Demand Management Program Evaluation

A Report Prepared for

Okanogan County Electric Cooperative

by

Lands Energy Consulting

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Contents

I. Introduction

Okanogan County Electric Cooperative ("OCEC") retained Lands Energy Consulting, Inc. (LEC) to perform a Demand Management Program Evaluation ("Evaluation"). LEC will evaluate OCEC's proposal to conduct a 200 customer demand management program ("Program"). The Program, which has received OCEC Board of Directors approval, will evaluate the benefits of using a demand-shifting device, the Brayden Energy Sentry, to reduce peak demand for residential customers.

The Evaluation will analyze:

i. The potential for OCEC savings on Bonneville Power Administration (BPA) demand and energy charges under the Priority Firm (PF) rate schedule effective October 1, 2011 for Full Requirements customers.

ii. The potential for OCEC savings on transmission charges under the BPA Network Transmission (NT) rate schedule effective October 1, 2011.

iii. The effect of the Program on OCEC revenues and gross margins due to reduction in residential demand charges and load shifting from heavy load to light load hours.

iv. Program design issues, including:

- Tariff language
- Customer agreement
- Marketing plan
- Staff support requirements
- Customer results billing information
- Target participant electric usage characteristics

II. OCEC Electric System

OCEC serves 3500 electric customers in Okanogan County, WA. OCEC's 2010 energy load was 55,318 MWH, with a peak demand of 21.3 MW. OCEC currently supplies this load with a Bonneville Power Administration ("BPA") Slice/Block power sales contract. BPA delivers power to OCEC via a BPA Network Transmission Agreement and a General Transfer Agreement with Okanogan PUD. OCEC is a member of Pacific Northwest Generating

Cooperative (“PNGC”), which manages the scheduling of power and transmission on behalf of OCEC.

Commencing October 1, 2011, OCEC will once again become a BPA Full Requirements customer for its share of BPA “Tier 1” power. PNGC will acquire resources to serve OCEC load in excess of its allocation of Tier 1 power.

OCEC has installed meters on all accounts that register hourly energy and can register peak demand across 15 minute intervals. OCEC interrogates the meters via a power line carrier communication system for preparation of monthly bills. These bills cover usage from midnight on the first of the month to midnight at the end of the month. This metering and communication system affords OCEC the ability to perform in-depth analysis on its customer power consumption.

III. Demand Response

Utilities must plan and construct their electric system to meet all expected load. Weather extremes and outage conditions can place electric facilities in jeopardy of overloads that could damage equipment and lead to uncontrolled outages if not remedied by relay action or operator intervention. Because serving load during extreme weather conditions requires construction of new peaking resources (or continued operation and maintenance of older, less efficient generation) that runs only a few hours a year, utilities have for many years relied upon various forms of peak load shedding programs (often referred to as “demand response” programs). The demand response programs can help the utility maintain reliable service without the need to invest in generating facilities that are used for only a few hours of the year, if at all.

Until recently, most demand response programs targeted large users of electricity that could withstand multi-hour service interruptions without incurring significant financial losses or causing equipment damage. For example, Idaho Power and PacifiCorp have utilized system operator-initiated demand response programs for irrigation customers for many years as a way to contribute to the reliable service of summer peak load, while minimizing customer inconvenience and avoiding peaking resource construction.

The introduction of inexpensive wide area communication networks and new generation electric meters in the past few years has created the opportunity to move demand response programs into residential customer homes. Almost all residential demand response programs rely on system operator action to control large numbers of air conditioning units to reduce summer peak load for a few hours during extremely hot days. The utility carefully designs the program to minimize customer discomfort due to interruptions to electric supply to the air conditioning unit.

For example, PacifiCorp's Cool Keeper program coordinates the cycling of commercial and residential customer condensers on air conditioning units to reduce peak load. The air conditioner fan continues to operate, circulating cool air throughout the building, even during interruptions to electric supply to the condenser. PacifiCorp claims that the program results in a barely perceptible rise in building temperature of 1-3 degrees during peak load events. PacifiCorp provides customers a credit of $20/year as a reward for participating in the program. PacifiCorp anticipates that the Cool Keeper program will provide as much as a 100 MW of demand response – enough to defer construction of two LM6000 simple cycle combustion turbine peaking units.

While many utilities have deployed summer demand response programs in recent years, winter demand response programs have less available history. This is because most people in the United States heat their homes in the winter with natural gas rather than electricity. As a result, winter peak load service causes problems for only a handful of utilities, most of which are located in the Pacific Northwest.

