opt-in TOU participation is attributable to heavy marketing as well as large users' ability to avoid higher priced tiers of the inclining block rate
- In Ontario, the 10% opt-out rate includes some customers who switched to a competitive retail provider even before the TOU rate was deployed

Residential dynamic pricing enrollment observations are similar to those of TOU

Residential Dynamic Pricing Enrollment Rates



Note: Pepco and BGE have deployed a default residential PTR. Results forthcoming.

Comments

- Dynamic pricing options considered include CPP, variable peak pricing (VPP), and peak time rebates (PTR)
- PTR enrollment is roughly 20% higher than CPP enrollment
- OG&E's VPP rate was rolled out on a full scale basis in 2012 and has reached its target enrollment rate of 20% a year ahead of schedule
- Availability of Gulf Power's CPP rate is limited
- Additionally, Pepco, BGE, SCE, and SDG&E have deployed a default residential PTR; results are forthcoming

Why are the full scale residential dynamic pricing enrollment levels slightly lower than the market research results?

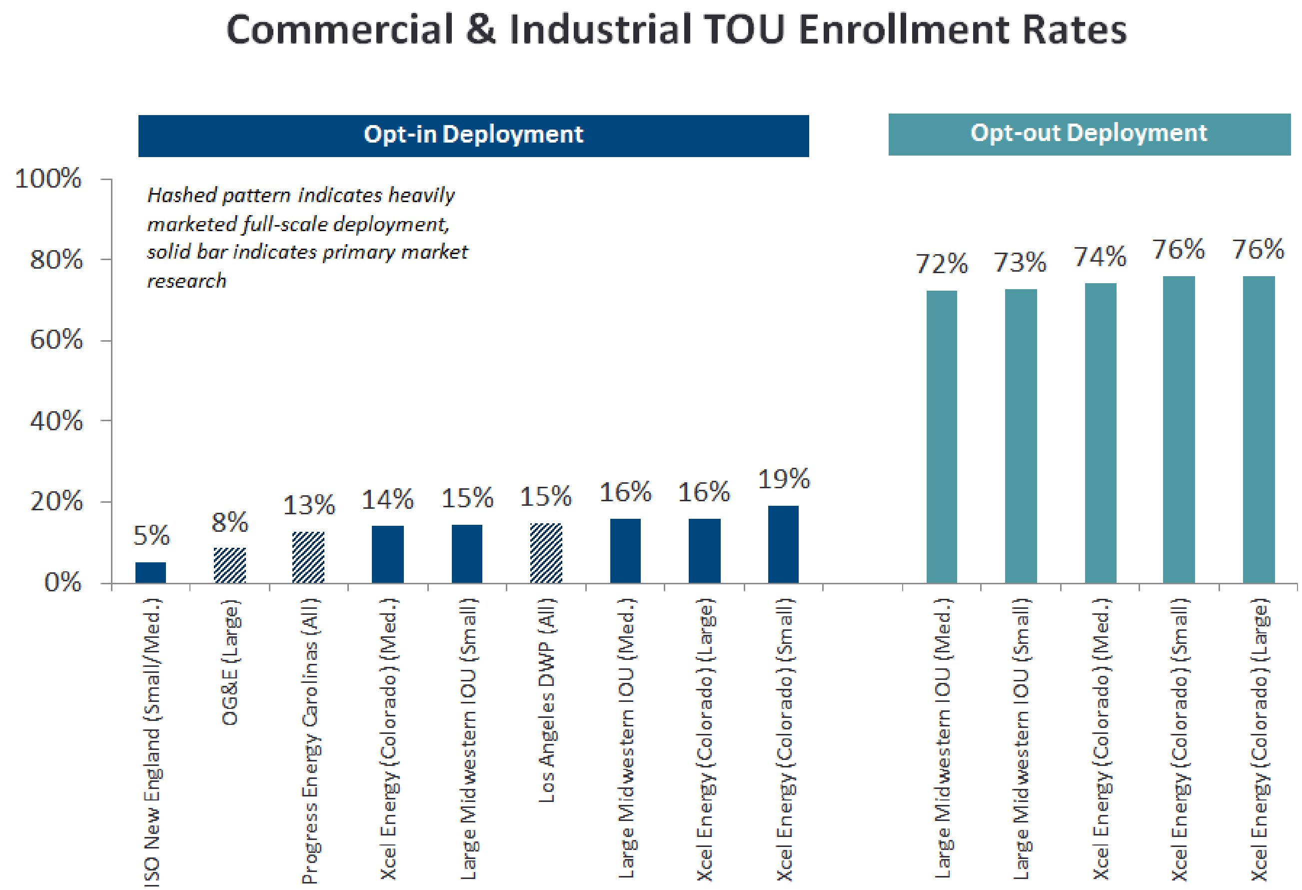
- The primary market research identifies all “likely participants” in the dynamic pricing rate, some of whom are very proactive and eager to sign up, while others would sign up but require more education, clear explanation, and additional outreach

- Most utility marketing budgets for dynamic pricing programs have been relatively low and are not designed to provide the type of outreach necessary to enroll customers falling in the latter category

- These customers represent untapped potential in the program and could likely be signed up with a more intensive marketing effort

- For example, heavily marketed utility energy efficiency programs with similar bill savings opportunities reach enrollment rates of 60%

C&I TOU enrollment levels are slightly lower than those of the residential class

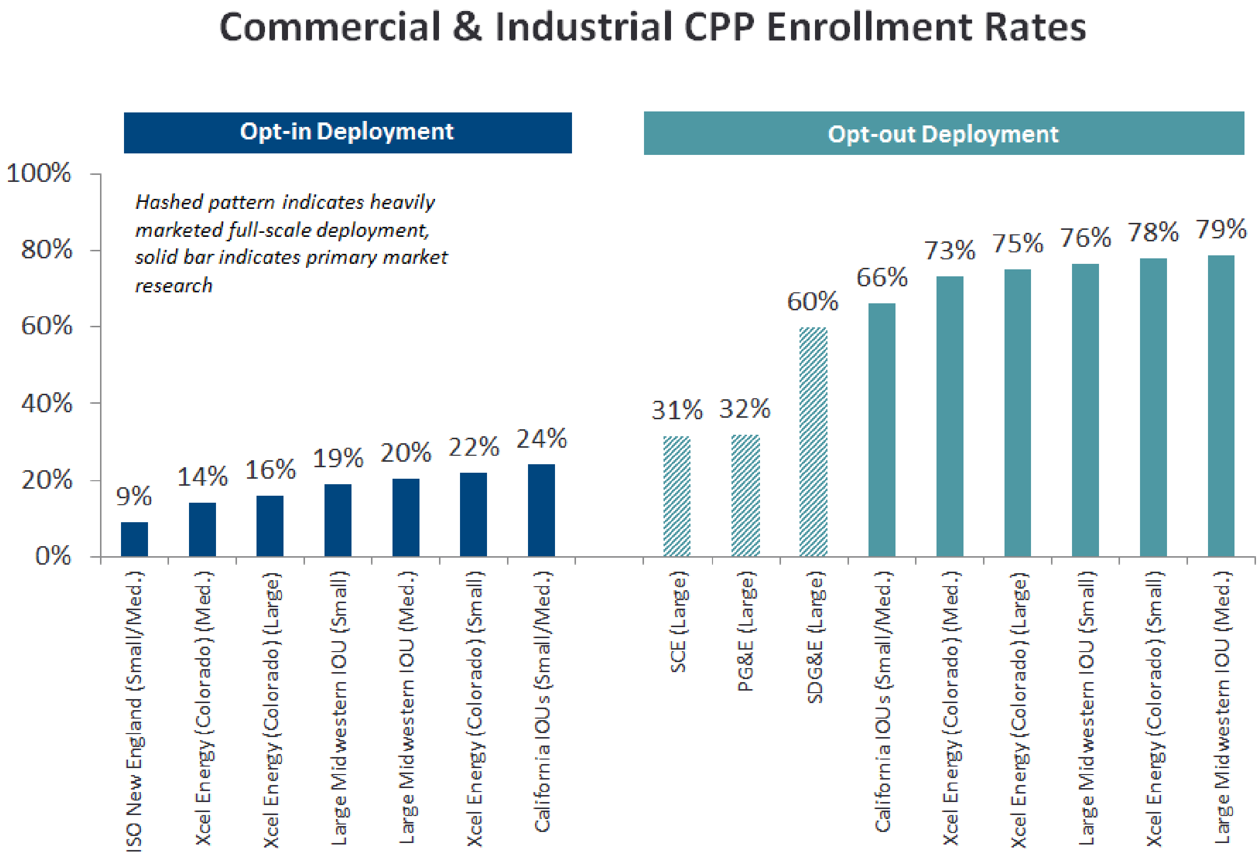


Note: Size of applicable C&I customer segment indicated in parentheses.

Comments

- Opt-in average = 13%
- Opt-out average = 74%
- Estimates are reported separately for Small, Medium, and Large C&I customers (as designated by the utility) where possible
- Full-scale opt-in deployment estimates were derived from FERC data, with a focus on the highest enrolled programs
- TOU rates are often offered on a mandatory basis to Large C&I customers; these are excluded from our assessment

There is limited full-scale CPP deployment experience for C&I customers



Note: Size of applicable C&I customer segment indicated in parentheses.

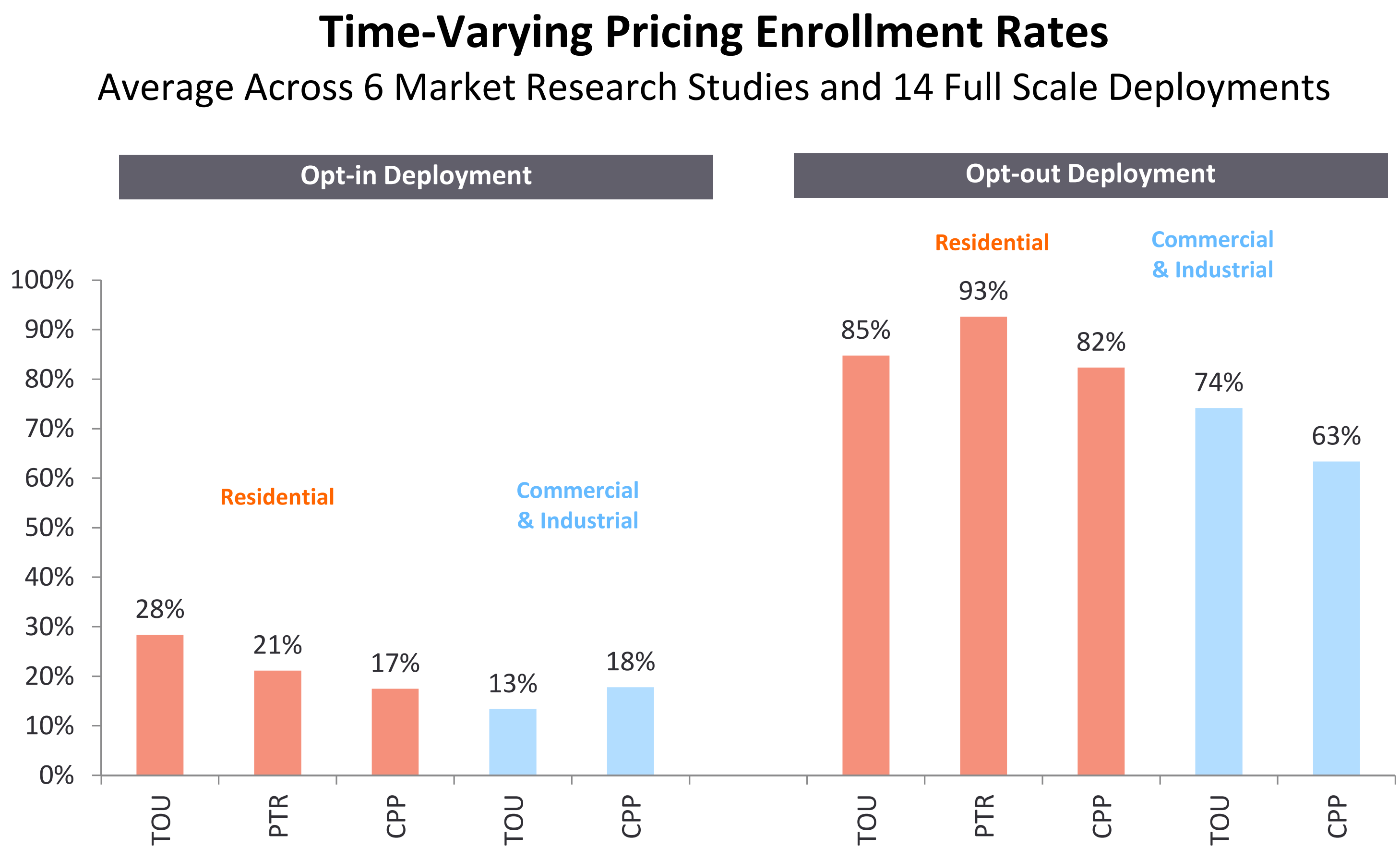
Comments

- Opt-in average = 18%
- Opt-out average = 63%
- C&I preferences for CPP rates tend to be slightly higher than for TOU rates – the opposite of the relationship observed among residential customers
- The California IOU default CPP offering began in 2011 and has experienced significant opt-outs - it may not have been effectively marketed. The rate is being deployed to smaller customers and further results are forthcoming

Preliminary conclusions can be drawn from our assessment, although further research and experience are needed

- Opt-out rate offerings produce enrollment levels that are between 3x and 5x higher than opt-in rate offerings
- Residential customers express a slightly higher likelihood to enroll in time-varying rates than small/medium C&I customers, both through market research and in full-scale deployments
- When offered in isolation, residential customers appear to have a slight preference for TOU over CPP; when offered as two competing rate options, more customers choose CPP
- Customers appear more likely to enroll in PTR than CPP
- Market research and full scale deployment results generally align well; in cases where full deployments produces lower enrollment estimates, it is likely that additional enrollment could be achieved through more focused marketing efforts

The results of our assessment can be averaged across the studies for each customer class and rate option



Offering enabling technology is likely to slightly increase participation among eligible customers

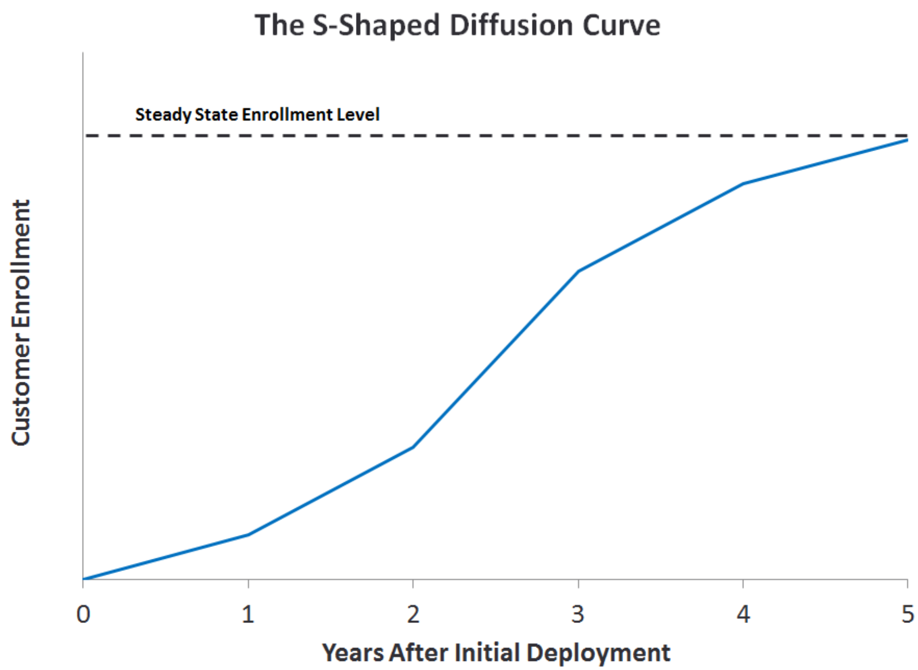
- For residential and small C&I customers, programmable communicating thermostats (PCTs) would automate reductions in air-conditioning load during critical peak periods
- For medium and large C&I customers, Auto-DR technology could be integrated with a facility's energy management system to automate load reductions during high priced periods of the CPP rates
- Market researchers have estimated that enrollment among tech-eligible customers will increase if they are also offered these technologies as part of the rate deployment
- **Opt-in enrollment among eligible customers is likely to increase by around 25% if offered enabling technology** (i.e., an enrollment rate of 20% would become 25% among tech-eligible customers)
- **For an opt-out rate offering, enrollment would likely increase by roughly 10%** (i.e. an enrollment rate of 80% would become 88% among tech-eligible customers)
- Large C&I customers are assumed to have more interest in Auto-DR than medium C&I customers due to a higher degree of sophistication in energy management capability

