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August 17, 2017

Via Electronic Filing and Federal Express

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
2017 Request for a General Rate Revision
Docket No. UE 319

Dear Filing Center:

Please find enclosed the Cross-Answering Testimony and Exhibits of Bradley G. Mullins (ICNU/400 – ICNU/408) on behalf of the Industrial Customers of Northwest Utilities (“ICNU”).

In accordance with OAR 860-001-0170(2) and per the Commission’s request, ICNU is also providing the Commission with four (4) hard copy sets of Mr. Mullins’ testimony and exhibits.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **Cross-Answering Testimony and Exhibits of Bradley G. Mullins** upon the parties shown below by mailing copies via U.S. Mail, postage prepaid.

Dated at Portland, Oregon, this 17th day of August, 2017

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 319

In the Matter of	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
Request for a General Rate Revision	)

CROSS-ANSWERING GENERAL RATE CASE TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE
INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

August 17, 2017

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EXHIBIT LIST

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS

A. Bradley G. Mullins, 333 S.W. Taylor St, Suite 400, Portland, Oregon 97204.

Q. ARE YOU THE SAME BRADLEY G. MULLINS THAT PREVIOUSLY SUBMITTED TESTIMONY IN THIS MATTER?

A. Yes. I previously filed Opening Power Cost Testimony and Opening General Rate Case Testimony in this matter—the 2018 General Rate Case ("GRC") filing of Portland General Electric Company (the "Company")—on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT IS THE PURPOSE OF YOUR CROSS ANSWERING TESTIMONY?

A. I address the cost allocation proposals the Oregon Citizens' Utility Board ("CUB") made with respect to energy efficiency acquired pursuant to Senate Bill ("SB") 838 funding.

Q. DOES ICNU SUPPORT CUB'S COST ALLOCATION PROPOSAL?

A. No. ICNU agrees with the position of the Company that adopting CUB's proposals would require customers with loads greater that 1 average megawatt ("aMW") to pay more than the 3% energy efficiency funding limitation established in SB 838.[1/] From ICNU's perspective, the equity surrounding the current statutory framework is not one that is appropriately addressed within the context of a cost of service study, and is in conflict with the "no benefit," "no pay" concept that was put in place to ensure that large customers are not provided with a direct benefit associated with SB 838 energy efficiency measures. These are primarily legal issues that ICNU will address more fully in briefing. I focus on several analytical problems associated with CUB's proposal, which I will discuss below.

[1/] PGE/1600 at 8:7-9.

II. BACKGROUND

Q. PLEASE PROVIDE SOME BACKGROUND ON ENERGY EFFICIENCY IN OREGON.

A. Oregon law establishes two sources of funding for the Company's energy efficiency programs. The first is the public purpose charge, established in 1999 through SB 1149, which imposes a 3% charge on all customers, the majority of which goes to the Energy Trust of Oregon ("Energy Trust") to administer energy efficiency programs in the Company's service territory. The other is SB 838, which allows the Company to collect additional revenues above the public purpose charge to fund cost-effective energy efficiency, but prohibits any customer over 1 aMW from paying more than the 3% public purpose charge for energy efficiency and from receiving "any direct benefit from energy conservation measures" funded under SB 838.

Q. DID THE THREE PERCENT CAP ON CUSTOMERS OVER 1 AMW ORIGINATE WITH SB 838?

A. No. The original public purpose charge acted essentially identically to SB 838. ORS 757.612(3)(f) used to read:

> The commission may establish a different public purpose charge than the public purpose charge otherwise described in subsection (2) of this section [i.e., 3% of the total revenues of an electric company] for an individual retail electricity consumer or any class of retail electricity consumers located within the service area of an electric company, provided that a retail electricity consumer with a load greater than one average megawatt is not required to pay a public purpose charge in excess of three percent of its total cost of electricity services.[2/]

As can be seen from the B-Engrossed version of SB 838, this language was amended out of the public purpose charge when SB 838 was passed and was effectively moved to ORS 757.689

[2/] 1999 Or. Laws Chap 865 § 3(3)(f).

where it currently resides.[3/] Thus, SB 838 did not change the situation in terms of how customer classes fund energy efficiency in Oregon. Since the state began incentivizing energy efficiency, customers over 1 aMW have funded up to 3% of these incentives, while customers under 1 aMW could have been asked to pay more. The primary thing that changed when SB 838 passed was the 18.4% cap on public purpose charge incentives that the Energy Trust informally agreed to impose on customers over 1 aMW.

Q. WHAT MEASURES ARE IN PLACE TO PREVENT LARGE CUSTOMERS FROM RECEIVING DIRECT BENEFITS FROM SB 838 ENERGY EFFICIENCY MEASURES?

A. Following passage of SB 838, the Energy Trust and stakeholders agreed informally that the Energy Trust would limit the amount of incentive funding from the public purpose charge that it provided to customers over 1 aMW to an amount that represented the cumulative average of the amount of incentives it provided to these customers in the years immediately preceding the passage of SB 838. Thus, under this informal agreement, the Energy Trust cannot provide, on a cumulative basis, more than 18.4% of incentives available under the public purpose charge to customers larger than 1 aMW in the Company's service territory. The Energy Trust recently reported that it has exceeded this cap.[4/]

3/ Exhibit ICNU/401 at 10, 28-29.
4/ Exhibit ICNU/408.

III. POLICY ISSUES WITH CUB'S ENERGY EFFICIENCY PROPOSAL

Q. WHY DOES CUB BELIEVE THAT THE EXISTING FUNDING MECHANISMS ARE UNFAIR?

A. Since customers over 1 aMW are not required to pay for energy efficiency funded through SB 838, CUB claims that "[r]esidential and small commercial customers are being asked to purchase more than their share of energy efficiency resources while not being credited with those resources."[5/] CUB also argues that the true "direct benefit" of energy efficiency is lower rates based on reduced system costs as a consequence of energy efficiency deferring or eliminating the need to purchase more expensive supply side resources. Thus, according to CUB, large customers are currently receiving a "direct benefit" from SB 838 funding in violation of this law, and redirecting the "system benefits" associated the SB 838 funding to small customers would resolve both this legal issue and the "fairness question" of small customers not receiving credit for a resource they are buying.

Q. IS CUB'S THEORY VALID?

A. No. Broadly, CUB's position—that the system benefits of energy efficiency funded through SB 838 is the "direct benefit" of this energy efficiency—would allow customers over 1 aMW to receive incentive funding from SB 838 revenue to implement energy efficiency measures at their sites, so long as the system benefits of the conservation measures pursued with this incentive are redirected to customers under 1 aMW. ICNU, the Company, and Staff all disputed this position in prior dockets, and have argued that the "direct benefit" of energy

5/ CUB/100 at 10:12-14.

efficiency is the reduced load a customer that implements a conservation measure realizes as the direct consequence of that measure.[6/]

Q. WHAT IS YOUR UNDERSTANDING OF THE SPECIFIC COST ALLOCATION PROPOSALS CUB PROPOSES?

A. As I understand, CUB has proposed two different cost allocation alternatives surrounding energy efficiency.

The first alternative CUB describes as a "Marginal Cost of Service Approach," which is the same approach which CUB advocated in the Company's 2015 General Rate Case, Docket No. UE 283. CUB offers no new testimony on this alternative and simply appends the testimony it filed in that matter, without modifying any of the assumptions or numbers presented in that matter based on updated information. ICNU filed testimony in that matter demonstrating that CUB's calculations were deeply flawed, and I continue to have the same concerns with that approach, particularly since CUB did not attempt to update the calculations to reflect more recent information. ICNU's testimony, as well as Staff's and the Company's in UE 283, is attached as Exhibits ICNU/403-407. One particularly egregious concern, however, that ICNU noted in that matter was that CUB's approach assumed the equivalent of approximately 800 aMW of energy efficiency savings in the test period. CUB did not address ICNU's concern with respect to that assumption, which clearly does not conform to any range of reasonableness associated with energy efficiency savings expected in the test period.

The second alternative CUB describes is an allocation credit, which is a somewhat different concept than was discussed in Docket No. UE 283. Under CUB's allocation credit

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[6/] Exhibits ICNU/404 at 4-8, ICNU/406 at 10-11, ICNU 407 at 6-11; see also, Docket No. UM 1713, ICNU Opening Comments at 8-11, Staff Opening Comments at 5, PGE Opening Comments at 4.

methodology, customers paying SB 838 surcharges should receive a credit for the value of what they purchase.[7/] The remainder of my testimony addresses this second alternative.

Q. WHAT WAS CUB'S BASIS FOR PROPOSING THE ALLOCATION CREDIT ALTERNATIVE?

A. CUB devotes only a small amount of testimony to the allocation credit alternative and does not, other than describing the mechanics of how it arrived at the allocation credit amount, describe why this particular approach is reasonable in light of its other testimony on energy efficiency. As I understand, however, the methodology is largely premised on the notion that is described under the heading, "Different Customer Classes Buy Different Sets of Resources."[8/] That is, CUB argues that small and large customers should be assumed to be acquiring a different resource mix from the Company, similar to what was contemplated with respect to the Voluntary Renewable Energy Tariff ("VRET") in Docket No. UM 1690.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE VRET PROGRAM.

A. The record in Docket No. UM 1690 speaks to the great number of complications and issues associated with assuming in rates that different customers acquire a different resource mix from the Company.[9/] House Bill ("HB") 4126 directed the Commission to consider the impact of allowing non-residential customers to acquire different renewable resources through a VRET. As a result, the Commission undertook an investigation that spanned a period of over two years, considering the various impacts how a VRET might be implemented in a just and reasonable manner. On June 10, 2016, the Commission adopted Staff's recommendation, which allowed utilities to adopt a VRET program, subject to a list of nine conditions.

7/ CUB/100 at 12:10-13:2.

8/ Id. at 8:3-9:2.

9/ Re Public Utility Commission of Oregon Investigation into Voluntary Renewable Energy Tariffs, Docket No. UM 1690, Order No. 16-251.

Q. WHAT WERE THE CONDITIONS?

A. Notable to this matter, condition number (7) stated that "[t]he regulated utility must demonstrate that there is no risk of cost-shifting on nonparticipating customers due to any direct or indirect VRET service and resource obligations, including stranded costs of the existing cost of service rate based system."[10/]

Q. WOULD THIS SAME CONDITION BE PERTINENT TO THIS MATTER?

A. Yes. If the Commission is to assume that small customers are acquiring a resource portfolio that is different than that reflected in the overall system cost of service, it would be necessary to ensure that the assignment does not result in cost-shifting, including consideration of stranded costs, just as it was necessary in the context of the VRET.

Q. HOW MIGHT CLASS BY CLASS ASSIGNMENT OF ENERGY EFFICIENCY SYSTEM BENEFITS RESULT IN COST SHIFTING?

A. Viewed from the context of energy efficiency, the notion of cost shifting takes a somewhat different form. Generally, a degree of cost shifting is accepted with respect to energy efficiency, as it is with a number of other customer decisions, including the decision to install self-generation or switch to natural gas. The amount of incentive funding provided to, and the amount of energy efficiency performed by, each customer has never been and never will be identical or perfectly equitable. As the loads of particular customers decline as a result of performing energy efficiency, fixed costs are shifted from those customers that perform energy efficiency measures to those that do not.[11/] Provided that the Company's full resource portfolio is allocated to customer classes on a cost-of-service basis, equity concerns surrounding this sort

[10/] Id., Appen. A at 8.

[11/] See Docket No. UE 283, PGE/100 at 3-4 ("In the long-run, our commitment to energy efficiency helps PGE displace the need for long-term, supply-side resources …. However, in the short-term, energy efficiency leads to reduced contributions to our existing fixed costs, which raises customer prices").

of cost shifting are generally tolerated, as it would be effectively impossible or, at a minimum, extremely administratively difficult and costly to eliminate all forms and degrees of cost-shifting. Notwithstanding, if CUB's proposal is adopted, allowing small customers to acquire a different resource portfolio than the utility's overall resource portfolio, these sorts of cost shifts are appropriately considered, just as they are in the context of the VRET or direct access programs.

Q. WHAT IS THE IMPACT OF THE COST SHIFTING?

A. The cost shifting resulting from allowing customers to purchase a portfolio of resources different from the utility's base resource portfolio has been subject to review for many years in the context of direct access customers. Those customers have elected not to acquire electrical services from the utility's resource portfolio, but instead, acquire those services from an energy service supplier. Within the context of direct access, transition adjustments were put into place to address the concerns of cost-shifting that results when a customer elects not to be served from the utility's base resource portfolio. In Schedule 128, for example, the current transition adjustment for a customer on Schedule 83 electing to participate in a short-term direct access program is \$35.51/MWh. On a per megawatt-hour basis, the CUB proposal produces an allocation credit of approximately \$6.23/MWh. CUB's proposal is not for customers under 1 aMW to eliminate their reliance on the Company's resource portfolio entirely, so the amount of the transition adjustment for direct access customers may not be appropriate to apply in this context, but it does illustrate that the stranded cost that is created as a result of directly assigning system energy efficiency benefits to small customer classes would likely significantly offset the economic benefit to these customers, and may eliminate it entirely.

Q. ARE THERE OTHER ISSUES WITH CUB'S PROPOSAL TO SINGLE OUT FOR DIFFERENT TREATMENT ENERGY EFFICIENCY PURCHASED THROUGH SB 838 FUNDING ON THE BASIS THAT DIFFERENT CUSTOMERS BUY DIFFERENT RESOURCES?

A. Yes. This appears to be directly at odds with prior Commission decisions. In Docket No. UE 234, for instance, ICNU argued that the costs of the Company's Automated Demand Response Pilot be treated solely as a capacity resource because it only provided capacity benefits.[12/] While other parties conceded that this was the case, they nevertheless proposed to allocate these costs based on a combination of energy and capacity, consistent with how the Company allocated its other production resources, on the basis that it was inappropriate to single out a single resource for special treatment. CUB argued that "ICNU seeks to 'pick and choose generation resources for cost allocations that favor industrial customers, rather than accepting the occasional unfavorable result that may occur' with the application of a consistent methodology."[13/] The Commission rejected ICNU's argument, finding that while:

> ICNU's proposed methodology may be reasonable for the specific resource in question, [] we cannot look at an allocation scheme for a given resource in isolation. If we adopted ICNU's proposed methodology without altering the cost allocation scheme for all other resources, it would result in a less fair allocation of costs in the aggregate.[14/]

CUB's proposal is an even more extreme example of the result ICNU sought and was denied in UE 234. Not only does it seek to single out a specific resource for special treatment, it singles out a *subset* of a specific resource for special treatment (energy efficiency funded from SB 838 rather than all energy efficiency). This distorts the cost allocation of all Company resources.

12/ Order No. 11-517 at 3-4 (Dec. 21, 2011).

13/ Id. at 4.

14/ Id. at 5.

Q. ARE SMALL CUSTOMER CLASSES CURRENTLY BEING DEPRIVED OF THE FULL SYSTEM BENEFITS ASSOCIATED WITH SB 838 ENERGY EFFICIENCY FUNDING?

A. No. Notwithstanding the concerns raised above, CUB's premise that customers who pay SB 838 charges are not receiving their fair share of the system benefits is misplaced. To the extent that a customer performs an energy efficiency measure as a result of SB 838 funding, it results in a reduction to the loads of that customer, and a corresponding reduction to the loads of that customer's rate class. As the loads of a rate class decline, smaller amounts of system costs are allocated to that class through the marginal cost of service study in a general rate case. Accordingly, small customer classes already receive the full system benefits associated with SB 838 due to reduced cost allocation, and no separate allocation methodology is required to directly assign those system benefits to the small customer classes. To the extent the system benefits of energy efficiency are viewed on a stand-alone basis—and allocated separately from the cost of service study, as CUB proposes—it would be necessary to eliminate the benefits that those customers are currently receiving in the cost of service study in connection with these declining cost allocations.

IV. MODELING CONCERNS WITH CUB'S PROPOSAL

Q. HAVE YOU REVIEWED CUB'S CALCULATION OF ITS PROPOSED ALLOCATION CREDIT AMOUNT?

A. Yes. CUB's calculation was detailed in Exhibit No. CUB/105. Basically, CUB calculated the cumulative amount of SB 838 energy efficiency over a ten-year period, to determine the amount it believes is representative of the SB 838 energy efficiency savings in the test period (1,178,542 MWh). CUB then multiplied this amount by the differential between the marginal cost of energy in the marginal cost of generation study ($32.33/MWh) and the total levelized cost of energy efficiency calculated by the Energy Trust ($26.10/MWh). This calculation yields an allocation credit of $7.3 million.

Q. DO YOU HAVE ANY CONCERNS WITH THE MECHANICS OF THE CUB PROPOSAL?

A. Yes. Apart from some of the policy issues identified above, there are a number of mechanical problems with the CUB proposal. First, CUB's testimony identified the allocation credit amount, but did not identify the way in which the cost of the credit would be allocated amongst the rate classes. Second, when establishing the 1,178,4542 MWh of SB 838 energy efficiency savings in the test period, CUB assumes a somewhat arbitrary 10-year measure life. Third, CUB assumes a levelized cost of 26.10/MWh, which likely does not accurately reflect the levelized cost associated with SB 838 energy efficiency.

Q. WITH RESPECT TO THE FIRST ISSUE, IS THE ALLOCATION OF THE COST OF THE CREDIT A MATERIAL FACTOR THAT CUB OMITTED FROM ITS TESTIMONY?

A. Yes. In response to ICNU Data Request 7, CUB confirmed that it did not detail how the credit would be funded between rate schedules.[15/] Under CUB's construct, the $7.3 million dollar allocation credit is representative of the incremental total-system benefit associated with SB 838 energy efficiency, not the subset of benefits received by customers larger than 1 aMW. CUBs testimony seems to imply that the entire cost of the $7.3 million credit would be allocated to customers with loads greater than 1 aMW. If that were the case, however, customers larger than 1aMW would be responsible for funding the entirety of the incremental system benefits associated SB 838, even though the benefits received by those customers

[15/] ICNU/402 at 6.

would be just a fraction of the total-system amount. CUB recognized in a data response that it did not plan to allocate the cost of the credit solely to customers over 1 aMW.[16]

Q. WHAT WOULD THE IMPACT OF CUB'S PROPOSAL BE IF THE COST OF THE CREDIT IS ALLOCATED ON THE BASIS OF PRODUCTION COSTS?

A. Table 1CA, below, details the rate impact of the allocation credit approach if the cost of the credit were spread on the same basis as other production costs.

TABLE 1CA
CUB Allocation Credit, Spread on Production Costs
(Whole Dollars)

	SB 838 Fund. %	Credit Benefit	Prod. Alloc. %	Credit Cost	Net Impact
Schedule 7	56.47%	4,142,790	47.89%	(3,513,239)	629,551
Schedule 15	0.20%	14,379	0.08%	(5,664)	8,715
Schedule 32	10.89%	798,608	8.87%	(650,844)	147,764
Schedule 38	0.35%	25,979	0.16%	(11,601)	14,378
Schedule 47	0.17%	12,239	0.14%	(10,243)	1,996
Schedule 49	0.45%	32,914	0.43%	(31,272)	1,642
Schedule 83	15.56%	1,141,616	15.67%	(1,149,646)	(8,030)
Schedule 85	14.83%	1,087,660	15.56%	(1,141,347)	(53,687)
Schedule 89	0.00%	-	3.13%	(229,753)	(229,753)
Schedule 90	0.00%	-	7.83%	(574,441)	(574,441)
Schedule 91/95	1.08%	79,102	0.24%	(17,493)	61,609
Schedule 92	0.02%	1,278	0.01%	(1,022)	256
Total	100.00%	7,336,565	100.00%	(7,336,565)	-

Q. WITH RESPECT TO THE SECOND ISSUE, WHAT CONCERNS DO YOU HAVE WITH RESPECT TO THE VOLUME (MWH) OF ENERGY EFFICIENCY ASSUMED IN THE CUB MODEL?

A. In calculating the volume of energy efficiency in the test period, the CUB model simply aggregates the total amount of annual energy efficiency achieved by the ETO over a 10-year period. It justifies this approach by assuming an average 10-year life with respect to energy

[16] Id. at 7.

efficiency measures.[17/] However, because CUB's model only accounts for ten years of SB 838 funding (2008 through 2017), this has the practical effect of imputing a minimum 10-year measure life even though a 10-year average, by definition, means that some measures last longer than 10 years and some last less than 10 years.

Q. WITH RESPECT TO THE THIRD ISSUE, DID CUB CONFIRM THAT ITS MODEL IS NOT BASED ON THE COST OF SB 838 ENERGY EFFICIENCY?

A. Yes. In response to ICNU Data Request 7(e) and 7(f), CUB confirmed that the $26.10/MWh levelized cost of energy efficiency included not only the costs of energy efficiency performed pursuant to SB 838, but also the cost of energy efficiency performed pursuant to SB 1149.[18/] Since SB 838 energy efficiency is incremental to energy efficiency performed pursuant to SB 1149, SB 838 energy efficiency is more expensive that SB 1149 energy efficiency.[19/] Because CUB's calculation uses the average levelized cost for both SB 838 and SB 1149 energy efficiency, it has understated the levelized cost of SB 838 energy efficiency in its model, and overstated the allocation credit amount. As CUB noted, however, there is no readily available source of information which identifies the levelized cost of SB 838 energy efficiency alone. CUB sought this information from the Company, but was directed to the Energy Trust's Annual Reports.[20/] This indicates that, even if the Commission were inclined to agree with CUB from a policy and legal perspective, there may be insufficient information in this docket to accurately implement CUB's proposal.

17/ Exhibit CUB/105.

18/ ICNU/402 at 7.

19/ See Energy Trust 2015 Annual Report, Appendix 10 (Oct. 24, 2016); Energy Trust 2014 Annual Report, Appendix 10 (Oct. 15, 2015); Energy Trust 2013 Annual Report, Appendix 10 (Dec. 17, 2014), all available at: https://www.energytrust.org/about/reports-financials/documents/.

20/ ICNU/402 at 1.

Q. DOES THIS CONCLUDE YOUR CROSS-ANSWERING TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT NO. ICNU/401

B-ENGROSSED SENATE BILL 838

74th OREGON LEGISLATIVE ASSEMBLY--2007 Regular Session

B-Engrossed
Senate Bill 838

Ordered by the House May 9
Including Senate Amendments dated April 6 and House Amendments dated May 9

Sponsored by Senator AVAKIAN; Senators ATKINSON, BATES, BROWN, BURDICK, CARTER, COURTNEY, DEVLIN, GORDLY, METSGER, MONNES ANDERSON, MONROE, MORRISETTE, PROZANSKI, STARR, WALKER, WESTLUND, Representative DINGFELDER (at the request of Governor Theodore R. Kulongoski)

SUMMARY

The following summary is not prepared by the sponsors of the measure and is not a part of the body thereof subject to consideration by the Legislative Assembly. It is an editor's brief statement of the essential features of the measure.

Establishes renewable portfolio standard for electric utilities and electricity service suppliers. Specifies renewable energy sources that can be used to generate electricity for purposes of complying with standard. Provides exemptions from compliance with standard.

Directs State Department of Energy to establish system of renewable energy certificates. Specifies renewable energy certificates that may be used to comply with renewable portfolio standard.

Establishes compliance requirements for renewable portfolio standards. Allows use of alternative compliance payments. Allows Public Utility Commission to impose penalty against electric company or electricity service supplier that fails to comply with standard.

Requires that utilities offer green power rate.

Extends required collection of public purpose charge to January 1, 2026.

Modifies laws relating to people's utility districts.

Declares emergency, effective on passage.

A BILL FOR AN ACT

Relating to electricity; creating new provisions; amending ORS 261.010, 261.030, 261.050, 261.235, 261.250, 261.253, 261.305, 261.335, 261.348, 261.355, 262.005, 262.015, 262.075, 757.612 and 757.687; and declaring an emergency.

Whereas the Legislative Assembly finds that it is in the interest of the state to promote research and development of new renewable energy sources in Oregon; and

Whereas the Legislative Assembly finds that it is necessary for Oregon's electric utilities to decrease their reliance on fossil fuels for electricity generation and to increase their use of renewable energy sources; and

Whereas this 2007 Act may be cited as the Oregon Renewable Energy Act; and

Whereas the Oregon Renewable Energy Act provides a comprehensive renewable energy policy for Oregon, enabling industry, government and all Oregonians to accelerate the transition to a more reliable and more affordable energy system; now, therefore,

Be It Enacted by the People of the State of Oregon:

DEFINITIONS

SECTION 1. Definitions. As used in sections 1 to 24 of this 2007 Act:

(1) "Banked renewable energy certificate" means a bundled or unbundled renewable energy certificate that is not used by an electric utility or electricity service supplier to comply

NOTE: Matter in **boldfaced** type in an amended section is new; matter [*italic and bracketed*] is existing law to be omitted. New sections are in **boldfaced** type.

with a renewable portfolio standard in a calendar year and that is carried forward for the purpose of compliance with a renewable portfolio standard in a subsequent year.

(2) "BPA electricity" means electricity provided by the Bonneville Power Administration, including all electricity from the Federal Columbia River Power System hydroelectric projects and other electricity acquired by the Bonneville Power Administration by contract.

(3) "Bundled renewable energy certificate" means a renewable energy certificate for qualifying electricity that is acquired:

(a) By an electric utility or electricity service supplier by a trade, purchase or other transfer of electricity that includes the certificate that was issued for the electricity; or

(b) By an electric utility by generation of the electricity for which the certificate was issued.

(4) "Compliance year" means the calendar year for which the electric utility or electricity service supplier seeks to establish compliance with the renewable portfolio standard applicable to the utility or supplier in the compliance report submitted under section 19 of this 2007 Act.

(5) "Consumer-owned utility" means a municipal electric utility, a people's utility district organized under ORS chapter 261 that sells electricity or an electric cooperative organized under ORS chapter 62.

(6) "Electric company" has the meaning given that term in ORS 757.600.

(7) "Electric utility" has the meaning given that term in ORS 757.600.

(8) "Electricity service supplier" has the meaning given that term in ORS 757.600.

(9) "Qualifying electricity" means electricity described in section 2 of this 2007 Act.

(10) "Renewable energy source" means a source of electricity described in section 4 of this 2007 Act.

(11) "Retail electricity consumer" means a retail electricity consumer, as defined in ORS 757.600, that is located in Oregon.

(12) "Unbundled renewable energy certificate" means a renewable energy certificate for qualifying electricity that is acquired by an electric utility or electricity service supplier by trade, purchase or other transfer without acquiring the electricity for which the certificate was issued.

QUALIFYING ELECTRICITY

SECTION 2. Qualifying electricity. (1) Except as provided in this section, and subject to section 15 of this 2007 Act, electricity generated from a renewable energy source may be used to comply with a renewable portfolio standard only if the facility that generates the electricity meets the requirements of section 3 of this 2007 Act.

(2) Any electricity that the Bonneville Power Administration has designated as environmentally preferred power, or has given a similar designation for electricity generated from a renewable resource, may be used to comply with a renewable portfolio standard.

(3) The Legislative Assembly finds that hydroelectric energy is an important renewable energy source and electricity from hydroelectric generators may be used to comply with a renewable portfolio standard as provided in sections 1 to 24 of this 2007 Act.

SECTION 3. Qualifying electricity; age of generating facility. (1) Except as provided in this section, electricity may be used to comply with a renewable portfolio standard only if

the electricity is generated by a facility that becomes operational on or after January 1, 1995.

(2) Electricity from a generating facility, other than a hydroelectric facility, that became operational before January 1, 1995, may be used to comply with a renewable portfolio standard if the electricity is attributable to capacity or efficiency upgrades made on or after January 1, 1995.

(3) Electricity from a hydroelectric facility that became operational before January 1, 1995, may be used to comply with a renewable portfolio standard if the electricity is attributable to efficiency upgrades made on or after January 1, 1995. If an efficiency upgrade is made to a Bonneville Power Administration facility, only that portion of the electricity generation attributable to Oregon's share of the electricity may be used to comply with a renewable portfolio standard.

(4) Subject to the limit imposed by section 4 (5) of this 2007 Act, electricity from a hydroelectric facility that is owned by an electric utility and that became operational before January 1, 1995, may be used to comply with a renewable portfolio standard if the facility is certified as a low-impact hydroelectric facility on or after January 1, 1995, by a national certification organization recognized by the State Department of Energy by rule.

SECTION 4. Renewable energy sources. (1) Electricity generated utilizing the following types of energy may be used to comply with a renewable portfolio standard:

(a) Wind energy.

(b) Solar photovoltaic and solar thermal energy.

(c) Wave, tidal and ocean thermal energy.

(d) Geothermal energy.

(2) Except as provided in subsection (3) of this section, electricity generated from biomass and biomass byproducts may be used to comply with a renewable portfolio standard, including but not limited to electricity generated from:

(a) Organic human or animal waste;

(b) Spent pulping liquor;

(c) Forest or rangeland woody debris from harvesting or thinning conducted to improve forest or rangeland ecological health and to reduce uncharacteristic stand replacing wildfire risk;

(d) Wood material from hardwood timber grown on land described in ORS 321.267 (3);

(e) Agricultural residues;

(f) Dedicated energy crops; and

(g) Landfill gas or biogas produced from organic matter, wastewater, anaerobic digesters or municipal solid waste.

(3) Electricity generated from the direct combustion of biomass may not be used to comply with a renewable portfolio standard if any of the biomass combusted to generate the electricity includes:

(a) Municipal solid waste; or

(b) Wood that has been treated with chemical preservatives such as creosote, pentachlorophenol or chromated copper arsenate.

(4) Electricity generated by a hydroelectric facility may be used to comply with a renewable portfolio standard only if:

(a) The facility is located outside any protected area designated by the Pacific Northwest Electric Power and Conservation Planning Council as of July 23, 1999, or any area protected

under the federal Wild and Scenic Rivers Act, Public Law 90-542, or the Oregon Scenic Waterways Act, ORS 390.805 to 390.925; or

(b) The electricity is attributable to efficiency upgrades made to the facility on or after January 1, 1995.

(5) Up to 50 average megawatts of electricity per year generated by an electric utility from certified low-impact hydroelectric facilities described in section 3 (4) of this 2007 Act may be used to comply with a renewable portfolio standard, without regard to the number of certified facilities operated by the electric utility or the generating capacity of those facilities. A hydroelectric facility described in this subsection is not subject to the requirements of subsection (4) of this section.

(6) Electricity generated from hydrogen gas derived from any source of energy described in subsections (1) to (5) of this section may be used to comply with a renewable portfolio standard.

(7) If electricity generation employs multiple energy sources, that portion of the electricity generated that is attributable to energy sources described in subsections (1) to (6) of this section may be used to comply with a renewable portfolio standard.

(8) The State Department of Energy by rule may approve energy sources other than those described in this section that may be used to comply with a renewable portfolio standard. The department may not approve petroleum, natural gas, coal or nuclear fission as an energy source that may be used to comply with a renewable portfolio standard.

RENEWABLE PORTFOLIO STANDARDS

<u>SECTION 5.</u> <u>Applicable standard.</u> (1) Electric utilities must comply with the applicable renewable portfolio standard described in section 6 or 7 of this 2007 Act.

(2) Electricity service suppliers must comply with the renewable portfolio standard established under section 9 of this 2007 Act.

<u>SECTION 6.</u> <u>Large utility renewable portfolio standard.</u> (1) The large utility renewable portfolio standard imposes the following requirements on an electric utility that makes sales of electricity to retail electricity consumers in an amount that equals one and one-half percent or more of all electricity sold to retail electricity consumers:

(a) At least five percent of the electricity sold by the utility to retail electricity consumers in each of the calendar years 2011, 2012, 2013 and 2014 must be qualifying electricity;

(b) At least 15 percent of the electricity sold by the utility to retail electricity consumers in each of the calendar years 2015, 2016, 2017, 2018 and 2019 must be qualifying electricity;

(c) At least 20 percent of the electricity sold by the utility to retail electricity consumers in each of the calendar years 2020, 2021, 2022, 2023 and 2024 must be qualifying electricity; and

(d) At least 25 percent of the electricity sold by the utility to retail electricity consumers in calendar year 2025 and subsequent calendar years must be qualifying electricity.

(2) If, on the effective date of this 2007 Act, an electric utility makes sales of electricity to retail electricity consumers in an amount that equals less than one and one-half percent of all electricity sold to retail electricity consumers, but in any three consecutive calendar years thereafter makes sales of electricity to retail electricity consumers in amounts that average one and one-half percent or more of all electricity sold to retail electricity consum-

ers, the utility is subject to the renewable portfolio standard described in subsection (3) of this section. The utility becomes subject to the standard described in subsection (3) of this section in the calendar year following the three-year period during which the utility makes sales of electricity to retail electricity consumers in amounts that average one and one-half percent or more of all electricity sold to retail electricity consumers.

(3) An electric utility described in subsection (2) of this section must comply with the following renewable portfolio standard:

(a) Beginning in the fourth calendar year after the calendar year in which the utility becomes subject to the standard described in this subsection, at least five percent of the electricity sold by the utility to retail electricity consumers in a calendar year must be qualifying electricity;

(b) Beginning in the 10th calendar year after the calendar year in which the utility becomes subject to the standard described in this subsection, at least 15 percent of the electricity sold by the utility to retail electricity consumers in a calendar year must be qualifying electricity;

(c) Beginning in the 15th calendar year after the calendar year in which the utility becomes subject to the standard described in this subsection, at least 20 percent of the electricity sold by the utility to retail electricity consumers in a calendar year must be qualifying electricity; and

(d) Beginning in the 20th calendar year after the calendar year in which the utility becomes subject to the standard described in this subsection, at least 25 percent of the electricity sold by the utility to retail electricity consumers in a calendar year must be qualifying electricity.

SECTION 7. Small electric utilities. (1) Except as provided in this section, an electric utility that makes sales of electricity to retail electricity consumers in an amount that equals less than one and one-half percent of all electricity sold to retail electricity consumers is not subject to sections 1 to 24 of this 2007 Act.

(2) Beginning in calendar year 2025, at least five percent of the electricity sold to retail electricity consumers in a calendar year by an electric utility described in subsection (1) of this section must be qualifying electricity.

(3) The exemption provided by subsection (1) of this section terminates if an electric utility, or a joint operating entity that includes the utility as a member, acquires electricity from an electricity generating facility that uses coal as an energy source or makes an investment on or after the effective date of this 2007 Act in an electricity generating facility that uses coal as an energy source. This subsection does not apply to:

(a) A wholesale market purchase by an electric utility for which the energy source for the electricity is not known;

(b) BPA electricity;

(c) A renewal or replacement contract for a contract for purchase of electricity entered into before the effective date of this 2007 Act;

(d) A purchase of electricity if the electricity is included in a contract for the purchase of qualifying electricity and is necessary to shape, firm or integrate the qualifying electricity; or

(e) Electricity provided to an electric utility under a contract for the acquisition of an interest in an electricity generating facility that was entered into by the utility before the

effective date of this 2007 Act.

(4) The exemption provided by subsection (1) of this section terminates for a consumer-owned utility if at any time after the effective date of this 2007 Act the utility acquires service territory of an electric company without the consent of the electric company.

(5) Beginning in the calendar year following the year in which an electric utility's exemption terminates under subsection (3) or (4) of this section, the utility is subject to the renewable portfolio standard described in section 6 (3) of this 2007 Act and related provisions of sections 1 to 24 of this 2007 Act.

(6) The provisions of this section do not affect the requirement that electric utilities offer a green power rate under section 23 of this 2007 Act.

SECTION 8. Exemptions from compliance with renewable portfolio standard. (1) Electric utilities are not required to comply with the renewable portfolio standards described in sections 6 and 7 of this 2007 Act to the extent that:

(a) Compliance with the standard would require the utility to acquire electricity in excess of the utility's projected load requirements in any calendar year; and

(b) Acquiring the additional electricity would require the utility to substitute qualifying electricity for electricity derived from an energy source other than coal, natural gas or petroleum.

(2)(a) Electric utilities are not required to comply with a renewable portfolio standard to the extent that compliance would require the utility to substitute qualifying electricity for electricity available to the utility under contracts for electricity from dams that are owned by Washington public utility districts and are located between the Grand Coulee Dam and the Columbia River's junction with the Snake River. The provisions of this subsection apply only to contracts entered into before the effective date of this 2007 Act and to renewal or replacement contracts for contracts entered into before the effective date of this 2007 Act.

(b) If a contract described in paragraph (a) of this subsection expires and is not renewed or replaced, the utility must comply, in the calendar year following the expiration of the contract, with the renewable portfolio standard applicable to the utility.

(3) A consumer-owned utility is not required to comply with a renewable portfolio standard to the extent that compliance would require the utility to reduce the utility's purchases of the lowest priced electricity from the Bonneville Power Administration pursuant to section 5 of the Pacific Northwest Electric Power Planning and Conservation Act of 1980, P.L. 96-501, as in effect on the effective date of this 2007 Act. The exemption provided by this subsection applies only to firm commitments for BPA electricity that the Bonneville Power Administration has assured will be available to a utility to meet agreed portions of the utility's load requirements for a defined period of time.

SECTION 9. Renewable portfolio standard for electricity service suppliers. An electricity service supplier must meet the requirements of the renewable portfolio standards that are applicable to the electric utilities that serve the territories in which the electricity service supplier sells electricity to retail electricity consumers. The Public Utility Commission shall establish procedures for implementation of the renewable portfolio standards for electricity service suppliers that sell electricity in the service territory of an electric company. If an electricity service supplier sells electricity in territories served by more than one electric company, the commission may provide for an aggregate standard based on the amount of electricity sold by the electricity service supplier in each territory. Pursuant to ORS 757.676,

a consumer-owned utility may establish procedures for the implementation of the renewable portfolio standards for electricity service suppliers that sell electricity in the territory served by the consumer-owned utility.

<u>SECTION 10.</u> <u>Manner of complying with renewable portfolio standards.</u> (1) Except as provided in subsection (2) of this section, an electric utility or electricity service supplier must comply with the renewable portfolio standard applicable to the utility or supplier in each calendar year by:

(a) Using bundled renewable energy certificates issued or acquired during the compliance year;

(b) Subject to the limitations described in sections 16 and 17 of this 2007 Act, using unbundled or banked renewable energy certificates; or

(c) Making alternative compliance payments as described in section 20 of this 2007 Act.

(2) Bundled or unbundled renewable energy certificates that are issued or acquired by an electric utility or electricity service supplier on or before March 31 in a calendar year may be used by the utility or supplier to comply with the renewable portfolio standard applicable to the utility or supplier for the preceding calendar year.

<u>SECTION 11.</u> <u>Implementation plan for electric companies; annual reports.</u> (1) An electric company that is subject to a renewable portfolio standard shall develop an implementation plan for meeting the requirements of the standard and file the plan with the Public Utility Commission. Implementation plans must be revised and updated at least once every two years.

(2) An implementation plan must at a minimum contain:

(a) Annual targets for acquisition and use of qualifying electricity; and

(b) The estimated cost of meeting the annual targets, including the cost of transmission, the cost of firming, shaping and integrating qualifying electricity, the cost of alternative compliance payments and the cost of acquiring renewable energy certificates.

(3) The commission shall acknowledge the implementation plan no later than six months after the plan is filed with the commission. The commission may acknowledge the plan subject to conditions specified by the commission.

(4) The commission shall adopt rules:

(a) Establishing requirements for the content of implementation plans;

(b) Establishing the procedure for acknowledgement of implementation plans under this section, including provisions for public comment; and

(c) Providing for the integration of the implementation plan with the integrated resource planning guidelines established by the commission and in effect on the effective date of this 2007 Act.

(5) The implementation plan filed under this section may include procedures that will be used by the electric company to determine whether the costs of constructing a facility that generates electricity from a renewable energy source, or the costs of acquiring bundled or unbundled renewable energy certificates, are consistent with the standards of the commission relating to least-cost, least-risk planning for acquisition of resources.

<u>SECTION 11a.</u> An electric company shall develop and file with the Public Utility Commission an initial implementation plan under section 11 of this 2007 Act no later than January 1, 2010.

COST LIMITATION

SECTION 12. **Limits on cost of compliance with renewable portfolio standard.** **(1) Electric utilities are not required to comply with a renewable portfolio standard during a compliance year to the extent that the incremental cost of compliance, the cost of unbundled renewable energy certificates and the cost of alternative compliance payments under section 20 of this 2007 Act exceeds four percent of the utility's annual revenue requirement for the compliance year.**

(2) For each electric company, the Public Utility Commission shall establish the annual revenue requirement for a compliance year no later than January 1 of the compliance year. The governing body of a consumer-owned utility shall establish the annual revenue requirement for the consumer-owned utility.

(3) The annual revenue requirement for an electric utility shall be calculated based only on the operations of the utility relating to electricity. The annual revenue requirement does not include any amount expended by the utility for energy efficiency programs for customers of the utility or for low income energy assistance, the incremental cost of compliance with a renewable portfolio standard, the cost of unbundled renewable energy certificates or the cost of alternative compliance payments under section 20 of this 2007 Act. The annual revenue requirement does include:

(a) All operating expenses of the utility during the compliance year, including depreciation and taxes; and

(b) For electric companies, an amount equal to the total rate base of the company for the compliance year multiplied by the rate of return established by the commission for debt and equity of the company.

(4) For the purposes of this section, the incremental cost of compliance with a renewable portfolio standard is the difference between the levelized annual delivered cost of the qualifying electricity and the levelized annual delivered cost of an equivalent amount of reasonably available electricity that is not qualifying electricity. For the purpose of this subsection, the commission or governing body of a consumer-owned utility shall use the net present value of delivered cost, including:

(a) Capital, operating and maintenance costs of generating facilities;

(b) Financing costs attributable to capital, operating and maintenance expenditures for generating facilities;

(c) Transmission and substation costs;

(d) Load following and ancillary services costs; and

(e) Costs associated with using other assets, physical or financial, to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs.

(5) For the purposes of this section, the governing body of a consumer-owned utility may include in the incremental cost of compliance with a renewable portfolio standard all expenses associated with research, development and demonstration projects related to the generation of qualifying electricity by the consumer-owned utility.

(6) The commission shall establish limits on the incremental cost of compliance with the renewable portfolio standard for electricity service suppliers under section 9 of this 2007 Act that are the equivalent of the cost limits applicable to the electric companies that serve the territories in which the electricity service supplier sells electricity to retail electricity con-

sumers. If an electricity service supplier sells electricity in territories served by more than one electric company, the commission may provide for an aggregate cost limit based on the amount of electricity sold by the electricity service supplier in each territory. Pursuant to ORS 757.676, a consumer-owned utility may establish limits on the cost of compliance with the renewable portfolio standard for electricity service suppliers that sell electricity in the territory served by the consumer-owned utility.

SECTION 12a. The Public Utility Commission shall establish the methodology for determining the annual revenue requirement of an electric company for purposes of section 12 of this 2007 Act no later than July 1, 2008.

COST RECOVERY

SECTION 13. Cost recovery by electric companies. (1) Except as provided in section 20 (5) of this 2007 Act, all prudently incurred costs associated with compliance with a renewable portfolio standard are recoverable in the rates of an electric company, including interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs and other costs associated with transmission and delivery of qualifying electricity to retail electricity consumers.

(2) Costs associated with compliance with a renewable portfolio standard are not an above-market cost for the purposes of ORS 757.600 to 757.687.

(3) The Public Utility Commission shall establish an automatic adjustment clause as defined in ORS 757.210 or another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission. Upon the request of any interested person, the commission shall conduct a hearing and allow interested persons to appear, to conduct discovery and to submit evidence and briefs on the terms of the automatic adjustment clause or other method for timely recovery of costs.

(4) An electric company must file with the commission for approval of a proposed rate change to recover costs under the terms of an automatic adjustment clause or other method for timely recovery of costs established under subsection (3) of this section. Upon the request of any interested person, the commission shall conduct a hearing and allow interested persons to appear, to conduct discovery and to submit evidence and briefs on whether the commission should approve the proposed rate change.

SECTION 13a. The Public Utility Commission shall establish the automatic adjustment clause or another method for timely recovery of costs as required by section 13 (3) of this 2007 Act no later than January 1, 2008. The clause or method shall apply to all prudently incurred costs described in section 13 (3) of this 2007 Act incurred by an electric company since the date of the company's last general rate case that was decided by the commission before the effective date of this 2007 Act.

RENEWABLE ENERGY CERTIFICATES

SECTION 14. Renewable energy certificates system. (1) The State Department of Energy shall establish a system of renewable energy certificates that can be used by an electric

utility or electricity service supplier to establish compliance with the applicable renewable portfolio standard. The department shall consult with the Public Utility Commission before establishing a system of renewable energy certificates under this section. The department may allow use of renewable energy certificates that are issued, monitored, accounted for or transferred by or through a regional system or trading program, including but not limited to the Western Renewable Energy Generation Information System. The system established by the department shall allow issuance, transfer and use of renewable energy certificates in electronic form.

(2) The validity of a bundled renewable energy certificate for purposes of compliance with the applicable renewable portfolio standard is not affected by the substitution of any other electricity for the qualifying electricity at any point after the time of generation.

SECTION 15. Renewable energy certificates that may be used to comply with standards. (1) A bundled renewable energy certificate may be used to comply with a renewable portfolio standard if:

(a) The facility that generates the qualifying electricity for which the certificate is issued is located in the United States and within the geographic boundary of the Western Electricity Coordinating Council; and

(b) The qualifying electricity for which the certificate is issued is delivered to the Bonneville Power Administration, to the transmission system of an electric utility or to another delivery point designated by an electric utility for the purpose of subsequent delivery to the electric utility.

(2) An unbundled renewable energy certificate may be used to comply with a renewable portfolio standard if the facility that generates the qualifying electricity for which the certificate is issued is located within the geographic boundary of the Western Electricity Coordinating Council.

(3) Renewable energy certificates issued for any electricity that the Bonneville Power Administration has designated as environmentally preferred power, or has given a similar designation for electricity generated from a renewable resource, may be used to comply with a renewable portfolio standard without regard to the location of the generating facility.

SECTION 16. Use, transfer and banking of certificates. (1) Renewable energy certificates may be traded, sold or otherwise transferred.

(2) Renewable energy certificates that are not used by an electric utility or electricity service supplier to comply with a renewable portfolio standard in a calendar year may be banked and carried forward indefinitely for the purpose of complying with a renewable portfolio standard in a subsequent year. For the purpose of complying with a renewable portfolio standard in any calendar year:

(a) Banked renewable energy certificates must be used, up to the limit imposed by section 17 of this 2007 Act, before other certificates are used; and

(b) Banked renewable energy certificates with the oldest issuance date must be used to comply with the standard before banked renewable energy certificates with more recent issuance dates are used.

(3) An electric utility or electricity service supplier is responsible for demonstrating that a renewable energy certificate used to comply with a renewable portfolio standard is derived from a renewable energy source and that the utility or supplier has not used, traded, sold or otherwise transferred the certificate.

(4) The same renewable energy certificate may be used by an electric utility or electricity service supplier to comply with a federal renewable portfolio standard and a renewable portfolio standard established under sections 1 to 24 of this 2007 Act. An electric utility or electricity service supplier that uses a renewable energy certificate to comply with a renewable portfolio standard imposed by any other state may not use the same certificate to comply with a renewable portfolio standard established under sections 1 to 24 of this 2007 Act.

<u>SECTION 17.</u> <u>Limitations on use of unbundled certificates to meet renewable portfolio standard.</u> (1) Except as otherwise provided in this section, unbundled renewable energy certificates, including banked unbundled renewable energy certificates, may not be used to meet more than 20 percent of the requirements of the large utility renewable portfolio standard described in section 6 of this 2007 Act for any compliance year.

(2) The limitation imposed by subsection (1) of this section does not apply to renewable energy certificates issued for electricity generated in Oregon from a renewable energy source by a net metering facility as defined in ORS 757.300, or another generating facility that is not directly connected to a distribution or transmission system.

(3) The limitation imposed by subsection (1) of this section does not apply to renewable energy certificates issued for electricity generated in Oregon by a qualifying facility under ORS 758.505 to 758.555.

(4) The limitation imposed by subsection (1) of this section does not apply to an electricity service supplier.

<u>SECTION 17a.</u> Notwithstanding section 17 (1) of this 2007 Act, for compliance years before 2020, a consumer-owned utility subject to the large utility renewable portfolio standard described in section 6 of this 2007 Act may use unbundled renewable energy certificates, including banked unbundled renewable energy certificates, to meet up to 50 percent of the requirements of the standard.

<u>SECTION 18.</u> <u>Multistate electric companies.</u> The Public Utility Commission by rule shall establish a process for allocating the use of renewable energy certificates by an electric company that makes sales of electricity to retail customers in more than one state.

COMPLIANCE REPORTS

<u>SECTION 19.</u> <u>Compliance reports.</u> (1) Each electric utility and electricity service supplier that is subject to a renewable portfolio standard shall make an annual compliance report for the purpose of detailing compliance, or failure to comply, with the renewable portfolio standard applicable in the compliance year. An electric company or electricity service supplier shall make the report to the Public Utility Commission. A consumer-owned utility shall make the report to the members or customers of the utility.

(2) The commission shall review each compliance report filed under this section by an electric company or electricity service supplier for the purposes of determining whether the company or supplier has complied with the renewable portfolio standard applicable to the company or supplier and the manner in which the company or supplier has complied. In reviewing the reports, the commission shall consider:

(a) The relative amounts of renewable energy certificates and other payments used by the company or supplier to meet the applicable renewable portfolio standard, including:

(A) Bundled renewable energy certificates;

(B) Unbundled renewable energy certificates;

(C) Banked renewable energy certificates; and

(D) Alternative compliance payments under section 20 of this 2007 Act.

(b) The timing of electricity purchases.

(c) The market prices for electricity purchases and unbundled renewable energy certificates.

(d) Whether the actions taken by the company or supplier are contributing to long term development of generating capacity using renewable energy sources.

(e) The effect of the actions taken by the company or supplier on the rates payable by retail electricity consumers.

(f) Good faith forecasting differences associated with the projected number of retail electricity consumers served and the availability of electricity from renewable energy sources.

(g) For electric companies, consistency with the implementation plan filed under section 11 of this 2007 Act, as acknowledged by the commission.

(h) Any other factors deemed reasonable by the commission.

(3) The commission by rule may establish requirements for compliance reports submitted by an electric company or electricity service supplier.

ALTERNATIVE COMPLIANCE PAYMENTS

SECTION 20. **Electric companies; electricity service suppliers.** **(1) The Public Utility Commission shall establish an alternative compliance rate for each compliance year for each electric company or electricity service supplier that is subject to a renewable portfolio standard. The rate shall be expressed in dollars per megawatt-hour.**

(2) The commission shall establish an alternative compliance rate based on the cost of qualifying electricity, contracts that the electric company or electricity service supplier has acquired for future delivery of qualifying electricity and the number of unbundled renewable energy certificates that the company or supplier anticipates using in the compliance year to meet the renewable portfolio standard applicable to the company or supplier. The commission shall also consider any determinations made under section 19 of this 2007 Act in reviewing the compliance report made by the electric company or electricity service supplier for the previous compliance year. In establishing an alternative compliance rate, the commission shall set the rate to provide adequate incentive for the electric company or electricity service supplier to purchase or generate qualifying electricity in lieu of using alternative compliance payments to meet the renewable portfolio standard applicable to the company or supplier.

(3) An electric company or electricity service supplier may elect to use, or may be required by the commission to use, alternative compliance payments to comply with the renewable portfolio standard applicable to the company or supplier. Any election by an electric company or electricity service supplier to use alternative compliance payments is subject to review by the commission under section 19 of this 2007 Act. An electric company or electricity service supplier may not be required to make alternative compliance payments that would result in the company or supplier exceeding the cost limitation established under section 12 of this 2007 Act.

(4) The commission shall determine for each electric company the extent to which alternative compliance payments may be recovered in the rates of the company. Each electric company shall deposit any amounts recovered in the rates of the company for alternative compliance payments in a holding account established by the company. Amounts in the holding account shall accrue interest at the rate of return authorized by the commission for the electric company.

(5) Amounts in holding accounts established under subsection (4) of this section may be expended by an electric company only for costs of acquiring new generating capacity from renewable energy sources, investments in efficiency upgrades to electricity generating facilities owned by the company and energy conservation programs within the company's service area. The commission must approve expenditures by an electric company from a holding account established under subsection (4) of this section. Amounts that are collected from customers and spent by an electric company under this subsection may not be included in the company's rate base.

(6) The commission shall require electricity service suppliers to establish holding accounts and make payments to those accounts on a substantially similar basis as provided for electric companies. The commission must approve expenditures by an electricity service supplier from a holding account established under this subsection. The commission may approve expenditures only for energy conservation programs for customers of the electricity service supplier.

SECTION 20a. The Public Utility Commission shall establish initial alternative compliance rates as required by section 20 of this 2007 Act no later than July 1, 2009.

SECTION 21. Consumer-owned utilities. The governing body of a consumer-owned utility shall establish an alternative compliance rate for the utility. To the extent possible, the alternative compliance rate shall be determined by the governing body of the consumer-owned utility in a manner similar to that used by the Public Utility Commission in establishing alternative compliance rates under section 20 of this 2007 Act. Amounts collected as alternative compliance payments by a consumer-owned utility may be used for the purposes specified in section 20 (5) of this 2007 Act and for the purpose of paying expenses associated with research, development and demonstration projects related to the generation of qualifying electricity by the utility.

PENALTY

SECTION 22. Penalty. If an electric company or electricity service supplier that is subject to a renewable portfolio standard under sections 1 to 24 of this 2007 Act fails to comply with the standard in the manner provided by sections 1 to 24 of this 2007 Act, the Public Utility Commission may impose a penalty against the company or supplier in an amount determined by the commission. A penalty under this section is in addition to any alternative compliance payment required or elected under section 20 of this 2007 Act. Moneys paid for penalties under this section shall be transmitted by the commission to the nongovernmental entity receiving moneys under ORS 757.612 (3)(d) and may be used only for the purposes specified in ORS 757.612 (1).

GREEN POWER RATE

SECTION 23. Green power rate. (1) Electric utilities shall allow retail electricity consumers to elect a green power rate. A significant portion of the electricity purchased or generated by a utility that is attributable to moneys paid by retail electricity consumers who elect the green power rate must be qualifying electricity, and the utility must inform consumers of the sources of the electricity purchased or generated by the utility that is attributable to moneys paid by consumers who elect the green power rate. The green power rate shall reasonably reflect the costs of the electricity purchased or generated by the utility that is attributable to moneys paid by retail electricity consumers who elect the green power rate. All prudently incurred costs associated with the green power rate are recoverable in a green power rate offered by an electric company.

(2) Any qualifying electricity procured by an electric utility to provide electricity under a green power rate under subsection (1) of this section or ORS 757.603 (2)(a) may not be used by the utility to comply with the requirements of a renewable portfolio standard.

(3) The provisions of subsection (1) of this section do not apply to electric companies that are subject to ORS 757.603 (2)(a).

(4) An electric utility may comply with the requirements of subsection (1) of this section by contracting with a third-party provider.

COMMUNITY-BASED RENEWABLE ENERGY PROJECTS

SECTION 24. Goal for community-based renewable energy projects. The Legislative Assembly finds that community-based renewable energy projects are an essential element of Oregon's energy future, and declares that it is the goal of the State of Oregon that by 2025 at least eight percent of Oregon's retail electrical load comes from small-scale renewable energy projects with a generating capacity of 20 megawatts or less. All agencies of the executive department as defined in ORS 174.112 shall establish policies and procedures promoting the goal declared in this section.

JOB IMPACT STUDY

SECTION 25. Job impact study. (1) The State Department of Energy shall periodically conduct a study to evaluate the impact of sections 1 to 24 of this 2007 Act on jobs in this state. The study shall assess the number of new jobs created in the renewable energy sector in this state and the average wage rates and the provision of health care and other benefits for those jobs. In addition, the study shall investigate the extent to which workforce training opportunities are being provided to employees to prepare the employees for jobs in the renewable energy sector.

(2) The department shall conduct the first study under this section not later than two years after the effective date of this 2007 Act.

SECTION 26. Section 25 of this 2007 Act is repealed January 2, 2026.

PUBLIC PURPOSE CHARGE

SECTION 27. ORS 757.612 is amended to read:

757.612. (1) There is established an annual public purpose expenditure standard for electric companies to fund new cost-effective local energy conservation, new market transformation efforts, the above-market costs of new renewable energy resources and new low-income weatherization. The public purpose expenditure standard shall be funded by the public purpose charge described in subsection (2) of this section.

(2)(a) Beginning on the date an electric company offers direct access to its retail electricity consumers, except residential electricity consumers, the electric company shall collect a public purpose charge from all of the retail electricity consumers located within its service area [*for a period of 10 years*] **until January 1, 2026**. Except as provided in paragraph (b) of this subsection, the public purpose charge shall be equal to three percent of the total revenues collected by the electric company or electricity service supplier from its retail electricity consumers for electricity services, distribution, ancillary services, metering and billing, transition charges and other types of costs included in electric rates on July 23, 1999.

(b) For an aluminum plant that averages more than 100 average megawatts of electricity use per year, beginning on March 1, 2002, the electric company whose territory abuts the greatest percentage of the site of the aluminum plant shall collect from the aluminum company a public purpose charge equal to one percent of the total revenue from the sale of electricity services to the aluminum plant from any source.

(3)(a) The Public Utility Commission shall establish rules implementing the provisions of this section relating to electric companies.

(b) Subject to paragraph (e) of this subsection, funds collected by an electric company through public purpose charges shall be allocated as follows:

(A) Sixty-three percent for new cost-effective conservation and new market transformation.

(B) Nineteen percent for the above-market costs of [*new renewable energy resources*] **constructing and operating new renewable energy resources with a nominal electric generating capacity, as defined in ORS 469.300, of 20 megawatts or less**.

(C) Thirteen percent for new low-income weatherization.

(D) Five percent shall be transferred to the Housing and Community Services Department Revolving Account created under ORS 456.574 and used for the purpose of providing grants as described in ORS 458.625 (2). Moneys deposited in the account under this subparagraph are continuously appropriated to the Housing and Community Services Department for the purposes of ORS 458.625 (2). Interest on moneys deposited in the account under this subparagraph shall accrue to the account.

(c) The costs of administering subsections (1) to (6) of this section for an electric company shall be paid out of the funds collected through public purpose charges. The commission may require that an electric company direct funds collected through public purpose charges to the state agencies responsible for implementing subsections (1) to (6) of this section in order to pay the costs of administering such responsibilities.

(d) The commission shall direct the manner in which public purpose charges are collected and spent by an electric company and may require an electric company to expend funds through competitive bids or other means designed to encourage competition, except that funds dedicated for low-income weatherization shall be directed to the Housing and Community Services Department as provided in subsection (7) of this section. The commission may also direct that funds collected by an electric company through public purpose charges be paid to a nongovernmental entity for investment in public purposes described in subsection (1) of this section. Notwithstanding any other provision of this subsection, at least 80 percent of the funds allocated for conservation shall be spent within the service area of the electric company that collected the funds.

(e)(A) The first 10 percent of the funds collected annually by an electric company under subsection (2) of this section shall be distributed to education service districts, as described in ORS 334.010, that are located in the service territory of the electric company. The funds shall be distributed to individual education service districts according to the weighted average daily membership (ADMw) of the component school districts of the education service district for the prior fiscal year as calculated under ORS 327.013. The commission shall establish by rule a methodology for distributing a proportionate share of funds under this paragraph to education service districts that are only partially located in the service territory of the electric company.

(B) An education service district that receives funds under this paragraph shall use the funds first to pay for energy audits for school districts located within the education service district. An education service district may not expend additional funds received under this paragraph on a school district facility until an energy audit has been completed for that school district. To the extent practicable, an education service district shall coordinate with the State Department of Energy and incorporate federal funding in complying with this paragraph. Following completion of an energy audit for an individual school district, the education service district may expend funds received under this paragraph to implement the energy audit. Once an energy audit has been conducted and completely implemented for each school district within the education service district, the education service district may expend funds received under this paragraph for any of the following purposes:

(i) Conducting energy audits. A school district shall conduct an energy audit prior to expending funds on any other purpose authorized under this paragraph unless the school district has performed an energy audit within the three years immediately prior to receiving the funds.

(ii) Weatherization and upgrading the energy efficiency of school district facilities.

(iii) Energy conservation education programs.

(iv) Purchasing electricity from environmentally focused sources and investing in renewable energy resources.

(f) The commission may **not** establish a different public purpose charge than the public purpose charge [*otherwise*] described in subsection (2) of this section [*for an individual retail electricity consumer or any class of retail electricity consumers located within the service area of an electric company, provided that a retail electricity consumer with a load greater than one average megawatt is not required to pay a public purpose charge in excess of three percent of its total cost of electricity services*].

[*(g) The commission shall remove from the rates of each electric company any costs for public purposes described in subsection (1) of this section that are included in rates. A rate adjustment under this paragraph shall be effective on the date that the electric company begins collecting public purpose charges.*]

(4) An electric company that satisfies its obligations under this section shall have no further obligation to invest in conservation, new market transformation[*, new renewable energy resources*] or new low-income weatherization or to provide a commercial energy conservation services program and is not subject to ORS 469.631 to 469.645[,] **and** 469.860 to 469.900 [*and 758.505 to 758.555*].

(5)(a) A retail electricity consumer that uses more than one average megawatt of electricity at any site in the prior year shall receive a credit against public purpose charges billed by an electric company for that site. The amount of the credit shall be equal to the total amount of qualifying expenditures for new energy conservation, not to exceed 68 percent of the annual public purpose charges, and the above-market costs of purchases of new renewable energy resources incurred by the retail electricity consumer, not to exceed 19 percent of the annual public purpose charges, less administration costs incurred under this subsection. The credit may not exceed, on an annual basis, the lesser of:

(A) The amount of the retail electricity consumer's qualifying expenditures; or

(B) The portion of the public purpose charge billed to the retail electricity consumer that is dedicated to new energy conservation, new market transformation or the above-market costs of new renewable energy resources.

(b) To obtain a credit under this subsection, a retail electricity consumer shall file with the State Department of Energy a description of the proposed conservation project or new renewable energy resource and a declaration that the retail electricity consumer plans to incur the qualifying expenditure. The State Department of Energy shall issue a notice of precertification within 30 days of receipt of the filing, if such filing is consistent with this subsection. The credit may be taken after a retail electricity consumer provides a letter from a certified public accountant to the State Department of Energy verifying that the precertified qualifying expenditure has been made.

(c) Credits earned by a retail electricity consumer as a result of qualifying expenditures that are not used in one year may be carried forward for use in subsequent years.

(d)(A) A retail electricity consumer that uses more than one average megawatt of electricity at any site in the prior year may request that the State Department of Energy hire an independent auditor to assess the potential for conservation investments at the site. If the independent auditor determines there is no available conservation measure at the site that would have a simple payback of one to 10 years, the retail electricity consumer shall be relieved of 54 percent of its payment obligation for public purpose charges related to the site. If the independent auditor determines that there are potential conservation measures available at the site, the retail electricity consumer shall be entitled to a credit against public purpose charges related to the site equal to 54 percent of the public purpose charges less the estimated cost of available conservation measures.

(B) A retail electricity consumer shall be entitled each year to the credit described in this subsection unless a subsequent independent audit determines that new conservation investment opportunities are available. The State Department of Energy may require that a new independent audit be performed on the site to determine whether new conservation measures are available, provided that the independent audits shall occur no more than once every two years.

(C) The retail electricity consumer shall pay the cost of the independent audits described in this subsection.

(6) Electric utilities and retail electricity consumers shall receive a fair and reasonable credit for the public purpose expenditures of their energy suppliers. The State Department of Energy shall adopt rules to determine eligible expenditures and the methodology by which such credits are accounted for and used. The rules also shall adopt methods to account for eligible public purpose expenditures made through consortia or collaborative projects.

(7)(a) In addition to the public purpose charge provided under subsection (2) of this section, beginning on October 1, 2001, an electric company shall collect funds for low-income electric bill payment assistance in an amount determined under paragraph (b) of this subsection.

(b) The total amount collected for low-income electric bill payment assistance under this section shall be $10 million per year. The commission shall determine each electric company's proportionate share of the total amount. The commission shall determine the amount to be collected from a retail electricity consumer, except that a retail electricity consumer is not required to pay more than $500 per month per site for low-income electric bill payment assistance.

(c) Funds collected by the low-income electric bill payment assistance charge shall be paid into the Housing and Community Services Department Revolving Account created under ORS 456.574. Moneys deposited in the account under this paragraph are continuously appropriated to the Housing and Community Services Department for the purpose of funding low-income electric bill payment assistance. Interest earned on moneys deposited in the account under this paragraph shall accrue to the account. The department's cost of administering this subsection shall be paid out of funds collected by the low-income electric bill payment assistance charge. Moneys deposited in the account under this paragraph shall be expended solely for low-income electric bill payment assistance. Funds collected from an electric company shall be expended in the service area of the electric company from which the funds are collected.

(d) The Housing and Community Services Department, in consultation with the federal Advisory Committee on Energy, shall determine the manner in which funds collected under this subsection will be allocated by the department to energy assistance program providers for the purpose of providing low-income bill payment and crisis assistance, including programs that effectively reduce service disconnections and related costs to retail electricity consumers and electric utilities. Priority assistance shall be directed to low-income electricity consumers who are in danger of having their electricity service disconnected.

(e) Notwithstanding ORS 293.140, interest on moneys deposited in the Housing and Community Services Department Revolving Account under this subsection shall accrue to the account and may be used to provide heating bill payment and crisis assistance to electricity consumers whose primary source of heat is not electricity.

(f) Notwithstanding ORS 757.310, the commission may allow an electric company to provide reduced rates or other payment or crisis assistance or low-income program assistance to a low-income household eligible for assistance under the federal Low Income Home Energy Assistance Act of 1981, as amended and in effect on July 23, 1999.

(8) For purposes of this section, "retail electricity consumers" includes any direct service industrial consumer that purchases electricity without purchasing distribution services from the electric utility.

SECTION 28. The amendments to ORS 757.612 (3)(b)(B) by section 27 of this 2007 Act become operative on January 1, 2008.

SECTION 29. ORS 757.687 is amended to read:

757.687. (1) Beginning on the date a consumer-owned utility provides direct access to any class of retail electric consumers, the consumer-owned utility shall collect from that consumer class a nonbypassable public purpose charge [*for a period of 10 years*] **until January 1, 2026**. Except as provided in subsection (8) of this section, the amount of the public purpose charge shall be sufficient to produce revenue of not less than three percent of the total revenue collected by the consumer-owned utility from its retail electricity consumers for electricity services, distribution, ancillary services, metering and billing, transition charges and any other costs included in rates as of July 23, 1999, except that the consumer-owned utility may exclude from the calculation of such costs any cost related to the public purposes described in subsection (5) of this section. If a consumer-owned utility has fewer than 17 consumers per mile of distribution line, the amount of the public purpose charge shall be sufficient to produce revenue not less than three percent of the total revenue from the sale of electricity services in the utility's service area to the consumer class that is provided direct access, or the utility's consumer class percentage share of state total electricity sales multiplied by three percent of total statewide retail electric revenue, whichever is less.

(2) Except as provided in subsection (9) of this section, the governing body of a consumer-owned utility shall determine the manner of collecting and expending funds for public purposes required by law to be assessed against and paid by the retail electric consumers of the utility. A determination by the governing body shall include:

(a) The manner for collecting public purpose charges;

(b) Public purpose programs upon which revenue from the charges may be expended; and

(c) The allocation of expenditures for each program.

(3) Beginning on the same date two years after July 23, 1999, a consumer-owned utility shall report annually to the State Department of Energy created under ORS 469.030 on the public purpose charges paid to the utility by its retail electric consumers and the public purposes on which the revenue was expended.

(4) A consumer-owned utility may comply with the public purpose requirements of this section by participating in collaborative efforts with other consumer-owned utilities located in this state.

(5) Funds assessed and paid by, and credits or other financial assistance issued or extended to, retail electric consumers for purposes of this section may, in the discretion of the governing body of the consumer-owned utility, be expended to fund programs for energy conservation, renewable resources or low-income energy services otherwise required by the laws of this state, adopted by the governing body pursuant to the National Energy Conservation Policy Act (Public Law 95-619, as amended November 10, 1981), or conducted by the utility pursuant to agreement with the Bonneville Power Administration under the Pacific Northwest Electric Power Planning and Conservation Act (Public Law 96-501). All such funds expended, credits issued and incremental costs incurred in connection with the performance of a consumer-owned utility's obligations under this section shall be credited toward the utility's public purpose funding obligation under this section.

(6) A consumer-owned utility also may credit toward its funding obligations under this section any incremental costs incurred by the utility for capital expenditures made to reduce its distribution system energy losses, existing biomass gas and waste to energy systems, existing hydroelectric generation projects using fish attraction water, for new energy conservation and renewable resource funding costs included in its wholesale power supplier's charges and for electric power generated by renewable or cogeneration resources pursuant to requirements of the Public Utilities Regulatory Policy Act of 1978 (Public Law 95-617), to the extent that such costs exceed the average cost of the utility's other electric power resources.

(7) A consumer-owned utility also may credit toward its public purpose funding obligations under this section any costs incurred in complying with ORS 469.649 to 469.659.

(8) Beginning on March 1, 2002, a consumer-owned utility whose territory abuts the greatest percentage of the site of an aluminum plant that averages more than 100 megawatts of electricity use per year shall collect from the aluminum company a public purpose charge equal to one percent of the total revenue from the sale of electricity services to the aluminum plant from any source.

(9)(a) A retail electricity consumer that uses more than one average megawatt of electricity at any site in the prior year shall receive a credit against public purpose charges billed by a consumer-owned utility for that site. The amount of the credit shall be equal to the total amount of qualifying expenditures for new energy conservation, not to exceed 68 percent of the annual public purpose charges, and the above-market costs of purchases of new renewable energy resources incurred by the retail electricity consumer, less administration costs incurred under this subsection. The credit shall not exceed, on an annual basis, the lesser of:

(A) The amount of the retail electricity consumer's qualifying expenditures; or

(B) The portion of the public purpose charge billed to the retail electricity consumer that is dedicated to new energy conservation, new market transformation or the above-market costs of new renewable resources.

(b) To obtain a credit under this subsection, a retail electricity consumer shall file with the department a description of the proposed conservation project, new market transformation or new renewable energy resource and a declaration that the retail electricity consumer plans to incur the qualifying expenditure. The department shall issue a notice of precertification within 30 days of receipt of the filing, if such filing is consistent with this subsection. Notice shall be issued to the retail electricity consumer and the appropriate consumer-owned utility. The credit may be taken after a retail electricity consumer provides a letter from a certified public accountant to the department verifying that the precertified qualifying expenditure has been made.

(c) Credits earned by a retail electricity consumer as a result of qualifying expenditures that are not used in one year may be carried forward for use in subsequent years.

(d)(A) A retail electricity consumer that uses more than one average megawatt of electricity at any site in the prior year may request that the department hire an independent auditor to assess the potential for conservation measures at the site. If the independent auditor determines there is no available conservation measure at the site that would have a simple payback of one to 10 years, the retail electricity consumer shall be relieved of 54 percent of its payment obligation for public purpose charges related to the site. If the auditor determines that there are potential conservation measures available at the site, the retail electricity consumer shall be entitled to a credit against public purpose charges related to the site equal to 54 percent of the public purpose charges less the estimated cost of available conservation measures.

(B) A retail electricity consumer shall be entitled each year to the credit described in this paragraph unless a subsequent audit determines that new conservation investment opportunities are available. The department may require that a new audit be performed on the site to determine whether new conservation measures are available, provided that the audits occur no more than once every two years.

(C) The retail electricity consumer shall pay the cost of the audits described in this subsection.