In October 2009, Puget Sound Energy ("PSE") announced a demand response pilot program targeting 700 Bainbridge Island central heating electric customers. When initiated, the program automatically cycles heating units and interrupts hot water heaters. PSE intends to evaluate the benefits of such a program, as well as to gain an understanding of the marketing, customer service, and technical performance characteristics associated with the pilot. PSE's recently released 2011 Integrated Resource Plan estimates that the pilot program will result in 1 MW of available load interruption during an extreme winter peak event.

As stated earlier, most demand response programs rely on the utility's system operations office to initiate load reduction. The system operator usually initiates load curtailment after exhausting most other sources of supply. PacifiCorp estimates that it will activate the Cool Keeper program for only 20 hours per year. Limited use of the program minimizes lost revenue from energy sales during curtailment, while avoiding extremely expensive energy purchases in the short run and construction of peaking resources in the long run.

IV. OCEC Demand Response Pilot Program

The OCEC Board of Directors approved the Program to evaluate the benefits of using the Brayden Energy Sentry device to reduce residential customer demand. OCEC would offer the program to as many as 200 customers. In approving the Program, the OCEC Board of Directors anticipated the potential for benefits from reduced demand charges from its power supplier and transmission service provider (BPA) and possible delay of the need to upgrade substation and distribution equipment due to reduced demand on heavily loaded facilities.

The customer that installs a Brayden Energy Sentry would enjoy a reduction in demand charges paid to OCEC.

OCEC received a federal grant to defray a portion of the cost of the Program.

A. OCEC Rate Structure

In recent years, OCEC adopted a somewhat unconventional rate structure for its residential customers. OCEC bills customers monthly for three separate charges: a customer charge, an energy charge, and a 15-minute interval demand charge. Although the energy charge is fairly modest (3.8¢/kWh), the monthly customer charge, at $40/month, is significantly higher than charged by most utilities for residential customers. Furthermore, few utilities have installed meters that would permit assessment of a demand charge for residential customers. The OCEC demand charge of $2.70/kW-month, coupled with the $40/month customer charge provides OCEC significant revenue certainty from its many "seasonal" (second home-owning) customers.

B. OCEC Load Profile

OCEC serves mostly residential and commercial customers. Due to a lack of natural gas service in the area, most homes in the OCEC service territory use an electric furnace and/or heat pump for home heating. Some customers also use their heat pumps (and/or air conditioners) to provide home cooling during the summer months. Winter temperatures in the Methow Valley occasionally drop below zero degrees Fahrenheit. In fact, the coldest recorded temperature in the State of Washington (-48° F) occurred in Mazama and Winthrop (both served by OCEC) in December 1968.

OCEC serves most of its load from BPA's Winthrop Substation. It also serves customers in the vicinity of Twisp via a 12.47 kV feeder connected to Okanogan PUD's Twisp Substation. In addition to serving the town of Winthrop from the Winthrop Substation, OCEC serves load between Mazama and Winthrop with a radial feeder that originates at the substation.

The Mazama Feeder experienced a significant overloading condition during January 2011, where the 15 minute peak load exceeded rated capacity by 29% (6.25 MW demand versus 4.85 MW rated capacity). During this period, the feeder load exceeded rated capacity for 93 separate 15 minute demand intervals. OCEC is currently evaluating construction options to upgrade the Mazama Feeder.

C. Brayden Energy Sentry

The Brayden Energy Sentry automatically shifts a portion of peak power usage into subsequent periods of time, thereby reducing peak demand for a given account. The device accomplishes the reduction by limiting the amount of energy available to an electric furnace, heat pump, or electric hot water heater through cycling circuit breakers on and off. The controlled device will run at a lower peak demand level, but for a longer period of time in order to maintain a comfortable temperature. As a result, the customer load factor (average use for the period divided by peak use) increases, but energy use for the period remains approximately the same. Brayden Corporation literature claims that the Energy Sentry can improve residential customer load factor from 20% to as high as 60-90%. The Energy Sentry gives the customer control over the settings that determine the performance of the device.

OCEC policy requires that a licensed electrician install the Energy Sentry and the interposing circuit breakers. The cost of the Energy Sentry is $700, with the cost of electrical installation estimated by OCEC to be approximately an additional $700. Installation costs could vary significantly.

D. Load Factor

LEC relied on calculations of monthly "load factor" to estimate the customer benefits of Energy Sentry deployment. Load factor provides a way to evaluate the effects of Energy Sentry operation without having to make complicated adjustments for temperature variability from one month to the next. Instead, LEC identified customers that had similar peak, monthly energy, and load factor characteristics compared to the Energy Sentry customers before device installation. LEC then compared the load factor for the Energy Sentry customer after device installation and the benchmark customer. This methodology tends to filter month to month and peak hour temperature variability when calculating load factor improvement attributable to the Energy Sentry. LEC can then calculate a "demand improvement" amount based on the load factor improvement estimate.