The proposed "steady state" enrollment rates

Class	Option	Opt-in	Opt-out
Residential	TOU - No Tech	28%	85%
Residential	CPP - No Tech	17%	82%
Residential	CPP - With Tech	22%	91%
Residential	PTR - No Tech	21%	93%
Residential	PTR - With Tech	26%	95%
Small C&I	TOU - No Tech	13%	74%
Small C&I	CPP - No Tech	18%	63%
Small C&I	CPP - With Tech	20%	69%
Small C&I	PTR - No Tech	22%	71%
Small C&I	PTR - With Tech	27%	78%
Medium C&I	CPP - No Tech	18%	63%
Medium C&I	CPP - With Tech	20%	69%
Large C&I	CPP - No Tech	18%	63%
Large C&I	CPP - With Tech	25%	69%

We account for a multi-year transition to the steady state enrollment levels

- Changes in participation are assumed to happen over a 5-year timeframe once the new rates are offered
- The ramp up to steady state participation follows an “S-shaped” diffusion curve, in which the rate of participation growth accelerates over the first half of the 5-year period, and then slows over the second half
- A similar (inverse) S-shaped diffusion curve is used to account for the rate at which customers opt-out of default rate options



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- FERC, Form 1 Database, 2012
- Lineweber, David, "Understanding Residential Customer Opinions of Time-Based Pricing Options in New England," prepared for ISO New England, May 2010
- Lineweber, David, "Understanding Business Customer Opinions of Time-Based Pricing Options in New England," prepared for ISO New England, May 2010
- Momentum Market Intelligence, "A Market Assessment of Time-Differentiated Rates Among Residential Customers in California," December 2003
- Momentum Market Intelligence, "A Market Assessment of Time-Differentiated Rates Among Small/Medium Commercial & Industrial Customers in California," July 2004
- PG&E, "PG&E's SmartRate Program Tops 100,000 Participants," PG&E Currents, May 28, 2013
- Various utility tariff sheets, as of January 2014

Non-Pricing Programs Included in Prior PGE Studies

Participation in non-pricing programs was updated using the most recent FERC data

FERC conducts a bi-annual survey of utility DR programs, including information on program impacts and enrollment

The 2012 PGE DR potential study enrollment estimates were based on data in the 2010 FERC survey, which was the most current information available at the time

FERC has since released the 2012 survey results and has discontinued the survey; information is now collected through EIA form 861, but with much less granularity

We have updated the enrollment estimates using the 2012 FERC survey

The 75th percentile of achieved enrollment is used as a "best practices" estimate

The FERC data provides a national distribution of actual enrollment in DR programs

To establish a "best practices" estimate of what could eventually be achieved through a new program, we use the 75th percentile of the distribution for each program type

The recent PacifiCorp DR potential study used the 50th percentile

However, since the purpose of our study is to estimate maximum achievable potential rather than the average participation rate, we recommend using the 75th percentile

We will acknowledge throughout the final report that the figures presented are estimates of maximum achievable potential rather than what is necessarily likely to occur, particularly in the short run given the relatively limited experience with DR in the Pacific Northwest

Updated estimates are fairly similar to those of the 2012 PGE potential study

Class	Option	PGE (2012)	PacifiCorp (2014)	PGE (2015)
Residential	DLC - Central A/C	20%	15%	**20%**
Residential	DLC - Space Heat	20%	15%	**20%**
Residential	DLC - Water Heating			**25%**
Small C&I	DLC - Central A/C	20%	3%	**14%**
Small C&I	DLC - Space Heat	20%	3%	**14%**
Small C&I	DLC - Water Heating			**2%**
Medium C&I	DLC - AutoDR	18%		**15%**
Medium C&I	Curtailable Tariff		24%	**20%**
Large C&I	DLC - AutoDR	18%		**25%**
Large C&I	Curtailable Tariff	17%	24%	**40%**

Note:
An average curtailable tariff participation rate of 30% for C&I customers was adjusted upward for large customers and downward for medium customers, based on an observation that large customers are more likely to participate (e.g., Xcel Energy's ISOC program)

In a couple of instances, we deviated from the 75th percentile assumption

Space heating DLC participation is assumed to be the same as air-conditioning DLC due to lack of better data

The 75th percentile participation rate of 30% for C&I customers in a curtailable tariff was adjusted upward for large customers and downward for medium customers, based on an observation that large customers are more likely to participate (e.g., Xcel Energy's highly subscribed "ISOC" program)

There is limited data available on Auto-DR adoption rates when deployed at scale; we have assumed that adoption would be similar to that of technology-enabled CPP for C&I customers, since it offers a similar financial incentive to manage load

New Non-Pricing Programs Not Included in Prior PGE Studies

We estimated participation rates for three new programs; two more are in development

Draft participation rates have been developed for:

- Bring-your-own-device (BYOD) load control (residential)
- Behavioral DR (residential)
- Irrigation load control (agricultural)

Participation rates are in development for:

- Smart water heating load control (residential)
- Electric vehicle charging load control (residential)
- All assumptions for these two programs are being developed in parallel and in coordination with PGE staff

Enrollment in BYOD programs will be driven partly by the market penetration of smart thermostats

We have based our estimates of the eligible population for BYOD programs on projections of market deployment for communication-enabled thermostats

Research by Berg Insight projects that over 25% of homes in North America will be equipped with a ‘smart system’ by 2020, relative to 6% currently

CMO, and Adobe Company, reports that smart thermostats are expected to have over 40% adoption by 2020

Acquity Group’s 2014 Internet of Things (IoT) survey reports that approximately 30% of consumers will adopt smart thermostats in the next 5 years

To be conservative, we use an assumption at the low end of this range

Source	Year	Market Penetration (%)
Berg Insight – N. America	2020	25%
CMO	2020	40%
Acquity Group – N. America	2020	30%

- We assume that smart thermostat market penetration in PGE's service territory will reach 25% of all homes by 2020
- The Energy Trust's interest in promoting smart thermostats could drive this estimate upward
- Additionally, rapid growth in central air-conditioning adoption in the Pacific Northwest relative to other parts of the country could lead to a future scenario that exceeds this estimate, as new A/C systems are installed with smart thermostats
- Note: Estimate could be refined further upon receiving the Navigant Research report on smart thermostats

Participation among eligible customers is likely similar to participation in conventional DLC programs

The BYOD program is assumed to be offered on an opt-in basis only

With a similar participation incentive as in the conventional DLC program, we assume that participation in the BYOD program would be similar to but slightly higher than that of the conventional DLC program

The intuitive reasoning for this is that customers who purchase a smart thermostat are more likely to be conscious about their energy usage and keen on using the features of their new device

To capture this, we estimate that participation in BYOD programs to be 25%, which is 5% higher than in DLC programs

We have modeled Behavioral DR both on an opt-in and an opt-out basis, similar to pricing programs

Behavioral Demand Response is essentially a peak time rebate (PTR) program without the accompanying financial incentive to reduce consumption during event hours

The no-incentive, no-risk nature of BDR programs could make customers slightly less likely to opt-in and slightly more likely to opt-out

To establish the BDR participation rates, we start with the PTR participation rates discussed previously in this presentation, and make adjustments to the share of customers that opt-in and opt-out

Three sources suggest that BDR participation could resemble that of a PTR program

OPower estimates that customer adoption of their opt-out BDR programs is upwards of 90%

Green Mountain Power (2012-2013)

- Recruitment strategies used a combination of mail, web and phone
- Participation in the opt-in, notification-only program achieved a 34% participation rate

MyMeter Program (four electric co-ops in Minnesota)

- Opt-in participation rates range from 9% to 16% per co-op, with more weight toward the high end of the range

Research supports a 20% opt-in and a 80% opt-out participation rate

Utility/Program	Opt-In Participation Rate (%)	Opt-Out Participation Rate (%)
OPower BDR program adoption rate		90%
Green Mountain Power	34%	
MN electric co-ops (MyMeter Program)	9-16%	

- In both the opt-in and opt-out deployment scenarios, we choose fairly conservative participation rates relative to the data that is available on BDR enrollment
- This is in recognition of the long-term uncertainty in enrollment in these programs and the fairly small scale at which the existing pilots were conducted

Irrigation Load Control Programs typically target large irrigation & drainage pumping systems

Many utilities, such as SCE, Entergy Arkansas, and Idaho Power focus on large customers

The 2014 PacifiCorp potential study sets the eligibility threshold at customers with pumps 25 HP and higher, representing 78% of total agricultural load

We propose that the eligible population be limited to customers on Schedule 49

- Comprises Irrigation & Drainage Pumping customers with loads >30 kW
- These customers represents about 75% of total Irrigation and Drainage load (based on PGE's February 2015 Rate Case Filing)

There are a few data points upon which to base PGE's irrigation DLC participation estimate

EnerNOC's 2013 Irrigation Load Control Report provides enrollment estimates for Rocky Mountain Power

- The Utah service territory had a participation rate of about 20% of eligible load, whereas the Idaho service territory had participation of 48% of eligible load
- All irrigation customers were eligible to participate
- Customers with loads <50 kW required to pay an enablement fee

Idaho Power has achieved significant enrollment

- Conversations with Idaho Power staff indicate that roughly 10% of irrigation customers are enrolled
- These participants are significantly larger than average, representing peak reduction capability of 39% of system peak coincident irrigation load

The recent PacifiCorp DSM potential study suggested a lower participation rate for Oregon

- Participation in California, Oregon, Washington, and Wyoming assumed to be 15% of eligible load, based on PacifiCorp program experience
- Assumed participation rates for Idaho and Utah were significantly higher, likely reflecting the different nature of the crops in those two states, leading farmers to be more likely to allow more regular curtailments to their irrigation cycle

There is support for a 15% participation rate assumption for Irrigation Load Control programs

Utility/Program	Opt-In Participation Rate (% eligible load)
PacifiCorp 2015 (CA, OR, WA, WY)	15%
RMP 2013 (Utah)	20%
Idaho Power	39%
RMP 2013 (Idaho)	48%

- The range of participation rates observed in existing programs is wide
- We have chosen an estimate on the low end of the range to avoid overstating participation that may be associated with hotter, drier climates like those of Idaho and Utah
- This assumption has the added benefit of being consistent with the Oregon assumption in the PacifiCorp potential study

Summary of Participation Assumptions for New Non-Pricing programs

Program	Eligible Population in 2020 (%)	Opt-In Participation Rate (%)	Opt-Out Participation Rate (%)
BYOD	25% of Residential Customers	25%	N/A
Behavioral DR	100%	20%	80%
Irrigation Load Control	75% of Irrigation Customers	15%	N/A

Sources for new non-pricing participation assumptions

- Acquity Group, The Internet of Things: The Future of Consumer Adoption, 2014.
- Applied Energy Group, PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034 Volume 5: Class 1 and 3 DSM Analysis Appendix, January 30, 2015.
- Berg Insight, Smart Homes and Home Automation, January 2015.
- CMO, 15 Mind-Blowing stats about the Internet of Things, April 17, 2015.
- Edison Institute, Innovations Across the Grid, Volume II, December 2014.
- EnerNOC, 2013 PacifiCorp Irrigation Load Control Program Report, March 3, 2014.
- Honeywell, Structuring a Residential Demand Response Program for the Future, June 2011.
- Illume, MyMeter Multi-Utility Impact Findings, March 2014.
- J. Bumgarner, The Cadmus Group, Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program, March 24, 2011.
- Opower, Using Behavioral Demand Response as a MISO Capacity Resource, June 4, 2014.
- R. Kiselewich, The Future of Residential Demand Response: BGE's Integration of Demand Response and Behavioral, E Source Forum 2014, September 29 - October 2, 2014.
- S. Blumsack and P. Hines, Load Impact Analysis of Green Mountain Power Critical Peak Events, 2012 and 2013, March 5, 2015.

Appendix B:
Per-Participant Load Impact Assumptions

Estimating Per-Participant DR Impacts for PGE

PRESENTED TO

PGE

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In this presentation

This presentation summarizes the methodology and assumptions behind our estimates of per-participant peak demand reductions for DR programs that could be offered in PGE's service territory

The presentation is divided into three sections

- Pricing programs
- Non-pricing programs included in prior PGE studies
- Non-pricing programs that are new to this study

Note that the impacts in this presentation are per average participant; they are not multiplied into participation rates to arrive at estimates of system-level impacts

Pricing Programs

Pricing impact estimates have undergone a significant overhaul relative to the 2012 study

Incorporated new findings of 24 pilots and full-scale rollouts that have occurred since the 2012 study, including the DOE-funded consumer behavior studies

Modified the impact estimation methodology to take advantage of the greater number of data points that are now available

- Differentiation in price responsiveness between TOU, CPP, and PTR rates
- Accounting for difference in average response under opt-in versus opt-out deployment
- Improved differentiation between winter and summer impacts

The following slides provide a step-by-step description of our approach

First, we established a reasonable peak-to-off-peak price ratio for each rate option

The peak-to-off-peak price ratio is the key driver of demand response among participants in time-varying rates

A higher price ratio means a stronger price signal and greater bill savings opportunities for participants – on average, participants provide larger peak demand reductions as a result

Price ratios are based on rate designs that have recently been offered by PGE or are currently under consideration

- TOU: 2-to-1
- CPP: 4-to-1*
- PTR: 8-to-1*

* Rate designs were provided by PGE. It would alternatively be useful to explore CPP and PTR rates with consistent price ratios.