(10) A retail electricity consumer with a load greater than one average megawatt shall not be required to pay a public purpose charge in excess of three percent of the consumer's total cost of electricity services unless the charge is established in an agreement between the consumer and the consumer-owned utility.

(11) Beginning on March 1, 2002, a consumer-owned utility shall have in operation a bill assistance program for households that qualify for federal low-income energy assistance in the consumer-owned utility's service area. A consumer-owned utility shall report annually to the Housing and Community Services Department detailing the utility's program and program expenditures.

(12) A consumer-owned utility may require an electricity service supplier to provide information necessary to ensure compliance with this section. The consumer-owned utility shall ensure the privacy and protection of any proprietary information provided.

PEOPLE'S UTILITY DISTRICTS

SECTION 30. ORS 261.010 is amended to read:

261.010. As used in this chapter, unless otherwise required by the context:

(1) "Affected territory" means that territory proposed to be formed into, annexed to or consolidated with a district.

(2) "Board of directors," "directors" or "board" means the governing body of a people's utility district, elected and functioning under the provisions of this chapter.

(3) "County governing body" means either the county court or board of county commissioners and, if the affected territory is composed of portions of two or more counties, the governing body of that county having the greatest portion of the assessed value of all taxable property within the affected territory, as shown by the most recent assessment roll of the counties.

(4) "Electors' petition" means a petition addressed to the county governing body and filed with the county clerk, containing the signatures of electors registered in the affected territory, equal to not less than three percent of the total number of votes cast for all candidates for Governor within the affected territory at the most recent election at which a candidate for Governor was elected to a full term, setting forth and particularly describing the boundaries of the parcel of territory, separate parcels of territory, city and district, or any of them, referred to therein, and requesting the county governing body to call an election to be held within the boundaries of the parcel of territory, separate parcels of territory, city and district, or any of them, for the formation of a district, the annexation of a parcel of territory or a city to a district, or the consolidation of two or more districts.

(5) "Electric cooperative" means a cooperative corporation owning and operating an electric distribution system.

(6) "Initial utility system" means a complete operating utility system, including energy efficiency measures and installations within the district or proposed district, capable of supplying the consumers required to be served by the district at the time of acquisition or construction with all of their existing water or electrical energy needs.

(7) "Parcel of territory" means a portion of unincorporated territory, or an area in a city comprised of less than the entire city.

(8) "People's utility district" or "district" means an incorporated people's utility district, created under the provisions of this chapter.

(9) "Replacement value of unreimbursed investment" means original cost new less depreciation of capitalized energy efficiency measures and installations in the premises of customers of an investor owned utility.

(10) "Separate parcel of territory" means unincorporated territory that is not contiguous to other territory that is a part of a district or that is described in a petition filed with the county clerk in pursuance of the provisions of this chapter, but when a proposed district includes territory in more than one county, the contiguous territory in each such county shall be considered as a separate parcel of territory. When a proposed district includes any area in a city comprised of less than the entire city, that area shall be considered as a separate parcel of territory.

(11) "Utility" means a plant, works or other property used for development, generation, storage, distribution or transmission of [*electric energy produced from resources including, but not limited to, hydroelectric, pump storage, wave, tidal, wind, solid waste, wood, straw or other fiber, coal or other thermal generation, geothermal or solar resources*] **electricity**, or development or transmission of water for domestic or municipal purposes, [*waterpower or electric energy,*] but transmission of water shall not include water for irrigation or reclamation purposes, except as secondary to and when used in conjunction with a hydroelectric plant.

SECTION 31. ORS 261.030 is amended to read:

261.030. Nothing contained in this chapter authorizes or empowers the board of directors of any people's utility district to interfere with or exercise any control over any existing utility owned and operated by any electric cooperative or city in the district unless by consent of the governing body of the electric cooperative or of the city council or the governing body of the plant owned by a city, when the control of the plant is vested in a governing body other than the city council or governing body of the city. However a district may participate fully with electric cooperatives and utilities owned by cities **in common facilities under ORS 261.235 to 261.255 and** in the formation and operation of joint operating agencies [*for electric power*] under ORS chapter 262.

SECTION 32. ORS 261.050 is amended to read:

261.050. **(1)** All property, real and personal, owned, used, operated or controlled by any people's utility district, in or for the production, transmission, distribution or furnishing of [*electric power or energy*] **electricity** or electric service for or to the public, shall be assessed and taxed in the same manner and for the same purposes, and the district and the directors and officers thereof shall be subject to the same requirements, as are provided by law in respect to assessment and taxation of similar property owned, used, operated or controlled by private corporations or individuals for the purpose of furnishing [*electric power or energy*] **electricity** or electric service to the public.

(2) If a people's utility district owns property jointly with a tax-exempt governmental or municipal entity, only that portion of the property, or that proportion of the property rights, directly owned, used, operated or controlled by the people's utility district shall be assessed and taxed pursuant to subsection (1) of this section.

SECTION 33. ORS 261.235 is amended to read:

261.235. As used in ORS 261.235 to 261.255, unless the context requires otherwise:

(1) "City" means a city organized under the law of California, Idaho, Montana, Nevada, Oregon or Washington and owning and operating an electric light and power system.

(2) "Common facilities" means any [*works and facilities necessary or incidental to*] **property used for** the generation, transmission, distribution or marketing of [*electric power*] **electricity** and related goods and [*commodities*] **services that are owned or operated jointly by a people's utility district organized under this chapter and at least one other city, district or electric cooperative**.

(3) "District" means a people's utility district organized under this chapter or a similar public utility district organized under the law of California, Idaho, Montana, Nevada or Washington.

(4) "Electric cooperative" means a cooperative corporation organized under the law of California, Idaho, Montana, Nevada, Oregon or Washington and owning and operating an electric distribution system.

SECTION 34. Section 35 of this 2007 Act is added to and made a part of ORS 261.235 to 261.255.

SECTION 35. A people's utility district may become a member of an electric cooperative, or of a limited liability company, for the purposes of planning, financing, constructing, acquiring, operating, owning or maintaining property used for the generation and associated transmission of electricity within or outside this state. A district may not become a stockholder in, or lend the credit of the district to, an electric cooperative or a limited liability company. If a district becomes a member of an electric cooperative or of a limited liability company, the district may not exercise the power of eminent domain for the benefit of the electric cooperative or limited liability company.

SECTION 36. ORS 261.250 is amended to read:

261.250. (1) In carrying out the powers granted in ORS 261.245 **and section 35 of this 2007 Act**, a district of this state [*shall be*] **is** liable only for its own acts with regard to the planning, financing, construction, acquisition, operation, ownership or maintenance of common facilities. No moneys or other contributions supplied by a district of this state for the planning, financing, construction, acquisition, operation or maintenance of common facilities shall be credited or applied otherwise to the account of any other participant in the common facilities.

(2) A district shall not exercise its power of eminent domain to acquire a then existing thermal power plant or any part thereof.

SECTION 37. ORS 261.253 is amended to read:

261.253. (1) [*No*] **A** public contract entered into by a noninvestor-owned electric utility [*shall*] **may not** contain a clause or condition that imposes an unconditional and unlimited financial obligation on the electric utility that is party to the contract unless the terms and conditions of the contract are subject to approval and are approved by the electors of the people's utility district or city that owns the electric utility.

(2) Nothing in subsection (1) of this section is intended to affect provisions of law requiring approval of electors for any particular type of public contract that are in effect on October 15, 1983, or that are later enacted.

(3) Nothing in subsection (1) of this section is intended to conflict with ORS 279C.650 to 279C.670.

(4) This section does not apply to a public contract executed in connection with:

(a) The acquisition of renewable energy certificates;

(b) The acquisition, construction, improvement or equipping of, or the financing of any interest in, a renewable energy facility; or

(c) The acquisition or financing of any interest in electrical capacity needed to shape, firm or integrate electricity from a renewable energy facility.

[*(4)*] **(5)** As used in this section:

(a) "Public contract" includes a contract, note, general obligation bond or revenue bond by which the people's utility district or city or any subdivision of any of them is obligated to pay for or finance the acquisition of goods, services, materials, real property or any interest therein, improvement, betterments or additions from any funds, including receipts from rates or charges assessed to or collected from its customers.

(b) "Unconditional and unlimited financial obligation" means a public contract containing a provision that the people's utility district or city that is party to the contract is obligated to make payments required by the contract whether or not the project to be undertaken thereunder is undertaken, completed, operable or operating notwithstanding the suspension, interruption, interference, reduction or curtailment of the output or product of the project.

SECTION 38. ORS 261.305 is amended to read:

261.305. People's utility districts shall have power:

(1) To have perpetual succession.

(2) To adopt a seal and alter it at pleasure.

(3) To sue and be sued, to plead and be impleaded.

(4) To acquire and hold, including by lease-purchase agreement, real and other property necessary or incident to the business of the districts, within or without, or partly within or partly without, the district, and to sell or dispose of that property; to acquire, develop and otherwise provide for a supply of water for domestic and municipal purposes, waterpower and electric energy, or

electric energy generated from any utility, and to distribute, sell and otherwise dispose of water, waterpower and electric energy, within or without the territory of such districts.

(5) To acquire, own, trade, sell or otherwise transfer renewable energy certificates.

[*(5)*] **(6)** To exercise the power of eminent domain for the purpose of acquiring any property, within or without the district, necessary for the carrying out of the provisions of this chapter.

[*(6)*] **(7)** To borrow money and incur indebtedness; to issue, sell and assume evidences of indebtedness; to refund and retire any indebtedness that may exist against or be assumed by the district or that may exist against the revenues of the district and to pledge any part of its revenues. Except as provided in ORS 261.355 and 261.380, no revenue or general obligation bonds shall be issued or sold without the approval of the electors. The board of directors may borrow from banks or other financial institutions[*, on notes payable within 12 months,*] such sums as the board of directors deems necessary or advisable[*; however, the amounts so borrowed, together with the principal amounts of other like borrowings then outstanding and unpaid, shall not exceed the amount that the board of directors estimates as the district's net income (determined in accordance with the system of accounts maintained by the board pursuant to ORS 261.470) for the 12 full calendar months following the date of the proposed borrowing, adjusted by adding to the net income an amount equal to the estimated charges to depreciation for the 12-month period*]. No indebtedness shall be incurred or assumed except [*on account of*] **for** the development, purchase and operation of [*a utility*] **electric utility facilities or for the purchase of electricity, electrical capacity or renewable energy certificates**.

[*(7) To enter into rental or lease-purchase agreements to rent, lease or acquire real or personal property, or both, required for district purposes. Except when approved by a majority of the electors of the district voting on the question, a people's utility district shall not enter into rental or leasing agreements when the annual aggregate amount of payment for any and all property directly related to a single transaction exceeds 10 percent of the revenues of the district in the preceding fiscal year.*]

(8) To exercise the powers otherwise granted to districts by ORS 271.390.

[*(8)*] **(9)** To levy and collect, or cause to be levied and collected, subject to constitutional limitations, taxes for the purpose of carrying on the operations and paying the obligations of the district as provided in this chapter.

[*(9)*] **(10)** To make contracts, to employ labor and professional staff, to set wages in conformance with ORS 261.345, to set salaries and provide compensation for services rendered by employees and by directors, to provide for life insurance, hospitalization, disability, health and welfare and retirement plans for employees, and to do all things necessary and convenient for full exercise of the powers herein granted. The provision for life insurance, hospitalization, disability, health and welfare and retirement plans for employees shall be in addition to any other authority of people's utility districts to participate in those plans and shall not repeal or modify any statutes except those that may be in conflict with the provision for life insurance, hospitalization, disability, health and welfare and retirement plans.

[*(10)*] **(11)** To enter into contracts with **any person, any public or private corporation,** the United States Government, [*with*] the State of Oregon, or with any other state, municipality or utility district, and with any department of any of these, for carrying out any provisions of this chapter.

[*(11)*] **(12)** To enter into agreements with the State of Oregon or with any local governmental unit, utility, special district or private or public corporation for the purpose of promoting economic growth and the expansion or addition of business and industry within the territory of the people's utility district. Before spending district funds under such an agreement, the board of directors shall enter on the written records of the district a brief statement that clearly indicates the purpose and amount of any proposed expenditure under the agreement.

[*(12)*] **(13)** To fix, maintain and collect rates and charges for any water, waterpower, [*electric energy*] **electricity** or other commodity or service furnished, developed or sold by the district.

[*(13)*] **(14)** To construct works across or along any street or public highway, or over any lands which are property of this state, or any subdivision thereof, and to have the same rights and privileges appertaining thereto as have been or may be granted to cities within the state, and to construct its works across and along any stream of water or watercourse. Any works across or along any state highway shall be constructed only with the permission of the Department of Transportation. Any works across or along any county highway shall be constructed only with the permission of the appropriate county court. Any works across or along any city street shall be constructed only with the permission of the city governing body and upon compliance with applicable city regulations and payment of any fees called for under applicable franchise agreements, intergovernmental agreements under ORS chapter 190 or contracts providing for payment of such fees. The district shall restore any such street or highway to its former state as near as may be, and shall not use the same in a manner unnecessarily to impair its usefulness.

[*(14)*] **(15)** To elect a board of five directors to manage its affairs.

[*(15)*] **(16)** To enter into franchise agreements with cities and pay fees under negotiated franchise agreements, intergovernmental agreements under ORS chapter 190 and contracts providing for the payment of such fees.

[*(16)*] **(17)** To take any other actions necessary or convenient for the proper exercise of the powers granted to a district by this chapter and by section 12, Article XI of the Oregon Constitution.

SECTION 39. ORS 261.335 is amended to read:

261.335. **(1) Except as provided in subsection (2) of this section,** people's utility districts are subject to the public contracting and purchasing requirements of ORS 279.835 to 279.855, 279C.005, 279C.100 to 279C.125 and 279C.300 to 279C.470 and ORS chapters 279A and 279B, except ORS 279A.140 and 279A.250 to 279A.290.

(2) The public contracting and purchasing requirements of ORS 279.835 to 279.855, 279C.005, 279C.100 to 279C.125 and 279C.300 to 279C.470 and ORS chapters 279A and 279B do not apply to contracts entered into by districts for the acquisition, construction, improvement or equipping of a renewable energy facility or for the purchase or sale of electricity, electrical capacity or renewable energy certificates.

SECTION 40. ORS 261.348 is amended to read:

261.348. **(1)** Notwithstanding any other law, people's utility districts and municipal electric utilities may enter into transactions with other persons or entities for the production, supply or delivery of electricity on an economic, dependable and cost-effective basis, including financial products contracts and other service contracts that reduce the risk of economic losses in the transactions. This [*section*] **subsection** does not authorize any transaction that:

[*(1)*] **(a)** Constitutes the investment of surplus funds for the purpose of receiving interest or other earnings from the investment; or

[*(2)*] **(b)** Is intended or useful for any purpose other than the production, supply or delivery of electricity on a cost-effective basis.

(2) Nothing in subsection (1) of this section prohibits a people's utility district or a mu-

nicipal electric utility from entering into any transaction for the acquisition, construction, improvement or equipping of a renewable energy facility or for the purchase or sale of electricity, electrical capacity or renewable energy certificates.

SECTION 41. ORS 261.355 is amended to read:

261.355. (1) For the purpose of carrying into effect the powers granted in this chapter, any district may issue and sell revenue bonds, when authorized by a majority of its electors voting at any primary election, general election or special election.

(2) All revenue bonds issued and sold under this chapter shall be so conditioned as to be paid solely from that portion of the revenues derived [*from*] **by** the district [*by*] **from** the sale of water, waterpower and [*electric energy*] **electricity**, or any of them, or any other service, commodity or facility which may be produced, used or furnished in connection therewith, remaining after paying from those revenues all expenses of operation and maintenance, including taxes.

(3) Notwithstanding subsection (1) of this section and subject to subsection (4) of this section, any district may, by a duly adopted resolution of its board, issue and sell revenue bonds for the purpose of **financing** betterments and extensions [*within the existing boundaries*] of the district, **including renewable energy facilities or the purchase or sale of electricity, electrical capacity or renewable energy certificates,** but the amount **of revenue bonds** so issued shall be limited to the reasonable value of the betterments and extensions plus an amount not to exceed 10 percent thereof for administrative purposes. Revenue bonds shall not be issued and sold for the purpose of acquiring an initial utility system or acquiring property or facilities owned by another entity that provides electric utility service **unless:**

(a) The acquisition is a voluntary transaction between the district and the other entity that provides electric utility service; or

(b) [*without first obtaining the affirmative vote of*] The electors within the district **have approved issuance of the bonds by a vote**.

(4) Not later than the 30th day prior to a board meeting at which adoption of a resolution under subsection (3) of this section will be considered, the district shall:

(a) Provide for and give public notice, reasonably calculated to give actual notice to interested persons including news media which have requested notice, of the time and place of the meeting and of the intent of the board to consider and possibly adopt the resolution; and

(b) Mail to its customers notice of the time and place of the meeting and of the intent of the board to consider and possibly adopt the resolution.

(5) **Except as provided in subsection (3)(a) of this section,** any authorizing resolution adopted for the purposes of subsection (3) of this section shall provide that electors residing within the district may file a petition with the district asking to have the question of whether to issue such bonds referred to a vote.

(6) If within 60 days after adoption of a resolution under subsection (3) of this section the district receives petitions containing valid signatures of not fewer than five percent of the electors of the district, the question of issuing the bonds shall be placed on the ballot at the next date on which a district election may be held under ORS 255.345 (1).

(7) When petitions containing the number of signatures required under subsection (6) of this section are filed with the district within 60 days after adoption of a resolution under subsection (3) of this section, revenue bonds shall not be sold until the resolution is approved by a majority of the electors of the district voting on the resolution.

(8) Any district issuing revenue bonds may pledge that part of the revenue which the district

may derive from its operations as security for payment of principal and interest thereon remaining after payment from such revenues of all expenses of operation and maintenance, including taxes, and consistent with the other provisions of this chapter.

(9) Prior to any district board taking formal action to issue and sell any revenue bonds, the board shall have on file with the secretary of the district a certificate executed by a qualified engineer that the net annual revenues of the district, including the property to be acquired or constructed with the proceeds of the bonds, shall be sufficient to pay the maximum amount that will be due in any one fiscal year for both principal of and interest on both the bonds then proposed to be issued and all bonds of the district then outstanding.

(10) **Except as provided in subsection (3)(a) of this section,** the district shall order an election for the authorization of revenue bonds to finance the acquisition or construction of an initial utility system, including the replacement value of the unreimbursed investment of an investor owned utility in energy efficiency measures and installations within the proposed district, as early as practicable under ORS 255.345 after filing the certificate required under subsection (9) of this section. An election under this subsection shall be held no more than twice in any one calendar year for any district. In even-numbered years no election shall be held on any other date than the date of the primary election or general election.

SECTION 42. ORS 262.005 is amended to read:

262.005. As used in ORS 262.015 to 262.105, unless the context requires otherwise:

(1) "Electric cooperative" means a cooperative corporation owning and operating an electric distribution system.

(2) "Joint operating agency" means an agency organized by three or more cities or people's utility districts under the laws of this state for the purposes and according to ORS 262.005 to 262.105.

(3) "Privately owned electric utility company" means an electric utility operated for profit and subject to regulation by the Public Utility Commission of Oregon or the equivalent officer or commission of any other state.

(4) "Utility properties" means [*plants, systems and facilities, and any enlargement or extension thereof, used for or incidental to the generation and transmission of electric power and energy,*] **a plant, works or other property used for development, generation, storage, distribution or transmission of electricity.** [*provided, however, that it shall not mean*] **"Utility properties" does not include** facilities for uranium refining, processing or reprocessing.

SECTION 43. ORS 262.015 is amended to read:

262.015. (1) Any three or more cities or people's utility districts or combinations thereof, organized under the laws of this state, may form a joint operating agency to plan, acquire, construct, own, operate and otherwise promote the development of utility properties [*in this state*] for the generation**,** [*and*] transmission **and marketing** of [*electric power and energy*] **electricity, electrical capacity or renewable energy certificates**.

(2) A joint operating agency may participate with other publicly owned utilities, including other joint operating agencies, or with electric cooperatives, or with privately owned electric utility companies, or with any combination thereof, for any purpose set forth in subsection (1) of this section, whether such agencies or utilities are organized or incorporated under the laws of this state or any other jurisdiction. However, no joint operating agency may act alone or as the managing participant to acquire, construct, own or operate utility properties[*, nor may a joint operating agency own more than 50 percent of any utility property, except combustion turbines*].

(3) Joint operating agencies, cities, people's utility districts and privately owned utilities, or combinations thereof, may participate in joint ownership of [*thermal generation and transmission*] **common** facilities in accordance with ORS 225.450 to 225.490 or 261.235 to 261.255.

SECTION 44. ORS 262.075 is amended to read:

262.075. (1) Each joint operating agency shall be a political subdivision of the State of Oregon, and shall be a municipal corporation with the right to sue and be sued in its own name. Except as otherwise provided, a joint operating agency shall have all the powers, rights, privileges and exemptions conferred on people's utility districts.

(2) A joint operating agency shall have the power to acquire, hold, sell and dispose of real and other property, within or without this state, which the board of directors in its discretion finds reasonably necessary or incident to the generation**,** [*and*] transmission **and marketing** of [*electric power and energy*] **electricity, electrical capacity or renewable energy certificates**. However, such an agency shall not acquire or operate any facilities for the distribution of [*electric energy*] **electricity**.

(3) A joint operating agency shall have the power of eminent domain which it may exercise for the purpose of acquiring property; however, a joint operating agency shall not condemn any properties owned by a publicly or privately owned utility which are being used for the generation or transmission of [*electric energy or power*] **electricity** or are being developed for such purposes with due diligence, except to acquire a right of way to cross such properties in a manner which will not interfere with the use thereof by the owner.

(4) A joint operating agency shall have the power to enter into contracts, leases and other undertakings considered necessary or proper by its board, including but not limited to contracts for any term relating to the purchase, sale, interchange, assignment, allocation, transfer or wheeling of power with the Government of the United States, or any agency thereof, and with any other municipal corporation or privately owned utility, or any combination thereof, within or without the state, and may purchase, deliver or receive power anywhere.

(5) A joint operating agency shall have the power to borrow money and incur indebtedness, to issue, sell and assume evidences of indebtedness, to refund and retire any indebtedness that may exist against the agency or its revenues, and to pledge any part of its revenues. A joint operating agency may borrow from banks or other financial institutions such sums on such terms as the board considers necessary or advisable. A joint operating agency may also issue, sell and assume bond anticipation notes, refunding bond anticipation notes, or their equivalent, which shall bear such date or dates, mature at such time or times, be in such denominations and in such form, be payable in such medium, at such place or places, and be subject to such terms of redemption, as the board considers necessary or advisable. The issuance and sale of revenue obligations by a joint operating agency shall be governed by ORS 262.085.

(6) The joint operating agency may apply for, accept, receive and expend appropriations, grants, loans, gifts, bequests and devises in carrying out its functions as provided by law.

COST RECOVERY FOR CONSERVATION MEASURES

SECTION 45. Section 46 of this 2007 Act is added to and made a part of ORS 757.600 to 757.687.

SECTION 46. (1) In addition to the public purpose charge established by ORS 757.612, the Public Utility Commission may authorize an electric company to include in its rates the costs

of funding or implementing cost-effective energy conservation measures implemented on or after the effective date of this 2007 Act. The costs may include amounts for weatherization programs that conserve energy.

(2) The commission shall ensure that a retail electricity consumer with a load greater than one average megawatt:

(a) Is not required to pay an amount that is more than three percent of the consumer's total cost of electricity service for the public purpose charge under ORS 757.612 and any amounts included in rates under this section; and

(b) Does not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates under this section.

MISCELLANEOUS

SECTION 47. The unit and section captions used in this 2007 Act are provided only for the convenience of the reader and do not become part of the statutory law of this state or express any legislative intent in the enactment of this 2007 Act.

SECTION 48. This 2007 Act being necessary for the immediate preservation of the public peace, health and safety, an emergency is declared to exist, and this 2007 Act takes effect on its passage.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT NO. ICNU/402

PGE RESPONSE TO CUB DATA REQUEST 002;

CUB RESPONSES TO ICNU DATA REQUESTS 001-008

March 23, 2017

TO: Sarah Knox-Ryan
Citizens Utility Board of Oregon (CUB)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to CUB Data Request No. 002
Dated March 10, 2017

Request:

Please provide in workable electronic Excel spreadsheets all of the embedded EE in PGE's system since 2008 (inclusive), separated out by rate class, SB 838 and SB 1149, both by capacity (MW) and energy (MWh). Please extend the spreadsheets out for the next 10 years, to include the staggered lifecycles of those same EE deployments.

Response:

PGE objects to this request as overly broad and unduly burdensome. Subject to and notwithstanding this objection, PGE responds as follows:

The historical annual energy efficiency savings achieved by customer class and funding program are reported by the Energy Trust of Oregon (ETO) and can be found on ETO's website in their annual reports. The website can be found at:

https://www.energytrust.org/about/reports-financials/

A revision to ETO's historical savings was released in February 2017. A summary of PGE Annual Savings for 2002-2015 by customer class, per the revision, can be found on page 14, Table 23 of the document, available at:

https://www.energytrust.org/wp-content/uploads/2017/03/True_Up_2016-FINAL_Report_ash_02.16.2017.pdf

Attachment 002-A provides the energy efficiency deployment forecast, provided by ETO to PGE in November 2016, with energy efficiency savings at the meter, line losses, and by SB 1149 and SB 838 for 2017 and the 2018 test-year.

CUB Data Responses to ICNU

001 Please provide all workpapers in support of CUB's opening testimony and exhibits.

CUB objects to this question to the extent that it calls for the production of CUB's work product. Notwithstanding that objection CUB states the following. CUB's workpapers were included as exhibits attached to our opening testimony.

002 Reference CUB/100 at 4:16-17. Please provide all documents or any other evidence in CUB's possession that support the statement that "CUB expressed concern … that exempting large customers would be unfair to small customers …."

CUB's statement was based on CUB's understanding of what took place during the 2007 legislative session. CUB's witness, Bob Jenks was supervising CUB's legislative program in 2007. Mr. Jenks refreshed his memory of this period of time when this issue came up in the UE 283 rate case (2014) by meeting with CUB's 2007 lobbyist, Jeff Bissonnette, CUB's 2007 Energy Program Director Jason Eisdorfer and PGE's Vice President of Public Policy, Dave Robertson all of whom were involved in the passage of SB 838.

In addition, PGE's Revised Surrebuttal testimony in UE 283 stated:

> In early 2007 during our discussions with CUB on the potential for legislation during the 2007 legislative session to provide additional energy efficiency spending, CUB raised concerns that if they were to support additional energy efficiency funding paid by residential and business customers, then they wanted assurances that large industrial customers would not receive direct benefits from energy efficiency projects carried out with those funds, generated from legislative language adopted as part of Senate Bill 838 (SB 838). Our recollection is CUB was concerned that the additional energy efficiency funding paid by residential and commercial customers would lead to a shift of the SB 1149 public purpose energy efficiency funding to fund more industrial measures. CUB ultimately supported the energy efficiency amendment to SB 838, and we believe CUB would not have supported the legislation without a broad understanding among the stakeholders that the funding would not lead to the undesired shift in 1149 dollars[1].

003 Reference CUB/100 at 7:15-8:1. Please provide all documents or any other evidence in CUB's possession that support the claims that it was not expected that SB 838 funding would become the largest source of energy efficiency funding and that "SB 838 was designed to take advantage of a limited opportunity for some additional residential and small business programs."

[1] UE 283/PGE/2200/Tinker - Robertson /2-3

CUB's statement was based on CUB's understanding of what took place during the 2007 legislative session. CUB's witness, Bob Jenks was supervising CUB's legislative program in 2007. Mr. Jenks refreshed his memory of this period of time when this issue came up in the UE 283 rate case (2014) by meeting with CUB's 2007 lobbyist, Jeff Bissonnette, CUB's 2007 Energy Program Director Jason Eisdorfer and PGE's Vice President of Public Policy, Dave Robertson all of whom were involved in the passage of SB 838.

CUB's understanding is that PGE proposed energy efficiency funding be added to SB 838 to acquire a limited amount of identified efficiency from residential and small commercial customers that could not be acquired under SB 1149 funding limitations. It was not supposed to be a large, permanent new funding mechanism for efficiency.

004 Please explain whether, in CUB's opinion, an incentive to pursue an energy efficiency measure constitutes a direct benefit to the customer receiving the incentive. Please explain you answer.

SB 838 provided legal direction to PGE and the PUC and therefore has to be viewed from the perspective of a regulated electric utility. From this perspective, incentives paid to customers are not viewed as a benefit.

The Cadmus Group, in determining the benefit of energy efficiency, names only two benefits: (1) utility avoided supply cost in the Utility Cost Test (UTC) and (2) utility avoided supply cost in the UTC coupled with tax benefits in the Total Resource Cost test.[2] The ETO, in its development of cost-effectiveness, lists out the five benefits that it considers: avoided costs, reduced transmission, risk, fuel costs, and non-energy benefits.[3] PGE has identified energy efficiency as a low-risk, least-cost resource and identified the following benefits: [4]

> 1. The value of the electrical and/or gas energy saved based on the avoided cost forecasts of the utilities whose customers are served by the Energy Trust, as reviewed and approved by the PUC. Periodically, Energy Trust will work with the utilities and PUC to develop an average, or merged cost forecast. This will be done separately for the electric utilities and gas utilities, so that Energy Trust program decisions are based on a single set of price forecasts for each fuel. Energy Trust may include factors such as hedge value, if not considered in the utility forecasts, based on agreement with the utilities and PUC.
>
> 2. Non-energy benefits will be quantified by a reasonable and practical method. Unless and until the OPUC develops an alternative approach, Energy Trust may use proxies for these benefits where research shows that

[2] *Id.* at pg 2, Table 2.
[3] http://energytrust.org/library/policies/4.06.000.pdf
[4] UE 283 CUB/202/Jenks-McGovern/10.

the benefits are large, they cannot be practically quantified, and they clearly influence consumer decisions.

3. For electricity, both line losses and avoided Transmission and Distribution construction.

4. Natural gas capacity benefits and benefits from reduced transmission and delivery losses will be included where significant and quantifiable.

5. In addition, the Energy Trust will apply in its analysis the 10% credit for energy efficiency as required under the Northwest Power Act and OPUC docket no. UM-551. This credit recognizes the benefits of conservation in addressing risk and uncertainty

005 Reference CUB/100 at 19:22-20:10:

a. Please provide the basis for CUB's recommendation to reclassify AMI meters as 50% customer related, 25% capacity related, 12.5% energy related, and 12.5% demand related, as opposed to other allocation percentages;

CUB's testimony demonstrated that these meters supply capacity and energy to the utility. Therefore, classifying them as 100% customer related is not an appropriate policy. CUB proposed a classification that we thought was reasonable, recognizing that meter investments have traditionally been made for the customer-related purpose of billing and are still used for customer-related billing purposes, but today are also being used to supply capacity, energy, and reliability services to the utility.

b. Please provide the basis for CUB's recommendation to reclassify CIS and MDMS programs as 50% customer related, 25% capacity related, 12.5% energy related, and 12.5% demand related, as opposed to other allocation percentages; and

CUB's testimony demonstrated that CIS and MDMS programs supply capacity and energy to the utility. Therefore, classifying them as 100% customer related is not an appropriate policy. CUB proposed a classification that we thought was reasonable, recognizing that these investments have traditionally been made for the customer-related purpose of billing, but will also be used to support energy and capacity related services.

c. Please provide the basis for CUB's recommendation to reclassify storage as 50% energy related and 50% capacity related as opposed to other allocation percentages.

Currently storage is incorrectly allocated as a customer related cost. Storage provides capacity and energy related services to the utility and cost allocation should recognize this.

CUB DATA RESPONSES TO ICNU

6a Request

Reference page 87 of the pdf of the combined testimony and exhibits CUB filed on June 16th in this docket.

a. Please clarify whether this page should be labeled as CUB Exhibit 105.

6a Response

Yes, the referenced page should be labeled as CUB Exhibit 105.

6b Request

b. Please provide an electronic version of this page.

6b Response

See Attachment.

7a Request

Reference CUB/100 at 12:10-13:2, regarding the allocation credit for Senate Bill ("SB") 838 energy efficiency:

a. Is the referenced $7.3 million amount the *total system* incremental benefit associated SB 838 energy efficiency in the test period, or is it the *subset* of the total system benefits that customers with loads one megawatt average or greater received?

7a Response

The $7.3 million allocation credit stated in CUB's testimony represents one methodology to value the total system benefit that is being received from the energy efficiency funded through SB 838.

7b Request

Does CUB agree that the table on page 13 details the rate schedules that will receive the proposed allocation credit, but does not detail how the cost of the credit will be funded between rate schedules?

7b Response

Yes.

7c Request

How would CUB allocate the cost of the credit under its alternative proposal, i.e. would CUB allocate the credit cost in the same way as other production costs, or would the cost go solely to customers with loads one average megawatt or greater?

7c Response

CUB did not make a proposal as to how the cost of the credit would be allocated. CUB has asked additional data requests of PGE to provide information related to this issue. CUB expects any proposals it makes will be fair and does not anticipate proposing an allocation solely to customers with loads one average megawatt or greater.

7d Request

Please describe the calculations behind the 1,178,542 MWh of 2018 SB 838 EE, and provide supporting workpapers.

7d Response

The workpaper is CUB Exhibit 105, (see attachment to ICNU DR 6(b) above).
In reaching its calculations, CUB assumed an average measure life of 10 years, took 10 years of EE savings, expressed in MW, and converted to MWh.

7e Request

In the referenced approach, did CUB assume the cost of EE from SB 838 funds to be the same as that from SB 1149 funds?

7e Response

The ETO annual reports did not identify separate levelized costs for PGE's SB 838 and SB 1149 funds. Therefore CUB used the levelized cost for PGE programs, recognizing that a majority of these programs are funded through SB 838.

7f Request

Does the $26.10/MWh levelized cost include any EE done with funds from SB 1149? If yes, please explain why the allocation credit appropriately includes the costs and benefits of SB 1149 funding for EE.

7f Response

The allocation credit is based on the actual SB 838 EE savings as reported by ETO. It does not include SB 1149 savings. When identifying the cost of the EE that was purchased by SB 838 dollars, CUB applied the levelized cost for all PGE programs, recognizing that most of PGE's programs are funded by SB 838 (see 7e above).

CUB DATA RESPONSE TO ICNU DATA REQUESTS

8 Request

If the Commission adopts CUB's embedded cost proposal for energy efficiency, would customers over 1 aMW be able to receive incentive funding from SB 838 funds?

8 Response

CUB objects to this question because it is asking the witness to draw a legal conclusion. SB 838 prohibits customers over 1 aMW from receiving a direct benefit from SB 838 EE funding. Whether they are eligible to receive incentive funding from SB 838 requires legal analysis as to whether this is a direct benefit.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT NO. ICNU/403

ICNU REBUTTAL TESTIMONY AND EXHIBITS (ICNU/400 – ICNU/404)

IN DOCKET NO. UE 283

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision.	)
	)

REBUTTAL TESTIMONY OF ALI AL-JABIR

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

August 13, 2014

TABLE OF CONTENTS TO THE
REBUTTAL TESTIMONY OF ALI AL-JABIR

Page

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ali Al-Jabir and my business address is 5151 Flynn Parkway, Suite 412 C/D, Corpus Christi, Texas, 78411. I am an energy advisor and a consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc ("BAI"). My qualifications are provided in Exhibit ICNU/401.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A. My testimony will respond to the Citizens' Utility Board of Oregon's ("CUB") proposal to adjust the class cost allocation factors for energy-related production costs in Portland General Electric Company's ("Company") generation marginal cost study to reflect differences in funding levels for energy efficiency ("EE") costs, as set forth by CUB in Section IV of its opening testimony in this proceeding.[1/]

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibits ICNU/401 through ICNU/404.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. CUB's proposal represents an unprecedented and inappropriate departure from traditional marginal cost theory. EE is not a proper marginal resource because it does not reflect a utility's costs to meet incremental load, and therefore, does not send proper price signals

[1/] CUB/100 at 20-37.

to customers. CUB's methodology, which allocates EE to customer classes based on customer payments to the Energy Trust of Oregon ("ETO"), arbitrarily distorts the marginal cost study and overemphasizes EE's impact on customer costs. The result is a marginal cost study that does not send proper price signals to customers and improperly shifts enormous costs from smaller customers to larger customers.

III. DESCRIPTION OF CUB'S ALLOCATION PROPOSAL

Q. CAN YOU PROVIDE A BRIEF DESCRIPTION OF ENERGY EFFICIENCY PROGRAMS?

A. EE involves reducing or modifying customer power and energy requirements using a variety of techniques, such as more efficient appliances, control of appliance operating times, and more efficient lighting and motors. EE measures can be undertaken directly and unilaterally by the customer, or can be facilitated by the intervention of the utility, or a third party like the ETO. It is important to recognize that many customers have already undertaken substantial EE and demand management measures in their plant operations or homes at their own expense and initiative in order to remain competitive or to conserve energy.

Q. DO INDUSTRIAL CUSTOMERS PURSUE EE EFFORTS USING INTERNAL FUNDING, OUTSIDE THE SCOPE OF COMPANY-FUNDED EE PROGRAMS?

A. Yes. Industrial customers operate in competitive global markets and therefore have a strong economic incentive to pursue independent EE efforts to reduce their operating costs. Moreover, these customers are sophisticated users of electricity who have a thorough understanding of their electricity requirements. These customers have both the means and the incentive to readily access the competitive EE services market to procure the equipment, advice and expertise needed to cost-effectively reduce their energy consumption, without intervention or funding by others. Furthermore, even when industrial customers receive incentive funding from organizations like the ETO, this only covers a portion of the costs of a conservation project. The rest are borne by the customer.

Q. PLEASE COMPARE THE COST ALLOCATION METHODOLOGY PROPOSED BY CUB IN THIS PROCEEDING WITH THE METHODOLOGY PROPOSED BY THE COMPANY.

A. Currently, the Company models its marginal production costs in its marginal cost of service study from a mix of traditional resources (simple cycle and combined cycle combustion turbines). The Company incorporates the impact of EE by modeling rate schedule loads based on their actual usage. This approach essentially internalizes the load reductions produced by EE efforts for each rate schedule.

By contrast, CUB uses EE to shift the costs of production resources in the Company's marginal cost of service study between rate classes. Specifically, CUB creates a resource mix for the Company which assumes that EE resources constitute 20.05% of the Company's theoretical resource needs. Importantly, CUB also develops a special allocation for the portion of the theoretical resource mix that it attributes to EE by giving each rate schedule credit for EE based on the level of ETO payments provided by that schedule, as calculated by CUB. CUB then subtracts these allocated EE-related amounts from the total system megawatts served by its theoretical resource mix. The resulting allocation of system megawatts to the rate schedules (net of EE) forms the basis for the modified production energy cost allocator developed by CUB that it then applies to the total production energy-related costs found in the Company's marginal cost study.[2/]

[2/] CUB/100 at 31 – 36.

Q. DOES CUB'S PROPOSAL HAVE A SIGNIFICANT IMPACT ON THE ALLOCATION OF COSTS TO THE RATE SCHEDULES?

A. Yes. Exhibit ICNU/402 compares the production energy cost allocation factors proposed by PGE to the modified allocation factors developed by CUB. As can be seen in Columns 1 and 2 of the Exhibit, CUB's proposal increases the production energy cost allocators for Schedules 89 and 90 relative to PGE's proposal, while reducing these allocation factors for residential and small commercial customers. Column 5 of the Exhibit shows the magnitude of the resulting changes in the allocation of production energy costs by rate schedule. The Exhibit shows that, on a combined basis, CUB's proposal would increase the allocation of such costs to Schedules 89 and 90 by almost $26 million relative to PGE's proposal, while reducing the cost allocation to Schedule 7 by $26.7 million. It should be noted that these figures are based on the Company's as-filed revenue requirement.

Exhibit ICNU/403 summarizes the change in overall cost allocation that results from CUB's proposal, relative to the cost allocation proposed by PGE. This Exhibit reinforces the fact that CUB's proposal would generate a massive cost shift that favors smaller customers on PGE's system at the expense of industrial customers. As shown in Column 6 of Exhibit ICNU/403, CUB's proposal would increase rates under Schedule 89 by 14.22% and under Schedule 90 by 17.93% relative to the Company's proposed allocation. By contrast, CUB's approach would reduce Schedule 7 rates by 3.03% and would also reduce Schedule 15 rates by 8.11%.[3/] Again, these figures are based on the Company's as-filed revenue requirement.

[3/] CUB/100 at 36, Table 9.

IV. RESPONSE TO CUB'S ALLOCATION PROPOSAL

Q. WHAT IS YOUR CONCERN WITH CUB'S PROPOSAL?

A. CUB's proposal ignores the fact that the purpose of a class cost of service study is to allocate a utility's cost of service rather than to allocate system benefits. These utility costs should be allocated consistent with sound principles of cost causation. When EE is included in the marginal cost study in the manner proposed by CUB, this causes a distortion of the price signals to customers by arbitrarily shifting the allocation of costs among the rate schedules.

Moreover, CUB does not propose to simply include EE in the marginal cost study. Rather, CUB allocates EE's benefits to different customer classes based on highly dubious assumptions, as explained further below. This raises significant questions about the value of CUB's marginal cost study. The drivers for a utility's incurrence of costs are primarily actual (or projected) customer demands and energy consumption. Therefore, it is appropriate to allocate energy-related generation costs based on actual forecasted test year usage, as proposed by the Company. Once one begins to distort the production energy cost allocation factor through arbitrary adjustments in an effort to capture the value of vaguely defined system benefits, as proposed by the CUB, one quickly deviates from the cost causation principles that define the development of a proper class cost of service study.

Q. WHY HAS CUB PROPOSED TO MODIFY PGE'S GENERATION MARGINAL COST STUDY?

A. CUB argues that EE is "the primary resource added to meet load growth," and therefore, "a model of energy marginal costs that excludes EE would be both inaccurate and misleading."[4] CUB also alleges that residential customers are unfairly subsidizing large customer conservation projects and that, due to an informal funding cap developed after the passage of Senate Bill ("SB") 838, the ETO may not be able to acquire all cost-effective energy efficiency from large customers in PGE's service territory in the near future.[5] CUB represents that its marginal cost proposal will remedy these issues.[6]

Q. GIVEN CUB'S CLAIM THAT A MARGINAL COST STUDY THAT EXCLUDES EE WOULD BE MISLEADING, ARE YOU AWARE OF ANY PRECEDENT IN OREGON OR IN OTHER JURISDICTIONS FOR ADJUSTING PRODUCTION COST ALLOCATORS TO REFLECT EE SYSTEM BENEFITS IN THE MANNER PROPOSED BY CUB?

A. No, I am not aware of any jurisdiction that has attempted to adjust cost allocators in a class cost of service study in an effort to capture system benefits derived from EE programs. In fact, I am not familiar with any jurisdiction that models EE as a marginal resource. Moreover, in response to discovery, neither the Company nor CUB could cite to any precedent supporting CUB's approach. In fact, CUB acknowledged that its proposal does not follow standard practice or precedent.[7]

Q. HAS THE COMPANY EXPRESSED CONCERNS WITH CUB'S PROPOSAL?

A. Yes. In its reply testimony in this proceeding, the Company pointed out that CUB's proposal goes beyond traditional marginal cost analysis. The Company also stated that EE in not a traditional capacity or energy resource.[8]

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[4] CUB/100 at 20:17-21:1.

[5] The rebuttal testimony of Bradley G. Mullins (ICNU/300) provides additional response to these issues.

[6] CUB/100 at 28.

[7] Exhibit ICNU/404 (PGE's Response to ICNU Data Request No. 138 and CUB's Response to ICNU Data Request No. 10a).

[8] PGE/1600 at 26.

Q. DO YOU AGREE WITH THE COMPANY'S TESTIMONY?

A. Yes. Under traditional economic theory, the definition of the marginal cost of generation is based on the cost associated with the next increment of demand or energy use on a utility's system. The increased demand or energy requirements could be met by owned or purchased generation resources. By contrast, EE resources are not used to meet increased demand or energy needs on the system. Rather, EE is designed to reduce demand or energy usage relative to current (or forecasted) levels. While CUB argues that the Company's marginal cost should be the resources the Company projects it will actually use to meet long-term demand in its Integrated Resource Plan ("IRP"),[9/] the marginal cost study is not designed necessarily to reflect a utility's actual resource mix. The study uses a *theoretical* resource mix to capture the costs necessary to make the utility financially whole for meeting the increased increment of demand.

Q. WHAT ARE THE BENEFITS OF SETTING PRICES AT MARGINAL COST?

A. According to theory, pricing services at marginal cost sends accurate price signals to customers that encourage them to conserve energy. The Commission has previously recognized these principles: "Oregon's general rate design approach is to set rates that reflect costs. This approach has the effect of emphasizing the appropriate economic incentives for energy conservation …. Oregon's general rate design approach of basing rate design on marginal cost considerations, rather than embedded cost or historic cost, has the effect of emphasizing the economic incentive for energy conservation."[10/]

9/ CUB/100 at 31:9-32:4.

10/ Docket No. UM 1409, Order No. 09-501 (Dec. 18, 2009); see also, Docket No. UM 827, Order No. 98-374, 1998 Ore. PUC LEXIS 246 at *6-*7 (Sept. 11, 1998) ("Proper calculation of marginal costs provides proper price signals to customers, which, in turn, can lead to more efficient consumption").

Q. HOW DOES INCLUDING EE AS A MARGINAL RESOURCE DIMINISH THESE BENEFITS?

A. Under CUB's analysis, incorporating EE in the marginal cost study is used as a means to shift the allocation of production costs among the rate schedules in a manner that deviates from a cost allocation that is based on customer usage characteristics. Including EE in the marginal cost study in this manner would distort the proper, cost-based price signals for customers. Consequently, it is conceptually flawed to devise a marginal cost study with a "theoretical" resource mix that includes EE resources on an equal par with traditional physical generation resources.

Q. ARE THERE OTHER REASONS WHY EE SHOULD NOT BE CONSIDERED A MARGINAL RESOURCE?

A. Yes. It is problematic to include EE in the marginal cost study as a resource on par with supply-side resources. This is because EE cannot be relied upon to meet long-run load requirements in the same manner as incremental supply side resources. EE measures are subject to a rebound effect, under which a portion of the energy savings associated with the implementation of EE programs is often eroded over time. This erosion occurs because the reduced end-use customer power costs resulting from EE programs stimulate an increase in the customer's energy consumption that partially offsets the initial EE program savings. Thus, one aMW of conservation does not necessarily result in one aMW of reduced load. While there is no consensus on the magnitude of the rebound effect among researchers, few dispute its existence.[11/]

[11/] See, e.g., Sheetal Gavankar & Roland Geyer, The Rebound Effect: State of the Debate and Implications for Energy Efficiency Research, University of California Santa Barbara Bren School of Environmental Science and Management (June 26, 2010) (finding approximate 30% impact); Kenneth Gillingham, et al., The Rebound Effect and Energy Efficiency Policy, Yale University School of Forestry & Environmental Studies (2013) (arguing that the rebound effect is overemphasized, yet still finding a 10%-30% impact on electric efficiency).

Furthermore, in some cases, investments in new technology may also degrade the energy savings associated with EE over time. For example, a customer may attain reduced energy usage due to an EE program but may subsequently invest in facility upgrades that consume greater amounts of electricity in total, thereby eroding some of the savings associated with the initial program implementation at that location. The Environmental Protection Agency has recognized these issues in technical documents released as part of its "111(d)" rulemaking, noting that EE programs "represent a diverse portfolio of programs, that range in measure lives from as little as a few years … to as long as fifteen or twenty years …."[12/]

Note that my testimony should not be interpreted to suggest that pursuing all cost-effective EE is not worthwhile or beneficial. Rather, it is simply to point out that the potential degradation of EE savings over time, as well as the diverse measure lives of various EE technologies raises doubts regarding the validity of using EE as a long-run resource in the marginal cost study, on an equal footing with supply-side resources.

Q. IF ONE WERE TO NEVERTHELESS EXPLICITLY MODEL EE RESOURCES IN THE MARGINAL COST STUDY DESPITE THE CONCERNS RAISED ABOVE, WOULD YOU EXPECT THIS TO INCREASE COSTS FOR SOME RATE SCHEDULES WHILE REDUCING COSTS FOR OTHER RATE SCHEDULES, AS REFLECTED IN THE CUB MODEL?

A. No. If the Commission believes that EE should be explicitly accounted for in the marginal cost study despite the concerns raised in my testimony, it should be noted that inclusion of EE in the cost study would not be expected to result in higher costs for some rate schedules and lower costs for others. If EE is a low-cost resource, as CUB alleges,

12/ Environmental Protection Agency, GHG Abatement Measures, (Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants), Docket ID No. EPA-HQ-OAR-2013-0602 at 5-35 (June 10, 2014), available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.

adding EE to the marginal cost study as an explicit resource should displace some of the more expensive supply-side resources that the Company included in its cost study, resulting in lower total marginal production energy costs at the system level. If these lower production energy costs were appropriately allocated to the rate schedules based on forecasted usage as proposed by the Company, this should result in a lower marginal cost of production for all rate schedules in the marginal cost study.

By contrast, CUB's effort to arbitrarily revise the allocation of energy-related production costs distorts the marginal cost pricing signals that the Company's cost study is intended to provide to customers, which is why it vastly increases costs for some customers while lowering costs for others.

Q. PLEASE EXPAND ON WHY CUB'S METHODOLOGY OF INCLUDING EE IN THE MARGINAL COST STUDY INCREASES COSTS FOR SOME CUSTOMERS WHILE REDUCING COSTS FOR OTHERS.

A. This occurs because CUB does not, strictly speaking, include EE as a resource in the marginal cost of energy, despite its claims otherwise.[13/] This is evident from Table 8 on page 35 of CUB's testimony, reproduced in part in Table 1, below:

TABLE 1
MARGINAL COST OF ENERGY
COMPANY FILING VERSUS CUB PROPOSAL

	Company Filing	CUB Proposal	
Marginal Cost of Energy	$975,598,466	$975,598,466	(a)

(a) See CUB 35:1, Table 8.

Here, it can be seen that CUB's and the Company's total marginal energy costs are identical. Thus, CUB's inclusion of EE in the marginal cost study does not actually

13/ CUB/100 at 31-36.

change the Company's marginal costs; it simply shifts marginal production costs between customer classes based on questionable assumptions about EE funding and acquisition.

Q. WHY ARE CUB'S ASSUMPTIONS QUESTIONABLE?

A. CUB's EE assumptions in its marginal cost study are based on the Company's IRP, which projects that it will meet approximately 20% of long-term load growth through energy efficiency measures.[14] CUB then takes this 20% figure and applies it to the Company's 2015 load projections.[15] This generates an assumption that the Company will achieve 800 aMW of EE in the test year.[16] This can be seen in Table 2, below:

TABLE 2
CUB PROPOSAL TO REALLOCATE MARGINAL COST OF ENERGY IN COMPANY'S INITIAL FILING

	Company		CUB				
	Load (aMW)	MCE* %	Load (aMW)	**EE aMW**	Net Load (aMW)	MCE* %	Load Delta
Schedule 7	1,717	43.0%	1,717	**(431)**	1,285	40.3%	-25%
Schedule 15	3	0.1%	3	**(2)**	2	0.0%	-51%
Schedule 32	352	8.8%	352	**(84)**	268	8.4%	-24%
Schedule 38	10	0.3%	10	**(3)**	7	0.2%	-28%
Schedule 47	4	0.1%	4	**(1)**	3	0.1%	-34%
Schedule 49	16	0.4%	16	**(4)**	12	0.4%	-24%
Schedule 83	624	15.6%	624	**(121)**	503	15.8%	-19%
Schedule 85	688	17.3%	688	**(118)**	571	17.9%	-17%
Schedule 89	239	6.0%	239	**(13)**	227	7.1%	-5%
Schedule 90	315	7.9%	315	**(14)**	301	9.4%	-4%
Schedule 91/95	20	0.5%	20	**(9)**	11	0.3%	-44%
Schedule 92	1	0.0%	1	**(0)**	1	0.0%	-18%
Total	3,990	100%	3,990	**(800)**	3,190	100%	-20%

*"Marginal Cost of Energy"

Moreover, because CUB allocates these aMWs to rate classes based on ETO funding levels, CUB assumes that all of this EE will be achieved through the ETO.

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[14] CUB/100 at 32.
[15] CUB/103.
[16] CUB/100 at 34, Table 7.

Q. WHAT IS WRONG WITH CUB'S METHODOLOGY?

A. The fallacy in CUB's methodology is readily apparent from the fact that the 800 aMWs assumed in the study exceeds the total EE the ETO acquired in PGE's service territory in 2013 by a factor of almost 23.[17/] In fact, it far exceeds the total EE the ETO has acquired since its inception, as represented in CUB's testimony.[18/] Furthermore, CUB's methodology assumes that all EE acquired in PGE's service territory is funded entirely by ETO dollars. This is demonstrably wrong. As I discussed earlier in my testimony, large industrial customers operate in competitive global markets and therefore have every incentive to implement EE initiatives using their own funds in an effort to reduce their operating costs. Furthermore, even when industrial customers receive ETO incentive funding, such funding covers, at most, 50% of the costs of the project.[19/] The remaining costs are borne by the customer. These self-implemented EE efforts are ignored under CUB's proposal.

Thus, the amount of EE CUB includes in its marginal cost study is both over-inclusive and under-inclusive. It is over-inclusive because it vastly overstates the amount of EE the ETO is likely to acquire in 2015, and it is under-inclusive because it does not account for EE measures that are customer-funded.

Q. WHY DOES THIS MATTER?

A. Because CUB's methodology results in an arbitrary shifting of production resource costs between customer classes, which distorts the marginal cost study. As discussed above,

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17/ ETO 2013 Annual Report at 25. The ETO reports that it achieved 35.62 aMWs of EE in 2013.

18/ CUB/100 at 23, Figure 1 (assuming 327.9 aMWs in total EE acquired by the ETO, less than half the amount assumed in CUB's marginal cost model).

19/ http://energytrust.org/industrial-and-ag/industry/; the Rebuttal Testimony of Bradley G. Mullins provides specific examples of the resources industrial customers provide on their own to implement conservation measures.

rates that are based on consistently applied cost-causation principles are not only fair and reasonable, but further the cause of stability, conservation and efficiency. When consumers are presented with price signals that convey the consequences of their consumption decisions (i.e., how much energy to consume, at what rate, and when) they tend to take actions which not only minimize their own costs, but those of the utility as well, thereby benefitting all customers. If the production cost allocation factors by rate schedule are arbitrarily and artificially increased or reduced in the marginal cost study, as CUB's methodology does, then prices these customers pay do not accurately reflect the costs of increased consumption.

CUB's approach comes close to one the Commission has previously rejected in the context of capacity and energy resources, and which CUB itself argued against. In addressing the cost allocation methodology to apply to PGE's automated demand response pilot program, the Commission adopted CUB's (as well as PGE's and Staff's) recommendation and rejected ICNU's proposal to apply the costs of this pilot program as a capacity charge.[20/] The Commission found that "we cannot look at an allocation scheme for a given resource in isolation. If we adopted ICNU's proposed methodology without altering the cost allocation scheme for all other resources, it would result in a less fair allocation of costs in the aggregate."[21/] CUB's proposal in this case demonstrates the Commission's point.

Q. DOES THE COMPANY'S MARGINAL COST OF SERVICE STUDY ALREADY CAPTURE THE EFFECTS OF EE?

A. Yes. As CUB recognizes, under PGE's cost study, "the Company models Schedule loads from actual usage, indirectly internalizing EE applied to each rate schedule. This means

20/ Docket No. UE 234, Order No. 11-517 (Dec. 21, 2011).

21/ Id. at 5.

that each customer class is affected by the energy efficiency programs that reduce the load from its class."[22] The Company's allocation of energy-related generation costs in its cost study is based on projected electricity consumption by rate schedule for the test year, using actual historical data as a starting point for the projections. These consumption projections internalize the impact of EE funded by each rate schedule through reductions in the test year energy usage used to develop the allocation factors for each schedule. The benefit of this approach is that it accurately reflects the impact of EE in the marginal cost study, unlike CUB's methodology. Load reductions that are actually achieved through EE measures are included in the model. This maintains the necessary relationship between pricing signals and cost-causation.

Q. WHAT ARE THE LIKELY CONSEQUENCES TO THE COMPANY'S SYSTEM FROM CUB'S PROPOSAL?

A. As the Company pointed out in its reply testimony, CUB's proposal could incent large industrial customers to opt for long-term direct access.[23] Because direct access customers do not pay the Company's energy charge, large customers currently on PGE's system could choose direct access as a means of avoiding the large, uneconomic production cost increases that would result from the proposal. If this were to transpire, PGE could be left with a significantly smaller customer base purchasing regulated generation service across which it could spread its production costs, to the detriment of all customers on the Company's system. Although transition charges would offset this difference for a period of time, under the Company's long-term opt-out program, transition charges cease after five years.

[22] CUB/100 at 33:6-9.
[23] PGE/1600 at 26-27.

Q. BASED ON THE FOREGOING CONSIDERATIONS, WHAT DO YOU CONCLUDE WITH RESPECT TO CUB'S PROPOSAL?

A. CUB's proposal represents an unwarranted and unprecedented deviation from generally accepted class cost allocation principles. By departing from such principles, CUB's proposal would result in rates that deviate dramatically from the Company's actual cost to serve the customer classes on its system, as determined by actual customer usage characteristics. Moreover, CUB's proposal would distort the marginal cost of service study results to achieve the goal of arbitrarily and dramatically shifting the allocation of the Company's production costs towards large industrial customers. For these reasons, the Commission should reject CUB's proposal.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
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Request for a General Rate Revision.	)
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EXHIBIT ICNU/401

QUALIFICATIONS OF ALI AL-JABIR

August 13, 2014

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Ali Al-Jabir. My business address is 5151 Flynn Parkway, Suite 412 C/D, Corpus Christi, Texas, 78411.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI").

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I am a graduate of the University of Texas at Austin ("UT-Austin"). I hold the degrees of Bachelor of Arts and Master of Arts in Economics, both from UT-Austin. I have also completed course work at Harvard University. I received my B.A. degree with highest honors, and I am a member of the Phi Beta Kappa Honor Society.

Q. PLEASE STATE YOUR EXPERIENCE.

A. I joined BAI in January 1997. My work consists of preparing economic studies and economic policy analysis related to investor-owned, cooperative, and municipal utilities. Prior to joining BAI, I was employed at the Public Utility Commission of Texas ("Texas Commission") since 1991, where I held various positions including Policy Advisor to the Chairman. As Policy Advisor, I advised the Chairman on policy decisions in numerous rate and rulemaking proceedings. In 1995, I advised the Texas Legislature on the development of the statutory framework for wholesale competition in the Electric Reliability Council of Texas ("ERCOT"), and I was involved in subsequent rulemakings at the Texas Commission to implement wholesale open access transmission service in the region.

During my tenure at the Texas Commission and in my present capacity, I have reviewed and analyzed several electric utility base rate and fuel filings in Texas. I have also worked on utility rate, fuel, and merger proceedings and rulemakings in Louisiana, Virginia, Missouri, Colorado, Indiana, Pennsylvania, North Carolina, South Carolina, Michigan, Rhode Island, Alberta and Nova Scotia. In addition to my work on such proceedings, I have drafted policy papers and comments regarding electric industry restructuring and competitive policy issues in Texas, Alabama, Louisiana, Georgia, and Delaware, as well as before the Federal Energy Regulatory Commission. I have been an invited speaker at several electric utility industry conferences, and I have presented seminars on utility regulation and industry restructuring.

BAI and its predecessor firms have been active in utility rate and economic consulting since 1937. The firm provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers, some competitive retail power providers and utilities and, on occasion, state regulatory agencies. In addition, we have prepared depreciation and feasibility studies relating to utility service. We assist in the negotiation of contracts and the solicitation and procurement of competitive energy supplies for large energy users, provide economic policy analysis on industry restructuring issues, and present seminars on utility regulation. In general, we are engaged in regulatory consulting, economic analysis, energy procurement, and contract negotiation.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas and Phoenix, Arizona.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN CONTESTED UTILITY PROCEEDINGS?

A. Yes, I have filed written testimony in the following dockets:

1. Texas Docket No. 10035 – Application of West Texas Utilities Company to Reconcile Fuel Costs and for Authority to Change Fixed Fuel Factors;

2. Texas Docket No. 10200 – Application of the Texas - New Mexico Power Company for Authority to Change Rates;

3. Texas Docket No. 10325 – Application of the Central Texas Electric Cooperative, Inc. for Authority to Change Rates;

4. Texas Docket No. 10600 – Application of the Brazos River Authority for Approval of Rates;

5. Texas Docket No. 10881 – Application of the New Era Electric Cooperative, Inc. for Authority to Change Rates;

6. Texas Docket No. 11244 – Petition of the Medina Electric Cooperative, Inc. to Reduce its Fixed Fuel Factor and the Application of the South Texas Electric Cooperative, Inc. for Authority to Refund an Over-Recovery of Fuel Cost Revenues and to Reduce its Fixed Fuel Factor;

7. Texas Docket No. 11271 – Application of Bowie-Cass Electric Cooperative, Inc. for Authority to Change Rates;

8. Texas Docket No. 11567 – Application of Kaufman County Electric Cooperative, Inc. for Authority to Change Rates;

9. Texas Docket No. 18607 – Application of West Texas Utilities Company for Authority to Reconcile Fuel Costs;

10. Texas Docket No. 20290 – Application of Central Power & Light Company for Authority to Reconcile Fuel Costs;

11. Virginia Case No. PUE980814 – In the matter of considering an electricity retail access pilot program: American Electric Power – Virginia;

12. Texas Docket No. 21111 – Application of Entergy Gulf States Inc. for Authority to Reconcile Fuel Costs and to Recover a Surcharge for Under-Recovered Fuel Costs;

13. Virginia Case No. PUE990717 – Application of Virginia Electric and Power Company to Revise Its Fuel Factor Pursuant to Virginia Code Section 56-249.6;

14. Texas Docket No. 22344 – Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule § 25.344;

15. Texas Docket No. 22350 – Application of TXU Electric Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Phase III);

16. Texas Docket No. 22352 – Application of Central Power and Light Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

17. Texas Docket No. 22353 – Application of Southwestern Electric Power Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

18. Texas Docket No. 22354 – Application of West Texas Utilities Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

19. Texas Docket No. 22356 – Application of Entergy Gulf States, Inc. for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344;

20. Texas Docket No. 22349 – Application of Texas-New Mexico Power Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

21. Virginia Case No. PUE000584 – Application of Virginia Electric and Power Company for Approval of a Functional Separation Plan under the Virginia Electric Utility Restructuring Act;

22. Texas Docket No. 24468 – Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southwest Power Pool;

23. Texas Docket No. 24469 – Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southeastern Electric Reliability Council;

24. Virginia Case No. PUE-2002-00377 – Application of Virginia Electric and Power Company to Revise Its Fuel Factor Pursuant to Section 56-249.6 of the Code of Virginia;

25. Texas Docket No. 27035 – Application of Central Power and Light Company for Authority to Reconcile Fuel Costs;

26. Texas Docket No. 28818 – Application of Entergy Gulf States, Inc. for Certification of an Independent Organization for the Entergy Settlement Area in Texas;

27. Virginia Case No. PUE-2000-00550 -- Appalachian Power Company d/b/a American Electric Power: Regional Transmission Entities;

28. Texas Docket No. 29408 – Application of Entergy Gulf States, Inc. for the Authority to Reconcile Fuel Costs;

29. Texas Docket No. 29801 – Application of Southwestern Public Service Company for: (1) Reconciliation of its Fuel Costs for 2002 and 2003; (2) A Finding of Special Circumstances; and (3) Related Relief;

30. Texas Docket No. 30143 -- Petition of El Paso Electric Company to Reconcile Fuel Costs;

31. Texas Docket No. 31540 – Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to PUC Substantive Rule 25.501;

32. Texas Docket No. 32795 – Staff's Petition to Initiate a Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA Section 39.253(f);

33. Texas Docket No. 33309 – Application of AEP Texas Central Company for Authority to Change Rates;

34. Texas Docket No. 33310 – Application of AEP Texas North Company for Authority to Change Rates;

35. Michigan Case No. U-15245 – In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Rate Relief;

36. Texas Docket No. 34800 **–** Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs;

37. Texas Docket No. 35717 – Application of Oncor Electric Delivery Company LLC for Authority to Change Rates;

38. RIPUC Docket No. 4065 – Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric Base Distribution Rates Pursuant to R.I.G.L. Sections 39-3-10 and 39-3-11; and

39. RIPUC Docket No. 4323 – Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric and Gas Base Distribution Rates Pursuant to R.I.G.L. Sections 39-3-10 and 39-1-3-11.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
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Request for a General Rate Revision.	)
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EXHIBIT ICNU/402

CHANGE IN COST ALLOCATION BASED ON PGE AND CUB GENERATION ENERGY ALLOCATION FACTORS

August 13, 2014

Change in Cost Allocation Based on
PGE and CUB Generation Energy Allocation Factors
(000)

Line	Schedule	PGE Generation Energy Allocation Factor (1)	CUB Generation Energy Allocation Factor (2)	CUB Power Supply Costs (3)	PGE Power Supply Costs (4)	Difference (5) = (3) - (4)	Percent Difference (6) = (5) / (4)
1	7	43.03%	40.30%	$393,157	$419,841	($26,683)	-6.4%
2	15	0.08%	0.05%	$484	$788	($304)	-38.6%
3	32	8.83%	8.40%	$81,920	$86,120	($4,200)	-4.9%
4	38	0.25%	0.23%	$2,247	$2,487	($240)	-9.6%
5	47	0.11%	0.09%	$863	$1,042	($179)	-17.2%
6	49	0.40%	0.38%	$3,706	$3,897	($191)	-4.9%
7	83	15.64%	15.76%	$153,751	$152,588	$1,164	0.8%
8	85	17.26%	17.89%	$174,492	$168,356	$6,137	3.6%
9	89	5.99%	7.10%	$69,277	$58,483	$10,794	18.5%
10	90	7.90%	9.44%	$92,137	$77,033	$15,104	19.6%
11	91&95	0.49%	0.35%	$3,382	$4,788	($1,406)	-29.4%
12	92	0.02%	0.02%	$181	$177	$4	2.2%
13	Total	100.00%	100.00%	$975,598	$975,598	($0)	0.0%

Data Source:

CUB Exhibit 103

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
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Request for a General Rate Revision.	)
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EXHIBIT ICNU/403

IMPACT OF CUB'S ALLOCATION PROPOSAL

August 13, 2014

ICNU/403
Al-Jabir/1

Impact of CUB's Allocation Proposal
(000)

Line	Schedule	PGE Power Supply (1)	CUB Power Supply (2)	CUB Cost Allocation (3)	PGE Allocation (4)	Difference (5) = (3) - (4)	Schedule Change from PGE 2015 (6) = (5) / (4)
1	7	$ 419,841	$ 393,157	$ 853,269	$ 879,952	$ (26,683)	-3.03%
2	15	$ 788	$ 484	$ 3,447	$ 3,751	$ (304)	-8.11%
3	32	$ 86,120	$ 81,920	$ 163,985	$ 168,185	$ (4,200)	-2.50%
4	38	$ 2,487	$ 2,247	$ 5,475	$ 5,715	$ (240)	-4.20%
5	47	$ 1,042	$ 863	$ 4,867	$ 5,046	$ (179)	-3.54%
6	49	$ 3,897	$ 3,706	$ 15,644	$ 15,835	$ (191)	-1.21%
7	83	$ 152,588	$ 153,751	$ 237,086	$ 235,923	$ 1,163	0.49%
8	85	$ 168,356	$ 174,492	$ 244,969	$ 238,833	$ 6,136	2.57%
9	89	$ 58,483	$ 69,277	$ 86,700	$ 75,906	$ 10,794	14.22%
10	90	$ 77,033	$ 92,137	$ 99,351	$ 84,247	$ 15,104	17.93%
11	91&95	$ 4,788	$ 3,382	$ 15,855	$ 17,260	$ (1,405)	-8.14%
12	92	$ 177	$ 181	$ 251	$ 247	$ 4	1.68%
13	Total	$ 975,598	$ 975,598	$ 1,730,900	$ 1,730,900	$ (0)	0.00%

Data Source:

CUB Exhibit 103

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT ICNU/404

PGE's Response to ICNU Data Request No. 138 and CUB's Response to ICNU Data Request No. 10a

August 13, 2014

July 23, 2014

TO: Bradley Van Cleve
Michael P. Gorman
Bradley Mullins

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 138
Dated July 9, 2014

Request:

Is the Company aware of any case precedent in Oregon or in any other jurisdiction for allocating energy efficiency costs to the customer classes by giving customer classes credit for the energy efficiency costs funded by each class, in the manner proposed by CUB in Section IV of its opening testimony in this proceeding? If the answer is yes, please provide complete citations to any case precedent on this issue.

Response:

No.

CUB's Response to ICNU Data Request 10a is excerpted below:

Data Request 010: At page 33, lines 3-5, of its opening testimony, CUB states that "CUB first gives each schedule credit for the EE it individually funded and subtracts it from the total scheduled load (gross of EE)." With regard to this statement:

> **Data Request 010a:** Is CUB aware of any case precedent in Oregon or in any other jurisdiction for allocating energy efficiency costs to the customer classes by giving customer classes credit for the energy efficiency costs funded by each class, in the manner proposed by CUB in this proceeding? If the answer is yes, please provide complete citations to any case precedent on this issue;
>
> **Data Response 010a:** No, CUB is not aware of any other jurisdiction having to deal with the unique situation in front of the Commission, the ETO and PGE's customers (refer to CUB's response to ICNU DR 003 above). CUB does not propose to be following standard practice or precedence to resolve this unique issue. Instead, CUB takes full responsibility and credit for its MC approach.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT NO. ICNU/404

EXCERPT OF ICNU REBUTTAL TESTIMONY AND EXHIBITS

(ICNU/300 – ICNU/306) IN DOCKET NO. UE 283

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Request for a General Rate Revision	)
____	)

REBUTTAL TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

August 13, 2014

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Exhibit ICNU/304—Energy Trust of Oregon, "Funding Limitations for Large Energy Users" (April 16, 2014)

Exhibit ICNU/305—Pinnacle Economics, Economic Impacts from Energy Trust of Oregon 2013 Program Activities, Final Report (May 5, 2014)

Exhibit ICNU/306—State & Local Energy Efficiency Action Network. (2014). Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector. Prepared by A. Goldberg, R.P. Taylor, and B. Hedman, Institute for Industrial Productivity (excerpt)

Exhibit ICNU/307—Corrected Calculation of Production Tax Credits Carry-forwards

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. ARE YOU THE SAME BRADLEY G. MULLINS THAT PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I originally filed testimony on behalf of the Industrial Customers of Northwest Utilities ("ICNU") addressing several revenue requirement and policy issues in the initial filing of Portland General Electric Company ("PGE" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. Parties in this proceeding have reached a settlement in principle on all issues with the exception of four: 1) the energy efficiency proposal made by the Citizens' Utility Board ("CUB"); 2) my proposal to recalculate the level of production tax credit ("PTC") carry-forwards included in rate base; 3) the Company's proposed Renewable Portfolio Standards ("RPS") carve-out mechanism; and, 4) the Company's return on equity ("ROE"). My testimony will address the first three of these remaining issues.