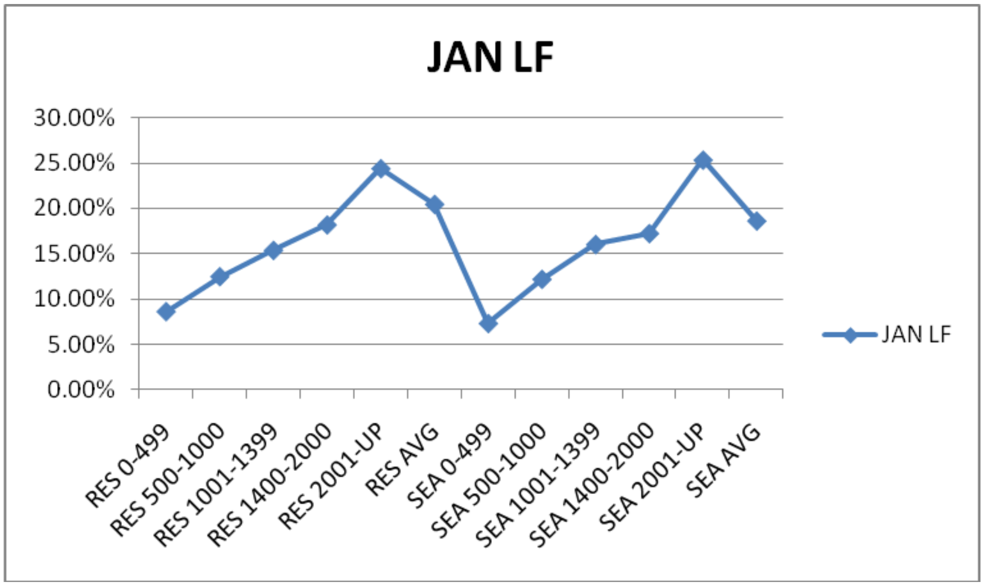
E. Preliminary Energy Sentry Results

Between March 2010 and February 2011, OCEC installed Energy Sentry devices on 11 homes. Of the 11 installations, only 4 occurred prior to the January 1, 2011 Mazama Feeder overloads. (Note: LEC examination of 7 of the installations revealed significant 2010 data quality issues when comparing 2010 monthly demand and energy billing amounts to 2011 monthly billing amounts. LEC was able to somewhat reconstruct 2010 data from hourly meter readings.) Evaluation of Energy Sentry customer data suggests that the Energy Sentry improves winter load factors by 15-25% and spring/summer load factors by about 5-15%. If the results for these installations prove typical, LEC expects that annual customer load factor improvement would average 15%/month due to Energy Sentry deployment.

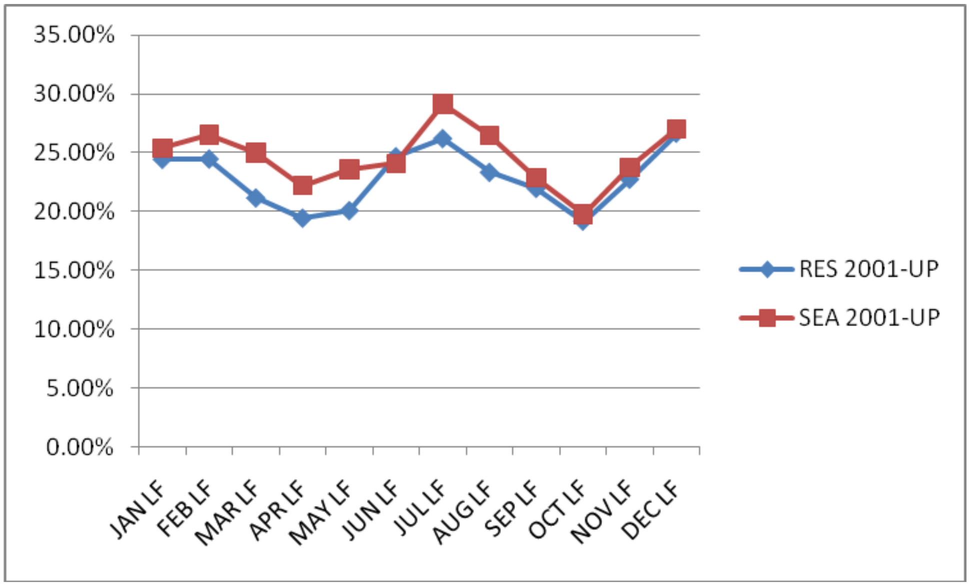
V. Customer Cost Benefits

A customer that installs the Energy Sentry would offset installation costs with monthly demand charge savings. LEC prepared a spreadsheet that evaluates the relationship between pre-Energy Sentry load factor, load factor improvement, average kWh usage, and installation cost in order to determine a simple payback for device installation.

