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CHIEF CLERK'S OFFICE

April 30, 2010

Ms. Elizabeth A. Rolando, Chief Clerk
Illinois Commerce Commission
527 East Capitol Avenue
Springfield, IL 62701

RE: Docket Nos. 06-0691, 06-0692 and 06-0693 (Cons.)
Ameren Illinois Utilities – Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP
Rider PSP – Power Smart Pricing - 2009 Annual Report

Dear Ms. Rolando:

In compliance with the findings in Docket Nos. 06-0691, 06-0692 and 06-0693 (Cons.), attached is an original and one copy of the Rider PSP – Power Smart Pricing Annual Report including the Financial Audit Report filed on behalf of the Ameren Illinois Utilities.

Attached is an additional copy of this letter which we ask that you return to us with acknowledgement and date of filing noted thereon. If you have any questions, please call Ms. Jackie Voiles at 217-535-5269 or me.

Sincerely,

D Scott Wiseman

D. Scott Wiseman, Vice President
Regulatory Affairs

DSW/cic
Attachment
cc: Tim Anderson – ICC w/attachments
Gene Beyer – ICC w/attachments
Harry Stoller – ICC w/attachments
Eric Schlaf – ICC w/attachments
Jackie Voiles – AIU w/attachments

NAVIGANT
CONSULTING

SUMMIT BLUE
CONSULTING, LLC

Power Smart Pricing
2009 Annual Report

Submitted to:
Ameren Illinois Utilities

FINAL REPORT
April 27, 2010

Prepared by

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Acknowledgments

CNT Energy prepared the 2009 Power Smart Pricing Operational Report. Their complete report is included as Appendix A in this document. Highlights from their report are included within the main body text of this document whenever the facts are relevant to the discussion. Readers who are not familiar with the Power Smart Pricing program may find it helpful to review Appendix A before reading this evaluation report.

Special thanks go to CNT Energy for their preparation of the chapter on participant bill savings in the evaluation report.

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Executive Summary

This report is the assessment of the Power Smart Pricing program for 2009. Program evaluation work will be concluded after the end of calendar year 2010, providing the opportunity to refine and update the assessment that was done this year with an additional year of program participation data. The following conclusions highlight the major findings presented in this 2009 report.

2009 was a summer of unusually mild weather during an economic recession. This created an electricity market where the real-time prices for a kWh never rose above 11 cents, and day-ahead prices never predicted a kWh to be over eight cents. This is in contrast to 2008 where there were 122 hours that were predicted to be over 13 cents by the day-ahead price.

Number of Customers Using Hourly Pricing

CNT Energy's marketing and enrollment efforts resulted in 7,422 active Power Smart Pricing participants as of December 31, 2009. This was a 136% increase over the participant count of 3,147 at the end of 2008. New participants in the program had higher average energy use than the existing participants. This is considered to be a result of a successful targeted marketing campaign used in 2009 to attract high use customers to the program.

Changes in Customers' Energy Use Patterns

Elasticity modeling done for 2009 shows that Power Smart Pricing participants continued to respond to variation in hourly prices during the summer season, even though 2009 electricity prices were much lower than 2008 prices. The overall own-price elasticity was –2.3%, meaning they reduced their electric usage by 2.3% for every 100% increase in the price of electricity.

Additional analysis revealed that customers show a much higher response to price when prices are above a given threshold. For example, during the summer season, the own-price elasticity is -1.0% when prices are below 13 cents per kWH, but when prices rise above 13 cents, the own-price elasticity jumps to -24.8%.

There were no High Price Alert days in 2009. However, on regular summer weekdays in 2009 PSP participants showed an average load reduction of 0.13 kW per hour between the hours of Noon and 5 p.m. when compared to a control group. This is similar to the load reduction of 0.18 kW per hour found for regular summer weekdays in 2008. Survey data reinforced the observation that PSP participants were continuing to shift their summer energy usage out of the high price afternoon period even though 2009 energy prices were much lower than 2008 prices.

In addition to shifting energy during the summer, participants also showed an overall reduction in energy use. Power Smart Pricing participants reduced their average energy use by 5.1% during the summer season and by 0.6% during the shoulder months. However, they did not show any energy savings during the winter months. This created an overall annual energy savings of 1.2% per year which is similar to the annual savings of 1.5% found in 2008.

VALUE OF THE PROGRAM TO PARTICIPANTS

In 2009, the aggregate savings for PSP participants was $1,388,996 which represented a 23.6% total savings compared to what the same bills would have been under the standard rate. Average annualized savings were $304.98 or 24.4%.[1] These percentage savings are three times greater than what was seen in 2008, largely due to the low market prices for electricity.

This estimate of bill savings does not include the additional savings that comes from the conservation effect of the program. Including an annual decrease in consumption of 151 kWh per customer at roughly ten cents/kWh for energy and distribution, there is an additional $15.10 that the average PSP participant avoided paying in 2009. If that savings had been included, the average annualized savings would have risen from 24.4% to 25.6%. For 6,652 participants, that represents an additional annualized aggregate bill savings of $100,445.

VALUE OF THE PROGRAM TO NON-PARTICIPANTS

A thorough assessment of the net benefits from the Power Smart Pricing program will be presented in the 2010 Annual Report to the Commission after the program has completed three full years of operation. Plans are in place for the 2010 Annual Report to contain a summary of all the costs and benefits related to the PSP program, including a probabilistic risk assessment of the net benefits.

This 2009 report includes a preview of what the basics of the 2010 net benefit assessment will look like. It looks at actual benefits and costs estimated for the years 2008 and 2009. This includes estimation of non-participant benefits from reduced MISO prices that are a consequence of the PSP program demand reductions. This preview offers the opportunity for a full year of review and discussion on refinement of the methodology before the final net benefit assessment results need to be completed in 2010. It is expected that this opportunity for careful thought and sharing of ideas will lead to a very robust final assessment.

[1] Due to the growing enrollment levels over the course of the year the overall savings percentage and the annualized average savings percentage are not the same. Annualized savings represent what the average customer would have paid if they were on the program for all 12 months of 2009.

Section I » Introduction

Summit Blue Consulting, a part of Navigant Consulting,[2] (Summit Blue/Navigant Consulting) was engaged by the Ameren Illinois Utilities (AIU) to perform three years of impact evaluation on the Power Smart Pricing (PSP) real-time pricing program for residential customers. The first year evaluation covered program participation impacts from the inception of the program in mid-year 2007 through the end of calendar year 2008. The report was filed with the Illinois Commerce Commission in May of 2009. This report is the second in the series of three planned annual impact evaluations and it presents results for program participation during calendar year 2009.

The introduction to this report starts with a recounting of background information on the potential benefits of real-time pricing rate designs, and a description of the unique characteristics of the Power Smart Pricing program. This is followed by a discussion of the objectives for the 2009 impact evaluation, and a summary of the organization of the remainder of this report.

Background: The Potential Benefits of Real-Time Pricing

Electricity prices are among the most volatile of any market commodity. Driving this volatility is the fact that electricity cannot be stored in significant quantities. As a result, during periods of high demand (hot summer days for example), hourly electric prices can vary substantially over just a 12-hour period. On extreme days, price spikes during resource constrained periods can see increases of 100 fold or more if there is not enough demand-side response to mitigate the system and supply-side factors that are driving prices up. These extremely high prices, even though they may occur only during a few hours each summer, can represent a substantial cost to all the customers in the regional electricity market.

While the costs of electricity in wholesale markets can vary dramatically, retail pricing, particularly for residential and small commercial customers, has largely remained subject to regulated tariffs. These tariffs typically have provided customers with fixed rates, i.e., they pay the same price for electricity regardless of when and how much is used. This fixed rate does not reflect the true cost to the economy of consuming electricity at a given point in time, and therefore it distorts key market decisions.

An important near-term challenge facing electricity markets is the rational pricing of retail electricity. The goal of any market — regulated or unregulated — is to allocate resources equitably, promote efficient investment, and provide incentives for innovation. Prices provide the market signals that are used to allocate resources. Specifically, the key is to appropriately price what is scarce. For electricity markets, what is scarce is on-peak energy. If the market is not designed to appropriately price what is scarce, the market will not be efficient and disconnects between demand and supply can occur, resulting in price spikes. Clearly, non-time-differentiated electricity rates cannot reflect the true costs at the wholesale level of on-peak electricity. With standard rates, customers have no idea what the actual cost of electricity is at any given time and they are not able to make choices regarding conserving a scarce resource. As a result, they cannot make decisions regarding the appropriate use of electricity required for an efficient market. Innovative pricing, such as real-time pricing (RTP), is one method of allowing for the interaction of demand and supply needed for efficient markets. Research on time-differentiated pricing is growing as the benefits of these pricing options are becoming better recognized. These options allow customers to see

[2] Summit Blue Consulting became a part of Navigant Consulting, Inc. on January 1, 2010.

the real wholesale costs of electricity and make decisions regarding their energy use based on market conditions. Overall, customers who see real prices and adjust their demand in response to these price signals can make the electricity system more efficient and stable. As a result, retail electric prices that better reflect the costs of obtaining power in wholesale markets can provide benefits to electricity markets, including the following:

- **Increased system reliability** as price mitigates demand when resources become scarce.
- **Reductions in costs** of electricity to all customers in a regional market as a result of better management of scarce supplies and reductions in capital costs incurred to meet peak demands.
- **Risk management** by allowing customers to manage a portion of the electricity price and commodity risks and be compensated for this service.
- **Environmental benefits** by promoting efficient use of resources and price signals to manage demand.
- **Customers benefit** from being on an RTP rate since now their ability to use electricity flexibly across on-peak and off-peak periods is valued, i.e., a key attribute of their energy use – flexibility in time-of-use – is given a value.
- **Market power mitigation** by providing a demand response to offset high prices for generated electricity.
- Providing the **incentives for innovation** needed to create technologies and value propositions for load management and peak demand response.
- RTP better reflects the actual cost of service, allowing a **more equitable distribution of costs** across customers and customer classes.
- Unlike conventional load control or curtailable/interruptible incentives, dynamic tariffs such as RTP can be made **available to all customers,** regardless of usage level or appliance ownership.

These potential benefits from RTP options can accrue to a number of entities:

- **Participants.** RTP participants can benefit by having the ability to make more informed choices regarding how they use electricity. This provides them the opportunity to lower their monthly bills.
- **Electricity customers not participating.** The RTP rate can also benefit all customers (participants and non-participants) in a regional electricity system because a relatively small fraction of price-responsive demand can have sizeable impacts on market-wide price spikes and electric system efficiency.
- **Utilities.** Utilities can benefit through load reductions on their delivery network during peak periods, and delaying or avoiding the need to make additional capital investments.

Recognition of these potential benefits has led to a number of pilot programs and a move towards time-differentiated rates for large customers. The Illinois legislature was one of the first legislative bodies to

encourage real-time pricing rates for residential customers. Illinois Public Act 94-0977 required that electric utilities which serve more than 100,000 customers must have RTP available to residential customers as a rate option. This Act led to the Illinois Commerce Commission (ICC) Docket 06-0961, which found that a residential RTP program would be likely to provide a net economic benefit to the residential community as a whole. As part of this docket, the Ameren Illinois Utilities (AIU) received approval to launch Power Smart Pricing (PSP).

Power Smart Pricing Program

Power Smart Pricing presents "de-averaged" electricity supply prices that are a direct pass through of MISO hourly prices without mark-up. These prices provide a day-ahead price signal to customers about the real cost of their electricity use.[3] The program also provides information regarding opportunities to control electricity bills through energy efficiency and peak load management. A key component of that information is the targeted use of "high price alerts" via email or phone on the evenings before expected high price days. MISO day-ahead prices are used as the basis of the high price alerts and they provide information on which hours are most critical for taking additional energy management actions.

PSP is an optional program for the Ameren Illinois Utilities' residential customers who participate through the program administrator, CNT Energy. In early 2007, the Ameren Illinois Utilities conducted a competitive solicitation to select the administrator for the program. CNT Energy (formerly the Community Energy Cooperative) was selected. CNT Energy provides all aspects of the enrollment process as well as ongoing participant support. That support includes a web interface that allows customers to compare bills, view, and analyze their hourly energy use, and conduct a home energy self-audit.

The Ameren Illinois Utilities' residential customer base is approximately one million households and will be subject to selective targeting for enrollment in the PSP program over the 2007 to 2010 contract period. Specific principles that apply to this enrollment are as follows:

- Participants in Power Smart Pricing pay an additional $2.25 per month to participate. This charge covers a portion of the $5 a month incremental cost of their interval demand meter. The additional cost of the meter and the other program expenses are not recovered from participants, instead they are recovered via Rider PSP which is applied to all residential customers. The charge is currently five cents per month.

- A two percent PSP market penetration objective affords a marketing approach where emphasis is on customer education and experience.

- Enroll participants that fully understand the PSP concept and program and therefore understand the associated risks and rewards.

- While the entire Ameren customer base is eligible for participating in PSP, certain customer segments may not be good candidates for participation because they are not likely to receive any economic benefit from participating in PSP. Experience has shown that these segments include customers with very low usage (due to the $2.25 monthly fee being a large part of their bills),

[3] The Ameren Illinois Utilities began billing day-ahead prices on June 1, 2008 under the PSP Program. Prior to that date, program participants were billed the real-time price.

customers with health issues (due to the risks involved in reducing energy consumption), and customers heating their homes primarily with electric space heat (due to a late-2007 rate redesign that provides them with a subsidized winter price).

- Incorporate basic energy efficiency and conservation awareness as a goal for on-going customer education.

The costs of the Power Smart Pricing program consist of the incremental cost of metering to collect hourly usage data, additional Ameren Illinois Utilities' expenses for software and data processing systems, and the program administrator and evaluation contracts.

Evaluation Objectives

There are two categories of objectives for the impact evaluation of the PSP program. The first category focuses on determining how PSP participants are responding to the real-time rates. The second category looks at assessing the net benefits of the program.

For Category One objectives, determination of participant response will be repeated annually for the 2008, 2009, and 2010 program year reports. Several basic evaluation objectives will be covered each year:

- Day-ahead vs. real-time prices – Does billing on day-ahead prices meet the need of providing demand response during hours of high real-time prices?
- Elasticity – How much do participants change their use in response to changing prices?
- Changes in hourly demand – When does most response occur? What time? What season?
- Conservation effect – Does participation in the program reduce overall energy use?
- Bill savings – How much do participants actually save on their electric bill?
- Participation in other Ameren energy efficiency programs – How do savings from PSP participation interact with savings from other Ameren energy efficiency programs?

Each annual report also offers opportunity for the in-depth evaluation of particular issues.

In the 2008 program year, a test group of 120 customers had PriceLights—tabletop glass orbs that glow different colors to reflect current electric price levels. For example, a red glow indicates a high price alert. The 2008 evaluation assessed differences in load reduction for customers with PriceLights.

The 2008 PriceLight program was a special offering funded by a one-year grant from the Illinois Clean Energy Community Foundation (ICECF). A small number of customers who were willing to contribute a portion of the subscription fee continued to use their PriceLights in 2009. However, since there was so little variation in price across the summer the PriceLights never changed their color. Anecdotally, CNT Energy received calls from several customers who thought their PriceLights were broken. Given that there was so little use of the PriceLights, it does not make sense to do a special study of their impacts in 2009.

However, other opportunities for in-depth evaluation are available. Examination of impact differences between two-year (experienced) participants and one-year (new) participants is an enhancement in the 2009 evaluation, as well as an identification of participants who are using the PSP rate to benefit from pre-cooling their home during nighttime hours in the summertime.