Q. ARE ANY OTHER WITNESSES PROVIDING REBUTTAL TESTIMONY ON BEHALF OF ICNU IN THIS PROCEEDING?

A. Yes. ICNU witness Mr. Ali Al-Jabir will also address, and present additional information regarding, CUB's energy efficiency proposal in the context of marginal cost pricing. ICNU witness Mr. Michael P. Gorman will address the Company's ROE.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony is summarized and organized as follows:

1. **CUB Energy Efficiency Proposal**. The Commission should reject the proposal made by CUB regarding energy efficiency. The proposal is a violation of energy efficiency funding limitations mandated by Oregon law and is not reasonable in light of the substantial investments being made by industrial customers in energy efficiency in this state.

2. **Direct Benefit Cap**. I recommend that the limitation CUB identified on Senate Bill ("SB") 1149 incentive funding for large customers be lifted, while still retaining the requirement that large customers receive no incentive funding out of SB 838 funds.

3. **Production Tax Credit Carry-Forwards**. I continue to recommend that the level of PTC carry-forwards included in rate base should be calculated based on the level of taxes that ratepayers pay, not the level of tax that the Company pays, which is often materially less than the amounts included in rates. Additionally, errors in the Company's calculation of the PTC carry-forward balance should be corrected if the Commission does not adopts my proposal.

4. **Renewable Portfolio Standards Carve-Out**. I continue to recommend that the Company's proposed RPS carve-out mechanism be rejected. Not only would this proposal require the Commission to set-aside the policies established in Docket No. UE 165, it is based on unsound technical principles, which the Company did not adequately address in its rebuttal filing.

II. CUB ENERGY EFFICIENCY PROPOSAL

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RESPONSE TO CUB'S ENERGY EFFICIENCY PROPOSAL.

A. While CUB has framed its proposal as a technical matter of incorporating energy efficiency into the Company's marginal cost of energy,[1/] the substance of what it has proposed is to reallocate costs to industrial customer classes. On its face, the proposal—which, as the Company recognized in its reply testimony, would result in double-digit

[1/] CUB/100 at 20:4-43:4.

rate increases for industrial customers[2/]—is unreasonable. Not only does it violate energy efficiency funding limitations established by Oregon law, this proposal would work contrary to the Commission's long-standing policy to encourage conservation, at a time when the need for support from industrial customers to perform energy efficiency is increasing.

Q. WHAT WAS CUB TRYING TO ACCOMPLISH WITH ITS ENERGY EFFICIENCY PROPOSAL?

A. The energy efficiency proposal made by CUB was premised on solving three general problems. The first is that the Company's marginal cost of energy is misstated because energy efficiency, "as the go-to energy resource," is not included.[3/] The second is that the Energy Trust of Oregon ("ETO") is in danger of not being able to acquire all cost-effective energy efficiency from the Company's largest customers in the coming years. The third is that residential customers have been paying a disproportionate amount for energy efficiency.

Q. HOW DID CUB PROPOSE TO SOLVE THESE PROBLEMS?

A. CUB proposed a new cost of service methodology, ultimately reflected in the marginal cost of energy, that would reallocate costs to industrial rate classes. The proposal would increase the amount of costs allocated to Schedules 89 and 90 by 14.22% ($10.8 million) and 17.93% ($15.1 million), respectively—a material shift in costs between rate classes.[4/]

2/ PGE/1600 at 26:22-27:1.

3/ CUB/100 at 20:19.

4/ Id. at 36:1, Table 9.

Q. DOES THE CUB PROPOSAL SOLVE ANY OF THESE PROBLEMS?

A. No. As Mr. Al-Jabir points out, despite its detailed discussion explaining why energy efficiency should be accounted for as a marginal energy resource, CUB does not, in fact, include energy efficiency as a resource in the marginal cost of energy. Additionally, the CUB proposal has no impact on the ability of the ETO to acquire additional energy efficiency, nor does it properly account for the substantial investments that industrial customers are making with their own funds to perform conservation.

Q. WILL THE CUB PROPOSAL ENABLE THE ETO TO ACQUIRE ADDITIONAL COST-EFFECTIVE CONSERVATION FROM LARGE INDUSTRIAL CUSTOMERS?

A. No. The statutory limitations placed on the amount of incentives that the ETO can provide to customers with loads in excess of one average megawatt ("aMW") cannot be bypassed as a result of a new cost of service methodology. Only action by the Oregon Legislature can have the effect of changing the law limiting the incentive funding provided to those customers. Therefore, the CUB proposal will have no impact on its stated objective. On the contrary, it is my view that the CUB proposal, if adopted, will send a message to large industrial customers that their efforts to pursue conservation are now being penalized, discouraging those customers, whose participation in energy efficiency is vital to the long-term policy objectives of this state,[5/] from performing energy efficiency in the future.

5/ This is particularly true as a result of the Environmental Protection Agency's proposed 111(d) regulations (42 U.S.C. § 7411), which will require Oregon to meet a large portion of its carbon reduction targets from energy efficiency measures.

Q. HOW DOES OREGON LAW LIMIT WHAT THE COMPANY IS PERMITTED TO COLLECT FROM CUSTOMERS TO FUND ENERGY EFFICIENCY?

A. The Company collects money from customers in rates to fund energy efficiency pursuant to SB 1149 and SB 838. SB 1149, the 1999 Oregon law that gave rise to the ETO, established a 3 percent public purpose charge that applies to the unbundled rate elements of all rate schedules, including costs paid by a direct access customer to an energy service supplier.[6/] Of the total public purpose charge, 63% is earmarked for "new cost-effective conservation …."[7/] SB 838, passed by the Oregon Legislature in 2007, allowed electric companies to collect additional amounts in rates to fund energy conservation measures, but prohibited the Company from collecting these additional amounts from customers with loads over one aMW.[8/] The customers with loads over one aMW, however, were also prohibited from receiving any "direct benefit" from the funds collected pursuant to SB 838.[9/]

Q. WOULD THE CUB PROPOSAL LIKELY VIOLATE THE FUNDING LIMITATIONS ESTABLISHED BY SB 838 AND SB 1149?

A. Yes. My understanding is that SB 838 not only limits the direct benefit to large customers from SB 838 funds, it also prohibits them from paying in rates an amount above the three percent SB 1149 public purpose charge to fund energy efficiency. Thus, the substance of the CUB proposal, in requiring industrial customers to pay additional amounts for energy efficiency, violates these funding limitations.

6/ ORS § 757.612.
7/ Id. § 757.612(3)(b)(A).
8/ ORS § 757.689.
9/ Id. § 757.689(2)(b).

Table 1, below, outlines the maximum amount of energy efficiency funding that the Company is authorized to collect by rate class pursuant to limits established in SB 1149 and SB 838. Note that the funds collected from large industrial customers on Schedules 89 and 90 are limited to the 3 percent public purpose charge established under SB 1149.[10/]

TABLE 1
MAXIMUM ENERGY EFFICIENCY FUNDING PERMITTED UNDER SB 1149 AND SB 838 IN THE TEST PERIOD
($000)

	(a) = Note 1	(b) = (a) * 3%	(c) = Note 2	(d) = (b) + (c)	(e) = (d) / (a)
	Rev. Req.	SB 1149	SB 838	Total	% of Rev. Req.
Schedule 7	$ 879,952	$ 26,399	$ 27,612	$ 54,011	6.1%
Schedule 15	3,751	113	96	208	5.6%
Schedule 32	168,185	5,046	5,323	10,368	6.2%
Schedule 38	5,715	171	173	345	6.0%
Schedule 47	5,046	151	82	233	4.6%
Schedule 49	15,835	475	219	694	4.4%
Schedule 83	235,923	7,078	7,609	14,687	6.2%
Schedule 85	238,833	7,165	7,249	14,414	6.0%
Schedule 89	75,906	2,277	-	2,277	3.0%
Schedule 90	84,247	2,527	-	2,527	3.0%
Schedule 91/95	17,260	518	527	1,045	6.1%
Schedule 92	247	7	9	16	6.4%

Note 1: Initial Filing
Note 2: Company's response to CUB Data Request 37A

Q WHAT AMOUNT WOULD BE COLLECTED FROM EACH CUSTOMER CLASS TO FUND ENERGY EFFICIENCY IF THE CUB PROPOSAL IS ADOPTED?

A. Table 2, below, details the total amount each customer class would pay in rates for energy efficiency if the CUB proposal is adopted. The table demonstrates that the funds

[10/] This table does not account for customers who self-direct conservation projects. In addition, the energy efficiency funds collected from certain customers on Schedule 85 with loads in excess of one aMW is also limited to the 3 percent public purpose charge.

collected from customers on Schedules 89 and 90 with loads in excess of one aMW would exceed the 3 percent limit established under SB 1149. In addition, several other customer classes will pay amounts less than the public purpose charge—with some rate classes, such as street lighting Schedules 91 and 95, effectively receiving a rebate for energy efficiency.

TABLE 2
ENERGY EFFICIENCY FUNDING UNDER
CUB PROPOSAL IN THE TEST PERIOD
($000)

	(a) = Note 1	(b) = (a) * 3%	(c) = Note 2	(d) = Note 3	(e) = (b) + (c) + (d)	(f) = (e) / (a)
	Rev. Req.	SB 1149	SB 838 (c)	**CUB Allocation**	Total w/ CUB Alloc.	% of Rev. Req.
Schedule 7	$ 879,952	$ 26,399	$ 27,612	**$ (26,683)**	$ 27,328	3.1%
Schedule 15	3,751	113	96	**(304)**	(96)	-2.6%
Schedule 32	168,185	5,046	5,323	**(4,200)**	6,168	3.7%
Schedule 38	5,715	171	173	**(240)**	105	1.8%
Schedule 47	5,046	151	82	**(179)**	54	1.1%
Schedule 49	15,835	475	219	**(191)**	503	3.2%
Schedule 83	235,923	7,078	7,609	**1,163**	15,850	6.7%
Schedule 85	238,833	7,165	7,249	**6,136**	20,551	8.6%
Schedule 89	75,906	2,277	-	**10,794**	13,071	17.2%
Schedule 90	84,247	2,527	-	**15,104**	17,631	20.9%
Schedule 91/95	17,260	518	527	**(1,405)**	(360)	-2.1%
Schedule 92	247	7	9	**4**	20	8.1%

Note 1: Initial Filing
Note 2: Company's response to CUB Data Request 37A
Note 3: CUB/100 at 36:1, Table 9 (column 4 minus column 5)

A comparison of Table 1 and Table 2 demonstrates the absurdity of CUB's proposal. Rates for Schedule 89 and 90 customers would be nearly nine percent (or more) higher than the next highest rate schedule to compensate for the fact that these customers pay, at most, 3.4 percent less to the ETO than other rate schedules.

Moreover, as Table 2 shows, while the form of the CUB proposal is framed within the context of cost of service, the economic substance of the proposal is to change the amount that each rate class pays to fund energy efficiency. The concept behind the CUB proposal is to reallocate costs between rate classes based on the level of ETO funding that each rate class contributes. Because the cost shifts resulting from CUB's proposal are directly attributable to energy efficiency acquired, as calculated by CUB, these increases are amounts "included in rates" to fund energy efficiency, in violation of the limits established in SB 1149 and SB 838.

Q. IS CUB'S PROPOSAL JUSTIFIED BASED ON FAIRNESS ARGUMENTS?

A. No. Even if it did not violate Oregon law, the fairness arguments made by CUB do not justify its proposal. CUB alleges that "residential customers buy half of all efficiency: without reflection of this fact in the marginal cost of service study, residential customers are effectively buying system resources."[11/] Accordingly, CUB proposed to "give[] credit where credit is due"[12/] by adjusting the loads used to allocate the marginal cost of energy, allegedly to give residential and small commercial customers credit for the energy efficiency they are funding.

Q. WHAT IS THE FUNDAMENTAL PROBLEM WITH CUB'S FAIRNESS ARGUMENTS?

A. CUB's marginal cost model does not equitably reallocate costs based on a realistic level of energy efficiency funding. As discussed in Mr. Al-Jabir's testimony, CUB's model assumes an amount of energy efficiency in the test year—800 aMWs—that is many times greater than what the ETO is likely to acquire. The ETO's most recent draft strategic

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11/ CUB/100 at 28:11-13.
12/ Id. at 34:3.

plan sets a goal of acquiring 240 aMWs between 2015 and 2019, in total.[13/] This is less than one-third of the amount CUB's model assumes will be acquired in 2015 alone. And the ETO admits its goal is "ambitious."[14/] Thus, even if CUB's equity arguments were valid and its method for reflecting energy efficiency in the marginal cost study was an appropriate way of addressing those arguments, CUB's model assumes an unreasonable amount of conservation, resulting in an unfair shift in costs to industrial customers.

Q. NOTWITHSTANDING, DO YOU AGREE WITH CUB THAT RESIDENTIAL CUSTOMERS ARE PAYING AN UNFAIR SHARE OF ENERGY EFFICIENCY?

A. No. The CUB proposal only reflects energy efficiency funding submitted directly to the ETO and ignores the fact that industrial customers are paying substantial amounts of their own money in order to perform conservation measures. For industrial customers, the incentives received from the ETO often represent only a fraction of the actual capital required to complete a large industrial energy efficiency project. The incentives provided by the ETO for large capital projects, for example, are based on annual energy savings, at a rate of $0.25 per kilowatt-hour saved, up to 50 percent of eligible project cost.[15/]

Q. CAN YOU PROVIDE SOME EXAMPLES OF THE INDEPENDENT INVESTMENTS THAT INDUSTRIAL CUSTOMERS ARE MAKING TO FUND ENERGY EFFICIENCY?

A. Yes. Pacific Natural Foods, a Tualatin-based producer of natural and organic food products, recently completed a number of projects in order to produce 1,757,132

13/ Energy Trust of Oregon, Draft 2015-2019 Strategic Plan at 5 (July 25, 2014), available at: http://energytrust.org/library/forms/Draft_Strategic_Plan_July-25-2014_for_public_comment.pdf.

14/ Id.

15/ Available at http://energytrust.org/industrial-and-ag/industry/

kilowatt-hour savings annually.[16/] These energy efficiency projects cost a total of $520,909, of which Pacific Natural Foods contributed $347,081 and the ETO contributed $173,891 in incentives.[17/]

Another example, Maxim Integrated Products, a Beaverton-based integrated circuit manufacturer, recently invested $75 million in order to upgrade its fabrication facility and improve its overall efficiency.[18/] As a part of this project, Maxim Integrated Products installed a highly-efficient "fan-wall" composed of six small fans with variable frequency drives, producing 3,725,224 in kilowatt-hour savings annually.[19/] This fan-wall, alone, cost approximately $1.5 million, of which Maxim Integrated Products contributed approximately $1.0 million of its own capital and the ETO contributed $533,760 in incentives.[20/]

These are just two examples done in conjunction with the ETO. Not only are there many more examples, many efficiency measures performed by industrial customers are self-funded, with customers receiving no incentives from the ETO at all.

16/ See Pacific Natural Foods Cooks up a Recipe for Savings, Energy Trust of Oregon at 1. A copy of this report can be found online at http://energytrust.org/library/case-studies/PacificFoods_CS_PE_1201.pdf.

17/ Id.

18/ See Area Development Online News Desk (June 29, 2012), available at http://areadevelopment.com/newsItems/6-29-2012/maxim-beaverton-oregon-fabrication-facility-expansion-251816556.shtml; see also Chip Fabricator Crystallizes Commitment to Energy Efficiency, Energy Trust of Oregon at 1, available at http://energytrust.org/library/case-studies/PE_MaximIntegrated_CS.pdf.

19/ Chip Fabricator Crystallizes Commitment to Energy Efficiency, Energy Trust of Oregon at 1, available at http://energytrust.org/library/case-studies/PE_MaximIntegrated_CS.pdf.

20/ Id.; Green Smart, Sustainable Building in the Northwest at 30 (Feb-Mar 2010) (estimating an ETO contribution of only about 30 percent of installation costs), available at http://www.oregonairreps.com/downloads/files/GreenSmart_March_2010.pdf.

Q. IF THESE CUSTOMER FUNDS WERE REFLECTED IN CUB'S MODEL, WOULD IT GENERATE THE SAME DEGREE OF COST SHIFTING?

A. No. If these customer funds were reflected in the CUB analysis, the results would likely be different.

Q. ARE THERE OTHER BENEFITS RESULTING FROM INDUSTRIAL CONSERVATION THAT CUB DID NOT ADDRESS?

A. Yes. CUB's equity arguments are limited in scope. Industrial projects reduce costs to the system. Thus, as the ETO reports, "Although a larger proportion of funding goes to large energy users than the portion of 1149 revenues contributed by that group, the cost of savings acquired is much lower than other projects and therefore the savings per ratepayer dollar invested are much higher. *All ratepayers are benefiting from the higher savings*."[21]

Further, there are benefits of large customer conservation projects that go beyond mere energy savings and are not present to the same degree with residential conservation. These projects improve product quality, lower emissions, enhance productivity, and improve worker health and safety.[22/] By reducing costs, large customer projects make Oregon's most significant employers more competitive in a global marketplace.[23/] They also allow businesses to retain and hire more workers. A report for the ETO prepared by Pinnacle Economics estimates that the net economic benefits from ETO programs in 2013 included $175.1 million in increased economic output, $60.4 million in increased

21/ ICNU/301 at 22 (emphasis added).

22/ ICNU/306 at 26-28, 46-47, 74-75 (State & Local Energy Efficiency Action Network. (Mar. 2014). Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector at 6-8, 26-27, 54-55. Prepared by A. Goldberg, R.P. Taylor, and B. Hedman, Institute for Industrial Productivity (excerpt). The full report is available at: http://energy.gov/sites/prod/files/2014/03/f13/industrial_energy_efficiency.pdf.

23/ Id. at 26-27.

wages, and 1,091 new jobs.[24/] These benefits impact the economy as a whole, and thus provide significant indirect benefits to residential customers.

Q. WHAT IS THE LIKELY IMPACT ON LARGE PROJECTS IF THE CUB PROPOSAL IS ADOPTED?

A. The theory behind CUB's approach is that the rate class performing an energy efficiency project should not receive the benefits of its project.[25/] Rather, the benefits should be reallocated based on the amount of funds that each rate class contributes to the ETO (disregarding the substantial investments being made by industrial customers to achieve these benefits).[26/] Accordingly, CUB's proposal is likely to disincentivize industrial customers, knowing that the benefits of their projects are being reallocated to another rate class, from investing in new conservation.

Q. PLEASE SUMMARIZE WHY THE COMMISSION SHOULD REJECT THE CUB ENERGY EFFICIENCY PROPOSAL.

A. Energy efficiency is a joint effort on behalf of the ETO and the utility customer, and imposing what amounts to little more than a penalty on large industrial customers, at a time when those customers are working aggressively to achieve Oregon's energy efficiency goals, is not good policy. Despite claiming that energy efficiency belongs in the marginal cost study, CUB's proposal does not model energy efficiency as a marginal resource. Despite claiming that smaller customers are unfairly subsidizing larger customer conservation projects, CUB's proposal shifts a material amount of costs to larger customers without any legitimate factual basis for doing so. And, despite claiming

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24/ ICNU/305 at 12 (Pinnacle Economics, Economic Impacts from Energy Trust of Oregon 2013 Program Activities, Final Report at 7 (May 5, 2014)).

25/ CUB/100 at 33:2-13.

26/ Id.

that funding limitations will soon inhibit the ETO's ability to acquire all cost-effective energy efficiency from industrial customers, CUB's proposal has no impact on these funding limitations and, as I understand, violates Oregon law. Accordingly, I recommend that the Commission reject the CUB proposal.

III. DIRECT BENEFIT CAP

Q. PLEASE RESTATE CUB'S CONCERN OVER THE ETO'S ABILITY TO ACHIEVE ALL COST-EFFECTIVE ENERGY EFFICIENCY.

A. As a justification for its energy efficiency proposal, CUB has testified that "under the current legal interpretation, PGE's industrial customers will very soon be restricted from receiving additional industrial EE programs because of the 'direct benefit' cap in SB 838."[27/] CUB argues that its marginal cost proposal, coupled with its unique interpretation of the phrase "direct benefits" in SB 838 discussed above, will solve this problem.

Q. HOW DO YOU PROPOSE TO RESOLVE CUB'S CONCERN?

A. While I recommend adherence to, and accounting for, the law prohibiting large industrial customers from receiving incentives out of SB 838 funds, I propose that the "direct benefit cap" referred to by CUB be lifted, enabling the ETO to utilize the entire amount of SB 1149 funds in the manner it believes to be in the public interest.

27/ CUB/100 at 38:8-10.

Q. EARLIER YOU PROVIDED AN OVERVIEW OF THE DIRECT BENEFIT CAP IN SB 838. IS THIS CAP PREVENTING THE ETO FROM ACQUIRING ALL COST-EFFECTIVE ENERGY EFFICIENCY IN THE COMPANY'S SERVICE TERRITORY?

A. No. To date, the ETO has been able to acquire all cost-effective energy efficiency from customers over 1 aMW and projects that it will be able to do so in 2014.[28/] More importantly, to the extent the ETO is in danger of not being able to acquire cost-effective energy efficiency from these customers, this is not because of the SB 838 direct benefit cap, it is because of the "current legal interpretation" of this cap.[29/]

Q. WHAT IS THE "CURRENT LEGAL INTERPRETATION" OF THE SB 838 DIRECT BENEFIT CAP?

A. CUB states that the "current interpretation of [SB 838] is to maintain industrial programs at the same percentage of funding as they were before [the passage of SB 838]."[30/] Thus, under this interpretation, customers over one aMW are only allowed to receive a certain percentage of SB 1149 conservation incentives from the public purpose charge.

Q. WHAT IS THE PERCENTAGE CAP OF SB 1149 INCENTIVES THE ETO STATES IT CAN PROVIDE TO CUSTOMERS OVER ONE aMW?

A. It is 18.4 percent.[31/] This percentage represents the average amount of incentives paid to large customers between 2005 and 2007 relative to total energy efficiency funding in that period.[32/] If the ETO exceeds the 18.4 percent industrial cap, it has two years to bring

28/ Energy Trust of Oregon, Conservation Advisory Council Meeting Notes at 2 (July 23, 2014), available at: http://energytrust.org/library/meetings/cac/CAC_Notes_140723.pdf; see also, ICNU/303 at 7 (PGE Resp. to ICNU DR 145); PGE Advice No. 14-08, Staff Report at 1 (June 17, 2014) (noting that PGE requested $4 million reduction to SB 838 funding and despite this reduction, "Energy Trust estimates it can still achieve its forecasted energy savings goals … for the years 2014-2016").

29/ CUB/100 at 38:8-10.

30/ Id. at 27:15-16.

31/ ICNU/304 at 2 (Energy Trust of Oregon, "Funding Limitations for Large Energy Users" (Apr. 16, 2014)).

32/ Id.

incentives back below the cap amount.[33/] The percentage cap for PacifiCorp is 27 percent.[34/]

Q. HOW WERE THESE PERCENTAGES ESTABLISHED?

A. ETO reports that they are the outcome of a "2008 informal multiparty agreement."[35/]

Q. IS THE ETO IN DANGER OF EXCEEDING THE INFORMAL 18.4 PERCENT INDUSTRIAL CAP FOR PGE?

A. Both the ETO and the Company indicate so. In an October 31, 2013 briefing paper, the ETO noted that, if "in PGE territory we were to continue >1aMW incentive spending at a rate equal to the average of the past 3 years (2010-2012, $5.9M), we would exceed the current spending limit in 2015."[36/] Additionally, in response to a CUB data request, the Company stated that the 18.4 percent industrial cap could prevent the acquisition of all cost-effective energy efficiency in the next five years.[37/]

Q. DOES THIS CONCERN ICNU?

A. Yes. Like CUB, ICNU wants the ETO to be able to acquire all cost-effective energy efficiency. As discussed above, industrial energy efficiency programs reduce system-wide costs and provide broad economic and welfare benefits, for the good of all customers.[38/] And, as CUB recognizes, industrial energy efficiency is often the cheapest to acquire.[39/] The ETO reports that "large site projects are 2.5 times more cost effective

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33/ Id.
34/ Id.
35/ Id. at 1.
36/ ICNU/301 at 7.
37/ ICNU/303 at 1 (PGE Resp. to CUB DR 27).
38/ Supra at 11-12.
39/ CUB/100 at 38:1.

than [smaller] site projects."[40/] Thus, ICNU agrees that something should be done to ensure the ETO can fund the most economic projects.

Q. WHAT DO YOU PROPOSE?

A. I propose that the Commission remove the 18.4 percent industrial cap on SB 1149 funding.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The 18.4 percent cap is not a statutory requirement. It is nowhere to be found in SB 838 or SB 1149. As CUB states, it is an "artificial cap placed on industrial programs by the current interpretation of the law."[41/] Furthermore, the 2008 informal multiparty agreement that established this "artificial cap" has no basis in the regulatory record. The ETO notes that, with respect to this agreement, the "details of the discussions and resulting methodology were not created within the formal regulatory docket process, [thus] the history is sparse and largely undocumented."[42/] While various ETO briefing papers refer to the 18.4 percent cap, they do not provide or refer to any document that established this cap.[43/] The closest ICNU has come to locating this agreement is a straw man proposal the ETO sent to various stakeholders in 2007 that outlines the process the ETO planned to establish following passage of SB 838.[44/] No final agreement appears to exist. Thus, the ETO has stated that its process "is meant to reflect our best

40/ ICNU/301 at 16.
41/ CUB/100 at 30:14-15.
42/ ICNU/301 at 21.
43/ See ICNU/301 at 7, 15, 21; ICNU/304 at 2.
44/ ICNU/302 at 5-8 (attachment to CUB Resp. to ICNU DR 11 (note that this attachment was originally part of a PGE response to a CUB data request in Advice No. 07-25 and is labeled accordingly)).

understanding of the intent at the time" of the informal agreement.[45/] In sum, the cap was not adopted in a regulatory proceeding and is not binding.

Q. ARE THERE ANY OTHER REASONS TO REMOVE THE 18.4 PERCENT CAP?

A. Yes. This cap is arbitrary. As proof of this, just look at PacifiCorp. It is subject to the same laws, yet the funding cap the ETO applies to PacifiCorp is 27 percent.[46/] This is because the industrial cap is entirely dependent on the amount of funding PGE and PacifiCorp provided to large customers between 2004 and 2007.[47/] Because PacifiCorp had more industrial conservation activity during this period, its cap is higher and it is not currently in danger of exceeding it.[48/] This makes no sense, particularly given the changed circumstances of the Company's industrial load. When the informal cap was implemented, "PGE activity was largely limited to one large paper mill. [Today, a] larger proportion of PGE's large customer loads are from the semiconductor industry. Energy Trust programs were not as active in that industry until recently."[49/] Thus, if the Company's service territory in 2005-2007 had an industrial profile similar to what it has today, its informal cap would almost certainly be higher and the ETO would have no problem acquiring all cost-effective conservation from large customers.

45/ ICNU/301 at 21.

46/ Id. at 4.

47/ Id. at 7. As further evidence of the arbitrariness of this cap, the baseline period is different for the Company than it is for PacifiCorp. For PGE it is 2005-2007, while it is 2004-2007 for PacifiCorp.

48/ Id. at 15.

49/ Id. at 21.

Q. HAS THE COMMISSION QUESTIONED WHETHER IT REMAINS GOOD POLICY TO MAINTAIN THE 18.4 PERCENT INFORMAL CAP?

A I am unaware of any formal statement the Commission has issued. However, various ETO papers indicate that the Commission "is aware of these issues and is questioning whether the methodology used to set Energy Trust's spending limit for >1aMW sites is the best policy."[50/]

Q. WOULD YOUR PROPOSAL RESULT IN THE ETO SPENDING ALL SB 1149 DOLLARS ON INDUSTRIAL CUSTOMERS?

A. No. I am not suggesting that the ETO should spend all SB 1149 energy efficiency dollars on industrial customers, just that it should have the freedom to pursue the most cost-effective options. Currently, the ETO is acquiring all cost-effective conservation from large customers even with the artificial 18.4 percent cap in place; thus, there is no reason to think that removing the cap would materially increase incentives to these customers. According to an October 2013 ETO briefing paper, "[i]f we assume the average incentive demand for the past three years in PGE ($5.8M) increases by 25% ($7.25M) and is sustained for the next three years, the cumulative % of incentives to total revenues from PGE large customers would increase from 17% to 20%."[51/] Thus, even a significant and unanticipated increase in incentive demand from industrial customers is not likely to result in a material shift of dollars to this customer group.

Q. HOW WOULD YOUR PROPOSAL COMPLY WITH SB 838?

A. I propose that the ETO be required to develop separate fund accounting for SB 1149 and SB 838 receipts in order prevent any funds received pursuant to SB 838 from being used

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50/ Id. at 7.

51/ Id. at 9.

to provide incentives to large customers. Under this proposal, large customers exceeding one aMW could receive incentives out of the SB 1149 fund, with no limitation. They would be prohibited, however, from receiving any incentive from the SB 838 fund, in compliance with that law's direct benefit limitation.[52/]

Q. PLEASE SUMMARIZE HOW YOU PROPOSE TO ADDRESS THE ISSUE RELATED TO THE DIRECT BENEFITS CAP.

A. To the extent the ETO is currently in danger of not being able to acquire all cost-effective energy efficiency, the use of an 18.4 percent cap on SB 1149 funding, which is not part of any formal agreement and has no basis in Oregon law, should be re-evaluated. I propose that the cap be eliminated and that the ETO be required to develop fund accounting in order to ensure that large industrial customers receive no incentives from SB 838 funds.

IV. PRODUCTION TAX CREDIT CARRY-FORWARDS

Q. DO YOU HAVE ANY GENERAL COMMENTS REGARDING THE COMPANY'S TAX CALCULATIONS BEFORE DISCUSSING PTC CARRY-FORWARDS?

A. Reviewing the Company's tax calculations in this proceeding has been difficult. Throughout the course of this proceeding, numerous errors and inconsistencies have been identified, the extent of which make it nearly impossible to have a clear understanding of the appropriate level of tax expense and accumulated deferred income taxes ("ADIT") to assume in rates. On May 12th, for example, the Company identified a $32.7 million error in its accumulated deferred income tax balance, which resulted in revenue

52/ ORS § 757.689(2)(b).

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision	)
	)

EXHIBI ICNU/301

STAFF RESPONSES TO ICNU DATA REQUESTS

August 13, 2014

Date: August 4, 2014

TO:

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FROM:

Judy Johnson
Senior Economist
Rates, Finance & Audit

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 283 – ICNU Data Request Set 3 (008)

Data Request ICNU 008:

008. Please provide all documents in Staff's possession that refer to the 18.4% cap on the Energy Trust of Oregon's ability to provide industrial energy efficiency funding in PGE's service territory, referenced in CUB/100 at 27.

Staff Response to ICNU 008:

008. See Attachment A.

From: Fred Gordon [mailto:Fred.Gordon@energytrust.org]
Sent: Thursday, June 06, 2013 2:30 PM
To: JOHNSON Juliet
Cc: Steve Lacey; Peter West; Elaine Prause; Margie Harris; Debbie Goldberg Menashe
Subject: >1 aMW

Juliet, we convened after our meeting with PUC and weren't 100% clear regarding what the PUC was asking for.
We came up with two versions of what the PUC staff is considering. Below, I describe both. It would be good to clarify what you want before we start doing more analysis.

WE'RE PRETTY SURE ABOUT THIS PART

The 2008 informal multiparty agreement locks in a percentage of 1149 funding that should go to customer over 1 aMw. PUC is questioning whether that is the best PUC policy. There may be a level of funding for customers >1 aMW that is the proper balance between getting all cost-effective measures and reasonable equity for funders. To determine this we need to look at the problem differently. The solution should leave sufficient revenue for other customer classes, gets all cost-effective measures.

WE'RE NOT SO SURE ABOUT THIS PART.

There seem to be two ways to gauge equity that were discussed, sometimes in rapid succession. They may be alternatives of complimentary perspectives. One is easy to do, one isn't.

1. **Assess whether large customer loads, as a share of all customer loads, grew.** This would be an indicator of whether perhaps funding from this class of customers grew, so it is reasonable to increase funding to them beyond the percentage from the pre-838 period. We think we have the data to look at this and will do so. This would inform analysis in any event. This analysis would not factor in rate differentials or the influence of self-direct on revenues, as we'd simply be looking at load trends.

2. **Assess what percent of *revenue* to Energy Trust comes from large customers.** PUC does not consider this a "dollar in/dollar out = 1" criteria, but will consider the level of revenue in vs. out from the large customers to assess the "right" level of funding for larger customers.

We can readily do #1, have explored how to do #2. If the PUC wants this information to proceed, we suggest that the PUC request data from the utilities regarding how much of the revenue to the Energy Trust came from customers over vs. under 1 aMW. We don't think we have the information in hand, and the task will require an understanding of rates which we'd need to build from scratch. In addition to rates, we don't have data in hand to gauge the impact of self-direct, and we know that it has changed significantly over time, as fewer customers are self-directing. It may have a sizeable influence on the trend. So we'd like to factor that in. For this analysis, we suggest a three year historical period would be enough to see whether there were trends that are meaningful or bumps to smooth out.

In either case, we're hearing that the PUC staff might want to:

- The amount of resource available from >1 aMw vs all customers.

- The amount of that which might be impacted by a cap (this will be highly speculative).
- How levelized cost for large customer projects compare to costs for other customers. If you agree that this is important, we'll do the added analysis, which will be imprecise, but meaningful.

So- Is the PUC staff currently thinking about the first option above, or the second, or both, considering that the second will require added work by the utilities, or less ideally and less accurately, by Energy Trust?
And, do we have it right that you also want us to take a cut at the three bullets below?

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EnergyTrust of Oregon

Large Energy User Funding Analysis

September 6, 2013

Background

Through SB838, electric utility customer sites with usage less than or equal to 1aMW can be charged an additional rate that is used to fund electric efficiency beyond the established public purpose charge from SB 1149 to meet efficiency resource needs identified in utility integrated resource planning. Because not all customers are paying in to the 838 fund, a 2008 informal multiparty agreement set a limit to the percentage of 1149 incentive funding that Energy Trust can allocate to customers over 1 aMW.

The limits, established separately for each utility, are calculated as either 2004-2007 total >1aMW incentives divided by 2004-2007 total 1149 efficiency funds directed to Energy Trust. For PacifiCorp this value is **27%** and for PGE it is **18%**. Compliance with this spending limit is calculated on a cumulative basis from 2008 forward, as an average of the % of 1149 incentives for >1aMW over that years 1149 total energy efficiency revenue to Energy Trust. 2008-2012 for PacifiCorp is 22% and PGE is 17% (1% below the limit of 18%).

Today the OPUC is questioning whether the methodology used to set Energy Trust's spending limit for >1aMW sites is the best policy. There may be a more appropriate level of funding for customers >1 aMW that brings the proper balance between getting all cost-effective measures and reasonable equity for funders. To determine this we need to look at the problem differently. The solution should leave sufficient revenue for other customer classes while not limiting the acquisition of all cost-effective savings. This paper summarizes an analysis of key questions to help frame the issue and make decisions.

Scope

To help inform the process to review the spending limit methodology, information that can provide the ability the gauge the balance between funder equity and best benefit for all ratepayers is needed.

Questions to be addressed:

1. How much are > 1aMW sites paying in to Energy Trust efficiency funding? How has this changed over time?
2. How much is currently being spent on them?
3. How much savings is acquired with current cap?
4. How levelized cost for large customer projects compare to costs for other customers.
5. How does self-direct factor into the whole issue?
6. How has the ratio of revenues received from <1aMW customer to spending for <1aMW has changed over time?
7. Whether the ratio of energy usage by > 1 aMW to other customers has grown or shrunk since base period.
8. Estimate how much savings we could end up foregoing with the current cap to spending
9. Looking at how limiting spending on > 1 aMW might affect levelized cost

Analysis

To help answer these questions, both utilities provided historical annual load and revenue data separated by 838 exempt (>1aMW sites) and non-exempt (<=1aMW sites) customer categories. The exempt group was further separated according to those that actively self-directing energy efficiency as well. Those sites don't contribute to 838 but also don't contribute to Energy Trust revenue.

This utility data was combined with Energy Trust's historical database of savings and incentives paid, also separated by those >1aMW and those <=1aMW. Below are brief responses to each question by utility, starting with PGE, based on the work attached in an excel file.

PGE

1. How much are > 1aMW sites paying in to Energy Trust efficiency funding? How has this changed over time?

Since 2005, they have contributed between $1.8 and $2.7million per year, equating to 6.5%-12% of the total 1149 energy efficiency revenues to Energy Trust with a trend towards a decreased percentage in more recent years. 2005-2007 averages 10.3%, 2008-2012 average is 8.1%.

	2005	2006	2007	2008	2009	2010	2011	2012
$M- revenues to ETO EE >1aMW	$2.48	$2.74	$1.82	$1.76	$1.76	$2.44	$2.58	$2.62
% of total ETO EE 1149 $ reported	11.8%	12.0%	7.1%	6.5%	6.6%	9.0%	9.0%	9.3%

2. How much is currently being spent on them?

Our current metric for limiting spending is measured by incentives spent on sites >1aMW as a percentage of total 1149 efficiency funds received. For PGE this limit is the average of this annual calculation for years 2005-2007, 18%. The cumulative average for 2008-2012 is 17% with specific years ranging from 9% to 27% in 2012. Actual incentives per year range from $1.3M to a high of $9.7M. 2012 incentives totaled $7.5M.

To estimate total 1149 dollars spent on these sites, we applied the current ratio of incentives to total budget for the Production Efficiency program, where most of the projects are seen, which is 64%. From this perspective, >1aMW sites have received 25% of total funds.

3. How much savings is acquired with current cap?

Annual savings have ranged from 1.6aMW to 14.4aMW, with 7.1aMW in 2012 and total of 47.4aMW from 2005-2012. Going forward, assuming a 1% annual increase in total 1149 efficiency funds collected (to represent load growth) and maintaining a cumulative average of 18% incentives vs. total collected, $5-$5.5M per year can be directed in incentives to >1aMW sites. Assuming an average acquisition rate of 11.3 cents per kWh, escalating by 2% per year, about 5aMW can be acquired per year at the current cap.

Due to the uncertainty in each of the assumptions behind this estimate, there's likely a range around that estimate of at least 25%.

4. How levelized cost for large customer projects compare to costs for other customers.

Levelized incentive costs for these projects have averaged just under 1cent/kWh since 2005,with 2012 being 1.2 cents/kWh and seeing much year to year variability, no real trend in cost up or down through time. This compares with levelized incentive costs for <=1aMW sites averaging 2.3cents/kWh.

5. How does self-direct factor into the whole issue?

Revenues to PGE from sites self-directing efficiency have increased over time from $16M in 2005 to $41M in 2012. Although a small proportion of >1aMW revenues, the efficiency public purpose charge they are self-directing is equal to 25% of the >1aMW efficiency revenues received by Energy Trust. Although the energy use and utility revenues for efficiency self-directors has increased the number of sites has declined. One large partial requirements self-director is mainly responsible for the large increase in load seen in 2010.

6. How has the ratio of revenues received from <1aMW customer to spending for <1aMW has changed over time?

The ratio of revenues received compared to spending has trended down over time reaching 35% of incentive dollars in 2012.

	2005	2006	2007	2008	2009	2010	2011	2012
>1aMW revenues to ETO	$ 2,483,367	$ 2,735,959	$ 1,824,171	$ 1,755,651	$ 1,762,977	$ 2,443,411	$ 2,578,003	$ 2,615,79
>1aMW incentive spending	$ 9,742,145	$ 1,282,158	$ 1,762,765	$ 2,421,817	$ 2,778,261	$ 4,189,900	$ 5,950,881	$ 7,508,72
>1aMW total spending	$ 15,222,102	$ 2,003,372	$ 2,754,320	$ 3,784,089	$ 4,341,033	$ 6,546,719	$ 9,298,252	$ 11,732,38
Revs/incentives	25%	213%	103%	72%	63%	58%	43%	35
Revs/total $	16%	137%	66%	46%	41%	37%	28%	22

7. Whether the ratio of energy usage by > 1 aMW to other customers has grown or shrunk since base period.

The ratio of energy use has remained very consistent over time, hovering around 19% of total load.

8. Estimate how much savings we could end up foregoing with the current cap to spending

Based on a high level estimate of ~ 5aMW acquired per year maintaining the cap of 18% incentives budget to total 1149 revenues, over the next five years, we anticipate 8-12 aMW of savings could be lost, or 32-48 aMW over a 20-year period. We may be able to "roll" projects forward in time and if funding continues to be limited, the issue will remain. Furthermore, many large efficiency projects are scheduled as part of other planned capital improvements, and might not be available if funding is not provided at the right time.

From our current resource assessment, about 20% of the 20 year achievable potential is estimated to be from industrial (~15%) and commercial (~5%) sites >1aMW.

9. Looking at how limiting spending on > 1 aMW might affect levelized cost

By limiting spending the ratio of lower levelized cost project spending would be maintained at roughly 30%. Using 2012 spending as an indicator of demand needing 40% of spending, the weighted average levelized cost would increase approximately 6%.

EnergyTrust
of Oregon

Large Energy User Funding Analysis

October 31, 2013

Background

Through SB838, electric utilities can add an additional amount to the bills of all customer sites with usage less than or equal to 1aMW. The resulting funds are to be used to fund electric efficiency beyond the established public purpose charge from SB 1149, to meet efficiency resource needs identified in utility integrated resource planning. Because larger customers are not paying in to the 838 fund, they are ineligible for efficiency program funding from 838. As a way of assuring that large customers are not benefitting from this added funding, a 2008 informal multiparty agreement set a limit to the percentage of 1149 incentive funding that Energy Trust can allocate to customers over 1 aMW.

The limits, established separately for each utility, are based on large customer funding prior to SB 838 implementation. They are calculated as the total *incentives* paid to >1aMW sites divided by total 1149 efficiency *revenues* directed to Energy Trust over a base pre-838 timeframe. For PacifiCorp the base period is 2004-2007 and for PGE, the base period is 2005-2007. For PacifiCorp this value is **27%** and for PGE it is **18%**.

Compliance with this spending limit is evaluated by comparing post-838 funding to these limits. The post-838 percentage for comparison to the numbers described above is calculated on a cumulative basis starting in 2008. It is the sum of incentives for >1aMW over the sum of total 1149 energy efficiency revenues to Energy Trust. 2008-2012 for PacifiCorp is 22% (five points beneath the limit of 27%) and for PGE is 17% (1% point below the limit of 18%).

There are two types of issues to be addressed: 1) Strong program interest from large sites is expected to continue, leading to the potential for the current funding cap methodology to limit Energy Trust's ability to acquire all cost effective resources. If in PGE territory we were to continue >1aMW incentive spending at a rate equal to the average of the past 3 years (2010-2012, $5.9M), we would exceed the current spending limit in 2015. The cap may cause us to redirect funds above the cap to higher cost projects from smaller, 838 eligible sites. It is also possible that as a consequence Energy Trust does not meet IRP goals in some years. The result may mean lost opportunity of low cost resource, unmet demand and unrealized savings.

2) Implementation of the spending limit is extremely challenging. A) Energy Trust still does not have access to knowing which meters and sites are paying 838 and which are not- the estimates cited above are based on the best available data. B) This is further complicated by the fact that the definition of a self-direct eligible site and an 838 exempt site differs. Meters that are <1aMW yet are included with a self-direct site definition totaling >1aMW pay 838 charges. Since they are meters within a self-direct site (total meter load >1aMW) the programs are only reasonably able to treat them as an exempt, 1149 only site. It's impossible to know which projects are on which meters and which ones are paying 838 or not paying 838. We run the risk of limiting program participation to sites which do have some meters paying 838.

Today the OPUC is aware of these issues and is questioning whether the methodology used to set Energy Trust's spending limit for >1aMW sites is the best policy. There may be a more appropriate level of funding for customers >1 aMW that brings the proper balance between getting all cost-effective measures and reasonable equity for funders. To determine this we need to look at the problem differently. The solution should leave sufficient revenue for other customer classes while not limiting the acquisition of all cost-effective savings. This paper summarizes an analysis of key questions to help frame the issue and make decisions and offers some recommendations to address both categories of issues.

Scope

To help inform the review of the spending limit methodology, information is needed that can help policymakers gauge the balance between funder equity and best benefit for all ratepayers.

Questions to be addressed:

1. How much are > 1aMW sites paying in to Energy Trust efficiency funding? How has this changed over time?
2. How much is currently being spent on them?
3. How much savings is acquired with current cap?
4. How levelized cost for large customer projects compare to costs for other customers.
5. How does self-direct factor into the whole issue?
6. How has the ratio of revenues received from <1aMW customer to spending for <1aMW has changed over time?
7. Whether the ratio of energy usage by > 1 aMW to other customers has grown or shrunk since base period.
8. Estimate how much savings we could end up foregoing with the current cap to spending
9. Looking at how limiting spending on > 1 aMW might affect levelized cost

Analysis

To answer these questions, both utilities provided historical annual load and revenue data separated by 838 exempt (>1aMW sites) and non-exempt (<=1aMW sites) customer categories. The exempt group was further separated into those that are versus are not actively self-directing energy efficiency. Those sites don't contribute to 838 but also don't contribute to Energy Trust revenue.

This utility data was combined with Energy Trust's historical database of savings and incentives paid (created by a third party contractor to date), also separated by those >1aMW and those <=1aMW. Below is a brief summary of key takeaways, followed by responses to each question for each utility.

Summary of key findings

- Dollars provided to Energy Trust by sites with loads greater than 1aMW have remained relatively steady over all years while non-exempt sites are contributing 36%--66% more per kWh in 1149 funds than in 2004/2005. This reflects 838 charge increases plus other rate increases over the years for the non-exempt meters.

- Demand for efficiency program spending from >1aMW sites has varied year to year but is expected to maintain recent levels or increase over the next 5 years, just how much of an increase is unknown.

- In recent years, >1aMW sites contribute 9% and 13% of total 1149 revenues (PGE/PAC) and receive 18% and 24% of 1149 incentives.

- The utility cost of savings from >1aMW sites is less than half the cost of non-exempt site projects

- Savings potential from >1aMW sites is estimated to be 20% of our current 20 year potential assessment.
- The risk of the current spending cap hindering acquisition is high in PGE territory but low for PAC.
- Although Energy Trust has historically spent more on large sites than the revenue collected from those sites, the value of the large site energy savings to the system has been significant and benefits all ratepayers.

Options

Option 1. Consider removing the exemption for >1aMW sites contributing to the 838 funds. This would require a legislative act.

- Large sites have received significantly more incentive benefit per dollar contributed compared to non-exempt sites as well as more savings per dollar received. However, the lower-cost savings benefit both large users directly and nonexempt sites through a lower cost energy system.
- If the large customer exemption were removed, the impact of removing the exemption would be an overall increase in Energy Trust funding from large customers from an average of 0.09 cents/kWh to 0.31 cents/kWh.

Option 2. Align implementation of 838 charges to self-direct site definitions.

Individual meters within a self-directing site may be <1aMW and therefore charged 838 rates. Administration of spending caps within a site is overly complex. For example, project eligibility would need to be tied to an 838 eligible meter. That level of precision is not reasonable to assume is possible in implementing a program. The risk to Energy Trust is that we would be limiting program participation for sites that are paying 838 at some meters. By aligning definitions, meters within a self-direct eligible site would not be charged 838, regardless of load and the risk of unnecessarily limited participation at some meters would be minimized.

Option 3. Revise the method for compliance with 838 from the current spending cap to some less restrictive cap.

The cap will result in a resource acquisition constraint in PGE territory but is not estimated to have an impact on acquisition in PAC. Removing the constraint ensures that all least cost resource can be acquired and reactive program design methods intended to comply with the cap don't result in damaging participant interest/relationships for future projects.

Removing or adjusting the cap results in small incremental risk to equity. Large site demand varies significantly by year. If we assume the average incentive demand for the past three years in PGE ($5.8M) increases by 25% ($7.25M) and is sustained for the next three years, the cumulative % of incentives to total revenues from PGE large customers would increase from 17% to 20%. This is still below the current PAC spending cap. It would allow PGE's >1aMW customer to spend about twice the revenue collected from them. That is roughly the limit for PacifiCorp.

There are several possible ways to set a different cap. The new cap for PGE might be set at a particular ratio of revenue from and to larger customers or it might be set at the same level as PacifiCorp. There might be a different way to assure compliance than the cap, but we do not recommend running separate programs for the same customer with 838 and 1149 funds as was suggested after SB 838 was passed. From a customer relationships and program effectiveness strategy, this is not feasible.

Option 4: Apply the limit across both utilities as a single limit.

This would provide some additional headroom, but might not provide a permanent solution.

Option 5. Maintain current policy. Based on our current projections (which depend greatly on what customers choose to do) this is likely to result in the need to limit funding to projects at >1aMW sites for PGE in 2015. A review of options for limiting program activity was provided as part of the board retreat packed for the June, 2012 retreat. All of the options would reduce acquisition of cost-effective savings. There would also be some disruption of customer relationships and the ability to pursue additional savings. The preferred options from that review might minimize this disruption.

DETAILED ANALYSIS OF UTILITY DATA

1. **How much are > 1aMW sites paying in to Energy Trust efficiency funding? How has this changed over time?**

PGE

Since 2005, they have contributed between $1.8 and $2.7million per year, equating to 6.5%-12% of the total 1149 energy efficiency revenues to Energy Trust with a trend towards a decreased percentage in more recent years. 2005-2007 averages 10.3%, 2008-2012 average is 8.1%.

	2005	2006	2007	2008	2009	2010	2011	2012
$M- revenues to ETO EE >1aMW	$2.48	$2.74	$1.82	$1.76	$1.76	$2.44	$2.58	$2.62
% of total ETO EE 1149 $ reported	11.8%	12.0%	7.1%	6.5%	6.6%	9.0%	9.0%	9.3%

The downward trend may be attributed to a few factors. Although load as a % of total load is not decreasing, rates for non-exempt sites have increased more than for exempt sites. Although the calculation of efficiency funds to Energy Trust from SB 1149 has not changed (56.7% of 3% of rates), the underlying $/kWh for non-exempt sites has increased due to SB 838 charges and other general rate case increases allocated to these customer segments that are not impacting the >1aMW sites.

PAC[1]

Since 2004, they have contributed between $1.9 and $2.9million per year, equating to 11%-22% of the total 1149 energy efficiency revenues to Energy Trust with a trend towards a decreased percentage in more recent years. 2004-2007 averages 18.5%, 2010-2012 average is 12.8%.

	2004	2005	2006	2007		2010	2011	2012
$M- revenues to ETO EE >1aMW	$2.9	$2.9	$2.7	$1.9		$2.3	$2.1	$2.7
% of total ETO EE 1149 $ reported	22%	21%	19%	12%		14%	11%	14%

Similar to PGE, 838 exempt revenues have not changed much over time but the revenues from non-exempt have increased due to 838 charges and other larger rate increases over the years than large customers have seen. These factors are leading to their revenues being a lower % of the total 1149 funds received.

2. **How much is currently being spent on them?**

PGE

Our current metric for limiting spending is measured by incentives spent on sites >1aMW as a percentage of total 1149 efficiency funds received. For PGE this limit is the average of this annual calculation for years 2005-2007, **18%**. The cumulative average for 2008-2012 is **17%** with specific years ranging from 9% to 27% in 2012. Actual incentives per year range from $1.3M to a high of $9.7M. 2012 incentives totaled $7.5M.

To estimate total 1149 dollars spent on these sites, we applied the current ratio of incentives to total budget for the Production Efficiency program, where most of the projects are seen, which is 64%. From this perspective, >1aMW sites have received 25% of total funds. Although more is being spent on these sites, significantly more savings are being acquired per kWh of load, and per dollar spent via these sites when viewed as a group than through smaller sites as a group.

PAC

For PAC our spending limit is the average of this annual calculation for years 2004-2007, **27%**. The cumulative average for 2008-2012 is **22%** with most recent years at 20 and 22%. Actual incentives per year range from $1.5M to a high of $9.2M. 2012 incentives totaled $3.8M, up from $3.6M in 2011.

[1] Our data analysis approach for PacifiCorp is slightly modified to work with the data provided by the utility which differs from what PGE was able to provide. PAC provided 2004-2007 and 2010-2012. Load and revenue detail for efficiency self -directors was not possible to distinguish from renewables only self-directors which make up the majority of PAC self-directors. The one exception is for efficiency specific revenue data from 2011 and 2012 which was available through monthly revenue reports provided outside of the data request for this study.

3. How much savings is acquired with current cap?

PGE

Annual savings from <1aMW PGE customers have ranged from 1.6aMW to 14.4aMW, with 7.1aMW in 2012 and total of 47.4aMW from 2005-2012. On average, the 20% of Energy Trust efficiency spending dedicated to this group is acquiring 34% of the savings. Going forward, assuming a 1% annual increase in total 1149 efficiency funds collected (to represent load and rate growth) and maintaining a cumulative average of 18% incentives vs. total 1149 PGE revenue collected, $5-$5.5M per year can be directed in incentives to >1aMW sites. Assuming an average acquisition cost of 11.3 cents per annual kWh saved, escalating by 2% per year, about 5aMW can be acquired per year at the current cap.

Due to the uncertainty in each of the assumptions behind this estimate, there's likely a range around that estimate of at least 25%.

PAC

Annual savings have ranged from 1.7aMW to 8.8aMW, with 4.9aMW in 2011 and 6.9aMW in 2012 for a total of 42 aMW from 2004-2012, averaging 4.7 aMW/yr. Energy Trust spending in PAC territory (>1aMW incentives / total revenues) has not yet reached the cumulative cap of 27%. Going forward, assuming a 1% annual increase in total 1149 efficiency funds collected (to represent load growth), to reach the 27% spending cap in 2016, annual spending on PacifiCorp sites >1aMW would need to increase by 40% to $6.5M per year (For reference the average of the past three years of spending has been $4.6M.) This implies that there's room within the PAC methodology to meet a 40% growth in demands from >1aMW sites for the next 4 years. Assuming an average acquisition cost rate of 8 cents per annual kWh (based on the last 3 years of project acquisition and escalating by 2% per year) about 9aMW can be acquired per year within the current cap.

Again, there is much uncertainty in each of the assumptions behind these estimates, there's likely a range around that estimate of at least 25%.

4. How does levelized cost for large customer projects compare to costs for other customers?

PGE

Levelized ***incentive*** costs for these projects have averaged just under 1cent/kWh since 2005, with 2012 being 1.2 cents/kWh. There is much year to year variability, and no real trend in cost up or down through time. This compares with levelized incentive costs for <=1aMW sites averaging 2.3cents/kWh.

PAC

Levelized incentive costs for PAC projects have also averaged under 1 cent/kWh since 2005, with 2012 being just 0.6 cents/kWh . There is much year to year variability with no real trend in cost up or down through time. This compares with levelized incentive costs for <=1aMW sites averaging 2.5 cents/kWh.

5. How does self-direct factor into the whole issue?

PGE

Revenues to PGE from sites self-directing efficiency have increased over time from $16M in 2005 to $41M in 2012. Although a small proportion of >1aMW revenues, the efficiency public purpose charge they are self-directing is equal to 25% of the >1aMW efficiency revenues received by Energy Trust. Although the energy use and utility revenues for efficiency self-directors has increased the number of sites has declined. One large partial requirements self-director is mainly responsible for the large increase in load seen in 2010.

PAC

PacifiCorp could not provide revenue, load and site data for efficiency self-directing sites. For 2011 and 2012, revenues but not loads from these sites were available. We do know that there are very few sites self-directing efficiency (yet several are self-directing their renewable portion of the PPC) and that in 2012, >1aMW revenues to Energy Trust would have been just 5% greater had these customers not self-directed. With current levels of self-direction, it really doesn't factor into the issue other than noting that over time the trend away from self-direct has helped maintain >1aMW revenue contributions to Energy Trust at a sustained annual level.

6. **How has the ratio of revenues received from >1aMW customer to spending for >1aMW changed over time?**

PGE

The ratio of 1149 revenues received compared to incentive spending has trended down over time reaching 35% of incentive dollars in 2012. When considered on a total 1149 spending basis (includes estimates for program management and administration costs), the ratio is now 22%.

	2005	2006	2007	2008	2009	2010	2011	2012
>1aMW revenues to ETO	$ 2,483,367	$ 2,735,959	$ 1,824,171	$ 1,755,651	$ 1,762,977	$ 2,443,411	$ 2,578,003	$ 2,615,79
>1aMW incentive spending	$ 9,742,145	$ 1,282,158	$ 1,762,765	$ 2,421,817	$ 2,778,261	$ 4,189,900	$ 5,950,881	$ 7,508,72
>1aMW total spending	$ 15,222,102	$ 2,003,372	$ 2,754,320	$ 3,784,089	$ 4,341,033	$ 6,546,719	$ 9,298,252	$ 11,732,38
Revs/incentives	25%	213%	103%	72%	63%	58%	43%	35
Revs/total $	16%	137%	66%	46%	41%	37%	28%	22

PAC

The ratio of revenues received compared to spending has bounced up and down over time from a low of 36% to a high of 125%. In 2012, revenues were 68% of incentive $s spent on >1aMW.

7. **Whether the ratio of energy usage by > 1 aMW to other customers has grown or shrunk since base period.**

PGE - The ratio of energy use has remained very consistent over time, hovering around 19% of total load.

PAC - The ratio of energy use has also remained very consistent over time, averaging around 19% of total load. Since we were unable to pull out load from sites self-directing efficiency over the years, this was calculation was done without adjusting load to reflect only those contributing to Energy Trust. We know that the number of sites self-directing efficiency has declined but can't confidently reflect that trend in load comparisons.

8. **Estimate how much savings we could end up foregoing with the current cap to spending**

PGE

Based on a high level estimate of ~ 5aMW acquired per year maintaining the cap of 18% incentives budget to total 1149 revenues, over the next five years, we anticipate 8-12 aMW of savings could be lost, or 32-48 aMW over a 20-year period. We may be able to "roll" projects forward in time if there are years with fewer large projects, but that would not address the cumulative decrease. If funding continues to be limited, the issue will remain. Furthermore, many large efficiency projects are scheduled as part of other planned capital improvements, and might not be available if funding is not provided at the right time.

From our current resource assessment, sites <1aMW provide about 20% of the 20 year achievable potential. Three quarters of that is from industrial sites, and one quarter from commercial and institutional sites.

PAC

In PAC territory, we don't foresee a short-term risk of needing to forego resource acquisition with the current methodology and demand. Annual demand for funding for customers>1 aMW would need to increase 40% and hold steady for the next 4 years to hit the spending cap.

9. **Looking at how limiting spending on > 1 aMW might affect levelized cost**

PGE

By limiting spending the ratio of lower levelized cost project spending would be maintained at roughly 30%. Using 2012 spending as an indicator of demand (40% of spending) and assuming that smaller projects could be found to make up the different, 10% of spending would shift from sites >1aMW to projects at smaller sites due to the current spending cap. This results in the weighted average levelized cost increasing approximately 6%.

PAC

Any >1aMWw incentives dollars that are shifted to non-exempt projects result in fewer savings acquired. (62% of what could have been acquired for >1aMW projects) The impact to levelized cost would depend on how much of the dollars intended to meet >1aMW demand was shift to non-exempt projects. Since we don't anticipate enough large site demand to cause us to reach the spending cap we don't foresee and impact to levelized cost for PAC.

EnergyTrust of Oregon

Large Energy User Funding Analysis

January 31, 2014

Background

Through SB838, electric utilities can add an additional amount to the bills of all customer sites with usage less than or equal to 1aMW. The resulting funds are to be used to fund electric efficiency beyond the established public purpose charge from SB 1149, to meet efficiency resource needs identified in utility integrated resource planning. Because larger customers are not paying in to the 838 fund, they are ineligible for efficiency program funding from 838. Language describing this efficiency funding mechanism in legislation reads as follows;

> SECTION 46.
> (1) In addition to the public purpose charge established by ORS 757.612, the Public Utility Commission may authorize an electric company to include in its rates the costs of funding or implementing cost-effective energy conservation measures implemented on or after the effective date of this 2007 Act. The costs may include amounts for weatherization programs that conserve energy.
> (2) The commission shall ensure that a retail electricity consumer with a load greater than one average megawatt:
>
> > (a) Is not required to pay an amount that is more than three percent of the consumers' total cost of electricity service for the public purpose charge under ORS 757.612 and any amounts included in rates under this section; and
> > (b) Does not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates under this section.

As a way of assuring that large customers are not benefitting from this added funding, a 2008 informal multiparty agreement set a limit to the percentage of 1149 incentive funding that Energy Trust can allocate to customers over 1 aMW.

The limits, established separately for each utility, are based on large customer funding prior to SB 838 implementation. They are calculated as the total *incentives* paid to >1aMW sites divided by total 1149 efficiency *revenues* directed to Energy Trust over a base pre-838 timeframe. For PacifiCorp the base period is 2004-2007 and for PGE, the base period is 2005-2007. For PacifiCorp this value is **27%** and for PGE it is **18%**. The large difference in limits between utilities reflects differences in size and volume of large customer projects during the base period years and is out of alignment with current utility specific large site activity. PGE activity for the past two years averaged 25%, incentives divided by total 1149 revenues.

Conformance with this spending limit is evaluated by comparing post-838 funding to these limits. The post-838 percentage for comparison to the numbers described above is calculated on a cumulative basis starting in 2008. It is the sum of incentives for >1aMW over the sum of total 1149 energy efficiency revenues to Energy Trust. For the years 2008-2012 for PacifiCorp this is 22% (five points beneath the limit of 27%) and for PGE is 17% (1% point below the limit of 18%).

Issue

Strong program interest from large sites is expected to continue, leading to the potential for the current funding cap methodology to limit Energy Trust's ability to acquire all cost effective resources. If in PGE territory we were to continue >1aMW incentive spending at a rate equal to the average of the past 3 years (2010-2012, $5.9M/yr. in incentives), we would exceed the current spending limit in 2015. In PAC territory, we don't foresee a short-term risk of needing to forego resource acquisition with the current methodology and demand. Annual demand for funding for customers>1 aMW would need to increase 40% and hold steady for the next 4 years to hit the spending cap.

To maintain compliance with the cap for PGE will cause us to limit annual spending on customers > 1 aMW. To reach goals we will need to redirect funds above the cap to higher cost projects from 838 eligible sites. On average, large site projects are 2.5 times more cost effective than 838 eligible site projects. Therefore directing funding away from large site projects would result in less savings at higher cost. It is also possible that as a consequence Energy Trust does not meet IRP goals in some years. The result may mean lost opportunity of low cost resource, unmet demand and unrealized savings. In the long run, some savings from larger sites will not be captured. This is a particular threat for "lost opportunity" savings that must be acquired during specific events, such as a major capital investment in a process line upgrade or redesign or a building renovation. A significant share of Energy Trust savings comes through such events.

Today the OPUC is aware of this issue and is questioning whether the current methodology used to set Energy Trust's spending limit for >1aMW sites is an optimal approach. There may be a more appropriate level of funding for customers >1 aMW that brings the proper balance between getting all cost-effective measures and reasonable equity for funders. The solution should leave sufficient revenue for other customer classes while not limiting the acquisition of all cost-effective savings. This paper summarizes an analysis of key questions to help frame the issue

Scope

To help inform the review of the spending limit methodology, information was gathered to help policymakers gauge the balance between funder equity and best benefit for all ratepayers.

Summary of key findings

- In recent years (2010-2012), >1aMW sites contributed about 9% and 13% of total 1149 revenues (PGE/PAC) and receive project incentives 20% and 25% of 1149 total spending.
- Dollars provided to Energy Trust by sites with loads greater than 1aMW have remained relatively steady over all years while non-exempt sites are contributing 2.5 times more per kWh in 1149 and 838 funds combined than they paid through 1149 only in 2004/2005 (prior to SB838). This reflects 838 charge increases plus other rate increases over the years for the non-838-exempt meters.
- Demand for efficiency program spending from >1aMW sites has varied year to year but is expected to maintain recent levels or increase over the next 5 years. The size and likelihood of an increase is unknown. Possible increases may come from deeper engagement with the semiconductor industry, possible increases in combined heat and power, accelerated capital investment by larger commercial and industrial businesses, or other drivers.

- On average, the cost to the utility system since 2010 for savings from >1aMW sites is 60% of the cost of non-exempt site projects. In other words, large site projects provide 1.3-2.5 times the savings per incentive of non-exempt sites on average.
- Savings potential from >1aMW sites is estimated to be 20% of our current 20 year potential assessment.
- The risk of the current spending cap hindering acquisition is high in PGE territory but low for PAC.
- Although Energy Trust has historically spent more on large sites than the revenue collected from those sites, the value of the large site energy savings to the system has been significant and benefits all ratepayers.

PGE Annual Statistics

	2005	2006	2007	2008	2009	2010	2011	2012
>1aMW EE 1149 revenues to ETO ($M)	$2.48	$2.74	$1.82	$1.76	$1.76	$2.44	$2.58	$2.62
Total EE 1149 revenues to ETO ($M)	$21.07	$22.72	$25.67	$26.89	$26.67	$27.07	$28.51	$28.12
>1aMW revenues as % of total ETO EE 1149	11.8%	12.0%	7.1%	6.5%	6.6%	9.0%	9.0%	9.3%
Total Incentive spending for >1aMW ($M)	$9.74	$1.28	$1.76	$2.42	$2.78	$4.19	$ 5.95	$7.51
>1aMW Incentives as % of total 1149 revenues to ETO [1]	18% = cap			17%				
Total EE 1149 spending for >1aMW ($M)[2]	$15.2	$2.0	$2.8	$3.8	$4.3	$6.5	$9.3	$11.7
Total EE 1149 spending ($M)	$27.8	$19.2	$21.9	$26.4	$26.7	$31.7	$30.2	$27.8
>1aMW EE 1149 spending as % of total	55%	10%	13%	14%	16%	21%	31%	42%
Total Savings from >1aMW (aMW)	14.4	1.6	7.8	2.4	3.0	5.7	5.3	7.1
Levelized cost of savings from >1aMW sites ($/kWh)	0.008	0.009	0.003	0.011	0.010	0.008	0.012	0.012

[1] This is our current metric for compliance with funding limitations
[2] Although Energy Trust can track the incentive dollars that are paid to >1aMW sites knowing that only 1149 funds are spent, all programs are delivered with the mix of 838 and 1149 funds, making the total 1149 dollars spent for >1aMW sites a reasonable estimation only. To estimate total 1149 dollars spent on these sites, we applied the current ratio of incentives to total budget for the Production Efficiency programs, where most of the large site projects are seen, which is 64%.

Levelized cost of savings from <=1aMW sites ($/kWh)	0.012	0.010	0.015	0.012	0.017	0.016	0.016	0.016
Cost/kWh of >1aMW sites as % of <=1aMW site projects	64%	87%	16%	91%	60%	52%	76%	75%

2010-2012 averages:

- >1aMW EE 1149 revenues as % of total EE 1149 revenues = **9.1%**
- >1aMW EE 1149 annual incentive spending as % of total annual EE 1149 revenues = **20%** (funding limit is set at cumulative incentives from customers >1aMW not exceeding 18% of cumulative revenue, actual cumulative spending 2008-2012 = 17%)
- >1aMW EE 1149 total spending as % of total EE 1149 spending= **31%**
- Incentive cost/kWh of >1aMW site projects as % of <=1aMW site projects = **68%**

PAC Annual Statistics

	2004	2005	2006	2007	2008	2009	2010	2011	2012
>1aMW EE 1149 revenues to ETO ($M)	$2.95	$2.90	$ 2.72	$ 1.86			$2.31	$2.07	$2.71
Total EE 1149 revenues to ETO ($M)	$ 13.35	$13.58	$ 14.6	$ 15.5	$ 16.1	$ 16.4	$ 16.25	$ 18.77	$ 19.6
>1aMW revenues as % of total ETO EE 1149	22.1%	21.4%	18.6%	12.0%			14.2%	11.0%	13.8%
Total Incentive spending for >1aMW ($M)	$ 8.11	$ 3.40	$ 2.19	$1.87	$2.5	$2.4	$ 5.60	$ 4.22	$ 3.99
>1aMW incentives as % of total 1149 revenues to ETO	27% = cap				2008-2012=22%				
Total EE 1149 spending for >1aMW ($M)	$12.67	$ 5.31	$3.43	$ 2.92	$ 3.9	$ 3.8	$ 8.74	$6.60	$ 6.24
Total EE 1149 spending ($M)	$21.48	$17.13	$ 16.66	$ 14.50	$ 14.8	$ 16.4	$ 20	$18.06	$ 18.7
>1aMW EE 1149 spending as % of total	59%	31%	21%	20%	27%	23%	44%	37%	33%
Total Savings from >1aMW (aMW)	7.3	4.2	1.7	3.1	3.3	2.4	8.4	4.9	6.9
Levelized cost of savings from >1aMW sites ($/kWh)	0.012	0.009	0.014	0.007	0.009	0.012	0.007	0.010	0.006

Levelized cost of savings from <=1aMW sites ($/kWh)	0.015	0.013	0.010	0.007	0.010	0.017	0.014	0.016	0.016
Cost/kWh of >1aMW sites as % of <=1aMW site projects	80%	70%	143%	89%	86%	67%	52%	62%	39%

2010-2012 averages:

- >1aMW EE 1149 revenues as % of total EE 1149 revenues = **13%**
- >1aMW EE 1149 annual incentive spending as % of total annual EE 1149 revenues = **26%** (funding limit is set at cumulative incentives from customers >1aMW not exceeding 27% of cumulative revenue, actual cumulative spending 2008-2012 = 22%)
- >1aMW EE 1149 total spending as % of total EE 1149 spending= **38%**
- Incentive cost/kWh of >1aMW site projects as % of <=1aMW site projects = **51%**

EnergyTrust of Oregon

Large Energy User Funding Limit

History of the Methodology Used in Determining the Limit and Current Status

March 12, 2014

Issue Summary

The 1999 Oregon law that gave rise to Energy Trust, SB 1149, required the electric utilities to devote three percent of their revenues to electric efficiency programs. The three-percent charge is collected from all electric customers regardless of the amount of energy they use. A 2007 state law, SB 838, authorized utilities, with OPUC approval, to collect additional electric efficiency funds from customers using less than one average megawatt (aMW) or more per year. Large customers (those using more than 1 aMW) were excluded from paying additional funding, and so are not supposed to receive direct benefit from SB 838 funding. The resulting funds are to be used to fund electric efficiency beyond the established public purpose charge from SB 1149, to meet efficiency resource needs identified in utility integrated resource planning. Because larger customers are not paying in to the 838 fund, they are ineligible for efficiency program funding from 838. Language describing this efficiency funding mechanism in legislation reads as follows;

> SECTION 46.
> (1) In addition to the public purpose charge established by ORS 757.612, the Public Utility Commission may authorize an electric company to include in its rates the costs of funding or implementing cost-effective energy conservation measures implemented on or after the effective date of this 2007 Act. The costs may include amounts for weatherization programs that conserve energy.
> (2) The commission shall ensure that a retail electricity consumer with a load greater than one average megawatt:
>> (a) Is not required to pay an amount that is more than three percent of the consumers' total cost of electricity service for the public purpose charge under ORS 757.612 and any amounts included in rates under this section; and
>> (b) Does not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates under this section.

As a way of assuring that large customers are not benefitting from this added funding, a 2008 informal multiparty agreement set a limit to the percentage of 1149 incentive funding that Energy Trust can allocate to customers over 1 aMW.

Due to success of the programs serving them, savings from large customers and incentives going to them have been increasing. Without a change, before 2015 Energy Trust will likely need to cap spending in PGE's service territory for these customers. In the fairly near term and in the long run, the limitation in SB 838 funding means that Energy Trust will not be able to pursue all cost-effective efficiency from these customers. In PAC territory, we don't foresee a short-term risk of needing to forego resource acquisition with the current methodology and demand but PAC customers will be impacted by program designs instituted to manage funding for PGE.