Impacts of time-varying rates were then simulated based on a comprehensive review of recent pilot results

PGE has recently conducted a CPP pilot and previously conducted a TOU pilot; the results are incorporated into our analysis, but have been supplemented with findings from dynamic pricing pilots across the globe to develop more robust estimates of price response

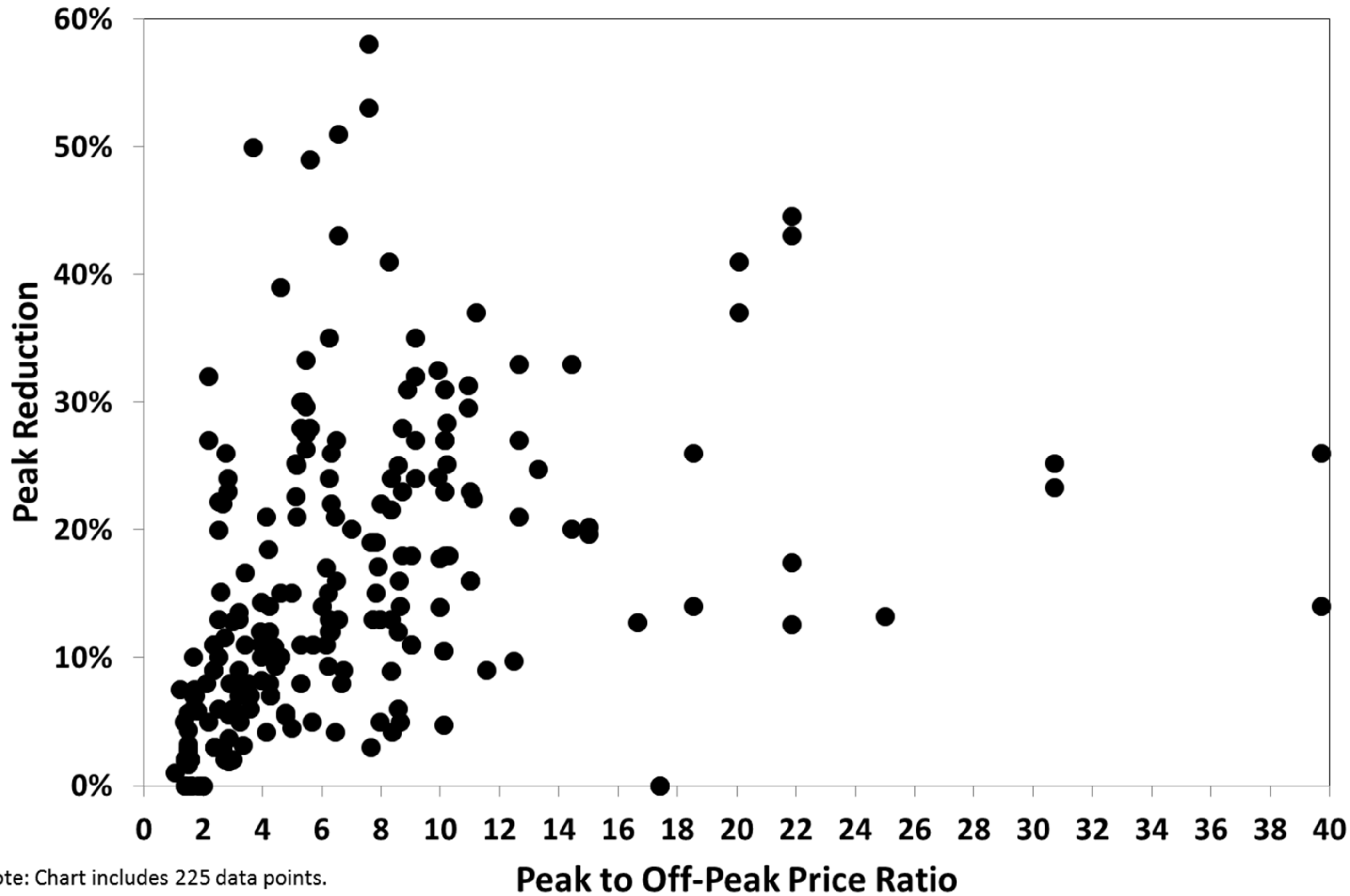
For residential customers, we rely on results from 225 pricing tests that have been conducted in a total of 42 pilots in the U.S. and internationally over roughly the past decade

Small and Medium C&I impacts are based on results of a dynamic pricing pilot in California

Large C&I impacts are based on experience with full-scale programs in the Northeastern U.S.

To estimate residential impacts, we begin with a survey of impacts from recent pilots

Results of All Residential Time-Varying Pricing Tests



Note: Chart includes 225 data points.

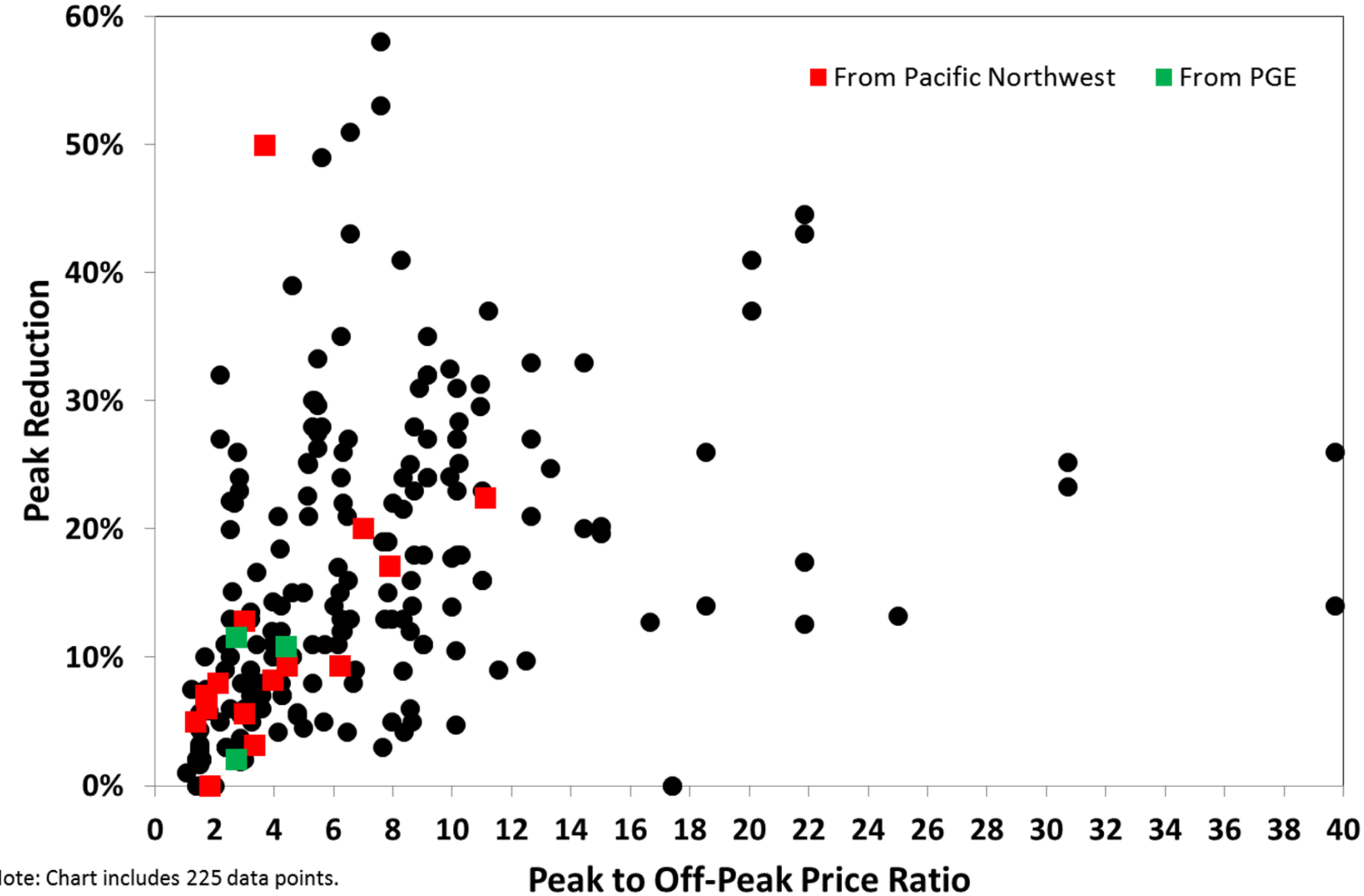
Our database of dynamic pricing pilots includes seven that have been conducted in the Pacific Northwest

Utility/Organization	State/Province	Name of Pilot	Year(s)	Rates Tested	Range of Price Ratios	Range of Peak Prices	Range of Impacts	Number of Pilot Participants	Season of System Peak
BC Hydro	British Columbia	Residential TOU/CPP Pilot	2007-2008	TOU CPP	TOU: 3.0-6.2 CPP: 7.9-11.1	TOU: 19-28¢ CPP: 50¢	TOU: 3-13%, CPP: 17-22%	TOU: 1,031 CPP: 273	Winter
Idaho Power	Idaho	Energy Watch (EW) and Time-of-Day (TOD) Pilot Programs	2005-2006	TOU CPP	TOU: 1.8 CPP: 3.7	TOU: 8¢ CPP: 20¢	TOU: 0% CPP: 50%	TOU: 85 CPP: 68	Summer
PacifiCorp	Oregon	TOU Rate Option	2002-2005	TOU	Summer: 1.7-2.1 Winter: 1.7	Summer: 11-14¢ Winter: 11¢	Summer: 6-8% Winter: 7%	~1200	Summer Winter
Portland General Electric (PGE)	Oregon	Residential TOU Option	2002-2003	TOU	2.7	8¢	8%	1,900	Winter
Portland General Electric (PGE)	Oregon	Critical Peak Pricing Pilot	2011-2013	CPP	4.4	44¢	11%	996	Winter
Puget Sound Energy	Washington	TOU Program	2001	TOU	1.4	See notes	5%	300,000	Winter
US DOE, PNNL, BPA, PacifiCorp, Portland General Electric, Public Utility District #1 of Clallam County, and City of Port Angeles	Washington/ Oregon	Olympic Peninsula Project	2006-2007	CPP	7.0	35¢	20%	112	Winter

Notes:
Could not find published estimates of TOU prices for Puget Sound Energy; only the price differential was available.
Price ratios are presented on an all-in basis.

The Pacific Northwest price ratios and impacts are generally consistent with those of other pilots

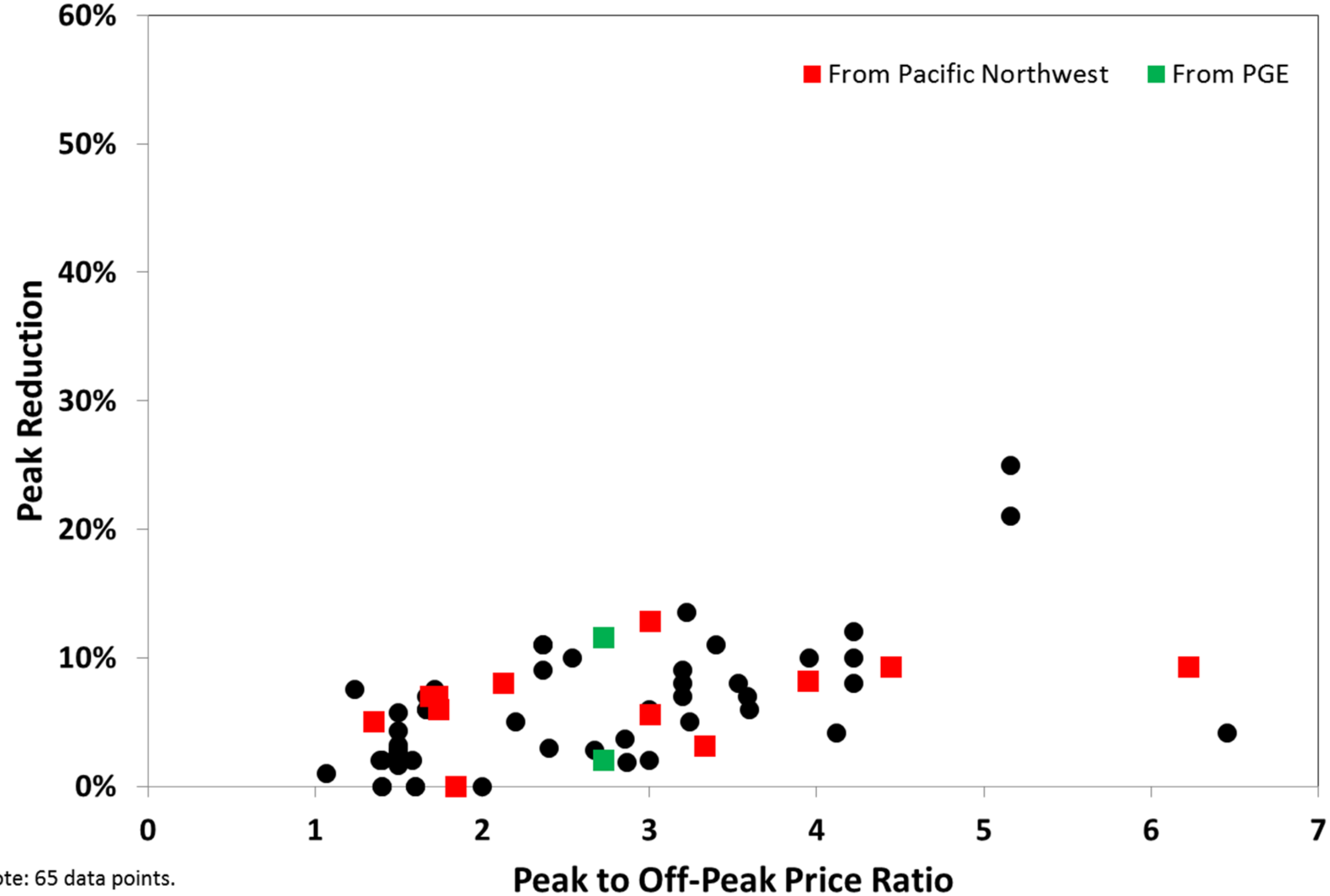
Results of All Residential Time-Varying Pricing Tests



Note: Chart includes 225 data points.

To estimate TOU impacts, we focus only on those pilots which tested TOU rates

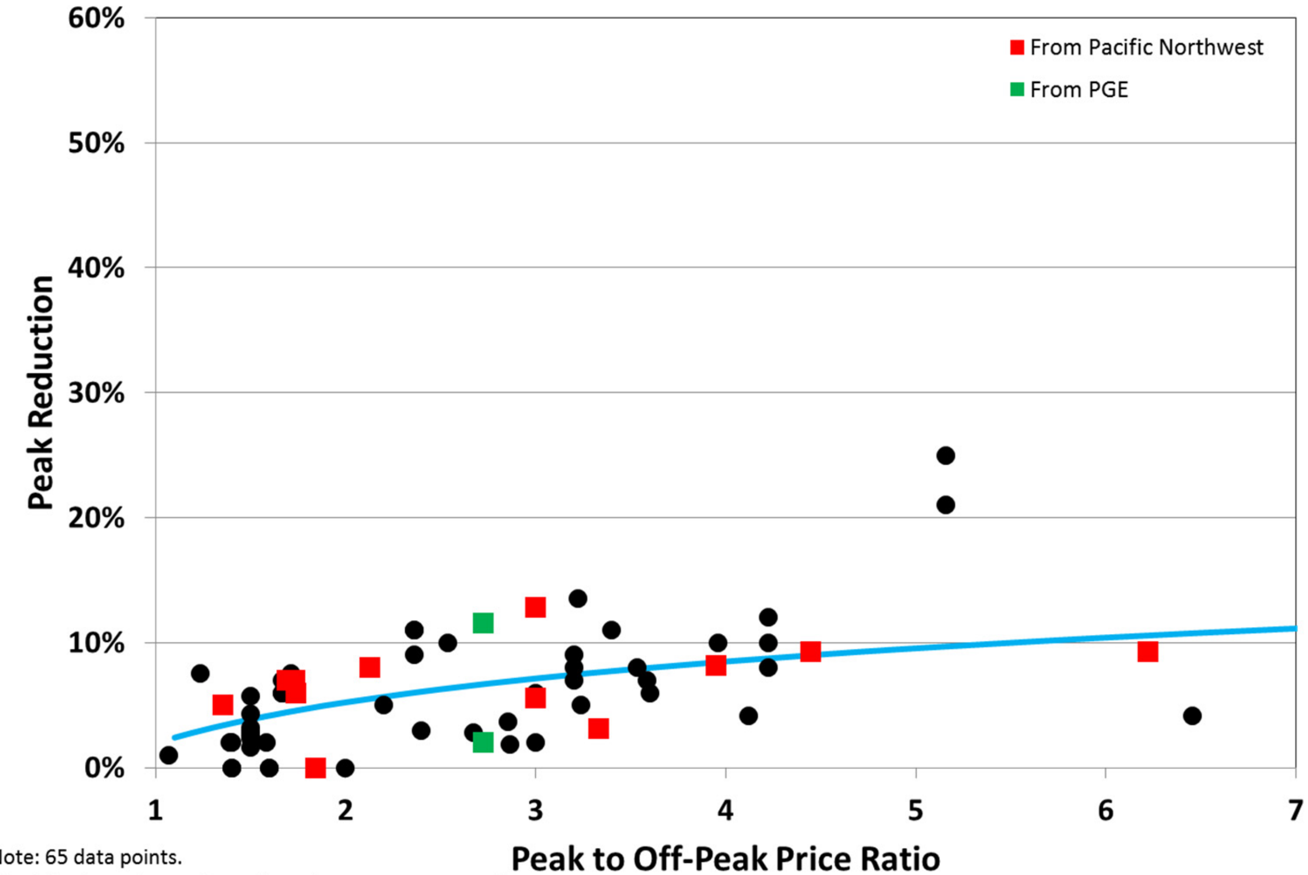
Results of Residential TOU Pricing Tests



Note: 65 data points.