The second category of evaluation objectives, assessment of net benefits, will be presented as a completed analysis in the 2010 report. The 2008 report started work on this objective by presenting the methodology to be used, including an approach for estimating market benefits for non-participants. This 2009 report tests the proposed approach for estimating market benefits and presents a preview of what the net benefits assessment will look like. As stated previously, the 2010 report will include the final net benefits assessment based on analysis of program data from 2007 through 2010. The cost/benefit analysis of this program will include a calculation of whether the benefits that non-participants receive exceed the Rider PSP charge they are paying to support the program.

Report Organization

Section II of this report presents the program impacts found from analysis of program participants' electric energy use during 2009. It answers the evaluation questions about participants' demand response posed in the previous section

Section III presents a preview of the estimation of economic benefits from the program, along with an initial assessment of net benefits. This work will be finalized in 2010.

Appendix A contains a complete copy of the 2009 Operational Report for the Power Smart Pricing program. The operational report was prepared by CNT Energy. Readers who are not familiar with the Power Smart Pricing program may find it helpful to review Appendix A before reading the rest of this evaluation report.

Appendices B, C, D and E present supporting detail for the impact evaluation sections of this report.

Section II » Program Impacts for 2009

2009 was another year of rapid growth in participation in the Power Smart Pricing program. At the end of 2008 there were 3,147 participants. By December 31 of 2009, the number of participants had grown to 7,422. This chapter will present findings on how participants changed their electric energy use in 2009 in response to real-time rates.

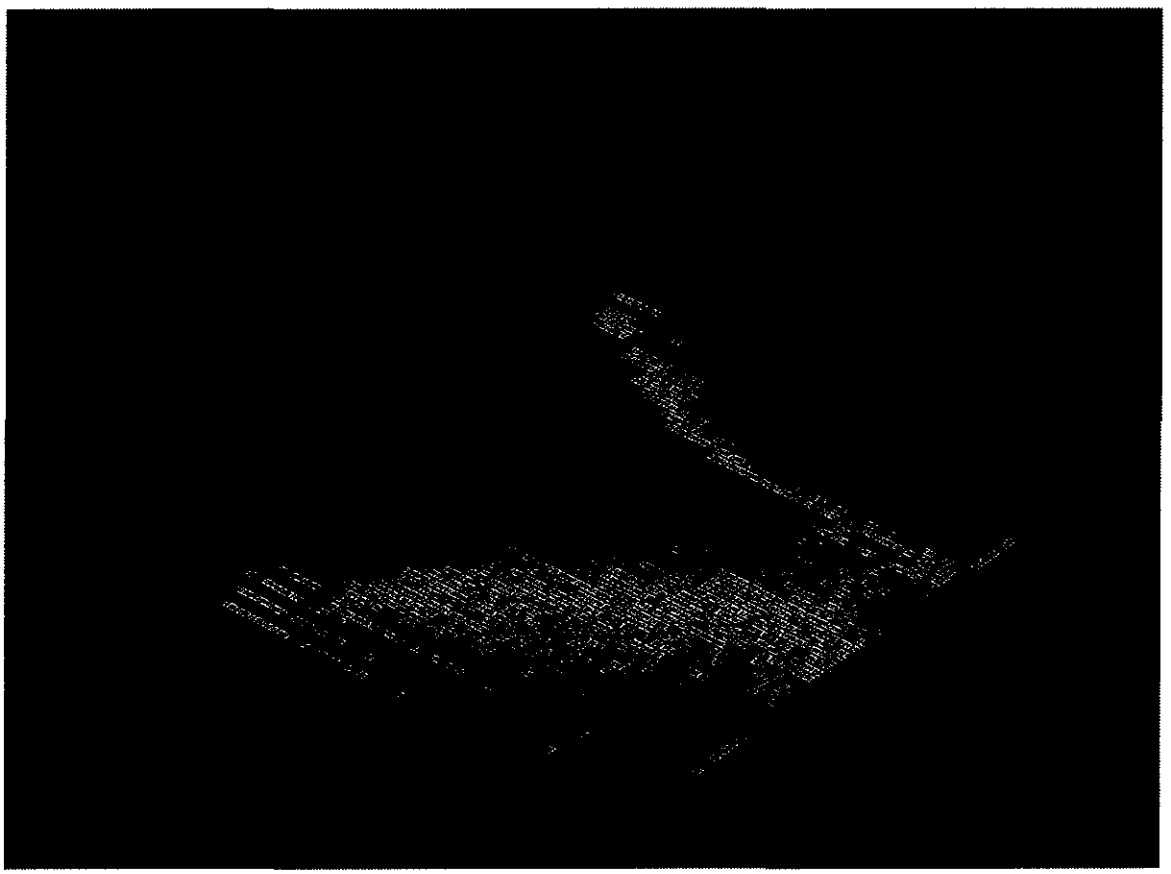
Much of the analysis focuses on hours of the year with high prices and high loads. This is where the action is. However, it is good to keep in mind that every customer uses electric energy every hour of the year, and most hours of the year are low price hours with low usage levels. This becomes apparent when viewing Figure 1 and Figure 2, which show the frequency distribution of hourly energy consumption for all PSP customers over prices and usage levels for 2008 and 2009, respectively.

Figure 1. Distribution of Hourly Prices and Average Loads per Customer in 2008

Both figures have a mountain shape that indicates the dominance of low price – low usage hours. In fact, many of the lowest use hours have been truncated and are not shown on the graph (i.e., the top of the mountain has been cut-off) because including them would make the peak so high that the variation around the base of the mountain would be indiscernible.

The kWh variable in these figures is the kWh usage for one customer during one hour. In the figure the range of this usage rate extends from zero to 20 kWh. There were some hours where hourly usage for some customers was greater than 20 kWh, and these observations are "piled up" and plotted at the edge of the range, hence the preponderance of yellow and green on the 20 kWh line. Similarly, the upper boundary of the price variable was arbitrarily set at 40 cents per kWh, although a few hours had higher prices. This can be seen in the orange and yellow shown on the 40 cents line. These arbitrary boundaries were needed to keep the scale of the chart focused on variations within the primary data.

Figure 2. Distribution of Hourly Prices and Loads per Customer in 2009



A comparison of the two figures is a quick way to understand the fundamental changes in prices and base usage between 2008 and 2009 for PSP participants. In 2008, prices ranged up to 40 cents per kWh. In 2009, they did not exceed nine cents per kWh. On the usage side, as many more participants joined the program, there was a surge in the number of hourly observations with usage greater than 20 kWh per hour. This indicates that customers with higher usage were joining the PSP program in 2009.

The rest of this section of the report will dig deeper into how these basic differences in price levels and usage levels in 2009 translated into program impacts.

Elasticity

A cornerstone of the impact evaluation of the PSP program is the understanding it provides about how much PSP participants change their use of electricity in response to hourly electricity prices. The most commonly used measure of the impact of price on energy consumption is the elasticity of demand. The elasticity of demand indicates the percent change in consumption in response to a 100% change in the price of the good. This section of the PSP impact evaluation presents two different methods for estimating the elasticity of demand that essentially reflect different assumptions about the residential energy demand function. Summit Blue/Navigant Consulting believes that the second method – Method B – is the more accurate of these two (i.e., more accurate than Method A).

Method A – Constant Own-Price Elasticity of Demand

The first method used to estimate the elasticity of demand is identical to that used in the 2008 PSP impact evaluation, in which a log-log demand specification generates a constant elasticity of demand. The model includes fixed effects accounting for household-specific constants. These constants capture the unobservable household-level features that cause a household to consume more or less energy than average. Such features include square footage of the residence, the household size, the absence/presence of attic insulation, and so forth.

The log-log fixed effects model is:

$$y_{it} = \alpha_i + \rho PRICE_t + \beta X_t + \varepsilon_{it}$$

Where:

y_{it} =	Natural log of household *i*'s consumption of electricity (kWh) in hour *t*.
α_i =	Customer-level fixed effect.
ρ =	Estimate of the own-price elasticity of demand.
$PRICE_t$ =	Natural log of the hourly price of electricity in hour *t*.
β =	Vector of parameters.
X_t =	Vector of weather variables in hour *t*.
ε_{it}=	Unobservable random variables

For such a log-log demand specification, ρ is the elasticity of demand. The expected sign for this estimate is negative, since an increase in price would be expected to cause a reduction in the consumption of electricity.

The available hourly data starts in mid-April 2007 with five customers. By the end of 2007, hourly data are available for 350 customers. By June 2008, there are data for 1,470 customers and by the last day of the data set available for analysis the data set includes hourly observations for over 7,000 customers.

In a very small number of hours, the price was zero or negative. This generally occurred in the middle of the night. Data for these hours was excluded from the datasets used for estimation. The natural log of a zero or negative value is an imaginary number. The inclusion of such values would make it impossible to implement a linear regression.

The elasticity was modeled by season, with the two seasons examined (Summer, Winter) defined in exactly the same manner as for the estimate of overall elasticity in the 2008 PSP impact evaluation;

"Summer" including June, July, and August, and "Winter" including all other months. As with the 2008 impact evaluation, only data-points between 10 a.m. and midnight were included in the data-set used for estimation.

Results – Method A

The estimate of the summer demand elasticity using 2009's data, as well as the estimate of the summer demand elasticity reported in the 2008 PSP impact evaluation, are presented in Table 1.

Table 1. Overall Summer Own-Price Elasticity Estimate

	Summer	
	Elasticity Coefficient	Statistically Significant at 90% Confidence Level?
Price (2007 – 2008 inclusive)	-4.3%	Yes
Price (2007 – 2009 inclusive)	-2.3%	Yes

As in the 2008 PSP impact evaluation, the overall elasticity estimate from the winter model did not have the expected negative sign, so there is no winter own-price elasticity to report. A number of reasons were provided in the 2008 PSP impact evaluation as likely causes of the unexpected sign.

These reasons include:

- The natural upswing of inelastic or nondiscretionary electricity consumption in the winter months, particularly the increased lighting requirements engendered by shorter days.
- Generally lower price volatility in the winter than in the summer months (although summer of 2009 prices were not volatile, those of the preceding summers were), meaning that there is less of an incentive both for customer participation (i.e., actively shifting consumption) and for habitual price awareness.

Noting the smaller (in absolute terms) estimate of elasticity once the 2009 consumption data was included in the dataset, Summit Blue/Navigant Consulting conducted some exploratory analysis to determine why the estimate had fallen.

The two major changes in the composition of the dataset since the 2008 PSP impact evaluation were the inclusion of another cohort of participants and the fact that summer prices in 2009 never exceeded $0.08 per kWh (in contrast, from the beginning of the dataset in April 2007 until the end of December 2008 there were 445 days in which the price exceeded $0.08 at some point during the day).

To determine whether the fall in the elasticity estimate was due to the new cohort, two ancillary regression models were estimated. Both use the same model specification as above, the only difference being that in one regression only those customers whose first observation occurred *before* 2009 ("experienced" participants) were included, and in the other regression only those customers whose first observation occurred *in* 2009 ("New" participants) were estimated.

The results of this are shown in Table 2.

Table 2. Elasticity Estimate by Cohort

	Summer	
	Elasticity Coefficient	Statistically Significant at 90% Confidence Level?
Experienced Participants	-1.3%	Yes
New Participants	-5.3%	Yes

The estimates presented in Table 2 suggest that the explanation for the decrease in demand elasticity is not that "new" participants are less price responsive than "experienced" participants. While there may be some exogenous reason for the drop in price responsiveness on the part of the "Experienced Participants" cohort,[4] the only other major change that is endogenous to the system is the much lower average prices observed during the summer of 2008.

If the elasticity of demand is in fact constant – as is implicitly assumed by the model specification – then the fact that prices were much lower in 2009 than they were in previous years should not affect the elasticity estimate. The implication of this analysis is that the assumption that the own-price elasticity of demand for electricity is constant may be too restrictive.

With this in mind, Summit Blue/Navigant Consulting further explored the data, using a series of regressions to estimate the slope of the implied demand curve at a variety of different price-points. The conclusion of this further analysis was that it is highly likely that the elasticity of demand varies by price and that, in addition to own-price effects, there is strong evidence to suggest the presence of cross-price effects. A consumer's consumption of electricity in any given hour of a day is a function not just of the price in that hour of the day, but also a function of the price in other hours of the day, indicating load-shifting. The details of this exploratory analysis may be found in Appendix B at the end of this report.

Method B – Two Constant Own-Price Elasticities of Demand

While exploratory analysis undertaken in Appendix B provides good direction for the PSP impact evaluation in 2010, a full analysis of sufficient robustness to be reported following the procedures suggested in Appendix B is beyond the scope of this year's PSP impact evaluation. Indeed, given the paucity of high-price data points in 2009, even the most robust analysis implemented according to the suggestions of Appendix B might not produce conclusive results.

Instead, Summit Blue/Navigant Consulting presents Method B as an interim step toward the more detailed variable elasticity analysis that will be undertaken in the 2010 PSP impact evaluation. Method B is an interim estimation of the elasticity of demand that assumes the elasticity of demand is constant both above and below a threshold price, but allows the demand elasticity to change across the threshold. The threshold price, $.13/kWh, somewhat arbitrarily serves as the lower boundary of the "high" price range.

[4] The question of behavior persistence will be addressed more fully in the final year of the PSP Impact Evaluation when there is more data available on how customer behaviors change over time.

This Method B provides results that are easily compared with the results reported in the 2009 PSP impact evaluation and the results reported in other similar studies, but somewhat relaxes the assumption of constant own-price elasticity of demand. It is anticipated that this assumption will be further relaxed in the 2010 PSP impact evaluation.

Summit Blue/Navigant Consulting believes that the results presented below are more accurate and should be used for comparison and reporting purposes rather than the estimate obtained by Method A, which Summit Blue/Navigant Consulting regards as being based on an assumption that is too restrictive.

In this case, Summit Blue/Navigant Consulting has estimated the same model as in Method A, for non-holiday weekdays, between 6 a.m. and midnight, by season (winter, summer, and shoulder), both below and above a threshold price implied by the analysis presented in Appendix B. Note that these estimates, as with those presented in Appendix B, will tend to be conservative because of intra-day correlation. This means that positive estimates of own-price elasticity observed below the chosen threshold price may safely be considered to be no different than zero, since otherwise it would imply that consumption will rise in tandem with prices – clearly a spurious conclusion.

Results – Method B

The results of the Method B regressions are reported below. Cells with values of N/A indicate nonsensical positive estimates and should be treated as equivalent to an estimate of zero. Model output with all parameter estimates are presented in Appendix C of this report.