Today the OPUC and stakeholders are questioning whether the methodology used to set Energy Trust's spending limit for >1aMW sites is the best policy. There may be a more appropriate level of funding for customers >1 aMW that brings the proper balance between getting all cost-effective measures and reasonable equity for funders. This paper documents the creation of the existing spending limit methodology and documents current discussions by stakeholders related to next steps.

Methodology

One of the first steps in implementing 838 efficiency funding was to set up processes for ensuring that large energy users were not charged and did not receive direct benefit from funds collected. Energy Trust, OPUC staff and utilities met informally to work through details. Since the details of the discussions and resulting methodology were not created within the formal regulatory docket process, the history is sparse and largely undocumented. The following description documents the practice that Energy Trust has followed since those discussions took place and is meant to reflect our best understanding of the intent at the time.

- Exempting large energy users from contributing towards 838 was, with PUC knowledge, addressed within specific customer billing systems at each utility, informed by site use and self-direct certification status. Utilities worked through their process with OPUC staff to ensure large energy users were not charged 838.

- The next step was to ensure that those that are not contributing are not directly benefiting. The group interpreted the need to show no direct benefits are received as meaning that the current spending practices should not be exceeded going forward. This could be shown by tracking what proportion (%) of public purpose charge funding (SB1149 only) went, collectively, to large energy users prior to the new 838 funding and limiting future spending (post 838) to not exceed that pre 838 baseline spending.

- Tracking project incentives paid to large energy users compared to total efficiency 1149 revenues to Energy Trust was the agreed upon metric to characterize spending. Incentive spending was thought to be a reasonable, but not perfect, indicator of spending to a specific customer class that was relatively easy to separate from other program data. Funding spent on delivery and program management is more challenging to separate between types of customers.

- To best represent current (pre-838) spending, Energy Trust elected to look at utility specific spending, not a combined look.

- There are slight differences in the baseline years selected by Energy Trust for comparison between utilities, 2005-2007 PGE and 2004-2007 for PAC. PGE had one very large ("megaproject") year and two small years in their baseline and PAC had four consistently high activity years. The PGE range was likely limited to three years because there was not much of an operational industrial program in 2004, and a significant proportion of large customer activity is from industrial customers.

- The resulting methodology sets the baseline funding limit as the sum of incentives in base years, divided by the sum of 1149 efficiency revenue to Energy Trust. This value is set as the funding cap, not to be exceeded.
    - The funding caps differ significantly by utility, PAC = 27%, PGE 18%
    - The difference is representative of specific project activity that occurred during the base period; PAC territory saw many forest products projects move forward while PGE activity was largely limited to one large paper mill. A larger proportion of PGE's large customer loads are from the semiconductor industry. Energy Trust programs were not as active in that industry until recently.

- Determining "compliance" against this funding limit was agreed to be calculated as a rolling, cumulative look. Because large projects can have lumpy impacts on program incentive spending with year by year variability, measuring compliance on a year to year basis did not seem appropriate. The resulting methodology takes a broader perspective. The sum of all large energy user post 838 incentives are divided by total 1149 revenues across the same time period. For example, to determine compliance with funding limits at the close of 2012, by utility, all large user incentives from 2008-2012 were summed and divided by the total 1149 efficiency revenues for each utility. PAC was 22% and PGE was 17%.

- The final step is to compare the "post 838" percentage to the baseline funding limit. Through 2012 activity, PAC is 5 percentage points below the limit and PGE is 1 percentage below their limit.
- If cumulative spending reached or exceeded baseline spending, parties agreed that time would be needed for "correction" to be able to adjust program spending below the limit within 2 years.

This development of a process to limit benefits was never a question of setting a dollar in (revenues from large customers) to dollar out (expenditures on large customers) measure but rather to find a way to set a reasonable level of spending for large users that made sure there was enough funding left for those who were contributing to 838.

Current Situation

In anticipation of reaching the funding limit in PGE territory before 2015, Energy Trust staff raised the topic of possible impacts on the program at the June 2013 board retreat. Program staff outlined possible program tactics that could be employed if we were to reach the limit and need to take actions to adjust program spending downward.

Due to possible limitations to acquire cost effective savings that could result from Energy Trust managing to the existing funding caps, OPUC staff asked Energy Trust to provide more information on the topic. Because Energy Trust did not have complete data describing r how much of the 1149 revenue received is from large energy users, OPUC staff issued a data request to utilities to provide that information. As a result, the full picture of costs and benefits to large energy users and all ratepayers could be compared. Although a larger portion of funding goes to large energy users than the portion of 1149 revenues contributed by that group, the cost of savings acquired is much lower than other projects and therefore the savings per ratepayer dollar invested are much higher. All ratepayers are benefiting from the higher savings.

Strong program interest from large sites is expected to continue, leading to the potential for the current funding cap methodology to limit Energy Trust's ability to acquire all cost effective resources. If in PGE territory we were to continue >1aMW incentive spending at a rate equal to the average of the past 3 years (2010-2012, $5.9M/yr. in incentives), we would exceed the current spending limit in 2015. In PAC territory, we don't foresee a short-term risk of needing to forego resource acquisition with the current methodology and demand. Annual demand for funding for customers>1 aMW would need to increase 40% and hold steady for the next 4 years to hit the spending cap.

To maintain compliance with the cap for PGE will cause us to limit annual spending on customers > 1 aMW. To reach goals we will need to redirect funds above the cap to higher cost projects from 838 eligible sites. On average, large site projects are 2.5 times more cost effective than 838 eligible site projects. Therefore directing funding away from large site projects would result in less savings at higher cost. It is also possible that as a consequence Energy Trust does not meet IRP goals in some years. The result may mean lost opportunity of low cost resource, unmet demand and unrealized savings. In the long run, some savings from larger sites will not be captured. This is a particular threat for "lost opportunity" savings that must be acquired during specific events, such as a major capital investment in a process line upgrade or redesign or a building renovation. A significant share of Energy Trust large customer savings comes through such events.

Outreach Efforts

Energy Trust convened a meeting of stakeholders January 31, 2014 to discuss the issue and current situation. In attendance were representatives from utilities, OPUC staff, CUB, ICNU, NWFPA, NWEC, NEEC, ODOE, and Energy Trust staff. A variety of views were heard. Stakeholders offered a range of ideas to address the funding limitations including;

- Expand 838 charges to large energy users (would require legislative action)
- Revisit the methodology so that it's more reflective of current large energy user potential activity and available cost effective resource
- Change the methodology to allow more funding to large users under the condition that those paying to 838 see direct rate benefit from the low cost efficiency in which they are investing (would require rate re-design)

No consensus was reached among attendees but Energy Trust did agree to keep the group fully informed of the situation going forward.

Next Steps

Energy Trust plans to provide results of the 2013 analysis in April 2014. If we have met or exceeded the funding limit in PGE territory, we plan to begin to take programmatic actions to lower funding and come back into compliance over a two year period. These actions will be worked through with our Conservation Advisory Council.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision	)
____	)

EXHIBIT ICNU/302

CUB RESPONSES TO ICNU DATA REQUESTS

August 13, 2014

Citizens' Utility Board of Oregon

610 SW Broadway, Suite 400
Portland, OR 97205
(503) 227-1984 ▪ fax (503) 274-2956 ▪ cub@oregoncub.org ▪ www.oregoncub.org

August 4, 2014

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Michael P. Gorman
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RE: UE 283 CUB's August 4, 2014 Data Responses to ICNU's July 24, 2014 Data Requests

Dear Brad, Brad and Michael:

The following are CUB's Data Responses to ICNU's Data Requests dated July 24, 2014.

I. <u>DATA REQUESTS</u>

0011 Please provide all documents in CUB's possession that memorialize or in any way refer to the 18.4% industrial cap on energy efficiency funding.

Response 0011: CUB has reviewed our archives and found the following documents: PGE Advice Filing 07-25, dated October 26, 2007, and also one attachment to a Data Response related to the Advice Filing. In the Advice Filing, PGE references the requirement that there would be "no shift in the allocation of Public Purpose Funding", and in the attachment provides the methodology used to prevent the shift in the allocation of the Public Purpose Funding.

0012 Please provide all documents in CUB's possession that demonstrate that ICNU agreed to the 18.4% industrial cap on energy efficiency funding.

Response 0012: CUB has no documents that demonstrate that ICNU agreed to the 18.4 % cap beyond PGE's Reply Testimony the UE 283 docket. ICNU opposed SB 838 which included the prohibition on industrial customers receiving a direct benefit from SB 838 energy efficiency programs.

PGE's Reply testimony in the UE 283 docket states that:

"To ensure that customers with loads less than one average megawatt were not subsidizing customers with over one average megawatt, PGE, PacifiCorp, the ETO, Staff, CUB and ICNU reached an informal agreement that the ETO would not exceed a historical amount of energy efficiency funding for the larger customers' energy efficiency projects. PGE's cap of 18% was an historical average of the ETO energy efficiency payments (under SB 1149) to PGE's customers over one average megawatt, for the three years preceding the passage of SB 838."

0013 In order to achieve all cost-effective energy efficiency, would CUB agree to removing the 18.4% industrial cap on energy efficiency funding and limiting such funding to customers over 1 aMW to the total energy efficiency funding derived from SB 1149 funds? If not, please explain in detail why not.

Response 0013: Yes. Our proposal in the UE 283 rate case would remove the 18.4% cap on industrial energy efficiency programs by recognizing that the direct benefits of SB 838 energy efficiency programs are lower costs for the utility system. Energy efficiency is a system resource, just like a natural gas plant or a wind farm. CUB would support increasing energy efficiency programs targeted at large customers as long as it is done in a manner that does not require a significant subsidy from customers with smaller loads. Our proposal accomplishes this because it flows the benefits of energy efficiency back to the classes of customers who fund that energy efficiency so the direct benefit from energy efficiency programs is directed at the classes of customers who pay for those programs.

0014 Please provide all data, documents, and other evidence relied on by CUB for its statement that "EE is a cumulative resource." CUB/100 at 21:7.

Response 0014: PGE[1] and The Energy Trust of Oregon[2] consider EE a cumulative resource. In addition, logistically, once a conservation measure has been adopted, and meets load for a particular structure, or appliance, that measure continues to serve in its capacity for its useful life. Data abounds online testifying to the useful life of conservation measures. The ETO provides analysis on conservation measures.[3]

In CUB's experience ratemaking has for at least 15 years treated energy efficiency as an expense in the year the expenditure is made, but the benefits of energy efficiency flow over the life of the measure. This means that in any particular year, customers are benefiting from energy efficiency measures that have been procured in previous years.

0015 Reference CUB's response to ICNU Data Request 3. Please provide all support for CUB's assertion that PGE "is unable to acquire all cost-effective energy efficiency in its forecasted test year."

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[1] LC 56 page 56 figure 4-2.
[2] http://energytrust.org/library/reports/Brief-Energy_Efficiency_Programs.pdf, page 20, figure 16
[3] http://energytrust.org/library/reports/resource_assesment/etoresourceassessfinal.pdf

Response 0015:

A. On January 31, 2014, CUB attended a meeting of stakeholders at the ETO where this issue was discussed.

B. In its UE 283 Response testimony, PGE stated that "spending will need to be curtailed in 2015 or sooner."[4] 2015 is the current test year.

C. In its LC 56 IRP Reply Comments, PGE suggests that "ETO is likely to reach it funding limit for industrial customers this year" and that ETO has estimated that 1.5 to 2 MWa of industrial EE measure will be missed annually.[5]

"With respect to the funding cap on industrial customers, CUB is correct; the ETO's forecast presumes that the funding limitation on industrial energy efficiency measures is removed or similarly resolved to allow unfettered ongoing large customer EE funding. Should the funding limitation not be resolved, the ETO has estimated that 1.5-2 MWa of incremental industrial EE measures will be missed annually. The ETO is likely to reach its funding limit for PGE's industrial customers this year.

PGE is advocating in its General Rate Case testimony for a resolution that addresses the current large customer EE funding constraint. Losing cost effective energy efficiency opportunities would ultimately require acquisition of more expensive resource alternatives to meet long term energy and capacity needs".

D. The Energy Trust forecasts Conservation losses without a resolution to this issue.

"If incentive funding for sites in PGE territory is capped over the next five years, 8-12 aMW of savings could be lost, or 32-48 aMW over a 20-year period. Energy Trust may be able to influence changes in project timing, although if funding continues to be limited, the issue will remain. Furthermore, many large efficiency projects are scheduled as part of other planned capital improvements and might not be available if funding is not provided at the right time".[6]

0016 Reference CUB's response to ICNU Data Request 3. Is it CUB's position that the 18.4% cap on industrial energy efficiency in PGE's service territory is the same as the "direct benefit" cap established in SB 838?

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[4] UE 283 PGE 1600 pg 25.
[5] LC 56 -PGE's Reply Comments at page 20.
[6] http://energytrust.org/library/reports/Brief-Energy_Efficiency_Programs.pdf, page 27-28

Response 0016: No. SB 838 requires the Commission to ensure that a large customer does "not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates under this section." This is not a cap on direct benefits – this is a prohibition on large industrial customers from receiving a direct benefit from SB 838 energy efficiency programs.

When the energy efficiency section was added to SB 838, CUB was assured that it would not lead to greater subsidies from small customers to industrial customers for energy efficiency programs because the direct benefit prohibition would prevent the shifting of established public purpose funded programs to industrial customers. The 18.4 % cap on industrial efficiency was believed to be adequate to prevent an expansion of the subsidies from small customers to large industrial customers for energy efficiency programs. As CUB's testimony shows, the 18.4 % cap on industrial efficiency is no longer adequate to prevent residential and small commercial customers from significantly subsidizing large industrial customers to support the system resource of energy efficiency.

In this sense, the 18.4% cap on industrial efficiency was the tool or the methodology that was selected to ensure that subsidies were not increased and industrial customers did not receive a direct benefit from SB 838 energy efficiency programs. But that methodology has not been successful at preventing the subsidy from growing to a point that it is significant. Industrial customers are clearly receiving a direct benefit from the lower cost resources that are being acquired through SB 838 energy efficiency programs, even though SB 838 prohibits such a direct benefit.

Sincerely,

Jaime McGovern, Ph.D.
Sr. Utility Analyst
Citizens' Utility Board of Oregon
610 SW Broadway, Ste. 400
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(503) 227-1984 phone
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From: "Fred Gordon" <fred@energytrust.org>
To: "KOHO Lori G." <Lori.Koho@state.or.us>, "Jones JR, Don (DSM)" <Don.Jones_JR@PacifiCorp.com>, "Joe Barra" <Joe.Barra@pgn.com>, "Laura Rooke" <Laura.Rooke@pgn.com>, "Julie Brandis" <julie@aoi.org>, "Michael B. Early " <mearly@icnu.org>, "Steve Lacey" <steve@energytrust.org>
Date: Tuesday, August 14, 2007 6:46 PM
Subject: Proposal for tracking expenditures for efficiency above and below 1 AMW/customer
CC: "Margie Harris" <margie@energytrust.org>, "John Volkman" <John.Volkman@energytrust.org>, "Linda Rudawitz" <Linda.Rudawitz@energytrust.org>, "Jill Steiner" <jill.steiner@energytrust.org>, "Matt Braman" <matt.braman@energytrust.org>

Pursuant to our last working group meeting at the PUC, I have met with PGE and Pacificorp to develop a proposal for how Energy Trust will assure that new efficiency funds under SB838 will go to the customers, as a group, who provide the funds. The attached proposal was developed with the active participation of PGE and Pacificorp. Due to time limitations and my illness, they have not seen the modest revisions in this draft. I hope and believe that the revisions are consistent with their preferences as stated in our meeting last Thursday. I will take responsibility for any needed corrections.

This document presents the proposal in three levels of detail- first in concept, then a summary of tasks to make it happen, then a detailed nuts-and-bolts description of what ET and the utilities would need to do under each task. I hope the detailed description can be taken as approximate, as the details will likely evolve slightly as we try to execute them. The details were developed to test the feasibility of the task set, to show that the method is reasonable and fair and as precise as practical, and to clarify likely assignments for utilities, ET planning staff and ET program operations.

If this proposal has the principles about right, I would be happy to take any further comments as needed to finalize it as soon as possible, as this agreement is the first step on a critical path to developing a filing. Agreement on these principles will define analytic work needed at the utilities and Energy Trust. I look forward to your comments.

If you think it necessary to meet individually or collectively to fully understand or to finalize this, let me know and I will work with the PUC staff to arrange it as quickly as possible.

Fred Gordon
Energy Trust of Oregon, Inc.
Director of Planning and Evaluation
phone: 503-445-7602
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STRAW MAN PROPOSAL FOR ADDRESSING REQUIREMENTS IN SB838 NOT TO INCREASE EFFICIENCY EXPENDITURES ON CUSTOMERS > 1 AMW

Summary: This is a draft proposal for an administrative system that assures that SB838 efficiency funding does not result in additional funding for customers who are not providing the funding. Specifically it assures that the Energy Trust (ET) will not, on a cumulative basis, spend a larger percentage of SB1149 money on incentives for all customers over 1 AMW than it expected to spend prior to the passage of SB838, This will not be more than it has spent on these customers historically. Additionally, SB838 money will not go directly to equipment over 1 AMW. Compliance is assured through the following system:

- A control percentage of spending > 1 AMW is established by reviewing the data for the past three years and reviewing forecasts of spending.
- If ET incentive spending for customers > 1AMW exceeds this percentage over a cumulative period (from the beginning of SB838 efficiency funding for that utility to the end of the last calendar year) then ET would be required to reduce spending on larger projects in the ensuing two calendar years to bring the cumulative total back into balance with the control percentage. This assures fairly while minimizing accounting costs. This system also provides the flexibility for the Energy Trust to pursue large, low cost projects by making balancing adjustments in later years.
- Cumulative compliance with the historic average is analyzed annually at the time of the annual report, and is also forecast each year as part of the budget process.

PUC performance metrics would be based on the combined funding from SB1149 and SB838. However, as needed, ET would describe cost and savings under each bill.

Basic Tasks. Steps to achieve these tasks are introduced in this section and detailed in the next section

1. **Define Boundary.** “1 AMW Per meter, totalized meter, or site or what?” We propose that to start the “customer” be defined as the meter so that the process can begin, but customers can propose “sites” consistent with the self-direct definition and utilities will certify and use these. Sites currently certified sites for self-direct are defined as “customers” from the beginning. An approach to estimation for new buildings is also developed in the detailed discussion below.

2. **Utilities will Project Load & Resource Potential from Customers Smaller than 1 AMW.** As requested ET can help utilities with the analysis. ET will need load data provided by utilities once the boundary definition is set, to analyze efficiency resources..

3. **Describe Historic ET Spending Patterns.** ET will develop an analysis of historic ET incentive funding by <1 and > 1 AMW, with data from utilities as needed.

4. **ET Develops Control Percentage.** This is the maximum percent of SB1149 funding to go to meters > 1 AMW. Two options for doing this are presented in the next section.

5. **ET will develop and Implement a Management Approach.** ET will develop systems to assure that over a multi-year period overall funding for customers >1 AMW does not exceed these trend forecasts, and to correct for temporary overages.

6. **Reporting.** ET will report on how it will stay within these bounds in two ways:

    a. As part of our budget process, we will forecast spending by program above and below 1 AMW.
    b. As part of our annual report process, we will report on how it went for the prior year and cumulatively from 2008 forward.
    c. If required by the legislature we will also report on spending and savings separately for SB838 funds and SB1149 funds. However the separation will be approximate, and will require agreement on assumptions.

Detailed Tasks:

1. ***Define Boundary.*** We propose that to start the "customer" be defined as the meter so that the process can begin, but customers can propose "sites" consistent with the self-direct definition and utilities will certify and use these. Customer with currently certified sites for self-direct would be defined in their entirety as "customers" from the beginning. This approach is proposed because
   - It is consistent with the self-direct program and thus will minimize customer confusion.
   - It also prevents utilities from needing to perform all the analyses to certify sites prior to the proposal for new funding, which would cause significant delay.
   - It also avoids the confusion which would occur if an analysis would require splitting efficiency measures between meters. Some measures save energy on multiple meters, and some customers do not know what loads are on which meter.

   Another issue is what to do with new buildings. The utilities have to figure this out to classify the buildings for rates- so we assume that ET will follow their lead. Options include:
   a. *Treat them all as <1 AMW since their historic load is zero* (convenient but not equitable; they would reap the benefits and not pay)
   b. *Use the projected connected load/meter that they provide to the utility x a standard load factor.* We could brainstorm with the utilities what the standard load factors are for various building types. Utilities need to classify by connected load anyway, the only new part is the load factor.

   Energy Trust may contract with some facilities for efficiency years before there's a utility capacity estimate or rate classification. We sometimes may need to rough out a pre-guess at the classification for purposes of forecasting spending in the two groups. Mistakes are not that big a deal as long as we can correct later.

2. **Utilities will Project Load &Resource Potential Below 1 AMW.**
   a. Utilities will provide total load by class of customer and utility < 1AMW and > 1 AMW for 2006.
   b. Utilities will apply this data to define the load in the rate class or other rate discriminator for the new charge..

   Utilities will also use this to update their their resource assessment to develop potential savings for each group by utility. This will influence the size of funding (depends on timing) Energy Trust will assist as requested.

3. **Describe Historic ET Spending Patterns.** Identify the % of ET incentive dollars in past three years which are >1 AMW per customer.. If the proposal above is accepted and customers will eventually be defined as sites consistent with the self-direction definition, ET will use functional sites as the basis for analysis, ET will
   a. Provide utilities with a list of participating customers, all of whom have signed releases allowing access to energy use information.
   b. Ask utilities to identify the subset with meters that fit the "large" definition".
   c. To provide energy use data consistent with the existing data-sharing agreement for all meters.
   d. For sites with a "large" meter, Energy Trust will assume that the entire site will eventually be certified as "large" and will allocate the entire incentive expenditure for site to the "large" category.

   ET will summarize the percent of SB1149 efficiency expenditures by year and for the total three year period which went to customers >1 AMW, both in total and by program. The total three-year all-program percentage would be used as the "control percentage". Data by program or year would be used only to help in forecasting and program planning.

4. **ET Develops Control Percentage**.
    a. ***Adjust for Forecast***. In early 2007, ET forecasted trends in spending by sector through 2012. The historic percentage could be adjusted for these trends. This would modestly decrease the amount of spending allowable for customers > 1 AMW. This would make the control percentage consistent with prior intent.
    b. Forecast only runs through Feb, 2012. After that point, the control percentage would be frozen.

5. **ET will develop and Implement a Management Approach.**
    a. Track % of ET incentive $ in each year which is going to customers > 1AMW.
        i. ET Develops a field in Fast Track database for utility rate class, which should track MW status. This field should be set up to record successive annual reclassifications provided by utilities.
        ii. Develop crystal report or other reporting tool which analyzes $ of incentives going to > 1 AMW by program. Report should work for both forecasting and reporting after the fact..
    b. Train PDCs and/or ATACs (ET contractors who work with the site) to identify when a project may be on a meter>1 AMW, and then identify the meter and have ET check the rate. ET must then directly acquire the load data, which is now done by the Program Management Contractor.
        i. This will involve some back-and-fill for projects where the project or study is already approved, but the project will be completed in 2008 or beyond.
        ii. This will need to become a key element of quality control and acceptance procedures for projects.
    c. Pro Rate Site Incentives to have the correct amount in < 1AMW and > 1AMW categories in the tracking system. *.* For customers who have projects covering multiple meters but have not certified a site. (We hope this is rare) We will need to train contractors to define a site consistently with the utility definition, and identify all meters. The contractor will work with ET personnel to come up with a pro-rate between large and small meters for the site. This will not impact how ET treats the site, but will influence allocation of costs from that site to large vs. small.
    d. ***Alternative to c: Identify Projects by Meter.*** For sites with large and small meters, require consumers and contractors to identify new potential projects by meter, as best they can.
        i. Where a measure serves more than one meter, the audit contractor and customer should estimate savings by meter the best they can, and use that to pro-rate costs. This will be problematic as a policy and not recommended because customers may not know what equipment is on which meter.

6. **Reporting**
    a. ***Savings reporting*** by SB838 versus SB1149 would be based on the same data and methods describe above. Once we track and pro rate we can report
    b. For ***cost reporting***, there are two options:
        i. *Option 1*. Assume that average cost/kwh is the same for both piles of money. For overall reporting, assign costs in proportion to savings by program. This is simple, but would result in reports of increased cost/kWh for SB1149, and probably understate costs for SB838. This is not recommended.
        ii. *Option 2*. Assume that cost/kwh for SB 1149 would remain same as 2007. Allocate costs above (SB1149 new kwh x 2007 costs) this level to SB838. This is recommended.
            1. Detail issue: use 07 forecasts or 06 annual report? Maybe 06 to prevent dust-up when 07 is not exactly as predicted.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision	)
	)

EXHIBIT ICNU/303

COMPANY RESPONSES TO ICNU DATA REQUESTS

August 13, 2014

March 20, 2014

TO: Nadine Hanhan
nadine@oregoncub.org
dockets@oregoncub.org

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to CUB Data Request No. 027
Dated March 6, 2014

Request:

Does PGE see any barriers over the next 5 years to achieving all cost effective energy efficiency contained in the IRP?

Response:

Yes, PGE does foresee potential barriers within the next five years to achieving all cost-effective energy efficiency (EE) in the IRP. To highlight one such barrier and as discussed in PGE's Response to CUB Data Request No. 026, large-user funding limitations could become a barrier to achieving all cost-effective EE savings in that business sector. Project interest for this customer group has been much higher in the past three years than the years against which the funding cap is measured. We expect this trend of interest to remain steady or increase, largely in the semiconductor industry, hospitals, and colleges and universities with a range of cost-effective projects.

May 6, 2014

TO: Nadine Hanhan
nadine@oregoncub.org
dockets@oregoncub.org

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to CUB Data Request No. 037
Dated April 23, 2014

Request:

Does the Company have predictions for the SB 1149 and SB 838 funds in 2015. If so, please provide them (a) SB 1149 funds broken down by customer class and (b) SB 838 funds broken down by customer class.

Response:

Attachment 037-A contains 2015 projections of both SB 1149 (Schedule 108) and SB 838 (Schedule 109) collections by rate schedule. For the SB 1149 projections, PGE presumed a January 1, 2015 on-line date for both Port Westward 2 and Tucannon River.

Rate Schedule	2015 SB 1149 Amount
Schedule 7	$26,423,221
Schedule 15	$109,524
Schedule 32	$5,239,857
Schedule 38	$180,309
Schedule 47	$98,694
Schedule 49	$259,070
Schedule 83	$7,581,648
Schedule 85	$7,523,811
Schedule 89	$1,584,333
Schedule 90	$1,724,197
Schedule 91/95	$540,061
Schedule 92	$8,026
Schedule 485	$403,213
Schedule 489	$256,089
Total	$51,932,052

July 30, 2014

TO: Bradley Van Cleve
Bradley Mullins
Ali Al-Jabir

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 142
Dated July 22, 2014

Request:

For each of the last ten years, please identify the total amount (in terms of dollars) of revenue PGE provided to the Energy Trust of Oregon to fund energy efficiency measures (please exclude funding earmarked for other ETO projects). Please separately identify the amount that represents SB 1149 dollars and the amount that represents SB 838 dollars.

Response:

Please reference Attachment 142-A for SB 838 amounts and Attachment 142-B for the SB 1149 amounts.

Energy Efficiency Funding - SCHEDULE 109

	January	February	March	April	May	June	July	August	September	October	November	December	Totals
2008													
Amount billed/collected						424,709.05	1,075,654.80	1,099,514.57	1,093,167.55	1,011,464.74	1,037,816.20	1,218,270.30	6,960,597.21
Uncollectible						(1,704.36)	(4,316.60)	(4,412.35)	(4,848.20)	(4,485.85)	(4,602.71)	(5,805.06)	(30,175.13)
Remittance	-	-	-	-	-	423,004.69	1,071,338.20	1,095,102.22	1,088,319.35	1,006,978.89	1,033,213.49	1,212,465.24	6,930,422.08
2009	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	1,506,202.89	1,290,742.48	1,264,145.82	1,130,646.20	997,876.60	1,010,406.28	1,023,179.50	1,174,138.73	1,062,515.39	992,677.15	1,052,393.05	1,330,470.08	13,835,394.17
Uncollectible	(7,177.06)	(6,150.39)	(6,180.41)	(5,527.73)	(4,878.62)	(4,939.88)	(5,359.41)	(6,150.14)	(5,226.51)	(4,882.98)	(5,176.72)	(6,830.63)	(68,480.48)
Remittance	1,499,025.83	1,284,592.09	1,257,965.41	1,125,118.47	992,997.98	1,005,466.40	1,017,820.09	1,167,988.59	1,057,288.88	987,794.17	1,047,216.33	1,323,639.45	13,766,913.69
2010	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	1,681,912.96	1,831,048.42	1,713,662.74	1,612,118.88	1,503,813.46	1,750,803.66	2,093,777.13	2,256,416.50	2,150,790.75	2,017,673.98	2,195,915.74	2,698,722.96	23,506,657.18
Uncollectible	(8,634.94)	(9,400.60)	(8,520.33)	(8,015.46)	(7,476.96)	(7,936.39)	(9,491.09)	(10,228.34)	(9,297.87)	(8,722.40)	(9,492.94)	(11,518.15)	(108,735.47)
Remittance	1,673,278.02	1,821,647.82	1,705,142.41	1,604,103.42	1,496,336.50	1,742,867.27	2,084,286.04	2,246,188.16	2,141,492.88	2,008,951.58	2,186,422.80	2,687,204.81	23,397,921.71
2011	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	2,884,237.22	2,591,139.62	2,624,890.14	2,286,873.17	2,105,726.10	2,036,665.78	2,014,948.89	2,162,966.11	2,221,738.35	2,023,787.90	2,228,587.06	2,716,953.89	27,898,514.23
Uncollectible	(12,309.92)	(11,058.98)	(11,854.00)	(10,327.52)	(9,509.46)	(8,594.73)	(8,503.08)	(9,127.72)	(10,344.41)	(9,422.76)	(10,376.30)	(12,022.52)	(123,451.40)
Remittance	2,871,927.30	2,580,080.64	2,613,036.14	2,276,545.65	2,096,216.64	2,028,071.05	2,006,445.81	2,153,838.39	2,211,393.94	2,014,365.14	2,218,210.76	2,704,931.37	27,775,062.83
2012	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	3,670,661.55	4,026,225.40	3,831,062.40	3,384,201.38	3,072,178.68	3,021,766.72	3,164,515.38	3,298,800.93	3,283,816.08	3,033,402.78	3,275,381.90	3,922,185.15	40,984,198.35
Uncollectible	(16,242.68)	(17,816.05)	(16,055.98)	(14,183.19)	(12,875.50)	(13,724.86)	(14,373.23)	(14,983.15)	(17,975.61)	(16,604.85)	(17,929.44)	(16,261.38)	(189,025.92)
Remittance	3,654,418.87	4,008,409.35	3,815,006.42	3,370,018.19	3,059,303.18	3,008,041.86	3,150,142.15	3,283,817.78	3,265,840.47	3,016,797.93	3,257,452.46	3,905,923.77	40,795,172.43
2013	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	4,844,489.23	4,650,345.50	4,226,700.25	3,857,869.62	3,668,170.73	3,649,967.92	3,928,210.80	4,041,299.86	4,041,561.52	3,644,599.95	3,817,118.31	5,222,503.16	49,592,836.85
Uncollectible	(20,085.25)	(19,280.33)	(17,278.75)	(15,770.97)	(14,995.48)	(14,077.93)	(15,151.11)	(15,587.29)	(14,052.51)	(12,672.27)	(13,272.12)	(17,683.40)	(189,907.41)
Remittance	4,824,403.98	4,631,065.17	4,209,421.50	3,842,098.65	3,653,175.25	3,635,889.99	3,913,059.69	4,025,712.57	4,027,509.01	3,631,927.68	3,803,846.19	5,204,819.76	49,402,929.44
2014	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	5,189,572.46	4,794,270.27	4,300,282.66	3,857,900.54	3,693,624.43	3,618,435.02							25,454,085.38
Uncollectible	(17,571.89)	(16,233.40)	(14,612.36)	(13,109.15)	(12,550.94)	(12,928.67)							(87,006.41)
Remittance	5,172,000.57	4,778,036.87	4,285,670.30	3,844,791.39	3,681,073.49	3,605,506.35	-	-	-	-	-	-	25,367,078.97
TOTAL June 2008 - YTD 2014	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	19,777,076.31	19,183,771.69	17,960,744.01	16,129,609.79	15,041,390.00	15,512,754.43	13,300,286.50	14,033,136.70	13,853,589.64	12,723,606.50	13,607,212.26	17,109,105.54	162,778,197.99
Uncollectible	(82,021.74)	(79,939.75)	(74,501.83)	(66,934.02)	(62,286.96)	(63,906.82)	(57,194.52)	(60,488.99)	(61,745.11)	(56,791.11)	(60,850.23)	(70,121.14)	(709,775.81)
Remittance	19,695,054.57	19,103,831.94	17,886,242.18	16,062,675.77	14,979,103.04	15,448,847.61	13,243,091.98	13,972,647.71	13,791,844.53	12,666,815.39	13,546,362.03	17,038,984.40	162,068,422.18

Note: Billing for program was initiated mid June 2008.

Energy Trust of Oregon - Conservation

MONTH / YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	YEAR-TO-DATE
2004	2,015,295.24	1,939,185.58	1,719,732.35	1,605,169.50	1,513,468.13	1,584,377.54	1,664,738.10	1,716,022.63	1,765,416.90	1,563,599.16	1,618,741.27	1,899,135.99	20,604,882.39
2005	2,097,525.58	1,886,136.99	1,778,874.54	1,736,003.64	1,624,344.71	1,632,069.82	1,617,230.33	1,783,809.95	1,752,086.50	1,652,082.05	1,606,512.61	2,103,365.56	21,270,042.27
2006	2,152,327.66	2,130,305.30	2,025,543.15	1,810,953.37	1,697,874.65	1,700,094.25	1,831,253.32	1,865,045.72	1,837,591.54	1,783,207.06	1,735,576.43	2,104,439.89	22,721,457.99
2007	2,460,334.41	2,288,903.57	2,093,926.82	1,915,104.39	1,806,263.47	1,899,976.14	2,122,985.42	2,154,028.52	2,070,427.37	2,023,704.91	2,183,865.70	2,447,920.13	25,467,440.86
2008	2,728,280.31	2,462,725.80	2,389,316.35	2,232,226.09	2,079,582.92	2,004,530.58	2,098,175.93	2,120,618.90	2,056,567.78	1,974,984.45	2,003,193.86	2,236,844.41	26,387,047.38
2009	2,778,935.67	2,572,090.40	2,404,169.27	2,205,095.50	1,964,631.38	1,945,723.21	2,038,859.22	2,311,188.16	2,114,281.82	2,002,015.66	2,095,786.63	2,536,021.87	26,968,798.79
2010	2,802,172.52	2,360,497.67	2,374,622.54	2,201,903.57	2,058,839.59	2,056,007.75	2,089,969.83	2,233,522.96	2,146,644.99	2,026,083.21	2,179,477.26	2,538,307.98	27,068,049.87
2011	2,776,973.21	2,606,150.77	2,605,180.72	2,341,970.21	2,195,423.94	2,134,608.35	2,243,263.40	2,253,490.84	2,348,904.28	2,178,641.51	2,287,854.69	2,725,666.56	28,698,128.48
2012	2,892,839.65	2,620,307.73	2,502,217.46	2,309,531.22	2,092,155.39	2,063,923.52	2,166,265.39	2,182,204.45	2,209,036.89	2,130,405.84	2,225,104.17	2,577,833.28	27,971,824.99
2013	2,782,804.74	2,360,709.07	2,235,951.47	2,072,721.54	2,047,128.50	1,974,726.35	2,091,302.29	2,065,387.97	2,184,065.56	1,998,758.98	2,093,016.01	2,741,384.40	26,647,956.88

July 30, 2014

TO: Bradley Van Cleve
Bradley Mullins
Ali Al-Jabir

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 145
Dated July 22, 2014

Request:

Please reconcile PGE's testimony that the 18% industrial energy efficiency cap will be reached in 2014 (PGE/1600 at 25:2) with its May 21, 2014 filing (Advice No. 14-08), which reduced Schedule 109 energy efficiency funding by $4 million and claimed that "[d]espite this level of reduction in annual funding, the ETO estimates that it can still achieve its forecasted energy efficiency savings goals of 37.6, 34.0, and 30.6 average megawatts for the years 2014-2016 respectively."

Response:

PGE objects to this request on the basis of ambiguity and relevance. Without waiving its objection, PGE responds as follows:

The ETO informed PGE that the industrial EE cap might be reached in 2014. Subsequent communications with the ETO now indicate that the cap may be reached in 2015 rather than 2014. Please reference PGE's Response to ICNU Data Request No. 147 for more information.

Regarding PGE Advice 14-08, PGE relied on the statements made by the ETO regarding the level of funding needed to achieve their energy efficiency goals. As stated in the transmittal letter to this filing, one reason for the reduction in Schedule 109 funding was to reduce the amount of funds that were carried over from prior periods.

August 1, 2014

TO: Bradley Van Cleve
Bradley Mullins
Ali Al-Jabir

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 147
Dated July 22, 2014

Request:

Please provide copies of all documents prepared by PGE in the last 5 years that refer or relate to: a) energy efficiency funding provided by customers over 1 aMW, b) energy savings due to energy efficiency measures implemented by customers over 1 aMW, c) the cap on investment in energy efficiency resulting SB 838, or d) the potential energy efficiency projects and energy savings available by rate class or rate schedule.

Response:

PGE objects to this request as overly broad and unduly burdensome. Subject to and without waiving its objection, PGE responds as follows:

PGE requested information from employees from the following departments: Rates & Regulatory Affairs, Integrated Resource Plan, and Customer Mass Programs. Attachment 147-A contains the material related to this request.

The documents included in Attachment 147-A include the notes from various ETO Conservation Advisory Council meetings, a summary of some of those meetings, and early 2013 results for PGE from the ETO that contain an estimate of the potential lost conservation opportunities due to the one average megawatt cap.

Further information may be found at the Energy Trust of Oregon's website:
http://energytrust.org/About/public-meetings/CACMeetings.aspx
http://energytrust.org/About/public-meetings/BDMeetings.aspx

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision	)
	)

EXHIBIT ICNU/304

ENERGY TRUST OF OREGON, "FUNDING LIMITATIONS FOR LARGE ENERGY USERS" (APRIL 16, 2014)

August 13, 2014

Funding Limitations for Large Energy Users

History of the Methodology Used in Determining the Limit and Current Status

April 16, 2014

Background

The 1999 Oregon law that gave rise to Energy Trust, SB 1149, required the electric utilities to devote three percent of their revenues to electric efficiency programs. The three-percent charge is collected from all electric customers regardless of the amount of energy they use. A 2007 state law, SB 838, authorized electric utilities to add an additional amount to the bills of all customer sites with usage less than or equal to 1aMW. The resulting funds are to be used to fund electric efficiency beyond the established public purpose charge from SB 1149, to meet efficiency resource needs identified in utility integrated resource planning.

Because larger customers are not paying in to the 838 fund, they are ineligible for efficiency program funding from 838. Language describing this efficiency funding mechanism in legislation reads as follows;

> SECTION 46.
> (1) In addition to the public purpose charge established by ORS 757.612, the Public Utility Commission may authorize an electric company to include in its rates the costs of funding or implementing cost-effective energy conservation measures implemented on or after the effective date of this 2007 Act. The costs may include amounts for weatherization programs that conserve energy.
> (2) The commission shall ensure that a retail electricity consumer with a load greater than one average megawatt:
>> (a) Is not required to pay an amount that is more than three percent of the consumers' total cost of electricity service for the public purpose charge under ORS 757.612 and any amounts included in rates under this section; and
>> (b) Does not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates under this section.

Large energy users are both commercial and industrial customers that span the mix of market segments from hospitals, higher education campuses and commercial real estate to food processing, cold storage facilities, metals, forest products, semiconductors and other manufacturing.

As a way of assuring that large customers are not benefitting from this added funding, a 2008 informal multiparty agreement set a limit to the percentage of 1149 incentive funding that Energy Trust can allocate to customers over 1 aMW.

Funding Limit Methodology

One of the first steps in implementing 838 efficiency funding was to set up processes for ensuring that large energy users were not charged and did not receive direct benefit from funds collected. This development of a process to limit benefits was never a question of setting a dollar in (revenues from large customers) to dollar out (expenditures on large customers) measure but rather to find a way to set a reasonable level of spending for large users that made sure they were not benefiting from 838 funding.

1. Defining the baseline "pre-838"

To ensure that those that are not contributing are not directly benefiting was interpreted as meaning that the “pre-838” spending practices should not be exceeded going forward. The baseline spending was defined as project incentives paid to >1aMW sites compared to total 1149 efficiency revenues and are calculated on a utility specific basis. For PacifiCorp the baseline period is 2005-2007 with incentives being 27% of total 1149 revenues. For PGE, the baseline period covers 2004-2007 with incentives being 18.4% of total 1149 revenues.

The difference is representative of specific project activity that occurred during the base period; PAC territory saw many forest products projects move forward while PGE activity was largely limited to one large paper mill. A larger and growing proportion of PGE’s large customer loads are from the semiconductor industry. Energy Trust programs were not as active in that industry until “post 838”.

2. Defining the current spending, “post 838”

Determining current spending was agreed to be calculated as a rolling, cumulative look. Because large projects can have lumpy impacts on program incentive spending with year by year variability, measuring compliance on a year to year basis did not seem appropriate. The resulting methodology takes a broader perspective by summing all large energy user post 838 incentives are divided by total 1149 revenues across the same time period.

For example, to determine spending through 2012, by utility, all large user incentives from 2008-2012 are summed and divided by the total 1149 efficiency revenues by utility. PacifiCorp was 22% and PGE was 17%.

3. Determining compliance to limits

The final step is to compare the “post 838” percentage to the baseline funding limit. Through 2012 activity, PAC is 5 percentage points below the limit and PGE is 1 percentage below their limit. 2013 results are currently in draft and expected to be finalized by May 2014.

If cumulative spending reached or exceeded baseline spending, parties agreed that time would be needed for “correction” to be able to adjust program spending below the limit within 2 years.

Results to Date

Due to success of the programs serving them, savings from large customers and incentives going to them have been increasing. Strong program interest from large sites is expected to continue, leading to the potential for the current funding cap methodology to limit Energy Trust’s ability to acquire all cost effective resources. If in PGE territory we were to continue >1aMW incentive spending at a rate equal to the average of the past 3 years (2010-2012, $5.9M/yr. in incentives), we would exceed the current spending limit in 2015. Figure 1 shows year by year incentive dollars to >1aMW participants as a percent of total 1149 efficiency revenue to Energy Trust for PGE. 2008 – 2012, program demand has been consistently increasing.

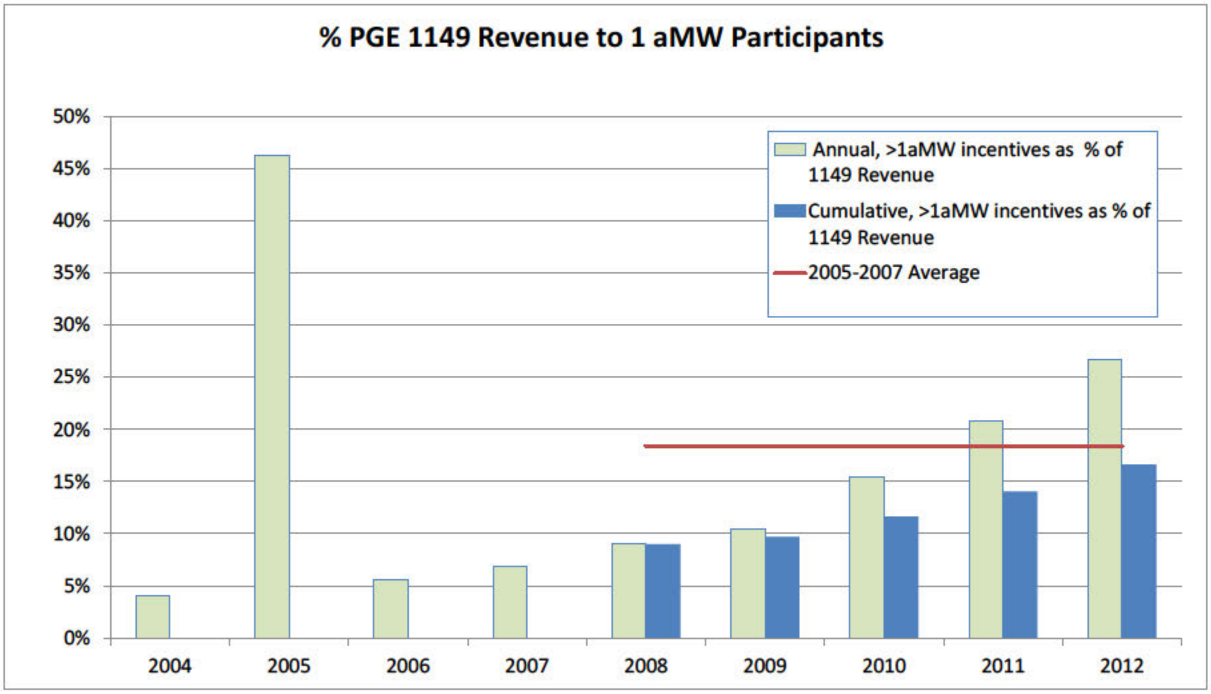

Figure 1

In PacifiCorp territory, we don't foresee a short-term risk of needing to forego resource acquisition with the current methodology and demand but PAC customers could be impacted by program designs or other changes instituted to manage funding for PGE. Figure 2 shows year by incentive dollars to >1aMW participants as a percent of total 1149 efficiency revenue to Energy Trust for PacifiCorp.

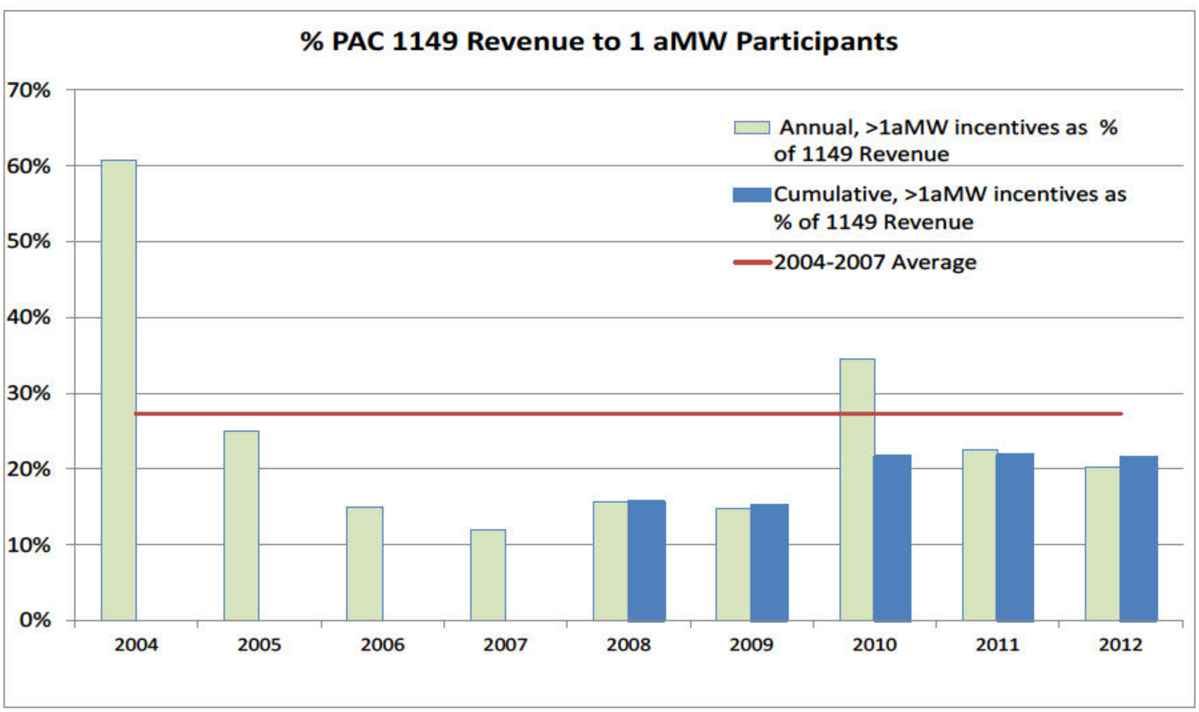

Figure 2

Possible Impacts

To reach goals we will need to redirect funds above the cap to smaller, higher cost projects from 838 eligible sites. On average, large site projects are 2.5 times more cost effective than 838 eligible site projects. Therefore directing funding away from large site projects would result in fewer savings at higher cost. It is also possible that as a consequence Energy Trust cannot acquire all cost effective resource in some years. The result may mean lost opportunity of low cost resource, unmet demand and unrealized savings. In the long run, some savings from larger sites will not be captured. This is a particular threat for "lost opportunity" savings that must be acquired during specific events, such as a major capital investment in a process line upgrade or redesign or a building renovation. A significant share of Energy Trust large customer savings comes through such events.

Outreach Efforts

In anticipation of reaching the funding limit in PGE territory before 2015, Energy Trust staff raised the topic of possible impacts on the program at the June 2013 board retreat. Program staff outlined program tactics that could be employed if we were to reach the limit and need to take actions to adjust program spending downward.
(http://energytrust.org/library/meetings/board/120607_Board_strategic_Planning_Workshop.pdf)

Energy Trust convened a meeting of stakeholders January 31, 2014 to discuss the issue and current situation. In attendance were representatives from utilities, OPUC staff, CUB, ICNU, NWFPA, NWEC, NEEC, ODOE, and Energy Trust staff. A variety of views were heard. Stakeholders offered a range of ideas to address the funding limitations including;

- Expand 838 charges to large energy users (would require legislative action)
- Revisit the methodology so that it's more reflective of current large energy user potential activity and available cost effective resource
- Change the methodology to allow more funding to large users under the condition that those paying to 838 see direct rate benefit from the low cost efficiency in which they are investing (would require rate re-design)

No consensus was reached among attendees but Energy Trust did agree to keep the group fully informed of the situation going forward.

Next Steps

Energy Trust plans to have final results of the 2013 analysis in April/May 2014. If we have met or exceeded the funding limit in PGE territory, we plan to begin to take programmatic actions to lower funding and come back into compliance over a two year period. These actions will be worked through with our Conservation Advisory Council.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision	)
____	)

EXHIBIT ICNU/305

PINNACLE ECONOMICS, ECONOMIC IMPACTS FROM ENERGY TRUST OF OREGON 2013 PROGRAM ACTIVITIES, FINAL REPORT (MAY 5, 2014)

August 13, 2014

Economic Impacts From Energy Trust of Oregon 2013 Program Activities

Final Report

pinnacle economics

3030 NW 12th Avenue
Camas, WA 98607
(503) 816-0295

May 5, 2014

Acknowledgements

This report was prepared by Pinnacle Economics for the Energy Trust of Oregon. Alec Josephson, senior economist, was the lead economist and author of this report. Mr. Josephson has directed and/or conducted all of the previous economic impact analyses of Energy Trust programs, as well as similar analyses for the Bonneville Power Administration, Consumers Energy of Michigan, the Hawaii Public Utility Commission, the U.S. Department of Energy, and the American Council for an Energy-Efficient Economy ("ACEEE").

Table of Contents

1. Introduction and Summary

Pinnacle Economics ("Pinnacle") was retained by Energy Trust of Oregon ("Energy Trust") to estimate the economic impacts of its energy efficiency and renewable energy programs in 2013 on the Oregon economy.[1] These impacts include changes in output, wages, business income, and employment in Oregon that resulted from 2013 program spending and activities. Each year, Energy Trust programs generate energy efficiency gains (i.e., energy savings) and renewable energy generation that continue into the future. As a result, Pinnacle also analyzed the economic impacts from the current program year that accumulate in following years.

For this analysis, *gross impacts* are calculated and then compared against a Base Case spending scenario, which assumes that funds that were paid to Energy Trust are returned and spent by Oregon ratepayers in the Oregon service territories of Portland General Electric (PGE), Pacific Power, Northwest Natural, and Cascade Natural Gas. The difference in economic impacts between the gross economic impacts attributed to Energy Trust program spending and the Base Case scenario is referred to as *net impacts*.[2]

In 2013, Energy Trust spending totaled $130.3 million. This spending was primarily focused on program implementation, with $118.1 million for energy efficiency programs and $7.9 million for renewable energy programs. In addition, the Energy Trust incurred $4.3 million in administrative and program support costs during the 2013 program year. On an annual basis, Energy Trust achieved energy efficiency savings and renewable energy generation during the 2013 program year totaling 60.7 average megawatts (aMW) of electricity (531,500 MWh) and 5.3 million therms of natural gas.

The gross and net economic impacts for Energy Trust 2013 program activities are shown in Table ES1. The changes in spending and energy savings/generation associated with these programs had the following <u>net</u> economic impacts on the Oregon economy in 2013:

- An increase of $175.1 million in output;
- An increase of $60.4 million in wages and $14.7 million in income to small business owners; and
- 1,091 full- and part-time jobs.

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[1] Some of these projects also received financial and/or technical assistance through state and federal tax credit programs. Based on evaluations, Energy Trust believes their participation to be critical to these projects.

[2] An analysis of the *net economic impacts* requires that only economic stimuli that are new or additive to the economy be counted, i.e., net impacts consider both the positive economic impacts from investment in energy efficiency and the negative economic impacts of foregone spending associated with program funding. By making adjustments for program funding, net economic impacts provide a more reliable measure of job and income creation. For example, if an impact of five net new jobs is reported, this means that spending on Energy Trust programs resulted in five more jobs relative to what would have occurred had the money been returned and spent by Oregon ratepayers in the utility service territories.

Table ES1: Gross and Net Economic Impacts, 2013

Impact Measure	Gross Impacts	Net Impacts
Output	$325,550,000	$175,089,000
Wages	$106,771,000	$60,448,000
Business Income	$21,654,000	$14,705,000
Jobs	2,312	1,091

Table ES2 reports the net economic impacts for every million dollars in Energy Trust spending.[3] For the 2013 program year, every million dollars in Energy Trust spending is associated with approximately $1.3 million in new economic activity in Oregon, including $463,800 in wages, $112,800 in business income, and 8.4 jobs.

Table ES2: Net Economic Impacts Per $1 Million in Energy Trust Spending, 2013

Impact Measure	Net Impacts Per $1 Million in Spending
Output	$1,343,500
Wages	$463,800
Business Income	$112,800
Jobs	8.4

The remainder of this report documents the analysis that was completed to develop these economic impact estimates.

[3] These are "fully loaded costs" that include Energy Trust program and administrative costs, as well as incentives paid to program participants.

2. Energy Trust 2013 Program Activities

2.A. 2013 Expenditures

For this analysis, budget information provided by Energy Trust was aggregated into several general categories to facilitate economic impact modeling for similar areas of spending. Table 1 shows the general areas of spending for Energy Trust and reflects actual expenditures for 2013.[4] As shown at the bottom of the table, total spending by Energy Trust in 2013 was $130.3 million.

As a general rule, spending on program incentives goes directly to equipment purchases and labor for installation. Common measures that receive incentives include high efficiency lighting, high efficiency HVAC systems, appliances, industrial process efficiency improvements, and home and commercial weatherization. Energy Trust also incurs non-incentive expenses for program delivery. In 2013, program expenditures[5] for energy efficiency measures totaled $118.1 million (a decrease of $10.2 million or -7.9 percent from previous year). Program expenditures for renewable energy resources totaled $7.9 million (a decrease of $13.9 million or -63.7 percent from 2012).

Table 1: Energy Trust Program Spending ($ millions), 2013

Spending Category	Total Program Expenses	Total Support Costs	Total
Energy Efficiency Programs	$118.1		$118.1
Renewable Energy Programs	$7.9		$7.9
Other Admin & Program Support		$4.3	$4.3
Total	**$126.1**	**$4.0**	**$130.3**

Source: Energy Trust of Oregon, "Statement of Functional Expenses"
Note: Energy Trust program spending includes $1.2 million in spending on projects in Clark County, Washington.

2.B. 2013 Energy Savings and Generation

Table 2 shows the total net energy saved and generated by Energy Trust programs in 2013. On an annualized basis, a total of 60.7 average megawatts were saved or generated as a direct result of Energy Trust program activities in 2013. This includes energy savings for both residential and commercial-industrial energy efficiency programs, as well as energy generated through Energy Trust's renewable energy program. It also includes the net energy savings attributed to market transformation effects by the Northwest Energy Efficiency Alliance (NEEA).

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[4] Energy Trust did not commission a full economic impact study for the 2012 program year. As a result, direct measures of program activity (spending and energy savings) for that year were provided by Energy Trust to provide additional context for this analysis. In addition, the economic impacts for 2012 were estimated by Energy Trust using economic impact results from the 2011 study and the level of program spending in 2012.

[5] Program expenditures are based on incentives and allocated support costs.

Table 2: Annualized Net Energy Savings and Generation, 2013

Program Sector	Annual kWh	Average MW (aMW)	Annual Therms
Residential Energy Efficiency	139,823,822	16.0	2,079,520
Commercial/Industrial Energy Efficiency	366,543,982	41.8	3,230,030
Energy Efficiency Subtotal	**506,367,804**	**57.8**	**5,309,550**
Renewable Energy	25,132,210	2.9	0
Total Energy Saved or Generated	**531,500,014**	**60.7**	**5,309,550**

Source: Energy Trust of Oregon
Notes: 1) Energy savings are reported on a net basis and have been adjusted by the Energy Trust for free-ridership, i.e., program participants who would have adopted energy efficient measures or renewable energy projects even in the absence of Energy Trust programs. 2) Net energy savings include energy savings attributed to market transformation effects by NEEA.

Electric energy savings form the bulk of net energy savings. In total, on an annualized basis, 506,368 MWh of electricity were saved as a result of energy efficiency programs in 2013. This is approximately 0.3 percent more than in 2012, when Energy Trust energy efficiency programs saved 504,602 MWh of electricity. The mix of electric energy savings across programs was approximately the same as in previous years. In 2013, commercial and industrial energy efficiency programs account for 72.4 percent of total electric energy savings (compared to 70.4 percent in 2012). Residential energy efficiency programs account for 27.6 percent of total electric energy savings in 2013 (compared to 29.6 percent in 2012).

Similar to previous years, the amount of energy generated by the renewable energy program in 2013 is relatively small compared to the energy savings attributed to the efficiency programs. In 2013, renewable energy projects generated approximately 25,132 MWh of electricity. This represents a decline of 41.1 percent from the previous program year.

The efficiency gains shown in Table 2 result in a loss of revenue to Oregon utilities due to lost power sales, and this loss of revenue is included in the gross economic impacts measured in this analysis.[6] If the utility sector had similar economic impact multipliers as other sectors in Oregon's economy, then the energy cost savings in other sectors would roughly cancel out the loss of revenue in the utility sector. For Oregon utilities, much of the spending impact flows outside the state, as Pacific Power is owned by an out-of-state company, and both Pacific Power and PGE have shareholders that are widely distributed throughout the country. Consequently, some of the revenue losses for utilities (and the resulting losses in employment and economic activity) accrue to businesses and households outside of Oregon.

[6] For this analysis, it was assumed that utilities did not sell saved power on the spot market, as estimates of the amount of power sold due to energy efficiency are generally unavailable. If utilities can sell conserved power on the market due to the efficiency programs, then there is an additional benefit in the form of increased revenues to the utility sector. As this was not included in this analysis, the results discussed here represent a lower bound for potential utility sector benefits.

There is an additional long-term benefit from the efficiency gains, as they delay the need for building new power generation. Power generated from new sources will almost certainly be more expensive than existing power resources due to increased costs of capital and issues associated with siting new power plants. In this sense, efficiency gains can be viewed as a means for prolonging the use of lower-cost resources and delaying the need for switching to higher cost power supplied by new generation. By enabling the efficient use of lower cost resources, these programs help the entire Oregon economy run more efficiently. This benefit was not explicitly modeled for this analysis because it is directly addressed in the Energy Trust's benefit/cost analysis. It is nevertheless an important issue and is one of the primary tenets underlying conservation and demand-side management programs.

3. ANALYSIS METHODS

Estimating the economic impacts attributable to Energy Trust programs is a complex process, as spending by Energy Trust—and subsequent changes in spending by program participants—unfold over a lengthy period of time. From this perspective, therefore, the most appropriate analytical framework for estimating the economic impacts is to classify them into the following categories:

- *Short-term* economic impacts associated with changes in business activity as a direct result of changes in spending by Energy Trust programs and participants.
- *Long-term* economic impacts associated with the subsequent changes in factor costs and optimal use of resources.

This analysis estimates the short-term economic impacts of Energy Trust program activities during the 2013 program year. The short-term economic impacts are those attributed to additional dollars accruing to Oregon businesses and households as a result of these programs. The economic modeling framework that best measures these short-term economic impacts is called input-output modeling. Input-output models provide an empirical representation of the economy and its inter-sectoral relationships, enabling the user to trace the effects (economic impacts) of a change in the demand for commodities (goods and services).

Because input-output models generally are not available for state and regional economies, special data techniques have been developed to estimate the necessary empirical relationships from a combination of national technological relationships and county-level measures of economic activity. This modeling framework, called IMPLAN (for IMpact Analysis for PLANning), is the technique that Pinnacle Economics has applied to the estimation of impacts.[7]

[7] IMPLAN was developed by the Forest Service of the US Department of Agriculture in cooperation with the Federal Emergency Management Agency and the Bureau of Land Management of the US Department of the Interior to assist federal agencies in their land and resource management planning. Staff at Pinnacle Economics used IMPLAN and the same modeling framework for all of our previous impact analyses for Energy Trust, as well as similar analyses conducted for the Bonneville Power Administration, Consumers Energy of Michigan, the Hawaii Public Utility Commission, the U.S. Department of Energy, and the American Council for an Energy-Efficient Economy ("ACEEE").

This analysis relies on 2012 IMPLAN data for the Oregon economy—the most current data available.

Input-output analysis employs specific terminology to identify the different types of economic impacts that result from economic activities. Expenditures made through Energy Trust programs affect the Oregon economy *directly*, through the purchases of goods and services in this state, and *indirectly*, as those purchases, in turn, generate purchases of intermediate goods and services from other, related sectors of the economy. In addition, the direct and indirect increases in employment and income enhance overall economy purchasing power, thereby *inducing* further consumption- and investment- driven stimulus. This cycle continues until the spending eventually leaks out of the local economy as a result of taxes, savings, or purchases of non-locally produced goods and services or "imports."

The IMPLAN model reports the following economic impact measures:

- *Total Industrial Output (Output)* is the value of production by industries for a specified period of time. Output can be also thought of as the value of sales including reductions or increases in business inventories.
- *Employee Compensation (Wages)* includes workers' wages and salaries, as well as other benefits such as health and life insurance, and retirement payments, and non-cash compensation.
- *Proprietary Income (Business Income)* represents the payments received by small-business owners or self-employed workers. Business income would include, for example, income received by private business owners, doctors, accountants, lawyers, etc.
- *Job* impacts include both full and part time employment. Over time, job impacts are referred to as person-years of employment.

All of the economic impacts measured in this analysis are transitory and depend on program spending and energy savings in each year. That is, economic impacts for each program year are generated by changes in final demand (spending) that can be directly or subsequently linked back to Energy Trust programs. The mix and level of program spending may change from year to year, or could end in any given year. This means that the economic impacts will also vary from year to year, or could end in any given year. This is particularly important when discussing employment impacts. Although employment impacts are reported as a mix of full- and part-time jobs, they are jobs that occur as spending occurs and should be considered person-years of employment. In addition, it is highly likely that some of the employment benefits accrue to the same individuals over time.

Within this modeling framework, the following terms are used to classify impacts:[8]

- *Gross Impacts* reflect the economic impacts with no adjustment made for impacts that might have occurred in the Base Case scenario. Gross impacts include:
    - *Program operations spending* as Energy Trust purchases labor and materials to carry out its energy efficiency and renewable energy programs.
    - *Incremental measure spending* by participants in Energy Trust programs.
    - *Reductions in energy consumption* and the associated lower operating costs to businesses and increases in household disposable income.[9]
    - *Reductions in utility revenues* as households and businesses consume less electricity and natural gas.

- *Net Impacts* are the effects of Energy Trust program activities that have been adjusted to reflect the Base Case scenario. That is, net impacts are those impacts over and above what would have occurred in the Base Case scenario. Net impacts are based on:
    - *Gross* Energy Trust program impacts (discussed above).
    - *Less foregone household spending* as a result of the public purpose charges that are collected from ratepayers and used by Energy Trust to cover program management and administrative costs, and as incentives in their energy efficiency and renewable energy programs.

4. Gross Economic Impacts

The gross economic impacts attributed to Energy Trust programs are based on the program costs (including administration costs), and the net incremental measure spending and net energy savings of program participants. Incremental measure spending by program participants consists of expenditures on energy efficiency equipment such as appliances and furnaces/boilers, heating, ventilation and air conditioning (HVAC) systems, lighting modifications, etc., and spending on renewable energy projects. In both cases, incremental measure spending includes spending on measure installation. This is important because expenditures on measure installation benefit local, Oregon contractors while spending on the measures themselves generally benefit non-local manufacturers.[10] As a result, spending on installation (labor) and equipment will produce substantially different economic impacts for the Oregon economy. Pinnacle received detailed

[8] Both incremental measure spending and energy savings are included on a net basis, i.e., both have been adjusted to account for potential free riders. In energy efficiency programs, free riders are participants who would have adopted the energy efficiency measure or renewable energy project even in the absence of the program.

[9] Energy savings include the net energy savings associated with market transformation efforts conducted by NEEA. These effects cannot be measured on a project-by-project basis. Thus, Pinnacle Economics allocated NEEA's commercial and industrial net energy savings on a *pro rata* basis using the distribution of net energy savings, across industry sectors, for the Energy Trust's commercial and industrial programs.

[10] For some measures, the use of "margining" on equipment sales generates economic benefits (albeit modest impacts) for Oregon retailers, wholesalers, and transporters.

incremental measure spending data from Energy Trust, and mapped this spending to over 30 different IMPLAN sectors.

Energy Trust also supplied detailed energy savings estimates, broken out by fuel type (electricity, natural gas) for program participants. For residences, lower energy costs will increase Oregon households' disposable income. Therefore, the estimated energy cost savings for residential customers were input into a modified consumption function representing the spending pattern of a middle-income household in Oregon, which mapped the spending to over 400 IMPLAN sectors.[11]

Energy savings for commercial-industrial program participants were first mapped to industry sector using North American Industrial Classification System ("NAICS") codes, and then cross-referenced to 237 different business sectors in the IMPLAN model.[12] From an input-output perspective, energy savings will affect Oregon businesses by lowering their production costs. To estimate the economic impacts associated with these lower energy costs, Pinnacle used an elasticity-based approach to estimate the change in output. That is, this approach assumes that lower energy costs increase the competitiveness of Oregon businesses, allowing them to decrease price, and increase output.[13]

Lastly, the energy savings for households and businesses translate into lower revenues to electric and natural gas utilities. Pinnacle used estimated energy savings, by fuel type, to reduce revenues to utilities. The gross economic impacts of Energy Trust programs for 2013 are shown in Table 3.

Table 3: Gross Economic Impacts, 2013

Impact Measure	Gross Impacts
Output	$325,550,000
Wages	$106,771,000
Business Income	$21,654,000
Jobs (person-years)	2,312

Sources: Pinnacle Economics using detailed Energy Trust program data and IMPLAN.

In 2013, spending and energy savings attributed to Energy Trust programs increased economic output in Oregon by $325.6 million, including increases of $106.8 million in wages and

[11] This consumption function was modified to exclude spending on electricity and natural gas.

[12] Over time, Energy Trust's commercial and industrial energy efficiency programs have expanded to more industry sectors. In 2006, energy savings were allocated to 100 industry sectors in the IMPLAN model. In this analysis, energy savings for commercial and industrial program participants are mapped to 237 industry sectors. This is modestly less than in 2010, when energy savings were mapped to 267 different business sectors, but still represents a 137 percent increase since 2006.

[13] Because we do not have elasticity coefficients for each of the 237 business sectors (and their commodities) that benefited from reduced energy costs, Pinnacle uses unitary elasticity, i.e., a 1 percent decrease in costs translates into a 1 percent increase in output.

$21.7 million in business income. This activity also supported 2,312 jobs in Oregon. Table 3, however, reports gross impacts that do not take into consideration alternative uses of Energy Trust and participant spending related to these programs. These net impacts are addressed in the next section.

5. Net Economic Impacts

All of the economic impacts reported in this section of the report are *net impacts* and reflect economic benefits over and above what would have occurred had Energy Trust programs not existed. To calculate net impacts, the economic impacts of the Base Case scenario are estimated first, which assumes that the money that is currently spent on Energy Trust programs is instead reallocated to, and spent by, utility ratepayers. The economic impacts resulting from the Base Case scenario are then subtracted from the gross impacts discussed in the previous section to determine net impacts.

Table 4 shows the net economic impacts attributed to Energy Trust programs in 2013. The net economic impacts are positive and (by design) significantly less than the gross economic impacts reported previously. The gross economic impacts include the assumption that revenues to utilities and other providers of energy services decline as a result of the energy savings by households and businesses. To this, we have now included the Base Case spending scenario that assumes that all Energy Trust funds are instead spent by ratepayers of the utilities according to the spending patterns of a typical Oregon household.

For 2013, Energy Trust programs had a net effect of increasing Oregon's economic output by $175.1 million relative to the Base Case scenario. This includes an increase of $60.4 million in wages and $14.7 million in business income within Oregon. Energy Trust programs also had a positive net impact on employment in Oregon, with 1,091 jobs sustained by Energy Trust program activities in 2013. This reflects jobs over and above what would have been created in the Base Case scenario, i.e., in the absence of Energy Trust's energy efficiency and renewable energy programs.

Table 4: Net Economic Impacts, 2013

Impact Measure	Net Impacts
Output	$175,089,000
Wages	$60,448,000
Business Income	$14,705,000
Jobs (person-years)	1,091

Sources: Pinnacle Economics using detailed Energy Trust program data and IMPLAN.

6. Economic Impacts Across All Program Years, 2002 Through 2013

An important dimension of energy efficiency programs is that energy savings and the associated economic impacts continue to benefit the economy after the first program year, when spending and installations occur, as most measures have estimated useful lives of eight to 20 years, or more.

The cost savings from these measures for homes and businesses also extend into future years (with some degradation as equipment ages and some increase in savings as rates increase) after the initial purchase. These cost savings continue to benefit the economy, as households spend less on electricity and natural gas and more on other consumer products, and businesses are able to produce goods and services more efficiently. As a consequence, the net effects from the first year when the equipment and program spending occur only capture a fraction of the overall benefit of these programs.

Table 5 shows the annualized economic impacts due to energy cost savings from energy efficiency measures installed in 2013. These estimates were calculated using the input-output model to estimate the economic impacts of reduced energy costs while setting all other costs (i.e., equipment purchases and program implementation costs) equal to zero. To truly isolate the impact of the energy cost savings, we also assumed that there are no lost utility revenues resulting from the measures installed and that utilities would be able to sell the unused power to other customers. This provides an estimate of energy efficiency benefits based solely on the reduced energy costs to the economy and excludes any additional benefits due to the spending on these programs and measures.