As demonstrated by the following graph, the customers with the most monthly usage also exhibit the highest load factor during January.



These same customers also exhibit similar load factors during the rest of the months of the year:



While it might appear that the biggest opportunity for load factor improvement lies with the lower load factor customers that use fewer kWh during the winter months, the demand associated with these customers is generally much less than the demand for the larger kWh user. For example:

a. A customer that used 500 kWh, with an 8% load factor in January would have a peak demand of 8.5 kW. If the customer installed an Energy Sentry device and improved the load factor 20% (to 28%), the corresponding demand drops to 2.4 kW – an improvement of 6 kW. However, keep in mind that the low usage could be due to a heating source other than electricity (wood or propane), in which case non-controllable load causes the peak and the Energy Sentry wouldn't function as intended. Or the load only occurs on a limited number of days during the month when the home is occupied, in which case the device would provide a lesser amount of demand reduction/load factor improvement than predicted.

b. A customer that used 3000 kWh, with a 20% load factor in January would have a peak demand of 20 kW. A 20% load factor improvement would reduce the peak demand to 10 kW. Given the size of the load, the customer probably uses an electric furnace or heat pump for heating. In this case, the Energy Sentry would likely perform as intended.

The following Table 1 shows the relationship between average monthly usage, demand reduction (assuming 15% load factor improvement), and payback period for a customer investment of $750 and $1500:

Table 1
Energy Sentry Payback – 15% LF Improvement

Load	Starting LF	Demand (kW)	Energy Sentry Demand (kW)	Demand Reduction (kW)	Monthly Savings ($)	$750 Inv Payback (Months)	$1500 Inv Payback (Months)	Available Customers
1 akW	12.5%	8.00	3.64	4.36	11.78	63.66	127.31	1497
2 akW	15.0%	13.33	6.67	6.67	18.00	41.67	83.33	593
3 akW	20.0%	15.00	8.57	6.43	17.36	43.21	86.42	221
4 akW	20.0%	20.00	11.43	8.57	23.14	32.41	64.81	92
5 akW	20.0%	25.00	14.29	10.71	28.93	25.93	51.85	40
6 akW	20.0%	30.00	17.14	12.86	34.71	21.60	43.21	24

Assuming a customer needs a five year (60 month) or less payback to entice them to install the Energy Sentry, only a handful of large customers would see an adequate benefit to participation at a $1500 customer investment. Reducing the customer investment by half to $750 would bring a much larger number of customers into the Program.

Given the relatively long payback period for either a $750 or $1500 customer investment, OCEC may encounter customer dissatisfaction should it elect to eliminate the demand charge component of residential rates at some future date – thereby eliminating the reason for the customer to install the Energy Sentry in the first place. On the other hand, OCEC could improve customer economics for Energy Sentry installation by raising the demand charge from the current $2.70/kW-mo. Such an increase could increase revenues from non-participants to potentially off-set reduced demand charge income from participants. Increasing the demand charge in this fashion would raise issues of fairness among customers – the effective energy rate of big user/Energy Sentry participants would go down, while the effective rate for smaller users would increase.

VI. OCEC Financial Benefits

OCEC receives potential Program financial benefits from three areas:

- BPA PF power demand charge reduction
- BPA NT transmission demand charge reduction
- Deferred construction expense due to reduced equipment loading

A. BPA Tier 1 and Tier 2 Service

The Regional Dialog process resulted in BPA allocating the power, energy, and financial benefit of the Federal System among its various customers. The Federal System includes the output of the federal hydro projects in the Columbia River Basin, the Energy Northwest Columbia Generation Project, and various contractual rights and obligations. OCEC receives a portion of this so-called "Tier 1" capability of the Federal System based on historic load served by BPA. OCEC's Tier 1 allocation of the Federal System equals 6.6 aMW, which slightly exceeds OCEC's 2010 energy load of 6.3 aMW. OCEC must serve any load above its Tier 1 allocation of the Federal System with either acquisition of non-federal sources of supply, or a purchase of "Tier 2" service from BPA.

OCEC has elected to work with PNGC to serve its load growth. From October 1, 2011 to September 30, 2013, OCEC will serve its Tier 2 load with a Short Term Tier 2 purchase from BPA. From October 1, 2014 through September 30, 2019, PNGC has arranged for OCEC to receive a share of "vintage" Tier 2 power, as well as a smaller market purchase. OCEC's share of these two purchases is less than 700 kW.

BPA Power Rate Demand Charge

Commencing October 1, 2011, BPA radically alters the billing determinants for the Priority Firm Rate (PF Rate) applicable to OCEC. Although the Energy Sentry could move some customer load from Heavy Load Hours (HLH) to Light Load Hours (LLH), the majority of the benefit of device installation comes in the form of reduced customer demand through improved load factor. Under the existing BPA PF Rate, a customer pays for power on an energy and demand basis. BPA charges separate rates for HLH and LLH load, plus a demand charge for a customer's peak demand recorded on the hour of BPA's generation system peak.