We then fit a curve to the summer data to capture the relationship between price ratio and impacts

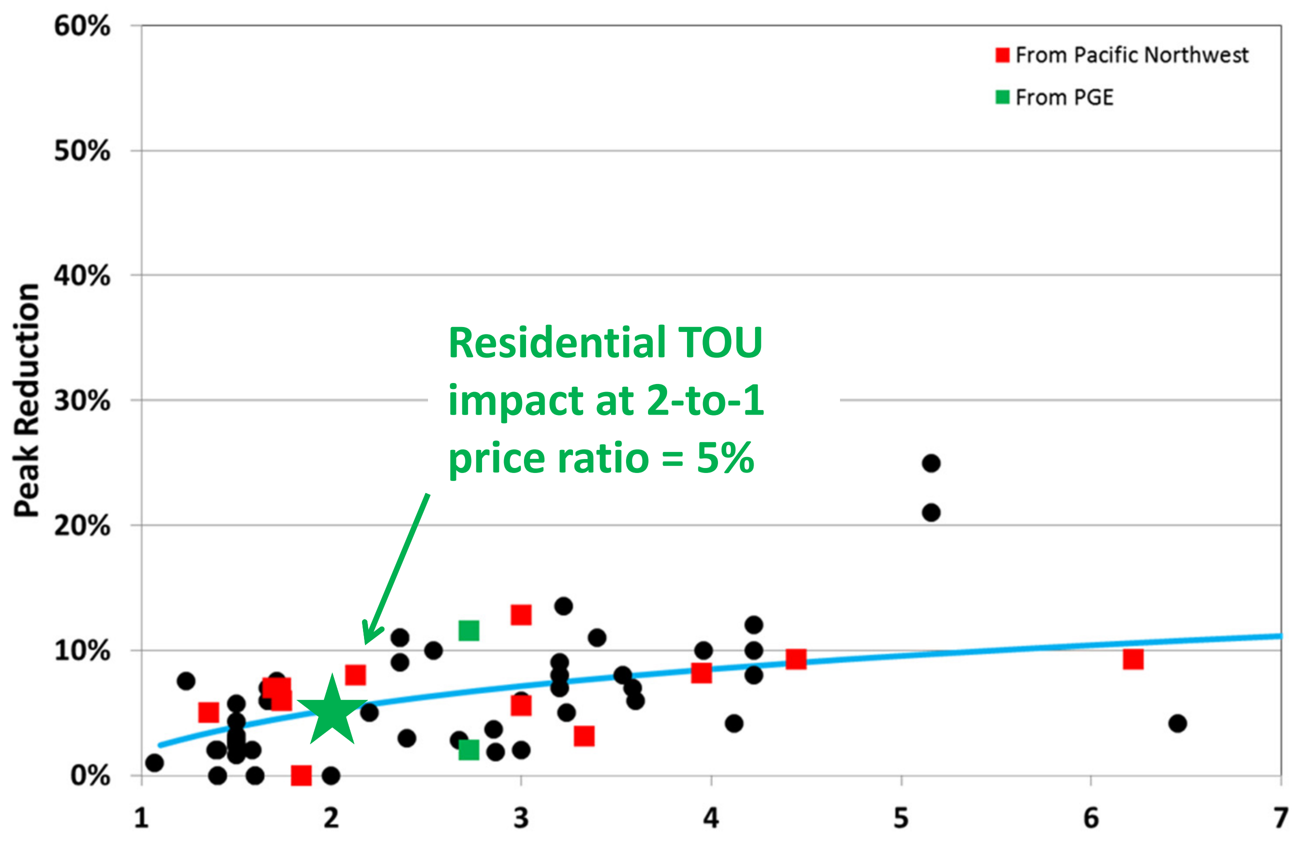
Results of Residential TOU Pricing Tests with Arc



Note: 65 data points.
20 winter impacts are shown for reference purposes only.

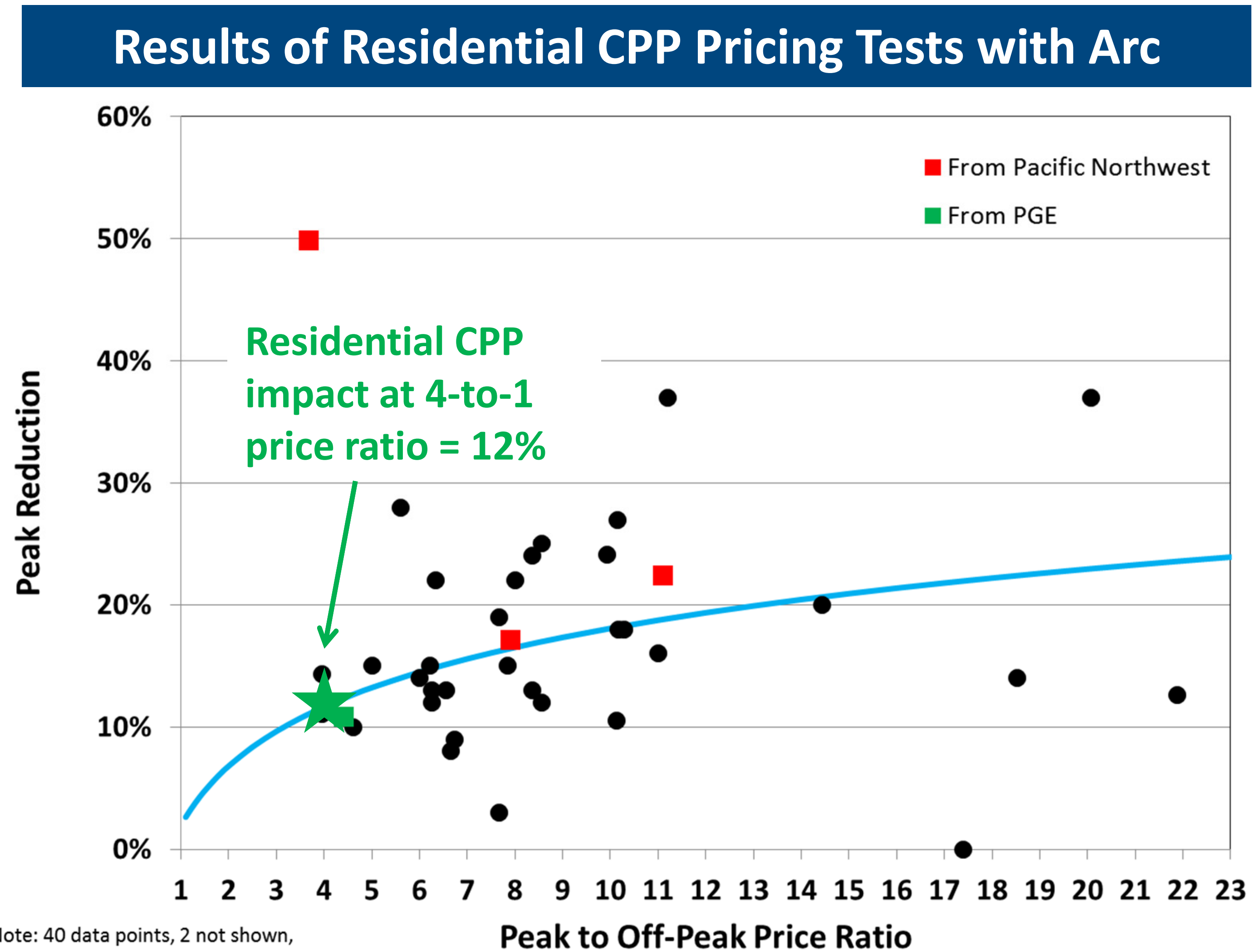
We use the arc to simulate the impact of the residential TOU rate for our study

Results of Residential TOU Pricing Tests with Arc



Note: 65 data points.
20 winter impacts are shown for reference purposes only.

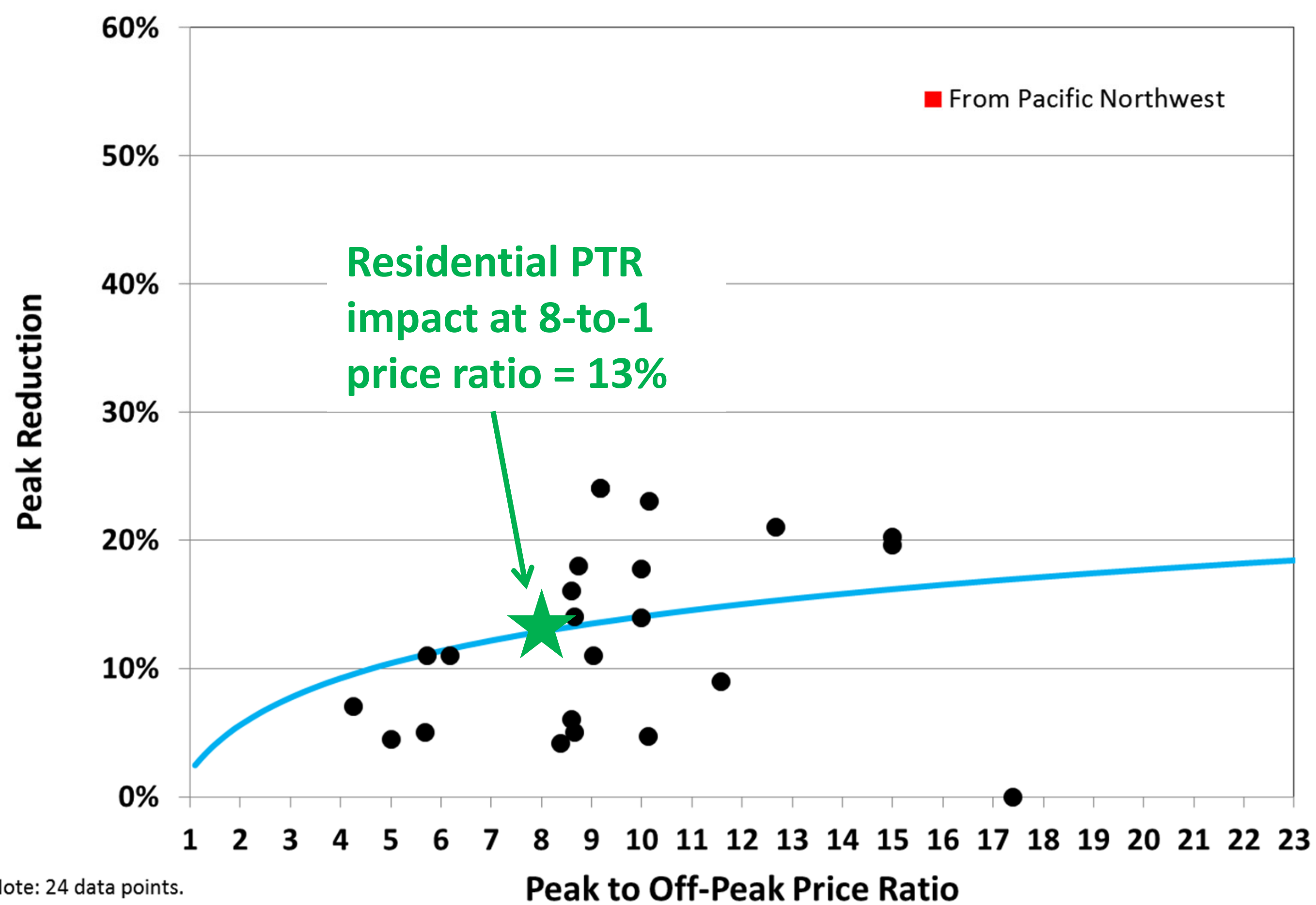
The same approach was used to estimate CPP impacts



Note: 40 data points, 2 not shown,
1 dropped as outlier in regression. 5 winter impacts are shown for reference purposes only.

PTR impacts were also estimated using the same approach

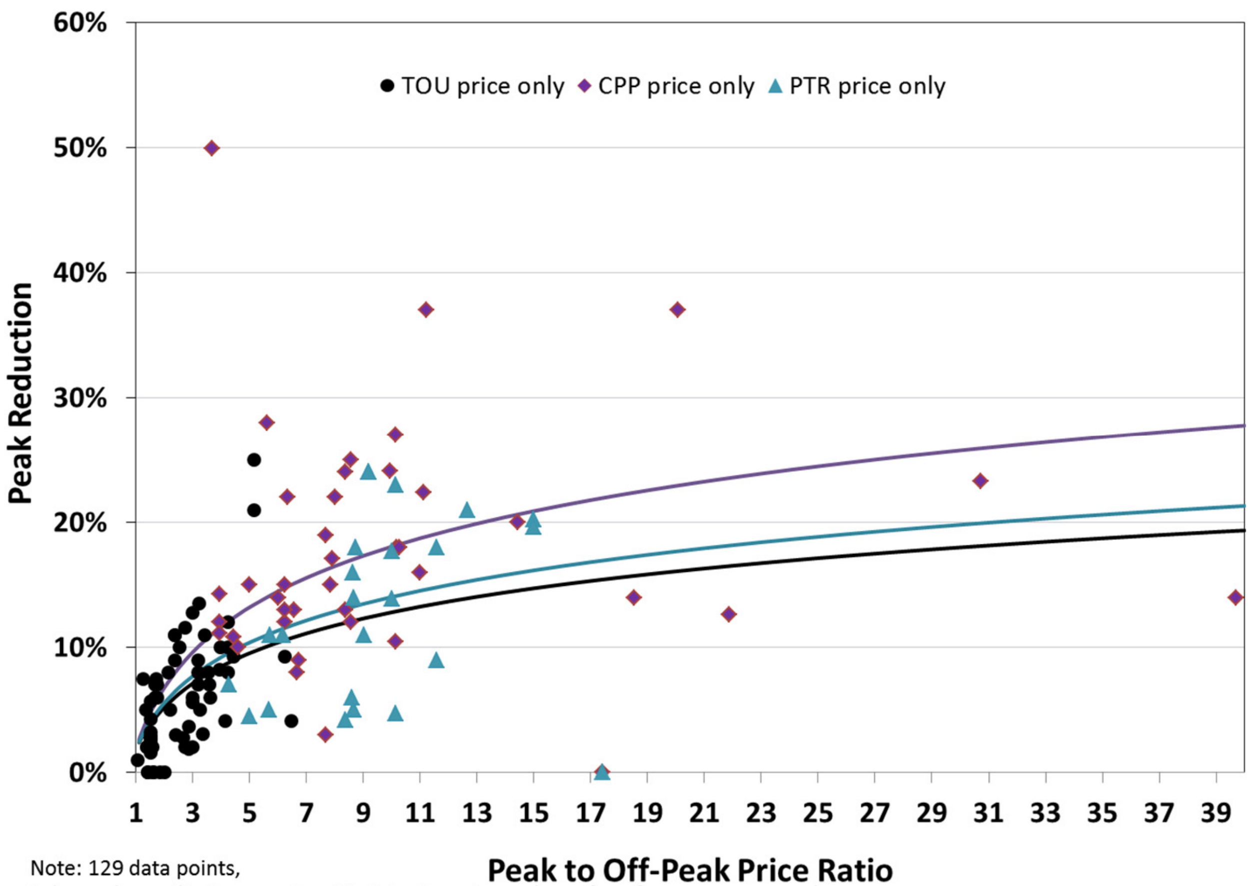
Results of Residential PTR Pricing Tests with Arc



Note: 24 data points.
2 winter impacts are shown for reference purposes only.