Table 5: Annualized Economic Impacts Due to Energy Savings Alone, 2013

Impact Measure	Impact Due to 2013 Energy Savings
Output	$66,694,000
Wages	$20,570,000
Business Income	$2,410,000
Jobs	538

Sources: Pinnacle Economics using detailed Energy Trust Program data and IMPLAN.
Notes: 1) Energy savings impacts are based on both electric and natural gas savings, and include the net energy savings attributed to NEEA's market transformation efforts. 2) Energy savings impacts do not include energy generation attributed to Energy Trust's renewable energy program.

To be consistent with previous impact reports, the energy savings impacts shown in Table 5 are reported on an annualized basis, i.e., they describe the economic impacts from energy savings for energy efficiency measures that were installed in 2013 and operated for an entire year. In the first program year, energy savings develop as energy efficiency measures are installed, and installation occurs over the course of the year. Pinnacle does not have data on when each individual installation was completed. Thus, we have assumed that installations occur evenly throughout the year and have used a 50 percent implementation adjustment factor for energy savings in the first program year. (The economic impacts shown earlier in this report are based on energy savings that have been adjusted using this implementation adjustment factor.)

Energy Trust first introduced its energy efficiency and renewable energy programs in Oregon in 2002. Thus, the 2013 program year represents the 12th year of program activity in this state. This section of the report looks at the net energy savings and net economic impacts over this 12-year period.

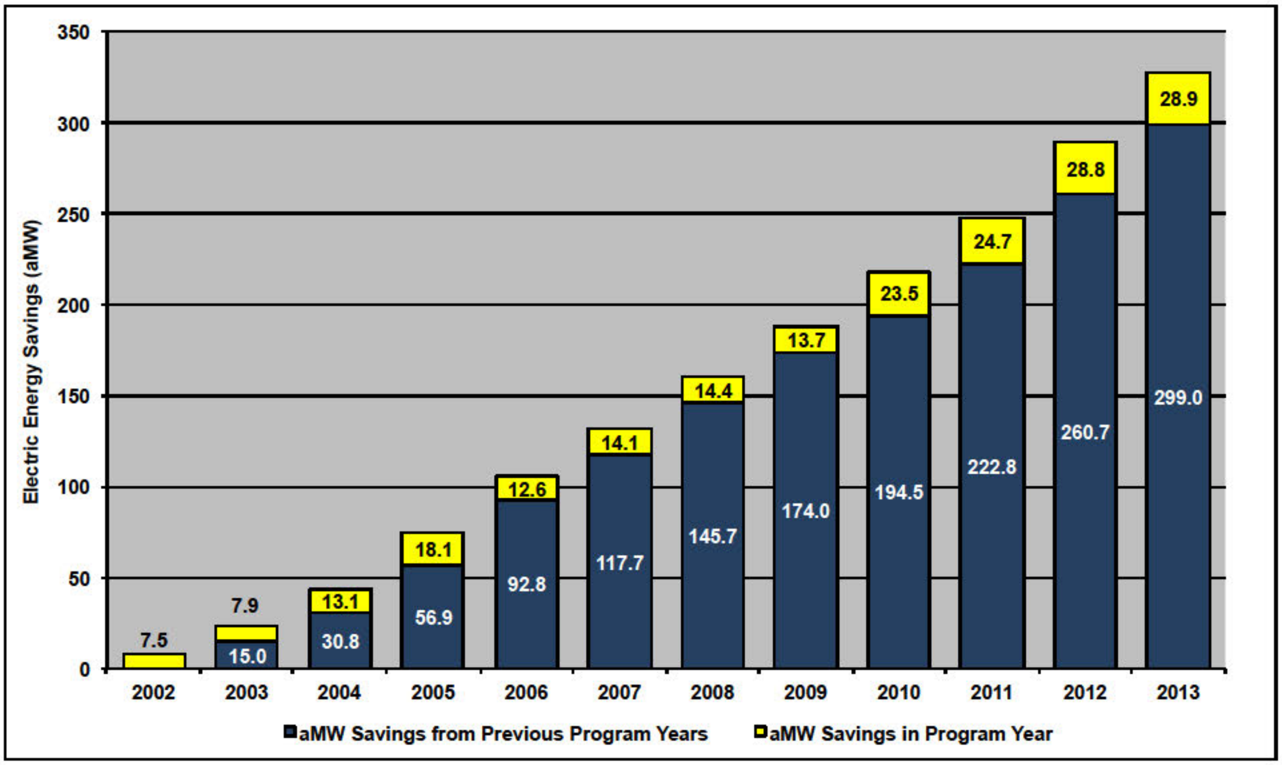
Program year impacts include the net economic impacts associated with net energy savings adjusted for measure implementation (i.e., 50 percent of the annualized net energy savings), and program and participant spending. **Future out-year impacts** are based on the annualized net energy savings installed in each program year with adjustments for the following:

- **Measure Estimated Useful Life (EUL).** To account for the Estimated Useful Life of installed measures, Energy Trust supplied a matrix of electric and natural gas "die-off" rates for each program year. These die-off rates allow net energy savings in future out-years to be adjusted for the percent of measures still in place. For example, Energy Trust estimates that 44 percent of the electric measures installed in the 2002 program year will be in operation in 2013. As a result, the electric energy savings associated with the 2002 program year are adjusted downward from 15.0 aMW in 2002 (annualized) to 6.7 aMW in 2013.
- **Program True Up.** Each year, the Energy Trust adjusts previously reported energy savings and renewable generation through a True Up process that includes corrections for transaction errors, new data, anticipated evaluation results, and actual evaluation results. Once completed, this True Up process results in the most accurate reporting of energy savings (both electric and natural gas savings) and renewable generation.[14]

To illustrate, Figure 1 reports the net electric energy savings (aMW) for energy efficiency measures installed as part of Energy Trust's energy efficiency programs between 2002 and 2013.

[14] The True Up process results in increases or decreases in reported energy savings for each program year. Although this has changed the distribution of reported energy savings over time, the overall effect on total energy savings attributed to Energy Trust energy efficiency programs is quite small. Between 2002 and 2012, Trued Up electric energy savings represent 98.2 percent of reported electric energy savings. Similarly, Trued Up natural gas savings represent 98.3 percent of reported natural gas savings between 2002 and 2012. True Up reports that provide detailed information about the adjustments made to energy savings in each annual True Up process are available on Energy Trust's website, energytrust.org.

Figure 1: Net Electric Energy Savings for Energy Trust Energy Efficiency Programs, 2002—2013

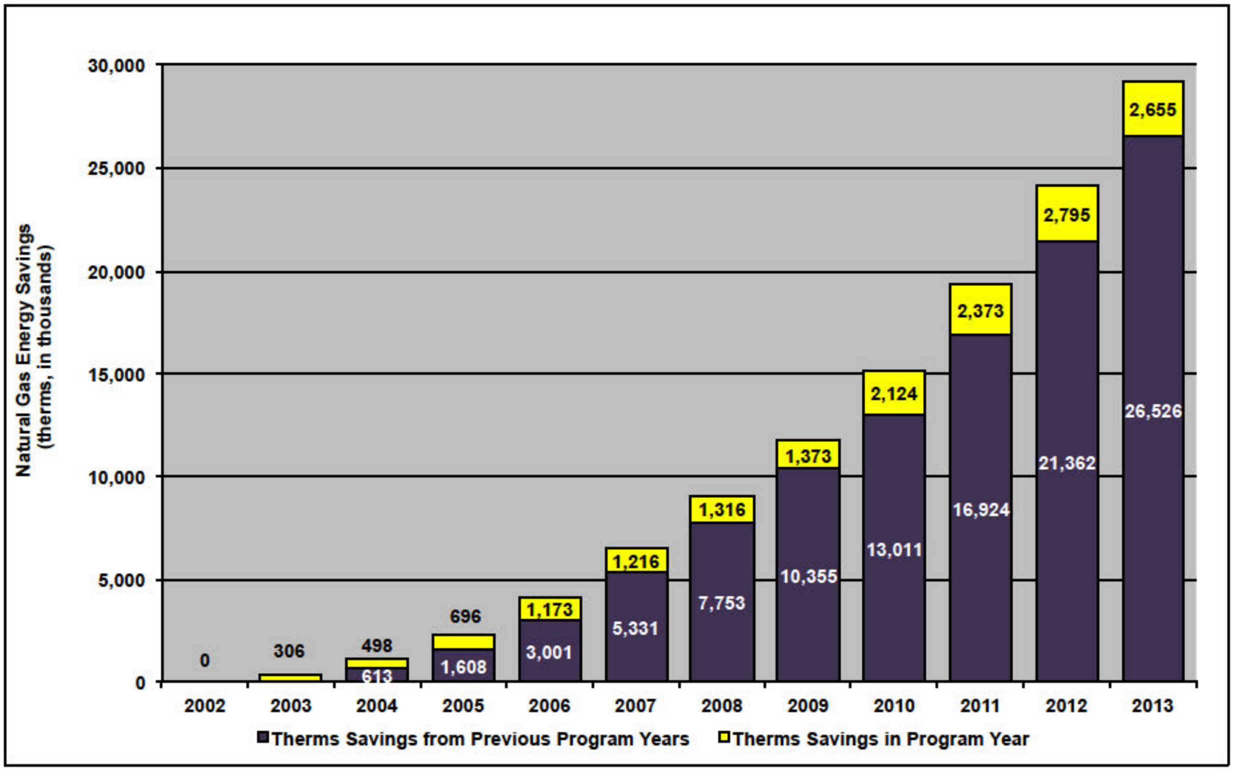


Sources: Calculations by Pinnacle Economics using detailed Energy Trust Program data
Notes: 1) Net electric energy savings have been adjusted for Energy Trust True Up. 2) Net electric energy savings include NEEA electric energy savings.

In 2013, Energy Trust's program activities included installation of energy efficiency measures that would yield an estimated 57.8 aMW of electric energy savings annually. As shown in Figure 1, these energy savings have been adjusted in the first program year to account for actual implementation throughout the year using the 50 percent implementation adjustment factor assumption referenced previously.

Figure 2 reports the net natural gas savings (in thousands of therms) for energy efficiency measures installed as part of the Energy Trust's energy efficiency programs between 2002 and 2013.

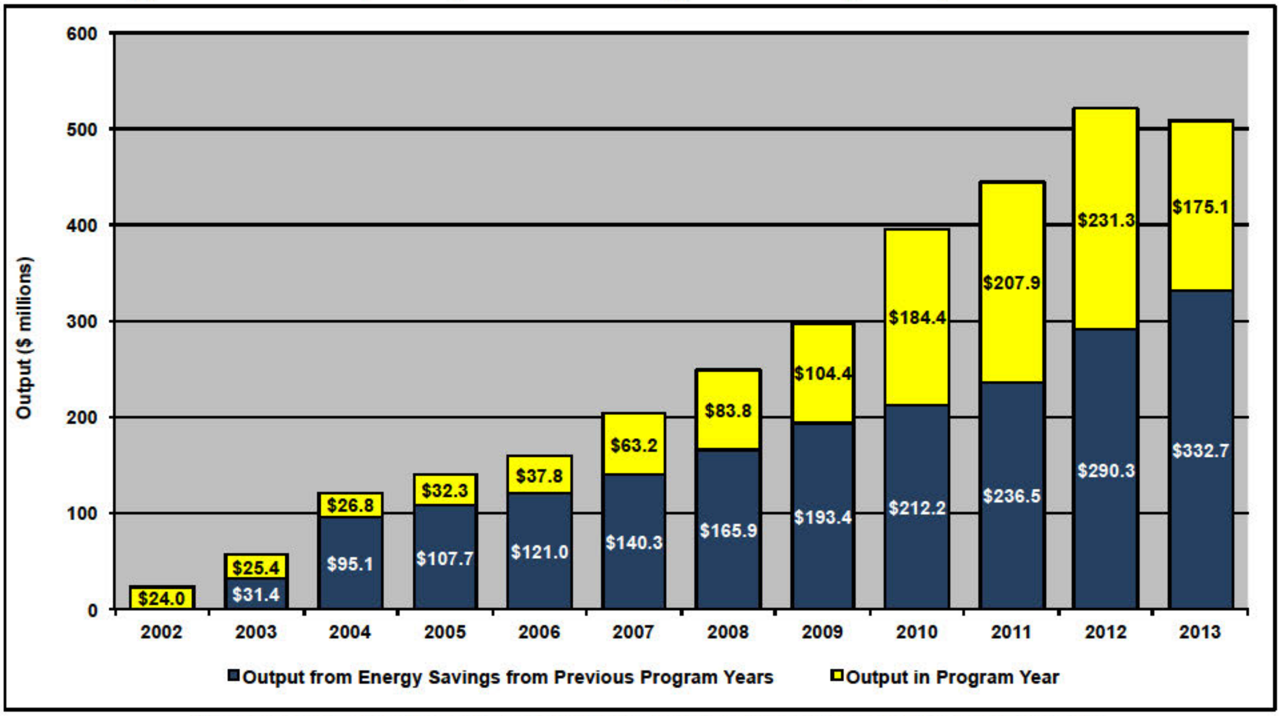
Figure 1: Net Natural Gas Energy Savings for Energy Trust Energy Efficiency Programs, 2002—2013



Sources: Calculations by Pinnacle Economics using detailed Energy Trust Program data
Notes: 1) Net natural gas energy savings have been adjusted for Energy Trust True Up. 2) Net natural gas energy savings include NEEA natural gas energy savings.

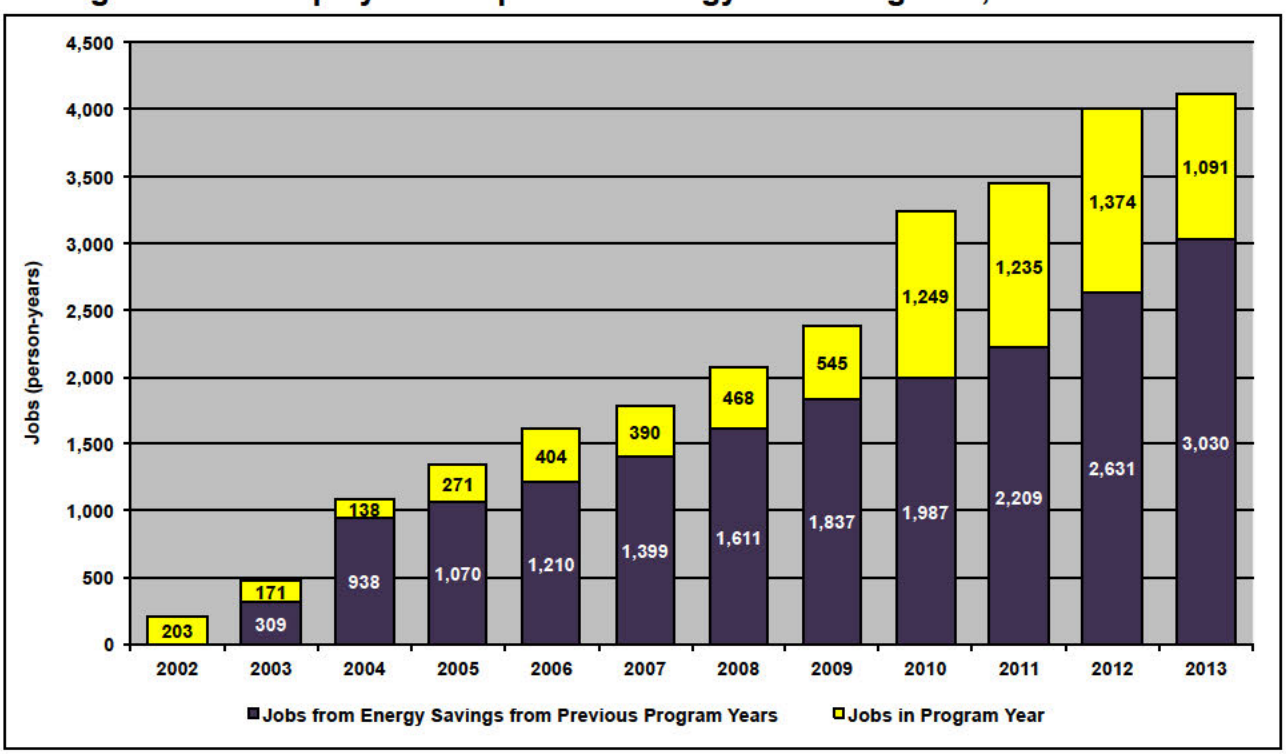
A similar effect occurs for the net economic impacts attributed to each program year. For businesses, energy savings lower production costs and enable businesses to increase output. Similarly, less residential spending on energy allows households to spend more on everything else. This contributes to increased employment as spending shifts to other goods and services in sectors that have a greater impact on the Oregon economy. Figures 3 and 4 show the annual output and job impacts, respectively, associated with Energy Trust program activities between 2002 and 2013.

Figure 3: Net Output Impacts Of Energy Trust Programs, 2002—2013



Sources: Pinnacle Economics using detailed Energy Trust Program data and IMPLAN.
Note: Energy savings impacts based on both electric and natural gas energy savings.

Figure 4: Net Employment Impacts Of Energy Trust Programs, 2002—2013



Sources: Pinnacle Economics using detailed Energy Trust Program data and IMPLAN.
Note: Energy savings impacts based on both electric and natural gas energy savings.

Table 7 reports the net economic impacts associated with Energy Trust' energy efficiency programs in Oregon between 2002 and 2013. The net economic impacts are based on spending and actual energy savings in each program year, as well as the annualized energy savings for energy efficiency measures in future out-years.

Table 7: Summary of Cumulative Net Impacts From Energy Trust Program Activities Between 2002 and 2013 (in millions of nominal dollars)

Economic Impact Measure	Cumulative Net Impacts During Program Years 2002-2013	Annualized Impacts in Future Years
Output	$3,123.0	$399.4
Wages	$928.7	$120.7
Business Income	$180.8	$17.1
Jobs (person-years)	25,770	3,567

Sources: Pinnacle Economics using detailed Energy Trust Program data and IMPLAN.

As is shown in Table 7, the spending and energy savings associated with Energy Trust program activities in Oregon between 2002 and 2013:

- Sustained, on a net basis, $3,123.0 million in output, including $928.7 million in wages, $180.8 million in business income and 25,770 person-years of employment over the twelve-year period.
- Will continue to generate additional energy savings that is linked to $399.4 million in output, including $120.7 million in wages, $17.1 million in business income, and 3,567 person-years of employment annually, albeit at diminishing levels, in the short run.

The cumulative net impacts reported in Table 7 are derived from previous analyses conducted by Pinnacle Economics that rely on a consistent methodology across program years. This methodology measures 1) **gross impacts** based on program spending, net incremental measure spending and energy savings, and foregone utility revenues, and 2) **net impacts** based on gross impacts less foregone household spending as a result of ratepayer charges used to fund Energy Trust program activities and incentives. Energy savings beyond each program year do not include energy savings from the renewable energy projects, and have been adjusted (reduced) to reflect the EUL of measures installed in each program year.

There are, however, other economic factors that could cause the economic impacts to decline over time in which case the economic impacts reported above would be overstated. Given the static nature of input-output modeling, in general, and the IMPLAN model used in this analysis, cumulative impacts do not take into account changes in production and business processes that Oregon businesses make in anticipation of future higher energy prices and/or increased market pressure from international competition to increase production efficiency. To the extent that Oregon businesses are already adjusting in anticipation of higher costs and/or tougher competition, then cumulative impacts presented here are overstated, as the overall market would become more efficient due to factors outside Energy Trust influence. However, Energy Trust savings estimates do not include the energy savings that program evaluations indicate would have happened, either immediately or in the very near future, without Energy Trust programs. This possible overstatement, therefore, only pertains to additional, future market-driven increases in efficiency. Furthermore, in a period of moderating forecasts of energy costs, this is less of a concern.

The cumulative numbers also rely on the critical assumption that each dollar saved will translate into a dollar of increased economic output for those businesses adopting conservation measures. This assumption is a simplifying assumption made in absence of better information specific to Oregon's economy. This assumption is reasonable in the short run, but in the long run it is likely that a dollar of energy savings will translate to less than a dollar of increased economic output (as reflected in the current economic variables for Oregon used in IMPLAN) if the overall market adopts more efficient production practices in anticipation of increased competition and higher energy costs. Consequently, the cumulative impacts shown here represent an upper bound. Despite these caveats, the ongoing and cumulative effect of conservation due to Energy Trust activities is nevertheless a significant net benefit to Oregon's economy.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision	)
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EXHIBIT ICNU/306

STATE & LOCAL ENERGY EFFICIENCY ACTION NETWORK. (2014). INDUSTRIAL ENERGY EFFICIENCY: DESIGNING EFFECTIVE STATE PROGRAMS FOR THE INDUSTRIAL SECTOR. PREPARED BY A. GOLDBERG, R.P. TAYLOR, AND B. HEDMAN, INSTITUTE FOR INDUSTRIAL PRODUCTIVITY (EXCERPT)

August 13, 2014

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Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector

Industrial Energy Efficiency and Combined Heat and Power Working Group

March 2014

The State and Local Energy Efficiency Action Network is a state and local effort facilitated by the federal government that helps states, utilities, and other local stakeholders take energy efficiency to scale and achieve all cost-effective energy efficiency by 2020.

Learn more at www.seeaction.energy.gov

Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector was developed as a product of the State and Local Energy Efficiency Action Network (SEE Action), facilitated by the U.S. Department of Energy/U.S. Environmental Protection Agency. Content does not imply an endorsement by the individuals or organizations that are part of SEE Action working groups, or reflect the views, policies, or otherwise of the federal government.

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Acronyms

BPA	Bonneville Power Administration
Btu	British thermal units
CEE	Consortium for Energy Efficiency
CEPS	clean energy portfolio standard(s)
CFA	Consolidated Funding Application
CHP	combined heat and power
C&I	commercial and industrial
DOE	U.S. Department of Energy
DSM	demand-side management
EERS	energy efficiency resource standard(s)
EPA	U.S. Environmental Protection Agency
EPI	energy performance indicator
EnMS	energy management system
ETO	Energy Trust of Oregon
EWEB	Eugene [Oregon] Water and Electric Board
FTE	full-time equivalent employee
GWh	gigawatt-hour
IEE	Industrial energy efficiency
IOF-WV	Industries of the Future West Virginia
IPE	NYSERDA's Industrial Process Efficiency program
IPMVP	International Performance Measurement and Verification Protocol
IRP	integrated resource planning
HVAC	heating, ventilating, and air conditioning
HPEM	High Performance Energy Management (BPA program)
kW	kilowatt
kWh	kilowatt hour
M&V	measurement and verification
MMBtu	million British thermal units
MW	megawatt
MW_{avg}	average megawatts
MWh	megawatt-hour
NAICS	North American Industry Classification System
NEEA	Northwest Energy Efficiency Alliance
NEB	non-energy benefit
NWFPA	Northwest Food Processors' Association
NYSERDA	New York State Energy Research and Development Authority
O&M	operations and maintenance
PAC	program administrator cost test
PDC	program delivery contractor
RMP	Rocky Mountain Power
SEM	strategic energy management
SEO	state energy office
SEP	U.S. Department of Energy Superior Energy Performance program
SME	small- and medium-sized enterprise
SWEEP	Southwest Energy Efficiency Project
Therm	100,000 Btu
TRC	total resource cost
UMP	Uniform Methods Project
WFE	Wisconsin Focus on Energy

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Executive Summary

Industry[1] is a key energy-using sector in the United States and accounted for about one-third of the nation's total primary energy consumption in 2012. In addition, the potential cost-effective energy savings in U.S industry is large—amounting to approximately 6,420 trillion British thermal units of primary energy (including combined heat and power), according to a comprehensive 2009 analysis by McKinsey & Company. In the United States, efforts to capture more of the potential energy savings in industry at the state level have grown in recent years as energy efficiency programs that capture cost-effective savings continue to be created and expand.

This report provides state regulators, utilities, and other program administrators an overview of the spectrum of U.S. industrial energy efficiency (IEE) programs[2] delivered by a variety of entities including utilities and program administrators. The report also assesses some of the key features of programs that have helped lead to success in generating increased energy savings and identifies new emerging directions in programs that might benefit from additional research and cross-discussion to promote adoption.

Why Do States Undertake Industrial Energy Efficiency Programs?

Many states have instituted energy efficiency programs funded by the public or ratepayers to achieve a variety of benefits. A core, compelling reason for this is because energy efficiency represents a least-cost option for supplying energy services compared to other prevailing options, providing both consumers and society with cost savings. Additional benefits can include environmental gains (including carbon or water use reduction), improved security against energy supply disruption or rapid price increases, and enhanced economic competitiveness. Most state governments have determined that it is necessary to include programs that cover all customers as part of their overall energy efficiency efforts, with industrial customers often a critical component. Experience has shown that the industrial sector historically saves more energy per program dollar than other customer classes: at the national level, IEE programs had an average cost of saved energy of $0.030 per kilowatt hour (kWh) in 2012—nearly one cent lower than the aggregate average energy efficiency program cost of $0.038/kWh.[3] Many of the well-established ratepayer-funded IEE programs in North America, such as those of Bonneville Power Authority, BC Hydro, Energy Trust of Oregon, or Wisconsin's Focus on Energy, continue to realize reliable energy savings from industry at or below the average costs they face for their programs overall. To realize these low-cost energy savings, however, requires a concerted effort developed specifically for the industrial sector and long-term, focused efforts addressing specific industrial needs and circumstances.

States have found that a larger amount of energy savings potential in industry can be gained from energy efficiency programs than can likely be achieved if industrial energy users pursue energy efficiency individually, with limited program assistance. Industrial companies are often aware of energy savings projects in their facilities and many companies have a solid record of developing these projects to save money; however, energy efficiency often cannot compete with other capital demands, even with similar or better paybacks. Moreover, industrial staff members often report that it is difficult to effectively navigate corporate project decision-making systems to get management endorsement for even quick payback energy efficiency projects. In addition, small- or medium-sized energy savings projects often do not compete well with other projects in garnering management attention and

[1] As defined by the Energy Information Administration (EIA), industry consists of the following types of activity: manufacturing (NAICS codes 31-33); agriculture, forestry, fishing, and hunting (NAICS code 11); mining, including oil and gas extraction (NAICS code 21); and construction (NAICS code 23). This report principally focuses on the manufacturing subsector.

[2] The best practices information presented in this report is based on a review of publically available literature on state energy efficiency programs and materials and presentations from related workshops and discussions with industrial energy efficiency experts and program administrators, including: the ACEEE Summer Study on Industry (July 2013, Niagara Falls), the ACEEE Resource Acquisition Conference (September 2013, Nashville), the Industrial Energy Efficiency and CHP Regional Dialogue Meetings (held in 2011, 2012 and 2013), the Midwestern Governor's Association Industrial Energy Productivity Meeting (November 2013, Chicago).

[3] Source: Aden et al. 2013 based on EIA 2012 demand-side management, energy efficiency, and load management programs data for more than 1,000 utilities. Note: To ensure consistency and comparability, these values only include the 182 organizations that reported residential, commercial, and industrial savings and expenditure data; transport sector energy efficiency program data are not included except as a component of the aggregate average.

enthusiasm. Finally, limitations on staff resources and knowhow can further hinder implementation of cost-effective energy efficiency measures.[4]

In states where ratepayer-funded energy efficiency programs are in place, industrial programs can make a significant difference, not only by fostering higher implementation of quick payback projects, but also by providing financial incentives that improve the economics of what would have been longer-term payback projects (3–6 years) that are well outside the typical interest scope of industrial managers. Program incentives to help industrial customers capture the potential for large, additional energy savings can strengthen the alignment of company incentives with the broader interests of energy users statewide in developing low-cost resources for energy service supply. In addition, other intensive but highly cost-effective initiatives of key medium-term interest can be fostered through multi-year programming, such as development of new strategic energy management (SEM) systems in industrial companies.

Even relatively simple programs providing technical assistance, fostering peer exchange, and disseminating practical information can make a difference by supporting facility or company energy management staff in their work and drawing company management attention to energy cost saving possibilities. Increasing awareness of the non-energy benefits (NEBs) that often accompany energy saving projects can help tip the scale in favor of project implementation.

The Wide Spectrum of Ongoing and Useful State Programs

There is wide variation in the types of IEE programs pursued by states, utilities, and energy efficiency program administrators. The dynamics of local economies, existing regulatory frameworks, political interest, and characteristics of local industrial sectors help define what different states feel are the most appropriate approaches for IEE programs. Within this wide spectrum of successful—if diverse—experience, all states can certainly launch new programs, or adapt existing programs, providing cost-saving benefits to industry and the state at large. Moreover, because of the diversity of programs and experience, each state can learn from others about new ideas and lessons learned in program design and implementation.

This report defines a state IEE program in broad terms as a program that provides information, services, and/or financial support to interested industrial facilities within the state for energy efficiency activities. Broadly speaking, there are two main types of IEE programs in the United States:

- Ratepayer-funded energy efficiency programs which are funded through electric and gas customer rates
- Non-ratepayer-funded programs, which are funded by other means (e.g., federal resources, state operating budgets) and are often run by out-of-state energy offices and universities.

This report principally focuses on ratepayer-funded programs, although non-ratepayer-funded programs are also touched upon. Many states also mix a variety of different offerings and funding streams. The National Association of State Energy Officials (NASEO) reports that at least 35 state energy offices operate some type of IEE program separate from, or in support of, ratepayer-funded programs. Forty-one states have ratepayer-funded energy efficiency programs, and just over one-half of states operate ratepayer-funded programs with clean energy portfolio standards/energy efficiency resource standards or utility energy efficiency targets. Some states have chosen to include a self-direct or opt-out option to industrial programs. Self-direct programs are defined in this report as programs that allow qualifying industrial customers to “self-direct” fees that would normally be charged for a ratepayer-funded program directly into energy efficiency investments in their own facilities instead of into a broader aggregated pool of funds collected through a public benefits charge for energy efficiency programs. Not to be confused with “opting out,” where the industrial company does not have to participate in the program, self-directed industrial customers are still obligated to spend money and deliver energy savings, either on a project-by-project basis, or over a certain amount of time.

[4] These IEE program challenges were identified through SEE Action Industrial Energy Efficiency and Combined Heat and Power Regional Dialogue Meetings held across the country in 2011, 2012, and 2013 (www1.eere.energy.gov/seeaction/ieechp_dialogues.html).

APPROACH	DESCRIPTION	PROGRAM EXAMPLES
KNOWLEDGE SHARING	• Low-cost or no-cost technical assistance • Workshops and other outreach • Peer exchange opportunities between industrial clusters or groups of companies • Success story dissemination	• West Virginia Industries of the Future • Southwest Energy Efficiency Project
PRESCRIPTIVE INCENTIVES	• Explicit incentives or rebates for certain specific eligible technologies (e.g., lighting, motors, drives, compressed air, process heating equipment)	• Rocky Mountain Power • Efficiency Vermont
CUSTOM INCENTIVES	• Specific energy efficiency projects tailored to individual customers or specific industrial facilities • May be a mix of technologies • Incentives or rebates often based on entire electricity or natural gas savings	• Xcel Energy • NYSERDA
MARKET TRANSFORMATION	• Streamlined path for introduction of new energy efficiency products to the market • Address structural barriers to energy efficiency (e.g., outdated building codes or lack of vendors offering an emerging technology)	• Northwest Energy Efficiency Alliance
ENERGY MANAGEMENT	• Operational, organizational, and behavioral changes through strategic energy management • Continuous energy improvement (e.g., embedded energy manager to provide leadership and organiza-tional continuity for implementing change)	• Wisconsin Focus on Energy • Energy Trust of Oregon
SELF-DIRECT	• Customer fees directed into energy efficiency investments in their own facilities instead of a broader aggregated pool of funds • Eligibility for customer participation often based on threshold amount of energy use or energy use capacity • Verified energy savings	• Puget Sound Energy • Michigan Self-Direct Energy Optimization

Source: Categorization adapted from Bradbury et al. (2013)

Figure ES-1. Spectrum of IEE state program approaches with program examples

Financial incentives and technical assistance are often provided to energy users to implement sufficient energy efficiency measures to meet specific statewide energy savings goals or pursue all cost-effective energy efficiency opportunities. The main types of offerings, shown in Figure ES-1, are the following:

- **Technical Assistance and Knowledge-Sharing Programs.** These programs typically offer no-cost or low-cost expertise and advice to industrial companies on new technologies and practices, share analytical tools, disseminate success stories and case studies, and offer networking opportunities.
- **Prescriptive Programs.** Standardized prescriptive program offerings provide explicit incentives for adoption of specified higher-efficiency technologies in applications that are common among a variety of commercial and industrial energy users.
- **Custom Programs.** These program offerings provide financial and technical support, usually for customized, often process-specific, project implementation designed to meet the explicit needs of specific industrial customers. They can unlock substantial energy savings beyond what is possible when targeting only individual pieces of equipment and are usually quite cost-effective.

- **Market Transformation Programs.** These programs aim to streamline the path from market introduction of new energy efficiency products or practices to their promotion and consumer acceptance. Adoption of the new products can be supported through increasingly stringent energy efficiency codes and standards, technical assistance, and/or financial incentives.
- **Strategic Energy Management and Energy Manager Support Programs.** Rather than focusing on technology and equipment, these programs seek to promote operational, organizational, and behavioral changes resulting in energy efficiency gains on a continuing basis. SEM involves the operation of internal cross-organization management systems for companies that need to identify and implement many energy efficiency measures year after year.

Experience from Designing and Delivering Programs

A central finding of this report is that achieving success in IEE programs requires significant upfront investment and steady commitment over a number of years. In practice, the experience of strong IEE programs shows that the dedicated effort required is worth it in terms of generating robust and low-cost energy savings. This is especially true in the industrial sector where energy improvement decisions may be linked to operational or capital cycles.

The industrial sector is heterogeneous; different plants have different needs, all of which takes time and skill to grasp. Industrial plant staff members are generally more sophisticated concerning energy matters compared to residential and many commercial energy users. However, internal decision-making processes in industrial companies concerning energy efficiency investments or energy use behavioral change can be complex. Plant operational cycles must be understood and typically define project scheduling. Often, non-energy benefits, including increased productivity, may provide a key tipping point benefit in favor of pursuing a given line of projects, but such benefits may not be immediately obvious. As detailed further in Chapter 4, the barriers and challenges of the industrial sector must be addressed if IEE programs are to create real value for their customers.

To overcome existing barriers and provide high value to industrial customers, programs require quality market assessments, steady and close interaction with customers, a critical mass of knowledgeable staff and strategically engaged consultants, and operational stability. This requires upfront investment and a multi-year focus.

There are 10 IEE program features highlighted by analysts and practitioners that consistently add value to industrial customers and contribute to program success. These program features are:

1. **Clearly demonstrating the value proposition of IEE projects to companies.**
   There are many direct and indirect benefits from IEE projects. A key point in making the value proposition case to industrial company managers is to lay out in simple and concise terms the operating cost savings and other benefits—including profits—that are being left on the table by not addressing cost-effective energy efficiency improvement opportunities.
2. **Developing long-term relationships with industrial customers that include continual joint efforts to identify IEE projects.** Maintaining relationships with key industrial customers is important in pure technical assistance programs as well as energy efficiency resource acquisition programs. It takes time and a steady relationship for program personnel to understand company circumstances and needs, and for company personnel to understand what a program can offer them. Projects tend to be identified over time, as circumstances change and opportunities arise.

   Maintaining quality long-term relationships is people-dependent. Most programs have found that it is necessary to have a consistent and savvy contact person for industrial customers to interact with, such as an account manager. Satisfaction of industrial customers with program delivery and results often hinges on the level of trust established in relationships with program staff or experts.

   Due to the importance of long-term relationships, substantial program investments in staffing or contracted expert capacity are necessary over a number of years to generate the best results. Contracting for program delivery capacity based on only short-term goals, with frequent changes in contractors, is not likely to succeed. Time and effort is needed to set up effective institutional systems.

3. **Ensuring program administrators have industrial sector credibility and offer quality technical expertise.** Effective IEE programs also develop credibility with the industrial customer by employing staff and/or contracted experts that understand the customer's industrial segment and have the technical expertise to provide quality technical advice and support on energy efficiency options and implementation issues specific to that industry and customer. Addressing industrial companies' core needs requires understanding a plant's production processes, operating issues, and the market context that it operates within. Effective IEE programs will adopt the language, engagement strategies, and metrics that are meaningful to the corporate managers who drive capital investment decisions. Understanding customer needs and their investment decision-making processes allows IEE program administrators to generate trust with their industrial customers, boosting IEE implementation rates while making better use of limited resources.
4. **Offering a combination of prescriptive and custom options to best support diverse customer needs.** A combination of both prescriptive offerings for common cross-cutting technologies and customized project offerings for more unique projects can best meet diverse customer needs and provide flexible choices to industries.
5. **Accommodating scheduling concerns.** Program flexibility to meet industry project scheduling requirements is important to meet industrial customer needs. Typically, scheduling of capital project implementation must consider both operational schedules that dictate when production lines may be taken out of operation and capital investment cycles and decision-making processes. Programs with multi-year operational planning can best accommodate company scheduling requirements and the ebb and flow of company project implementation progress.
6. **Streamlining and expediting application processes.** Industrial customers may perceive the application and implementation procedures for IEE programs to be administratively complex and burdensome. Achieving the right balance between meeting key program administration needs for information and keeping program procedures simple and efficient may often require a continual process of evaluation and improvement.
7. **Conducting continual and targeted program outreach.** Even where industrial programs are well established, various industrial customers may remain unaware of the industrial program offerings that may be most applicable or useful for them due to staff turnover and internal demands. Steady and continual outreach and dissemination of information, such as examples of successful past projects, is important to encourage participation. Effective long-term relationships with industrial customers create better information flow and can assist in program outreach efforts.
8. **Leveraging partnerships.** Successful IEE programs often partner with federal, state, and regional agencies and organizations to leverage their expertise, access to customers, and program implementation support capacities. Partnerships can help programs by providing technical expertise, program design and implementation guidance, and expanding program outreach and implementation channels.
9. **Setting medium- to long-term goals as an investment signal for industrial customers.** Most state IEE programs have found that establishing and reporting on energy savings goals in three-year cycles is effective. Medium- and longer-term goals and coordinated funding cycles set a framework for long-term programming and can signal increased certainty to the market and program administrators.
10. **Undertaking proper project measurement and verification and completing program evaluations.** Effective measurement and verification (M&V) of project energy savings is critical to program administrators and regulators to assess the actual results of program activities and measure the contribution of projects and aggregate programs for achieving their goals. Manufacturers also can obtain clear views of the results of investment. Planning for M&V during the program design phase as well as periodic evaluation and adjustment in M&V approaches is important. If NEBs can be included in project assessments, they can further improve understanding of these often important benefits in conveying the value proposition for future energy efficiency projects. Finally, it is useful for programs to undertake periodic process and/or operational strategy evaluations of their full range of activities to assess where program efficiency and results can be further improved.

Self-Direct Programs

This report's review of self-directed IEE programs found a wide range in program structures. Some programs leave obligations of self-directed industries only vaguely defined, include little reporting, and little or no monitoring of energy-saving actions. Such programs ultimately may be little different in terms of results from provisions allowing industry to opt out of energy efficiency programs entirely. At the other end of the spectrum, some programs require verified self-directed customer investment and energy savings to be achieved in order for payment into the programs to be waived. Clarity in self-directed customer obligations and M&V of results are necessary if the policy goal is to ensure that self-directed industrial customers contribute to overall efforts to ensure least-cost electricity or gas service at a level on par with the contributions of other customers.

Emerging Industrial Program Directions

Most states with active IEE programs continue to devote much effort to expanding and improving their programs. There are four key areas of particular interest for further program evolution.

- **Expanding and strengthening strategic energy management programs in industry.** Efforts to support implementation of SEM systems in industry (and also commercial and institutional) are gaining momentum in state programs and internationally. Successful implementation of SEM in many industries could have a dramatic impact on capturing more unrealized energy efficiency potential. The benefits of supporting internal company platforms for continual identification and implementation of energy savings measures include more comprehensive identification and prioritization of energy savings investments (including across organizations), high-impact and low-cost behavioral changes, and operational and maintenance improvements, all contributing to the company bottom line. For example, use of greater submetering as part of an SEM initiative may allow previously unclear issues and solutions to come to light, or enable a new energy intensity program to be put in place.

  SEM implementation can be effectively supported through technical assistance and recognition programs or through energy efficiency resource acquisition programs. One key common challenge is how to easily convey options for introducing SEM into different corporate environments and the value proposition of these management systems. Experience has shown that company senior management support for SEM initiatives is necessary for success and strategies are needed to garner such support.

- **Providing energy efficiency incentives for whole-facility performance.** Program expansion to assess energy savings from SEM implementation could provide directions for taking energy efficiency programs that encompass process- or plant-wide opportunities (e.g., providing incentives and assessing savings credits for whole industrial facility performance) as opposed to performance of individual investments or measures. Efforts are underway to determine baselines and performance metrics that can provide sufficiently robust measurements of facility savings so that regulators and the public are confident that funds have produced real and new energy efficiency savings.

- **Valuing and expanding quantification and recognition of project NEBs.** Although there is wide variation between projects, several studies have shown that NEBs from IEE projects, such as broader productivity or quality gains, can be as high as or even higher than the energy cost saving benefits achieved by the projects. Awareness of the importance of quantifying or otherwise highlighting key and large co-benefits is growing. Even so, quantification of these benefits tends to occur mainly after project commissioning as part of project evaluation efforts. Some co-benefits, such as water savings, are relatively easy to quantify, while others, such as safety improvements, are more complex to assess. If programs employed systematic ways to assess some of the NEBs for key projects earlier in the project cycle, the clarity added to both the resulting total returns and shorter project payback could tip the scale on a variety of projects from "wait and see" to implementation.

- **Continuing efforts to expand industrial natural gas efficiency programs.** Although natural gas efficiency programs have been implemented in various states for years, effective coverage of the industrial sector is much less common than for electricity efficiency programs, even though industry accounts for about 26%

of total end-use natural gas consumption in the United States. A key challenge is that most large industrial customers purchase their gas through third-party suppliers, rather than their distribution companies. Another challenge is the recent decrease in natural gas prices (even though many gas saving projects are still cost-effective at current prices). Nevertheless, a number of states and Canadian provinces continue to serve as promising examples in delivery of industrial natural gas efficiency programs, which other states may profit from reviewing. In addition, innovative concepts are under consideration to increase the effectiveness and the reach of gas efficiency programs. One such concept proposes to pool gas and electric efficiency funds to allow participating manufacturers to implement larger and more holistic programs with the flexibility to deliver both electricity and gas savings.

The Importance of Cross Exchange

As this report will show, the experience gained by various states in developing and implementing IEE programs is both diverse and rich. Often, however, valuable details of different programs—and the successes, failures, and lessons learned—are not well known or are poorly understood out-of-state, even though other state practitioners could benefit from these experiences. In addition, early ideas on new programs or improvements to existing ones are common among various practitioners. Opportunities for peer exchange on design and operational specifics could further programs' progress. Finally, there are benefits from greater mutual understanding that can be gained from increased cross-state exchange among different types of stakeholders in the IEE program practice, including regulatory agencies, program administrators, and involved industrial energy users in different states, as well as associated experts.

Various formal and informal networking mechanisms exist for further information exchange. In addition, the State and Local Energy Efficiency Action Network (SEE Action) can play a role in organizational and implementation specific activities on program design and implementation topics of greatest interest. Regional IEE organizations also are well-placed to help foster the increased cross-exchange needed to further ramp up the promising results in IEE programs in the states.

Conclusion

Many opportunities remain to incorporate cost-effective, energy-efficient technologies, processes, and practices into U.S. manufacturing. IEE remains a large untapped potential for states and utilities looking to improve energy efficiency, reduce emissions, and promote economic development. Successful IEE programs vary substantially in operational mode, scope, and financial capacity, but also exhibit common threads and challenges.

Gaining industry support for IEE programs is key; one of the best means to gain increased industry support is by demonstrating the high value of efficiency programs to industrial customers. Experience highlighted in this report will show that IEE programs can effectively deliver value to industries in terms of lower costs, reduced environmental impact, and improved competitiveness, and can help alleviate common resistance by industry to pay into ratepayer programs.

The development and operation of a highly valued IEE program requires a close understanding of the special needs of industrial customers, flexibility in program offerings, and sustained engagement. In practical terms, this means helping industry achieve concrete energy cost reduction benefits, improved competitive position, and additional NEBs such as enhanced productivity and product quality well above the costs of paying into the program. Flexibility in addressing project scheduling and investment cycles, provision of high-quality technical expertise, and comprehensive offerings that include both prescriptive and custom incentives are features of successful programs.

In addition to responding to the needs of industrial customers, IEE programs that leverage strategic partnerships, have robust M&V and evaluation methodologies, and seek to introduce more holistic program approaches, such as SEM and pooled gas and electric programs, will ultimately help program administrators operate more effective programs and deliver significant additional energy savings. As this report will show, states' experience in developing and implementing IEE programs is both diverse and rich. There are benefits from greater mutual understanding that can be gained from increased cross-state exchange among regulatory agencies, program administrators, industrial energy users, and associated experts.

Table ES-1 summarizes the key issues and considerations for regulators and program administrators in designing and implementing effective energy efficiency programs for industry, as well as programs that address that issue. They do not cover all decisions or issues that regulators and program administrators may need to consider because there will undoubtedly be jurisdiction- and case-specific topics that are not anticipated here. However, these considerations provide a starting point for addressing many of the issues that typically arise.

Table ES-1. Summary of Key Issues and Considerations for Regulators and Program Administrators

Topic	Issue	Considerations for Regulators and Program Administrators	Program Examples
The value of energy efficiency projects	Energy efficiency projects may compete with core business investments and decision-making is often split across business units.	• Clearly demonstrate the value proposition of energy efficiency projects to companies • Relay the operating cost savings and other benefits—including profits—lost if energy efficiency improvement opportunities are not addressed.	• Bonneville Power Administration • New York State Energy Research and Development Authority • West Virginia Industries of the Future
Relationships with industrial customers	It takes a long-term relationship for programs to understand industrial operation and needs, and for industrial companies to understand what a program can offer them.	• Long-term relationships with industrial companies enable joint identification of energy efficiency opportunities • Stability in program support and personnel over a number of years is critical.	• Energy Trust of Oregon
Industrial sector credibility and technical expertise	Addressing industrial companies' core needs requires understanding a plant's production processes, operating issues, and the market context the plant operates within.	Effective IEE programs develop credibility with industrial companies by employing staff/contractor experts that understand the industrial segment and have the technical expertise to provide quality technical advice and support issues specific to that industry and customer.	• Efficiency Vermont • Wisconsin Focus on Energy • Xcel Energy (Colorado and Minnesota)
Diverse industrial customer needs	Manufacturers use energy differently than the commercial sector, typically having significant process-related consumption. Focusing on simple common technology fixes alone will miss many of the opportunities.	A combination of both prescriptive offerings for common crosscutting technology and customized project offerings for larger, more unique projects can best meet diverse customer needs and provide flexible choices to industries.	• Rocky Mountain Power • CenterPoint Energy • Xcel Energy
Project scheduling	Scheduling of energy efficiency investments can be heavily dependent on a plant's operational and capital cycle, as proposed equipment changes must be guided through rigorous, competitive, and time-consuming approval processes.	Programs with multi-year operational planning can best accommodate company scheduling requirements, as scheduling of capital project implementation must consider both operational schedules that dictate when production lines may be taken out of operation as well as capital investment cycles and decision-making processes.	• NYSERDA

Topic	Issue	Considerations for Regulators and Program Administrators	Program Examples
Application processes	Industrial customers may perceive the application and implementation procedures for IEE programs to be administratively complex and burdensome.	Achieving the right balance between meeting key program administration needs for information and keeping program procedures simple and efficient may often require a continual process of evaluation and improvement.	• BPA • NYSERDA
Program outreach	Various industrial customers may be unaware of the industrial program offerings that may be most applicable or useful for them due to staff turnover and internal demands.	Steady and continual outreach and dissemination of information, such as examples of successful past projects, is important to encourage participation.	• AlabamaSAVES • NYSERDA
Leveraging partnerships	A range of federal, national, regional, and state initiatives and resources are relevant to state IEE programs, including those provided by the U.S. Department of Energy, the U.S. Environmental Protection Agency ENERGY STAR® program, state energy offices, and the Manufacturing Extension Partnership.	Successful IEE programs often partner with federal, state, and regional agencies and organizations to leverage their expertise, access to customers, and program implementation support capacities.	• AlabamaSAVES • Northwest Energy Efficiency Alliance, Northwest Food Processors Association and BPA
Medium- and long-term goals	Industrial companies and program administrators seek market certainty and reduced risk in ramping up the implementation of cost-effective energy efficiency measures.	Regulators and program administrators can set energy savings goals or targets for the medium- to long-term, coordinated with funding cycles (e.g., in three-year cycles).	• Michigan Self-Direct Energy Optimization Program • Southwest Energy Efficiency Project
Measurement, verification, and evaluation	Effective M&V is critical for program administrators to assess results and measure progress, and is also useful for industrial companies to verify results of their investments.	• Guidelines for M&V need to be clearly defined and periodically reviewed and adjusted • Periodic impact and process evaluations help identify where IEE program efficiency and results can be further improved • Non-energy benefits (NEBs) can be a key element of both project M&V and program evaluation.	• DOE's Uniform Methods Project • International Performance Measurement and Verification Protocol • ETO process evaluations • NYSERDA, Mass-achusetts, and BPA valuation of NEBs
Self-direct programs	There is a wide range in structures of self-direct programs: from those that are only vaguely defined, and include little M&V of energy saving actions, to those that require verified self-directed customer investment and energy savings to be achieved in order for payment into the programs to be waived.	Clarity in self-directed customer obligations and M&V of results are necessary if the policy goal is to ensure that self-directed industrial customers contribute to overall efforts to ensure least-cost electricity or gas service at a level on par with the contributions of other customers.	• Michigan Self-Direct Energy Optimization Program • Puget Sound Energy • Xcel Energy

Emerging Industrial Program Directions			
Topic	**Issue**	**Considerations for Regulators and Program Administrators**	**Program Examples**
Expanding and strengthening strategic energy management programs	Efforts to support implementation of SEM in industry are gaining momentum in state programs.	The challenge of crediting SEM (how to quantify and credit energy savings specifically achieved through SEM), as well as other SEM-related topics, is worthy of further research and cross-exchange.	• AEP Ohio • BPA • BC Hydro • ETO • WFE • Xcel Energy
Program approaches for whole-facility performance	Significant challenges exist in determining baselines and performance metrics that can provide sufficiently robust measurements of facility savings while maintaining practical and easy-to-implement methodologies.	Work on crediting energy savings from SEM could facilitate the provision of incentives and assessing savings credits for whole industrial facility performance, as opposed to performance of individual investments or measures.	• European experience
Capturing non-energy benefits at the project level	Although there is wide variation between projects, several studies have shown that NEBs from IEE projects, such as broader productivity or quality gains, can be as high as or even higher than the energy cost saving benefits achieved by the projects.	If programs employed systematic ways to assess NEBs earlier in the project cycle, the resulting total returns and shorter payback could tip the scale on a variety of projects from "wait and see" to implementation.	• Energy Trust of Oregon
Expanding natural gas programs	• There is less coverage of the industrial sector in natural gas efficiency programs than in electricity efficiency programs. • Most large industrial customers purchase their gas through third-party suppliers rather than their distribution companies. • Most single-fuel utilities administer energy efficiency programs on their own. However, energy efficiency opportunities typically lead to savings in both gas and electric energy use.	• Gas and electric efficiency measures—when delivered together as part of the same project or a combined program—can result in larger, more effective programs that capture more of the technically and economically viable energy efficiency potential. • Innovative concepts are under consideration to increase the effectiveness and the reach of natural gas efficiency programs.	• Efficiency Vermont • ETO • NYSERDA • PG&E • WFE

1. Introduction

The purpose of this report is to inform state regulators, utilities, and other program administrators about the significant benefits that states in the United States have experienced with industrial energy efficiency (IEE) programs, and to assist these stakeholders in successfully developing and implementing IEE programs in their service territories. This report defines a state IEE program in broad terms as a program that provides information, services, and/or financial support to interested industrial facilities within the state for energy efficiency activities.

This report recognizes that states have their own circumstances, industrial market characteristics, and regulatory structures, and therefore will respond with their own IEE program approaches. These approaches range from ratepayer-funded energy programs—often required under mandatory energy efficiency resource standards (EERS)[5] or other clean energy portfolio standard (CEPS)[6] or through demand-side management (DSM) programs—to knowledge sharing and technical assistance outreach programs without a regulatory incentive structure. The report does not attempt to make specific recommendations that could potentially conflict or be incompatible with individual state regulatory environments. Instead, it explores the practical, proven approaches states have taken. This information can be used by state policymakers and program administrators who wish to further develop their existing IEE programs or start new programs to achieve greater energy savings from industrial customers.

The best practices information presented in this report is based on a review of publically available literature on state energy efficiency programs and materials and presentations from related workshops,[7] and discussions with industrial efficiency experts and program administrators.

The report first provides an overview of why states support strong efforts to promote energy efficiency in the industrial sector and summarizes the current status of IEE programs in the United States. It then illustrates the breadth of existing approaches and program offerings and describes how programs have matured as administrators gain knowledge and experience of customer needs and ramp up energy efficiency improvements.

This is followed by a characterization of IEE program design features intended to respond to industrial customer needs, and highlights of proven practices from states with longstanding experience that have overcome challenges to engaging industrial customers and ensuring broad program uptake. The report focuses on the industrial manufacturing sector—as opposed to industry[8] more broadly defined (which typically includes agriculture, mining, and construction)—but recognizes that many state programs target broader industrial subsectors, combine offerings for industrial and commercial customers, or tend to structure offerings based on customers' energy consumption. In exploring how programs respond to manufacturers' needs, the report identifies programs that target specific industrial process improvements, as well as crosscutting support systems such as motor systems.

Finally, the report discusses two additional topics:

- **Self-direct programs** that allow some customers to "self-direct" their program fees directly into energy efficiency investments in their own facilities instead of into a broader aggregated pool of funding. Concepts that can be used to ensure these programs are achieving energy savings are discussed.
- **Next-generation IEE programs** that expand IEE savings options and industrial participation through strategic energy management (SEM) programs, facility-level programs, better integration of non-energy benefits (NEBs) and fuel sources, and other innovative approaches.

[5] EERS policies aim for quantifiable energy savings by recognizing that energy efficiency is a utility system resource and should be considered by the utility at the same time that supply resources are evaluated.

[6] Clean energy portfolio standards include renewable energy portfolio standards (RPS), EERS, and alternative energy portfolio standards (APS).

[7] Including: the ACEEE Summer Study on Industry (July 2013, Niagara Falls), the ACEEE Resource Acquisition Conference (September 2013, Nashville), the Industrial Energy Efficiency and CHP Regional Dialogue Meetings (held in 2011, 2012 and 2013), the Midwestern Governor's Association Industrial Energy Productivity Meeting (November 2013, Chicago).

[8] As defined by the Energy Information Administration, industry consists of the following types of activity: manufacturing (NAICS codes 31-33); agriculture, forestry, fishing, and hunting (NAICS code 11); mining, including oil and gas extraction (NAICS code 21); and construction (NAICS code 23). This report principally focuses on the manufacturing subsector.

The focus of the report is primarily on ratepayer-funded programs (funded by energy utility customers) due to their relative size in spending terms.[9] Programs that are funded from other sources such as state energy offices are also noted. Numerous examples, case studies, and program descriptions are provided throughout the report. The program examples highlighted here have been successful, not only because they have been able to respond to manufacturers' needs and achieve significant energy savings, but also because they demonstrate cost-effectiveness (according to the relevant cost test the state requires), have good rates of participation, or show they have some longevity and a track record of successful projects. Because this report does not attempt to profile all programs, this by no means suggests that other programs have not been successful.

Although not the focus of this report, the policy contexts for establishing IEE programs are important. These topics include[10]:

- Types of policy mechanisms, such as the decision process for setting CEPS and establishing ratepayer-funded energy efficiency programs
- Institutional guidance for including energy efficiency in integrated resource planning (IRP) processes
- Aligning utility and customer interests in increasing energy efficiency
- Funding sustainability and sources
- Standard criteria for evaluating and screening programs for cost-effectiveness (cost-effectiveness tests)
- Types of data and metrics derived by evaluators for use in impact evaluation of IEE programs
- Choice of program administrator.

[9] In a study of electric IEE program spending in 2010, the bulk of the spending (84%) came from ratepayer-funded utility program budgets, with the remainder of the funding coming from state and federal budgets, universities, nonprofit organizations, and other groups (Chittum and Nowak 2012).

[10] Key resources include Chittum 2012, DOE 2007, EPA 2006, Hayes et al. 2011, Nowak et al. 2011, Sedano 2011, SEE Action Network 2011a, 2011b, and 2012c, Taylor et al. 2012, and Woolf et al. 2012.

2. The Importance of Industrial Energy Efficiency Programs

Effectively managing and reducing energy use in the U.S. industrial sector through increased efficiencies is a key federal, state, and local policy priority as well as a good business decision. The industrial sector is a significant consumer of energy, accounting for about one-third of total U.S. energy consumption (EIA 2013). Implementation of cost-effective industrial energy efficiency (IEE) measures can help defer the need to build more power generation, transmission, and distribution capacity while also enhancing energy security and mitigating risk considerations. Beyond the local and national policy benefits of improved energy efficiency, it is also a key tool in helping U.S. manufacturers reduce their costs and increase competitiveness. To help meet state energy efficiency goals, energy efficiency program administrators are looking to tap the large and cost-effective resource potential the manufacturing sector holds.

2.1. Manufacturing is an Important Sector

The industrial sector accounts for around one-third of all end-use energy in the United States and remains the largest energy user in the U.S. economy (Figure 1). Although IEE has increased dramatically and manufacturing energy intensity has fallen since 1990, industry is projected to consume 34.8 quads of primary energy in 2020 (EIA 2013a). Estimates of the potential to reduce industrial energy consumption through efficiency measures by 2020 are as high as 18% (McKinsey 2009).[11] The energy intensity of production in industrial subsectors varies widely, from 52.3 end-use Btu per dollar of value added in cement production, to 0.4 Btu per dollar in computer assembly. Opportunities for subsector-specific processes make up 67% of the IEE potential, while opportunities in crosscutting energy support systems, such as steam systems and motor systems, comprise the remaining 33%. Sixty-one percent of the total opportunity resides in energy-intensive sectors such as iron and steel, cement, and chemicals, with the remaining 39% in non-energy-intensive sectors (McKinsey 2009).

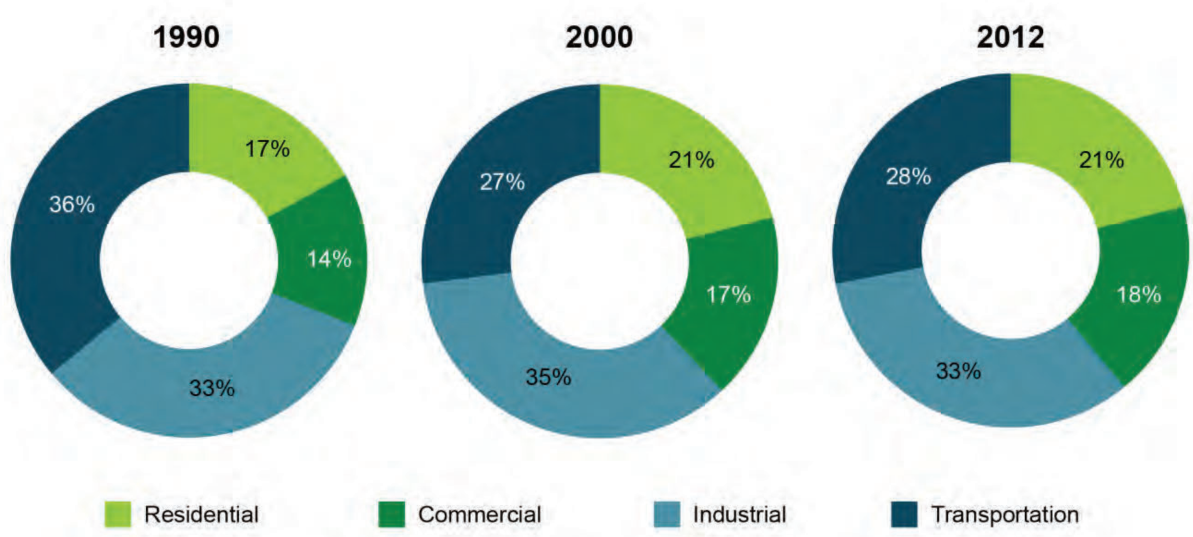


Figure 1. Energy consumption in the United States (1990, 2002, and 2012)

[11] Other estimates are similar; the National Academy of Sciences (NAS) concluded in 2010 in *Real Prospects for Energy Efficiency in the United States* that 14%–22% of industrial energy use could be saved through cost-effective energy efficiency improvements (those with an internal rate of return of at least 10% or that exceed a company's cost of capital by a risk premium). These innovations would save 4.9–7.7 quads annually by 2020.

Figure 2 shows the 2020 IEE potential in various subsectors and cross-sectorial systems, referred to as clusters. The energy savings potential is shown in both direct reductions in end-use energy and in primary energy terms that includes all of the upstream energy consumed in the delivery of energy to the industrial consumer. The potential in primary energy terms reflects the full fuel cycle basis and the avoided electricity losses possible through IEE.

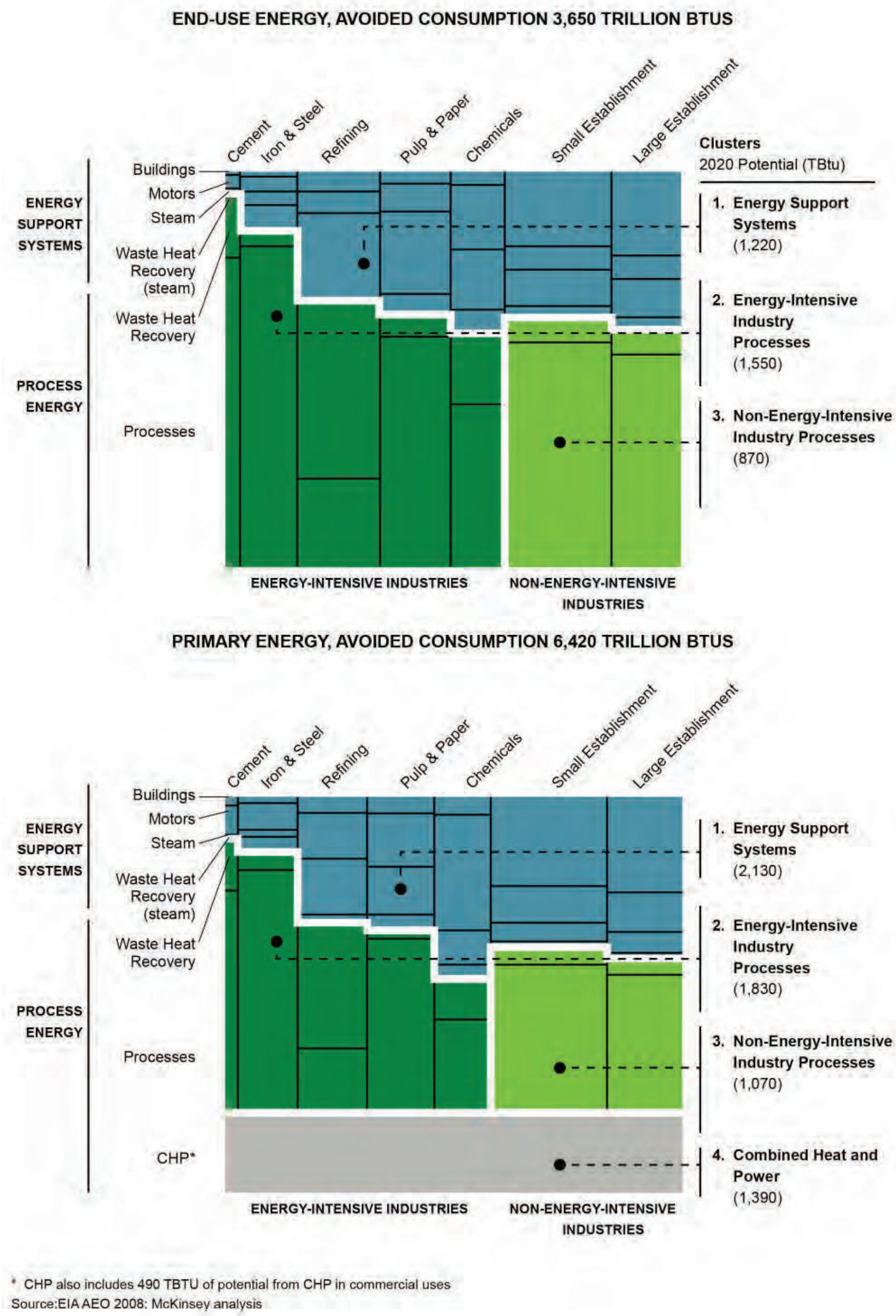
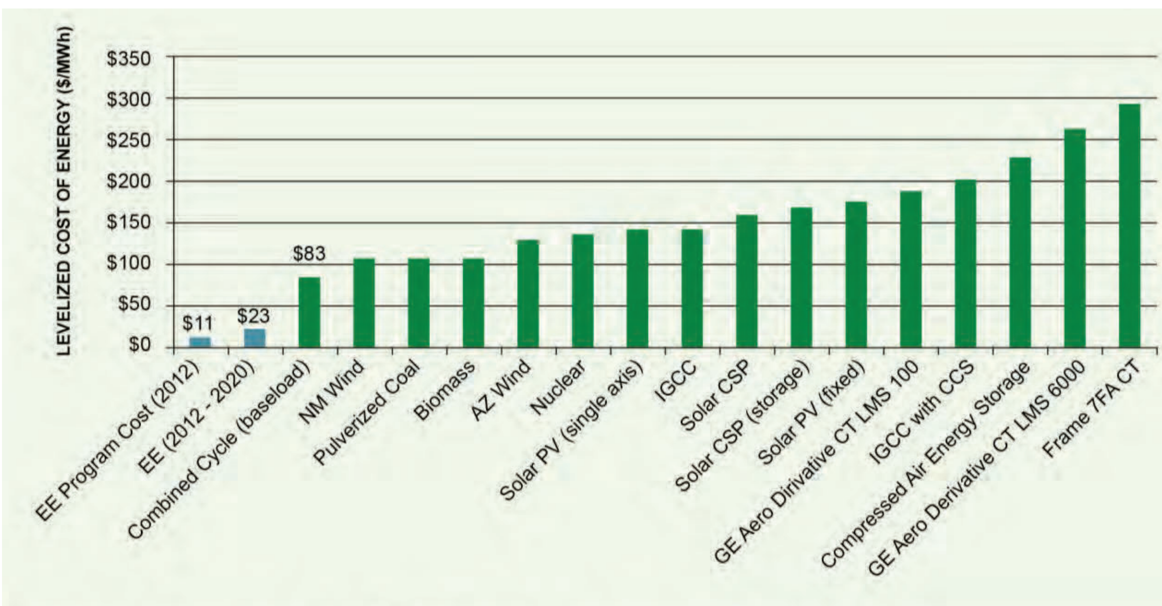


Figure 2. Clusters of end-use energy efficiency potential in the industrial sector

2.2. Industrial Energy Efficiency Resources Are Cost-Effective

Delivery of electricity efficiency resources generally costs much less than delivery of new electricity supply resources in most regions of the country. In most electric power systems, delivery of reliable energy efficiency resources to meet electrical energy consumption (kilowatt-hours [kWh]) costs somewhere between 15%–50% of the cost of power from new central station generation (Lazard 2011). A study examining evaluation results across 14 states found that energy efficiency programs on average cost the sponsoring utility or program administrator about $0.025 per kWh saved and about $3.40 per million Btu of natural gas saved over the life of energy efficiency measures. When costs paid directly by participants are also included, the average cost of efficiency savings is about $0.046 per kWh and $6.80 per million Btu. This is far less than the cost of power from new central station generating plants, which can range from $0.07 to more than $0.30 per kWh (ACEEE 2009, Lazard 2009, SEE Action Network 2011a).

Energy efficiency resources offer cost advantages for meeting new power capacity (kilowatts [kW]) needs as well. Similarly, the costs of improvements in the efficient use of natural gas also are generally substantially lower than acquiring new natural gas supply resources over the medium term, although gas industry structure and economics are different from those of the power sector (Trombley and Taylor 2013).[12] As an example of the economic attractiveness of energy efficiency, Figure 3 highlights the levelized costs[13] of different energy resources in Tucson Electric Power's service area.



Conventional resource costs include fuel, capital, O&M, transmission, and interconnection costs.
Renewable resource costs include generation, delivery, backup capacity, and system integration costs.
Data Source: Tucson Electric Power 2012 IRP, 2012 DSM Report, and 10/31/2012 TEP Rate Case Technical Conference

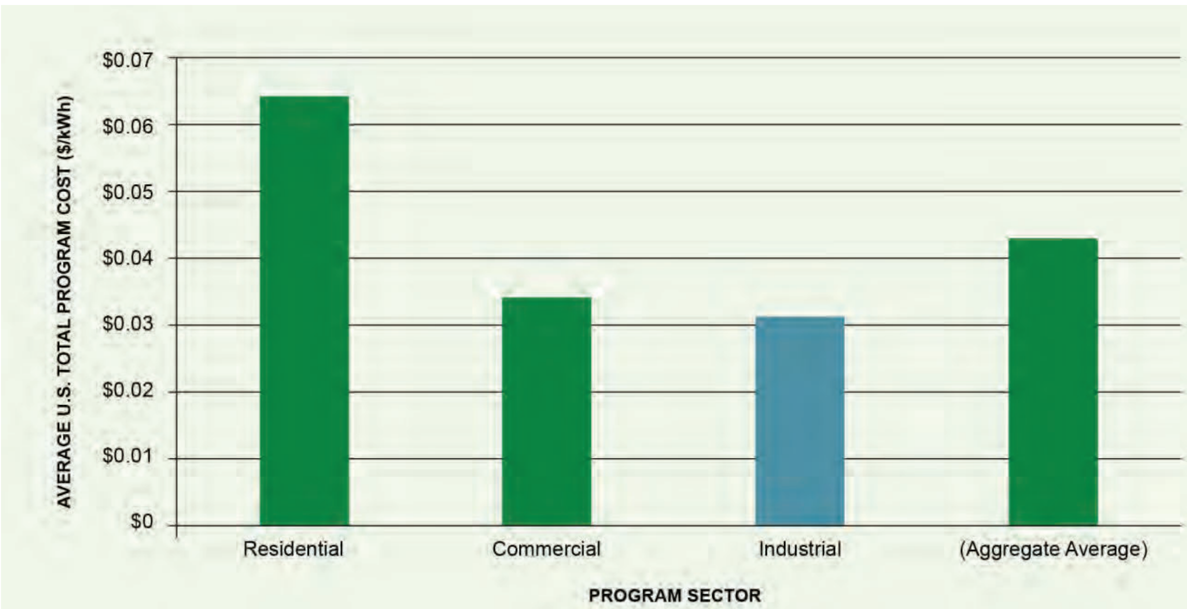
Figure 3. Levelized costs of energy resources in Tucson Electric Power's service area

[12] Although natural gas prices were at an all-time low in 2012, prices have already rebounded to around $4 per MMBtu and current forecasts estimate that prices will remain steady or slightly increase at $4 to $6 per MMBtu for the foreseeable future. Natural gas energy efficiency programs remain cost-effective when gas prices reach around $4 per MMBtu (using the Total Resource Cost test), so under the more likely natural gas price paths, these programs will continue to remain cost-effective. The program design implications of providing incentives for natural gas savings are discussed in Chapter 6.