Table 3. Method B Summer Elasticity Estimates

	Summer - $0.13 Threshold Price	
	Elasticity Coefficient	Statistically Significant at 90% Confidence Level?
Below Threshold Price	-1.0%	Yes
Above and Including Threshold Price	-24.8%	Yes

Table 4. Method B Winter Elasticity Estimates

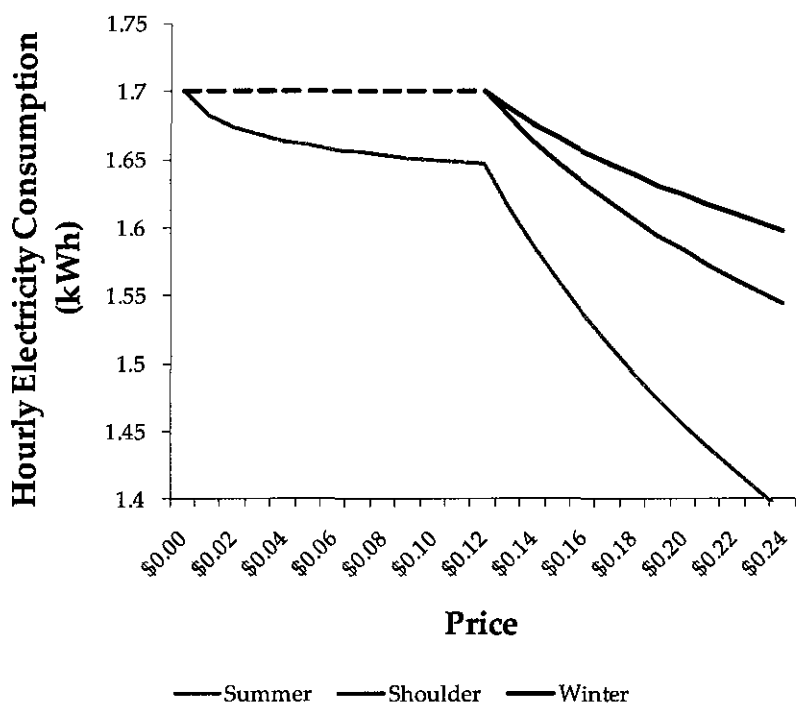
	Winter - $0.13 Threshold Price	
	Elasticity Coefficient	Statistically Significant at 90% Confidence Level?
Below Threshold Price	N/A	Yes
Above and Including Threshold Price	-8.7%	Yes

Table 5. Method B Shoulder Season Elasticity Estimates

	Shoulder - $0.13 Threshold Price	
	Elasticity Coefficient	Statistically Significant at 90% Confidence Level?
Below Threshold Price	N/A	Yes
Above and Including Threshold Price	-13.5%	Yes

In order to provide the reader with some context as to the meaning of these estimates, Summit Blue/Navigant Consulting has plotted the implied demand curve for a customer whose average base hourly consumption of electricity is 1.7 kWh (see Figure 3). From this plot the predicted consumption for such a consumer may be observed at each price level. Where the demand curve line is dashed indicates positive nonsensical estimates of the own-price elasticity of demand.

Figure 3. Demand Curves by Season Implied by Method B Estimates[5]



The analysis and results presented above should be understood to be both a significant improvement on those presented in the 2009 PSP impact evaluation, and a step toward a more rigorous and robust analysis of the consumer demand function for electricity. It is expected that the analysis to be presented in the PSP impact evaluation report for 2010 will make use of either a regime-changing model with

[5] Although no prices exceeding $0.08 were observed in the summer of 2009, hourly prices exceeding $0.24 (the x-axis limit of Figure 3) were observed in all seasons over the entire period of analysis.

Markov-switching (to better assess a threshold price) or an almost ideal demand system framework (to better control for cross-price effects) or some amalgam of both. Readers interested in these frameworks are encouraged to read the final section of Appendix B, which presents these frameworks in greater detail, along with some citations of previous work of a similar nature performed using them.

Hourly Demand Impacts

An elasticity estimate is a way to describe general price responsiveness in a single number. Elasticity measurements provide a convenient way to compare results across studies, and they also provide a predictive modeling tool that can be used to create ex ante estimates of savings in future years under different price scenarios.

There is additional information about the hourly demand impacts of the PSP program in 2009 that can be gained by comparing typical load curves for PSP participants to load curves for a control group of similar customers that did not participate in the program. The difference in these load curves is a good indicator of the ex post hourly impacts of the program in 2009 if the control group is a good match to the participants.

This section describes the methodology used to develop a good set of matched control group load curves, and then results of the comparisons will be summarized and shown in graphical form.

Methodology

The objective of the hourly demand impact study is to compare average load curves for PSP participants to a matched control group. In the 2008 evaluation, hourly demands were estimated for the following day types:

1. Regular Summer Weekdays
2. Regular Summer Weekend Days
3. High Price Alert Summer Weekdays
4. High Price Alert Weekends
5. Regular Shoulder Month Weekdays
6. Regular Shoulder Month Weekend Days
7. Regular Winter Weekdays
8. Regular Winter Weekend Days

In 2009, the summer was very cool and there were no High Price Alert days. Consequently, hourly demand estimates will only be developed for the other six day types (Summer, Shoulder, Winter – Weekdays and Weekend Days).

The basis of the typical load curves developed for PSP participants was the same collected and cleaned hourly load data that was used for the development of the elasticity models. While the elasticity study looked at all available hourly data going back to 2007, the load curve study used only data for the calendar years of 2008 and 2009.

The hourly data for the control group came from the Ameren-Illinois load research sample. Average load curve information was supplied for twelve different customer groups. The twelve customer groups covered four strata for each of three companies. The three companies were CIPS, CILCO, and IP. The four strata had the following definitions:

Strata 1: Low Summer, Low Winter

Strata 2: Low Summer, High Winter

Strata 3: High Summer, Low Winter

Strata 4: High Summer, High Winter

For these strata designations, summer is defined as June, July, August, and September. Winter is December, January, and February and shoulder months are April, May, October, and November. Low summer use is defined as a maximum monthly kWh usage less than or equal to 1,300 kWh, and high summer use is over 1,300 kWh. Low/High Winter use is determined by looking at the winter-to-shoulder ratio. The winter-to-shoulder ratio compares average winter use per day to average shoulder use per day for each customer. If the winter-to-shoulder ratio is less than or equal to 1.6, then the customer is Low Winter use; otherwise they are High Winter. The one exception to these definitions is for CILCO where the cut-off for the winter-to-shoulder ratio is 1.8 instead of 1.6.[6]

The goal of the load curve comparisons is to make a control group that is very closely matched to the characteristics of the participant group. In this way, the observable difference in the load curves for the two groups is most likely to represent the impact of the PSP program on the participants' energy use. If not for the program, the two load curves would be the same because the two groups are similar.

Given the data available for this analysis, the best way to create a matched control group was to determine which load research group each PSP participant matched best. This was done by looking at the company designation for each customer and using the strata definitions to place each PSP participant into the appropriate strata. This step created several interesting observations about PSP participants that are shown in Table 6.

Table 6. Comparison of Strata

	All Residential Customers	PSP Participants 2008	PSP Participants 2009
Low Summer – Low Winter	52%	43%	44%
Low Summer – High Winter	12%	11%	12%
High Summer – Low Winter	31%	40%	36%
High Summer – High Winter	5%	5%	8%
TOTAL	100%	100%	100%

[6] The 1.8 cut-off for CILCO was determined by the AIU load research team based on differences in weather patterns and base usage in the CILCO service territory.

PSP participants in both 2008 and 2009 are less likely to be low energy users than the general residential customer population. While 52% of all residential customers are in the low use category (Low Summer – Low Winter), only 43%-44% of PSP participants are low energy users. PSP participants show a good representation across the smaller High Winter use categories, matching the distribution of the residential customers almost exactly in 2008 (17% High Winter users for residential customers compared to 16% for PSP participants in 2008). The biggest change in the composition of the PSP participants in 2009 compared to 2008 comes from a surge in the number of High Summer – High Winter users, moving from 5% to 8%. This reflects the impact of the targeted marketing that was done throughout the year to attract high winter users to the program. It makes sense to target this group since customers who use more electricity have a greater opportunity to save money on the PSP rate, as well as having a higher electric bill and more of an incentive to try to save.

After determining the correct strata designation for each PSP participant, average load curves were developed by strata for each of the day types of interest. These average load curves could be compared directly to similar day types for each strata calculated from the Load Research data. The result is a series of 32 graphs (eight day types by four strata), which show the estimated hourly demand impacts of the PSP program.

These graphs were reviewed to see if there were obvious differences in the shape of the program impacts across the four strata for a given day type. The conclusion was that each strata responded similarly to similar hours of the same day type. The magnitude of the response varied; since low use strata had noticeably lower load curves than high use strata, the differences between the PSP participant group and the Load Research control group occurred in the same hours with roughly the same percentage impact. Based on this visual observation, it was determined that the four strata could be combined to create a good overall estimate of the hourly demand impacts for each day type. Consolidating the strata charts by day type increases the sample size and smoothes out the curves, creating a better estimate of typical hourly demand impacts. In the 2008 evaluation report, the set of 32 load shapes across individual strata groups were presented to illustrate these points. Since strata variations showed the same characteristics in 2009, the revised set of 32 load shapes will not be included in this report. The 2009 individual strata charts do not add any new information to the on-going evaluation, and leaving them out creates the opportunity to look at differences in load shapes for a variety of other customer subgroups instead.

The final overall control group load curves for each day type were constructed by weighting the strata-level control group load curves based on the distribution of customers in the corresponding PSP participant strata. For example, the strata one comparison curves were known to represent 43% of all the PSP participants. This weighting creates final overall load curves that compare actual PSP participant loads on the given day type to a matched comparison group created from the Load Research data.

Results

In 2009, average hourly demand impacts from the PSP program were estimated for three different seasons. The following season definitions were used:

Summer – June, July, August[7]

Winter – January, February[8]

[7] Seasons for load curve comparisons were defined based on similarity of usage patterns, not standard rate tariff definitions. Summer is June, July, and August.

Spring/Fall – March, April, May, September, October, November

Results for each season will be presented separately, starting with summer. The summer season is generally the season of greatest interest since it is the season of the system peak.

Summer Weekdays

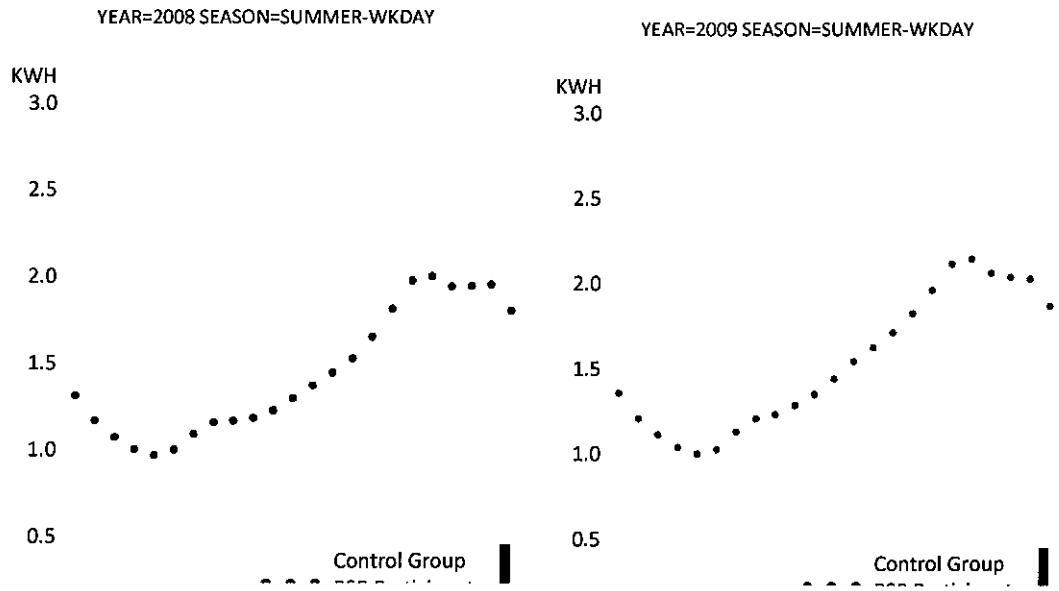
As previously discussed, there were no High Price Alert days during the summer of 2009. In 2008, these were the days that showed the most daytime load impact for PSP participants with an average load reduction of 0.23 kW per customer from Noon to 5 p.m. On other summer weekdays, PSP participants continued to show lower daytime use and higher nighttime use, with an average load reduction of 0.15 kW per customer from Noon to 5 p.m. The important question for 2009 is whether or not PSP participants continued to show daytime load reductions on regular summer days even though the weather was cooler and prices were lower than the summer before.

A comparison of the summer weekday load curves for 2008 and 2009 given in Figure 4 shows that PSP participants continued to alter their daily load shape in 2009. In 2009, PSP participants showed greater usage than the control group during evening and nighttime hours and similar use during the daytime. In comparison, in 2008 the evening and nighttime hours were also higher, but daytime use was actually lower than the control group.

In 2008, the difference between the PSP participants and the control group was used without adjustment to estimate the average load reduction of 0.15 kW per customer from noon to 5 p.m. Using this same method in 2009 would create an average load reduction estimate of zero reduction for the same time period. This is not a reasonable answer since the comparison of the load shapes shows a definite daytime response for PSP customers. Why does the 2008 method not work for estimating load reductions in 2009?

[8] December was not included in the winter season for this study because quality-checked load research data for December 2008 was not available at the time the analysis was completed.

Figure 4. Summer Weekday Average Load Shapes for 2008 and 2009

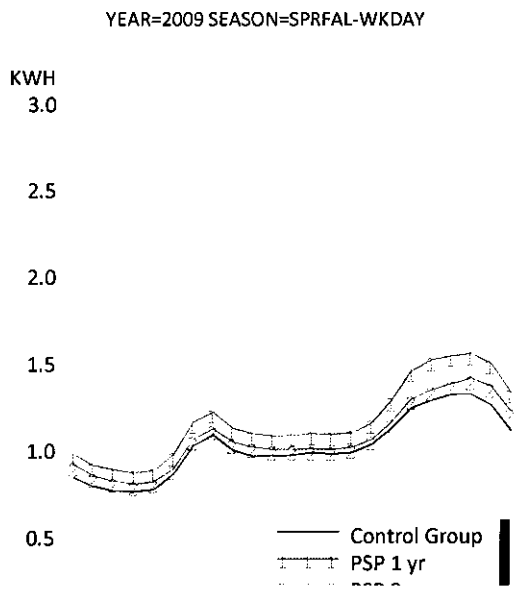


The most likely answer is that base use for PSP participants has changed since 2008. This would be consistent with the previous finding that there are now more High Summer – High Winter customers in the PSP participant group. There was also a significant increase in program participation between year-end 2008 and year-end 2009. The number of participants more than doubled, going from 3,147 to 7,422.

These conditions could create some real differences in the base use of participants who have been in the program for two or more years versus those that are new participants. If the base use for PSP participants has actually changed because of new participants, a different method for estimating average summer impacts from the comparison load shapes could be warranted.

One good method for assessing changes in base use is to look at usage during the Spring and Fall seasons. All electric use in these months tends to be base use since outdoor temperatures are moderate and electric space heating and air conditioning are not significant factors. Figure 5 shows that new one-year participants have a decidedly greater base use than the older two-year participants during the Spring and Fall months, and this greater use is particularly strong in the evening hours. This supports the conclusion that the PSP participant group has a higher average base use in 2009.

Figure 5. Comparison of Base Use Load Shapes for 1-year vs. 2-year Participants



The increased base use of new PSP participants may be simply a result of targeted marketing to high use customers, but it is also possible that the increased use of PSP participants in 2009 is spurred by their access to low rates. While elasticity estimates are generally referenced when predicting decreased usage due to higher prices, elasticity works both ways and lower prices could cause increased use. Did the general low rates for PSP participants in 2009 encourage them to use more energy and increase their base use compared to regular customers on standard rates?

Anticipating a need to answer this question in the evaluation, a special series of survey questions were included in the Fall 2009 participant survey.[9] These questions tried to assess participant awareness of the low rates in 2009, and then follow-up with a question on whether or not they changed their energy usage in response to their awareness. A neutral open-ended question was asked about how they changed their energy use if they had indicated they did make changes. This was done to create the opportunity for customers to report that they were using more energy because prices were so low, without offering that possibility as a leading question.