Price elasticity appears to be higher for CPP rates than PTR or TOU

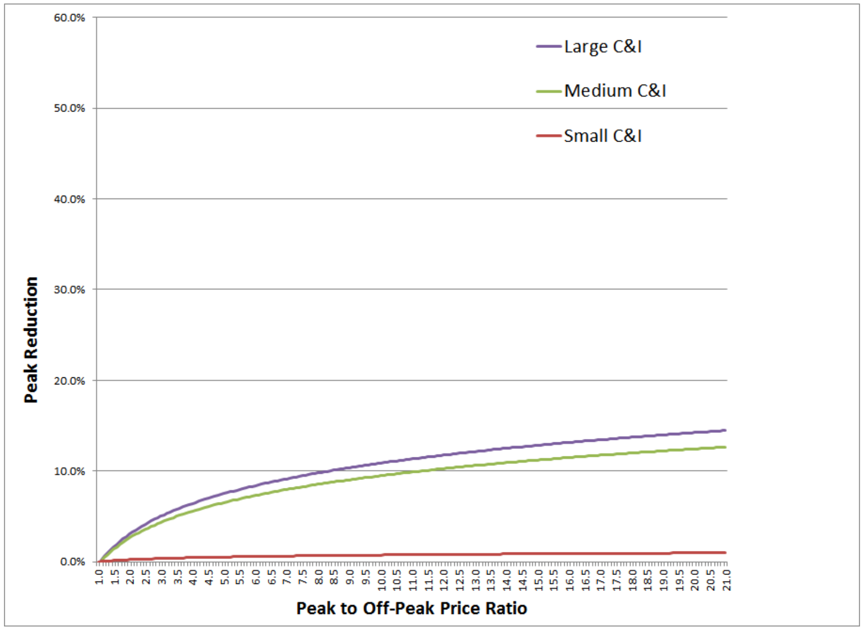
Results of All Residential Time-Varying Pricing Tests



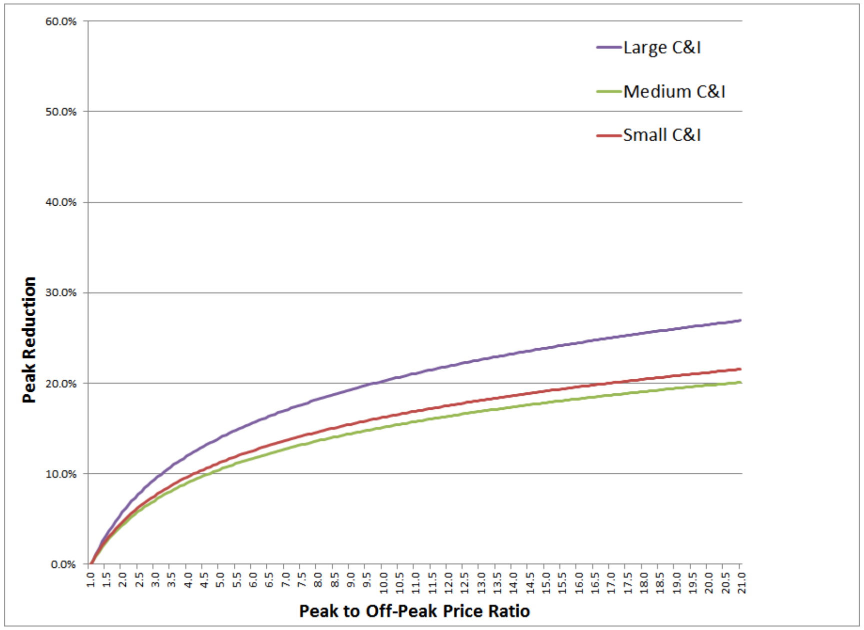
Note: 129 data points,
1 dropped as outlier in regression. 26 winter impacts are shown for reference purposes only.

C&I impacts were estimated using a similar approach, but fewer pilots have been conducted for these customers

C&I Arcs without Tech



C&I Arcs with Tech



Seasonal variation is based on the relationship observed in a limited number of pilots

To develop winter impact estimates, we created a scaling factor based on the relationship observed in pilots that tested both rates

The challenge is that there is not a consistent seasonal relationship across these pilots (see table)

Recognizing this uncertainty, but remaining consistent with the directional relationship in the PGE studies, we assumed a slightly higher degree of price responsiveness (10%) in the winter than in the summer

New primary research (e.g., the upcoming PTR pilot) is needed to refine this assumption

Pilot	Winter impact relative to summer
PGE TOU	Much larger (6x)
PGE CPP	Slightly larger*
PacifiCorp	Similar
Ontario TOU	Slightly smaller
Australian TOU	Much smaller (0.4x)
Xcel	Relationship varies

* Based on very limited summer data

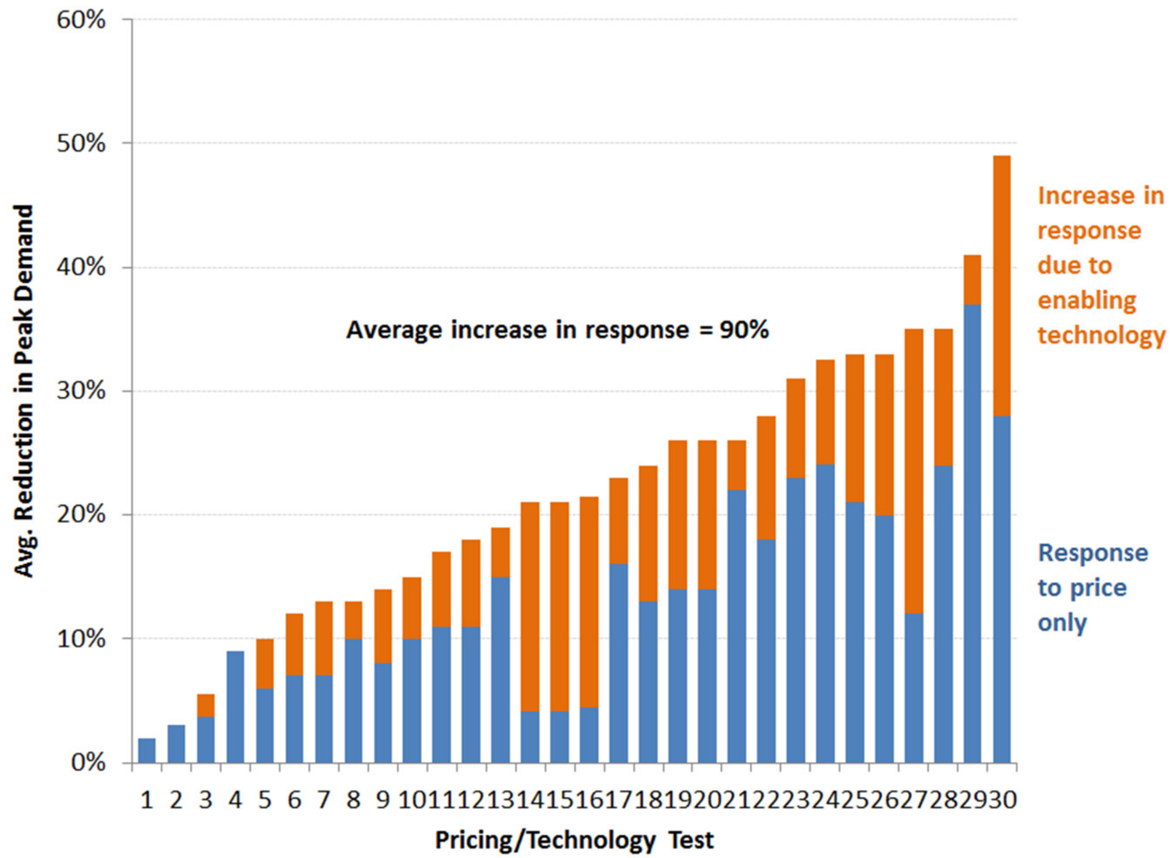
Impacts are scaled to account for enabling technology

Based on the relationship observed in other pilots, we assume a 90% increase in response attributable to technology (largely smart thermostats)

Winter technology impacts are assumed to be 80% of summer technology impacts based on the relationship observed in direct load control programs

TOU is not coupled with enabling technology because it does not have a dispatchable price signal

Price Response with and without Tech



Per-customer pricing impacts are scaled down in the opt-out deployment scenario

A new dynamic pricing pilot by the Sacramento Municipal Utility District (SMUD) found that the average residential participant's peak reduction was smaller under opt-out deployment than under opt-in deployment

This is likely due to a lower level of awareness/engagement among participants in the opt-out deployment scenario; note that, due to higher enrollment rates in the opt-out deployment scenario, aggregate impacts are still larger

Per-customer TOU impacts were 40% lower when offered on an opt-out basis

Per-customer CPP impacts were roughly 50% lower

We have accounted for this relationship in our modeling of the residential impacts

We also simulated the impact of a TOU rate for irrigation customers

A 2001/2002 irrigation TOU pilot in Idaho found that customers produced, on average, a 9% reduction in peak for a TOU with a 3.5-to-1 price ratio

We used the Arc of Price Responsiveness to scale these impacts to the TOU price ratio we're analyzing in this study

The resulting peak reduction estimate is 4.7% for a TOU rate

Summary of draft results

		Without Tech			With Tech		
		TOU	CPP	PTR	TOU	CPP	PTR
Opt-in Deployment							
Residential	Summer	5.2%	11.7%	12.9%	N/A	31.0%	34.2%
	Winter	5.8%	12.8%	14.2%	N/A	24.8%	27.4%
Small C&I	Summer	0.2%	0.4%	0.7%	N/A	9.6%	14.6%
	Winter	0.2%	0.5%	0.7%	N/A	7.7%	11.7%
Medium C&I	Summer	2.6%	5.6%	N/A	N/A	9.0%	N/A
	Winter	2.6%	5.6%	N/A	N/A	9.0%	N/A
Large C&I	Summer	3.1%	6.4%	N/A	N/A	12.0%	N/A
	Winter	3.1%	6.4%	N/A	N/A	12.0%	N/A
Agricultural	Summer	4.7%	N/A	N/A	N/A	N/A	N/A
	Winter	4.7%	N/A	N/A	N/A	N/A	N/A
Opt-out Deployment							
Residential	Summer	3.1%	5.8%	6.4%	N/A	15.5%	17.1%
	Winter	3.5%	6.4%	7.1%	N/A	12.4%	13.7%
Small C&I	Summer	0.2%	0.4%	0.7%	N/A	9.6%	14.6%
	Winter	0.2%	0.5%	0.7%	N/A	7.7%	11.7%
Medium C&I	Summer	2.6%	5.6%	N/A	N/A	9.0%	N/A
	Winter	2.6%	5.6%	N/A	N/A	9.0%	N/A
Large C&I	Summer	3.1%	6.4%	N/A	N/A	12.0%	N/A
	Winter	3.1%	6.4%	N/A	N/A	12.0%	N/A
Agricultural	Summer	4.7%	N/A	N/A	N/A	N/A	N/A
	Winter	4.7%	N/A	N/A	N/A	N/A	N/A

Notes:

Impacts are average per eligible participant – individual participants could produce larger or smaller impacts

For ease of comparison, tech impacts are expressed as a % of the average customer even though they would only apply to customers with electric A/C or space heat, who have higher peak demand

Non-Pricing Programs
Included in Prior PGE Studies

We estimate per-participant impacts for the following non-pricing programs from prior studies

	Residential	Small C&I	Medium C&I	Large C&I
DLC - A/C	X	X		
DLC - Space heat	X	X		
DLC - Water heating	X	X		
DLC - Auto-DR			X	X
Curtailable tariff			X	X

Updates to assumptions for conventional non-pricing programs were fairly minor

Impact assumptions remain stable for the conventional non-pricing programs analyzed in prior studies for PGE, since these programs are well established with a long history of performance

Where applicable, we revised the estimates to be more consistent with findings of studies in the Pacific Northwest

We also compared the 2012 assumptions to those of the more recent PacifiCorp potential study and resolved any discrepancies to ensure consistency

We relied on the following Pacific Northwest DR studies to refine our impact estimates

- Avista, “Idaho Load Management Pilot,” 2010
- Cadmus Group, “Kootenai DR Pilot Evaluation: Full Pilot Results,” 2011
- Cadmus Group, “OPALCO DR Pilot Evaluation”, 2013
- Itron, “Draft Phase I Report Portland General Electric Energy Partner Program Evaluation,” 2015
- Lawrence Berkeley National Lab, “Northwest Open Automated Demand Response Technology Demonstration Project,” 2009
- Michaels Energy, “Demand Response and Snapback Impact Study”, 2013
- Navigant and EMI, “2011 EM&V Report for the Puget Sound Energy Residential Demand Response Pilot Program,” 2012
- Navigant, “Assessing Demand Response (DR) Program Potential for the Seventh Power Plan”, 2014
- Nexant, “SmartPricing Options Final Evaluation - The Final report on pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study”, 2014
- Rocky Mountain Power, “Utah Energy Efficiency and Peak Reduction annual Report”, 2014

The following assumptions were updated for this study

Residential air-conditioning DLC

- Reduced slightly from 1.0 kW to 0.8 kW to reflect lower-than-average impacts observed in Pacific Northwest studies

Residential space heat DLC

- Increased from 0.6 kW to 1.0 kW
- Even higher impacts are observed in Pacific Northwest studies, but a 2004 PGE study found impacts in the 0.7 kW range
- Note that the relationship between space heat and air-conditioning has been reversed based on this revision

Assumption updates (cont'd)

Small C&I air-conditioning and space heat

- Scaled to be consistent with residential assumption (1.5x residential load reduction capability)

Medium and Large C&I Auto-DR

- Increased from 15-20% of peak load to 30% of peak load to establish appropriate relationship between curtailable tariff impacts and Auto-DR impacts
- Assumed to be offered in conjunction with curtailable tariff type of program and provides 50% incremental increase in load reduction relative to impact with no technology
- There is a significant range of uncertainty around this assumption; to be discussed further with PGE relative to the findings of its Auto-DR pilot, which referenced a fairly broad range of impacts

Summary of assumptions for non-pricing impacts from prior studies

Class	Program	Season	2012 Assumption	Updated 2015 Assumption
Residential	DLC - Central A/C	Summer	1.0 kW	0.8 kW
Residential	DLC - Space Heat	Winter	0.6 kW	1.0 kW
Residential	DLC - Water Heating	Summer	0.4 kW	0.4 kW
Residential	DLC - Water Heating	Winter	0.8 kW	0.8 kW
Small C&I	DLC - Central A/C	Summer	2.0 kW	1.2 kW
Small C&I	DLC - Space Heat	Winter	1.2 kW	1.5 kW
Small C&I	DLC - Water Heating	Summer	1.2 kW	1.2 kW
Small C&I	DLC - Water Heating	Winter	0.6 kW	0.6 kW
Medium C&I	DLC - Auto-DR	Year-round	15%	30%
Medium C&I	Curtailable tariff	Year-round	N/A	20%
Large C&I	DLC - Auto-DR	Year-round	20%	30%
Large C&I	Curtailable tariff	Year-round	20%	20%

New Non-Pricing Programs
Not Included in Prior PGE Studies

We estimated per-participant peak demand impacts for three new programs; two more are in development

Draft impact estimates have been developed for:

- Bring-your-own-device (BYOD) load control (residential)
- Behavioral DR (residential)
- Irrigation load control (agricultural)

Impact estimates are in development for:

- Smart water heating load control (residential)
- Electric vehicle charging load control (residential)
- Developing assumptions for these programs requires ongoing interaction with PGE staff, which is already underway

We relied on the following data sources to develop our impact estimates for new non-pricing programs

- Applied Energy Group, PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034 Volume 5: Class 1 and 3 DSM Analysis Appendix, January 30, 2015
- Austin Energy, PowerSaver Program website, Accessed May 1, 2015
- Con Ed of NY, Rider L – Direct Load Control Program filing, Case C14-E-0121, April 3, 2014
- Edison Foundation, Innovations Across the Grid, December 2013 and December 2014
- Hydro One website, Accessed May 1, 2015.
- Illume, MyMeter Multi-Utility Impact Findings, March 2014.
- J. Bumgarner, The Cadmus Group, Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program, March 24, 2011.
- Nest Inc., White Paper: Rush Hour Rewards, Results from Summer 2013, May 2014.
- Opower, Using Behavioral Demand Response as a MISO Capacity Resource, June 4, 2014.
- Rocky Mountain Power, Utah Energy Efficiency and Peak Reduction Annual Report, June 26, 2013 and May 16, 2014.
- S. Blumsack and P. Hines, "Load Impact Analysis of Green Mountain Power Critical Peak Events, 2012 and 2013", March 5, 2015.
- Southern California Edison website, Accessed May 1, 2015.