[13] Levelized cost is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kWh cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle, expressed in terms of real dollars to remove the impact of inflation, and often converted to equal annual payments. Key inputs to calculating levelized costs include overnight capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.

Not only is energy efficiency, in general, a more cost-effective option than new supply resources, recent studies suggest that IEE is often among the lower cost, if not the lowest cost, energy efficiency resource (Bradbury et al. 2013, Chittum 2011). Accordingly, many energy efficiency program administrators are not only looking to the industrial sector as a large potential source for energy efficiency resources, but also as a relatively low-cost energy savings acquisition option.

Figure 4 illustrates that the industrial sector has the lowest cost of saved energy on a national level, although it is important to note that cost structures vary by program and sector at the state level (Aden et al. 2013). In British Columbia, for example, the well-established industrial program under the electric utility's Power Smart Program is expected to provide energy savings at a cost to the utility of $0.015 Canadian per kWh during FY 2012–14, compared to utility costs of $0.031 Canadian per kWh for the residential program (Taylor et al. 2012). Additional examples are discussed in Appendix A, including programs in Wisconsin, Rhode Island, Oregon, and the Northwest. These show that industrial programs can often be twice as cost-effective as programs targeting the residential sector.



Source: Aden et al. 2013 based on EIA 2012 DSM, energy efficiency and load management programs data for more than 1,000 utilities www.eia.gov/electricity/data/eia861.

Note: To ensure consistency and comparability, this figure only includes the 182 organizations that reported residential, commercial, and industrial savings and expenditure data; transport sector energy efficiency program data are not included in this figure except as a component of the aggregate average.

Figure 4. Average costs of energy efficiency programs by sector (2012)

2.3. Industrial Energy Efficiency Creates Value for Companies and Society

IEE provides numerous benefits to industrial customers, to utilities, to all ratepayers, and to society as a whole.

Industrial Companies

Energy efficiency reduces costs and increases manufacturers' operational efficiency and productivity. It also often results in a number of co-benefits such as reduced material loss, improved product quality, and lower emissions. In addition, investors increasingly value corporate commitment to energy efficiency and sustainability as an indicator of sound governance and business acumen. Research consistently suggests that NEBs from efficiency measures in the industrial sector are substantial (Hall and Roth 2003, Worrell et al. 2003, Lung et al. 2005, Chittum 2012, Lazar and Colburn 2013). Facilities that take advantage of IEE program offerings provide a valuable hedge against energy supply disruptions or shortages, energy price volatility, and price spikes. For example, Darigold, a dairy and food processing company with 1,400 employees in the Northwest, adopted an energy reduction strategy in 2001. Due to SEM practices and energy-efficient capital improvements implemented since 2001, the company's energy intensity decreased by 21% in 2012. In addition, its productivity grew, the reliability and safety of its equipment increased, the risk of work-related injuries associated with operating machinery decreased, and the company experienced less workforce turnover (IIP 2012a). An analysis of NEBs in Wisconsin found that in calendar year 2010, participants in Focus on Energy business programs enjoyed $8.9 million in NEBs above and beyond the estimated $56 million in annual energy savings for the same year's business customers (Chittum 2012). Productivity and NEBs enjoyed by industrial customers are further discussed in Chapter 6.

System-Wide Benefits

States have found that specific IEE programs can help deliver a larger slice of the energy savings potential in industry than can likely be achieved if industrial energy users pursue energy efficiency on their own with no program assistance of any kind. Company staff are often aware of profitable energy saving opportunities, and many companies have a solid record of developing these projects to save money. However, focus is often on projects that can pay off in one or two years. Other projects that have substantial potential long-term benefits, but that have higher initial costs and longer payback periods, are left on the table. IEE programs can make a key difference, not only by fostering greater adoption of short payback projects, but additionally providing financial incentives that improve the payback of projects outside industrial managers' typical interest scope (less than two years). Program incentives to help industrial customers capture significant additional cost-effective energy savings potential can improve the alignment of company business practices with the broader interest of energy users statewide in developing lowest-cost energy supply resources.

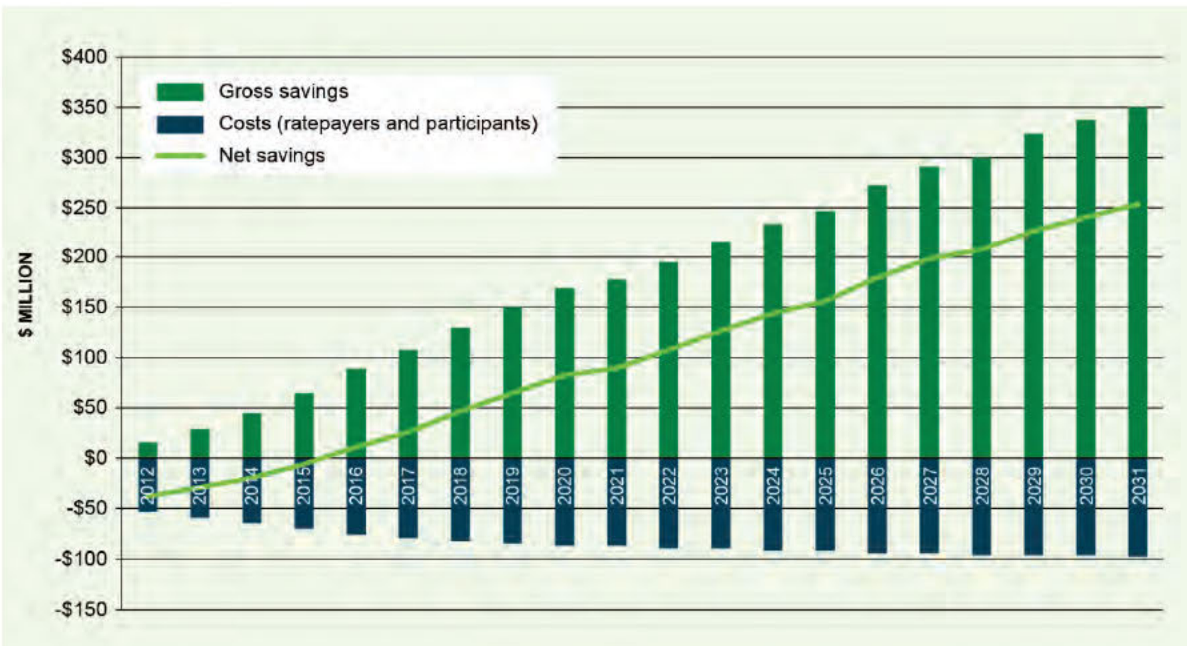
Implementation of cost-effective energy efficiency measures, if made within the context of ratepayer-funded energy efficiency programs, ultimately reduces the energy bills of all consumers. This is because energy efficiency can eliminate or delay the need to build more power generation, transmission, and distribution capacity. As a result, efficiency investments tend to lower electricity prices over the medium-to-long term due to the avoidance of utility rate increases otherwise necessary to develop more expensive new supply and transmission resources. How fast rates may decline relative to the no-energy efficiency base case, and by how much, depends primarily on how fast electricity demand is growing and the differences between the marginal costs for new supply and the marginal costs of energy efficiency resources. Generally speaking, however, a small rate increase in the near term (for energy efficiency program costs) will result in lower level rates in the long term compared to a no-energy efficiency base case (Taylor et al. 2012). This is especially true in regions where energy demand is growing and when other NEBs such as the environmental and public health externalities associated with the extraction of fuels and the extension of power transmission and distribution capacity are accounted for.

However, in order to achieve decreases in rates over time, it will be necessary to provide efficiency services to the vast majority of customers, including industrial customers, which represent a large share of potential savings. If this goal is achieved, then most customers will eventually be program participants and will enjoy the benefits of the efficiency programs, mitigating the issue of differential treatment. Therefore, pursuing the goal of achieving all cost-effective energy efficiency could lead to a reduction, not an increase, in rate impact concerns, as the vast majority of customers experience reduced bills over time. As participation levels increase, thoughtful program designs can ensure that all customers have a fair opportunity to participate (SEE Action Network 2011c).

As an example of the impact of energy efficiency programs on system costs, ACEEE recently modeled the benefits of Ohio's EERS, estimating it could save customers a total of almost $5.6 billion in avoided energy expenditures by 2020 and result in reduced wholesale energy and capacity prices, with wholesale energy price mitigation savings of $880 million (in 2012 dollars) and wholesale capacity price mitigation of $1,320 million (Neubauer et al. 2013).

In another example in the Pacific Northwest, acquisition of efficiency resources to meet additional electricity demand is far cheaper than developing new generation and can help moderate increases in consumer prices. The cost for additional supply of electricity from new sources is substantially higher than current average prices. The Sixth Northwest Conservation and Power Plan, issued in 2010, estimates the long-run averaged levelized cost of new electricity from natural gas-fired combined-cycle power plants to be about $0.092 per kWh, and the cost of Columbia Basin wind power to be about $0.104 per kWh. Compared to this, the average levelized cost of securing the Plan's aggressive portfolio of energy efficiency resources over 2010–2029 is $0.036 per kWh, including consumer costs (Taylor et al. 2012). The Plan also shows that energy efficiency reduced expected electricity loads by approximately 4,000 average MW since 1980 through the end of 2009, helping to level out demand.

Figure 5, from the Vermont Department of Public Service, illustrates how efficiency programs are expected to deliver long-term system savings relative to costs over 20 years.



Source: Vermont Department of Public Service (2011)

Figure 5. Efficiency Vermont costs and savings, high-efficiency case 2012–31 (current $)

Society as a Whole

IEE not only benefits individual companies at which the efficiency improvements are installed as well as all other utility ratepayers, but it also creates broader societal value. In addition to delivering cost-effective energy resources, energy efficiency reduces environmental impacts from energy production and use, and enhances energy supply security. Reductions in energy use, in addition to reducing greenhouse gas emissions, lead to lowering the burden of local air pollution, improving water use and efficiency, minimizing waste, and protecting the health and safety of workers. A recent U.S. Environmental Protection Agency (EPA) report calculated that each ton of reduced emissions from power plants (which might be displaced through IEE) has the following public health cost savings benefits: $130,000 to $290,000 for particle emissions ($PM_{2.5}$), $35,000 to $78,000 for sulfur dioxide (SO_2), and $5,200 to $12,000 for nitrogen oxides (NO_X) (EPA 2013a, Lazar and Colburn 2013).

Large quantities of water are also used in many industrial applications, mostly in process cooling. Energy efficiency measures often reduce water consumption and heat rejection control strategies can impact both process efficiency and water use. For example, significant opportunities exist to upgrade cooling towers to improve thermal capability, increasing energy efficiency and reducing water use. In water-constrained regions with significant industrial activity such as Texas, water- and energy-saving technologies can help to alleviate water scarcity and increase access for other users (Texas IOF 2013).

2.4. The Role of Energy Efficiency in an Expanding Manufacturing Base

Several trends suggest that the United States is beginning a major expansion of manufacturing capacity in a number of sectors (*The Economist* 2013). The U.S. government is tracking billions of dollars in planned manufacturing investments, including in fertilizers, chemicals, steel, cement, and assembly industries. Ample, low-cost natural gas supplies coupled with favorable foreign exchange rates and increasing labor productivity trends are attracting new investment in the U.S. manufacturing sector. For example, nearly 100 chemical industry investments valued at $71.7 billion had been announced through the end of March 2013 (American Chemical Council, May 2013). Companies such as Dow Chemical and Vallourec (steel tube producer) have announced new investments to take advantage of low gas prices and to supply extraction equipment.

The expansion of U.S. manufacturing has brought new awareness of the potential for energy efficiency to support the wider goal of increasing industrial competitiveness, productivity, and innovation. The installation of the most efficient processes and equipment (both in retrofitting existing systems and as new capacity is developed) serves as a hedge to maintain competitiveness for the future when energy supply and price conditions may once again change. Energy efficiency remains a profitable investment opportunity even in a low natural gas price environment and provides the added value of using this valuable domestic resource wisely and efficiently.

Lower American energy prices could result in up to one million additional manufacturing jobs (*The Economist* 2013). Manufacturing is often the key economic engine for local economies, so to the extent that energy efficiency investments help these facilities survive and grow, they support job retention and job growth within the local area. For example, Whirlpool attributes its ability to maintain the majority of its workforce at its Clyde, Ohio, plant, to industrial efficiency and production upgrades made at the facility, in addition to its production of a highly efficient line of front-load washing machines (NRDC 2012, Selko 2013).

2.5. The Current Status of State Industrial Energy Efficiency Programs

This report defines a state IEE program in broad terms as a program that provides information, services, and/or financial support to interested industrial facilities within the state for energy efficiency activities. IEE programs may have multiple goals but almost always have a public interest objective in mind—whether it is least-cost resource development, environmental benefits, consumer benefits, or economic development. State IEE programs can be administered by utilities, program administrators, or state energy offices. The most common are ratepayer-funded energy efficiency programs administrated by utilities and program administrators.[14]

IEE programs in the United States vary widely from state to state, as well as within states in both form and function. Some states have passed legislation mandating that a certain level of energy efficiency resources should be acquired or that all cost-effective energy efficiency opportunities should be pursued. Some programs may focus on electricity only, gas only, both of these energy sources, or all energy sources. State utility regulators, utilities, and energy efficiency program administrators often play pivotal roles in approving and delivering IEE programs. State energy offices are also important drivers of programs. Program funding may come from electric and natural gas ratepayers, funds from the state operating budget, federal and other sources, or a combination of sources. Program offerings are diverse, ranging from prescriptive incentives, custom/process efficiency, market transformation, strategic energy management, and self-direct program types (as described in Chapter 3).

In practice, because many states have chosen to include the manufacturing sector in energy efficiency programs funded by energy utility customers, ratepayer-funded programs are the focus of this report. These programs are predominantly funded by customers of electric and gas utilities. This is done either implicitly or explicitly, as charges added to electric and gas utility bills either as a cost of service and embedded in the total costs customers pay or as a separate line item to bills. These funds are often channeled into a public benefits fund or demand-side management (DSM) fund and programs are administered by utilities and/or energy efficiency program administrators.

[14] In a study of electric IEE program spending in 2010, the bulk of the spending (84%) came from ratepayer-funded utility program budgets; the remainder of the funding came from state federal budgets, universities, nonprofit organizations, and other groups (Chittum and Nowak 2012).

As of January 2014, 28 states have policies in place that establish specific energy savings targets, either through EERS, CEPS, or specific utility goals (ACEEE 2013a and ACEEE 2013b). Many states without energy efficiency targets still have ratepayer-funded programs.[15] In total, 41 states now require utility customers to contribute to supporting energy efficiency programs (Chittum in Uhlenhuth 2013). At least 35 state energy offices (SEOs) administer energy programs for manufacturers and the industrial sector (NASEO 2012). Appendix A provides a more detailed landscape of the scope and breadth of state IEE programs and the policy mechanisms that IEE programs currently operate under, including CEPS, energy savings targets for individual utilities, requirements to pursue all cost-effective energy efficiency opportunities, DSM mandates, or voluntary SEO-run programs.

Under these ratepayer-funded energy efficiency programs, utilities remain primarily responsible for administering and implementing programs with regulatory oversight. However, third-party energy efficiency program administrators also offer energy efficiency programs (ACEEE 2012). Although it is more common for each utility to develop and administer its own program, some states, such as Oregon, through the Energy Trust of Oregon (ETO), have unique programs set up to coordinate activities across the state and retain experts on staff to run the program. Others, like DTE Energy in Michigan, contract the work out to third parties while managing program savings targets (Taylor et al. 2012). Whatever the type of program administrator, each administrator operates under guidance and rules from the state utility regulator.[16]

Industrial Customer Class Coverage

Ratepayer-funded energy efficiency programs are typically designed to include all customer classes—residential, commercial, and industrial. In some states, however, industrial customers have been able to “opt out”[17] from programs altogether, or “self-direct” the funds—that they would have otherwise paid to the fund or utility—to their own direct energy efficiency actions.

Although there are many ratepayer-funded programs that include the industrial sector, there also are many states where development of programs has met with resistance by some manufacturers. In some cases, industrial customers may feel that they can design and implement energy efficiency efforts by themselves and do not want to provide funds through their utility bills for a separate entity to provide design and implementation assistance. In addition, industrial companies often are concerned that they fund a higher share of the program costs and receive less practical benefit compared with other ratepayer classes.

To address these concerns, some states allow industrials to opt out entirely as a “special customer class” from paying energy efficiency system benefit charges and not participate in programs at all. States with legislative opt-out clauses for large customers include Arkansas, Indiana, Kentucky, Maine, Michigan, Texas, and North Carolina (ACEEE 2013, Lewin 2013, Paradis 2013). States that are currently considering opt-out provisions include Oklahoma, Illinois, Louisiana, and Ohio (Ballard 2013, Elliott 2013, Ohio Township Association 2013).

Other states allow manufacturers (usually energy-intensive) to self-direct program funds toward their own energy efficiency activities. Examples include Massachusetts, Minnesota, Ohio, Oregon, Vermont, Washington, and Wisconsin. Note that regulatory oversight, use of program funds, and verification of savings will vary between states and program administrators. Self-direct programs, as opposed to full opt-out provisions, can be an attractive option if properly designed and monitored. Best practices in self-direct program design are further discussed in Chapter 5.

However, opt-out and loosely defined and monitored self-direct programs can be viewed as unfair to other customer classes who are required to pay program costs for energy efficiency resource acquisition that benefits all ratepayers, including manufacturers. Other system resources, such as new generation assets, are generally paid for

[15] Examples of states without EERS/energy efficiency targets but with ratepayer-funded energy efficiency programs include Idaho (Idaho Power), Wyoming (Rocky Mountain Power), and Utah (Rocky Mountain Power).

[16] For a discussion on choice of program administrator, see Sedano (2011).

[17] Opt-out programs allow large customers to fully opt out of paying their energy efficiency charges with no corresponding obligation to make energy efficiency investments on their own (ACEEE 2012b).

by all customers (Chittum 2011). The logic of energy efficiency programs is to procure least-cost energy efficiency resources, as opposed to only energy supply resources, for an entire utility system, ultimately reducing bills for all customers. Capturing cost-effective energy efficiency resources from all customer classes is an important element of an overall least-cost energy strategy for a utility, state, and region.

Many states have focused their energy efficiency program activities on the commercial and residential sectors due to the lower complexity of deploying common solutions throughout these markets. However, as regulators and program managers seek to meet increasing CEPS targets, they have begun to look at the industrial sector for greater energy savings. In addition, federal efficiency appliance standards are raising the baseline efficiency levels for many common residential and commercial measures such as lighting and home appliances, which further reduces the savings potential for these measures.

As a result, energy efficiency program administrators are increasingly turning to the industrial sector to help meet efficiency goals and are rethinking IEE program design and delivery to better meet industrial customers' evolving needs. Custom and tailored approaches are important for engaging industrial customers and responding to their specific needs.

Whatever framework they operate under, IEE programs can provide a variety of offerings and many programs offer a combination of services. For example, financial incentives for investments may be coupled with direct technical assistance. The major types of IEE program offerings generally in use in state IEE programs are discussed in Chapter 3.

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3. How States Successfully Promote Industrial Energy Efficiency

Every industrial energy efficiency (IEE) program administrator can learn from its own experience and from the successes of others. This chapter summarizes the lessons and experiences of IEE program administrators, describes ways in which some states have been able to provide attractive offerings to manufacturers in a cost-effective manner, and explores how programs have matured and adapted through time to match evolving manufacturers' needs while simultaneously meeting statewide goals. Many states have effective IEE programs that have active participation from manufacturers and are producing verifiable energy savings.

As shown in Figure 6, these successful IEE programs represent a "spectrum of approaches," ranging from efforts by some states to promote IEE generally through knowledge sharing and technical assistance, to direct financial support of the implementation of strategic energy management and continuous improvement practices. Each offering can be effective in its own way and be an appropriate choice for individual states, depending on their regulatory contexts and circumstances. However, a more comprehensive set of program offerings—including combinations of the approaches on the spectrum (Figure 6)—is likely to deliver greater overall energy savings.

The spectrum highlights the range of program offerings that states can leverage as experience accrues and relationships develop with industrial customers. Effective IEE programs typically evolve over time with program administrators refining the program in cycles to increase its effectiveness.

Many mature IEE programs offer a suite of services to address diverse needs according to manufacturing sector, regional cluster, and each company's knowledge of and experience with IEE. These programs also provide companies with access to different offerings as they progress through an energy management pathway and look to implement more sophisticated improvement measures over time.

EXAMPLE 1: THE COLORADO INDUSTRIAL ENERGY CHALLENGE

The Colorado Industrial Energy Challenge (CIEC) is a voluntary program designed to help industrial facilities improve energy performance. The CIEC program challenges companies to set a five-year energy efficiency goal, and provides assistance in the form of free energy assessments, networking and training opportunities, and public recognition from the governor's office. The program is open to industrial facilities in Colorado with more than $300,000 in annual energy costs. The Southwest Energy Efficiency Project leads and coordinates the program with funding from the Colorado Governor's Energy Office and the U.S. Department of Energy (DOE). To join the program, companies sign a commitment letter agreeing to set a five-year goal for reducing total energy use or energy intensity and report energy information, energy efficiency project implementation, and progress toward the goal. As of 2013, the program has participation from around thirty facilities, and many have undertaken innovative projects to save energy and money. For example, Avago, a manufacturer of semiconductor devices, set a goal as part of CEIC to reduce energy intensity by 40% from 2008 levels by 2013. Avago implemented a project to use waste heat from a chiller condenser that would have otherwise been sent to cooling towers to preheat ultra-pure water needed in the manufacturing process. A heat exchanger now intercepts the rejected heat and pre-heats the cold water needed as feedstock for the process. The project cost $14,000, with a payback of only one month. It generates yearly savings of nearly $200,000, saves 28,000 decatherms of natural gas per year, reduces water use (through evaporation), and reduces CO_2 emissions by 1,600 tons per year.

Source: SWEEP 2013b

The spectrum of program approaches is discussed below and includes examples of successful state programs in each category. Detailed information on successful programs is provided in Appendix B.

APPROACH	DESCRIPTION	PROGRAM EXAMPLES
KNOWLEDGE SHARING	• Low-cost or no-cost technical assistance • Workshops and other outreach • Peer exchange opportunities between industrial clusters or groups of companies • Success story dissemination	• West Virginia Industries of the Future • Southwest Energy Efficiency Project
PRESCRIPTIVE INCENTIVES	• Explicit incentives or rebates for certain specific eligible technologies (e.g., lighting, motors, drives, compressed air, process heating equipment)	• Rocky Mountain Power • Efficiency Vermont
CUSTOM INCENTIVES	• Specific energy efficiency projects tailored to individual customers or specific industrial facilities • May be a mix of technologies • Incentives or rebates often based on entire electricity or natural gas savings	• Xcel Energy • NYSERDA
MARKET TRANSFORMATION	• Streamlined path for introduction of new energy efficiency products to the market • Address structural barriers to energy efficiency (e.g., outdated building codes or lack of vendors offering an emerging technology)	• Northwest Energy Efficiency Alliance
ENERGY MANAGEMENT	• Operational, organizational, and behavioral changes through strategic energy management • Continuous energy improvement (e.g., embedded energy manager to provide leadership and organizational continuity for implementing change)	• Wisconsin Focus on Energy • Energy Trust of Oregon
SELF-DIRECT	• Customer fees directed into energy efficiency investments in their own facilities instead of a broader aggregated pool of funds • Eligibility for customer participation often based on threshold amount of energy use or energy use capacity • Verified energy savings	• Puget Sound Energy • Michigan Self-Direct Energy Optimization

Figure 6. Spectrum of IEE state program approaches with program examples

3.1. Technical Assistance and Knowledge Sharing

Technical assistance and knowledge sharing programs are those that provide low-cost or no-cost expertise on energy-efficient technologies and practices, create networking opportunities between industrial clusters or groups of companies, and capture success stories and disseminate case studies. Some programs may also link companies with energy efficiency equipment and solution providers, leverage federal and other government resources so that industries may take advantage of equipment rebates, or direct customers to low- or no-cost industrial assessments funded through or by other programs.

Technical assistance and knowledge sharing programs are often initiated by program administrators voluntarily (i.e., without regulatory proceedings mandating ratepayer-funded programs and collection of a public benefits charge). Peer learning often provides a powerful driver for companies to implement energy efficiency measures and reap the productivity or competitive advantages their peers have enjoyed from similar investments. In those states that do not currently have ratepayer-funded programs, technical assistance and knowledge sharing programs can still generate significant energy savings to both manufacturers and society.

Examples of effective programs in this category include:

- The Colorado Industrial Energy Challenge (Example 1), which has been effective in its public recognition of IEE performance and providing companies with an opportunity to showcase their energy efficiency achievements
- The Industrial Energy Efficiency Network in the Southeast (Example 2), which hosts an effective peer exchange forum that provides a strong driver to share lessons learned
- The West Virginia Industries of the Future (WV-IOF) (Example 3), which has effectively leveraged partnerships with academic institutions and the U.S. Department of Energy (DOE) to provide training, technical assistance, and energy assessments to industrial staff.

EXAMPLE 2. THE SOUTHEAST INDUSTRIAL ENERGY EFFICIENCY NETWORK

The Industrial Energy Efficiency Network in the Southeast[18] is a regionally focused collaborative effort that unites cross-sector industrials in a peer-to-peer manufacturing network. As a platform for collaboration and education rather than providing technical assistance from a central program administrator to individual companies, the Network elevates energy efficiency best practices and project implementation, links manufacturers to financial and technical resources, and promotes strategic energy management practices.

Elevation of project ideas leads to implementation successes, with companies meeting regularly to share project experiences from initial conception through to measurable savings and other benefits. The exchange of qualified vendor references between peer energy managers is designed to shorten the time to project initiation. The Network offers a venue for activity at individual companies to be validated and celebrated by energy management peers.

The Network received an initial seed grant from DOE and is financed by public benefactors. Attendance at the peer-to-peer meetings continues to grow, with the average attendance around 80; manufacturers in the group have been actively making referrals to other firms in order to deepen the pool for collaboration. Firms are learning new tactics to manage energy at both the corporate and plant levels.

Sources: Marsh 2011, Marsh and Glatt 2011

3.2. Prescriptive and Custom Efficiency Offerings

Prescriptive and customized project offerings provide manufacturers with a financial incentive, often paired with technical assistance, for energy-efficient equipment and projects. Incentives for prescriptive and customized efficiency offerings are usually provided through ratepayer-funded programs. However, some non-ratepayer programs have designed IEE revolving funds in order to provide financial incentives (and technical support) on a self-sustaining basis.[19]

Prescriptive Offerings

Many energy efficiency programs have traditionally engaged the industrial sector through prescriptive incentives for lighting, motors, mechanical drives, compressed air, process heating equipment, and other energy support systems and equipment (Harris 2012). Prescriptive or standardized offerings provide explicit incentive or rebate amounts for certain specific eligible technologies. They can be useful for targeting those crosscutting pieces of equipment that are applicable across diverse commercial and industrial (C&I) sectors, and at both large facilities as well as small and medium enterprises (SME), such as variable speed drives for motor systems.

Prescriptive incentives for cross-cutting technologies can play an important role in helping to deploy high efficiency equipment across a broad base of industrial customers in different sectors and size classes. IEE programs have historically found it challenging to address the needs of SMEs as they have less staff capacity to address energy

[18] The program was previously administered by the Southeast Energy Efficiency Alliance (SEEA).

[19] Non-ratepayer-funded programs include AlabamaSAVES and the Tennessee Energy Efficiency Loan program administered by Pathway Lending. Pathway Lending received seed funding from the Tennessee State Energy Office, Tennessee Valley Authority, and DOE, but financing is leveraged principally through private community development banks. Low interest loans are available for businesses to invest in energy upgrades and the energy savings form a primary component of the principle repayment plan. These programs are profiled in Appendix B.

efficiency and generally have implemented fewer energy efficiency projects than larger companies. Taking advantage of less labor-intensive program offerings, such as prescriptive offerings—as long as eligible technologies are relevant to their situation—is a successful way to engage SMEs that may still have "low hanging" efficiency opportunities involving common technologies.

Prescriptive incentives are widespread throughout many states and are most often included as part of joint C&I rebate programs.[20] Although these measures may apply to manufacturing facilities, they do not address the majority of industrial energy-consuming equipment and processes. Some utilities have prescriptive measures for compressed air equipment, but in general a much larger percentage of energy savings projects specific to key industrial processes are categorized as custom measures (Seryak and Schreier 2013).

Custom Offerings

Instead of focusing on specific equipment upgrades, process or custom efficiency programs emphasize achieving savings from the manufacturing process itself, where the potential for energy savings is greatest (Harris 2012). Custom programs allow individual customers to develop specific energy efficiency projects that may be a mix of technologies and practices and qualify for incentives as long as they meet a required cost/benefit hurdle. Custom efficiency programs usually offer incentives based on a facility's entire electricity (kWh) or natural gas (therm) savings. Custom programs that use a per-unit-of-production calculation method shift the emphasis from traditional equipment upgrades (e.g., drives, motors) to improving a firm's ratio of energy use to physical output (Harris 2012). This allows program administrators to credit savings acquired via the implementation of a wide variety of technologies or plant and process modifications (Bradbury et al. 2013) rather than by choosing specific eligible technologies as in prescriptive rebate programs.

EXAMPLE 3. WEST VIRGINIA INDUSTRIES OF THE FUTURE

Industries of the Future West Virginia (IOF-WV), West Virginia's IEE program, was the nation's first state-level program (IOF-WV 2013) and helps manufacturers create financial savings through energy efficiency. IOF-WV teams work with individual companies to assess high priority research needs and develop projects that improve energy efficiency and environmental performance. IOF-WV grew out of a collaboration between West Virginia University, the West Virginia Development Office and DOE. The program provides technical assistance, conducts energy assessments, and runs best practice workshops on system-wide and component-specific topics to teach employees how to operate plants more efficiently. For example, the IOF-WV team conducted a plant-wide energy assessment at the Pechiney (now Alcan) facility in Ravenswood, West Virginia, from March 2002 to November 2003. The team identified $2.5 million in annual energy savings with average payback of less than 8 months. The assessment identified numerous areas for energy savings:

- Turning off comfort heating furnaces in summer months and in places where they are ineffective ($1,014,000 per year)
- Burner tuning and maintenance ($692,000 per year)
- Repair of compressed air leaks ($112,000 per year)
- Turning off idle equipment ($16,000 per year)
- Improving annealing furnace operating practice and modifying nitrogen plant control strategies to prevent waste of nitrogen ($75,000 per year).

The program is funded by a mix of state energy program funds, DOE funds, private sector leveraged funds, and cost-share.

Source: IOF-WV 2013, NASEO 2012

[20] The Database of State Incentives for Renewables and Efficiency (DSIRE) contains comprehensive information on rebates for specific technologies. See www.dsireusa.org.

Custom programs allow individual customers to develop specific energy efficiency projects that may be a mix of technologies and practices and qualify for incentives as long as they meet a required cost/benefit hurdle. Custom efficiency programs usually offer incentives based on a facility's entire electricity (kWh) or natural gas (therm) savings. Custom programs that use a per-unit-of-production calculation method shift the emphasis from traditional equipment upgrades (drives, motors, etc.) to improving a firm's ratio of energy use to physical output (Harris 2012). This allows program administrators to credit savings acquired via the implementation of a wide variety of technologies or plant and process modifications (Bradbury et al. 2013) rather than by choosing specific eligible technologies as in prescriptive rebate programs.

Custom programs generally require specialized resources to administer and support and may require greater program budgets than prescriptive offerings (Chittum et al. 2009). However, because they tend to deliver much larger savings and offer attractive paybacks per project, unit administration cost per kWh is often lower than prescriptive projects. Custom programs can be very cost-effective because they can unlock significant savings not possible through targeting individual pieces of equipment (Bradbury et al. 2013). CenterPoint Energy (see Example 4) has a successful custom program that was designed to address a gap in CenterPoint Energy's program coverage by reaching out to energy-intensive industrial customers who cannot avail themselves of standardized energy savings measures.

EXAMPLE 4. CENTERPOINT ENERGY CUSTOM PROCESS REBATE PROGRAM

CenterPoint Energy is an electric and gas utility based in Minneapolis, Minnesota, and has operated its rebate programs since the late 1990s. CenterPoint Energy provides financial incentives to customers who improve energy efficiency through innovative, customized energy-saving projects.

The Custom Process Rebate Program provides assistance and financial support to energy efficiency projects that do not qualify under prescriptive programs. Rebates primarily go to large-volume and dual-fuel customers that use throughput for process rather than heating purposes. Financial incentives are awarded to customers to assist with the first cost of the energy efficiency upgrade. The program has promoted such projects as bio-methane energy recovery, waste-heat energy recovery, boiler flue-gas condensers, thermal oxidizers, integral quench furnaces, heat-treat ovens, control packages, window replacement, stack economizers, and enthalpy wheels.

Each prospective project is compared to a base case to calculate efficiencies gained by installing the new technology. Once a project passes all requirements, an appropriate financial incentive is awarded to assist with the first cost of the energy efficiency upgrade(s). In some instances, C&I customers reach out to CenterPoint, seeking more effective energy efficiency processes. CenterPoint also works with customers to develop customized systems and solutions, and offers to buy down the new equipment, paying up to 50% of incremental cost.

In 2011, the program processed 148 custom projects that achieved a savings of 374,000 decatherms. The Custom Process Rebate Program addressed a gap in CenterPoint Energy's program coverage by reaching out to energy-intensive industrial customers who cannot avail themselves of standardized energy savings measures.

Source: Heffner et al. 2013

3.3. Market Transformation Programs

Market transformation programs work to streamline the path from the introduction and promotion of new energy efficiency products into the market to the establishment of customer acceptance. Market transformation programs require a long-term focus and are intended to address structural barriers to energy efficiency such as outdated building codes or lack of vendors offering an emerging technology. Their goal is to change marketplace behavior to increase acceptance of energy efficiency technologies and practices, but effecting this change can take time (often 5 to 15 years) (Taylor et al. 2012). Energy savings from these programs typically grow slowly in the early years, but are more likely to be persistent without relying on continued direct policy intervention once market acceptance is achieved (Taylor et al. 2012). An example of a successful market transformation program is the Northwest Energy Efficiency Alliance (NEEA) (Example 5). The initial phases of the process involve significant investments of time and effort to identify promising technologies and ideas and develop and test operational approaches to promote them. This type of effort is difficult for energy efficiency program administrators to justify because the costs are high for initial savings return. However, when an idea takes off, savings can materialize quickly, especially because program administrators in the Northwest (e.g., Energy Trust of Oregon and BPA) provide program support and leverage NEEA's market transformation solutions, pushing up market penetration rates and energy savings (Taylor et al. 2012).

3.4. Strategic Energy Management and Energy Manager/Staffing Programs

Traditionally, IEE programs have generally focused on promoting energy efficiency technology and supporting the installation of new, more efficient equipment or processes. In contrast, continuous energy improvement,[21] strategic energy management (SEM), or energy manager programs seek to promote operational, organizational, and behavioral changes that result in greater efficiency gains on a continuing basis. Although technology-based programs typically involve energy assessments to identify specific efficiency opportunities, organizational issues often prevent cost-effective measures from being implemented. SEM and energy manager programs focus on establishing the framework and internal processes for managing energy use, as well as on implementing capital projects.

Strategic Energy Management Programs

SEM programs help support the deployment of holistic energy management strategies and seek to encourage energy savings generated from changes in corporate culture, behavior, and operations and maintenance (O&M) practices. SEM programs, which in this report also include the adoption of energy management systems (EnMS), usually involve establishing a team representing personnel from across the organization (rather than just one energy manager) and require corporate management support to raise energy efficiency as a priority within the firm. SEM programs support the development of baselines, energy performance indicators, and metering capabilities. Although implementation of capital projects is still guided by energy management processes to identify and prioritize energy efficiency opportunities, SEM programs also encourage best practices in O&M independent of new investments.

SEM programs can be an effective tool for companies that want to extend their efforts to systematically identify and prioritize capital projects beyond the isolated technical improvements they may have already made at their facilities. At the same time, SEM can also provide a framework for saving energy at little or no cost through changes in operational efficiency. For example, J.R. Simplot's corporate energy manager noted that by simply

EXAMPLE 5. NEEA'S MARKET TRANSFORMATION PROGRAM

The Northwest Energy Efficiency Alliance is a regional nonprofit alliance of more than 100 Northwest utilities and energy efficiency organizations working on behalf of more than 12 million energy consumers. It operates in Oregon, Washington, Idaho, and Montana. Formed in 1996, NEEA was tasked to undertake energy efficiency market transformation initiatives throughout the region in support of both regional utility energy efficiency programs and the energy efficiency agenda overall. NEEA works across residential, commercial, and industrial sectors; helps accelerate the innovation and adoption of energy-efficient products; and identifies, develops, and advances emerging technologies to fill the energy efficiency pipeline with new products. NEEA's costs are paid by the Bonneville Power Administration, the Energy Trust of Oregon, and distribution utilities.

NEEA's market transformation initiatives involve identifying promising technologies and developing and implementing programs that allow them to be effectively picked up in the marketplace on a sustainable basis. NEEA tracks the energy savings resulting from its various initiatives, which include both savings from ratepayer programs of the utilities or ETO that build directly from NEEA's innovations, as well as savings directly from overall market penetration. Since 1996, the region has cost-effectively delivered, on average, over 900 MW of energy efficiency per year through market transformation.

Sources: Taylor et al. (2012), NEAA (2013).

[21] While the term "continuous energy improvement" was common in the past, the term "strategic energy management" has gained currency in today's programs.

applying behavioral changes, one plant was able to realize a 3% reduction in energy consumption in one year alone, with no capital expenditures (Sturtevant 2013). Energy management practices can be an especially attractive option for companies that do not have the capacity at that time to make significant investments, or are in the middle of operational cycles that limit plant modifications.

Examples of SEM programs include the BPA, the Energy Trust of Oregon (ETO), Wisconsin Focus on Energy (WFE), Xcel Energy Process Efficiency Program, BC Hydro, and AEP Ohio. An overview of the programs is provided in Table 1. Note that these programs' SEM offerings are often integrated into prescriptive or custom/process incentive programs but incentives for SEM can be different from custom or prescriptive incentives. Federal programs such as ENERGY STAR® offer resources that can be used and incorporated into an SEM offering.

BPA and ETO's SEM programs involve training "cohorts," or groups of non-competing companies, on SEM approaches. Companies typically meet monthly, with homework and coaching provided between meetings. These programs measure total energy savings achieved through the SEM training process, including savings from O&M changes, and provide incentives per unit of energy savings. BPA also offers a "track and tune" program to help companies find and implement low- and no-cost energy saving opportunities, and provides assistance with developing more sophisticated systems for monitoring energy consumption and measuring savings (Kolwey 2013).

Energy Manager Programs

A knowledgeable and dedicated energy manager is often the key to successfully implementing SEM within a company. An energy manager who works within and for the company for a period of time can provide leadership and organizational continuity for implementing change. Energy managers help guide energy efficiency capital expenditures through the company's approval process and provide the leadership and communication skills needed to inspire collaboration and minimize resistance to change within the organization. However, given the competitive pressures imposed on manufacturers today, many organizations are not able to obtain or reassign staff with the skill set to be a fulltime energy manager. Many organizations may lack awareness of the costs and benefits of hiring a fulltime staff member relative to other business investment opportunities and may also not anticipate the scope of the responsibilities. BPA's Energy Project Manager program (Example 6) has been successful in promoting the value of energy managers, as indicated by the fact that several facilities have gone on to hire their own energy managers after receiving BPA support.

To overcome these challenges, some IEE programs specifically support the placement of on-site energy managers in industrial facilities or with the corporate office. The energy manager can either be sourced as an existing staff member from within the company or brought in as an external expert (Russell 2013b). In some cases, programs provide support for on-site energy managers for a period of one year or longer. Program-sponsored energy manager initiatives promote the development of a cadre of experts needed to support SEM and achieve continuous energy efficiency gains over time (Russell 2013b).

For example, WFE provides a staffing grant to facilities that have already documented their major energy improvement needs. Reimbursements are paid upon implementation of energy efficiency projects. Twenty-eight facilities have been served to date. In 2010, 35 projects facilitated by the staffing grant in seven facilities generated energy savings of 278,872 MMBtu, or an average of 54,823 MMBtu per recipient). Staffing grant savings averaged $0.91 per MMBtu. Note that the energy savings totals include some projects that were not eligible for additional investment incentives (Russell 2013b).

BPA and Puget Sound Energy also have energy manager co-funding programs. Puget Sound Energy, BPA, and WFE programs provide partial financial support for the energy manager position assigned from existing personnel within the facility. The advantage of assigning an existing employee is that the person has already garnered trust of his/her colleagues and is familiar with the operational and technical processes of the workplace.

Roving energy project managers that assist multiple companies (as opposed to embedded energy managers for a single facility as described above) can also be an effective option, particularly for SMEs. SMEs often lack technical expertise and can thus benefit from external personnel who can share their technical and implementation experience from working with companies in similar applications. A roving energy manager can assist five to six companies at once by providing energy project management support and implementing energy efficiency opportunities identified through an energy audit (Weir 2013). For example, from 2010 to 2012, the Minnesota Energy Resources Corporation provided an energy management team coordinator to help the internal energy management teams of five industrial customers identify and implement energy conservation improvements (i.e., the coordinator dedicated 20% of total work time to each customer).

Table 1. Selected Energy Management and Energy Manager/Staffing Programs

Energy Management Offering	SEM Incentives	Customer Size
BONNEVILLE POWER ADMINISTRATION—ENERGY SMART INDUSTRIAL PROGRAM		
- High Performance Energy Management (HPEM): Provides training and individual assistance to 8–15 companies for one year. Measurement and incentive funding is available for 3–5 years. **- Track and Tune**: Low/no-cost operations O&M with incentive funding over 3–5 years and tools for interval data acquisition and performance tracking. - **Energy Project Manager (EPM) Program**: Funding of energy efficiency staff to support project identification and implementation (see Example 6).	$0.025/kWh for 3 or 5 years, for O&M savings	18,000 MWh/yr (guideline)
ENERGY TRUST OF OREGON—PRODUCTION EFFICIENCY PROGRAM		
- Industrial Energy Improvement (IEI): Year-long engagement provides cohorts of manufacturing companies trainings on SEM principles, tools, and practices designed to help companies manage their energy strategically. **- Corporate SEM (CSEM):** Focuses on corporate sites, instead of the cohort model, CSEM provides training and on-site activities on SEM principles and practices (9–12 months). **- SEM-Maintenance:** Helps former SEM participants maintain, deepen, and continue the integration of SEM into their business' operations. - **CORE Improvement**: Offering similar to IEI in focus and structure but services and instructions are tailored to small to medium manufacturers. - **ISO 5001 pilot implementation** (see Chapter 6).	$0.02/kWh, $0.20/therm for 1 year of savings. SEM-Maintenance: $0.01/kWh, $0.10/therm	IEI/CSEM: More than 8,000,000 kWh/yr, or if eligible for gas, 500,000 therms/yr usage. CORE: Spending $50,000–$500,000 on total energy costs (electricity and gas combined)
WISCONSIN FOCUS ON ENERGY—INDUSTRIAL PROGRAM		
- Practical Energy Management: Provides best practice training events and applies its industry-specific Energy Best Practice Guidebooks to key cluster industries. **- Staffing grants:** Allow companies to hire an FTE.	Grants for energy staff	Customers with more than $60,000 in monthly bills
XCEL ENERGY—PROCESS EFFICIENCY PROGRAM (CO & MN)		
Provides individual assistance in developing a 3–5 year energy management plan using the Envinta One-2-Five Energy Methodology that evaluates energy intensive processes, benchmarks energy management practices, and provides an assessment prioritizing opportunities.	For capital projects only	> 2,000 MWh/yr of savings potential
BC HYDRO—POWER SMART		
- Industrial Energy Manager: Offers funding for large customers to hire an on-site energy manager and a structured support group of local companies that share best practices. **- Energy Management Assessment:** Free assessment of opportunities, customized SEM action plan, and rating against the Energy Management Scorecard. **- Various free energy management tools and training**, employee awareness kits, and customer recognition through public media.	Co-funding of energy manager	> 20 GWh annually
AEP OHIO—CONTINUOUS ENERGY IMPROVEMENT PROGRAM		
- **Coaching assistance, tools, and templates** to help meet plant and corporate cost saving targets. - **Custom statistical models** to help measure and manage energy intensity. - An **Energy Coach** to help identify and implement opportunities.	$0.06 /kWh (or $0.02/kWh over 3 years)	> 10 GWh annually

Sources: Batmale and Gilless 2013, IIP 2013, Kolwey 2013, Russell 2013, Nowak et al. 2012, BC Hydro 2013, AEP Ohio 2013, Xcel Energy 2010

EXAMPLE 6. BPA'S ENERGY PROJECT MANAGER PROGRAM

BPA has introduced an Energy Project Manager (EPM) program that funds a position for an engineer at an industrial facility. This individual can be an existing staff engineer or someone specifically hired for the position. One of the primary requirements is that the facility has the potential for, and commits to, annual energy savings of 1 million kWh through efficiency projects.

Initially, BPA and the customer estimate achievable energy savings. The energy manager is then required to develop a plan with updates every three to six months. The savings are tabulated according to the upfront feasibility studies for specific projects and revised according to final measurement and verification of achieved savings. Once the EPM is assigned and the estimated savings have been agreed, an initial $25,000 funding payment is made to the facility. The program also reimburses a fixed rate per kWh saved ($0.025 per KWh saved) subject to a funding cap of $250,000 maximum annual amount. Additional incentives are available for capital and O&M projects.

From 2009 through March 2013, 28 energy managers had been placed in a variety of industries and capacity savings averaging 16.6 MW had been implemented. More than half of program participants apply for term renewals. Some facilities are currently in years 2–3 of their participation. BPA has found that several facilities have gone on to hire their own energy managers after receiving this type of funding support for several years.

Sources: BPA 2012a, DOE 2010, Kolwey 2013, Russell 2013b

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4. Program Features that Respond to Manufacturers' Needs

The spectrum of program approaches discussed in Chapter 3 demonstrates that there are a range of program offerings designed to help manufacturers improve their energy efficiency. These can range from providing technical assistance to offering financial incentives for common technologies to sponsoring an energy manager to guide a facility toward behavioral changes that result in more energy-efficient operations and maintenance. These approaches can be customized to meet a variety of conditions, and fundamental success factors can be worked into a wide variety of program designs and policy environments.

Effective industrial energy efficiency (IEE) programs will adopt the language, engagement strategies, and metrics that are meaningful to the corporate managers who drive capital investment decisions. Understanding customer needs and the investment decision-making processes allows state IEE program administrators to boost implementation rates while making better use of limited resources.

This chapter first discusses the special needs and characteristics of industrial companies as energy users and provides basic information that may help program administrators recognize and navigate prevailing capital investment practices and corporate culture perspectives on energy. The reader should keep in mind these are generalizations, and may not be applicable to any specific industrial customer. It then discusses reasons why manufacturers may resist participating in state IEE programs. Finally, building on approaches that are currently operating in a variety of state contexts, it explores specific features that can respond to manufacturers' needs.

For the most part, these features are engagement strategies that have been proven to provide value to industrial customers. With greater industrial engagement and participation, state goals such as providing utility customers with low-cost energy resources and environmental benefits can be met more quickly and cost-effectively. The program examples highlighted here have been successful, not only because they have been able to respond to manufacturers' needs and achieve significant energy savings, but also because they often demonstrate cost-effectiveness (according to whatever cost tests a state may require for the program), have had good rates of participation, or show they have some longevity and a track record of successful projects.

4.1. Special Needs and Characteristics of Manufacturers as Energy Users

Manufacturing is Complex and Sophisticated

Understanding energy use patterns in manufacturing plants can be far more complex than in other end-user sectors. Manufacturing uses energy in various common technologies such as boilers, air compressors, or motors, as well as in processes that are specific to each industry.

Although the technical choices and energy use characteristics for various common technologies may at times be straightforward, the economics of adopting energy savings measures in these cases can still be complicated, as they are heavily related to production patterns that typically change with the ups and downs of market demands. Energy use tied to specific manufacturing processes, then, is highly plant-specific and typically requires a level of specialized knowledge that often is found only among subsector technical experts.

Industrial companies are also generally more knowledgeable about energy issues than other customer categories, especially in factories where the cost of energy is a substantial proportion of overall costs. For example, in the steel industry, energy accounts for about 15% of total manufacturing costs, and in the glass industry, energy costs are 8%–12% of production cost (DOE 2013a). Even in applications where energy is not a large proportion of costs, some industrial managers view energy as a cost that can be controlled more easily than labor or feedstock inputs—at least in the near term.

Manufacturing is Heterogeneous

The industrial sector is very diverse, comprising a wide variety of different industry subsectors with different production processes and energy use characteristics. Even within subsector processes, product mix output and energy use patterns vary substantially. In the chemical industry, for example, it is typical for individual plants to continually adjust their product outputs as market conditions change and new opportunities arise. Such changes often require adjustments in process flows and the equipment and energy use patterns of different parts of a facility.

The industrial sector includes a broad spectrum of company size and technical sophistication ranging from very large companies with internal engineering staff to small and medium enterprises (SMEs) with limited technical capabilities.

The heterogeneity of the manufacturing sector can make it difficult for IEE programs to meet the specific needs of individual companies. To some extent, fairly simple programs designed to assist companies to save energy in common technology applications can be designed to be relevant to a wide range of manufacturing plants, providing some value. However, focus on simple common technology fixes alone will tend to put programs on only the periphery of manufacturing energy use and savings concerns. Manufacturers use energy differently than the commercial sector, typically having significant process-related consumption in addition to heating, ventilating, and air conditioning (HVAC) and lighting loads. Although it varies depending on manufacturing subsector, HVAC and lighting typically make up around 20% of total energy consumption (Kolwey 2012).

Although manufacturing as a sector is usually heterogeneous, industries may cluster in certain service areas for a variety of reasons. This creates opportunities for program administrators to concentrate energy efficiency process expertise in such places. Wisconsin's cluster approach is discussed in Section 4.7.

Energy Efficiency is Often Not Integrated into a Company's Decision-Making Process

Because energy can be a significant percentage of total manufacturing costs, lowering energy costs through increased efficiency can improve a company's bottom line and overall competitiveness. However, the decision-making processes of industrial companies involve a variety of participants, concerns, and procedures. There is a range of reasons why internal decision-making processes may not result in implementation of highly cost-effective energy efficiency opportunities, including:

- Energy efficiency projects may compete with core business investments that dominate attention, as well as investments for safety, environmental, and other regulatory requirements
- Decision-making is often split across business units
- The skills required to identify and pursue energy efficiency opportunities are not always present.

Projects focusing on operating cost savings may not compete well internally with projects focusing on expansion or new market development, despite very attractive financial returns. The profit benefits of investments leading to operating cost reductions may be difficult to clearly identify or communicate. Sometimes, other major investments may be seen as more core to the business, attracting higher priority. At other times, access to financing for operating cost saving projects also may be a barrier. Projects may be difficult to finance with outside loan capital if they are relatively small, due to lukewarm interest among financiers and high transaction costs.

Large companies often split responsibility for plant operations, energy bills, and investment decisions across different organizational units. A plant manager may be interested in energy efficiency, but does not see the actual energy bills or get credit for reducing them. A procurement manager may be motivated to minimize first costs instead of life-cycle costs, even if efficient choices save operating costs at the plant level. These "principal-agent" or "split-incentive" barriers can keep cost-effective improvements from happening.

In addition, in some cases manufacturers concerned about controlling energy costs may focus on efforts to gain more favorable energy pricing and contractual arrangements with energy suppliers and not necessarily on improving the efficiency of energy use in operations.

Finally, the skills required to identify and implement IEE opportunities are not always present in existing staff or staff are tasked with addressing other priorities. Companies often lack in-house staff capacity and specialized expertise in energy management and technology skill sets. This prevents cost-effective measures from being identified, and also prevents known options from being advanced to the implementation stage.

Operational Cycles Influence When Energy Efficiency Investments Can Be Made

Energy efficiency investments are heavily dependent on the industrial customer's operational cycle, which can span four to seven years on average (Chittum 2009). Maintaining stable production is critical in industry. Project implementation can require temporary downtime for equipment installation and testing, impacting plant operations and production. Flexible scheduling to best match production requirements—for example, delaying implementation to times when many projects can be done at once or to planned shutdowns—will minimize plant interruptions and reduce management concerns.

In addition, IEE projects can often be significantly larger than projects in other sectors, requiring completion of comprehensive project approval processes and careful consideration by various personnel across a number of corporate divisions. Time horizons for project approval may be long. Moreover, implementation scheduling may require linkages to a variety of other project implementation measures at the same time.

Co-Benefits Are Often Not Included in the Cost-Benefit Analysis for Energy Efficiency Projects

Although additional co-benefits or non-energy benefits (NEBs) from energy efficiency projects may be substantial for the industrial customer, they are generally not included in the cost-benefit analysis for energy efficiency projects. This is despite extensive evidence that NEBs can be a key part of project benefits and can reduce payback times for new investments. Co-benefits may even exceed the value of energy savings. A 2003 study of commercial and IEE programs in Wisconsin valued these benefits at approximately 2.5 times the projected energy savings of the installed technologies (Hall and Roth 2003). In a recent survey of 30 energy managers, engineers, sustainability managers, plant managers, presidents, and vice presidents from a diverse pool of companies nationwide, 90% of energy projects were found to also have a broader productivity impact (Russell 2013a). For one company surveyed, energy improvements provided a fourfold return in the form of production improvements and some companies claimed that NEBs "dominated" the returns from energy projects. NEBs are further discussed in Chapter 6.

4.2. Industrial Participation in Energy Efficiency Programs

Historically, energy efficiency program administrators have struggled to create programs that overcome concerns from manufacturers about perceived or real costs, potential risk for production disruptions, or lack of flexibility in prescriptive incentive programs. When new ratepayer energy efficiency programs are being contemplated, large industries may resist paying systems benefits charges. In cases where some types of industrial programs have already been put in place as part of resource acquisition efforts, some industries remain lukewarm about participating. Several common reasons for this include:

- Saving energy is already claimed to be a business imperative and many industrial customers feel they can best manage their own energy needs, so they may think there is no added value in participating in IEE programs.
- Manufacturers are not aware of the IEE program offerings that may be most useful for their operations.
- IEE program offerings may not be flexible enough to meet the most pressing energy efficiency investment priorities of manufacturers and may be considered administratively complex and burdensome.
- Available IEE programs are perceived as being unresponsive to core energy issues in plants that are subsector- and site-specific.
- IEE program administrators may be perceived to have insufficient expertise in manufacturing and/or are not knowledgeable about key customer concerns and needs.
- There is a mismatch between industrial planning and project cycles and IEE program terms. Equipment replacement or refurbishment or plant retrofits can often only occur at the end of appointed times in operational cycles.

- Industrial firms can be sensitive about releasing confidential information and may be concerned that programs end up sharing information on what they consider to be their competitive advantage.

All of these observations help explain why manufacturers may not always respond quickly or positively to IEE program offerings. Program designers who are aware of the issues and concerns that can limit industrial participation can be better equipped to design programs that address these concerns and better meet the specific needs of their industrial market (Section 4.7 discusses how program administrators have been able to provide significant value to their industrial customers).

As described in further detail below, successful IEE programs that provide value both to individual industrial energy users and to society at large:

- Clearly demonstrate the value proposition of energy efficiency projects and IEE programs
- Develop long-term relationships with industrial customers, with continual efforts to identify effective projects
- Accommodate project scheduling issues
- Provide both common technology and customized project development options
- Ensure that program administrators have industrial sector credibility and can offer high quality technical expertise targeted to specific subsectors
- Streamline and accelerate application processes
- Leverage strategic partnerships
- Conduct active and continuing program outreach
- Set medium- and long-term energy efficiency goals as an investment signal for industrial customers
- Ensure robust evaluation, monitoring, and verification.

EXAMPLE 7. NORPAC'S WASHINGTON MILL BENEFITS FROM CUSTOM EFFICIENCY OFFERING

NORPAC, a large paper mill in Washington State, is the largest newsprint and specialty paper mill in North America. The 33-year-old mill produces 750,000 tons of paper a year and is the largest industrial consumer of electricity in the state, requiring about 200 MW_{avg} of power. It takes a lot of energy, water, and wood to make paper and the process begins with wood chips. Refining wood chips is a mechanical process that requires large amounts of energy.

Bonneville Power Administration (BPA) and the Cowlitz County Public Utility District (PUD) funded the installation of new screening equipment between refiners that reduces the electricity and chemicals used to refine wood chips and reduces the amount of pulp needed for the process. The equipment is estimated to save NORPAC 100 million kilowatt-hours of electricity per year, equivalent to cutting its power requirements by about 12%, and is enough energy to power 8,000 Northwest homes.

The improved refining processes have also allowed NORPAC to expand its product line. The mill can now produce a brighter and whiter paper that is made from fewer wood chips than a similar grade from its competitors.

NORPAC employs 415 full-time employees and about 30 contractors and the construction phase of the project created 64 full-time family-wage jobs.

BPA has funded about $21 million for three custom projects at NORPAC, and Cowlitz PUD will contribute up to an additional $3.9 million. NORPAC is funding the remaining $35 million of the $60 million project.

Source: Taylor et al. (2012); BPA (2012b)

4.3. Clearly Demonstrate the Energy Efficiency Project Value Proposition to Companies

Energy efficiency measures, which generally lower the cost of production or increase output per input costs, have repeatedly demonstrated their effectiveness in improving a facility's bottom line and in increasing company competitiveness and productivity. Benefits can include strong life-cycle cost savings with sometimes minimal capital investment, a variety of non-energy co-benefits, and even reputational advantages. It is not uncommon for manufacturing facilities to realize energy efficiency improvements as high as 10%, with corresponding cost savings and financial paybacks of two years or less when they implement basic operational and maintenance improvements. For example, as part of the U.S. Department of Energy's (DOE's) Superior Energy Performance (SEP) program, 14 pilot plants have implemented the global energy management standard, ISO 50001, and achieved SEP certification. Nine of these plants have shown an average energy performance improvement of 10% in the first 18 months of SEP implementation, with an average payback of 1.7 years (DOE 2013c). Energy Trust of Oregon (ETO) and AEP Ohio also estimate that their industrial customers can typically achieve 5%–15% savings through energy management with little or no capital investment (ETO 2013, AEP Ohio 2013). And Efficiency Vermont estimates its Continuous Energy Improvement program can help companies cut energy consumption by 10%–15% within the first three years and 25%–35% within six years (Efficiency Vermont 2013).

Many companies that have participated in IEE programs have experienced strong cost savings benefits, and successful IEE programs document how program offerings have helped their industrial customers' bottom lines. For example, the Bonneville Power Administration (BPA) extensively documents results from its Energy Smart Industrial Program. Success stories include:

- The NORPAC pulp and paper mill in Washington State, which cut its power requirements by 12% per year through upgrades financed by BPA (Example 7)
- J.R. Simplot, which identified energy savings of $715,000 per year with a three-year payback (Example 8)
- Irving Tissue, which, through participation in the New York State Energy Research and Development Authority's (NYSERDA's) industrial FlexTech and Industrial Process Efficiency (IPE) programs, was able to save 14,800,000 kWh per year (Example 9).

EXAMPLE 8. SIMPLOT AND CASCADE ENGINEERING IDENTIFY $1,000,000 IN ELECTRICAL SAVINGS

J.R. Simplot Company is one of the largest privately-held corporations in the United States, consisting of AgriBusiness, Land and Livestock, and Food Group divisions. The company was successful in developing and integrating a company-wide energy management program and worked with Cascade Energy within local utility energy programs to obtain energy study co-funding and implementation incentives. Simplot is also a U.S. Department of Energy Better Plants Challenge Partner and a U.S. Environmental Protection Agency (EPA) ENERGY STAR® partner.

Simplot and Cascade Energy have joined forces on 14 detailed energy studies at nine facilities over the past 10 years. Cascade provided facility scoping, energy analysis, project costing, design assistance, commissioning, and final inspection services on these projects. Cascade evaluated refrigeration, compressed air, hydraulics, pumping systems, processes, and controls at both existing and new facilities. Simplot implemented seven of the largest projects to date, capturing well over half the identified energy savings.

Energy Savings: $715,000 per year or 21,000,000 kWh per year ($1,000,000 or 36,000,000 kWh per year identified)

Investment: $950,000 to date ($2,000,000 identified)

Financial Return: Three-year simple payback on implemented projects

Source: EPA 2013b

PacifiCorp, an investor-owned utility operating in five northwestern states, offers extensive ratepayer-funded energy efficiency programs throughout their territory. For those customers participating in IEE programs, PacifiCorp has found that a one-dollar investment can yield $4.10 to $5.60 in long-term savings. The utility has documented that these energy savings are predictable over time, measurable, and long-lasting (WGA 2013).

A key point in making the value proposition case to industrial company managers is to lay out in simple and concise terms the operating cost savings and other benefits—including profits—that are being left on the table by not addressing cost-effective energy efficiency improvement opportunities. The case can then move on to the simple steps required to capture the most prominent savings opportunities. Cost-saving examples and success stories from similar companies in similar situations can also greatly help to further buttress the case. Discussion and exchange with peers can also be a strong driver for energy efficiency with individuals and companies. Many successful programs offer a venue for peer exchange.

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Document results from successful IEE projects.
- Include non-energy benefits of energy efficiency measures in the value proposition.
- Develop case studies and examples for different industrial sectors.

4.4. Develop Long-Term Relationships with Industrial Customers and Continue to Refine Project Offerings

Maintaining multi-year and steady relationships with individual industrial customers is a key factor for achieving success in state IEE programs. All the energy efficiency programs that have been successful with industry have this element in common.

The reasons why long-term, steady relationships with individual customers are so important stem in large part from the particular characteristics and needs of the industrial sector described previously. Key reasons include:

- Strong understanding of industrial customer circumstances and needs. To add real value to existing energy efficiency efforts at a customer facility, program staff need to understand the specific circumstances of the plant as well as their plans and issues.
- Develop projects on a flexible timeframe. IEE projects tend to be identified over time, as plant circumstances change and opportunities arise. In addition, project implementation scheduling must accommodate a host of industrial client concerns (see Section 4.5). Successful program staff consistently report that the best results are maintained through steady dialogue and contact, responding to the opportunities when they arise.
- Build synergies between program offerings. Proven results with industrial customers often involve a variety of program offerings and services. Typically, these are delivered at different times, as opportunities and customer needs develop, but they are also often interrelated and build on each other. For example, assistance in completing an audit may often lead to identification of a project for program support or an energy management improvement opportunity. Joint work on completion of a customized project may lead to identification of a number of simple prescriptive project options that a company was not aware of. Advice on how to access a key process expert may lead to a new project.

EXAMPLE 9. IRVING TISSUE BENEFITS FROM NYSERDA'S INDUSTRIAL OFFERINGS

The New York State Energy Research and Development Authority's (NYSERDA's) longstanding technical assistance program—known as FlexTech—and its Industrial Process Efficiency grant programs have assisted Irving Tissue, a tissue, paper towel, and napkin manufacturer located in Fort Edward, New York, with increasing its new plants' efficiency. The company was considering a major plant expansion to improve productivity and competitiveness. To ensure that the new operation was cost competitive, Irving Tissue worked with manufacturers, suppliers, and NYSERDA to build energy efficiency into the new paper-making systems. A proposed upgrade for a more efficient vacuum system would create significant energy and cost savings while delivering a higher quality product. However, the cost of the system was too great for the company to self-finance. The Industrial Process Efficiency program was not only able to provide grant funding for the vacuum, but also was able to recommend the installation of premium efficiency motors and variable-speed drives. NYSERDA was able to finance $1.8 million of the full incremental cost of $4.3 million for the efficiency upgrades. The new papermaking machine is saving 14,800,000 kWh per year compared with a standard paper machine.

Source: NASEO 2012

The importance of building long-term relationships is bolstered by a stable and skilled IEE program contact for industrial customer interaction. Satisfaction of industrial customers with program delivery and results often hinge on the degree of success achieved in establishing a strong relationship with program staff. Within IEE programs, the industrial program account management system provides a structure for steady engagement with industrial customers. Individual account managers may be staff, long-term contractors, or a blend of these (see Section 4.7). Successful programs have a cadre of skilled staff and experts to develop, build, and maintain the long-term relationships with individual customers needed for industrial program success.

Many programs become steadily stronger because of long-lasting industrial customer relationships. IEE program administrators that have developed long-term relationships with industrial customers can track the status of the firm's energy efficiency efforts and investments made over time. This enables them to provide continued relevant solutions to the company.

In their efforts to maintain steady, regular dialogue with industrial customers, successful IEE programs engage at the customer's corporate level as well as the plant level. Note that this can be a challenging task for a regional program, especially when corporate headquarters is located outside the region. Identifying an internal energy champion within the industrial company and connecting with several additional staff so relationships can continue despite staff changes also helps foster long-lasting relationships.

In ETO's Production Efficiency program (see Example 11), additional customer support has encouraged more cost-effective savings. The ETO program focuses on long-term relationships using a business-like approach to customer relations to help customers achieve significant ongoing savings. Increased program delivery expenditures have delivered higher savings and lower resource acquisition costs than increased incentive levels. Customers recognize the value of program assistance in customer satisfaction surveys (Nowak et al. 2012).

EXAMPLE 10. XCEL ENERGY INCENTIVES AND TECHNICAL SUPPORT

Xcel Energy operates in eight states. Their incentives portfolio has been lauded by industrial customers for offering simple incentive applications for providing a full suite of programs—custom, self-direct, and process energy efficiency incentives. Xcel representatives noted that they see the most manufacturing participation where there is flexibility and incentive stability.

Xcel's Process Efficiency (PE) program in Colorado integrates its technical assistance, energy management support, and incentive programs. The PE program is available to industrial customers with energy conservation potential of at least 2 GWh, which usually translates to total annual electricity consumption of at least 20 GWh. The program offers a free scoping assessment and provides support for strategic energy management. A second more detailed assessment is then undertaken, for which the customers pays 25% of the cost, up to $7,500. After the detailed assessment is completed, Xcel Energy and the customer sign an agreement that specifies which projects will be implemented, the timeframe for implementation, and the incentive amount based on the rate of $400 per kilowatt of peak demand reduction. Xcel Energy encourages the customer to agree to complete projects within a year, but allows longer timeframes if needed.

Source: Kolwey 2012, WGA 2012

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Understand the industrial customer's circumstances, needs, and operational cycles.
- Build synergies between program offerings.
- Develop stable, long-lasting relationships for maximum results.

EXAMPLE 11. ENERGY TRUST OF OREGON PRODUCTION EFFICIENCY PROGRAM

Recognizing that large manufacturers can realize deep energy savings with low-cost changes, the Energy Trust of Oregon (ETO) offers the Industrial and Agricultural Production Efficiency program, a custom and prescriptive rebate program, to help achieve these savings. Portland General Electric, Pacific Power, NW Natural, and Cascade Natural Gas customers, who pay into the state public benefit fund, qualify.

The program promotes innovative IEE technological and behavioral approaches and provides technical expertise, training, and project funding to help companies plan, manage, and improve their energy efficiency. All industrial size classes are eligible, but the program focuses on measures that will yield more significant energy savings: custom projects for industrial process improvements, strategies for large energy users, and projects with certain low-cost changes that can yield significant energy savings. The program also offers prescriptive incentives available for projects such as lighting and heat pumps.

ETO provides free technical services, typically valued at $20,000 to $50,000, to complete a study of energy efficiency opportunities. Custom incentives are calculated on a case-by-case basis. Incentives of $0.08 per kWh and $0.04 per therm are also available for operations and maintenance improvements (up to 50% of eligible project costs or up to 90% if completed within 90 days), energy management practices ($0.02 per kWh saved or $0.20 per therm saved), and custom process or production equipment projects (up to 50% of project costs).

ETO contracts with energy efficiency account managers throughout Oregon, termed program delivery contractors, and with energy efficiency process engineers termed allied technical assistance contractors, who provide detailed technical and scoping studies to determine the most cost-effective energy upgrades.

ETO's 2013 energy savings from industrial customers reached 16.9 MW_{avg} of electricity and 2.2 million therms of natural gas. The Production Efficiency program completes nearly a thousand projects per year.

Sources: ETO 2012, ETO 2013b, Nowak et al. 2013

4.5. Ensure Program Administrators Have Industrial Sector Credibility and Offer High Quality Technical Expertise

As discussed in the previous section, development of long-term relationships between industrial customers, program administrators, and experts is important for IEE program success. Effective IEE programs also develop credibility with the industrial customer by employing staff and/or contracted experts that understand the customer's industrial segment, and have the technical expertise to provide quality technical advice and support on energy efficiency options and implementation issues specific to that industry and that customer.

Addressing industrial companies' core needs requires understanding a plant's production processes, operating issues, and the market context that the plant operates within. Effective IEE programs will adopt the language, engagement strategies, and metrics that are meaningful to the corporate managers who drive capital investment decisions. Understanding customer needs and their investment decision-making processes allows IEE program administrators to generate trust with their industrial customers, boosting IEE implementation rates while making better use of limited resources.

Access to specific subsector technical expertise for specific short-term assignment is almost always necessary. Engagement of technical experts can address customers' specific technical needs such as completing diagnostics, developing new internal metering programs, assessing technology options for new projects, and developing project-specific measurement and verification (M&V) plans.

There are different approaches to ensure that this key program contact function is effective. Some program administrators rely heavily on in-house staff for this function. For example, Efficiency Vermont maintains six account managers in charge of all day-to-day relations with industrial customers. On the other side of the spectrum, some program administrators rely heavily on contractors to undertake day-to-day account-manager type functions for their industry programs. One example includes Wisconsin's long-standing Focus on Energy program, which one contractor has operated successfully for almost 14 years, providing steady service to large industrial customers under the Focus on Energy brand (Taylor et al. 2012). Others rely heavily on contractors to undertake day-to-day account-manager type functions.

A mixed approach can also be adopted, using both in-house and contractor staff to maintain day-to-day dialogue. In Oregon, for example, nine of ETO's 80–85 internal staff are responsible for delivery of the industry and agriculture Production Efficiency program. These staff work together with six outsourced Program Delivery Contractor (PDC) teams. The PDC teams include six to seven people each, working on day-to-day delivery of the program. There are currently 30–35 PDC full-time equivalent employees (FTEs), and approximately 10–20 FTEs that provide technical assistance and energy management advice that, in 2012, served 800 discrete facilities with 1,000 projects covering a mix of types and sizes of industrial and agricultural customers (Crossman 2013).[22] ETO places emphasis on maintenance of close individual client contact by its in-house staff as well as by its PDCs (Taylor et al. 2012).

Wisconsin's Focus on Energy program has used a "cluster" approach to organize program delivery with greater subsector and industrial process expertise for specific industrial groups, such as food processors, pulp and paper manufacturers, or plastics companies. Including workshops with cluster members and relevant trade associations, this approach also has fostered cross-peer exchange and learning (Taylor et al. 2012, Chittum 2009). In 2012, its program for large energy users generated savings of 61,344,005 kWh and 3,119,919 therms (see Appendix B-7).

Xcel found that one of the biggest challenges in implementing IEE projects is that technical needs vary from industry to industry and company to company with no standard template for implementation. To address this, Xcel's team of account managers works closely with industrial customers to understand their production processes and operational needs, and provides both initial energy audits and continued support throughout project construction (WGA 2013). Similar to many other programs, Xcel's efforts to provide project development support expertise extends beyond basic diagnostic service to help move projects through the implementation stage, helping decision makers to make a go/no go decision based on accurate, complete, and customized project information. In Colorado, Xcel's custom and process efficiency programs generated average savings of 10,838,108 kWh per year from 2010–2012 (see Appendix B-8).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Invest in knowledgeable, skilled technical staff.
- Use high quality technical assistance to enhance prescriptive and custom program success.
- Recognize that technical needs vary from industry to industry and company to company.