Table 7 shows the results of this series of questions. Only 66% of respondents were aware that 2009 summer prices were lower than 2008 prices. Of those who were aware of the lower prices, 70% indicated that they changed their use of energy in 2009 compared to 2008. Review of the verbatim responses to the open-ended question on how they changed their use revealed only eight customers who made any mention of using electricity more, or even reducing their efforts to shift/save, because of the low prices. Most customers reported taking the load reduction and shifting actions recommended in the PSP

[9] The Fall 2009 participant survey was part of the Fall Newsletter sent to all PSP customers. Responses were voluntary and were received from approximately 950 participants.

literature. The conclusion from review of this data is that the low prices in 2009 were not a contributing factor to the overall increase in base use for PSP participants.

Table 7. Survey Responses on Increased Use Due to Low Prices in 2009

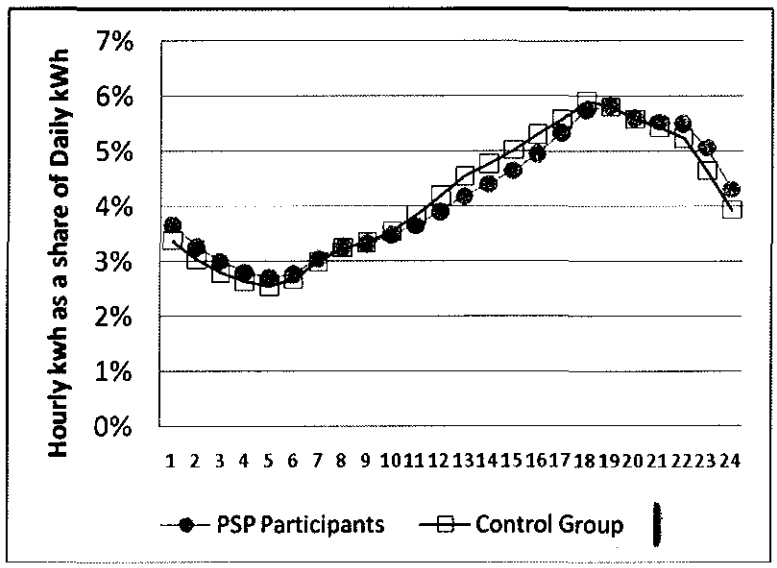
Survey Question	Total N = 941
"Think about the prices you paid for electricity this summer compared to what you paid for electricity last summer." Number who feel Summer 2009 prices are lower than 2008:	618 (66%)
Of these, number that said they changed how they used electricity in Summer 2009:	432 (70%)
Of these, number that said they used more electricity or "did not make heroic efforts" to save in 2009 because prices were low:	8 (2%)

Now that an increase in base use as a distinguishing characteristic of new 2009 PSP participants has been established, it becomes necessary to develop a better method for estimating the summer hourly impacts of the program.[10]

The best method for estimating the hourly summer impacts of the PSP program in 2009 is to create indexed load shapes for each group, the control group, and the PSP participants, and then calculate the hourly differences based on the average daily kWh consumption for PSP participants. Figure 6 shows the indexed load shapes, and this brings the relationship between participants and the control group very much in line with what was seen in 2008. Therefore, while overall use has increased a bit for PSP participants, their basic response pattern on regular summer days has not changed.

[10] It is noted that, theoretically, the weighting of the different strata load curves for the control group to match the distribution of PSP participants should create an overall control group load curve that reflects the PSP participants' move towards high use strata. While this is true, the fact that the weighting does not work as well in 2009 as it did in 2008 indicates that PSP participants are coming from the higher use customers *within* each strata, as well as from different strata.

Figure 6. Indexed Summer Weekday Load Shapes for 2009



Using the indexed load curves and applying the same average daily kWh use to each group, the 2009 estimate of the average hourly load reduction per customer from Noon to 5 p.m. on summer weekdays is -0.13 kW. This is very close to the estimate of -0.15 kW reported last year for 2008.

However, the indexing method was not used last year because there was less of a difference in base use between the two groups. Table 8 shows that in 2008 PSP participants only used slightly more energy on summer weekdays than the control group, an additional one kWh per day. In 2009, this increased to a difference of 2.6 kWh/day.

Table 8. Average Daily kWh Use for Summer Weekdays

	Control Group	PSP Participants	Difference
2008	33.3 kWh/day	34.3 kWh/day	+1.0 kWh/day
2009	34.0 kWh/day	36.6 kWh/day	+2.6 kWh/day

While use of the indexing method would have had less of an effect on 2008 estimates than it has shown in 2009, it is still a better method for even-handed comparison of hourly load differences between the two groups. Data from 2008 was used to re-estimate the average summer impacts using the indexing method for that year. The results in Table 9 show that the original estimate of -0.15 kW average load reduction for the hours of noon to 5 p.m. on regular Summer Weekdays would change to -0.18 kW using the indexing method, and the estimate of -0.23 kW for High Price summer days would change to -0.27 kW. This does not change the general finding from the 2008 study that on High Price summer days (summer peak days) four PSP customers contribute approximately the same amount of load reduction as one Direct Load Control customer would.

Table 9. Average Load Reduction for PSP Participants During the Hours of Noon to 5 p.m.

	2008 Original Estimate	2008 Revised Estimate	2009 Estimate
High Price Summer Days	-0.23 kW/cust	-0.27 kW/cust	Not Available
Regular Summer Weekdays	-0.15 kW/cust	-0.18 kW/cust	-0.13 kW/cust

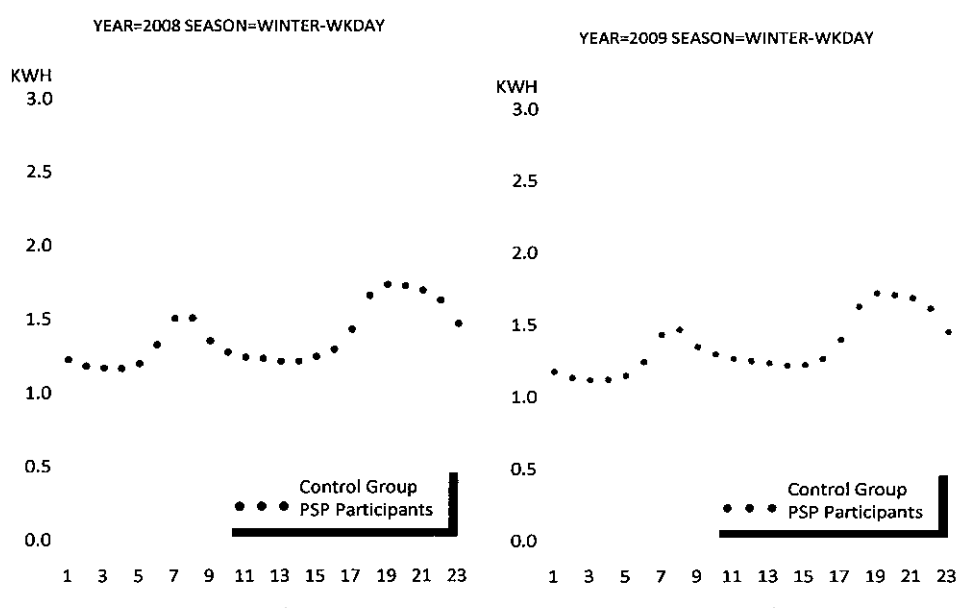
We recommend use of indexed load shapes as a better method for estimation of hourly PSP impacts in the future because it adjusts for any differences in average daily use that may exist between the control group and the PSP participants. While this difference was considered to be insignificant in 2008, it is growing and it has become important to adjust for it.

Winter Weekdays

The single-hump load shape for summer changes to the traditional double-hump load shape in winter for both the PSP participant group and the control group. There is a morning peak between 6 a.m. to 8 a.m. when customers are getting ready for their day and before many of them leave their home, and a second peak in the evening from 5 p.m. to 9 p.m. when many come back home again and everyone is turning on lights, cooking dinner and being active within their homes.

In the 2008 evaluation, it was found that PSP participants have slightly more nighttime use in winter than regular customers. Figure 7 shows that this same relationship does not continue in 2009. In 2009, the average daily load shape is nearly identical for PSP participants and the control group.

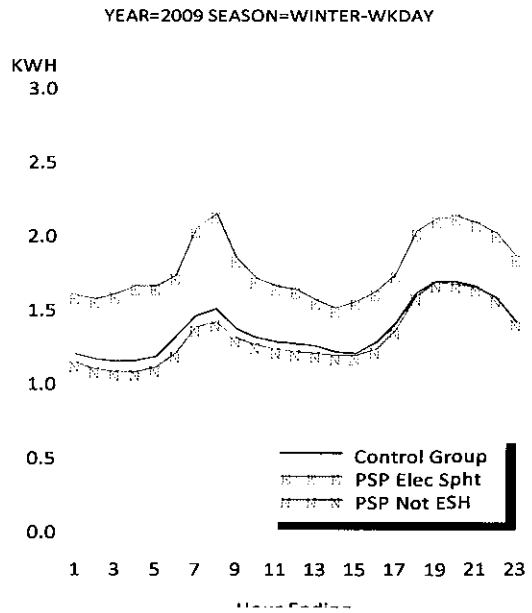
Figure 7. Winter Weekday Average Load Shapes for 2008 and 2009



It is likely that this change is coming from a difference in the saturation of electric space heating within the PSP participant group. This hypothesis is based on the observation that electric space heat customers

have very distinctive load shapes in the winter, and a small additional influx of electric space heat users could make small differences in the overall participant load shape. Figure 8 illustrates the unique winter load shape of electric space heat customers. Additional work would have to be done to isolate the impact of electric space heat customers on the overall load shape, but this effort does not seem warranted at this time given the very small difference between PSP participant and control group load shapes on Winter Weekdays.

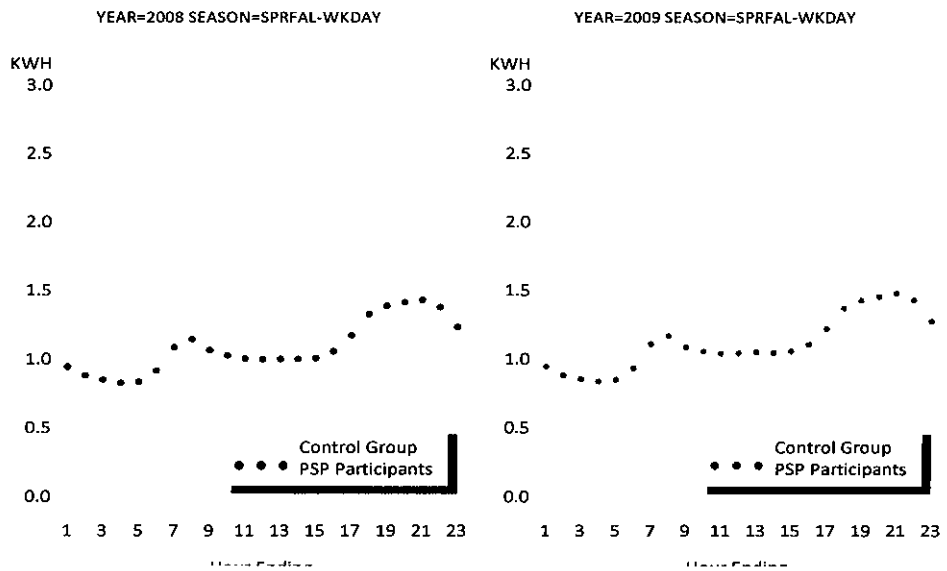
Figure 8. 2009 Winter Weekday Load Shapes for Electric Space Heat vs. Other Heat



Spring/Fall Weekdays

In 2008, it was noted that PSP participants and the control group had very similar load shapes in the Spring and Fall. Figure 9 shows that in 2009 the load shapes remained very similar during this season, but total use for PSP customers increased across all hours. There is some indication that use increased even more in the evening hours. As presented previously, this increase in base use is largely coming from the new participants in the PSP program.

Figure 9. Spring/Fall Weekday Load Shapes for 2008 and 2009



Customers Using Super-Cooling

One strategy that PSP participants can use to save money on their electric bill is super-cooling. On hot summer days, they can run their air conditioning overnight, when prices are low, to super-cool their home. Then, if they can keep it insulated from the daytime heat (i.e., draw down window shades, limit door openings, etc.) they can stay comfortable for much of the day without using expensive daytime energy. The added benefit of this strategy is an overall reduction in energy use. Air conditioning runs more efficiently when outdoor temperatures are lower, and this reduces total energy use.

Of course, this strategy can be used at various levels of intensity. Some people may just turn off their air conditioning when they leave for work in the morning and then turn it back on when they get home in the evening so they can sleep comfortably. Others may make conscious efforts to make their home extra cool during the nighttime and ride through the daytime with low outdoor temperature infiltration and regular fans for comfort.

The available hourly data was examined to estimate how many PSP customers are using super cooling strategies at different levels of intensity. To do this, data for the five hottest weekdays during the summer was selected. Since we are looking at activity during the night before and the night after the hottest day, a period of thirty-six hours was analyzed which spanned from 9 p.m. on the evening before the hottest day and continued through 9 a.m. on the morning after the hottest day.

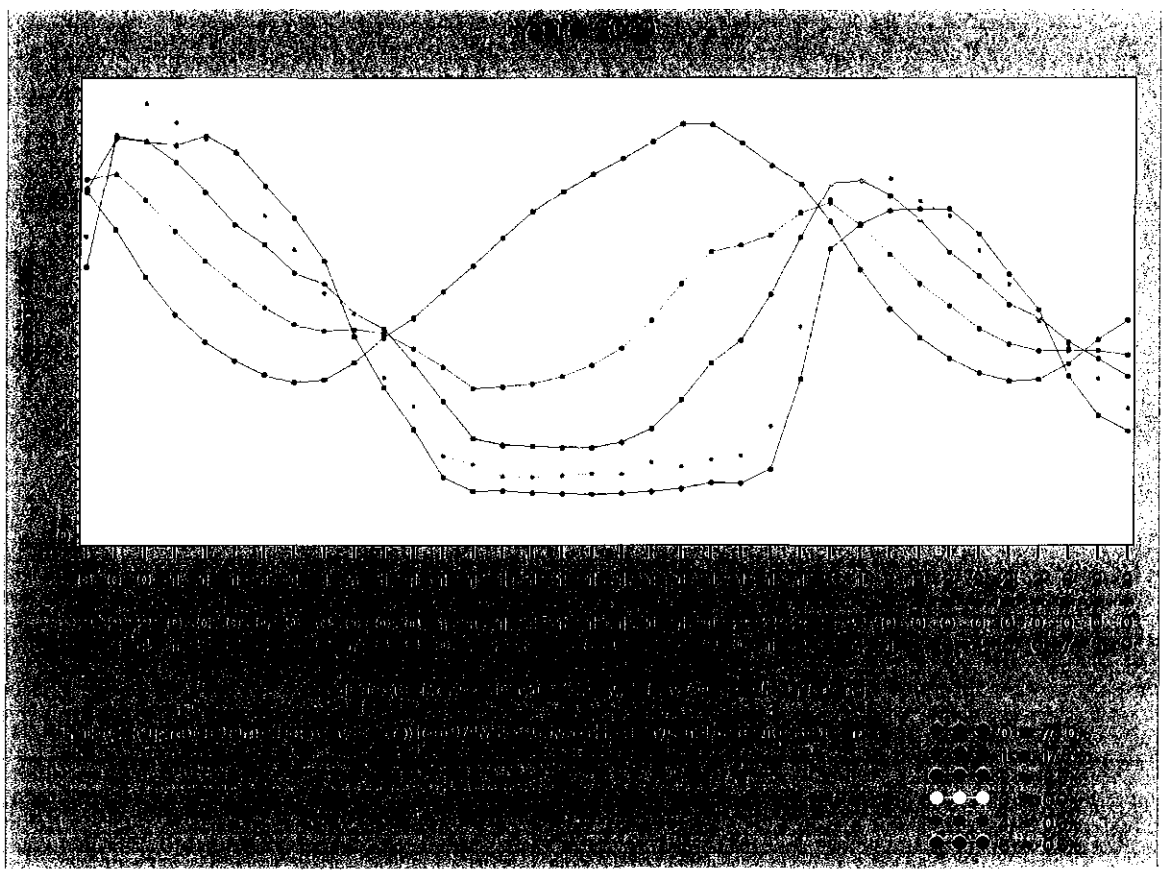
To gauge the intensity of super cooling efforts, a ratio was developed for each individual customer's usage pattern on each individual hot day. The ratio compared the total 9 p.m. to 9 a.m. usage before the hot daytime to the total 9 a.m. to 9 p.m. usage during the hot day. Each customer day was then assigned to a group by taking the integer value of their ratio. Customer days with a ratio of zero used more energy

during the daytime than during the nighttime. Customer days with a ratio of one used between 1.0 and 1.9 times more energy during the nighttime period than during the daytime period, etc.