We have identified key elements of "Bring Your Own Device" Type Programs

Bring Your Own Device/Thermostat ("BYOD" or "BYOT") programs provide an alternative to utility direct-install programs, reducing equipment and installation costs

The incentive structure for participating in BYOD programs is diverse

- One-time rebate/refund, with or without a minimum time commitment
- Fixed annual/monthly participation incentive in addition to a one-time rebate
- Variable monthly incentive based on kWh savings

Programs also include monetary incentives to thermostat vendors and annual compensation for portal/interface maintenance

Customers can opt out of individual events without penalty

Our assumptions are based on research of five different BYOD programs

We have identified five primary programs

- Hydro One
- Austin Energy
- Con Edison of NY
- Southern California Edison
- "Rush Hour Rewards (RHR)" program by Nest Inc.

These programs have been able to successfully sign up new customers

- As of December 2014, Austin Energy had enrolled 7,000 thermostats (out of ~383,000 residential customers), with a planned expansion to 70,000 thermostats
- Con Edison enrolled 2,000 customers in its first year and believes that it can achieve 5,000 new sign-ups each year
  - Low enrollment may be explained by a relatively small number of eligible thermostats currently installed (~30,000)
- In 2013 Nest's Rush Hour Rewards program included over 2,000 customers from Austin Energy, Reliant, and Southern California Edison. Nest is currently expanding this program, and enrollment has likely increased since then

Our BYOD program impact estimates are similar to those of other Residential A/C DLC programs

Austin Energy's *Power Partner Thermostat* program has achieved a per device load shed of up to 33% during a peak event

Con Edison expects 1.0 kW of peak load reduction per thermostat based on its experience with other Residential DLC participants

Nest's "RHR" program studied the peak load impacts across three different utilities (Austin Energy, Reliant, and Southern California Edison)

- A total of 19 events were studied across the three utilities
- Each event reduced load by an average of 1.18 kW per device
- Only 14.5% of customers reduced their temperature during an event

Research suggests a per-customer peak reduction of around 1 kW

Utility/Program	Number of Participants	Customer Incentive	Peak Demand Impact (%/customer)	Peak Demand Impact (kW/customer)
Austin Energy	7,000	$85/one-time	33%	N/A
SCE	N/A	$1.25/kWh reduced	N/A	N/A
Con Ed of NY	2,000	$85/one-time; $25 annual for additional participation	N/A	1.0
Hydro One	2,000	$100-125/one-time	N/A	N/A
Nest Inc.'s "RHR"	2,000	N/A	55%	1.18

The available data suggests that per-customer impacts are similar to that of a utility-administered DLC program; we therefore assume the same summer and winter impacts that are being modeled in the conventional programs

Impacts of Behavioral DR programs were based primarily on programs conducted by OPower

Behavioral Demand Response aims to increase customer engagement

Achieved via a software-centered approach based on targeted and customized email, mobile, and interactive voice response (IVR) communications

Customers are notified of DR events ahead of time and receive post-event feedback on performance

Easy to deploy and scale relative to other DR programs that require hardware installations

No financial incentives are offered for load reductions

OPower reports significant summer peak savings from BDR programs

Deployed to 150k customers in Consumers Energy (MI), Green Mountain Power (VT), and Glendale Water & Power (CA)

- Achieved peak load reductions of 3% on average (max 5%)

BGE launched BDR in combination with a Peak Time Rebate Program

- 5% average reduction at peak across homes without a device (~0.2kW/home)

Added benefit of customer engagement and increased satisfaction, although it is possible that customers could find the notifications to be intrusive

Others are also exploring the potential of Behavioral DR

In Minnesota, four electric co-ops used MyMeter – a program that gives utility customers more detailed info about their energy use

- In 2013, demand reduction ranged between 1.8 – 2.8% per customer
- This program is different from those offered by Opower, as information is driven through an in-home display

In the fall of 2012 and summer of 2013, Green Mountain Power study tested a behavioral DR-like program

- GMP ran fourteen peak event tests for seven treatment groups with varying rate structures and informational treatments
- Customers who stayed on a flat rate, but were notified of peak events, reduced by peak demand by 3.4% and 8.2% in 2012 and 2013, respectively (0.030 - 0.073 kW)

We have heard that Silver Spring Networks may be developing BDR capability. However, we have not yet found any evidence and further research is needed

Research suggests a 3% reduction impact for Behavioral DR programs would be reasonable

Utility/Program	Summer Peak Demand Impact (%)
Consumers Energy, Green Mountain Power, and Glendale Water & Power	3.0%
BGE	5.0%
MN electric co-ops (MyMeter Program)	1.8-2.8%
Green Mountain Power	3.4-8.2%

- Since little is known about the persistence of BDR impacts over the long-term, we assume an impact from the lower end of this range, of 3%
- To establish a winter impact, we use the same assumption that is used in our dynamic pricing analysis, that winter impacts are 10% higher than summer impacts; this is because BDR similarly relies on behavioral response from customers rather than targeting a specific end-use

There is support for high per-customer impacts from Irrigation Load Control programs

Irrigation Load Control consists of scheduling or shutting off irrigation pumps above a certain size

The programs researched are available only during the summer and typically provide a fixed (per event) incentive payment

Customers can opt out of a maximum number of events per year

In the Pacific Northwest, PacifiCorp has experience with such programs in Idaho and Utah; Idaho Power and a number of electric cooperatives also offer irrigation load control programs

Southern California Edison and Entergy also offer irrigation load control programs, as do coops in other parts of the US

Estimates of irrigation peak load reductions are fairly large on a per-participant basis

Rocky Mountain Power (part of PacifiCorp) ran its irrigation load control program in 2009 and 2010 with customers in Idaho

- About 2,000 customers were enrolled between 2009 and 2010
- Aggregate reductions in 2009 was 206 MW out of 260 MW of irrigation load
- In 2010, reductions amounted to 156 MW out of 283 MW of load

RMP also ran a program in Utah that achieved reductions in the 62-73% range

FERC's DR Study reports peak demand reductions of about 60% for electric cooperatives

Southern California Edison and Entergy report impacts of 82% and 49%, respectively

In its 2014 DR potential study, PacifiCorp's assumed that 100% of agricultural irrigation load could be curtailed during an event

Our research suggests peak reductions in the 65%-75% range for Irrigation Load Control programs

Utility/Program	Peak Demand Impact (MW)	Baseline Demand (MW)	Peak Demand Impact (%)
PacifiCorp DR potential study	N/A	N/A	100%
Southern California Edison			89%
RMP 2009	205	260	79%
RMP 2010	156	283	55%
RMP 2012	35	48	73%
RMP 2013	16	26	62%
Various Coops (FERC 2013 Study)	N/A	N/A	60% (mean)
Entergy (Arkansas)			49%

Notes: Peak demand impact % calculated for RMP 2009-2012 as (peak demand impact) / (baseline demand).
RMP 2009-10 from The Cadmus Group, *Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program,* March 24, 2011, pp. 1-2.
RMP 2012 from Rocky Mountain Power, *Utah Energy Efficiency and Peak Reduction Annual Report,* Revised June 26, 2013, p. 19.
RMP 2013 from Rocky Mountain Power, *Utah Energy Efficiency and Peak Reduction Annual Report,* May 16, 2014, p. 19.

Summary of Impact Assumptions for New Non-Pricing programs

Program	Winter Peak Demand Impact (kW)	Winter Peak Demand Impact (%)	Summer Peak Demand Impact (kW)	Summer Peak Demand Impact (%)
BYOD	1.0 kW		0.8 kW	
Behavioral DR		3.3%		3%
Irrigation Load Control		N/A		70%

Appendix C:
Cost-Effectiveness Adjustments

Should the incentive payment be included as a cost in the TRC cost-effectiveness test?

If every participant valued their loss of comfort at an amount equal to the incentive payment (assume $90/year), then it would be correct to include the full incentive amount as a cost in the TRC test

However, every participant is unique and will therefore value the loss of comfort differently; consider four prototypical customers in a DLC program:

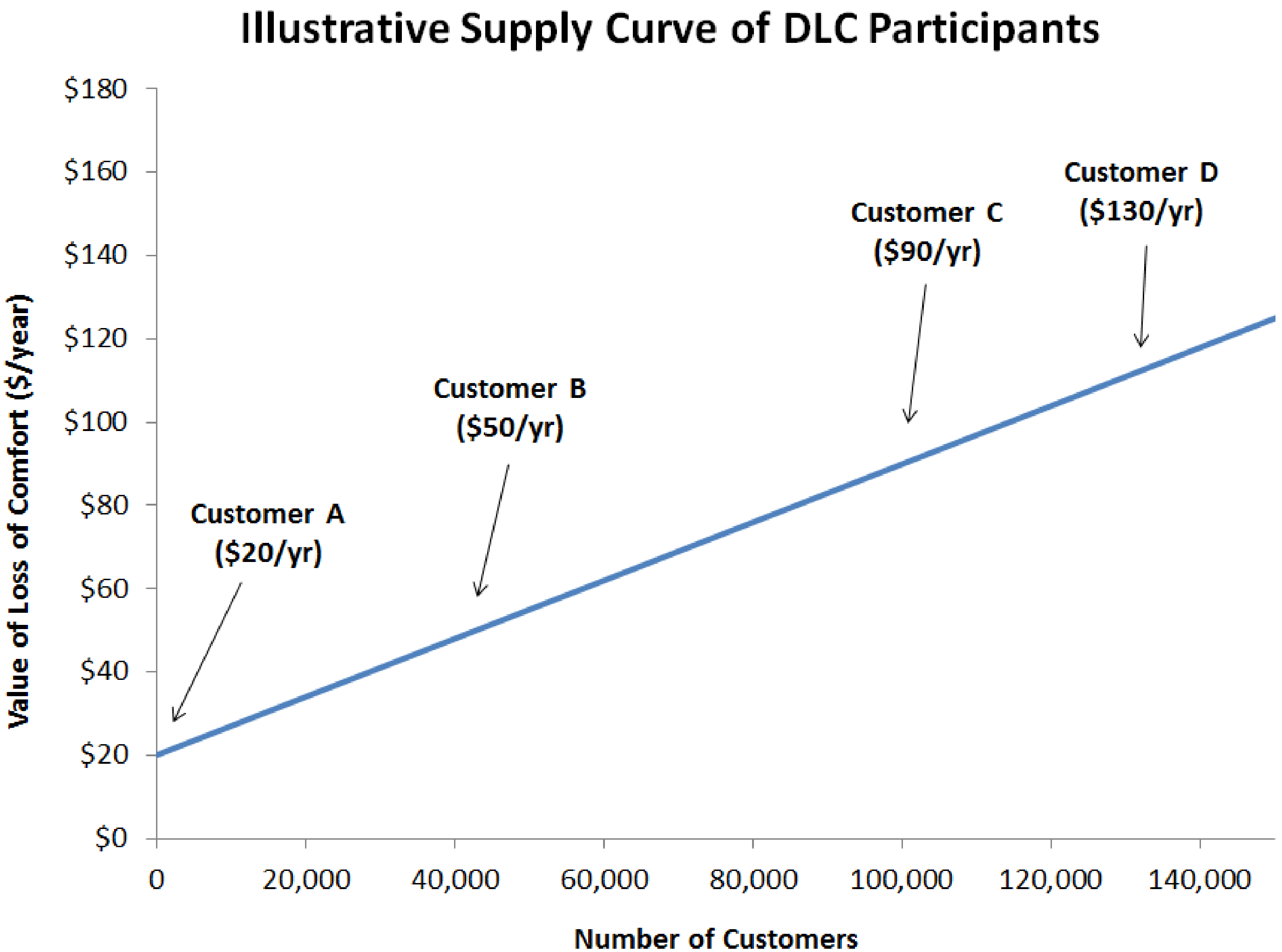
Customer A, for example, is rarely home and therefore only values his loss of comfort from participating in the DLC program at $20/year – his "profit" from participating in the program would be $70/year

Customer B is home more often, but does not particularly mind relinquishing control of his air-conditioner occasionally; he values the loss of comfort at $50/kW year

Customer C places higher value on comfort, and the cost of participating is roughly the same to him as the incentive payment that he receives; this is the "marginal" customer

Customer D is more temperature-sensitive and does not like the idea of curtailing use of his air-conditioner; his value of lost comfort is $130/year, or $40 more than the incentive payment that is being offered

The prototypical customers represent a “supply curve” of participants in the DLC program



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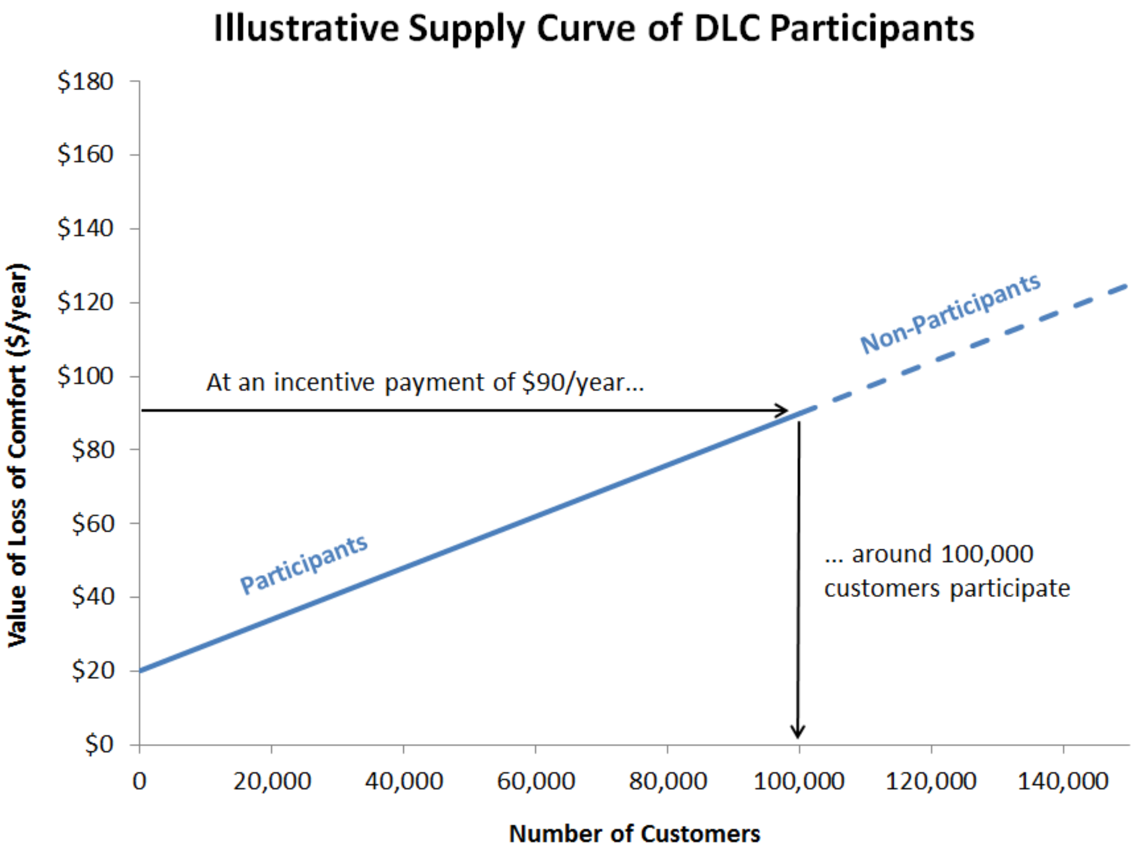
The cost associated with "loss of comfort" should be the average across all participants