4.6. Offer a Combination of Prescriptive and Custom Offerings to Best Support Diverse Customer Needs

A combination of both prescriptive offerings for common cross-cutting technology and customized project offerings for larger, complex projects in IEE programs can best meet diverse customer needs and provide flexible choices to industries. Prescriptive offerings—typically involving rebates for a portion of the cost of common technology equipment upgrades or certain other clearly defined actions—can be relatively simple for both customers and administrators. However, their value to large customers may not be significant. Custom approaches are needed for the larger, complex, or process-specific projects. If both types of offerings are included, IEE incentive program offerings can be tailored to accommodate both large manufacturers and SMEs, depending on the state's industrial base.

[22] For ETO's Production Efficiency program, incentives are budgeted at 63%, delivery at 26%, and internal costs are 11% (Crossman 2013).

Xcel's programs (Example 10) have been lauded by industrial customers for offering simple incentive applications for providing a full suite of programs—custom, self-direct, and process energy efficiency incentives. ETO (Example 11) has been successful in its ability to help its Oregon industrial customers realize deep energy savings through low-cost changes as well as complex custom approaches. Rocky Mountain Power (Example 12) couples its custom Energy FinAnswer program with the complementary Energy FinAnswer Express program offering prescriptive rebates to target deep savings as well as quick wins. Efficiency Vermont, NYSERDA, and PG&E, among others, also provide both prescriptive technology and customized project development options.

Including customized project offerings requires administrator investment in program capacity and development of mechanisms to access specific technical expertise (see Section 4.7). However, the energy savings can be well worth the investment. In Vermont, six industrial account managers are actively engaged full-time in Efficiency Vermont industrial programs, centering primarily on customized project identification, development, delivery, and savings measurement and verification. Their work yields nearly 90% of Efficiency Vermont's annual industrial program energy savings delivery (Taylor et al. 2012).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Prescriptive offerings support common cross-cutting technologies or practices.
- Custom offerings support larger, complex, or process-specific energy efficiency measures.
- Offering prescriptive and custom offerings allows programs to accommodate large industrials and SMEs.

4.7. Accommodate Industrial Project Scheduling Needs

Scheduling energy efficiency investments can be heavily dependent on a plant's operational cycle. Equipment is normally renewed or refurbished at the end of an operational cycle. The timing of a major investment window can be difficult to predict, particularly by someone not engaged in the plant's day-to-day activities (Chittum et al. 2009).

Operational cycles and investment windows can be few and far between, and proposed equipment changes must be guided through rigorous, competitive, and time-consuming capital expenditure approval processes. Firms often have long timeframes between identifying an opportunity and project implementation, especially when large companies consider large dollar proposals.

IEE program cycles may not match industrial company timing for allocating capital for projects. Manufacturers, particularly large organizations, need time to secure capital and plan for potential plant shutdown to accommodate energy efficiency assessments and project implementation. This often leads to a "phased approach" to energy efficiency implementation.

Programs with flexible timelines that can accommodate an industrial client's investment cycle will help to maximize energy efficiency implementation. Programs that are not limited to one-year timeframes but instead accommodate multi-year projects and application periods—or have multi-year planning and operation as their standard operating procedure—allow companies the flexibility to consider and implement program offerings on a schedule that matches their decision and investment cycle. This, in turn, can promote higher program participation levels. To the extent possible, program managers should also be mindful of industrial operational and investment cycles and time recruitment and outreach accordingly (Russell 2013b). In addition, by examining current and projected economic trends in the industrial sector, an efficiency program can anticipate when the next large cycle of construction, infrastructure, and capital investment is likely to occur (Harris 2012) and therefore help to encourage energy efficiency, either from new production equipment or a new facility (Seryak and Schreier 2013).

For example, evaluations of NYSERDA's IPE program suggested that program managers should target specific industrial subsectors based on an understanding of a firm's hours of operation, capital plans, level of interest in energy efficiency and sustainability initiatives, and capacity utilization.[23] The IPE Program is positioned to take advantage of potential capacity investments by developing lists that classify industrial customers using North American Industry Classification System (NAICS) codes to include evidence of plant capacity constraints, using capacity utilization data published by the U.S. Federal Reserve System. Companies with a high capacity utilization rate relative to their historical averages are prioritized for targeted outreach concerning large infrastructure investments. Firms reporting mid- or low-capacity utilization rates are targeted to increase the productive capacity of existing facilities, implement and/or adopt a strategic approach to energy management, and/or implement low- and no-cost operational improvements (Harris 2012). NYSERDA estimates that its IPE program will save 200,000 megawatt-hours per year and 735,000 million Btu (MMBtu) per year from 2012 through 2015 (see Appendix B-5).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Accommodate multi-year projects and application periods or have multi-year planning and operation as their standard operating procedure.
- Understand the operational cycle and capital approval process cycle of individual industrials.
- Monitor economic and investment trends of industries in your region to plan for expansion and new plant opportunities industrials and SMEs.

EXAMPLE 12. ROCKY MOUNTAIN POWER'S ENERGY FINANSWER AND FINANSWER EXPRESS PROGRAMS

Rocky Mountain Power's (RMP's) Energy FinAnswer program in Idaho offers engineering services, technical expertise, and cash incentives to help industrial and commercial customers upgrade to the most energy-efficient systems, tailored to the needs of retrofit or new construction projects. The Energy FinAnswer program is a long-standing program that has been in place in some form since the 1990s. It has continued to evolve to accommodate changing market and company resource positions.

RMP is involved from the very beginning of projects and starts by reviewing facility plans and identifying possible efficiency opportunities. The next step involves the utility preparing a free energy analysis report to provide specific recommendations and estimates of what each efficiency measure will cost and how much the customer will save. RMP also includes an incentive offer and any commissioning requirements. The incentive amount available is typically $0.12 per kWh of annual energy savings plus an additional $50 per kW for average monthly on-peak demand savings. Prior to July 2013, incentives were capped at 50% of the project cost and at least one-year payback (if the payback is less than one year, the incentive is reduced so that the payback equals one year). Program revisions in July 2013 increased the incentive cap to 70% of project cost. The two parties sign an incentive agreement form before the company proceeds with any purchase orders for the equipment. RMP allows two years for customers to implement the projects.

The program provides a number of resources, including case studies of past projects, to help those interested in the program determine their own project plans, and provides a list of engineering firms under contract to provide program services. Energy FinAnswer has a complementary program, Energy FinAnswer Express, which offers simple, prescriptive incentives for lighting, HVAC, and other common efficiency upgrades. Customers typically receive the incentive payment within 45 days of completing a post-installation report. These two programs complement each other in the market, providing a broad platform of services and incentives for a wide variety of energy efficiency projects.

In 2012, RMP generated electrical gross savings of 4,473,114 kWh per year across 81 measures under its FinAnswer Express program and 318,915 kWh per year across seven measures under its Energy FinAnswer program.

Source: Rocky Mountain Power 2013a, Rocky Mountain Power 2013b, Kolwey 2012

[23] The capacity utilization rate describes the extent to which the industrial sector's production capabilities are actually being used to produce the current level of output. In general, a high rate of capacity utilization is a positive indicator of economic health.

4.8. Streamline and Expedite Application Processes

Industrial customers may perceive the application and implementation procedures for IEE programs to be administratively complex and burdensome. Achieving the right balance between meeting key program administration needs for information and streamlining the application process is helpful.

As an example, BPA began using a third party to evaluate and then help streamline procedures to address industrial concerns about the application process. A third party also helps individual companies navigate application procedures.

NYSERDA also provides upfront assistance to help companies navigate the application process, and uses a Consolidated Funding Application (CFA) developed as part of a statewide plan to streamline and expedite the grant application process. Because the CFA is commonly used across a range of programs, this simplifies the application process and applicants may already have experience with this documentation.

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Streamlined application procedures encourage participation.
- Assistance in navigating the application process is helpful to industrials.
- Balancing program administrative needs for information with keeping procedures simple and efficient may require continual evaluation and improvement.

4.9. Conduct Continual and Targeted Program Outreach

Manufacturers are sometimes unaware of the industrial program offerings that may be most applicable or useful for them. Significant outreach and development of information, such as examples of successful past projects, is often necessary to encourage participation. As an example, Wisconsin's Focus on Energy program provides program engineers who reach out to industrial firms via numerous training classes, webinar series, and outreach to industrial associations. The AlabamaSAVES loan program formed partnerships with Bank of America, Philips Lighting, Metrus Energy, and Efficiency Finance, not only to provide private sector leveraging of funds, but also to conduct marketing and outreach for the program itself. Using their existing sales and marketing channels and networks with Alabama industries and contractors, these private partners are driving program uptake and demand in the market (NASEO 2012). As of April 2013, more than 20 loans have closed and nearly $17 million in funding has been put toward the installation of energy efficiency projects. The initial $60 million in funding will continue to cycle through loans and has the potential to finance up to $121 million in projects over the next 20 years (see Appendix B-1).

NYSERDA's IPE program demonstrates an awareness of industrial customers' decision-making processes when it markets its offerings to potential program participants. When marketing IPE incentives for non-process equipment upgrades (motors, lighting, etc.), NYSERDA targets facility directors and executives. In contrast, when working to secure process-efficiency projects, NYSERDA conducts targeted outreach to industrial staff in charge of production lines and revenue-generating projects, as well as members of continuous improvement teams and executives, who consider the costs and benefits of energy efficiency projects that affect production capability. This approach reflects research findings that show facility maintenance and process engineers play a critical role in the decision-making processes within their companies (Harris and Gonzales 2013).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Continual and targeted outreach is needed to make sure industrials are aware of applicable program offerings.

4.10. Leverage Strategic Partnerships

Successful IEE programs often partner with a variety of federal, state, and regional organizations to share technical expertise, program design, and implementation guidance, and leverage access to customers for outreach and implementation. For example, the collection of assessment and recommendation data in DOE's Industrial Assessment Center Database is commonly used by program staff and support contractors to inform thousands of investments in state and utility IEE programs.[24] The database includes information on the type of facility assessed (size, industry, energy usage, etc.) and details of resulting recommendations (type, energy and cost savings, etc.). In addition, DOE's Combined Heat and Power (CHP) Technical Assistance Partnerships (formerly called the Clean Energy Application Centers) promote and assist in transforming the market for CHP, waste heat to power, and district energy technologies and concepts throughout the United States. And the EPA ENERGY STAR for Industry program provides guidance, tools, and recognition to help industrial companies improve their energy performance.

Efforts by SEOs complement and support ratepayer-funded programs. States can provide resources or programs, such as tax incentives, that utilities often cannot. States are not constrained by regulatory cost-effectiveness tests that may limit what programs are offered. Therefore, states can often support IEE activities such as training, certification, and recognition awards. SEOs use their established partnerships with other relevant stakeholders and program administrators, such as utilities, regional energy efficiency groups, and the National Institute of Standards and Technology's Manufacturing Extension Partnership (MEP), to coordinate and expand programs with existing resources available to manufacturers. SEO energy assessment and audit programs typically include utility cost-share. Training workshops organized or supported by SEOs are often offered in conjunction with universities and MEP, and typically leverage DOE efforts (NASEO 2012). For example, Washington State has an IEE award program that is hosted by the governor, who recognizes leaders in IEE.

In another example, the Alabama SEO brought together key state partners including the Alabama Industrial Assessment Center, University of Alabama in Huntsville, and the Alabama Technology Network to implement AlabamaSAVES, a revolving fund loan program, and Alabama E3.[25] Over time, the SEO will coordinate both programs so they can grow together and companies who take advantage of E3 assessments can finance energy efficiency upgrades through AlabamaSAVES (NASEO 2012) (profiled in Appendix B).

BPA partnered with the Northwest Energy Efficiency Alliance (NEEA) to consolidate costs and expand program resources in an effort to reach more customers and initiate more projects. As a regional organization, NEEA was able to support replication of the BPA approach across a variety of local distribution utilities in the BPA service area. Similar regional energy efficiency organizations exist in most regions of the United States, and can be engaged in similar ways.

In 2008, NEEA partnered with the Northwest Food Processors' Association (NWFPA), the largest industrial trade organization in the region, representing more than 100 food processing enterprises, to convene food processing industry leadership around common energy reduction goals and strategic energy management practices. Aggregating energy saving efforts through NWFPA allows the industry to apply resources toward a unified energy reduction goal—sharing the risk, efficiency, and energy savings potential. The partnership was able to secure buy-in and establish trust when reaching out to potential customers and leveraged funding from the State Technologies Advancement Collaborative and DOE's technical assistance resources to establish a customized program dedicated to the unique needs of the northwest region's food processing industry (IIP 2012, Chittum et al. 2009).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Partner with federal, state, and regional organizations to leverage their expertise, access to customers, and program implementation support capacities.
- Partnerships can help programs by providing technical expertise, program design, and implementation guidance as well as expanding program outreach and implementation channels.

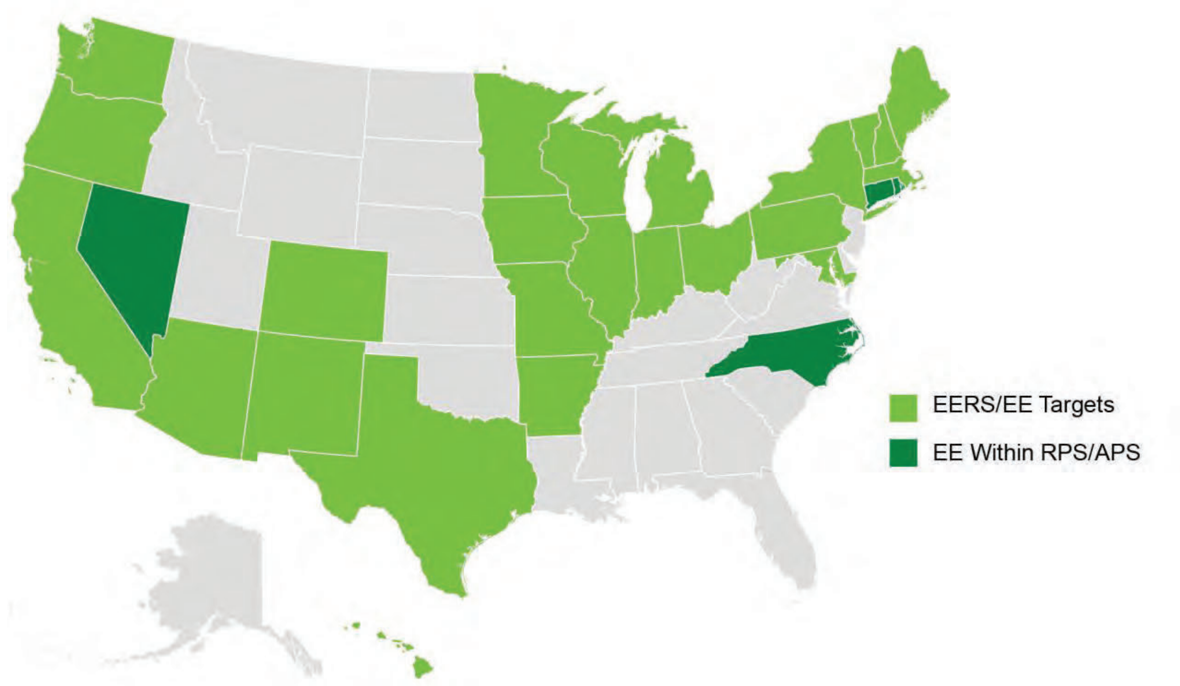
[24] http://iac.rutgers.edu/database

[25] E3—Economy, Energy, and Environment—is a coordinated federal and local technical assistance initiative that helps communities work with their manufacturing base to adapt and thrive in a new business era focused on sustainability for SME manufacturing companies.

4.11. Set Medium- and Long-Term Energy Efficiency Goals as an Investment Signal for Manufacturers

To provide signals of certainty to the market, regulators and program administrators can set energy savings goals or targets for the medium- to long-term to reduce risk in ramping energy efficiency measures implementation. Specific targets and extended program lengths (minimum three years) can give both program administrators and manufacturers the confidence to invest over sufficiently long program timeframes.

CEPS are an important tool states use to set goals and targets. A CEPS sets electricity and/or natural gas energy savings targets, usually expressed in energy savings delivered per year (including cumulative delivery over a period) or a percentage of utility sales. CEPS have gained popularity in the United States, and 28 states now have some sort of high-level energy savings target (see Figure 7). The longer-term goals associated with CEPS send a clear signal to market players about the importance of energy efficiency in utility planning and create a level of certainty to encourage large-scale investment in energy efficiency technology and services. Longer-term goals also help build customer engagement and develop an energy efficiency workforce and market infrastructure (ACEEE 2012, SEE Action Network 2011a).



Sources: ACEEE 2013a and 2013b

Figure 7. Energy efficiency resource standards and targets

CEPS are often designed and integrated into the integrated resource planning (IRP) processes to ensure that acquired energy efficiency resources are cost-effective compared with supply resources. An IRP can be a powerful impetus for promoting energy efficiency and other demand management alternatives to new supply. Although the amount of available cost-effective energy efficiency will vary based on local circumstances, some quantity will likely always be available at a lower levelized cost per megawatt-hour than supply side alternatives. Thus, any planning process that requires utilities to consider demand-side resources as part of an integrated strategy to meet customer demand is likely to promote energy efficiency. This is especially true where IRP processes are mandatory and overseen by a utility regulatory commission, because the IRP requirement may require utilities to consider demand-side programs that benefit ratepayers even if the programs do not benefit shareholders. In some circumstances, cost-effective energy efficiency measures may even be available in sufficient quantities to satisfy all of the projected load growth within the planning timeframe (SEE Action Network 2011b).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Longer-term goals provide increased certainty to the market and to program administrators.
- Higher annual savings targets require a more comprehensive set of program offerings and will drive programs to IEE.

4.12 Ensure Robust Measurement, Verification, and Evaluation

M&V of project energy savings is critical to program administrators and regulators to assess the actual results of program activities and to measure the contribution of projects and aggregate programs for achieving their goals. Robust M&V programs also allow customers to obtain clear views of the results of their efficiency investments. In addition, effective M&V enables program administrators to undertake periodic process and operational strategy evaluations to assess where program efficiency and results can be further improved.

Require Robust Measurement and Verification

Measurement and verification requirements

Planning for M&V during the design phase of a program is key to ensuring that energy savings can be tracked and program success can be systematically assessed. M&V is required at some level in all programs, and M&V plans and requirements are a condition of funding in most programs. For example, NYSERDA has stringent technical analysis and M&V requirements for its programs, and performance-based incentive payments are only provided on a verified kWh or MMBtu energy-saved basis (Taylor et al. 2012).

Clear, concise guidelines for M&V requirements benefit both project and program evaluations. Planning for M&V during the program design phase and periodic evaluation and adjustment in M&V guidelines are both important. In most custom projects, M&V plans are an integrated part of the process. Some program administrators will help design project M&V plans and may assist in arranging financing of meter installation to execute the plan.

Submetering can further strengthen M&V programs, because measuring energy use at the project or equipment level provides the discrete data needed to demonstrate the savings from a specific project or plant improvement (which is typically not the case when this type of data is not collected). Submetering can be a necessity for proper M&V of many projects, and is best applied both before and after project implementation.

Broadening the scope of project M&V to include benefits beyond energy savings can be used in the cost-effectiveness analysis of projects and programs, further quantifying the full economic and societal benefits of energy efficiency investments, and improving overall cost-effectiveness of energy efficiency measures. If these are to be included, M&V plans need to extend requirements and guidelines to non-energy benefits.

Consistent methodologies in measurement and verification protocols

Current M&V practices in the United States use multiple methods for calculating verifiable energy savings. These methods were initially developed to meet the needs of individual energy efficiency program administrators and regulators. Although the methods serve their original objectives well, they have resulted in differing and incomparable savings results—even for identical measures. These differences can be significant, and inconsistent results have limited the acceptance of reported energy savings beyond specific program applications.

Increasing the consistency and transparency of how energy savings are determined through consistent and clear M&V protocols strengthens the credibility of energy efficiency programs. Examples of existing protocols include the International Performance Measurement and Verification (IPMVP) protocol, which is used in Xcel's self-direct programs, and the Superior Energy Performance (SEP) M&V protocol, which will play an important role in DOE's Industrial Strategic Energy Management Accelerator[26] initiative.

Another opportunity for common methodologies is DOE's Uniform Methods Project (UMP). Through UMP, DOE aims to establish easy-to-follow protocols based on commonly accepted engineering and statistical methods for determining gross savings for a core set of commonly deployed energy efficiency measures. The protocols provide guidance on energy savings determinations, which will be available as a reference to improve M&V practices. The addition of industrial measures in UMP provides a potential opportunity to create consistent protocols for IEE programs that would make it easier and less costly for efficiency programs to quickly establish good M&V practices because they no longer have to develop protocols from scratch (DOE 2013b).

Use Evaluations to Support Continual Program Improvement

Periodic process evaluations identify ways to improve program design and delivery

Robust M&V plans enable program administrators to conduct periodic process evaluations that identify successes and weaknesses in program implementation and point to ways to improve program design and delivery. Process evaluations can be initiated during the first year of operation to identify lessons learned from implementation as soon as possible and to apply them to subsequent program cycles. They can also be helpful in adjusting programs to match manufacturers' needs on a continuing basis. ETO regularly commissions process and impact evaluations, which have identified specific areas for improvement in its Industrial Production Efficiency program. These areas include:

- To maximize the effectiveness of program marketing, program staff can improve their understanding and augment the marketing skills of contractors to increase uptake of programs.
- To add credibility to program reporting and enhance marketing efforts, staff improved specific and consistent definitions of data entry categories and date variables to report program activity by year, thereby improving data collection, tracking, and processing.
- To simplify the program review and oversight function, and to enhance quality control of technical studies, program staff promulgated and implemented uniform procedures and standards or guidelines for both the technical studies and the review of those studies (ETO 2006).

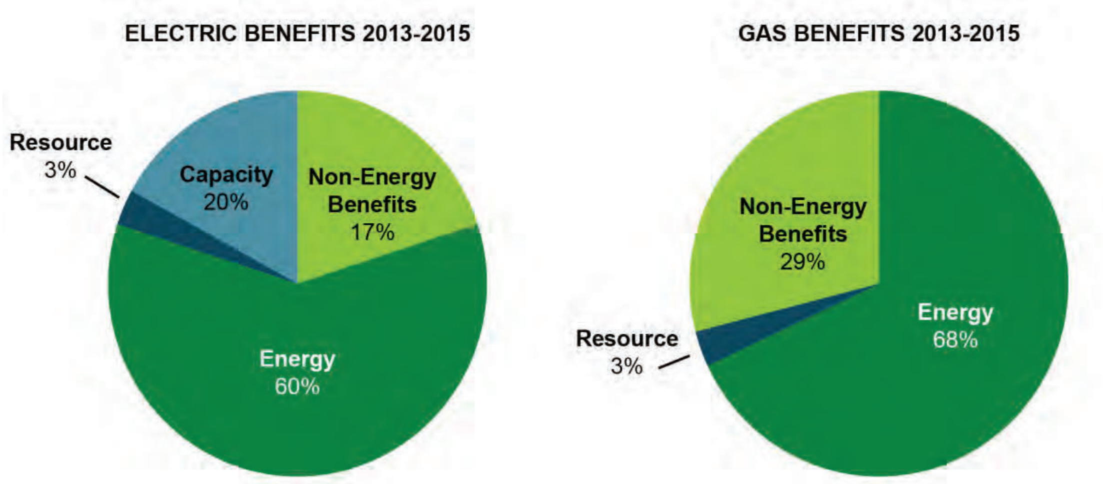
Include non-energy benefits in program evaluations

In addition to M&V methods, NEBs can be included in program evaluation to prove the improved cost-effectiveness resulting from NEBs additional to energy saving benefits in both projects and programs (for a discussion of NEBs at the industrial customer level, see Chapter 6). Many studies suggest that the NEBs of IEE measures can be quite large, often far greater than any energy savings (Chittum 2012). Including NEB elements in program cost-effectiveness evaluations could significantly increase the benefit-to-cost ratios of IEE programs.

Because valuing NEBs can be difficult and has sometimes proven controversial, most states that currently account for NEBs typically do so only for benefits that are readily quantifiable, mostly confined to water and other fuel savings (Kushler et al. 2012). Some regulators and stakeholders resist including benefits such as improved participant/public health, comfort, and property values because they are "externalities" outside the usual realm of utility regulation, and if benefits occur outside the system, it could create an implication that other stakeholders might be expected to contribute to energy efficiency funding to the extent that they receive benefits. Estimating the value of some NEBs can also be complicated, leading many administrators to resist attempts at monetizing all of them (Lazar and Colburn 2013). Thus, it may be most practical to focus on only the key NEBs most amenable to quantification. Examples of programs that incorporate a relatively large range of NEBs include NYSERDA, Massachusetts, and BPA.

[26] The Industrial Strategic Energy Management Accelerator is designed to demonstrate SEP as a practical and cost-effective energy efficiency program offering. Signatories to this Accelerator are utilities and energy efficiency program administrators that agree to deploy SEP to a set of industrial customers across their service territories. This Accelerator was launched in December 2013.

Over the last decade, Massachusetts has integrated NEBs when estimating the value of its energy efficiency program offerings to the whole utility system (using the Total Resource Cost Test). Figure 8 shows that NEBs represent approximately a quarter of total benefits that accrue to the system. Note that many benefits, such as productivity gains or environmental benefits are not included, meaning that if these positive environmental and social externalities were included, NEBs would in fact be much greater.[27]



Source: Halfpenny 2013

Figure 8. The value of non-energy benefits in Massachusetts' energy efficiency programs

Acknowledge free ridership and positive spillover effects

Free ridership is a situation in which a program incentivizes a company to implement an energy project that they would have conducted on their own without the program's financial and/or technical assistance. Program administrators want to get the most from the incentives they offer by encouraging projects that would not have otherwise been implemented. However, identifying and preventing free ridership is complicated, and estimating the impact can be costly. Based on surveys that ask people to relate why they made energy conservation investments, it is difficult to make accurate estimates.

Although the number of "free riders" can be high for certain programs, other end users may see substantial energy cost-saving advantages from some of the investments or concepts being promoted in an energy efficiency program and decide to undertake measures themselves without receiving any program incentives or being otherwise involved with the program. This "spillover effect" can work to mitigate or neutralize the level of free ridership. For example, NYSERDA has found that for most (though not all) IEE delivery programs, "spillover" equals or exceeds "free riders" (Taylor et al. 2012).

Programs in Vermont, British Columbia, New York, and Oregon attempt to estimate free riders and report net savings against targets for at least some of their specific IEE programs (Taylor et al. 2012). Regulators and program administrators can expect some level of free ridership, and may wish to accept moderate levels, as long as the programs remain cost-effective overall.

As with other key elements of project M&V, it is important that any needs to consider free ridership or spillover effects in assessing how energy savings from specific project and programs will be credited to users and administrators be clearly stated and agreed to by all parties prior to project and program implementation efforts.

[27] **Approved NEBs**: 1) C&I new construction and retrofit: operations and maintenance costs, administrative costs, material handling; 2) Low income: utility savings, rate discounts, bad debt write off, terminations and reconnections, collections and notices; 3) Residential new construction and retrofit: customer perceived savings, thermal comfort health benefits, noise reduction rental marketability, property value increase, reduced tenant complaints, lighting quality, home durability, equipment maintenance. **Not approved**: national security, economic development, reduced waste.

This includes clarification of both what specific types of projects must consider free ridership and spillover, and details on the quantification methodologies to be used. Ambiguity about how reported savings may be discounted in after-the-fact evaluations may lead to contentious arguments or inhibit project implementation.

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Effective M&V is critical for program administrators to assess results and measure progress, and useful for industrials to verify results of their investments.
- Guidelines for M&V need to be clearly defined and periodically reviewed and adjusted.
- Periodic impact and process evaluations help identity where IEE program efficiency and results can be further improved.
- NEBs can be a key element of both project M&V and program evaluation.
- Any needs to make allowances for free ridership and spillover effects should be clearly stated and agreed by all parties prior to project or program implementation.

5. Designing Effective Self-Direct Programs

Effectively capturing energy efficiency opportunities within the industrial sector adds substantially to total state program energy savings and often helps lower total unit costs of saved energy. As discussed in Chapter 3, maximizing industrial energy efficiency (IEE) typically brings down overall system costs over the medium term, which is in the interest of all utility customers.

There is a strong public policy case for including the industrial sector in ratepayer-funded energy efficiency programs. A large portion of the overall available energy efficiency potential resides in this sector, and the unit costs of energy savings in industrial projects is typically lower than in most other sectors targeted for resource acquisition (see Chapter 3). In addition, many advocates point out an issue of fairness—why are certain customers exempted from paying into ratepayer-funded programs even though they ultimately benefit from lower total system costs?

However, industrial customers often raise legitimate concerns about the extent to which ratepayer-funded energy efficiency programs will be able to meet their specific needs. Especially when programs are first being contemplated, industries may be skeptical about whether the programs will be administered with enough flexibility to meet their priorities. They may be skeptical about the IEE capability of program administrators compared with their own capabilities, and they may have concerns about administratively complex and burdensome participation requirements. In essence, many industries—especially larger ones—may raise concerns that the benefits that they might receive from a ratepayer energy efficiency program will not be commensurate with the costs of paying into the program and dealing with administrative requirements.

As of January 2014, 16 states offer “self-direct” programs. To achieve energy savings, these programs must be designed and implemented to meet both the public policy objective of the programs and the industrial customers’ desire for greater flexibility and control of energy efficiency efforts in their own companies. Self-direct programs should not be confused with “opt-out” program clauses. “Opt out” means that a class of consumers is allowed to not participate in a ratepayer-funded energy efficiency program—these customers do not pay into the system, do not have an obligation to deliver energy savings, and do not directly benefit from participation in the programs. Under self-direct programs, qualifying consumers implement their own energy savings programs, often without design and implementation assistance from a program administrator. However, they are still obligated to spend money and deliver energy savings, either on a project-by-project basis or over a certain amount of time. A self-direct option keeps large customers in the energy savings portfolio but allows them the flexibility to take advantage of cost-effective energy efficiency opportunities. There is wide variability in terms of the industrial savings requirements and measurement and verification (M&V) rigor across existing self-direct programs. As such, those that employ high levels of M&V rigor and achieve robust industrial savings can serve as the best examples for delivering successful self-direct programs.

Some self-direct programs have proven to be effective tools to both deliver low-cost energy savings for system-wide benefits and to help industrial customers achieve substantial cost savings and bottom-line benefits through energy efficiency improvements. This chapter describes the types of self-direct programs common among the states, outlines program features that help achieve both public policy goals and increased flexibility for industrial customers, and provides examples of successful self-direct programs currently in operation. Readers should note that the program design features discussed in Chapter 4, such as demonstrating the value proposition of energy efficiency to customers, also apply to self-direct programs.

5.1. What are Self-Direct Programs?

In this report, self-direct programs are defined as programs that allow some customers, usually large industrial ones, to “self-direct” fees directly into energy efficiency investments in their own facilities instead of into a broader aggregated pool of funds collected through a public benefits charge for energy efficiency programs. This is in contrast to opt-out provisions, which allow large customers to fully opt out of paying their energy efficiency charge with no corresponding obligation to make energy efficiency investments on their own (ACEEE 2012b).[28]

Self-direct programs usually define eligibility for customer participation in terms of a threshold amount of energy use or energy use capacity (e.g., megawatt-hour [MWh] or megawatt [MW]), with the view that, generally speaking, only larger customers are likely to have the capacity to undertake serious energy efficiency programs themselves and attempting self-direction among small consumers is inefficient.

Self-direct programs may be administered by a utility, state regulatory authority, or state agency. In Oregon, for example, the state's self-direct program is overseen by the state energy office (although the customized administrator-managed industrial offering—the Production Efficiency program—is implemented by the Energy Trust of Oregon). In Vermont, self-direct customers report their programs to the state utility regulator, although there is currently only one customer that uses the large self-direct program and two customers that use the smaller self-direct program.[29] In Michigan and Washington, self-direct customers report their plans to their utilities, and validation of plans falls to the state utility regulatory commission.

Table 2 illustrates the continuum of self-direct programs existing in the states, showing differences in the rigor with which the programs are structured to ensure achievement of public policy energy savings delivery goals. As programs move down the continuum from the least to the most structured programs, they vary in two key ways: 1) accounting with respect to energy efficiency payments that would be required without self-direction and with respect to use of funds, and 2) extent of M&V of energy savings and follow-up by utility regulatory commissions or program administrators.

Table 2. Structure of Self-Direct Programs

Public Benefit Maximization

Program Type	Energy Efficiency Payment	Measurement and Verification of Savings	Use of Funds	Follow-Up	Examples
Less structured self-direct	None	Minimal; self-reported	Company uses retained cash for energy efficiency	None to minimal	MN, OH
More structured, lower oversight self-direct	Fully or partially paid on bill	Minimal; self-reported	Rate credit or project rebate	Minimal	MT, OR
More structured, higher oversight self-direct	Fully or partially paid on bill	Robust; similar to ratepayer-funded programs	Personal escrow, rate credit, or project rebate	Minimal to substantial	WA, CO

Source: Adapted from Chittum in Elliott 2013

In the less structured cases, programs may exempt a customer entirely from paying energy efficiency charges, and require them to simply channel the funds directly into their own energy efficiency projects. To be considered self-direct programs as defined above, however, there should be some level of formal reporting on funds spent and the projects implemented. In more structured cases, there are reporting mechanisms that aim to ensure that self-

[28] It should be noted that some states have "self-direct" terminology in legislation that provides energy-intensive customers to be fully exempted from energy efficiency charges to direct towards energy efficiency measures, but there is minimal to no oversight or requirements to report on implementation of measures. This is in reality equivalent to opt-out provisions (Chittum 2011).

[29] See http://aceee.org/sector/state-policy/vermont for more information that distinguishes both programs.

direct customers spend at least as much on energy efficiency projects as they would have on energy efficiency charges. Customers may be exempted from paying energy efficiency charges for a certain time if they undertake a reported project or set of projects as planned. More commonly, customers are required to pay most or all energy efficiency charges and then receive project rebates or rate credits against their qualified expenditures on self-direct projects. Ongoing accounts of energy efficiency payment requirements against qualified energy efficiency project expenditures also may be used.

Programs also vary substantially as to the extent of program follow-up on project execution and on energy savings M&V. Some less-structured programs require some documentation stating the customer has invested in energy efficiency in the past or plans to do so in the future, but the customer is not required to provide detailed information on its investment. More structured programs require that purchase receipts or other evidence of investments be submitted, but energy savings reporting may be minimal or the reported savings may not be verified. Finally, the most structured programs with high levels of administrative oversight are subject to M&V protocols in the same way as administrator-managed IEE programs. In some cases, a small portion of energy efficiency charges may be retained by program administrators rather than fully rebated to customers to help cover oversight costs (Chittum 2011).

Figure 9 provides a snapshot of the prevalence of self-direct programs among the states as of January 2014. At least 16 states have some type of self-direct program, and six states have opt-out provisions. Figure 9 also provides a sense of the prevalence of less structured and more structured programs by state. However, it should be noted that definition into these categories is not a perfect science and characterization of individual state programs requires customized review.

Source: Elliott (2013)

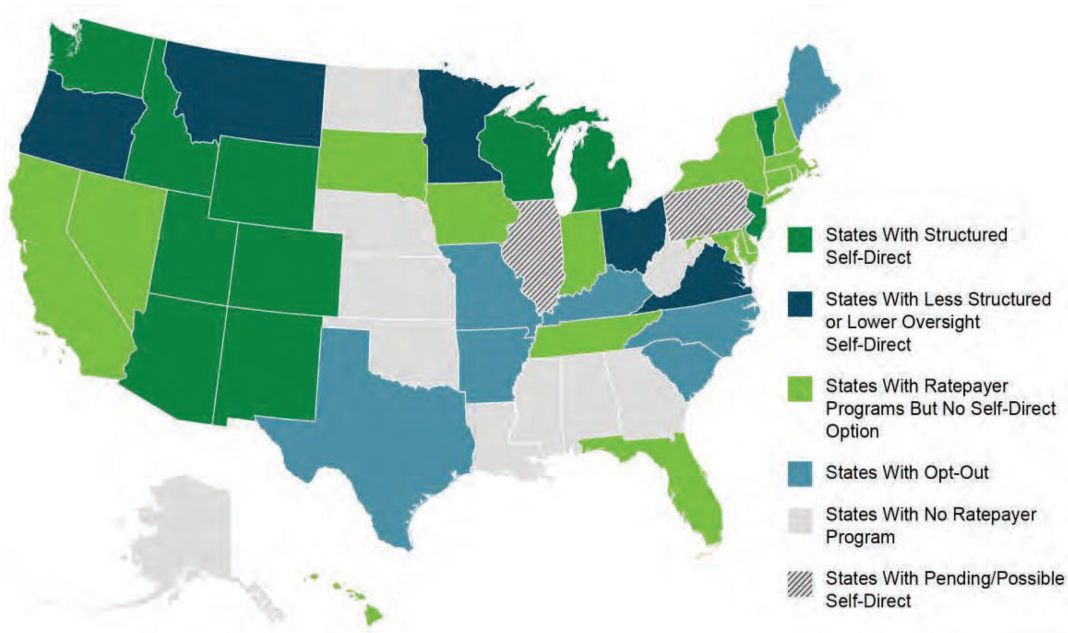


Figure 9. Current snapshot of self-direct programs (subject to review)

5.2. Ensuring Achievement of Public Policy Goals

To meet basic energy efficiency public policy goals, it is necessary to ensure that self-direct programs are producing cost-effective energy savings equal to or greater than what would have been realized in a traditional, administrator-directed program. Based on the experience of the most successful programs, one path to achieving this is to operate self-direct programs as one option within the overall energy efficiency program. Rather than designing a self-direct program as a means of avoiding participating in the state's resource acquisition effort altogether, the program can be designed as a program choice for industry's participation in the state's overall resource acquisition effort. Industries can choose to direct their own efforts or to have staff and consulting experts from the program administrator work with them as part of an administrator-directed program. Minimum expenditures (e.g., energy efficiency charges or equivalent amounts) are expected to be the same for either choice.

From the public policy perspective, it is important to ensure that self-direct customers meet their energy savings requirement with the funds they would otherwise pay into the ratepayer-funded program for the benefit of all.

There are competing viewpoints about whether one type of program can achieve greater savings or leverage greater benefits for the industrial customers as well as all system users, and states have had differing experience with the value of self-direct programs compared with core programs managed by a utility or program administrator. This report does not compare the effectiveness of these two types of programs. Instead, for states that are choosing to introduce or allow self-direct programs as an option, it highlights how self-direct programs in some states have been able to provide an attractive alternative to large customers while meeting public policy goals.

Set Goals to Achieve at Least Equivalent Performance

Where self-direct programs are offered as part of overall energy efficiency programs, large consumers are asked to report on their actual programmed energy efficiency investments. If the investments are assessed by program administrators as meeting program criteria, the customers receive rebates or credits against ongoing energy efficiency payments or they receive energy efficiency payment exceptions related to the size of the investment. The assumption is that customers participating in the self-direct program must pay the energy efficiency contributions, similar to all other customers, unless they are excused from payment based on evidence of comparable investments they have programmed themselves.

Some self-direct programs simply ask that customers spend a certain amount of money on energy efficiency. However, solely focusing on spending fails to take account of the quantity of energy savings delivered. Developing concrete savings goals can help improve the working relationship between the customer and the self-direct program administration. Instead of focusing on dollars, these goals keep the conversation focused on energy. When customers buy into the idea of energy savings goals, they may squeeze more energy savings out of every dollar spent (Chittum 2011).

For example, in Michigan's self-direct program, large customers must develop energy optimization plans that set annual energy savings targets based on the previous year's energy consumption, factoring out changes in business activity, energy required for pollution control equipment, or, if relevant, weather normalization (see Example 13).

Another example is the Eugene [Oregon] Water and Electric Board (EWEB) self-direct program. EWEB's individual self-directing customers develop energy savings goals in collaboration with utility staff. Goals are based primarily on the percent of load a customer represents. EWEB notes that they are acquiring more efficiency from their two self-directing customers than they had in the past when the customers were using EWEB's standard program offerings (Chittum 2011).

Energy Savings Measurement and Verification

Some form of energy savings M&V is needed to ensure that self-direct programs are achieving expected energy savings. Data collection to track the amount of funds directed toward energy efficiency projects—and the savings achieved from those projects—is necessary to determine whether a self-direct program is performing as effectively as a traditional program might (Chittum 2011).

Most self-direct programs do not penalize customers for failure to demonstrate verified energy savings or meet goals. Although such structures may not be always necessary, some self-direct program administrators have found that requiring companies to pay back energy efficiency charges if no or insufficient action is taken can encourage customers to meet energy savings goals or use up all of their allotted energy efficiency funds. If a company earns rate credits or rebates in advance of project implementation, customers may have to pay back a portion of the rate credit or rebate if a planned project does not come to fruition. Michigan's self-direct program (see Example 13) asks customers to meet set energy savings targets. If a customer fails to meet its targets, it must repay energy efficiency charges in proportion to the shortfall. Puget Sound Energy's self-direct customers simply lose their allotted energy efficiency fund credits if they do not dedicate all resources toward implementation of energy efficiency measures (Example 14).

Self-Direct Options as Complementary to Core Industrial Offerings

In states that may be starting out and do not have mature industrial offerings that provide quality technical assistance or if manufacturers may be seeking opt-out provisions, self-direct programs can be viewed as attractive options to ensure the industrial sector remains in the program portfolio. If IEE potential is substantial and capacities can be developed, the most complete service package can include both strong administrator-directed industrial programs and strong self-direct programs. Ultimately, both administrator and self-direct programs have their comparative advantages.

As experience accumulates, states may wish to offer self-direct options as complementary to, rather than instead of, core program offerings for companies interested in going beyond those offerings (Elliott 2013). For instance, Xcel Energy (Example 15) in Colorado provides a self-direct program alongside a range of other prescriptive and custom program offerings. With the potential for wide variability in participation, not all industrial customers can be expected to self-direct funds effectively toward all cost-effective opportunities. They also may be interested in the specialized technical support that a statewide program can potentially provide. Comprehensive and mature industrial offerings as part of administrator-directed core programs have many times demonstrated added value to manufacturers. At least three self-direct programs—in Oregon, Michigan, and Wisconsin—reported that customers who had been self-directing or had considered self-directing chose to return to paying the energy efficiency charge and using core ratepayer programs because these programs yielded substantial benefits. The ratepayer-funded industrial offerings in these states are robust and have evolved to meet customer needs over time (Chittum 2011).

It is interesting to note that Rocky Mountain Power allowed industrial customers above a certain size threshold to opt out of paying 50% of the ratepayer surcharge if they could show—through third-party audit—that there are no more energy efficiency opportunities below a certain payback period. During the 10-year period that the credit was in place, no companies took up the credit, which implies that participants either could not prove that all energy efficiency opportunities had been implemented or valued the energy efficiency program offerings more than the exemption.

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Structure self-direct programs as part of a larger portfolio of robust IEE programs that are responsive to industrial and other large customers' needs.
- Develop self-direct programs with active engagement with industrial customers to ensure the programs meet user needs.
- Allow flexibility in eligible technologies and timelines.
- Require verified energy savings equivalent to what would be achieved with core program offerings, with routine progress reporting and robust approaches for measurement and verification.
- Consider escrow-like accounts to structure a "use it-or-lose-it" fund base that encourages greater participation.

EXAMPLE 13. MICHIGAN'S SELF-DIRECT ENERGY OPTIMIZATION PROGRAM

Under Michigan's 2008 Public Act 295 (PA 295), certain customers may create and implement—or self-direct—a customized energy optimization (i.e., energy efficiency) plan and thus be exempt from paying the full energy optimization (EO) surcharge to its utility provider. The EO plan is consistent with the energy savings goals required of electric utilities as part of the state's energy efficiency resource standards. The plan identifies targets, planned projects, and verification process for approval by their utility, and the utility approves the plan and reports aggregated program data to the Public Service Commission.

Self-direct customers do not pay fully into the energy efficiency fund in exchange for the execution of their energy savings plan. They do pay a portion of their assigned charges to cover administration of the self-direct program and a portion of the public benefit charge that funds programs for low-income consumers.

In the first years of PA 295 implementation (2009 and 2010), the self-direct option was made available only to large customers with at least 2 MW of peak demand (or 10 MW peak demand for aggregate sites). For 2011 and 2012, PA 295 allows customers with at least 1 MW annual peak demand in the preceding year or 5 MW aggregate at all of the customer's sites within a service provider's territory to participate. The number of customers enrolled to self-direct their own EO program has dropped from 79 in 2010 to 47 in 2011 to 32 in 2012. This reflects the perceived value of the flexibility and comprehensive program options that are being offered under utility programs. Electric reductions from self-direct programs reached 53,593 MWh across customers from all providers (DTE Electric, Consumers Energy, Efficiency United, and cooperative and municipal utilities).

PA 295 specifies that all but the largest self-direct customers must hire an energy efficiency service company to develop an EO plan, which sets annual energy savings targets based on the previous year's energy consumption, factoring out changes in business activity, energy required for pollution control equipment, and weather normalization. As an alternation to normalizing for weather, the self-directing company can choose to base savings off of a three-year average annual demand for all retail customers in the state. Very large customers (more than 2 MW per site or 10 MW in aggregate) are not required to hire an energy efficiency services company.

Every year, the self-direct customer must submit a report detailing the energy savings projects and estimated energy savings. The third-party energy efficiency service company hired by the company is responsible for notifying the utility if the targets are not being met. If the targets are not met, the self-direct customer must pay the utility a portion of the avoided public benefit charge proportional to the percentage by which it missed the target. If the company exceeds their goal, excess savings may be applied to the following year's goal.

For 2009 and 2010, 26 customers of DTE Energy took advantage of the self-direct option, although DTE has reported that several customers may opt back in to DTE Energy's efficiency program due to the low surcharge.

Source: Taylor et al. 2012, Chittum 2011, Michigan Public Service Commission 2013

EXAMPLE 14. PUGET SOUND LARGE POWER USER SELF-DIRECTED ELECTRICITY CONSERVATION PROGRAM

Program Overview

One of Puget Sound Energy's (PSE) four commercial and industrial programs is the Large Power User Self-Directed Electricity Conservation Program, which started in its current form in 2006 (a pilot program was initiated in 1999). The self-direct program provides funding for customers that contribute to a conservation fund. Self-direct customers have access to 82.5% of the fund. Although participants in other PSE commercial and industrial programs are limited to maximum incentives of 70% of the measure cost, self-direct customers may fund up to 100% of measure cost. PSE keeps 7.5% of the conservation fund for program administration and 10% for Northwest Energy Efficiency Alliance market transformation programs activities. Customers are eligible under the self-direct program when they take three-phase service at greater than 50,000 volts.

PSE requests customers to calculate electric energy savings using standard engineering practices and to document data, assumptions, and calculations for PSE review. PSE reviews savings calculations and reserves the right to modify energy savings estimates. After receipt of project final cost documentation, a PSE Energy Management Engineer conducts a post-installation site inspection to review installed equipment and confirm implementation of the M&V plan. Actual savings may be trued-up based on post-installation energy use monitoring.

PSE works with self-direct customers to track energy efficiency contributions for future use and allows them to earn an incentive against their tracked contributions whenever an approved project is completed. The program focuses on large customers that often have in-house engineering resources, which can help reduce overall program costs and guarantee successful implementation of efficiency measures funded. PSE relies on trade allies such as energy service companies to help self-direct customers identify and implement projects.

Participation Process

PSE's program is creatively structured in that it combines grants with a competitive bid process. The program begins with a non-competitive phase during which customers are guaranteed access to their portion of energy efficiency fees and are responsible for proposing cost-effective projects to use their allocation. At the end of the non-competitive phase, customers not proposing projects to fully use their allocation forfeit their remaining balance to a competitive bid phase. Funds are aggregated together and disbursed via a competitive bid process among all self-direct customers, encouraging highly cost-effective projects. The projects funded as a result of this competitive bid process are generally more cost-effective than those funded during the first two years, as customers compete against each other to make a case for their projects. The program saw a very large volume of competitive projects proposed during the competitive bid process. For example, in 2009, self-direct customers proposed cost-effective energy efficiency investments of more than four times the amount of funding actually available in the aggregated fund.

All projects must meet PSE's avoided cost requirements. Although the customer submits its own proposal and M&V plan, PSE reviews the proposal and plan. Upon approval, PSE enters into a funding allocation agreement with the company and conducts a post-installation inspection after the measure is implemented.

Program Performance

PSE reports its self-direct program is acquiring energy efficiency at a cost equal to its other programs and that the program is acquiring more efficiency resources than would have otherwise been the case. Participation rates are also higher in the self-direct program among eligible customer classes than in other programs.

Each year, more customers qualify for the self-direct program; for the 2010–2013 program period, 54 customers were eligible. PSE has awarded more than $12 million in project incentives and projects 42,000 MWh per year in annual savings. As the program matures, PSE is seeing a shift toward longer payback projects, in part because more commercial customers have begun to participate in the self-direct program.

Sources: Puget Sound Energy 2012, Chittum 2011

EXAMPLE 15. XCEL ENERGY'S COLORADO SELF-DIRECT PROGRAM

Program Overview

Xcel Energy launched the Colorado Self-Directed Custom Efficiency Product in 2009. The program provides rebates to large commercial and industrial electricity customers who engineer, implement, and commission qualifying projects at their facilities. Self-direct customers perform the design, engineering, measurement, verification, and reporting of energy efficiency projects approved by Xcel Energy. The intent of the offering is to allow customers with the internal expertise, or access to expertise (through a third party), to drive their own energy efficiency projects while providing utility incentives to help them overcome financial barriers to implementation. Customers must have access to appropriate resources to properly identify, quantify, scope, and implement a project—without the assistance of Xcel Energy.

Due to this increased reporting and validation burden placed on the customer, Xcel Energy is able to provide a larger rebate than those offered through other incentive programs in exchange for the in-house engineering analysis required of a self-direct customer. Self-direct customers continue to pay their assigned energy efficiency charge, and self-direct projects are reimbursed through a rebate. Customers may earn rebates of up to 50% of the incremental project costs, either $525 per kilowatt (kW) or $0.10 per kilowatt-hour (kWh). Eligible business customers must have aggregate peak demand at all meters of at least 2 megawatts (MW) in any single month and have an aggregate annual usage of at least 10,000,000 kWh.

Participation Process

Participation is a multi-step process:

- Customers receive a rebate application from their Xcel Energy account manager, who ensures that all eligibility requirements are met. Pre-qualified customers then identify energy efficiency opportunities in their building and submit a detailed energy efficiency improvement plan to Xcel Energy.
- Xcel Energy reviews the project and provides a total resource cost (TRC) calculator for the customer to analyze the cost/benefit relationship of the project. To qualify for a rebate, the TRC must be greater than 1.0 and payback periods must be greater than one year and less than the lifetime of the equipment.
- Upon review and pre-approval of the improvement plan, customers are notified of project approval and potential rebate amount. At this stage, a monitoring plan is finalized to verify the project's results.
- Upon project completion, the customer submits a completion report including measurement and verification of the energy savings if savings are anticipated to be greater than 250,000 kWh. Once Xcel Energy approves the completion report, the rebate, based on measurement and verification savings, is issued to the customer.

Program Performance

Since its inception, the program has seen considerable customer interest and has achieved early success. Participating customers report high satisfaction with the program and vendors are optimistic about the future of performance contracting due to increasing customer prioritization in addressing energy costs.

- Since the 2009 launch, the self-direct program has achieved more than 26 gigawatt-hours (GWh) and 3,531 kW of savings and paid rebates in excess of $3.4 million (average savings per participant is 1.7 GWh with TRCs of more than 2.0).
- 2010 had 10 projects and achieved savings of 8.97 GWh against a goal of 4.4.
- 2011 had two participants and achieved 7.67 GWh against a goal of 5.6 GWh.
- 2013 has a pipeline of more than 8 GWh.

In 2012, TRC was 1.79, Utility Cost Test was 4.67; and lifetime cost of conserved energy was $0.01 per kWh.

Source: Nowak et al. 2013

6. Emerging Industrial Program Directions

Well-designed self-direct programs such as those discussed in the previous chapter are likely to play an important role in states that have clean energy portfolio standards (CEPS) but do not have mature industrial program offerings, or where manufacturers may be seeking opt-out provisions. However, in other circumstances, other types of programs may be more relevant. For example, states with long-standing industrial programs may want to ramp up efforts or, at the other end of the spectrum, there may be no regulatory driver to acquire energy efficiency resources. This chapter discusses promising opportunities for the next level programs that can further address some of the traditional barriers to industrial participation and expand the development of energy efficiency potential present in manufacturing facilities.

This chapter focuses on new program opportunities rather than providing detailed pathways for immediate implementation because further research, regulatory guidance, and implementation experience is needed. Some approaches, such as next-level strategic energy management (SEM) programs, are based on proven practices that states have implemented for years, while others are in the development stage and may not be market-ready.

The approaches discussed below could result in increased industry participation, develop deeper or harder-to-find savings, enhance the value of certain energy efficiency projects to manufacturers, and expand the fuel options for IEE programs. Initial discussions on these innovative or emerging approaches include:

- Further expanding the use of SEM programs and overcoming current challenges with crediting savings from SEM improvements
- Compensating customers beyond individual energy management or equipment installation and for performance at the whole-facility level
- Integrating non-energy benefits (NEBs) more effectively at the industrial customer level
- Developing new mechanisms that allow natural gas saving projects to receive incentives.

6.1. Next-Level Energy Management Programs

As discussed in Section 3.4, SEM and energy manager/staffing programs seek to promote operational, organizational, and behavioral changes that result in greater efficiency gains on a continuing basis. SEM programs seek to move beyond incentives for equipment and technologies toward a systems focus that rewards operational efficiency, maintenance improvements, “lean” techniques, and ongoing implementation strategies. SEM programs, although diverse in nature, usually offer incentives for operations and maintenance (O&M) improvements, provide energy management training and workshops, and offer support to establish energy tracking systems. Energy manager/energy staffing placement programs provide financing for an energy manager or dedicated personnel to provide leadership and technical expertise beyond discrete projects to identify opportunities and bring them through to implementation on a continuous basis. In practice, several program administrators have tended to offer both SEM and energy manager/energy staffing programs. Incentives are often provided for operational efficiency measures, energy tracking systems, and staff time (see Chapter 3).

The success of these programs has been noted by long-standing administrators, such as Wisconsin Focus on Energy, which has been offering SEM for 1 years, and there is growing interest in applying this approach in new service territories. Administrators that have traditionally offered prescriptive and custom programs are now piloting energy management programs. Recent programs have been introduced by DTE Energy, the Energy Trust of Oregon (ETO), Southern California Edison, Vectren (Indiana), Rocky Mountain Power (PacifiCorp) in Utah and Wyoming (the latter as an energy manager pilot), and Minnesota Energy Resources Corporation (see Table 3).

Table 3. Recent Energy Management Programs, Pilots, and Initiatives

Activities	Incentives (Where Applicable)
Energy Trust of Oregon CORE Improvement	
The CORE Improvement offering is designed to implement strategic energy management (SEM) for highly motivated small and medium industrial cohorts. Through a 12–15 month engagement, plants participate in four peer-to-peer cohort workshops, and SEM coaches meet with participants individually. These meetings leverage tools and resources to ensure that assignments are applicable to the site and effective for each facility.	Technical services in the form of the SEM coaches, which cost around \$25,000–\$40,000 per facility over the 15 month engagement.
Energy Trust of Oregon ISO 50001 Pilot	
In 2012, the Energy Trust of Oregon (ETO) initiated a pilot offering under the Production Efficiency program to deploy energy management practices to the ISO 50001 level to establish a system that could be externally certified.	Financial incentives for achieving certification within six months of completing the statistical energy savings model (as well as incentives already available from existing ETO programs)
Minnesota Energy Resources Corporation Energy Management Team Coordinator Pilot	
Minnesota Energy Resources Corporation (MERC) undertook a pilot program from August 2010 to June 2012 to help industrial customers identify and implement energy conservation improvements. The pilot provided an Energy Management Team Coordinator to assist the internal Energy Management Teams of five MERC customers (i.e., the coordinator dedicated 20% of work time to each customer). Customers were recruited as part of MERC's Commercial & Industrial Turn-Key Efficiency program, requiring minimum annual gas usage of 500,000 therms. During the two-year pilot, the coordinator worked with each participating customer to implement an energy management system similar to ISO 50001 and based on U.S. Environmental Protection Agency's ENERGY STAR program publication, Teaming Up to Save Energy. The results of the pilot were positive. Participants outperformed the comparison group by implementing an average of nearly twice the number of energy savings projects, achieving higher annual energy savings, and attaining a conversion ratio of three times the achieved therms savings compared with identified potential therms savings.	
Northwest SEM Collaborative	
The Northwest Energy Efficiency Alliance (NEEA), Bonneville Power Authority (BPA), Energy Trust of Oregon (ETO), BC Hydro, and a number of Northwest utilities are taking a collaborative approach to industrial SEM to share best practices in SEM research, design, implementation, and evaluation. The Collaborative aims to help energy efficiency program administrators accelerate the adoption of SEM in the industrial sector by focusing on: • Strategic planning: Provide long-term direction for the Northwest SEM community • Solution improvement: Enhance the efficiency and effectiveness of Northwest SEM offerings • Program innovation: Increase the reach of industrial Northwest SEM programs • Knowledge transfer: Broaden and deepen the extended SEM community's capabilities and skill sets.	
NEEA SEM Cohorts (Montana)	
NEEA and Northwestern Energy are partnering to work with SEM cohorts, groups of Montana companies that share both their experiences launching energy-saving programs and their vision of a more competitive Montana business community. Representatives from each organization champion energy management goals and regularly share results. Northwestern Energy and NEEA provide training and support on developing SEM plans, and participating companies meet regularly and share their experiences and progress throughout the nine-month program (NEEA 2013b).	
Rocky Mountain Power (PacifiCorp) Schedule 24 Revisions (Utah)	
Effective July 2013, Rocky Mountain Power (PacifiCorp) revised its programs through Schedule 140, which introduces incentives for operations and maintenance (O&M) savings and copayment for an internal energy project manager over 12–18 months.	\$0.02/kWh for annual O&M savings; and \$0.025/kWh annual savings for energy project manager co-funding with minimum savings of 1,000,000 kWh for 12–18 months

Source: Carl 2012, Batmale and Gilless 2013, ETO 2013a, Franklin Energy 2013, Rocky Mountain Power 2013

Despite the interest in expanding SEM programs in other service territories, these efforts are challenging to implement because of the following issues, which include the lack of common policy guidance and regulatory rules:

- Crediting savings from improvements from SEM
- Determining appropriate baselines
- Justifying incentives for energy management hardware such as submetering and for support of energy managers, which do not directly save energy
- Evaluating SEM typically requires both quantitative information (demonstrated energy savings) as well as qualitative information (energy management practices).

An initial discussion of design considerations that would support more and better energy management programs—i.e., "next generation energy management programs"—is provided below. It is important to note that early adopters have been leading the way in overcoming these challenges and some of their experience is touched on here. For example, the Northwest SEM Collaborative is leading a work program that would drive greater understanding and consensus on SEM research, design, implementation, and evaluation. In-depth coverage of these issues, however, is not provided in this chapter.

Incentives for Submetering

Attention to improving facility metering can generate more accurate knowledge of where energy is being used. This is often the first step to create a continuous energy savings program. Constant monitoring allows the facility to gauge the ongoing effectiveness of its portfolio of energy savings investments and measures. Utility incentives that include submeters and other energy monitoring equipment would allow companies to fine tune operational performance, identify new opportunities for projects, and inform where to focus resources, and track progress.

However, many program administrators face challenges in providing incentives for submetering or other energy management hardware. Although meters do not directly save energy, accurate metering is a critical element of effective benchmarking and verifiable measurement and verification (M&V). Effective strategies that could be used by energy efficiency program administrators include rolling meter costs into the overall measure cost or treating submetering as a persistence strategy for certain energy efficiency measure types, especially O&M measures.

Energy Management Maturity

Energy management approaches are diverse and can range from a set of principles with top-level commitment based on the "Plan Do Check Act" framework, focused O&M improvements, implementing energy management system (EnMS) standards (ISO 50001), lean manufacturing techniques, or use of energy management software tools such as energy management information systems. In addition, the energy management approach employed by an individual company will mature as experience accrues—implementing new technologies, replacing outdated technology with newer, more energy-efficient systems, and investing in energy management assets throughout the organization. The SEM approach itself becomes more sophisticated and energy savings persist.

As well as focusing on the quantitative aspects of M&V from SEM (i.e., energy savings—see next section), program administrators and industrial customers need to be able to assess industrial customer energy management practices and maturity. Energy management assessments are used as a diagnostic tool to determine baseline practices at the beginning of a customer's participation in SEM and are also useful to assess progress and evaluate programs. In addition, maturity models can help to integrate SEM within other business improvement and productivity models (IIP and MSS 2013).

Several successful programs that already assess energy management maturity include:

- The Northwest Energy Efficiency Alliance (NEEA) and the Northwest Food Processors' Association's (NWFPA's) Industrial Energy Roadmap outlines an "Energy Efficiency Self-Assessment" to help enterprises gauge their current level of energy efficiency efforts and understand how energy is viewed within the organization. The self-assessment helps both enterprise and evaluator establish a level of energy management sophistication, creating a roadmap on SEM implementation improvement.

- BC Hydro's Energy Management Scorecard serves to rate companies' energy management in multiple areas, identifying critical areas for improvement and outlining ways to excel in those areas.
- Xcel Energy helps companies benchmark their energy management practices.
- The U.S. Department of Energy's (DOE's) Superior Energy Performance (SEP) program has developed an industrial facility Best Practice Scorecard, which enables companies with mature EnMS to earn credits by implementing energy management best practices as well as improving energy performance. The best practices are activities, processes, or procedures that are above and beyond what is required by ISO 50001 and encourage "best in class" companies to continually improve their EnMS, which will lead to improved performance and sustained energy savings (SEP 2012).
- EPA's ENERGY STAR® program has several assessment matrices that gauge the amount of energy management implementation presently in place for an industrial company or facility. Matrices address energy management programs, plant programs, and small or medium sized plants.

Baselines, Energy Models, and Measurement and Verification

Traditionally, prescriptive approaches use deemed savings for common equipment or verify the savings from replacing a piece of equipment, where estimating the before and after energy consumption is relatively straightforward. With industrial custom projects, M&V analysis is done for each project at the measure level because of the high specificity of the industrial process and application. Using either method, utilities can be relatively confident in the amount of energy savings resulting from replacing existing equipment with more efficient equipment.

SEM programs move away from the equipment focus to continuous improvement across all factors that affect energy use—equipment, systems optimization, O&M, and behavior. In this way, SEM programs unlock the potential of persistent O&M and behavioral savings, which have rarely been included as eligible measures in traditional programs. However, SEM programs that focus on "how,"—for example using a piece of equipment less or using it more optimally—often suffer from an inability to confidently quantify savings or demonstrate persistence over time (Milward et al. 2013).

Attributing savings to projects identified through SEM programs is challenging, but tracking success will be increasingly important as SEM programs become more widespread and their effectiveness is put under regulatory scrutiny. SEM M&V can also be a valuable tool for industrial managers, by making energy performance visible, meaningful, and actionable. SEM M&V requires the development of a robust baseline (typically for a period of one year or more) and an energy model against which actual performance is measured. The general approach is described in Example 16.

Although SEM is broader than just O&M or operational efficiency, the approach as described in Example 16 that subtracts out the savings from capital projects is currently the most common M&V approach to credit financial incentives for SEM. Current programs deploying this approach apply traditional incentives for custom retrofit measures, where retrofit measure savings are subtracted from facility-wide savings, and then a lower incentive is paid on the difference (Gilless 2013). Programs that estimate and incentivize SEM program savings in this way include NEEA, ETO, the Bonneville Power Administration (BPA), and Rocky Mountain Power (PacifiCorp).

In contrast, in addition to crediting operational efficiency, BPA also tracks the increased number of equipment retrofits due to SEM and includes this information in its program results. Companies participating in BPA's High Performance Energy Manager Program (HPEM) show that companies tend to significantly increase the number of capital projects after enrolling in the program: new capital projects submitted after HPEM adoption rose to 23 projects compared with 10 projects beforehand (Wallner 2011). Energy management programs that estimate program results solely in terms of increased numbers of equipment retrofit projects (i.e., they do not count operational, behavioral, or non-equipment savings) include BC Hydro and Xcel Energy (Wallner 2012).

Experience from energy management programs in Europe also supports this observation. Participants in Ireland's Energy Agreements Programme were surveyed to understand how the Irish energy management standard, primarily driven by impending carbon limits, had contributed to their energy efficiency efforts. Surveys report that 67% of the projects to save energy were derived or driven by the EnMS process, and since the introduction of EnMS in Ireland in 2005, the pace of energy savings has increased (Reinaud et al. 2012).

Engaging Supply Chains

Utility or third-party energy management programs may wish to encourage these leading companies with mature SEM experience to collaborate with their supply chains to improve supplier energy management performance. For example, the NEEA-NWFPA Energy Efficiency Assessment recognizes "Industry Collaborators" as companies that actively work outside their own facilities to collaborate with suppliers, utilities, organizations, competitors, consortiums, and associations. Similar program initiatives also exist abroad. In the Netherlands' Long Term Agreements, companies meet one third of their reduction target outside the plant boundaries by engaging their value chains. In Japan's benchmarking policy, companies that demonstrate that they are already at global best practice can collaborate with other companies in their supply chain instead of searching for additional savings within their own operations (Goldberg et al. 2012).

EXAMPLE 16. BASELINES AND ENERGY MODELS

To isolate the effect of strategic energy management (SEM) versus capital projects and other variables, program administrators and customers typically develop an energy use baseline and an energy (regression) model for the entire facility. Payments are made based on actual savings once equipment changes and other variables have been subtracted. Robust models require reliable sources of facility and production data to establish the facility baseline and any savings. For example, the Energy Trust of Oregon and the Bonneville Power Administration model a facility's energy consumption as a function of production and other variables such as weather to determine a baseline level. Using meter-level analysis, they then track actual performance against projected usage—the difference is the potential savings. Actions and measures taken to reduce energy use and the dates of those actions are also tracked in order to be able to tie changes in energy use in the model to actual energy efficiency actions taken. To calculate the annual SEM incentive for the customer, savings from all capital projects are subtracted out (because capital projects receive their own incentives) so that only operations and maintenance savings are included in the cost-effectiveness evaluations of SEM programs (Kolwey 2013, Crossman 2013).

The Consortium for Energy Efficiency and the Northwest SEM Collaborative are actively working to develop a greater common understanding of these issues and to provide guidance to regulators and program administrators to promote more widespread deployment of SEM programs.

At the implementation level, new developments in intelligent technology are emerging as promising tools to ease the burden of determining baselines and using energy models. Companies with longstanding experience with SEM approaches perhaps started out looking at their energy use once a week or month and might have updated their energy models once a year. However, recent developments in information technology systems such as for submeters, energy management information systems, and Intelligent Efficiency, are paving the way toward giving manufacturers the ability to track and measure their energy use and savings performance data in real time across their entire operation. Self-diagnostic, comparative, and anticipatory analytical capabilities of smart devices are enabling a new level of process energy management and systems optimization within companies and can help prevent the degradation of energy savings. With this information, companies can prioritize different operations, tune up systems and integrate demand response, and support less costly measurement and verification.

6.2. Whole-Facility Energy Intensity Programs

The building up of energy baseline and consumption models that were developed to allow customers to receive incentives for SEM implementation provides possible new directions: customers could be compensated beyond individual energy management or operational efficiency and be paid for performance at the whole-facility level—i.e., incentives are not separated by project or equipment installation.

Under this new program model, utilities or program administrators could work with customers to agree on an energy baseline for a certain period (e.g., a year) and provide incentives based on improvements in energy intensity below the baseline. These types of pay-for-performance programs resemble power-purchasing agreements for renewables or white certificates schemes in Europe. They could also be closely integrated into national initiatives and provide greater applicability for a single company with industrial facilities in multiple service territories.

However, the outlook for these programs is likely longer-term because of a range of technical and policy questions such as:

- Accepted methods for setting baselines. There already are existing methods, such as the International Performance Measurement and Verification Protocol (IPMVP) Option D and those used by the New York State Energy Research and Development Authority (NYSERDA), Connecticut Light & Power, and outlined in BPA's Energy Efficiency Implementation Manual (2013) (Seryak and Schreier 2013). The Consortium for Energy Efficiency (CEE) and the Northwest SEM Collaborative are working to gain a common understanding of these issues.
- Whether incentives for improvements in energy intensity can become a commonly accepted policy approach for regulators and legislators across different states—there can be regulatory concerns and restrictions to base analysis of savings on intensity reduction (Crossman 2013).
- The inability of many industrial customers to quickly and effectively analyze their energy consumption information provided by utilities.

EXAMPLE 17. EPA ENERGY STAR PROGRAM

EPA's ENERGY STAR program for industry has developed a number of whole-plant energy benchmarks known as ENERGY STAR plant energy performance indicators (EPIs). These tools provide an energy performance score for plants based on the energy performance of the plant type nationally. To learn more about which industrial sectors have an EPI, visit www.energystar.gov/epis.

6.3. Enhancing the Value of Industrial Energy Efficiency Projects through Non-Energy Benefits

Energy efficiency measures often result in a number of non-energy benefits (NEBs) such as increased productivity, reduced material loss, improved product quality, and lower emissions. In addition, investors increasingly value corporate commitment to energy efficiency and sustainability as an indicator of sound governance and business acumen. Several studies have shown that NEBs from IEE projects, such as broader productivity or quality gains, can be as high as or even higher than the energy cost saving benefits achieved by the projects (Kushler et al. 2012, Chittum 2012, Lazar and Colburn 2013). Full quantification of NEBs for use by implementers and industrial customers at the project or measure level is not commonplace.

NEBs can play an important role in persuading industrial customers to participate in programs. A 2003 study of commercial and industrial (C&I) energy efficiency programs in Wisconsin valued these benefits at approximately 2.5 times the projected energy savings of the installed technologies (Hall and Roth 2003). Worrell et al. (2003) analyzed the NEBs that accrued to industrial customers from 52 energy efficiency projects, where 55% of the cost savings came from productivity improvements as summarized in Table 4. Lung et al. (2005) undertook a similar study with 81 projects (Table 5), showing that 31% of the savings were attributable to NEBs.

Table 4. Energy Cost Savings and Non-Energy Cost Savings from 52 IEE Projects

Total project investment	$54.2 million
Total annual energy savings	$12.9 million (45% of total savings)
Total annual productivity savings	$15.7 million (55% of total savings)
Combined total savings	$28.6 million
Average energy payback	4.2 years
Average payback including energy and non-energy benefits	1.9 years

Source: Worrell et al. 2003

Table 5. Energy and Non-Energy Cost Benefits from 81 IEE Projects

Total project costs	$68.2 million
Total annual energy savings	$47.7 million (69% of total savings)
Total annual non-energy savings	$21.1 million (31% of total savings)
Total annual savings	$68.7 million
Simple payback of energy savings	1.43 years
Simple payback of non-energy benefits	0.99 years

Source: Lung et al. 2005

In a recent survey of 30 energy managers, engineers, sustainability managers, plant managers, presidents, and vice presidents from a diverse pool of companies nationwide, 90% of energy projects were found to also have a broader productivity impact (Russell 2013a). For one company surveyed, energy improvements provided a four-fold return in the form of production improvements and some companies claimed that NEBs "dominated" the returns from energy projects.