Figure 10 illustrates the average load shapes for each of these groups, and provides a summary of the number of customers in each group. It shows that in 2009, 78% of participants used more energy during the daytime than during the nighttime period while 22% exhibited some significant load shifting to the off-peak hours. Presumably, these significant load shifts are related to super cooling strategies. This is not to say that the 78% did nothing to respond to price, but simply that they did not make shifts that were as extreme as some other customers did. The five hottest days in 2008 were also examined and results were very similar, with 24% of customers showing extreme shift patterns.

This graph also illustrates that about 18% of customers are practicing lower intensity super cooling with the remaining 6% using more extreme intensity practices. There are obvious inflection points around 7 a.m. to 8 a.m. in the morning and later at 10 p.m. to 11 p.m. were the super cooling groups start making their transition in usage.

Figure 10. Load Shapes on Hottest Days for Different Super Cooling Intensities



One curious observation is that off-peak loads appear to be higher on the night before rather than the night after. Our initial thoughts were that the loads on the night after would be higher because of snapback. Of course, the outdoor weather has a large influence on the overnight loads. It is likely that the evenings before were hotter than the evenings after. It is also interesting to note that the average nighttime peaks for the extreme intensity super cooling groups are as high as the daytime peaks of the

regular participants. This is an indication that it may be larger users that are making use of super cooling strategies the most.

Appendix D offers the interested reader additional load curve comparisons for various subgroups of customers.

Conservation Effects

The conservation effect can be defined as the percentage change in average total energy used by customers over a defined time period. For example, an annual conservation effect of 3% means that the average total annual use for participants is 3% less in the years following their joining the program, when compared to the years before. This effect is also evident when seasons (i.e., summer, winter, and shoulder) are modeled independently of the rest of the year.

The conservation effect gives a good indication of how customers are (or are not) changing their overall behavior with regard to their overall level of energy use once on the program, even when there are not many high price days. In addition, it shows how much total energy is saved when air conditioning load is shifted to later in the day by customers setting their thermostats to a higher than normal temperature at the peak cooling time. This reduces the energy needed to cool even when the thermostat returns to its usual temperature because the temperature outside will have fallen from its high point in the late afternoon.

The next section describes the econometric models used to estimate the conservation effect for this year of the study, and this is followed by a section that presents the results from the models.

Methodology

Approach

For this task, we used an approach that compared weather-normalized average monthly use from the pre-participation period to the post-participation period for each participating customer and for a control group. The control group was comprised of individuals in AIU's load research samples.

Usage and other related data were available both across a group of customers (i.e., cross-sectional) and over time (i.e., time-series). With this type of data, known as "panel" data, it is possible to control at the same time for differences across facilities as well as differences across periods in time through the use of a fixed effects model. The term "fixed effect" refers to the assumption that differences across customers can be explained in large part by customer-specific intercept terms, as discussed below.

Because the consumption data in the panel model includes some months before and after customers started to participate in the program, the pre-participation months of consumption act as controls for post-participation months. In addition, this model, unlike annual pre/post-participation models such as annual change models, does not require a full year of post-participation data.

The fixed effects model can be viewed as a type of differencing model in which all characteristics of the customer that(a) are independent of time, and (b) determine the level of energy consumption, are captured within the customer-specific constant terms. In other words, differences in customer

characteristics that cause variation in the level of energy consumption, such as building size and structure, are captured by constant terms representing each unique customer facility.

Algebraically, the fixed-effect panel data model is described as:

$$y_{it} = \alpha_i + \beta x_{it} + \Delta E \cdot F_{it} + \varepsilon_{it}$$

Where:

y_{it} = Energy consumption for site *i* during month *t*

α_i = Constant term for site *i*

β = Vector of coefficients

x = Vector of variables that represent factors causing changes in monthly consumption (i.e., the time-effects variables such as weather)

ΔE = Coefficient that represents change in energy use for participants

F_{it} = Flag indicating participation in the program for each month (set to one if participating and zero if not participating), for site *i* during month *t*

ε = Error term

In practice, rather than estimating a unique intercept term for each customer, an equivalent approach is employed that expresses both the dependent and independent variables in terms of deviations from the time-series means for each customer. The resulting estimated coefficients from this "deviation from the mean" approach are equal to the coefficients found by having customer-specific intercept terms.

That is, it can be shown that:

$$\alpha_i = \overline{y_i} - \beta \overline{x_i}$$

This implies that the customer-specific intercept term captures the difference between the average energy use for that customer and the predicted average energy use (from the model) during the time period used in the model. Therefore, the fixed-effects model explains the month-to-month deviation in energy use rather than the level of energy use.

Participation in Other Energy Efficiency Programs

423 of the customers in the data set also participated in one or more of five other residential efficiency programs that were offered by AIU in 2009.

Of these customers, 397 participated in one EE program, 27 participated in two EE programs, and four customers participated in three EE programs. Total savings for each program from the initial month of participation through the end of 2009 for the participating customers, and number of participants, are shown in Table 10.

Estimated annual savings and date of measure installation were available for all PSP participants and these values were included in the model to prevent savings from the measures being attributed

incorrectly to the PSP program. Annual savings were distributed by month equally throughout the year, starting in the month that the measure was installed.

Table 10. Savings and Participation in Other EE Programs[11]

	Home Energy Performance	ARCA Appliance Recycling	HVAC New	Lighting & Appliances	Demand Response
Total Savings (kWh)	11,709	196,530	31,720	26,131	1,194
Average Savings (kWh/day)	1.00	5.24	8.87	1.19	0.46
Participants	82	181	29	128	38
Average Number of Months of Savings	5	7	4	6	2

An attempt was made to compare PSP customer participation in these programs to the general participation rates observed for all residential customers. The evaluation report on overall results of the residential energy efficiency programs in Program Year One (PY1) provides some information on participation rates for the overall population.[12] However, PY1 for energy efficiency programs does not coincide with calendar year 2009 which is the focus of this study. It was not possible to make the comparison using existing reports.

Data

Data was available for years 2007, 2008, and 2009 and it included both the PSP participants and a much smaller control group. The basic unit of time for the data in the conservation model was one billing period. This billing period was usually, but not always, approximately one calendar month. There were some occasions in which there was more or less than one billing period in each calendar month.

The data included the following categories:

1. Basic customer data – customer account number, primary month, primary year, and number of billing days in each billing period.

2. Energy data – kWh used during each billing period, expressed as kWh/day to normalize for the number of days in the billing period.

3. Pricing data – number of high-priced days in the billing period.

4. Climate data - average monthly temperature, heating degree days, cooling degree days, and temperature humidity index for each billing period. Heating degree days, cooling degree days

[11] Descriptions of these programs can be found in "ActOnEnergy Energy Efficiency and Demand-Response Program Results, Year One Activities" prepared by Ameren Illinois Utilities, January 2010.
[12] See "Residential Program Portfolio: PY1 Evaluation Report", prepared by The Cadmus Group, Inc., October 23, 2009.

and the temperature humidity index were normalized for billing days in the period (e.g., average heating degree days per day during the period).

5. A participation flag that indicates whether or not the customer was a participant during each billing period. This is set to zero if the customer was not participating and set to one in the first billing period that the customer started participating, and for all subsequent months. This was zero in all months for the control group.
6. A flag indicating if the customer was in the control group or the PSP group.
7. Effects of participation in other energy efficiency programs – this data was the estimated (non-verified) savings due to the customers' participation in one or more of five other energy efficiency programs. Savings were given as estimated kWh saved per month, starting at the month in which the measure was installed, and then normalized for the billing days in the period.

Regression Model

The regression model was run using all available Control Group and PSP Group data. Some data screening was done to ensure a sufficient number of data points per customer for a reliable result. For example, customers in the PSP Group that had less than five data points in which the participant flag was set were excluded.

The model was then run in two ways:

1. Annually, by strata. The strata designations were supplied by AIU and there are four of them, as follows:
    - Strata 1: Low Summer, Low Winter
    - Strata 2: Low Summer, High Winter
    - Strata 3: High Summer, Low Winter
    - Strata 4: High Summer, High Winter
2. By season and annually for the whole population. The seasons are defined as:
    - Winter – November, December, January
    - Summer- June, July, August
    - Shoulder – all other months

Once the models had been run and verified as statistically significant, the change in consumption was then calculated as the coefficient of the participation flag times the number of days in the period of the model.

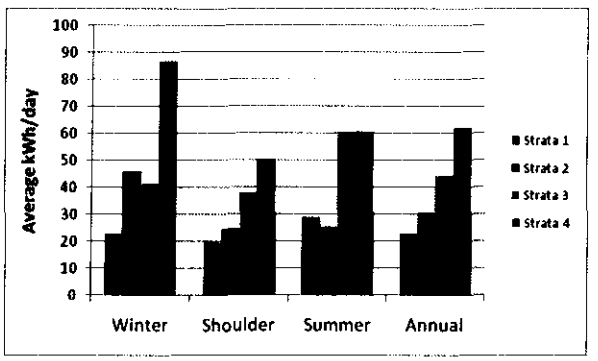
Results

The key result from the conservation modeling is that Power Smart Pricing participants reduced their total energy use in response to variations in hourly prices during both the summer season and shoulder months, but increased their total energy use in the winter months. Overall, the annual energy use of participants was lower when compared with the time before they joined the program. Precision levels for the savings estimates range from 11% to 20% at the 90% confidence interval, and all of the estimates are statistically significant at the 99% confidence level.

Baseline

A simple statistical analysis was first done to determine average kWh use by strata, for each season and annually, to establish a baseline total energy use in the months when customers were not participating. As can be seen in Figure 11, customers in stratum one and three use more in winter than in summer, and the converse is true of stratum two and four. Annual energy use and energy use in shoulder months increases moving through strata one to strata four.

Figure 11. Average Energy Use by Strata and by Season



Savings

Table 11 shows the results of the conservation model when run by season and for the whole year. For the seasonal analyses, the data for each season was run as a separate model. The variables included in the model were: PSP Participation flag, average THI/day, average HDD/day, and the estimates of savings from the other energy efficiency programs. The inclusion of savings estimates from the five other energy efficiency programs improved the model, but the individual realization rates for the savings estimates were not significant.

The results show that PSP customers saved over 5% of total summer use, and just over half a percent of use in the shoulder months. The result for winter was not valid, but comparing the annual savings value of 1.2% and the values for summer and shoulder implies that the savings were negative in the winter.

The overall savings effect of 151 kWh per customer per year (1.2%) for the period of 2008-2009 is very similar to the 2008 reported savings of 186 kWh per customer (1.5%). We believe this new estimate to be a more accurate value as the data set contains more data points (i.e., customers) over a longer time period. If, in fact, summer savings are related to shifting air conditioning use, it is possible that savings were suppressed in the summer of 2009. The cooler weather meant less total use of air conditioning, and that would translate into less savings from air conditioning.

Table 11. Conservation Effect by Season

Season	kWh Savings	Days	Average Base kWh Use	Savings %
Winter	not valid	90	3,403	
Shoulder	33	183	5,408	0.6%
Summer	203	92	3,948	5.1%
Annual	151	365	12,759	1.2%

Savings were also modeled by strata as a verification of the overall estimates. Modeling the data by strata showed that those strata with a higher winter use had an overall negative savings value, and those with higher summer use had positive savings, as shown in Table 12. A weighting was given to each strata based on the number of customers in the analysis group, and a weighted average for the savings was calculated. This compares well with the seasonal and annual model shown above, with annual savings for all strata at 1.8%.

Table 12. Annual Conservation Effect by Strata

Strata	Savings (kWh)	Strata Weighting[13]	Average Annual kWh Use	Customer Count	Savings as % of Total Use
1	234	47%	8,246	2256	2.8%
2	-264	11%	11,149	465	-2.4%
3	434	36%	16,181	1534	2.7%
4	-848	6%	22,652	240	-3.7%
Weighted Average	183		12,300		1.8%

Interpretation of Results

It is sometimes useful to look only at seasonal, or incremental, energy use, i.e., energy use related to heating or cooling due to changes in the outside temperature. A good estimate of this can be made by simply subtracting energy use in shoulder months from energy use in winter and in summer. Table 13 shows seasonal energy use for the four stratum and compares energy savings due to the program with seasonal use. The percentages of savings of seasonal use ranges from -14 to 21, which implies that those who increase their use in winter do so at about the same rate as those who decrease their use in summer

Because customers in strata one and three have higher winter use, we can assume there must be some kind of heating-related electricity use in their homes. Their overall use increases after beginning participation in the program. This could be because as prices are lower in the winter, there is a take-back effect: i.e., "prices are low so I can heat my house more." For strata two and four, the picture is more straightforward. As they have higher summer use, they conserve more in the summer when prices are high, and thus show an overall decrease in annual use.

[13] These strata weights differ slightly from the participant population strata weights reported previously because some participants did not have sufficient data to be included in the billing analysis. The strata weights for the analysis group are used here since the primary purpose of the calculation is to show the relationship to the results from the overall model.

To conclude, total energy use tends to go up when usage, like space heating, coincides with low prices and down when usage, like air conditioning, coincides with high prices.

Table 13. Seasonal Energy Use and Savings by Strata

Strata	Incremental Winter Use	Incremental Summer Use	Savings as % of Incremental Use
1	259	863	21%
2	1746	189	-14%
3	239	2129	18%
4	2774	1285	-21%
Weighted Average			13%

Bill Savings

In 2009, the aggregate savings for Power Smart Pricing participants was $1,388,996.09 which represents a 23.6% total savings compared to what the same bills would have been under the standard rate. Average annualized savings were $304.98 or 24.4%.[14] However, savings varied greatly by month, and to a lesser extent by which Ameren Illinois utility the participant was a customer of, because the underlying standard rates were different. In addition, despite the reintroduction of a subsidized electric Space Heat rate in December, 2007, and active efforts to discourage customers who were taking service under that rate to sign up for PSP, 117 customers eligible for the subsidized electric Space Heat rate have still chosen Power Smart Pricing. For those customers, bill impacts varied greatly.