- Customers will only participate if their loss of comfort is less than the incentive payment
- In this purely illustrative example, the average loss of comfort among participants is $50 per year, which is 55% of the incentive payment
- The remaining 45% is simply a transfer payment and should not be considered a cost in the TRC test (which is consistent with treatment of energy efficiency programs)
- While that estimate would change depending on the slope of the supply curve, it is more realistic than assuming all customers incur a cost of $90/year
- We count 50% of the incentive as a cost in the base case of our analysis for this reason

We tested the sensitivity of our findings to the amount of incentive counted as a cost

Class	Program	Opt-in Base Case (50%)	Opt-in 0%	Opt-in 100%
Residential	AC DLC	1.12	1.57	0.87
Residential	Space Heating DLC	1.31	1.78	1.03
Residential	Water Heating DLC	1.30	2.09	0.94
Residential	AC/Space Heating DLC	1.82	3.10	1.29
Residential	TOU	1.24	1.24	1.24
Residential	PTR	1.75	4.49	1.24
Residential	PTR w/Tech	1.32	2.26	0.98
Residential	CPP	1.62	1.62	1.62
Residential	CPP w/Tech	1.49	1.49	1.49
Residential	Behavioral DR	0.85	0.80	0.80
Residential	BYOT - AC	1.94	3.55	1.27
Residential	BYOT - Space Heating	1.98	3.30	1.41
Residential	BYOT - AC/Space Heating	2.43	5.39	1.57
Small C&I	AC DLC	1.00	1.51	0.75
Small C&I	Space Heating DLC	1.07	1.52	0.83
Small C&I	Water Heating DLC	0.79	1.14	0.60
Small C&I	AC/Space Heating DLC	1.40	2.41	0.98
Small C&I	TOU	0.06	0.06	0.06
Small C&I	PTR	0.17	0.18	0.16
Small C&I	PTR w/Tech	0.79	1.03	0.64
Small C&I	CPP	0.08	0.08	0.08
Small C&I	CPP w/Tech	0.55	0.55	0.55
Medium C&I	Third-Party DLC	1.59	2.09	1.23
Medium C&I	Curtailable Tariff	5.37	28.26	2.96
Medium C&I	CPP	1.94	1.94	1.94
Medium C&I	CPP w/Tech	1.38	1.38	1.38
Large C&I	Third-Party DLC	1.57	2.06	1.22
Large C&I	Curtailable Tariff	6.30	168.36	3.21
Large C&I	CPP	14.42	14.42	14.42
Large C&I	CPP w/Tech	6.70	6.70	6.70
Agricultural	Pumping Load Control	0.78	1.02	0.63
Agricultural	TOU	0.29	0.29	0.29

The table at left shows benefit-cost ratios assuming that 50%, 100%, and 0% of the incentive payment is counted as a cost in the TRC cost-effectiveness test, for **opt-in** program deployment

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Cost-effectiveness sensitivity case results (cont'd)

Class	Program	Opt-out Base Case (50%)	Opt-out 0%	Opt-out 100%
Residential	AC DLC	N/A	N/A	N/A
Residential	Space Heating DLC	N/A	N/A	N/A
Residential	Water Heating DLC	N/A	N/A	N/A
Residential	AC/Space Heating DLC	N/A	N/A	N/A
Residential	TOU	1.24	1.05	1.05
Residential	PTR	1.49	2.76	1.06
Residential	PTR w/Tech	0.86	1.16	0.69
Residential	CPP	1.15	1.04	1.04
Residential	CPP w/Tech	0.83	0.80	0.80
Residential	Behavioral DR	1.04	0.97	0.97
Residential	BYOT - AC	N/A	N/A	N/A
Residential	BYOT - Space Heating	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	N/A	N/A	N/A
Small C&I	AC DLC	N/A	N/A	N/A
Small C&I	Space Heating DLC	N/A	N/A	N/A
Small C&I	Water Heating DLC	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	N/A	N/A	N/A
Small C&I	TOU	0.11	0.09	0.09
Small C&I	PTR	0.30	0.30	0.26
Small C&I	PTR w/Tech	0.82	1.07	0.66
Small C&I	CPP	0.11	0.10	0.10
Small C&I	CPP w/Tech	0.60	0.58	0.58
Medium C&I	Third-Party DLC	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	N/A	N/A	N/A
Medium C&I	CPP	4.80	3.56	3.56
Medium C&I	CPP w/Tech	1.76	1.63	1.63
Large C&I	Third-Party DLC	N/A	N/A	N/A
Large C&I	Curtailable Tariff	N/A	N/A	N/A
Large C&I	CPP	42.10	34.79	34.79
Large C&I	CPP w/Tech	7.15	7.02	7.02
Agricultural	Pumping Load Control	N/A	N/A	N/A
Agricultural	TOU	0.83	0.63	0.63

The table at left shows benefit-cost ratios assuming that 50%, 100%, and 0% of the incentive payment is counted as a cost in the TRC cost-effectiveness test, for **opt-out** program deployment

DRAFT - Confidential

Avoided costs derates are derived from the California cost-effectiveness protocols

The California PUC currently defines three factors that are used to adjust avoided capacity costs to better reflect the value of demand response:

(A) **Availability:** "The A Factor is intended to represent the portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted."

(B) **Notification time:** "The B factor calculation should be done by examination of past DR events to determine how often the additional information available for shorter notification times would have resulted in different decisions about events calls… By examining past events, an estimate can be made of how often a curtailment event would have been accurately predicted, not predicted but needed, or predicted but not needed in advance of the notification time required by a particular program."

(C) **Trigger:** "The C factor should account for the triggers or conditions that permit the LSE to call each DR program. LSEs consider customer acceptance and transparency in establishing DR triggers. However, in general, programs with flexible triggers have a higher value than programs with triggers that rely on specific conditions.

Additionally, the CPUC defines two factors used to adjust T&D costs and energy cost, but those are specific to avoided assumptions in California and not directly applicable to this analysis for PGE

For more information, see the 2010 California DR Cost Effectiveness Protocols report:
http://www.cpuc.ca.gov/NR/rdonlyres/7D2FEDB9-4FD6-4CCB-B88F-DC190DFE9AFA/0/Protocolsfinal.DOC

The CPUC is currently examining the possible modification and expansion of these factors

Avoided cost derates used in the PGE analysis

Class	Program	A) Availability	B) Notification	C) Trigger	Combined
Residential	TOU - No Tech	65%	100%	100%	65%
Residential	CPP - No Tech	60%	88%	100%	53%
Residential	CPP - With Tech	60%	88%	100%	53%
Residential	PTR - No Tech	60%	88%	100%	53%
Residential	PTR - With Tech	60%	88%	100%	53%
Residential	DLC - Central A/C	70%	100%	95%	67%
Residential	DLC - Space Heat	70%	100%	95%	67%
Residential	DLC - Water Heating	85%	100%	95%	81%
Residential	DLC - BYOT	70%	100%	95%	67%
Residential	Behavioral DR	70%	88%	100%	62%
Small C&I	TOU - No Tech	65%	100%	100%	65%
Small C&I	CPP - No Tech	60%	88%	100%	53%
Small C&I	CPP - With Tech	60%	88%	100%	53%
Small C&I	PTR - No Tech	60%	88%	100%	53%
Small C&I	PTR - With Tech	60%	88%	100%	53%
Small C&I	DLC - Central A/C	70%	100%	95%	67%
Small C&I	DLC - Space Heat	70%	100%	95%	67%
Small C&I	DLC - Water Heating	85%	100%	95%	81%
Medium C&I	CPP - No Tech	60%	88%	100%	53%
Medium C&I	CPP - With Tech	60%	88%	100%	53%
Medium C&I	DLC - AutoDR	75%	100%	95%	71%
Medium C&I	Curtailable Tariff	75%	88%	100%	66%
Large C&I	CPP - No Tech	60%	88%	100%	53%
Large C&I	CPP - With Tech	60%	88%	100%	53%
Large C&I	DLC - AutoDR	75%	100%	95%	71%
Large C&I	Curtailable Tariff	75%	88%	100%	66%
Agriculture	DLC - Pumping	75%	100%	95%	71%

- Values at left represent the percent of the avoided cost that is attributed to the DR program
- Estimates are based on a survey of values developed by the California IOUs across a wide variety of DR programs
- Values are calibrated to capture appropriate relative relationships across the programs evaluated for PGE and intuitive estimates were developed for those programs for which there is not a clear example in the California data

Appendix D:

Annual Potential Estimates and Benefit-Cost Ratios

See the accompanying MS Excel file titled “PGE DR Potential Results - Annual Tables.xlsx”.

Measure-level Peak Reduction Potential: Summer (MW, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Summer	0.0	42.0	43.2	44.6	45.7
Residential	PTR	Summer	0.0	94.3	97.2	100.3	102.9
Residential	PTR w/Tech	Summer	0.0	23.5	24.3	25.0	25.7
Residential	CPP	Summer	0.0	76.2	78.3	80.8	82.9
Residential	CPP w/Tech	Summer	0.0	20.4	21.0	21.6	22.2
Residential	Behavioral DR	Summer	45.2	38.1	39.3	40.6	41.7
Residential	BYOT - AC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Summer	0.0	0.5	0.6	0.6	0.6
Small C&I	PTR	Summer	0.0	1.7	1.8	2.0	2.1
Small C&I	PTR w/Tech	Summer	0.0	3.7	4.0	4.3	4.6
Small C&I	CPP	Summer	0.0	0.9	1.0	1.0	1.1
Small C&I	CPP w/Tech	Summer	0.0	2.2	2.3	2.5	2.6
Medium C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Summer	0.0	21.9	23.3	25.2	26.8
Medium C&I	CPP w/Tech	Summer	0.0	38.5	41.1	44.4	47.3
Large C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Summer	0.0	40.9	44.3	48.4	52.1
Large C&I	CPP w/Tech	Summer	0.0	83.9	90.9	99.4	106.9
Agricultural	Pumping Load Control	Summer	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Summer	0.0	1.7	1.6	1.4	1.3

Measure-level Peak Reduction Potential: Summer (MW, grossed up for line losses)

Maximum Achievable Potential Opt-In Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	11.0	106.5	120.9	134.2	144.3
Residential	Space Heating DLC	Summer	0.0	0.0	0.0	0.0	0.0
Residential	Water Heating DLC	Summer	3.6	31.0	32.3	33.8	35.2
Residential	AC/Space Heating DLC	Summer	1.4	12.3	13.0	13.7	14.3
Residential	TOU	Summer	0.0	22.7	23.9	24.6	25.3
Residential	PTR	Summer	0.0	42.6	44.7	46.1	47.3
Residential	PTR w/Tech	Summer	0.0	12.9	13.5	13.9	14.3
Residential	CPP	Summer	0.0	31.9	33.5	34.6	35.5
Residential	CPP w/Tech	Summer	0.0	9.6	10.1	10.4	10.7
Residential	Behavioral DR	Summer	1.1	9.5	9.8	10.2	10.4
Residential	BYOT - AC	Summer	1.9	42.1	44.5	46.9	49.0
Residential	BYOT - Space Heating	Summer	0.0	0.0	0.0	0.0	0.0
Residential	BYOT - AC/Space Heating	Summer	0.9	7.7	8.1	8.6	8.9
Residential	Smart Water Heater DLC	Summer	0.1	7.6	20.5	33.7	44.5
Residential	Electric Vehicle DLC	Summer	0.4	1.3	2.7	4.9	6.9
Small C&I	AC DLC	Summer	1.5	12.8	13.8	14.9	15.9
Small C&I	Space Heating DLC	Summer	0.0	0.0	0.0	0.0	0.0
Small C&I	Water Heating DLC	Summer	0.1	0.7	0.7	0.8	0.8
Small C&I	AC/Space Heating DLC	Summer	0.4	3.4	3.7	4.0	4.2
Small C&I	TOU	Summer	0.0	0.1	0.1	0.1	0.1
Small C&I	PTR	Summer	0.0	0.5	0.5	0.6	0.6
Small C&I	PTR w/Tech	Summer	0.0	1.2	1.4	1.5	1.6
Small C&I	CPP	Summer	0.0	0.2	0.3	0.3	0.3
Small C&I	CPP w/Tech	Summer	0.0	0.6	0.7	0.7	0.8
Medium C&I	Third-Party DLC	Summer	5.2	46.1	49.6	53.6	57.1
Medium C&I	Curtailable Tariff	Summer	23.3	24.6	26.5	28.6	30.4
Medium C&I	CPP	Summer	0.0	6.1	6.7	7.2	7.7
Medium C&I	CPP w/Tech	Summer	0.0	10.9	11.9	12.9	13.7
Large C&I	Third-Party DLC	Summer	7.0	62.8	68.6	75.1	80.7
Large C&I	Curtailable Tariff	Summer	75.5	80.4	87.8	96.1	103.3
Large C&I	CPP	Summer	0.0	11.4	12.6	13.8	14.9
Large C&I	CPP w/Tech	Summer	0.0	29.6	32.9	36.0	38.7
Agricultural	Pumping Load Control	Summer	0.5	3.8	3.5	3.2	2.9
Agricultural	TOU	Summer	0.0	0.3	0.3	0.2	0.2

Measure-level Peak Reduction Potential: Summer (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Summer	0.0%	1.2%	1.1%	1.1%	1.1%
Residential	PTR	Summer	0.0%	2.6%	2.6%	2.5%	2.5%
Residential	PTR w/Tech	Summer	0.0%	0.7%	0.6%	0.6%	0.6%
Residential	CPP	Summer	0.0%	2.1%	2.1%	2.0%	2.0%
Residential	CPP w/Tech	Summer	0.0%	0.6%	0.6%	0.5%	0.5%
Residential	Behavioral DR	Summer	1.3%	1.1%	1.0%	1.0%	1.0%
Residential	BYOT - AC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	CPP	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Medium C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Summer	0.0%	0.6%	0.6%	0.6%	0.6%
Medium C&I	CPP w/Tech	Summer	0.0%	1.1%	1.1%	1.1%	1.1%
Large C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Summer	0.0%	1.1%	1.2%	1.2%	1.2%
Large C&I	CPP w/Tech	Summer	0.0%	2.3%	2.4%	2.5%	2.5%
Agricultural	Pumping Load Control	Summer	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%

Measure-level Peak Reduction Potential: Summer (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-in Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	0.3%	3.0%	3.2%	3.3%	3.4%
Residential	Space Heating DLC	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	Water Heating DLC	Summer	0.1%	0.9%	0.9%	0.8%	0.8%
Residential	AC/Space Heating DLC	Summer	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	TOU	Summer	0.0%	0.6%	0.6%	0.6%	0.6%
Residential	PTR	Summer	0.0%	1.2%	1.2%	1.2%	1.1%
Residential	PTR w/Tech	Summer	0.0%	0.4%	0.4%	0.3%	0.3%
Residential	CPP	Summer	0.0%	0.9%	0.9%	0.9%	0.8%
Residential	CPP w/Tech	Summer	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	Behavioral DR	Summer	0.0%	0.3%	0.3%	0.3%	0.2%
Residential	BYOT - AC	Summer	0.1%	1.2%	1.2%	1.2%	1.2%
Residential	BYOT - Space Heating	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	BYOT - AC/Space Heating	Summer	0.0%	0.2%	0.2%	0.2%	0.2%
Residential	Smart Water Heater DLC	Summer	0.0%	0.2%	0.5%	0.8%	1.1%
Residential	Electric Vehicle DLC	Summer	0.0%	0.0%	0.1%	0.1%	0.2%
Small C&I	AC DLC	Summer	0.0%	0.4%	0.4%	0.4%	0.4%
Small C&I	Space Heating DLC	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	Water Heating DLC	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	AC/Space Heating DLC	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I	Third-Party DLC	Summer	0.1%	1.3%	1.3%	1.3%	1.4%
Medium C&I	Curtailable Tariff	Summer	0.7%	0.7%	0.7%	0.7%	0.7%
Medium C&I	CPP	Summer	0.0%	0.2%	0.2%	0.2%	0.2%
Medium C&I	CPP w/Tech	Summer	0.0%	0.3%	0.3%	0.3%	0.3%
Large C&I	Third-Party DLC	Summer	0.2%	1.7%	1.8%	1.9%	1.9%
Large C&I	Curtailable Tariff	Summer	2.1%	2.2%	2.3%	2.4%	2.5%
Large C&I	CPP	Summer	0.0%	0.3%	0.3%	0.3%	0.4%
Large C&I	CPP w/Tech	Summer	0.0%	0.8%	0.9%	0.9%	0.9%
Agricultural	Pumping Load Control	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Agricultural	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%