However, at the industrial customer level, NEBs are often not quantified prior to making an investment. Some assessment of NEBs may be undertaken post-implementation for evaluation or recognition purposes, but this is for measures that already pass the cost-effectiveness test on energy cost considerations alone. ETO tries to address NEBs upfront and will help industrial customers to quantify NEBs to support the investment decision for projects that are of interest to the industrial customer but do not quite satisfy the cost-effectiveness test. For ETO, water savings is a common NEB to be quantified and is relatively straightforward to quantify relative to other NEBs, such as improved safety and employee morale (Crossman 2013).

Valuing NEBs at the project level prior to an investment could significantly broaden the number and types of projects eligible for program support and incentivize additional efforts for the industrial customer. Although this may require additional engineering resources, collaborative opportunities with water utilities could be pursued to bring additional incentives for water and energy efficiency measures (e.g., steam leaks, steam traps).

As well as focusing on water benefits, using lean approaches can provide benefits in the "non-energy wastes." For example, an hour shaved off of a two-hour line start-up saves energy, scrap material (from sub-optimal line speed), and an hour of staff labor (Gilless 2013).

6.4. Natural Gas Industrial Efficiency Programs

Energy efficiency programs designed to help natural gas customers reduce energy use and costs have existed for more than 30 years in a number of states (ACEEE 2012c). The first customer energy efficiency programs were primarily targeted at residential customers and typically focused on increasing home insulation, reducing air leaks, and installing high-efficiency furnaces. Also, many of these early programs targeted the needs of low-income customers who had difficulty keeping up with rising winter heating costs at a time when natural gas prices were increasing rapidly. Making energy affordable was a primary objective of many of these early gas programs and still is one of the goals of most programs today.

Although the roots of natural gas efficiency programs lie within residential markets, there are a growing number of programs that now serve a broad range of gas customers, from homeowners to, increasingly, large industries. However, although opportunities for natural gas savings in the industrial sector are significant, most of the current IEE program activity at the state level focuses on electricity. In 2011, $6.8 billion was budgeted for overall electric programs (residential, commercial, and industrial); C&I program budgets were approximately $2.6 billion. In contrast, $1.2 billion was budgeted for overall gas programs in 2011, with approximately $350 million for natural gas C&I programs (CEE 2012). Total C&I natural gas program expenditures were approximately $225 million in 2011, with $50 million specific to industrial programs (AGA 2013).[30] Further, estimates show that C&I customers accounted for more than 50% of gas efficiency program savings in 2011 (approximately 71.8 trillion Btu out of a total savings of 125.2 trillion Btu), with industrial programs accounting for 30 trillion Btu on their own (AGA 2013).

Natural gas utilities recover energy efficiency costs in a number of ways, one of which is to apply a surcharge to the delivery charge (other methods include special energy efficiency tariffs or riders or cost recovery via base rates). Nearly 40% of U.S. industrial customers have separate purchasing agreements with wholesale gas suppliers or third-party marketers for the commodity. However, 88% of the natural gas volumes delivered by U.S. utilities to industrial customers were purchased from a third party, which implies that large industrials predominantly acquire their natural gas supply from a source other than the utility. Thus gas utilities serve those large industrial customers mainly with transportation services, so typically they would not include large-volume industrial customers in their gas efficiency programs. With the industrial sector being the second largest end-use consumer of natural gas (after electric generators)—accounting for 26% of total U.S. end-use gas consumption (EIA 2013)[31]—this represents an enormous opportunity in gas savings by targeting industrial customers.

In addition to this challenge, recent low gas prices have made energy efficiency challenging from a cost-effectiveness perspective. Gas utilities are continuing to deliver energy efficiency programs in this low price environment and most gas efficiency programs still continue to pass cost-effectiveness tests. Where engaged, industrial customers tend to be one of the most cost-effective options in the portfolio of efficiency program offerings. Although natural gas prices were at an all-time low in 2012, prices have already rebounded to around $4 per million Btu (MMBtu) and current forecasts estimate that prices will remain in the range of $4 to $6 per MMBtu for the foreseeable future (EIA 2013).[32] In addition, the attractive price outlook for natural gas has created an opportunity for industrial customers to invest in new technologies, processes, and systems. Industrial gas efficiency programs can help ensure that these investments are based on the latest, most efficient practices and technologies, ensuring continued benefits for customers and the state. A particular efficiency opportunity driven by the positive long-term outlook for natural gas supply and price in the United States is combined heat and power (CHP). CHP can play a unique role in IEE programs because it is not only a highly efficient use of the natural gas resource, but reduces load requirements on electric utilities similarly to straight electric efficiency measures. By providing both electricity and useful thermal energy at the industrial facility in one energy-efficient step, CHP delivers overall energy savings both from its own high efficiency and from avoiding transmission and distribution line losses that normally occur in delivering power from the central station generator to the customer.

The organization of utility service provision often impacts the way in which energy efficiency program services are delivered and their cost-effectiveness evaluated. Most single-fuel utilities administer energy efficiency programs on their own. However, energy efficiency opportunities typically lead to savings from end uses that reduce both gas and electric energy use. Delivered together as part of the same project or program, gas and electric efficiency measures may very well pass cost-effectiveness tests even if the gas measures on their own do not. Delivering gas and electric efficiency programs together has the benefit of avoiding the loss of technically and economically viable energy efficiency potential. Energy efficiency technical potential comes from individual end uses and the interaction of those measures with one another and the facility itself in which they are implemented. Ignoring the benefits of energy savings from “other fuels” may lead regulators and administrators of gas efficiency programs to

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[30] Overall gas efficiency program budgets for 2012 were $1.4 billion (AGA 2013).

[31] The power generation sector is the largest consumer of natural gas, using an estimated 32.5% of total gas consumption in 2013 (EIA Annual Energy Outlook 2013).

[32] Natural gas energy efficiency programs remain cost-effective when gas prices reach around $4 per MMBtu (using the total resource cost test).

undervalue investment in packages of measures that deliver savings across fuels. The resulting customer under-investment may foreclose on energy efficiency savings opportunities because long-lived equipment is installed that is oversized or because certain improvements can only be technically or economically installed in conjunction with a broader package of measures (Hoffman et al. 2013).

Some states have been able to overcome the cost-effectiveness challenges and can serve as promising examples for other states that wish to further increase gas savings and meet CEPS targets through industrial gas efficiency programs and/or combined electric and gas efficiency programs. For example, PG&E's gas efficiency program in California achieves 60% of its savings through industrial customers, in contrast to 20% of its electricity savings from industrial programs (Sethuraman 2013).

Programs that offer incentives for industrial gas savings as well as electric savings include NYSERDA, ETO, Wisconsin Focus on Energy, Efficiency Vermont, NSTAR, and CenterPoint Energy (Example 4). Another example of a holistic approach to energy savings is an innovative mechanism being proposed by the Utah Association of Energy Users. The proposal suggests that gas utilities offer large industrial customers the opportunity to voluntarily "opt in" to a demand-side management fund, through a self-assessed contribution of 1%–3% of their gas expenses, and to pool these funds with contributions already made to electric public benefits funds. Participating manufacturers could then self-direct these funds to cover both electric and gas energy efficiency opportunities, thereby implementing larger and more effective programs with the flexibility to deliver both electricity and gas savings (Weir 2013).

In summary, industrial customers provide a large savings potential for natural gas utilities and regulators that aim to reduce energy consumption and costs, infrastructure costs, and greenhouse gas emissions through efficiency programs. To achieve this, it is important to align policy goals with implementation rules and evaluation methodologies. Clear and streamlined guidance can help utilities to work with their industrial customers to implement building and process efficiency measures and optimize energy use, while being able to track and credit energy savings to the efficiency program, rather than to new, more stringent energy codes.

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7. Conclusion

Building on the improvements in energy efficiency in the U.S. industrial sector that have occurred over the past decades in response to volatile energy prices, fuel shortages, and technological advances is essential to maintaining U.S. industry's viability in an increasingly competitive world. The fact is that many opportunities remain to incorporate cost-effective, energy-efficient technologies, processes, and practices into U.S. manufacturing. Industrial energy efficiency (IEE) remains a large untapped potential for states and utilities that want to improve energy efficiency, reduce emissions, and promote economic development. Successful IEE programs vary substantially in operational mode, scope, and financial capacity, but also exhibit common threads and challenges.

As this report shows, the states' experience gained in developing and implementing IEE programs is both diverse and rich. In Table 6, specific issues discussed in each of the preceding chapters are summarized for regulators and program administrators to consider when designing and implementing effective energy efficiency programs for industry. They do not cover all decisions or issues that regulators and program administrators may need to consider because there will undoubtedly be jurisdiction- and case-specific topics that are not anticipated here. However, these considerations provide a starting point for addressing many of the issues that typically arise.

Table 6. Summary of Key Issues and Considerations for Regulators

Topic	Issue	Considerations for Regulators and Program Administrators	Program Examples
The value of energy efficiency projects	Energy efficiency projects may compete with core business investments and decision-making is often split across business units.	• Clearly demonstrate the value proposition of energy efficiency projects to companies • Relay the operating cost savings and other benefits—including profits—lost if energy efficiency improvement opportunities are not addressed.	• Bonneville Power Administration • New York State Energy Research and Development Authority • West Virginia Industries of the Future
Relationships with industrial customers	It takes a long-term relationship for programs to understand industrial operation and needs, and for industrial companies to understand what a program can offer them.	• Long-term relationships with industrial companies enable joint identification of energy efficiency opportunities • Stability in program support and personnel over a number of years is critical.	• Energy Trust of Oregon
Industrial sector credibility and technical expertise	Addressing industrial companies' core needs requires understanding a plant's production processes, operating issues, and the market context the plant operates within.	Effective IEE programs develop credibility with industrials by employing staff/contractor experts that understand the industrial segment and have the technical expertise to provide quality technical advice and support issues specific to that industry and customer.	• Efficiency Vermont • Wisconsin Focus on Energy • Xcel Energy (Colorado and Minnesota)
Diverse industrial customer needs	Manufacturers use energy differently than the commercial sector, typically having significant process-related consumption. Focusing on simple common technology fixes alone will miss many of the opportunities.	A combination of both prescriptive offerings for common crosscutting technology and customized project offerings for larger, more unique projects can best meet diverse customer needs and provide flexible choices to industries.	• Rocky Mountain Power • CenterPoint Energy • Xcel Energy

Topic	Issue	Considerations for Regulators and Program Administrators	Program Examples
Project scheduling	Scheduling of energy efficiency investments can be heavily dependent on a plant's operational and capital cycle, as proposed equipment changes must be guided through rigorous, competitive, and time-consuming approval processes.	Programs with multi-year operational planning can best accommodate company scheduling requirements, as scheduling of capital project implementation must consider both operational schedules that dictate when production lines may be taken out of operation as well as capital investment cycles and decision-making processes.	• NYSERDA
Application processes	Industrial customers may perceive the application and implementation procedures for IEE programs to be administratively complex and burdensome.	Achieving the right balance between meeting key program administration needs for information and keeping program procedures simple and efficient may often require a continual process of evaluation and improvement.	• BPA • NYSERDA
Program outreach	Various industrial customers may be unaware of the industrial program offerings that may be most applicable or useful for them due to staff turnover and internal demands.	Steady and continual outreach and dissemination of information, such as examples of successful past projects, is important to encourage participation.	• AlabamaSAVES • NYSERDA
Leveraging partnerships	A range of federal, national, regional, and state initiatives and resources are relevant to state IEE programs, including those provided by the U.S. Department of Energy, the U.S. Environmental Protection Agency ENERGY STAR® program, state energy offices, and the Manufacturing Extension Partnership.	Successful IEE programs often partner with federal, state, and regional agencies and organizations to leverage their expertise, access to customers, and program implementation support capacities.	• AlabamaSAVES • Northwest Energy Efficiency Alliance, Northwest Food Processors Association and BPA
Medium- and long-term goals	Industrial companies and program administrators seek market certainty and reduced risk in ramping up the implementation of cost-effective energy efficiency measures.	Regulators and program administrators can set energy savings goals or targets for the medium- to long-term, coordinated with funding cycles (e.g., in three-year cycles).	• Michigan Self-Direct Energy Optimization Program • Southwest Energy Efficiency Project
Measurement, verification, and evaluation	Effective M&V is critical for program administrators to assess results and measure progress, and is also useful for industrial to verify results of their investments.	• Guidelines for M&V need to be clearly defined and periodically reviewed and adjusted • Periodic impact and process evaluations help identify where IEE program efficiency and results can be further improved • Non-energy benefits (NEBs) can be a key element of both project M&V and program evaluation.	• DOE's Uniform Methods Project • International Performance Measurement and Verification Protocol • ETO process evaluations • NYSERDA, Mass-achusetts, and BPA valuation of NEBs

Topic	Issue	Considerations for Regulators and Program Administrators	Program Examples
Self-direct programs	There is a wide range in structures of self-direct programs: from those that are only vaguely defined, and include little M&V of energy saving actions, to those that require verified self-directed customer investment and energy savings to be achieved in order for payment into the programs to be waived.	Clarity in self-directed customer obligations and M&V of results are necessary if the policy goal is to ensure that self-directed industrial customers contribute to overall efforts to ensure least-cost electricity or gas service at a level on par with the contributions of other customers.	• Michigan Self-Direct Energy Optimization Program • Puget Sound Energy • Xcel Energy
Emerging Industrial Program Directions			
Expanding and strengthening strategic energy management programs	Efforts to support implementation of SEM in industry are gaining momentum in state programs.	The challenge of crediting SEM (how to quantify and credit energy savings specifically achieved through SEM), as well as other SEM-related topics, is worthy of further research and cross-exchange.	• AEP Ohio • BPA • BC Hydro • ETO • WFE • Xcel Energy
Program approaches for whole-facility performance	Significant challenges exist in determining baselines and performance metrics that can provide sufficiently robust measurements of facility savings while maintaining practical and easy-to-implement methodologies.	Work on crediting energy savings from SEM could facilitate the provision of incentives and assessing savings credits for whole industrial facility performance, as opposed to performance of individual investments or measures.	• European experience
Capturing non-energy benefits at the project level	Although there is wide variation between projects, several studies have shown that NEBs from IEE projects, such as broader productivity or quality gains, can be as high as or even higher than the energy cost saving benefits achieved by the projects.	If programs employed systematic ways to assess NEBs earlier in the project cycle, the resulting total returns and shorter payback could tip the scale on a variety of projects from “wait and see” to implementation.	• Energy Trust of Oregon
Expanding natural gas programs	• There is less coverage of the industrial sector in natural gas efficiency programs than in electricity efficiency programs. • Most large industrial customers purchase their gas through third-party suppliers rather than their distribution companies. • Most single-fuel utilities administer energy efficiency programs on their own. However, energy efficiency opportunities typically lead to savings in both gas and electric energy use.	• Gas and electric efficiency measures—when delivered together as part of the same project or a combined program—can result in larger, more effective programs that capture more of the technically and economically viable energy efficiency potential. • Innovative concepts are under consideration to increase the effectiveness and the reach of natural gas efficiency programs.	• Efficiency Vermont • ETO • NYSERDA • PG&E • WFE

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT NO. ICNU/405

EXCERPT OF PGE REPLY TESTIMONY (PGE/1600)

IN DOCKET NO. UE 283

UE 283 / PGE / 1600
Tnker – Liddle

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Jay Tinker
Christopher A. Liddle

July 16, 2014

III. Energy Efficiency in Marginal Costs

Q. What policy issue does CUB raise in its reply testimony?

A. CUB raises an issue regarding Senate Bill 838's (SB 838) exemption of customers over one average megawatt and the Energy Trust Of Oregon's (ETO) 18% spending cap on industrial customer energy efficiency.

Q. Please explain the issue.

A. In 2007 with the passage of SB 838, the Oregon Renewable Energy Act, the OPUC was authorized to approve the collection of additional energy efficiency funds from PacifiCorp and PGE customers using less than one average megawatt per year.[17] Customers with annual loads of more than one average megawatt were not required to pay these supplemental energy efficiency charges nor allowed to receive the benefits. To ensure that customers with loads less than one average megawatt were not subsidizing customers with over one average megawatt, PGE, PacifiCorp, the ETO, OPUC Staff, CUB, and ICNU reached an informal agreement that the ETO would not exceed a historical amount of energy efficiency funding for the larger customers' energy efficiency projects. PGE's cap of 18% was an historical average of the ETO energy efficiency payments (under SB 1149) to PGE's customers over one average megawatt, for the three years preceding the passage of SB 838.

Q. Does PacifiCorp have the same cap as PGE?

A. No. PacifiCorp's cap is 27%; again based on an historical average of energy efficiency payments from the ETO to PacifiCorp's industrial customers over one average megawatt. The ETO initially found more industrial energy efficiency opportunities in PacifiCorp's territory than PGE's.

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[17] One average megawatt is the definition used in SB1149 based on one meter or a collection of meters within a certain distance from each other.

Q. How close is the ETO to reaching the 18% cap?

A. PGE estimates that the 18% cap will be reached in 2014.

Q. What happens when the cap is reached?

A. The ETO will have two years to scale back payments to PGE's customers over one average megawatt to bring the total spending within the cap.

Q. What are the consequences of the ETO scaling back funding for energy efficiency measures to PGE's customers over one average megawatt?

A. The ETO will limit funding of energy efficiency measures directed to industrial customers. Given that industrial customers currently present a significant portion of cost-effective, energy-efficiency opportunities for the ETO, PGE is concerned that such a response would lower overall PGE acquired energy efficiency. This, in turn, impacts the ETO's ability to meet the targets used in the IRP. PGE's interest is that the ETO pursue all cost-effective energy efficiency; but because of the cap, not all cost effective energy efficiency will be pursued.

Q. Is the ETO concerned about the cap?

A. Yes. In its June 2013 briefing paper for the ETO Board of Directors on ETO energy efficiency programs, the Energy Trust states that given trends in program investment, spending for large customers of PGE will need to be curtailed in 2015 or sooner. The Energy Trust shares PGE's concern that given the funding limitation, the ETO may not be able to secure all cost-effective, energy efficiency from the large customers. In fact, the ETO's 20-year resource assessment shows that more than 50% of energy efficiency savings potential in large sites remains to be acquired. If incentive funding is capped for those sites, the ETO predicts that over the next five years, 8-12 aMW of savings could be lost and 32-48 aMW lost over twenty years.

Q. What does CUB propose?

A. CUB proposes including energy efficiency in the generation marginal cost of service study.

Q. What is PGE's response to the CUB proposal?

A. PGE understands the fairness issues being raised by CUB, including concerns that residential customers are paying disproportionately for energy efficiency. However, CUB's proposal goes beyond traditional marginal cost analysis and it may draw legal challenges. The resulting rate impacts of CUB's proposal are significant for the larger industrial customers and may create an incentive for them to choose direct access.

Q. How does CUB's proposal go beyond traditional marginal cost analysis?

A. Marginal cost analysis is aimed at determining the cost of generating an additional increment of output (marginal generation capacity and marginal energy costs) to meet an increment of load, so that prices can lead to efficient consumption decisions by consumers. Energy efficiency is not a traditional capacity or energy resource.

Q. What does the legislation require?

A. Senate Bill 838, at Chapter 301 Oregon Laws 2007, Section 46 directs the OPUC to ensure that a retail electricity customer with a load greater than one average megawatt is not required to pay an amount that is more than three percent of the customer's electricity cost for the public purpose charge and does not receive any direct benefit from the energy efficiency measures if the costs of the measures are included in rates under SB 838.

Q. Please explain PGE's concern that CUB's proposal may incent large industrial customers to choose direct access.

A. Given the double digit rate impacts of CUB's proposal and the fact that direct access customers do not pay the energy cost to PGE (which is where the marginal cost of energy efficiency as a resource would be included), industrial cost of service customers may be incented to choose long term direct access to avoid the rate increases imposed by CUB's proposal.

Q. What does PGE propose with regard to the cap?

A. Given the statutory prohibition on industrial customers bearing costs associated with SB 838 energy efficiency measures, ratemaking may not be the means to address CUB's concern. The only solution may be a legislative solution. For this reason, PGE does not have a counter proposal to CUB's but offers a willingness to engage with the parties to work on a solution, legislative or otherwise.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT NO. ICNU/406

EXCERPT OF REVISED SURREBUTTAL TESTIMONY AND EXHIBITS OF PGE (PGE/2200 – PGE/2201) IN DOCKET NO. UE 283

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Revised Surrebuttal Testimony of

Jay Tinker
Dave Robertson

September 9, 2014

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I. Introduction

Q. Please state your name and position with Portland General Electric (PGE).

A. My name is Jay Tinker. I am the Director of Rates and Regulatory Affairs at PGE. My qualifications appear in PGE Exhibit 1600. My name is Dave Robertson and I am Vice President, Public Policy for PGE. My qualifications appear at the end of this testimony.

Q. Why is PGE filing this revised testimony?

A. Following our surrebuttal filing, we noted that there was some ambiguity in our testimony on the SB 838 legislative history. This revised testimony clarifies our recollection as it relates to views expressed by the Citizens Utility Board (CUB) during the 2007 legislative session on PGE's proposed additional energy efficiency funding paid by residential and commercial customers. In addition to clarifying earlier testimony, Dave Robertson, PGE Vice President for Public Policy, is added as a witness.

Q. What prompts this revised filing?

A. The ambiguity in our original surrebuttal policy testimony was brought to our attention by Bob Jenks from CUB, during a meeting on Friday, September 5, 2014.

Q. What is the clarification?

A. In early 2007 during our discussions with CUB on the potential for legislation during the 2007 legislative session to provide additional energy efficiency spending, CUB raised concerns that if they were to support additional energy efficiency funding paid by residential and business customers, then they wanted assurances that large industrial customers would not receive direct benefits from energy efficiency projects carried out with those funds, generated from legislative language adopted as part of Senate Bill 838 (SB 838). Our recollection is CUB was concerned that the additional energy efficiency funding paid by residential and commercial customers would lead to a shift of the SB 1149 public purpose energy efficiency funding to fund more industrial measures. CUB ultimately supported the energy efficiency amendment to SB 838, and we believe CUB would not have supported the legislation without a broad understanding among the stakeholders that the funding would not lead to the undesired shift in 1149 dollars.

Q. Did you find any corroboration that PGE provided assurances to CUB's concerns?

A. Yes. We found a letter in our archives, that while unsigned we believe was sent to CUB around February 2007, setting forth the principle of excluding Schedule 89 customers from the then-new initiative. We state:

> The intent here is 'no pay, no play.' In asking the OPUC to exempt these customers, we would also ask that they work with the ETO to cap public purpose charge expenditures on behalf of this group at current levels. If later it appeared that more cost effective EE was available through these customers, and they were willing to pay for it, adjustments could be made.

The letter is attached as PGE Exhibit 2201.

Q. In addition to this explanation for the revision, are there any other changes in testimony?

A. Yes. We made clarifying changes to pages 6, 7, and 8. For ease of tracking, we are submitting the redlined testimony as well. In addition, we noted that a footnote was dropped in finalizing our testimony and have added it back to page 7.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony is to address the remaining policy issue discussed by other parties in their rebuttal testimony. I also introduce other concluding PGE testimony in Docket No. UE 283.

Q. How is your testimony organized?

A. In this section, I provide an update of this rate case. In the next section, I address the Citizens' Utility Board of Oregon's (CUB) position that energy efficiency is a marginal resource and should be included in the marginal cost of service study.

Q. What is the current status of the UE 283 proceeding?

A. PGE and other parties held settlement discussions on May 20 and 27; on July 7, 8, 11, and 28; and on August 19. During those meetings the parties settled all but one issue. We also held settlement discussions in Docket No. UE 286, which addresses the bifurcated power costs for the 2015 test year and settled all power cost issues as well.

Q. What is the revised net increase proposed for this case?

A. As demonstrated in PGE Exhibit 2300, the revised increase in this case, including changes to base business and trackers for Port Westward 2 and the Tucannon River Wind Project, total approximately $45.8 million. As stated in our initial filing, however, PGE is also proposing to apply customer credits totaling approximately $29.0 million on January 1, 2015. Consequently, the requested net increase based on all components is currently proposed to be approximately $16.8 million. This represents a very moderate increase for two new generating plants that are the primary drivers of this case.

Q. How do these amounts compare to PGE's initial filing?

A. PGE's initial UE 283 filing on February 13, 2014, requested a net increase of approximately $81.5 million for all the components listed above.

Q. What other Surrebuttal Testimony is PGE submitting?

A. PGE submits surrebuttal testimony in the following areas:

- 2300 – Revenue Requirement. This testimony summarizes PGE's revised revenue requirement based on all updates and stipulations

- 2400 – Port Westward 2. This testimony supplements the record regarding the development, selection, and execution of the Port Westward 2 flexible capacity resource.

II. Energy Efficiency in Marginal Costs

Q. Please summarize the parties' rebuttal testimony.

A. Staff, while sympathetic to CUB, does not support CUB's approach of including energy efficiency as a marginal cost resource, suggesting that this may violate Senate Bill 838 and the solution may rest with the legislature. The Industrial Customers of Northwest Utilities (ICNU), sensitive to the double digit impact on large industrial customers from CUB's approach, asserts that the approach violates the law and works contrary to the Public Utility Commission of Oregon's (PUC) policy to encourage energy efficiency. ICNU's proposed solution is to lift the Energy Trust of Oregon's (ETO) 18% cap; in essence, lifting the limitation on Senate Bill 1149 funds used for large customer energy efficiency measures to allow the ETO to acquire cost-effective, energy efficiency measures without regard to the customer class producing them. The Northwest Energy Coalition raises concerns that the cap will be reached in 2014 and states its preferred solution is legislative. In their rebuttal testimony, CUB defends its proposals and alleges that PGE is acting too passively and imprudently by not proposing a solution.

Q. How does PGE respond to the allegation that PGE has been imprudent because it does not propose a solution?

A. PGE is acting prudently by working within existing laws and processes. While utilities were responsible to administer energy efficiency programs prior to 2002, Senate Bill 1149 removed the utilities from energy efficiency work, and delegated to the Commission the authority over energy efficiency spending. The solution to the problem posed by the cap does not rest with PGE alone, but with the Commission, the ETO and the parties to the informal agreement establishing the cap, particularly ICNU and CUB. PGE is available to support a consensus solution.

Q. PGE states it is acting within the existing laws and processes for obtaining energy efficiency. What do you mean?

A. The existing structure for energy efficiency is that PGE collects monies from customers pursuant to Senate Bills 1149 (SB 1149, public purpose charge) and 838 (SB 838, additional energy efficiency funding) and sends the bulk of the funds to the ETO for energy efficiency acquisition. With regard to SB 838 funding, PGE works with the ETO to identify all achievable energy efficiency and includes this target in its Integrated Resource Plan; the ETO designs its programs to acquire all the cost-effective energy efficiency it can, consistent with SB 838's limitations that customers over one average megawatt do not receive a direct benefit.

Q. Regarding the SB 1149 public purpose charge, does the law specifically restrict the customer groups from which energy efficiency is obtained?

A. No. Of the three percent public purpose charge collected from utility customers, 56.7% is distributed to energy efficiency. The funds are distributed by the ETO to benefit customers. The ETO aims to obtain the most cost-effective energy efficiency, targeting opportunities with residential, commercial, and industrial customers. Dynamic factors, including technology and the economy, drive the sectors from which energy efficiency opportunities exist. For example, in the ETO's early years much of the ETO's savings came from compact fluorescent lights (CFLs) and much of that among residential customers. The energy efficiency savings were abundant and low cost. In its 2015-2019 Draft Strategic Plan prepared for its Board of Directors, dated June 13, 2014, the ETO reports that after many years of energy efficiency, mainstays such as residential insulation, central heat pumps, energy-efficient showerheads and non-LED efficient lighting are nearing a point of market saturation. There are greatly diminished cost-effective residential savings opportunities like CFLs but there are numerous high-tech energy efficiency programs, particularly around new construction and data centers. In the future, the opportunities may again rest with residential customers. To some extent, there will always be groups funding disproportionately to the direct benefit they receive, but over time that may balance out.

Q. If there is no restriction on how SB 1149 funds are spent, why did the stakeholders informally agree to limit the ETO spending of SB 1149 energy efficiency funds after SB 838 was enacted?

A. PGE's informal agreement to support limits in SB 1149 spending, was reached in the legislative session while the proposal for additional energy efficiency was pending. This was necessary to secure CUB's support for the legislative concept. During the 2007 legislative session, PGE had discussions on the concept of additional energy efficiency and CUB expressed a concern that, if the additional energy efficiency funding were provided then it may lead to a shift in SB 1149 energy efficiency funding toward greater industrial spending. From CUB's expressed concerns, such a shift would erode the SB 838 prohibition against large industrial customers directly benefitting from the funding. After passage of SB 838, the ETO, Staff, CUB, ICNU, and the utilities informally agreed to set the cap based on an historical level of SB 1149 funding for large industrial energy efficiency in each utility's service area.

Q. What is the history of the additional SB 838 energy efficiency funding and how it would be spent?

A. The additional SB 838 energy efficiency funding resulted from PGE and other stakeholders' discussions of the concept during the 2007 legislative session. PGE intended for the additional funding to reach all cost-effective energy efficiency potential identified in PGE's IRP. In particular, opportunities were identified among small and medium sized businesses, schools, and moderate-income residential customers. We also stated that our IRP resource analysis[1] showed no incremental opportunities for industrial customers above the ETO forecast and thus, industrial customers would neither receive the benefit from, nor contribute to, the cost of the additional funding.

Q. Please discuss the no-direct-benefit provision in SB 838 and its meaning.

A. In the section providing for energy efficiency funding, in addition to the public purpose funding (Section 46 of SB 838), the Commission is to ensure that large industrial customers not be required to pay more than the 3% public purpose charge and not receive any direct benefit from the energy efficiency measures if the cost of the measures are funded by the SB 838 charges, which are collected from residential and commercial customers. We have reviewed our records and not found anything that defines direct benefit.

Q. What does PGE mean by "direct benefit" with regard to energy efficiency?

A. When PGE discussed energy efficiency benefit in the legislature, we were referring to the incentives paid and the corresponding specific load reductions derived from energy efficiency measures funded by the ETO. In this instance, the customer receives the benefit of the reduction in usage but they also pay a large share of the cost of the energy efficiency measure(s) installed. We did not intend to include, as a direct benefit, the overall customer

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[1] See PGE's 2007 Integrated Resource Plan, pages 60-63, Docket No. LC 43.

benefit from lower system costs produced when energy efficiency replaces the acquisition of new supply-side resources. That would be an indirect benefit, which all customers will realize.

Q. Does PGE agree with CUB's assertion that the direct benefit prohibition in SB 838 extends to reduced costs from system benefits?

A. No.

Q. Since PGE does not support CUB's reallocation of marginal energy costs, what does PGE recommend with regard to achieving all cost effective energy efficiency and the 18% cap?

A. Given the PUC's direct authority over the manner in which public purpose funds are collected and spent, and its oversight authority of the ETO to ensure that the Trust produces a high level of energy efficiency savings, PGE recommends that the Commission either resolve the cap issue in this case or alternatively, open an investigation or a policy docket, if it requires further information. If a policy docket is chosen, the following questions or issues are suggested:

- Are large customers receiving a direct benefit from SB 838 funded energy efficiency?
- What are the barriers to the ETO of obtaining all cost-effective energy efficiency?
- What other options exist to gain all cost effective energy efficiency, including from large industrial customers?
- Should the ETO approach be flexible to take advantage of energy efficiency savings brought about by changes in technology and the economy?
- Should there continue to be a cap, and if so, what criteria should be used to set it?

III. Qualifications

Q. Mr. Robertson, please describe your educational background and experience.

A. I received a Bachelor of Science/Arts degree from Willamette University in political science. In addition, I have taken the utility executive course in utility management from the University of Idaho. I joined PGE in 2004 as the Director of PGE's Governmental Affairs departments. I entered my current position as Vice President, Public Policy, in 2009, and oversee PGE's corporate communications, government relations, environmental policy and community affairs.

I also serve on several community and business boards including the executive committee of the Portland Business Alliance, the Oregon Business Association Board, and Portland Center Stage Board.

Q. Does this conclude your testimony?

A. Yes.

Date is auto-filled

Dear Jason/Bob,

When we met last month to discuss PGE's proposed plan to acquire more cost-effective energy efficiency, I attempted to clarify a few points we made in the proposal and agreed to get back to you with more details on some of the recommendations. This letter formalizes the concepts and clarifications that I provided at that time.

PGE Requirements – A strong say in how the money gets spent

Both CUB and the ETO Policy Group voiced concern that PGE might attempt to exert too much control over how the ETO spent energy efficiency dollars. It is PGE's intention to have the targets for incremental EE established as part of its acknowledged Integrated Resource Plan. We would influence how the money gets spent by presenting proposals in that planning process and urging the OPUC to adopt these proposals. We expect the OPUC would then direct the ETO how to spend any funds collected by PGE to implement adopted proposals. We don't anticipate exerting strong influence over the ETO's use of any of the funds provided they are being expended consistent with the acknowledged Integrated Resource Plan and the OPUC's directions.

Exclude Schedule 89 Customers (>1MW) from new initiatives and associated costs

The intent here is 'no pay, no play'. In asking the OPUC to exempt these customers, we would also ask that they work with the ETO to cap public purpose charge expenditures on behalf of this group at current levels. If later it appeared that more cost-effective EE was available through these customers, and they were willing to pay for it, adjustments could be made.

Near zero risk of non-recovery of all costs

Post SB1149, it is not clear that the OPUC can authorize rate recovery of funds that PGE spends on energy efficiency. Paul Graham believes that the limitations were intended to preclude duplicative spending during the implementation of SB1149. Since we are past that point, we ought to be able to delete the language that causes the uncertainty, specifically:

"The commission shall remove from the rates of each electric company any costs for public purposes described in subsection (1) of this section that are included in rates. A rate adjustment under this paragraph shall be effective on the date that the electric company begins collecting public purpose charges".

PGE intends to pursue this legislative change.

New full-time positions and marketing expenditures in support of EE

CUB expressed concerns about the roles and responsibilities of new positions at PGE in support of EE (e.g. would they duplicate existing positions in other organizations?). There were also concerns about the nature of the marketing activities that would be undertaken (e.g. would the activities directly support ETO programs or would they be designed to support PGE's image in EE?). Expected roles and responsibilities of the new positions as well as a description of anticipated marketing activities are outlined below:

Key Job Responsibilities, Outreach FTEs – ETO programs (additional 3.5 FTEs recommended)

These positions are intended to facilitate effective and efficient delivery to small/medium business customers of ETO programs.

- Build and maintain strong relationships with professional and trade associations that support EE programs.
- Work collaboratively with the ETO and ODOE to identify and target specific market sectors for outreach.
- Take prospects identified in PGE's contact center and facilitate their reaching appropriate programs and services.
- Conduct walkthroughs of customer facilities and recommend areas of opportunity.
- Meet with key decision makers at a company and effectively advocate the appropriate energy efficiency solutions to meet their needs.
- Present all key ETO and ODOE program elements to the customer and ensure their understanding of program benefits and timelines and options.
- Connect customers to program vendors.
- Help customers review vendor proposals.
- Provide project management assistance such as mapping out timelines, identifying milestones, etc.
- Facilitate verification when project completed.
- Ensure required program forms are filled out and submitted to ETO and ODOE.

Key Job Responsibilities ESD/Schools Support (2 incremental FTEs)

These positions are intended to aid ESDs that have had trouble getting projects underway and to reinstitute valuable assistance in the areas of education and training.

- Review current audits and update as appropriate.

- Identify financing options to implement programs, such as performance contracting or managing Energy Tax Credits.
- Provide project management assistance to:
  - map out project steps and identify project milestones,
  - get RFPs issued to vendors,
  - choose appropriate vendors,
  - complete needed forms,
  - facilitate and/or conduct inspections and verifications when warranted.
- Train maintenance staff in using new measures to ensure maximum energy efficiency achieved and work with them to ensure persistence.

Key Job Responsibilities Low Income Support (5.5 incremental FTEs)

CAP agencies have not increased staff to fully utilize SB1149 funding. These positions supplement the 2.5 existing PGE FTEs who facilitate work with the counties and CAP Agencies to meet this gap.

- Assist CAP organizations to conduct audits and identify needed measures for qualifying homes.
- Work with CADO organizations to implement recommended measures.
- Inspect and verify completed work. Train homeowner in using new measures most effectively.
- Conduct energy efficiency classes for program recipients/agency clients.

Marketing Support (no incremental FTEs)

This funding and activity is designed to market and promote programs (primarily ETO's) to our customers, in the residential market, where our communications vehicles, data bases and customer knowledge position us to be particularly efficient and effective.

- Market Assessments to more precisely identify underserved markets to share with ETO (required by new IRP process guidelines).
- Develop targeted lists of PGE customers for ETO program outreach.
- Have resources available to meet with and otherwise support the ETO in program development and review.
- General customer communication on ETO programs, such as newsletters, bill inserts, web presence.

- Increased corporate advertising focus on energy efficiency (will be managed carefully to ensure considered appropriate by stakeholders).

- Customer surveys to check that customers are aware of the programs and that program participants are satisfied.

- Educational outreach not covered above.

I hope you find these clarifications to be consistent with our discussion. Any input you might have would be appreciated.

Regards,

Joe Barra,
Director, Customer Energy Resources

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT NO. ICNU/407

EXCERPT OF STAFF REBUTTAL TESTIMONY (STAFF/1300)

IN DOCKET NO. UE 283

CASE: UE 283
WITNESSES: GEORGE R. COMPTON
& SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF JOINT EXHIBIT 1300

Remaining Rate Spread/Cost-Of-Service Issues

August 13, 2014

Q. Please state your names, occupation, and business address.

A. My name is George R. Compton. I am a Senior Economist in the Energy – Rates, Finance, and Audit section of the Public Utility Commission of Oregon. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088.

My name is Suparna Bhattacharya. I am a utility Economist in the Energy – Rates, Finance, and Audit section of the Public Utility Commission of Oregon. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088.

Q. Have you filed opening testimony in this proceeding?

A. Yes, we filed opening testimony Exhibit 700 and Exhibit 800; our qualification statements are provided in Exhibit Staff/ 701 and Exhibit Staff/801.

Q. What is the purpose of this testimony?

A. In this testimony we respond to the Energy-Efficiency (EE) and Marginal-Cost-of-Service and related rate spread issues that are addressed on behalf of the Citizens' Utility Board of Oregon (CUB) by Bob Jenks and Jaime McGovern in their joint Opening Testimony, Exhibit CUB/100.[1]

CUB's Proposal to Re-Allocate Energy Costs from Residential to Industrial Customers: Introduction

Q. Have you reviewed Section IV labeled "Energy Efficiency and Marginal Cost of Service," and Section V, labeled "Overcoming the Cap on Industrial EE" of CUB's Opening Testimony?

A. Yes.

[1] "IV. Energy Efficiency and Marginal Cost of Service," CUB/100, Jenks-McGovern/20. Related is "V. Overcoming the Cap on Industrial EE," CUB/100, Jenks-McGovern/37.

Q. What are the primary concerns expressed by CUB in Sections IV and V of their testimony?

A. The two primary concerns are: 1) a legal cap placed upon energy efficiency (EE) projects conducted by the ETO (Energy Trust of Oregon) for PGE's industrial customers is being reached, thereby compromising best-cost-efficiency opportunities;[2] 2) ETO contributions from the residential class far outstrip the project funding directed back to that class.[3] A prime source of these concerns is the fact that "SB 838 allowed additional funding for EE, but put a cap on the amount of funding that a utility could receive from customers with loads of more than 1aMW."[4] The industrial EE project cap is generally viewed as the quid pro quo of the cap placed on the funding paid out by those large customers. Limits placed on EE funding by large industrial customers are supposed to translate to limitations placed on the "direct benefits" which those customers receive from EE.

Q. What is the primary mechanism that CUB suggests for dealing with these concerns?

A. CUB suggests including energy efficiency within the marginal cost of service. They introduce a methodology that would credit the residential class for its full ETO contributions by way of a reduced energy cost allocation that would be offset by an increased allocation to industrial customers.[5]

Q. How, in CUB's estimation, would altering the energy cost allocation resolve the concerns identified above?

A. In CUB's view, shifting a significant portion of the revenue requirement from residential customers to industrial customers corrects the inequity of residential ratepayers' funding, through the ETO, more industrial energy efficiency projects than residential projects.[6] Also, CUB believes that increasing the industrial

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[2] *See* CUB/100, Jenks-McGovern/37, Section V.
[3] *See* CUB/100, Jenks-McGovern/28, lines 14-20.
[4] *See* CUB/100, Jenks-McGovern/42, lines 14-16. SB 838 and its implications are discussed in some detail later in this testimony.
[5] This is the subject of Section IV. of CUB's testimony (CUB/100, Jenks-McGovern/20-37).
[6] *See* CUB/100, Jenks-McGovern/39, lines 10-20.

revenue requirement would neutralize the prohibition against "direct benefits" that industrial customers would derive from the added EE made possible by SB 838.[7] Eliminating *net* benefits would render moot the basis of the cap placed by SB 838 on the funding of any industrial EE projects possibly attributable to the added revenues collected under SB 838.

Q. Do you agree with how CUB would resolve their concerns in this general rate case? If not, why not?

A. While Staff is sympathetic to both issues CUB is addressing, we do not agree--for two primary reasons. First, we believe CUB's approach may violate SB 838, which in Staff's estimation places both a cap on charges for energy efficiency funding that can be assessed to industrial customers larger than 1 aMW and limits the amount of ETO funding that can be directed to EE projects for those same customers. The CUB approach would allow a portion of the additional Energy Trust funding provided by residential customers under SB 838 to benefit the specific individual industrial customers, including customers over 1 aMW, who participate in ETO-funded projects. At the same time, all industrial customers would receive a rate increase due to the cost allocations shift away from residential customers. Both outcomes appear to be in conflict with SB 838.

Second, we do not believe, given the PGE resource supply and cost structure, that EE/conservation (ETO funded or otherwise) constitutes a marginal cost resource for the purpose of rate case cost allocations and pricing.

I. Energy Efficiency as a Marginal Cost Resource

Q. What is the basis for CUB's assertion that energy efficiency is a marginal cost resource?

A. They say, "for Oregon residential customers, EE [energy efficiency] has been the primary resource added to meet growth. Therefore, as the go-to resource,

[7] *See* CUB/100, Jenks-McGovern/36, lines 2-6; and Jenks-McGovern/38, lines 13-23 through Jenks-McGovern/39, lines 1-9.

EE must be included in the modeling of energy marginal costs."[8] CUB also shows EE comprising 20% of PGE's 2025 "projected cumulative new resources," with base-load gas only comprising 51%.[9]

Q. Do you consider EE as a marginal cost resource?

A. No. EE is a system resource that is comparable to conventional generation resources in the sense that EE can supplant or be a substitute for the latter. But that comparability does not make EE a marginal cost resource. A marginal cost resource is one whose level is adjusted up or down to meet changes in electricity use. While EE has taken place and in the future will continue to take place in the presence of load growth, and while the presence of EE allows PGE to install less gas capacity than otherwise, load growth, per se, does not cause EE to occur at the high level that is being projected.

Conservation/EE is acquired to the extent money is available to fund Energy Trust activities. *An increase or decrease in loads does not cause an increase or decrease in EE in order to meet that increase or decrease*. Given PGE's resource supply mix and cost structure, the overriding consequence of PGE adjusting future growth projections would be to alter the megawatts of thermal capability connected with the 51% gas plant figure noted above.[10]

It is true that were there no growth in loads or no need to replace plant that is retired due to age or obsolescence, there would be less value in conservation because no new plant or other capacity investment would be avoided due to the improved energy efficiency.

Q. Earlier you made the connection between having a marginal cost resource and pricing. Would you please elaborate?

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[8] *See* CUB/100, Jenks-McGovern/20, lines 17-20.

[9] *See* CUB/100, Jenks-McGovern/32.

[10] If, for example, PGE were to elevate its 2030 growth needs by 100 aMW (gross of conservation), the expected added capacity expansion would be nearly 75 aMW of thermal, and nearly 25 aMW of renewable resources, with the only aMW of EE being what was funded by the extra ETO revenues generated by the added gross revenues associated with the added 100 aMW of load.

A. In their Reply Testimony explaining how "CUB's proposal go[es] beyond traditional marginal cost analysis," PGE's Jay Tinker and Christopher Liddle say the following (with my addition in brackets):

> Marginal cost analysis is aimed at determining the cost of generating an additional increment of output (marginal generation capacity and marginal energy costs) to meet an increment of load, so that prices can lead to efficient consumption decisions by consumers. Energy efficiency is not a traditional capacity or energy resource [in the sense that it is adjusted upwards or downwards in the presence of conventional increases or decreases in electricity demand].[11]

An economic ideal is to have electricity prices reflect marginal energy and capacity costs. It has long been Oregon's regulatory policy to allocate costs in a manner in keeping with that economic ideal—hence the use of what are effectively marginal costs for the purpose of allocating costs among customer schedules rather than using, solely, embedded/average costs.

Conservation should be part of any analysis to supply electricity at least cost. However, cost effective conservation should be acquired regardless of load growth and from that standpoint is not a resource that is added primarily if there is additional electricity use or a requirement to replace fully depreciated plant with expensive new plant.

II. CUB's Proposal is of Dubious Legality

Q. Earlier in this testimony you mentioned CUB's complaint that "ETO contributions by the residential class far outstrip the project funding directed back to that class," and that, according to CUB, this inequity should be rectified by "shifting a significant portion of the revenue requirement from residential customers to industrial customers" via the marginal cost study. What is CUB's cost re-allocation mechanism by which that objective would be accomplished?

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[11] *See* PGE/1600, Tinker-Liddle/26, lines 11-15.

A. CUB's approach is to *not* base the different rate schedules' energy cost allocations on the shares of energy consumed by each schedule but rather on what those shares would be if subtracted from each schedules' consumption was an amount of aMW of conservation that was secured by that schedule's ETO contributions—regardless of where the ETO projects were actually targeted. Based upon the previously mentioned 20% "contribution" towards "cumulative new resources,"[12] the total secured conservation figure used by CUB is 20% of the load projected for cost allocations purposes. Each customer schedule would have its allocated load reduced by the portion of that 20% that it funded, i.e., without regard for what schedules actually had their loads reduced by the ETO-funded conservation projects.[13] This way, for example, if the residential class funded half of the ETO projects, it would have its load reduced for marginal cost allocations purposes by the entire amount of aMW that were avoided by half the projects *even if the entire ETO funding was dedicated to projects that actually reduced large industrial loads* and nothing went to reducing residential loads.

Q. For customer schedules to reap the benefits of what they paid for sounds eminently reasonable. What could be wrong with that?

A. As stated in the introductory segment of this testimony, Staff has legal concerns regarding CUB's approach.

Q. Would you please provide some background on the legal issues?

A. The 2007 legislature adopted SB 838. It authorized, for all but the largest customers, public purpose charges beyond the standard 3% level that was introduced by SB 1149. To avoid inequities caused by the larger customers' not sharing in the increased ETO burden, SB 838 declares that those customers should not benefit from projects bankrolled by the added funding coming from the other customer schedules.

Q. What is the precise SB 838 text to which you refer?

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[12] *See* CUB/100, Jenks-McGovern/32.
[13] CUB describes this methodology at CUB/100, Jenks-McGovern/31-34.

A. It is as follows:

> (2) The commission shall ensure that a [added emphasis] retail electricity customer [singular, added emphasis] with a load greater than one average megawatt:
> (a) Is not required to pay an amount that is more than three percent of the consumer's total cost of electricity service for the public purpose charge under ORS 77.612 and any amounts included in rates under this section; and
> (b) Does not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates under this section.

Q. Attempting to make straightforward interpretations of the above language, how might you question the legality of the CUB proposal which you have just described?

A. First, the CUB plan does nothing to limit the benefits received *individually* from large industrial customers who are fortunate to receive EE funding from the ETO for projects specific to those customers. In fact, CUB lauds its proposal for its ability to, in its estimation, get around the direct-benefit provision of (2)(b) by virtue of its causing industrial customers to experience a rate increase that would offset the benefits those customers receive from the EE projects.[14] But, obviously, the EE projects won't be spread uniformly across the industrial class. *Some* industrial customers will benefit far more than would be offset by the rate increase they would share with *all* of the industrial class. Staff concludes that CUB's approach will allow continued EE funding to large industrial customers, which would violate the (2)(b) prohibition against a large customer receiving a direct benefit (via a dedicated ETO EE project) from the additional EE funding made possible by SB 838.

Second, the added industrial rate increase perpetrated under the CUB proposal is inconsistent with (2)(a) of SB 838, which prohibits a large customer

[14] The industrial rate increase makes possible the residential rate decrease, which in turn compensates the latter customers for their added ETO funding, most of which ostensibly would be going into the industrial EE projects. *See* CUB/100, Jenks-McGovern/41, line 18 to Jenks-McGovern/42 ("Section E. Implementing CUB's Proposed Marginal Cost Study Will Allow Residential And Small business Customers To Purchase All The Cheap EE Available From Industrial Customers Because Residential And Small Business Customers Will Get Credit For That Purchase").

(whether or not it participates in any ETO EE projects) from having to pay more than the three percent standard for, or in behalf of, "the public purpose."

Q. You just referred to the "prohibition against a large customer receiving a direct benefit (via a dedicated ETO EE project) from the additional EE funding made possible by SB 838" Doesn't CUB propose to get around that stricture by imposing a separate definition of "direct benefit"—i.e., by asking "the Commission [to] recognize that the direct benefit of EE is lower power costs, and not the receiving of incentive payments" for EE projects. CUB continues, "then the proper way to implement the SB 838 cap would be to place the cap on the receipt of direct benefits [as just defined by CUB] and not on the receipt of incentive payments through EE programs aimed at a customer class [in our case the large industrial customers]. This could be done by implementing the marginal cost/cost allocation approach advocated for by CUB."[15] Please respond.

A. Preceding your citation was the sentence, "The direct benefit to all customers (industrial and non-industrial alike) is the lower cost associated with energy efficiency."[16] Staff agrees that all customers benefit *on a systems basis* from cost-effective EE. But even if the CUB-defined direct benefits to large industrial customers are precisely offset by their proposed rate increase[17], there remain the benefits which *some* customers receive *directly* from the ETO-funded EE projects dedicated to *them*. Are we supposed to refer to these latter benefits as "indirect benefits"? I would say that it makes more sense to refer to these latter as the "direct benefits," with the *system* benefits that all customers receive from the specific EE projects labeled as the "indirect benefits." But the point is that however one chooses to label the benefits that the target customers receive from the EE projects, they are benefits indeed. In saying that the large customers are "not [to] receive any direct benefit from [the designated]

[15] *See* CUB/100, Jenks-McGovern/38, lines 21-23 through Jenks-McGovern/39, lines 1-3.
[16] *See* CUB/100, Jenks-McGovern/38, lines 19-20.
[17] As a technical matter I did not see where CUB actually measured the system benefit from EE in terms of reduced power costs to large industrial customers so that they could be offset by some rate increase to those customers.

conservation measures," clause (2)(b) should not be held hostage to a semantic distinction as to what constitutes a direct benefit versus what constitutes an indirect benefit.

Q. Have you prepared a simplified numerical example that captures the essence of the CUB approach and illustrates how the cited passages from SB 838 would be violated by its adoption?

A. Yes I have. The following shows ETO-funded conservation reducing loads by 20%. For illustrative purposes, and in keeping with the presumption that the funding of industrial EE is more cost-beneficial than funding residential EE, the entire load reduction occurs with the industrial class, although the large bulk of the ETO funding comes from the residential class. As seen below, the CUB approach adjusts loads *for allocations purposes* in order to reflect differences in ETO *funding* between the customer classes.

Hypothetical Loads *Absent* ETO-Funded Conservation

Customer Class	Hypothetical Load
Residential	700 aMW
Industrial	500 aMW
Total	1,200 aMW

Achieved Loads and Conventional Energy Cost Allocations

Customer Class	Actual Load	Share of Energy Costs
Residential	700 aMW	70%
Industrial	300 aMW (1)	30%
Total	1,000 aMW	100%

CUB'S Alternative Energy Cost Allocation Approach

Customer Class	Adjusted Load	Share of Energy Costs
Residential	520 aMW (3)	65%
Industrial	280 aMW	35%
Total	800 aMW (2)	100%

(1) In this example, all of the ETO-funded EE goes to the Industrial Class (reducing the load from 500 aMW to 300 aMW). For illustration purposes, the level of EE is exaggerated.

(2) The adjusted total load is reduced by 20% from the projected actual load as justified by CUB above in this testimony.

(3) The Residential Class receives a much larger load reduction *adjustment* (from 700 aMW down to 520 aMW) due to having contributed proportionately more to the ETO funding

> pool than, by assumption, did the Industrial Class. This same disparity in ETO contributions is shown in Jenks-McGovern's Table 7[18], where, for example, Residential Schedule 7 is shown (in the first numerical column) as having only slightly more than 7 times the load of Industrial Schedule 89, but benefits from some 34 times the energy allocation offset (column 3) due to, ostensibly, having made 34 times Schedule 89's ETO contribution.

What we see from this example is that the relative generosity of the Residential Class in supporting "outsized" ETO-funded industrial EE causes the Industrial Class to experience a rate increase in the sense that it would bear energy costs (at 35%) that are above its proportion of energy consumption (at 30%). That rate increase will apply to all the industrial customers—not just to those who benefit directly from the ETO-funded conservation projects.

Q. What does Staff conclude from your numerical illustration?

A. Funding additional EE for industrial customers, including customers over 1 aMW, and increasing the rates for these customers are contrary to a plain reading of SB 838.

Q. Having rejected the CUB approach, how would Staff eliminate the concerns about industrial customers receiving outsized EE benefits compared to their ETO contributions?

A. "Fairness" holds that since all customers benefit equally from *system* benefits obtained from ETO-funded EE, all customers should contribute equally.[19] The obvious legal remedy to achieve this would be to repeal, or dramatically revise, SB 838 so that all customers would indeed contribute equally. Also implied in statements by CUB is that the public purpose charge should be applied just to the energy portion of customers' bills, not to the entire portion.[20] Residential customers bear a differentially greater burden due to their disproportionately

[18] *See* CUB/100, Jenks-McGovern/34.

[19] As CUB has said, "[t]he direct benefit of any EE investment is the benefit of a system that functions at a lower cost and functions more efficiently. [All] Customers benefit from EE because it lowers the costs of the utility and puts downward pressure on rates. Large customers benefit for the same reason as all customers." CUB/100, Jenks-McGovern/41, lines 10-13.

[20] *See* CUB/100, Jenks-McGovern/26, lines 10-20.

greater distribution costs compared to what are incurred by large industrial customers.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT NO. ICNU/408

PGE 2016 REPORT – GREATER THAN 1 aMW ANALYSIS PROJECT

Greater Than 1 aMW Analysis Project

Portland General Electric (PGE) 2016 Report

Prepared by CLEAResult for:
Energy Trust of Oregon
06.21.2017

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PROJECT OVERVIEW

The purpose of this project is to determine the percentage of SB 1149 funds that Energy Trust spent on sites that used more than 1 aMW (>1aMW) in 2016. This percentage was compared to Energy Trust's historical spending percentages from 2005-2007 to determine if spending on this group of customers has changed since the inception of SB 838.

PROJECT RESULTS

Key Findings

- While overall 1149 revenue ($28 million) in 2016 was close to 2015, >1aMW incentives increased by almost $1.4 million
- Total kWh savings for PGE in 2016 increased by over 23.5 million kWh while savings at >1aMW sites decreased by 3.5 million kWh during the same period
- The cumulative post-838 share of 1149 revenue spent on incentives at >1aMW sites saw an increase from 18.2% to 18.7% due to the increase in spending in 2016, meaning the pre-838 baseline of 18.4% has been passed

In 2016, total incentive spending on >1aMW users was 23% of SB 1149 revenue, an increase of 6% since 2015 and the highest level since 2013. Average spending per site was up to $103,000 from an average of $86,000 last year, while average savings was down to 592,000 from kWh from an average of close to 695,000 kWh in 2015. Table 1 also shows the average percentage of SB 1149 revenue spending on >1aMW customers since 2008, and the percentage of total savings from >1aMW customers.

Table 1: Comparison of analysis and results 2014 -2016

PGE >1aMW Customer Activity	2014	2015	2016	Change in Overall Percentage
% 1149 revenue to >1aMW customers	19.6%	17.4%	22.8%	5.4%
Cumulative average % 1149 revenue to >1aMW customers since 2008	18.3%	18.2%	18.7%	0.5%
% Total kWh savings from >1aMW customers	23.0%	23.6%	18.9%	-4.7%

*Historical baseline average is 18.4%

Tables 2 & 3 below show SB 1149 revenue, incentives spent on >1aMW customers, the percentage of total SB 1149 revenue spent on the >1aMW sites, total kWh savings from projects at >1aMW sites, and the number of sites receiving incentives for 2005-2007 and 2008-2014.

Table 2: Summary of spending and kWh savings for >1aMW customers 2005-2007 (pre-838)

Pre-838 Results				
Energy Efficiency 1149 Revenue	2005	2006	2007	2005-2007 (average)
Energy Efficiency 1149 Revenue	$21,065,813	$22,720,384	$25,673,961	$23,153,386
Incentives to >1aMW Sites	$9,742,145	$1,282,158	$1,762,765	$4,262,356
>1aMW Incentives as a Percent of 1149 Revenue	46%	6%	7%	18.4%
Number of >1aMW Sites Receiving Incentives	39	30	27	32
Savings from >1aMW Sites (kWh)	126,503,077	14,056,604	68,431,766	69,663,816
Total Savings (kwh)	213,903,461	121,192,910	139,322,053	158,139,475
Percent of Total Savings from >1aMW Sites	59%	12%	49%	44%

Table 3: Summary of spending and kWh savings for >1aMW customers 2008-2016 (post-838)

Post-838 Results										
PGE	2008	2009	2010	2011	2012	2013	2014	2015	2016	2008-2016 (average)
Energy Efficiency 1149 Revenue	$26,890,837	$26,669,621	$27,065,764	$28,510,770	$28,119,658	$26,484,405	$28,741,721	$28,723,137	$28,127,435	**$27,703,705**
Incentives to >1aMW Sites	$2,421,817	$2,778,741	$4,189,900	$5,950,881	$7,508,724	$6,705,824	$5,621,248	$5,004,680	$6,413,577	**$5,117,266**
>1aMW Sites Incentives as a Percent of 1149 Revenue	9%	10%	15%	21%	27%	25%	20%	17%	23%	**18.7%**
Cumulative Average	9%	10%	12%	14%	17%	18.1%	18.3%	18.2%	18.7%	**18.7%**
Number of >1aMW Sites Receiving Incentives	41	48	49	54	56	56	55	57	62	**53**
Savings from >1aMW Sites (kWh)	21,022,885	26,348,517	49,949,458	46,516,463	62,520,010	95,229,586	73,813,874	40,267,774	36,740,007	**50,267,619**
Total Savings (kwh)	145,935,756	150,705,221	219,884,055	244,453,313	282,316,497	311,992,892	321,470,265	170,374,245	194,005,002	**226,793,027**
Percent of Total Savings from 838-Exempt Sites	14%	17%	23%	19%	22%	31%	23%	24%	19%	**22%**
Potential additional incentives to >1aMW sites (Sensitivity Analysis)	*n/a*	*n/a*	*n/a*	*$39,727*	*$0*	*$0*	*$0*	*$0*	*$0*	***n/a***

Chart 1 shows the cumulative average of 1149 spending from 2005-2007 and 2008-2016. The horizontal line indicates the cumulative average from 2005-2007, which is the historical baseline and threshold for spending in the post-SB 838 period. Annual 1149 spending on >1aMW sites and the cumulative average increased from 2008 through 2012, but decreased slightly in 2013 and 2014. The cumulative average of the post-838 period (18.7%) is now just above the historical threshold of 18.4%. If revenue remained consistent in 2017, it would require a decrease in spending on >1aMW sites of over $2 million from incentive totals in 2016 to $4.4 million to lower the cumulative average below the 18.4% threshold

Chart 1: Cumulative average of SB 1149 revenue spending on >1aMW customer incentives 2004-2016, pre & post-838

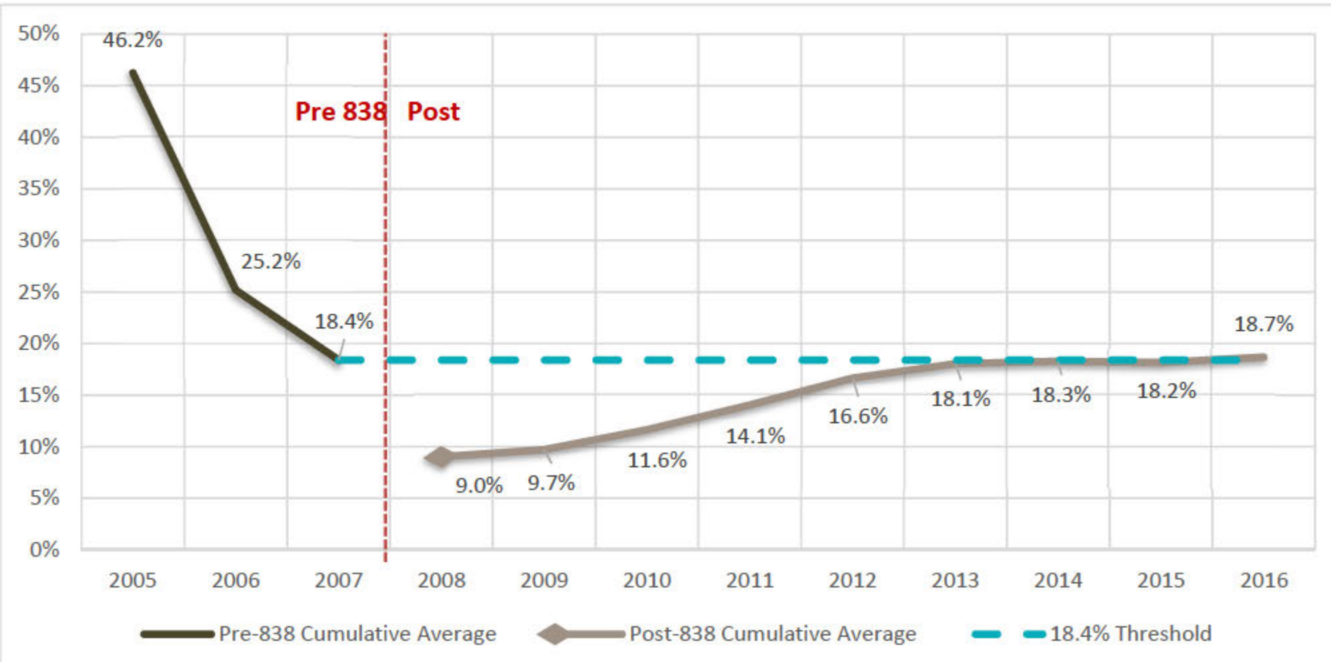


Table 4 below shows PGE spending on >1aMW customers by program by year beginning in 2005. Programs include Production Efficiency (PE), Existing Buildings (BE), and New Building Efficiency (NBE) projects.

Table 4: Summary of incentive spending & savings by program by year on >1aMW customers 2005-2016, pre & post-838

PGE	Production Efficiency		Existing Buildings		New Building		Total	
	$	kWh	$	kWh	$	kWh	$	kWh
Pre-838 Results								
2005	$8,134,413	N/A	$1,236,725	N/A	$371,008	N/A	$9,742,145	126,503,077
2006	$942,023	N/A	$111,121	N/A	$229,014	N/A	$1,282,158	14,056,604
2007	$1,520,782	N/A	$73,324	N/A	$168,659	N/A	$1,762,765	68,431,766
Post-838 Results								
2008	$1,989,391	N/A	$294,243	N/A	$138,184	N/A	$2,421,817	21,022,885
2009	$1,466,194	N/A	$781,466	N/A	$531,081	N/A	$2,778,741	26,348,517
2010	$3,097,231	43,322,367	$1,042,144	6,495,907	$50,525	131,184	$4,189,900	49,949,458
2011	$4,397,749	39,347,943	$1,513,314	6,703,335	$39,818	465,185	$5,950,881	46,516,463
2012	$5,774,602	51,916,828	$1,673,182	10,428,884	$60,940	174,338	$7,508,724	62,520,050
2013	$4,824,179	81,668,283	$1,654,099	11,204,217	$227,546	2,357,086	$6,705,824	95,229,586

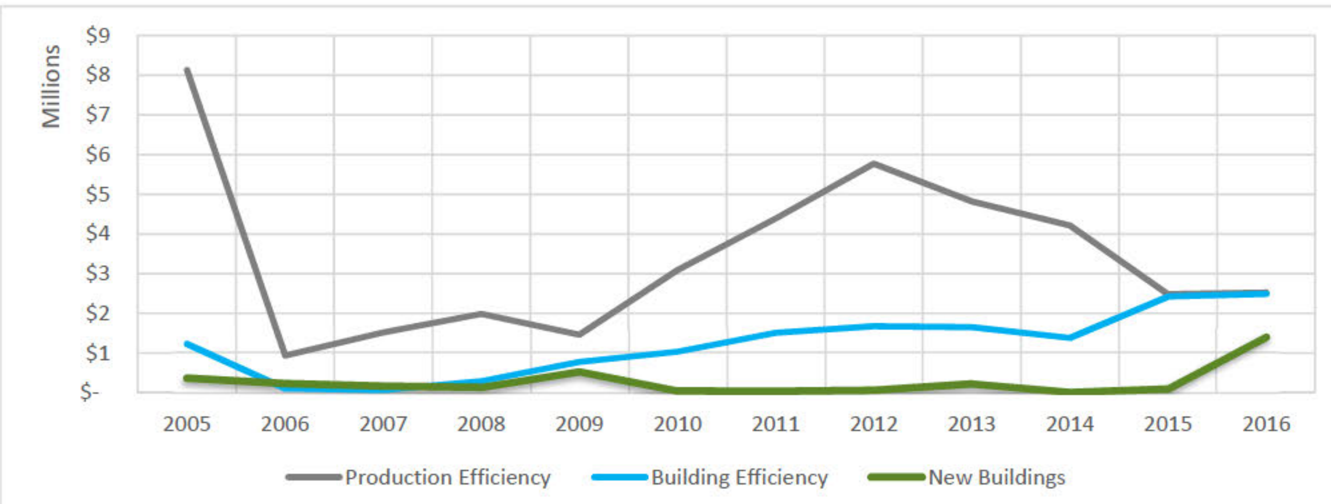
2014	$4,219,172	66,948,131	$1,384,860	6,765,869	$17,216	99,874	$5,621,248	73,813,874
2015	$2,485,462	28,953,430	$2,425,927	11,013,332	$93,291	301,012	$5,004,680	40,267,774
2016	$2,525,003	20,114,928	$2,490,249	9,377,647	$1,398,325	7,247,432	$6,413,577	36,740,007

Chart 2 below shows spending by program by year in graphical form. Each program category demonstrates unique year to year incentive spending patterns:

- New Buildings program spending increased over $1.3 million from 2015
- Production Efficiency and Existing Buildings program spending increased only slightly from 2015

The largest single >1aMW project was $1.2 million data center through the Existing Buildings program and the only large project above $1 million.

Chart 2: PGE >1aMW incentives by program 2005-2016, pre & post-838



METHODOLOGY

To calculate the incentive spending and percentages, a list of PGE >1aMW customers was compared to Energy Trust incentive program data, which includes incentives paid to all commercial and industrial PGE customers. Due to differences in the way that each data set is coded, address was the primary identifying characteristic to match >1aMW customers with incentive recipients.

There were several challenges to using address as the primary identifying characteristic. These challenges included:

- Some sites include multiple addresses
- A few addresses have multiple sites
- Some addresses have multiple customer names (typically, multiple divisions or business lines at one address)
- Multiple addresses exist for the same physical location (ie, one data set uses an address on a particular street, and the other uses an address on the cross street or a parallel street)
- Discrepancies in spelling or entry of addresses between data sets
- Generic locations are listed on the PGE >1aMW customer list instead of addresses; for example, "Warehouse" instead of "123 Main Street"
- For large industrial sites, the >1aMW customer list may contain an address for an adjacent office building and does not include every building address within the site

CLEAResult used newer software in addition to past methods to match project addresses to 1aMW sites:

- Both site and project addresses were normalized using Alteryx address normalization functionality
- Direct matches where street addresses matched exactly were considered matches
- Matching of 4-digit zip code extensions (usually indicate the same block)
- Alteryx geo-spatial tools were used to determine closest adjacent projects to 1aMW sites by distance
- Sites with the closest projects in proximity and no direct address match were given the first priority for analysis and review
- Projects with highest kWh savings were given higher priority and additional scrutiny
- Projects and site addresses that matched with different company names were researched and included if proof existed that both were of the same company (often due to company mergers or using corporate names)

ASSUMPTIONS

The primary premise of this analysis is the site definition. The OR SB 1149 definition of a site is: "'Site' means a single contiguous area of land containing buildings or other structures that are separated by not more than 1,000 feet, or buildings and related structures that are interconnected by facilities owned by a single retail electricity consumer and that are served through a single electric meter."

The site definition used to identify incentives paid to >1aMW user sites cannot be strictly applied to individual meters at large sites because neither CLEAResult nor Energy Trust has granular level data on the meters at a given site. Therefore, CLEAResult assumes that >1aMW user sites with generic addresses, such as "South of A Street," or multiple close addresses, match Energy Trust incentive program data when the address is a close match. These instances occur most frequently for the three site types outlined below with a set of assumptions are used to overcome uncertainty in each case.

There are three main business types that compose the majority of the >1aMW list: large industrial, hospitals, and college campuses. Each of these business types are typically physically constructed in a campus-like manner with many buildings clustered together that are owned by a single entity. Assumptions must be made when selecting one of these businesses as a match due to subtle differences between the way the >1aMW user list is constructed and the way the Energy Trust incentive program data reports the location of a project:

Large Industrial

- The >1aMW user list typically reports a single address for the site

  - The reported address is typically adjacent to the actual industrial site
  - This address may be a central office that handles billing for all structures
- The Energy Trust incentive project list reports each individual building address within a site
  - The addresses reported on this list don't always align with the >1aMW user list address
- An assumption is made that all addresses on the Energy Trust incentive project list are part of a single site if the >1aMW user list contains an address that is adjacent or within close proximity to all other addresses
  - If a single office reports for several different industrial sites these sites must be relatively close to be considered a match

Hospitals

- The >1aMW user list handles hospital sites by reporting some sites with a single address and other sites with multiple addresses within a campus
  - Single address entries are typically within the hospital campus but not part of the main structures
    - This address may be a central office that handles billing, similar to large industrial
  - Sites with multiple addresses often times do not include every potential address within the site
- The Energy Trust incentive project list reports each individual building address within a site
  - A single health care company often times owns several different sites within a city where each site is relatively close together
  - Each hospital campus is clearly finite and separate from any other site regardless of whether the proximity to other sites is near or far
- An assumption is made for single address entries that all addresses on the Energy Trust incentive project list are part of a single site if they are within the finite campus where the >1aMW user address is located
- An assumption is made for multiple address entries that all addresses within the associated campus are part of a single site even if the >1aMW user list does not provide a complete list of addresses for the site

College Campuses

- The >1aMW user list always gives multiple addresses for a single site
  - Every potential address within a single college campus is not given
- The Energy Trust incentive project list reports each individual building address within a site
- An assumption is made that all addresses on the Energy Trust incentive project list for a college campus are part of a single site even if the >1aMW user list does not provide every address