Under the PF-12 Rate Schedule, BPA allocates the output and the cost of the Federal Columbia River Power System ("Federal System") among its public agency customers. Instead of charging separate demand and energy charges, BPA assesses customers a large Customer Charge designed to recover the cost of the Federal System allocated to each customer. Customers pay for deviations from allocated demand and energy amounts, but the Customer Charge will constitute most of the dollar value of a customer's BPA Wholesale Power Bill.

BPA will calculate the demand portion of OCEC's post-October 1, 2011 Wholesale Power Bill with the following equation:

Tier 1 CSP – aHLH – CDQ – SuperPeak

Where:

Tier 1 CSP = The Tier 1 Customer System Peak is the Customer's maximum Actual Hourly Tier 1 Load during the Heavy Load Hours of the month, in kilowatts.

aHLH = Average of the Customer's Actual Hourly Tier 1 Loads during the HLH, in kilowatts

CDQ = Contract Demand Quantity specified in the Customer's CHWM Contract, Exhibit B, section 2, in kilowatts

SuperPeak = Super Peak Credit, if any, specified in the Customer's CHWM Contract, Exhibit A, section 9, in kilowatts

If the Demand Charge billing determinant calculation results in a value less than zero, the billing determinant is deemed to be zero.

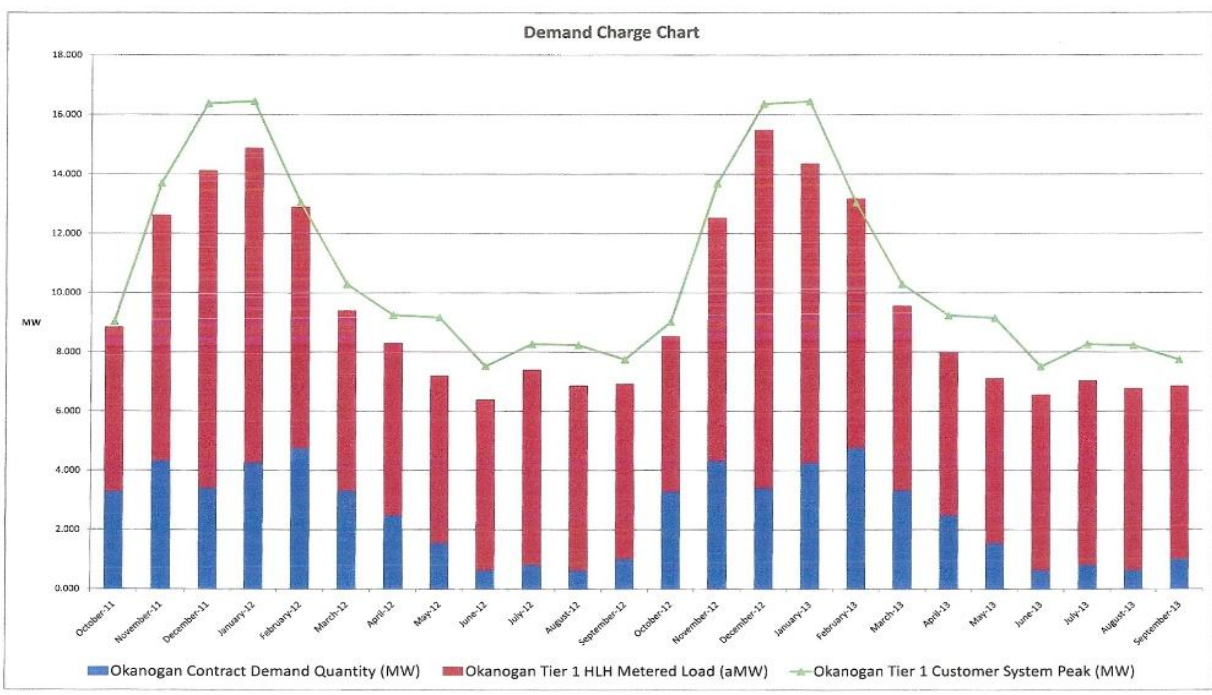
The Super Peak portion of the demand charge calculation credits the customer for any amount of non-federal resource or Tier 2 purchase used to serve a customer's load that is reliably available during the following periods ("HE" means Hour Ending):

October – February HE 0800 through HE 1000 and HE 1800 through HE 2000
March – May HE 0700 through HE 1200
June – September HE 1400 through HE 1900

For purposes of this analysis, OCEC demand charges would be zero in months where the combination of average HLH energy loads, Contract Demand Quantity, and non-federal resource/Tier 2 purchase Super Peak capability are less than its peak hour load. However, in months where OCEC peak demand hour load exceeds the combination of the Contract Demand Quantity and the average HLH energy load, BPA would assess a demand charge on the difference that ranges from $8.50/kW-month in May to $10.75/kW-month in August.