Measure-level Peak Reduction Potential: Winter (MW, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Winter	0.0	61.7	62.8	64.1	65.2
Residential	PTR	Winter	0.0	136.2	138.9	141.8	144.1
Residential	PTR w/Tech	Winter	0.0	24.6	25.0	25.6	26.0
Residential	CPP	Winter	0.0	109.4	111.3	113.6	115.5
Residential	CPP w/Tech	Winter	0.0	21.2	21.6	22.1	22.4
Residential	Behavioral DR	Winter	65.6	54.6	55.7	56.9	57.9
Residential	BYOT - AC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Winter	0.0	0.5	0.5	0.5	0.6
Small C&I	PTR	Winter	0.0	1.7	1.8	1.9	2.0
Small C&I	PTR w/Tech	Winter	0.0	2.7	2.9	3.1	3.3
Small C&I	CPP	Winter	0.0	0.8	0.9	0.9	1.0
Small C&I	CPP w/Tech	Winter	0.0	1.6	1.7	1.8	1.9
Medium C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Winter	0.0	18.1	19.2	20.7	22.0
Medium C&I	CPP w/Tech	Winter	0.0	31.8	33.9	36.5	38.8
Large C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Winter	0.0	35.4	38.2	41.6	44.7
Large C&I	CPP w/Tech	Winter	0.0	72.5	78.4	85.5	91.7
Agricultural	Pumping Load Control	Winter	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Winter	0.0	0.0	0.0	0.0	0.0

Measure-level Peak Reduction Potential: Winter (MW, grossed up for line losses)

Maximum Achievable Potential Opt-In Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	0.0	0.0	0.0	0.0	0.0
Residential	Space Heating DLC	Winter	2.3	20.1	21.2	22.4	23.3
Residential	Water Heating DLC	Winter	7.2	61.9	64.5	67.6	70.4
Residential	AC/Space Heating DLC	Winter	1.7	15.4	16.2	17.1	17.9
Residential	TOU	Winter	0.0	33.0	34.3	35.0	35.6
Residential	PTR	Winter	0.0	61.0	63.4	64.7	65.8
Residential	PTR w/Tech	Winter	0.0	13.4	13.9	14.2	14.5
Residential	CPP	Winter	0.0	45.4	47.2	48.2	49.0
Residential	CPP w/Tech	Winter	0.0	10.0	10.4	10.6	10.8
Residential	Behavioral DR	Winter	1.6	13.6	13.9	14.2	14.5
Residential	BYOT - AC	Winter	0.0	0.0	0.0	0.0	0.0
Residential	BYOT - Space Heating	Winter	1.4	12.6	13.2	14.0	14.6
Residential	BYOT - AC/Space Heating	Winter	1.1	9.6	10.1	10.7	11.2
Residential	Smart Water Heater DLC	Winter	0.2	15.1	41.1	67.5	88.9
Residential	Electric Vehicle DLC	Winter	0.3	0.9	2.0	3.5	5.0
Small C&I	AC DLC	Winter	0.0	0.0	0.0	0.0	0.0
Small C&I	Space Heating DLC	Winter	0.7	6.0	6.5	7.1	7.5
Small C&I	Water Heating DLC	Winter	0.2	1.3	1.4	1.5	1.6
Small C&I	AC/Space Heating DLC	Winter	0.5	4.3	4.6	5.0	5.3
Small C&I	TOU	Winter	0.0	0.1	0.1	0.1	0.1
Small C&I	PTR	Winter	0.0	0.5	0.5	0.6	0.6
Small C&I	PTR w/Tech	Winter	0.0	0.9	1.0	1.1	1.1
Small C&I	CPP	Winter	0.0	0.3	0.3	0.3	0.4
Small C&I	CPP w/Tech	Winter	0.0	0.4	0.5	0.5	0.6
Medium C&I	Third-Party DLC	Winter	4.2	38.1	40.9	44.1	46.8
Medium C&I	Curtailable Tariff	Winter	19.0	20.3	21.8	23.5	25.0
Medium C&I	CPP	Winter	0.0	5.0	5.5	5.9	6.3
Medium C&I	CPP w/Tech	Winter	0.0	9.0	9.8	10.6	11.2
Large C&I	Third-Party DLC	Winter	6.0	54.3	59.2	64.5	69.2
Large C&I	Curtailable Tariff	Winter	64.3	69.5	75.7	82.6	88.6
Large C&I	CPP	Winter	0.0	9.8	10.9	11.9	12.8
Large C&I	CPP w/Tech	Winter	0.0	25.6	28.4	31.0	33.2
Agricultural	Pumping Load Control	Winter	0.0	0.0	0.0	0.0	0.0
Agricultural	TOU	Winter	0.0	0.0	0.0	0.0	0.0

Measure-level Peak Reduction Potential: Winter (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Winter	0.0%	1.7%	1.6%	1.6%	1.6%
Residential	PTR	Winter	0.0%	3.7%	3.6%	3.5%	3.4%
Residential	PTR w/Tech	Winter	0.0%	0.7%	0.6%	0.6%	0.6%
Residential	CPP	Winter	0.0%	3.0%	2.9%	2.8%	2.7%
Residential	CPP w/Tech	Winter	0.0%	0.6%	0.6%	0.5%	0.5%
Residential	Behavioral DR	Winter	1.8%	1.5%	1.4%	1.4%	1.4%
Residential	BYOT - AC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	CPP	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Winter	0.0%	0.5%	0.5%	0.5%	0.5%
Medium C&I	CPP w/Tech	Winter	0.0%	0.9%	0.9%	0.9%	0.9%
Large C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Winter	0.0%	1.0%	1.0%	1.0%	1.1%
Large C&I	CPP w/Tech	Winter	0.0%	2.0%	2.0%	2.1%	2.2%
Agricultural	Pumping Load Control	Winter	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%

Measure-level Peak Reduction Potential: Winter (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-in Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	Space Heating DLC	Winter	0.1%	0.5%	0.5%	0.6%	0.6%
Residential	Water Heating DLC	Winter	0.2%	1.7%	1.7%	1.7%	1.7%
Residential	AC/Space Heating DLC	Winter	0.0%	0.4%	0.4%	0.4%	0.4%
Residential	TOU	Winter	0.0%	0.9%	0.9%	0.9%	0.8%
Residential	PTR	Winter	0.0%	1.7%	1.6%	1.6%	1.6%
Residential	PTR w/Tech	Winter	0.0%	0.4%	0.4%	0.4%	0.3%
Residential	CPP	Winter	0.0%	1.2%	1.2%	1.2%	1.2%
Residential	CPP w/Tech	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	Behavioral DR	Winter	0.0%	0.4%	0.4%	0.4%	0.3%
Residential	BYOT - AC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	BYOT - Space Heating	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	BYOT - AC/Space Heating	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	Smart Water Heater DLC	Winter	0.0%	0.4%	1.1%	1.7%	2.1%
Residential	Electric Vehicle DLC	Winter	0.0%	0.0%	0.1%	0.1%	0.1%
Small C&I	AC DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	Space Heating DLC	Winter	0.0%	0.2%	0.2%	0.2%	0.2%
Small C&I	Water Heating DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	AC/Space Heating DLC	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I	Third-Party DLC	Winter	0.1%	1.0%	1.1%	1.1%	1.1%
Medium C&I	Curtailable Tariff	Winter	0.5%	0.6%	0.6%	0.6%	0.6%
Medium C&I	CPP	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Medium C&I	CPP w/Tech	Winter	0.0%	0.2%	0.3%	0.3%	0.3%
Large C&I	Third-Party DLC	Winter	0.2%	1.5%	1.5%	1.6%	1.6%
Large C&I	Curtailable Tariff	Winter	1.8%	1.9%	2.0%	2.0%	2.1%
Large C&I	CPP	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Large C&I	CPP w/Tech	Winter	0.0%	0.7%	0.7%	0.8%	0.8%
Agricultural	Pumping Load Control	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Agricultural	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%

Benefit-Cost Ratios

Opt-out Scenario (Red text indicates ratio is less than 1.0)

Class	Program	Ratio
Residential	AC DLC	N/A
Residential	Space Heating DLC	N/A
Residential	Water Heating DLC	N/A
Residential	AC/Space Heating DLC	N/A
Residential	TOU	1.24
Residential	PTR	1.49
Residential	PTR w/Tech	0.86
Residential	CPP	1.15
Residential	CPP w/Tech	0.83
Residential	Behavioral DR	1.04
Residential	BYOT - AC	N/A
Residential	BYOT - Space Heating	N/A
Residential	BYOT - AC/Space Heating	N/A
Residential	Smart Water Heater DLC	N/A
Residential	Electric Vehicle DLC	N/A
Small C&I	AC DLC	N/A
Small C&I	Space Heating DLC	N/A
Small C&I	Water Heating DLC	N/A
Small C&I	AC/Space Heating DLC	N/A
Small C&I	TOU	0.11
Small C&I	PTR	0.30
Small C&I	PTR w/Tech	0.82
Small C&I	CPP	0.11
Small C&I	CPP w/Tech	0.60
Medium C&I	Third-Party DLC	N/A
Medium C&I	Curtailable Tariff	N/A
Medium C&I	CPP	4.80
Medium C&I	CPP w/Tech	1.76
Large C&I	Third-Party DLC	N/A
Large C&I	Curtailable Tariff	N/A
Large C&I	CPP	42.10
Large C&I	CPP w/Tech	7.15
Agricultural	Pumping Load Control	N/A
Agricultural	TOU	0.83

Benefit-Cost Ratios

Opt-in Scenario (Red text indicates ratio is less than 1.0)

Class	Program	Ratio
Residential	AC DLC	1.12
Residential	Space Heating DLC	1.31
Residential	Water Heating DLC	1.30
Residential	AC/Space Heating DLC	1.82
Residential	TOU	1.24
Residential	PTR	1.75
Residential	PTR w/Tech	1.32
Residential	CPP	1.62
Residential	CPP w/Tech	1.49
Residential	Behavioral DR	0.85
Residential	BYOT - AC	1.94
Residential	BYOT - Space Heating	1.98
Residential	BYOT - AC/Space Heating	2.43
Residential	Smart Water Heater DLC	2.22
Residential	Electric Vehicle DLC	0.14
Small C&I	AC DLC	1.00
Small C&I	Space Heating DLC	1.07
Small C&I	Water Heating DLC	0.79
Small C&I	AC/Space Heating DLC	1.40
Small C&I	TOU	0.06
Small C&I	PTR	0.17
Small C&I	PTR w/Tech	0.79
Small C&I	CPP	0.08
Small C&I	CPP w/Tech	0.55
Medium C&I	Third-Party DLC	1.59
Medium C&I	Curtailable Tariff	5.37
Medium C&I	CPP	1.94
Medium C&I	CPP w/Tech	1.38
Large C&I	Third-Party DLC	1.57
Large C&I	Curtailable Tariff	6.30
Large C&I	CPP	14.42
Large C&I	CPP w/Tech	6.70
Agricultural	Pumping Load Control	0.78
Agricultural	TOU	0.29

Exhibit PLC-S-2

CAMBRIDGE
NEW YORK
SAN FRANCISCO
WASHINGTON
TORONTO
LONDON
MADRID
ROME

THE Brattle GROUP

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 12

QUESTION NO. 4

PLEASE REFER TO THE DIRECT TESTIMONY OF KAREN LEFKOWITZ, PAGE 48, LINE 20 TO PAGE 49, LINE 7:

A. PLEASE INDICATE IF THE COMPANY BELIEVES THAT THERE ARE FREE-RIDERSHIP EFFECTS ASSOCIATED WITH ITS PEAK ENERGY SAVINGS PROGRAM?
B. IF THE COMPANY'S RESPONSE IS AN UNQUALIFIED "NO," PLEASE PROVIDE ALL ANALYSES CONDUCTED OR COMMISSIONED BY THE COMPANY SUPPORTING A ZERO VALUE FOR FREE-RIDERSHIP EFFECTS.
C. IF THE COMPANY'S RESPONSE IS AN UNQUALIFIED "YES," PLEASE PROVIDE ALL ANALYSES CONDUCTED OR COMMISSIONED BY THE COMPANY REGARDING FREE-RIDERSHIP EFFECTS AND ITS PEAK ENERGY SAVINGS PROGRAM.
D. PLEASE EXPLAIN THE COMPANY'S POSITION THAT FREE RIDERSHIP EFFECTS SHOULD BE A "ZERO" VALUE IN ITS COST-EFFECTIVENESS SCREENING.
E. PLEASE PROVIDE OTHER EXAMPLES ASSOCIATED WITH THE COMPANY'S OR EMPOWER ENERGY EFFICIENCY PROGRAMS THAT IGNORE FREE-RIDERSHIP EFFECTS."
F. PLEASE PROVIDE ANY DATA PEPCO RELIED ON TO ASSUME THAT PEAK ENERGY SAVINGS PROGRAM PARTICIPANTS WILL REDUCE USAGE IN THE HOURS BEFORE AND AFTER THE PEAK ENERGY SAVINGS HOURS."

RESPONSE:

a) Yes, due to the manner that PESC reductions are calculated based upon the Commission approved retail dynamic pricing tariff, there will be both customers who receive higher credit amounts then their reduction actions warrant (free riders) and customers who receive credit amounts that are less than their reduction actions warrant ("under paid riders"). This is primarily due to the use of a Customer Baseline Loadshape to predict what the consumption would have been by the customer, but for the PESC event.

Note that it is difficult to determine free ridership rates for this Program. For example, customers may have taken actions that include scheduling a vacation out of town during a typical week when temperature conditions are high and their energy use would have been high – this decision reduces regional electric loads and is provides benefits. Similarly, if a customer was on vacation out of town prior to an event, it is likely that they would become "under paid riders" for the PESC Program.

b) Refer to the response to part A.

c) The Company has not performed this analysis. Panel regression modeling provides some insight into customer behavior, but the PJM capacity market revenue stream is primarily based upon reducing loads to or below a specified Firm Service Level. PJM Energy market earnings are based on an alternative model. The basis for customer credit payments is based upon a CBL method, please refer to the response to part A above.

d) Please refer to the response to part A. For any given PESC event there will be both free riders and "under paid riders". The quantity of each is largely related to the weather and resulting load conditions on the event day versus the weather and resulting load conditions on the days selected for a comparison event. Event days are more likely to have higher temperature conditions than non-event days over time and therefore the quantity of free riders may be exceeded by the quantity of under paid riders.

e) Pepco's Energy Wise Rewards Program cost-effectiveness, that is part of Pepco's EmPOWER portfolio, does not include an adjustment for free riders. Under this program air conditioning compressor loads are reduced when the program is activated.

f) Pepco conducted a study of its residential direct load control impacts to develop an estimate of the quantity of load shifted from event hours to non-event hours. This study found that the snapback of energy consumption does occur after a cycling event, but due to a variety of factors, such as air conditioner size and weather conditions there is considerable variation across customers. In the PESC Program, a similar snapback impact has been assumed for AMI cost-effectiveness purposes. This snapback has been assumed to be 50 percent of the energy avoided during an event period over future years. Pepco has not developed a statistically based snapback estimate for the PESC Program.

SPONSOR: Karen Lefkowitz/Mario Giovannini