Methodology

The two methods, aggregate savings and average annualized savings, used to calculate the 2009 PSP savings were the same as those used to calculate the 2008 PSP savings. Only the aggregate savings method was used for 2007 PSP savings reporting, due to less than a full year of PSP bills (PSP promotional campaigns didn't start until October 2007, after the rate relief settlement) and the resultant small number of months of participants' bills. CNT Energy recalculated PSP bills to show what they would have been under the appropriate Ameren standard rate and the difference between the two was the savings (either positive or negative). Distribution charges and taxes are the same for PSP customers and standard rate customers, and were not changed. The recalculation took into account the line items in the Electric Supply portion of the bill.

Within that section, several line items (the Market Value Adjustment, the Supply Cost Adjustment, and the General Assembly Rate Relief Credit) remained the same. The hourly energy charges were replaced by multiplying the monthly kWh by the appropriate summer/non-summer standard rate tariff (prorated as needed for bills that spanned both periods), and the Transmission Service Charge was recalculated to be on a kWh basis rather than a kW-day basis. The recalculated standard rate bills also did not include the $2.25 PSP Participation Charge or the RTP Supplier Charge.

[14] Due to the growing enrollment levels over the course of the year the overall savings percentage and the annualized average savings percentage are not the same. Annualized savings represent what the average customer would have paid if they were on the program for all 12 months of 2009.

The recalculations of bills focused on recreating a bill for the same usage as the PSP bill. It did not take into account the conservation effect reported in the previous section that suggests an average overall decrease in annual consumption of 151 kWh per customer, because that amount is an indirect observation, not clearly stated on actual bills.

Results

Table 14 shows the average monthly bill and savings/loss for all Power Smart Pricing customers. The summer savings are the result of the unusually low summer energy prices. A reduced overall system load, due to the combination of a cool summer and economic slowdown, worked to create these low prices. The large early and late year savings are also the direct result of the very low energy prices that were seen in the market and passed through directly to PSP participants.

Table 14. Overall Average Bill Impacts

	Savings/ (Loss)	Savings/ (Loss) %	Avg kWh	Comparable Standard Rate Bill	PSP Bill
January	$ 27.24	23.3%	1,073	$ 116.92	$ 89.68
February	$ 30.28	30.0%	895	$ 100.78	$ 70.50
March	$ 32.48	35.9%	786	$ 90.45	$ 57.97
April	$ 34.24	39.0%	756	$ 87.83	$ 53.59
May	$ 29.38	34.1%	775	$ 86.03	$ 56.66
June	$ 20.03	16.7%	1,117	$ 119.74	$ 99.71
July	$ 14.62	11.9%	1,136	$ 123.04	$ 108.42
August	$ 13.29	11.1%	1,103	$ 119.81	$ 106.52
September	$ 22.86	23.8%	881	$ 95.95	$ 73.09
October	$ 25.00	29.9%	792	$ 83.59	$ 58.59
November	$ 29.75	30.8%	954	$ 96.45	$ 66.71
December	$ 25.82	20.1%	1,250	$ 128.40	$ 102.58
Totals:	$ 304.98	24.4%	11,517	$ 1,249.00	$ 944.02

If savings/losses are broken out by utility, the impact of the various underlying standard rates (and the special Space Heat rates) can be seen in the following tables.

Savings for Ameren CIPS customers were higher than for Ameren IP customers in a large part because the underlying standard rates for Ameren CIPS were higher, in particular the non-summer first 800 kWh block (7.484 cents/kWh versus 6.874 cents/kWh).

Table 15. Ameren IP and Ameren CIPS Monthly Bill Savings

	Ameren IP			Ameren CIPS		
	Avg kWh	Savings/ (Loss)	Savings/ (Loss) %	Avg kWh	Savings/ (Loss)	Savings/ (Loss) %
January	1,067	$ 27.44	22.9%	1,181	$ 33.81	27.6%
February	897	$ 30.08	29.1%	979	$ 36.77	35.2%
March	787	$ 31.94	34.5%	852	$38.80	41.6%
April	768	$ 33.92	37.4%	785	$ 39.22	44.7%
May	799	$ 29.39	32.7%	786	$ 32.00	38.5%
June	1,141	$ 20.30	16.2%	1,219	$ 22.15	18.3%
July	1,166	$ 14.76	11.4%	1,142	$ 16.50	14.4%
August	1,129	$ 13.51	10.7%	1,140	$ 14.75	13.0%
September	900	$ 23.12	22.8%	908	$ 24.53	27.2%
October	801	$ 24.33	28.1%	856	$ 30.09	35.6%
November	957	$ 29.09	29.3%	1,112	$ 37.56	36.6%
December	1,255	$ 25.77	19.4%	1,439	$ 32.92	23.5%
Totals:	11,668	$ 303.65	23.4%	12,399	$ 359.12	28.6%

Ameren CILCO and Ameren CIPS-ME do not have a special Space Heat rates and instead all standard rate customers pay a very low charge for non-summer usage over 800 kWh. (2.334 cents/kWh and 0.992 cents/kWh respectively).

A small number of Ameren CIPS-ME customers at the end of 2009 appear to have significantly higher winter monthly usage suggesting that some of them have electric heat. As a result the average savings for these customers is lower.

Table 16. Ameren CILCO and Ameren CIPS-ME Monthly Bill Savings

	Ameren CILCO			Ameren CIPS-ME		
	Avg kWh	Savings/ (Loss)	Savings/ (Loss) %	Avg kWh	Savings/ (Loss)	Savings/ (Loss) %
January	981	$ 23.01	23.3%	1,624	$ 0.75	0.6%
February	799	$ 27.39	31.9%	1,170	$ 12.92	13.7%
March	722	$ 30.73	38.7%	847	$ 23.53	29.7%
April	676	$ 32.27	42.4%	795	$ 30.53	38.4%
May	658	$ 27.40	38.2%	773	$ 27.38	35.4%
June	914	$ 16.89	18.3%	1,123	$ 20.24	18.5%
July	975	$ 11.97	12.2%	1,210	$ 17.38	14.5%
August	944	$ 10.87	11.5%	1,124	$ 14.61	13.1%
September	765	$ 20.11	26.3%	850	$ 21.73	25.8%
October	688	$ 23.51	33.8%	735	$ 22.23	31.4%
November	787	$ 25.79	33.5%	839	$ 23.37	31.1%
December	1,011	$ 18.94	19.7%	1,100	$ 13.77	14.4%
Totals:	9,920	$ 268.88	26.5%	12,190	$ 228.43	20.5%

As noted above, 117 PSP customers were eligible for the special standard rate Space Heat rates had they not switched to PSP. For those customers, many experienced their lowest savings (or loss) in winter months. However, former Space Heat customers with moderate usage were still able to save money during the winter. The lower overall hourly prices did lead to all but three of these customers having net savings for the year. CNT Energy reached out to the customers with the largest losses to discuss their participation in the program and several of them decided to leave after their twelve month term was up.

Table 17. Ameren IP and Ameren CIPS Former Space Heat Customers Monthly Bill Savings

	Ameren IP Former Space Heat			Ameren CIPS Former Space Heat		
	Avg kWh	Savings/ (Loss)	Savings/ (Loss) %	Avg kWh	Savings/ (Loss)	Savings/ (Loss) %
January	1,492	$ 5.21	8.8%	2,265	$ 12.57	12.2%
February	1,324	$ 8.48	12.1%	1,933	$ 13.90	14.4%
March	1,095	$ 21.18	24.5%	1,301	$ 29.52	29.2%
April	853	$ 26.24	31.9%	1,061	$ 34.03	37.4%
May	741	$ 25.67	33.2%	807	$ 35.12	41.9%
June	793	$ 17.51	21.4%	1,039	$ 26.39	27.5%
July	1,015	$ 14.88	11.2%	1,099	$ 17.45	15.8%
August	963	$ 12.27	9.2%	1,106	$ 15.39	13.9%
September	942	$ 20.77	17.1%	1,004	$ 21.07	21.0%
October	760	$ 18.56	22.8%	844	$ 26.30	31.7%
November	805	$ 17.07	25.3%	1,017	$ 25.70	30.6%
December	1,081	$ 11.72	18.2%	1,597	$ 22.52	21.3%
Totals:	11,864	$ 199.56	17.5%	15,073	$ 279.96	22.7%

As stated in the Methodology section, the recalculation of individual customer bills focused on recreating a bill for the same usage as the PSP bill. It did not take into account the conservation effect reported in the previous section that estimates an overall decrease in annual consumption of 151 kWh per customer. However, at roughly ten cents/kWh for energy and distribution, that is an additional $15.10 that the average PSP participant avoided paying in 2009. If that savings had been included, the average annualized savings would have risen from 24.4% to 25.6%. For 6,652 participants (the number of participants in December 2009), that represents an additional annualized aggregate bill savings of $100,445.

Day-Ahead Prices vs. Real-Time Prices

Before considering changes in use, it is important to have a thorough understanding of what real-time prices were like in 2009. More specifically, we examine both day-ahead prices (which are what participants paid) and real-time prices (which reflect actual market conditions). In 2008, customer perception of a discrepancy between day-ahead prices and real-time prices was seen as a barrier to entry for the program. In June 2008, billing for participants was switched from real-time prices to day-ahead prices for increased predictability and to limit the confusion caused by two different pricing information mechanisms.

2009 was a summer of unusually mild weather during an economic recession. This created an electricity market where the real-time prices for a kWh never rose above 11 cents, and day-ahead prices never predicted a kWh to be over nine cents. This is in contrast to 2008, where there were 122 hours that were predicted to be over 13 cents by the day-ahead price.

The key purpose for comparing these prices again in 2009 is to document the continuing relationship between real-time price and day-ahead price patterns. Even though 2009 prices were relatively low compared to past years, documenting the relationship between day-ahead and real-time prices is important for determining that day-ahead prices continue to elicit the appropriate response from participants during the hours of the day that have the highest real-time prices.

Methodology

In order to understand the relationship between real-time prices and day-ahead prices, the analysis focused on the highest priced hours predicted by 2009 day-ahead prices . In general, the highest priced hours are defined by High Price Alert days. On High Price Alert days, the customer is contacted the evening before to raise their awareness to the need for action in hopes that they will reduce their load. In 2009 there were no High Price Alert days. Although no High Price Alert days occurred, participants can still benefit from the program by responding to day-ahead prices. Non-participants are billed at a standard rate that does not fluctuate with the actual price of energy.

The highest day-ahead price hours were selected for comparison with real-time prices. Because prices in 2009 were so much lower than in 2008, a much lower threshold of day-ahead prices was used to generate sufficient data for analysis. In 2008, the threshold was thirteen cents per kWh; in 2009 this was lowered to five cents.

Results

Figure 12 presents 24-hour price plots for the ten days in 2009 when the day-ahead price for at least one hour was predicted to be over five cents per kWh. The day-ahead price and the real-time price curves follow similar patterns. Participants in the program who reduce their loads according to the day-ahead price will be achieve savings at the right time of day to achieve meaningful system load reductions . Day-ahead and real-time prices are not exact matches but their correlation is sufficiently strong that day-ahead prices are an excellent aid in predicting the rise and fall of real-time prices.

Figure 12. 24-Hour Price Cycles on Days in 2009 When At Least One Hour Was Predicted to be > Five cents/kWh

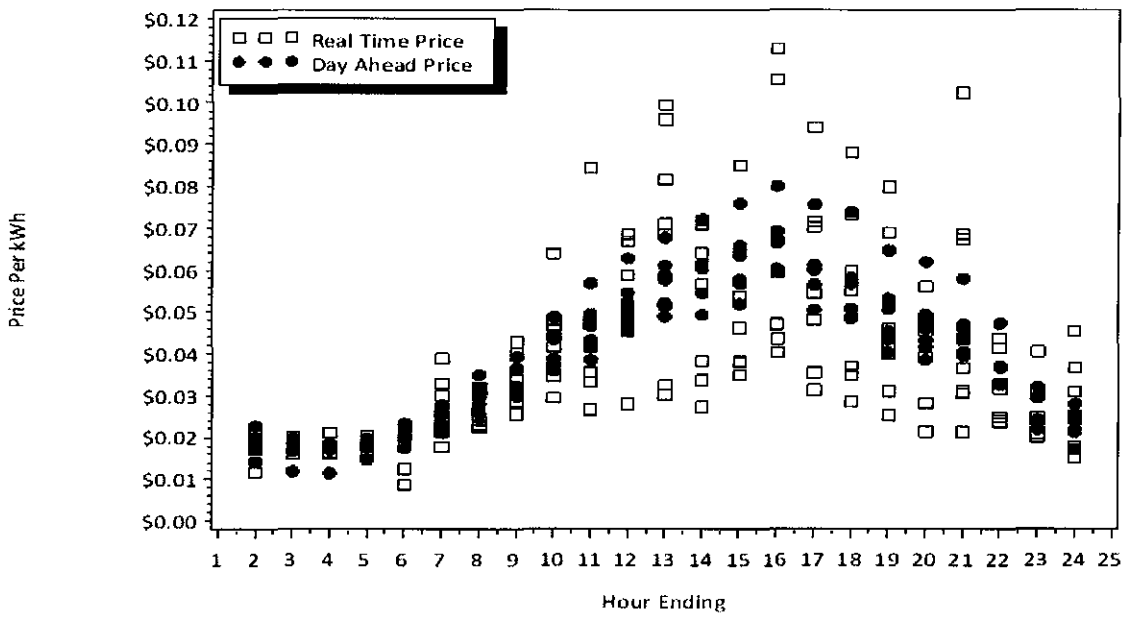
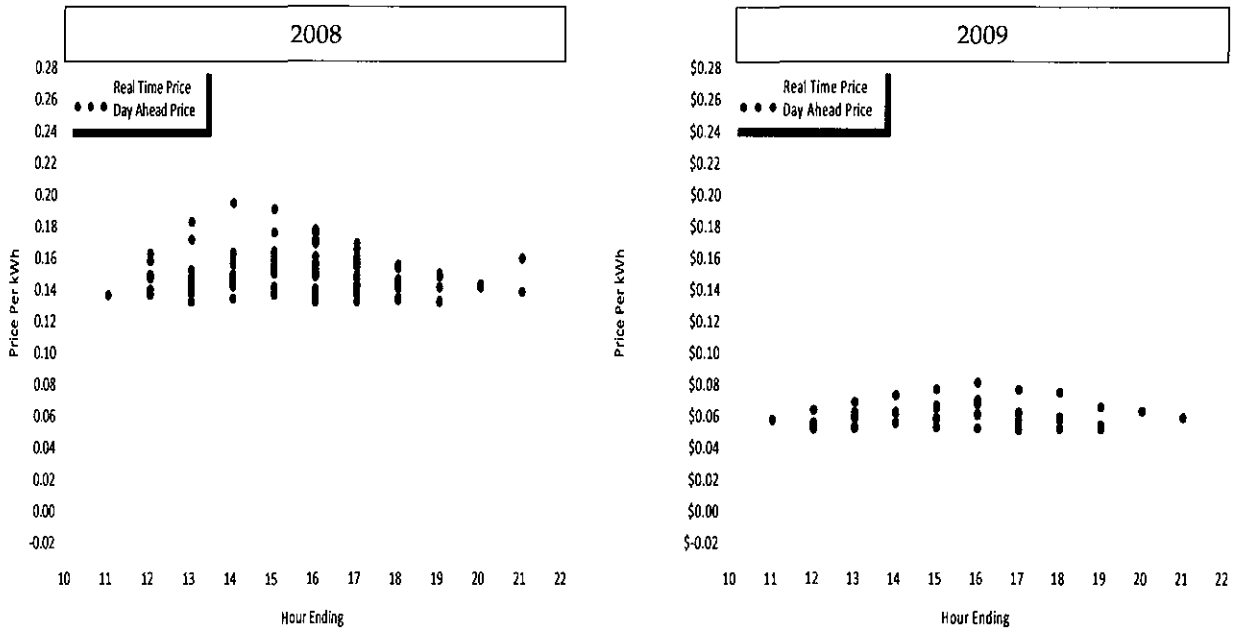


Figure 13 highlights the 52 hours in 2009 when the day-ahead price was predicted to be over five cents. Of these 52 hours, the real-time price was greater than the day-ahead price for 22 hours. The mean difference was two cents per kWh for these hours. The day-ahead price was higher than the real-time price for 30 hours with a mean difference of 1.7 cents per kWh. Overall, customers are more likely to be paying more by being on day-ahead pricing during the higher price hours in 2009, but the difference in prices is very small.