PNGC developed a graph of the relationship between the forecast monthly OCEC peak load, average Tier 1 HLH load and the specified Contract Demand Quantity.

Graph 1
OCEC Demand Charge Chart
(Prepared by PNGC)



The demand charge chart indicates that, <u>on average</u>, OCEC could expect to pay demand charges to BPA for a portion of its peak hourly demand for 11 out of 12 months of the year. Depending on weather conditions, OCEC will likely have 2-3 additional months per year where demand tracks below the forecast and OCEC pays no demand charge as well. To the extent OCEC adds non-Federal resources to meet load growth in a shape that matches its load profile, it may have fewer months yet where BPA charges for demand. In months where BPA does charge OCEC for demand, however, the Program could reduce the demand charges by as much as $10.75/kW reduced.

B. BPA NT Transmission Rate Demand Charge

BPA did not change its billing determinants under the NT Transmission Rate for the new transmission rate period commencing October 1, 2011. A customer pays $1.868/kW-month for its electric system demand at the time of the BPA transmission system peak. During the winter, peak load on the BPA transmission system sometimes correlates to individual utilities' peak loads. However, BPA transmission peak load occurs at hours other than when Northwest utility loads peak during other months. Because of a lack of correlation between transmission system peak and utility peak loads, the Energy Sentry may cause only a slight decrease to OCEC load at the time of BPA transmission system peak, and therefore BPA NT Transmission Rate demand charges.

C. Equipment Loading Relief

Load growth on the OCEC electric system, coupled with cold weather extremes, has placed certain equipment near or above rated loading limits. In particular, the Mazama Feeder out of the Winthrop Substation experienced a load peak January 1, 2011 that exceeded the 15 minute feeder rating by 29% (6.25 MW demand versus 4.85 MW rated capacity). During this same cold weather outbreak, the Mazama Feeder's load exceeded the 15 minute rating on 93 occasions.

As a practical matter, neither the Program nor a full deployment of Energy Sentry devices on the OCEC electric system will likely reduce load on the Mazama Feeder in time to delay or eliminate the need to upgrade equipment.

VII. Effect of Energy Sentry Deployment on OCEC Margins

Given the available OCEC customer load information (including Energy Sentry installed accounts), LEC can estimate system-wide lost revenue due to Energy Sentry reduction of customer peak demand. The OCEC customer receives $2.70/kW month of savings for every kW of demand reduction attributable to the Energy Sentry device, regardless of when the savings occurs during the month. Customers receive this benefit (and OCEC foregoes the associated revenue) regardless of whether OCEC sees any associated BPA demand charge reduction.

Estimating BPA PF and NT demand reduction is more difficult for two reasons. First, the monthly Contract Demand Quantity and demand off-set from new non-federal resources serving OCEC load will determine the level of PF demand charge savings (if any) attributable to Energy Sentry deployment. Second, BPA calculates PF and NT demand charges on an integrated hourly basis, whereas OCEC determines customer peak demand on a 15 minute demand interval. As a result, diversity among individual Energy Sentry customer peaks, as well as the Energy Sentry's tendency to "smooth" load within an hour (across 4-15 minute demand periods) will cause the hourly integrated effects of the Energy Sentry to be significantly less than the sum of the customer non-coincident peak demand reductions.

Table 2 below provides a summary of expected Program OCEC demand charge lost revenue, as well as maximum savings on BPA power and transmission demand charges assuming a .40 diversity factor among the OCEC non-coincident peak reductions resulting from Energy Sentry deployment. LEC used the average of the monthly demand charges for the PF-12 rate to calculate the BPA PF savings - $9.62/kW-month – and $1.868/kW-month to calculate the NT rate demand charge savings.

Table 2

Lost Demand Charge Revenue and BPA Savings Estimate

(.4x Diversity Factor – BPA Demand Charge All 12 Months)

Load	Average Monthly Reduction (kW)	Pilot Customers	NCP Demand Reduction (kW)	OCEC Lost Demand Charge Revenue	BPA PF Demand Reduction (.4x NCP kW)	BPA PF Savings ($/mo)	BPA NT Demand Reduction (.4x NCP) kW	BPA NT Savings ($/mo)
1 - 2 akW	5.52	120	662	1786.91	264.73	2546.68	264.73	495
2 - 3 akW	6.55	49	321	866.25	128.33	1234.57	128.33	240
3 - 4 akW	7.50	17	128	344.25	51.00	490.62	51.00	95
4 - 5 akW	9.64	7	68	182.25	27.00	259.74	27.00	50
5 - 6 akW	11.79	3	35	95.46	14.14	136.05	14.14	26
6 + akW	12.86	4	51	138.86	20.57	197.90	20.57	38
Total		200	1,264	3,414	506	4,866	506	945
Annual			15,173	40,968	6,069	58,387	6,069	11,337