Figure 13. Comparison of DAP and RTP on High Price Hours in 2008 and 2009



The ability of day-ahead prices to forecast real-time prices can become problematic to the extent that errors are heteroskedastic—that is, the variance of prices rises as prices rise. Even so, predictability was not a serious problem in 2008, when prices were much higher than in 2009. Real-time prices were generally lower than day-ahead prices in 2008. There were only a few hours in 2008 where real-time prices spiked, becoming much higher than day-ahead prices. Future years of data will provide more insight into how well day-ahead prices predict real-time prices during periods of high prices.

From two years of observation, it appears that the day-ahead price is a good proxy for real-time prices for administration of the Power Smart Pricing program. Customers pay a bit more, but they are protected from occasional real time price spikes. There is enough correlation between the day-ahead and real-time prices that customers are rewarded for shifting behavior in the hours that will create the most demand reduction benefits for the system.

Section III » Preview of Net Benefit Assessment for 2010

After reviewing several alternatives, the 2008 report recommended the following methodology for estimating the net benefits of the PSP program in 2010:

1. Create a MISO-based regression model to predict LMPs from hourly demand and other publicly available information;

2. Use results from the impact evaluation of the PSP program to estimate demand reductions for different participation levels;

3. Use the regression model and estimated demand reductions to estimate reduction in LMPs;

4. Follow the Brattle method for estimating market benefits, but without adjusting for lost profit to suppliers;

5. Add a probabilistic approach to assess future market benefits based on weather and load risks over a ten year time frame, similar to what was done in the Summit Blue IEA study; and

6. Quantify additional benefits from reduced price volatility, and avoided energy and demand costs using the basic methods outlined by Dr. Neenan.

This section of the 2009 report will present a preview of what the 2010 net benefit assessment will look like, focusing on a realistic illustration of putting this basic methodology into action. The preview offers the opportunity for a full year of review and discussion on refinement of this methodology before the final net benefit assessment results need to be completed in 2010. It is expected that this opportunity for careful thought and sharing of ideas will lead to a very robust final assessment.

The first part of this section of the report will cover work done to address items one through four, the estimation of market effects. Market effects refers to the price reduction benefits that accrue to non-participants because system demand has been lowered by the program.

Item five, adding a probabilistic approach to assess future market benefits, is not included in this report but will be developed over the coming year to be part of the 2010 final net benefits assessment. However, this report does present a preview of some of the confidence intervals, or probability distributions, that will be used with key inputs in the final assessment. We believe it is best to refine the basic methodology before adding the forecasting and probability enhancements.

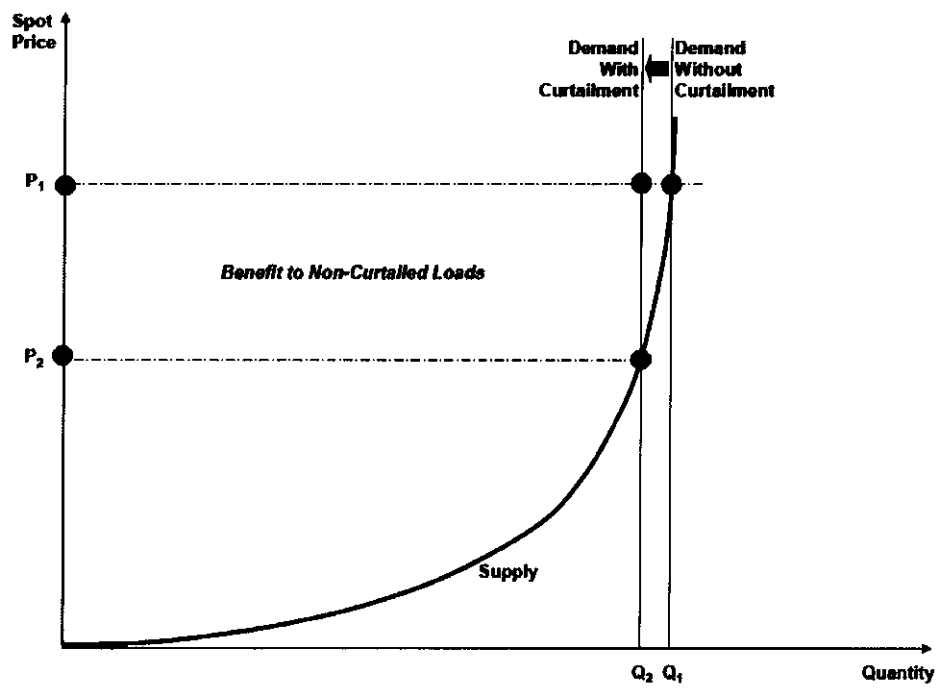
Item six, quantifying all benefits, will be addressed in the second part of this section, along with a comparison to program costs. This will provide a preview of the net benefits assessment methodology using realistic values for 2008 and 2009. Quantification of the benefits related to reduced price volatility will be left for the final net benefits assessment in 2010 when an additional year of historical information will be available for analysis.

Estimating Market Effects

Following the approach outlined in the 2008 PSP impact evaluation, we use regression analysis to estimate the benefit of the PSP program that accrues to non-participants. This is called the market effects.

With reference to Figure 14, this benefit arises because a reduction in energy consumption due to the PSP program serves to reduce the locational marginal price (LMP), and this price reduction applies to all customers in the market.

Figure 14. Conceptual Diagram of Direct Energy Benefits to Non-Curtailed Loads

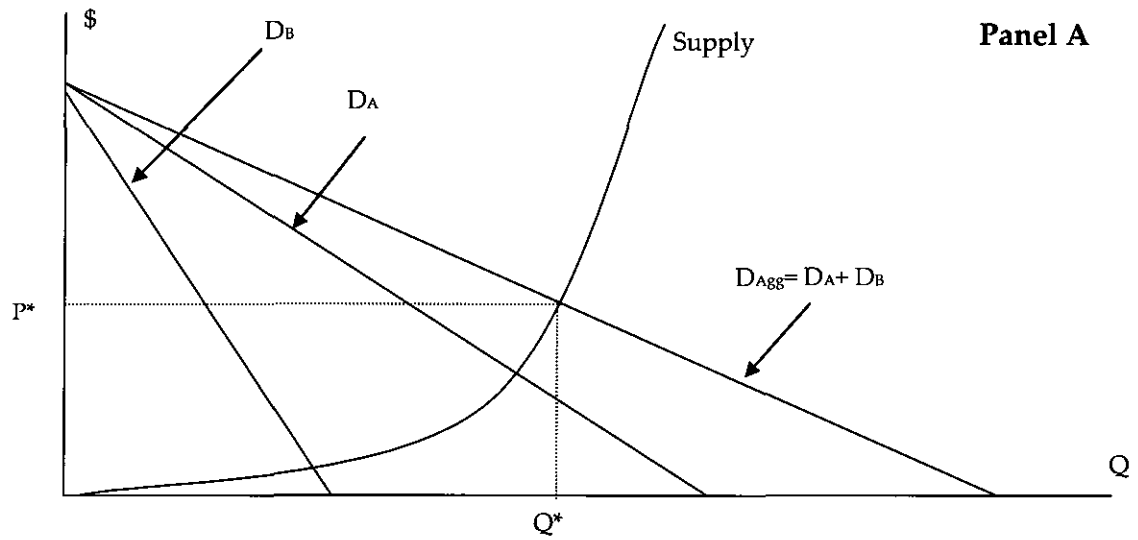


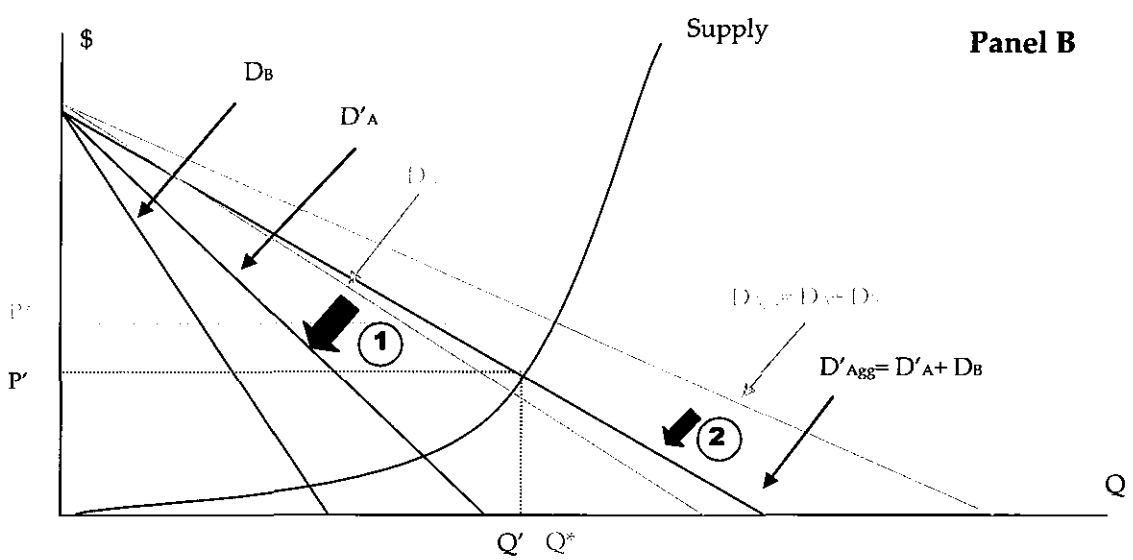
Source: Quantifying Demand Response Benefits in PJM, prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI) by The Brattle Group, January 29, 2007, page 20.

In particular, LMPs in the MISO market include an energy price component that is the market clearing price of energy in the MISO market. It follows that a demand reduction at any given hub generates a price reduction *throughout* the MISO market. This point is illustrated in the 2-hub market in Figure 15.

Aggregate demand is the horizontal summation of the demands for each hub, A and B. In Panel A, the initial market clearing price P* is determined from the intersection of *aggregate* demand D_{Agg} and supply S. Panel B illustrates the overall market effect of a demand reduction program, such as the PSP program, for one of the hubs, hub A. Demand at hub A shifts down from D_A to D'_A (arrow (1) in the diagram), causing aggregate demand to shift down (arrow (2) in the diagram), which in turns moves the market clearing price from P* to P′. This price reduction applies to the entire market.

Figure 15. Illustration of How a Demand Reduction Influences Price in a 2-Hub Market





In the following discussion, we focus on the market-wide benefit of the PSP program that arises via its effect on the energy price.

The standard supply function $Q_t(\cdot)$ takes as arguments input and output prices, as well as technological factors that may cause the supply curve to shift. Over periods short enough for little or no change in input prices (coal, natural gas) or technology factors, the function reduces to a simple relationship between the energy price and the quantity supplied at the price. Over our study horizon (summer 2007-summer 2009) input prices have shifted and technology may have changed, but we avoid the necessity of fully and properly accounting for these factors by separately estimating supply functions for each of the three summers. In this case, the effects of these factors are embedded in the constant term for each estimated supply equation.

Formally, we estimate for each summer season a supply equation of the form,

$$Q_t = \alpha_0 + \alpha_1 \ln(P_t) + \alpha_2 Q_{t-1} + \alpha_3 Out_t + \varepsilon_t$$

Where Q_t is the MISO load in hour t, measured in gigawatts; $\ln(p_t)$ is the log of real-time energy price at hour t, measured in \$/MW; Out_t is the reported generator outage at hour t, measured in gigawatts, and is included as a technological factor that changes considerably over the course of the season and even over the course of a day; Q_{t-1} is included as a technology proxy to capture the structural impediments to hourly changes in generation; and ε_t is the error term capturing unobserved factors influencing supply.

There is an interesting statistical/conceptual relationship at issue in the estimation of the supply equation. We expect that as real-time price P_t increases, supply starts to asymptotically approach an upper limit Q^{Max} due to fixed or quasi-fixed capacity, as illustrated in Figure 15. This relationship implies that as P_t continues to rise the supply response decreases—the effect of P_t falls towards zero. The econometric implication is that the coefficient on P_t in a regression will be close to zero at high prices and therefore it becomes statistically difficult to conclude that it is not equal to zero. In other words, more and more data is necessary to obtain statistically significant estimates of the supply equation as the equation approaches Q^{Max}.

A major concern with hourly time series data is the potential for an autoregressive error structure. For instance, if the error in the model prediction at hour *t-1* is positive, it is likely to be positive in hour *t* as well, because the unobservable variables influencing the prediction error at hour *t-1* are likely to persist at hour *t*. Failure to account for such an error structure will lead to inefficient and, in the presence of a lagged dependent variable, biased parameter estimates and invalid statistical inference.

Preliminary analysis revealed that the data exhibits considerable error autocorrelation with long (24-hour) lags. We took two measures to address this issue. First and most importantly, we drew a subsample of 20% of the observations for each season, restricting the sample to those hours with the highest real-time energy prices. Although this does not guarantee the complete purging of error autocorrelation, it is likely to significantly dampen it. Second, in model estimation with this subsample we test for autoregressive error processes (up to fourth order) and where statistical inference indicates the presence of autoregressive errors we use the parameter estimates from the appropriate corrected regression in the calculation of market effects.

Over the next year, we will continue to examine and refine specifications of the supply equation. For instance, one promising approach with the high-price subsample is to estimate a random effects or fixed effects model in which the cross-section is the particular day of the season and the effects parameter(s) account for the correlation across hours within the day. A reasonable argument could be made that such a specification is likely to provide unbiased estimates of the supply equation. Some testing of this

alternative modeling approach was done for the summer of 2007, for both the case where the energy price enters the supply equation linearly and where it enters in logged form. It was found that the estimated price effects are smaller than for the models we present here, but the statistical significance is higher due to lower standard errors. We intend to investigate this alternative modeling approach further for the 2010 evaluation.

A final estimation issue is supply-demand simultaneity bias in supply equation estimation. This arises in the case where unobservable factors affecting energy demand and energy supply are correlated, potentially interfering with unbiased estimation of supply equation parameters, in particular the price parameter. In the absence of a good theoretical case or empirical evidence for such correlation in the hourly energy market—a market dominated by intra-daily demand shifts that have the effect of strongly identifying the supply equation—we assume that such correlation is not a significant identification issue. We plan to give this issue additional consideration over the final year of the project. In particular we will investigate the use of instrumental variables estimation to eliminate simultaneity bias.