As stated earlier, whether or not OCEC pays a PF demand charge to BPA in a given month depends on the Contract Demand Quantity, average Tier 1 energy usage, and the capacity of non-federal resources. Accordingly, LEC cannot determine PF demand charge savings with any certainty. Since the PF demand charge for a given month could be $0 even without wide-scale

Energy Sentry deployment on the OCEC electric system, Table 3 provides a calculation of OCEC net margin as a function of the number of months OCEC pays a PF demand charge.

Table 3

OCEC Net Margin

Months PF Demand Charge Paid	PF Demand Charge ($/kW-mo)	PF Demand Reduction (kW)	PF Annual Demand Charge Savings ($)	NT Annual Demand Charge Savings ($)	OCEC Lost Revenue ($)	OCEC Net Annual Savings ($)
0	9.62	506	0	6,069	-40,968	-34,898
1	9.62	506	4,866	6,069	-40,968	-30,033
2	9.62	506	9,731	6,069	-40,968	-25,167
3	9.62	506	14,597	6,069	-40,968	-20,302
4	9.62	506	19,462	6,069	-40,968	-15,436
5	9.62	506	24,328	6,069	-40,968	-10,571
6	9.62	506	29,193	6,069	-40,968	-5,705
7	9.62	506	34,059	6,069	-40,968	-840
8	9.62	506	38,924	6,069	-40,968	4,026
9	9.62	506	43,790	6,069	-40,968	8,892
10	9.62	506	48,656	6,069	-40,968	13,757
11	9.62	506	53,521	6,069	-40,968	18,623
12	9.62	506	58,387	6,069	-40,968	23,488

Table 2 demonstrates that the breakeven point for OCEC net margin occurs when BPA assesses a demand charge to OCEC for eight out of twelve months of a given year.

VIII. Program Design, Administration, and Analysis

OCEC will require significant effort to design the Program, market the Program to likely participants, ensure that participants perform their obligations, and analyze the data. LEC believes that OCEC needs to prepare to devote significant staff (and/or contractor) resources to successfully implement the Program.

A. Program Design

OCEC intends to use proceeds from a government grant to provide Program customers with $700 to be used for licensed electrician installation of the Energy Sentry device and associated circuit modifications. The customer would purchase the Energy Sentry device itself, possibly through a fixed monthly charge on the customer's bill. The customer benefits from a reduction in monthly demand charge due to the load-shifting capabilities of the Energy Sentry device.

In order to collect enough data to determine whether or not to extend the Energy Sentry program to all residential customers, OCEC should plan to operate the Program for a minimum of two years. This will allow a year to ramp up to the 200 customer target, plus at least a year of results with the Energy Sentry devices deployed across the entire group.

OCEC should spell out customer and OCEC obligations in a standard form Customer Participation Agreement. This agreement should contain the following terms:

- OCEC contribution to customer installation cost (upfront or upon completion), with customer responsible for all costs in excess of contribution.
- Terms for OCEC to finance the cost of the Energy Sentry device (customer pays OCEC $15/month for 60 months) if so-elected by customer.
- Customer contracts with a licensed electrician for device installation.
- OCEC makes no guarantee that customer will realize savings to cover out-of-pocket costs.
- OCEC not liable for customer equipment damage due to Energy Sentry operation.
- Customer permits OCEC to share usage information with contractors and others with a legitimate interest in results, provided that OCEC protects customer privacy through redacted customer name prior to release of data to third parties.
- OCEC can terminate program at will after 1/1/14.
- Customer can terminate program participation after two years – allows OCEC adequate time to collect data.

In addition to terms contained in the Customer Participation Agreement, OCEC should plan to modify its residential customer electric tariffs to reference the Program and its key features.

B. Marketing Plan

As discussed in Section V above, a full-time resident with electric furnace or heat pump heating will likely provide the best opportunity for Energy Sentry peak demand reduction of sufficient magnitude to offset the customer's cost of program participation over a reasonable period of time. The marketing program should target this class of customers in a non-discriminatory fashion. One approach would involve a system-wide residential customer solicitation that invites customers to evaluate their individual situation (perhaps with customer specific information in the mailing itself) and contact OCEC for more details if they appear to qualify. If the initial mailing does not attract enough interest to fill the 200 participant quota, then OCEC should consider making individual contact with high usage/low load factor customers to attempt to interest them in the program.

C. Program Administration

The staff time required to administer the Program will be the most difficult aspect of the Program for OCEC to support. On the front-end, the Program requires significant staff time to prepare standardized customer agreements, solicit customer interest, qualify individual customers for participation, order equipment, ensure that customers use a licensed electrician for installation, analyze data, prepare updates for management and the Board of Directors, etc. With only 17 employees (and a new General Manager due to be selected in the near future), the Program workload will likely displace other high priority work. As a result, OCEC should consider hiring a part-time employee (or contractor) to administer the Program.

D. Results Analysis

In order to provide adequate information to inform a decision whether or not to extend the Program to the entire OCEC customer base, OCEC should collect the following data:

- Fifteen minute and sixty minute demand information for all participating customers, as well as similar information for a carefully selected control group of customers. Ideally, the control group would have similar (pre-Energy Sentry) load characteristics to the participating customers' loads. The control group provides OCEC the ability to benchmark Program results against non-participating customers to estimate the effects of weather variability on load factor.

- Customer specific information on feeder, heating and cooling source, occupancy pattern (full time vs. seasonal), number of circuits controlled by the Energy Sentry, Energy Sentry customer-determined settings, etc.

- Hourly deliveries of power to OCEC at Winthrop and Twisp Substations – ideally by individual feeder if supported by existing metering

- Hourly temperature as measured at the Winthrop fish hatchery

- All OCEC direct costs allocable to the Program

This information should enable OCEC to determine an estimate of system demand reduction attributable to the Program. In addition, OCEC should consider providing customers participating in the Program with information detailing estimated savings attributable to the Energy Sentry device.

IX. Overall Program Assessment

LEC cannot determine if the Program will have a positive or negative financial effect on OCEC due to the monthly variability of the demand charge component of the BPA PF-12 power rate and the amount of anticipated peak demand diversity among Project participants. However, LEC's analysis indicates that even under the most conservative assumptions of BPA demand charge application (e.g., OCEC pays a demand charge every month), the Program only generates $24,500 per year of net margin for OCEC – exclusive of the cost of equipment and program administration.

If OCEC doesn't have access to grant money to cover at least half the cost of installation, any expansion of Energy Sentry installation beyond the initial 200 residences would likely not result in a reasonable payback period for OCEC. Furthermore, only a handful of high usage residences would see a financial benefit from avoidance of OCEC demand charges if OCEC placed the entire cost of the Energy Sentry device and installation on the customer.

Based on the analysis contained in this Evaluation, LEC forecasts limited, if any, potential financial benefit to OCEC of implementing the Program. However, proper Program implementation will require significant oversight and involvement from staff. The combination of benefit and staff commitment, in LEC's opinion, doesn't appear to justify Program adoption.

X. Conclusions

Based on the results of this Evaluation, LEC submits to OCEC the following conclusions regarding the Program:

A. LEC evaluation of the 11 existing Energy Sentry installations indicates the device should improve individual customer winter load factors by 15-25% and spring/summer load factors by about 5-15%. If the results for these installations prove typical, LEC expects that annual customer load factor improvement would average 15%/month due to Energy Sentry deployment.

B. Due to the monthly variability of the demand charge component of the BPA PF-12 power rate and the uncertainty of the amount of anticipated peak demand diversity among Project participants. LEC is unable to predict the exact magnitude of potential BPA power and transmission cost savings to OCEC attributable to the Program. However, LEC forecasts limited, if any, potential financial benefit to OCEC of implementing the Program.

C. Neither the Program, nor a full deployment of Energy Sentry devices would provide enough timely demand reduction to defer construction of additional Mazama Feeder capacity.

D. In order for all but the largest residential customers to enjoy a reasonable payback on Energy Sentry installation (five year simple payback), OCEC will need to cover at least 50% of the cost of the Energy Sentry device and related installation expense.

E. Program administration will require significant staff resources to design the Program, market participation to customers, support implementation, and evaluate data.

XI. Recommendations

LEC does not believe that expected Program financial benefits justify the staff commitment necessary to design, market, implement, and evaluate the Program. However, should OCEC's Board of Directors and management elect to move forward with the Program, LEC recommends that OCEC incorporate the following elements into the Program design:

- Commit to at least a two year term (through the end of 2013) to provide adequate customer data and experience with the BPA PF-12 rate schedule to determine whether to expand Energy Sentry deployment to a broader group of customers.
- Prepare a standard form customer Program participation agreement (see Section IX.A for LEC recommended terms and conditions).
- Target for Program participation full-time resident electric heat customers with monthly average energy usage of at least 1500 kWh/month.
- Select a control group of customers that don't participate in the Program, but exhibit similar usage patterns to Program participants in order to provide a benchmark against which to measure Energy Sentry performance.
- Hire a part-time employee (or contractor) to administer the Program.