Supply Equation Estimation Results

Table 18 presents estimated supply equations for each of three summers (June-August, 2007-2009). Equations pertain to the highest 20% hourly real-time prices in each season (N=444); as revealed by the range of prices used in estimation (see Figure 16), this implies that the portion of the supply equation fitted to the data varied from year to year.[15] In all years we present the model with the highest statistically significant autoregressive error structure. In particular, the 2007 and 2008 models include a first-order autoregressive structure, while the 2009 model has no autoregression in the errors.

Model fit is high mainly due to the inclusion of lagged load Q_{t-1}. Outages have a small effect on supply. The price effect is statistically significant in the 2007 and 2008 models but not in the 2009 model. Nonetheless, in the analysis below we calculate market effects for 2009 as well as the previous years because the point estimate for 2009 is our best estimate of the true value of the price coefficient, though for all calculations we provide confidence bounds.

[15] We considered estimating the 2009 model for prices in the range of the 2007-2008 models, but in 2009 there were only 32 hours with prices greater than $75/MW, the minimum price used in 2007-2008.

Table 18. Supply Equation Estimation Results

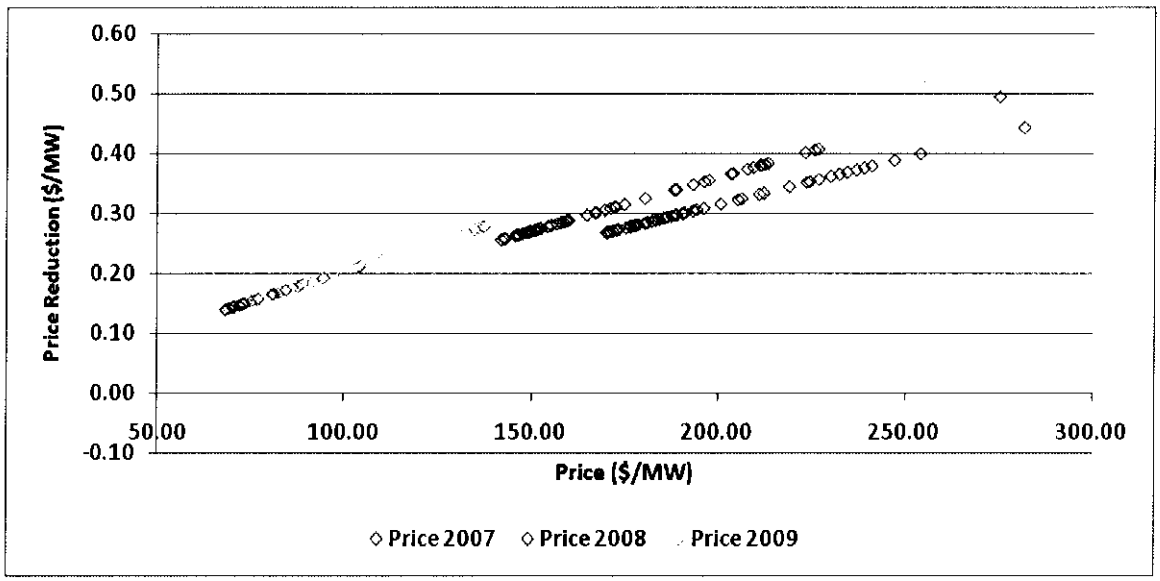
Variable	2007	2008	2009
	Parameter Estimate (standard error)		
Intercept	3.8581**	4.9619***	5.7860***
	(1.9498)	(1.7818)	(1.9259)
Log price	0.5546*	0.6354**	0.5101
	(0.3013)	(0.2529)	(0.3636)
Lagged load (Q_{t-1})	0.9263***	0.9068***	0.9195***
	(0.0158)	(0.0152)	(0.0181)
Outages	-0.0203	-0.0781*	-0.2082
	(0.0542)	(0.0467)	(0.0791)***
Lagged error (ε_{t-1})	0.2589***	0.2761***	-
	(0.0461)	(0.0459)	-
Model price range ($/MW):	75.00-275.26	91.80-461.45	31.22-254.35
Model R-squared	0.9528	0.9539	0.8804

*Significant at .10 level
**Significant at .05 level
***Significant at .01 level

Program Benefits to Non-Participants Induced by Energy Price Changes

Figure 16 presents the estimated price reduction from a one MW reduction in load for the 50 highest price hours in each of the summers of the study period. Price reductions were typically in the range of $.20 to $.40 per MW per hour. The figure confirms that prices were lower in 2009 than in previous years, but indicates that the supply curve was steeper in 2009 than in previous years, so that for a given price a demand reduction in 2009 effected a greater price reduction than in 2007 and 2008.

Figure 16. The Real-time (Hourly) Energy Price Reduction from a One MW Reduction in Demand



These energy price reduction equations can now be used in combination with demand reductions from the PSP program in 2008 and 2009 to estimate non-participant benefits in those years. The program benefit to non-participants for a given hour is calculated by first determining from the supply equation the price reduction induced by the PSP program (the values presented in Figure 16), and then multiplying this price reduction by the total MISO load for the hour.

Table 19 presents program benefits for non-participants for the 50 highest price hours in each summer of the program, 2008 and 2009.

Price reductions for 2008 were calculated using an overall program-induced load reduction of 0.75 MW for the 50 highest price hours. This is based on the 2008 evaluation findings that average peak hour loads were reduced by 0.25 kW per PSP participant between the hours of noon and 5 p.m. across all High Price Alert days. This is roughly equivalent to the 50 highest price hours for the summer. 0.25 kW for 3000 participants creates a 0.75 MW program-induced load reduction.

Price reductions for 2009 were calculated in a similar manner using an overall program-induced load reduction of 1.05 MW for the 50 highest price hours. This is based on the 2009 evaluation findings that PSP participants reduced their hourly loads by an average of 0.15 kW per customer on all summer weekdays. This reduction is a conservative estimate of what would have occurred on the 50 highest price hours. 0.15 kW for 7000 participants creates a 1.05 MW program-induced load reduction.

Non-participant benefits are not monotonically decreasing in price reductions due to shifts in the supply curve arising from changing values for Q_{t-1} and Out_t in the supply equation. Although 2009 had more participants and greater total demand reduction, non-participant benefits are lower because price reductions per MW were considerably lower in 2009 (see Figure 16).

Table 19. Program Benefits to Non-participants, 50 Highest Price Hours, 2008-2009

2008			2009		
Price ($/MW)	Price Reduction ($/MW)	Non-Participant Benefit ($)	Price ($/MW)	Price Reduction ($/MW)	Non-Participant Benefit ($)
461.45	0.54	**41,024**	254.35	0.54	**42,360**
330.86	0.39	**31,949**	137.71	0.29	**22,410**
316.93	0.37	**25,875**	137.17	0.29	**22,714**
281.76	0.33	**27,996**	135.98	0.29	**22,826**
253.98	0.30	**24,902**	134.89	0.29	**21,141**
247.02	0.29	**21,977**	132.7	0.28	**19,855**
240.99	0.28	**21,839**	114.83	0.24	**17,880**
238.90	0.28	**22,285**	110.69	0.23	**19,683**
236.85	0.28	**22,555**	104.52	0.22	**16,040**
234.34	0.28	**22,328**	103.93	0.22	**18,886**
232.36	0.27	**20,238**	103.21	0.22	**15,603**
230.04	0.27	**19,629**	97.15	0.21	**16,250**
226.85	0.27	**18,852**	94.93	0.20	**17,587**
224.44	0.26	**21,075**	94.25	0.20	**17,059**
223.63	0.26	**17,839**	92.05	0.20	**14,969**
218.98	0.26	**20,428**	89.09	0.19	**15,718**
212.11	0.25	**21,943**	88.56	0.19	**14,439**
210.96	0.25	**19,172**	87.68	0.19	**15,305**
206.26	0.24	**19,194**	86.3	0.18	**11,996**
205.27	0.24	**18,229**	84.64	0.18	**14,844**
200.66	0.24	**20,314**	84.39	0.18	**12,897**
196.10	0.23	**17,199**	83.19	0.18	**13,459**
194.26	0.23	**19,800**	82.35	0.17	**13,778**
193.30	0.23	**16,467**	81.41	0.17	**12,825**
191.01	0.23	**16,145**	81.15	0.17	**14,946**
190.34	0.22	**16,571**	80.93	0.17	**14,622**
188.86	0.22	**17,427**	80.42	0.17	**13,926**
188.56	0.22	**17,740**	77.32	0.16	**14,315**
187.60	0.22	**18,222**	77.24	0.16	**11,720**
186.36	0.22	**16,687**	76.84	0.16	**12,441**
185.45	0.22	**17,805**	75.86	0.16	**11,979**
184.25	0.22	**17,602**	75.19	0.16	**13,456**
183.30	0.22	**16,922**	74.07	0.16	**13,857**
182.31	0.22	**19,145**	73.55	0.16	**12,409**
181.00	0.21	**15,987**	73.26	0.16	**12,276**

2008			2009		
Price ($/MW)	Price Reduction ($/MW)	Non-Participant Benefit ($)	Price ($/MW)	Price Reduction ($/MW)	Non-Participant Benefit ($)
180.33	0.21	**17,964**	72.99	0.15	**11,445**
178.58	0.21	**14,959**	72.91	0.15	**12,920**
178.13	0.21	**16,286**	72.22	0.15	**12,748**
177.58	0.21	**15,387**	72.2	0.15	**12,355**
177.51	0.21	**17,989**	72.01	0.15	**11,580**
176.69	0.21	**15,861**	71.02	0.15	**9,864**
176.48	0.21	**15,898**	70.75	0.15	**11,753**
175.36	0.21	**16,067**	70.44	0.15	**9,865**
173.29	0.20	**14,652**	70.35	0.15	**11,628**
172.75	0.20	**14,722**	70.3	0.15	**10,584**
171.89	0.20	**16,767**	70.23	0.15	**9,378**
171.08	0.20	**15,938**	69.39	0.15	**10,271**
170.43	0.20	**16,473**	69.13	0.15	**12,229**
170.36	0.20	**16,102**	68.7	0.15	**12,146**
170.35	0.20	**15,087**	68.48	0.15	**11,952**
170.20	0.20	**15,149**	68.2	0.14	**11,508**
Total Market Effect:		**$978,664**			**$758,700**

Non-Participant Benefits from Congestion Price Reductions

In preliminary analysis, we used regression methods to also examine the effect of the program on the congestion price component of LMPs. We found no statistical effect of hub loads on hub marginal congestion prices, indicating the PSP program is unlikely to generate significant non-participant benefits via congestion price reductions.

Net Benefits Assessment

The primary objective of the net benefits assessment is to answer the question: "Is the PSP program cost effective?" A net benefits assessment looks at all of the benefits of the program, both for participants and non-participants, and compares those benefits to the total costs of the program. If there are net benefits, i.e., benefits are greater than costs, then the program is contributing to an overall reduction in the cost of electricity for consumers.

Methodology

The first step is to identify the separate benefits and costs that should be quantified. While there are many such costs and benefits which were discussed in the 2008 report, this assessment will focus on those which are most important and quantifiable. There are three benefit components and three cost components for this assessment, and each will be described in more detail below. The second step is to compare total benefits to total costs to determine if there are positive net benefits for the program.

BENEFIT #1: REDUCTION IN MISO PRICE

This is the market effects benefit discussed in detail in the previous section of this report. It represents the price reduction benefits that accrue to non-participants because system demand has been lowered by the program.

BENEFIT #2: AVOIDED CAPACITY COSTS

Following the MISO resource adequacy requirement, AIU secures capacity to cover their monthly load requirements. Contracts for this capacity are made at the beginning of the year, with the ability to buy or sell in the month-ahead capacity markets as needed. This means there is an advance benefit (both annual and month ahead) related to demand reductions from the PSP program. The main point is that demand reductions caused by the PSP program reduce AIU capacity costs. As shown in Table 20, the annual value of the avoided capacity cost was $16.25/kW-year for 2008 and $9.21/kW-year for 2009.

Table 20. Avoided Capacity Costs for 2008 and 2009

BGS 3b – BGS 4	2008		2009	
	$/kW-day	$/kW-month	$/kW-day	$/kW-month
January	0.015	0.465	0.006	0.186
February	0.008	0.234	0.003	0.084
March	0.005	0.155	0.002	0.062
April	0.005	0.150	0.001	0.030
May	0.005	0.155	0.001	0.031
June	**0.029**	**0.870**	**0.007**	**0.210**
July	**0.221**	**6.851**	**0.150**	**4.650**
August	**0.221**	**6.851**	**0.117**	**3.627**
September	0.011	0.330	0.005	0.150
October	0.002	0.062	0.002	0.062
November	0.002	0.060	0.002	0.060
December	0.002	0.062	0.002	0.062
Annual Total:		$16.25		$9.21
Summer Total:		**$14.57**		**$8.49**

Source: AIU work papers and monthly filings with the ICC

Previous sections of this report have shown that demand reductions from the PSP program vary by season. The largest savings occur at peak times during the summer months. For simplicity in the net benefits calculation, only summer demand reductions will be considered. This is when the greatest demand reductions occur and also when the avoided capacity costs are the highest. Avoided capacity costs for the summer months of June, July and August are $14.57 for 2008 and $8.49 for 2009. The value of demand reductions during the other seasons is minimal compared to the summer benefit.

BENEFIT #3: AVOIDED ENERGY COSTS

In the design of the PSP program, the avoided energy costs become the major source of participant benefits. Due to this unique characteristic of the program, there is a straightforward and simple way to

quantify the avoided energy costs from the program. Since the PSP program is all about having customers pay the real-time energy costs on an hourly basis, their bills represent actual energy costs. The difference between what they paid for energy on a real-time basis compared to what they would have paid on the standard rate alternative is essentially the quantification of the avoided energy costs that occurred.

This difference was presented in a previous section of this report as bill savings, but a few adjustments to the reported bill savings need to be made to create the appropriate value to use in the net benefits assessment. When the bill savings were reported, it was a straight comparison of PSP total bills to the same kWh usage billed on the standard rate tariff. The PSP bills include a $2.25 charge per month to cover approximately half of the incremental metering costs required for participation in the program. This meter charge offsets benefits that came from avoided energy costs. To get the total avoided energy costs the meter charge should be added back. In the net benefits assessment, the total cost of the additional metering will be accounted for as a cost of the program.

A final adjustment that is needed is the addition of the avoided energy cost associated with the energy that was conserved after the PSP participant joined the program. The previous section on bill savings credits each of these conserved kWh at ten cents, since that is roughly equivalent to what the PSP participant would have paid for them on the alternative standard rate. However, we estimate that the avoided energy cost associated with these conserved kWh is only seven cents per kWh, so we would add in avoided cost benefits of seven cents per conserved kWh. It is true that the PSP participants also receive the benefit of not paying the three cent distribution charge related to each conserved kWh, but this savings to participants is offset by a reduction in income to AIU to cover their distribution costs. Since this three cents represents a transfer of costs from one party to another rather than a true reduction in overall system costs, it is not included in the net benefits assessment.

COST #1: PROGRAM IMPLEMENTATION COSTS – CNT

As program implementer, CNT Energy is responsible for administration and marketing of the PSP program. They provide an accounting of their program-related expenses each year in their annual report, and these are the program implementation costs.

COST #2: PROGRAM IMPLEMENTATION COSTS – AIU

AIU handles meter acquisition and installation as well as billing for the PSP program. Those costs are also part of the program implementation costs.

COST #3: EVALUATION COSTS

The Illinois Power Agency Act SB1592 defines components that must be included in the net benefits assessment of energy efficiency programs in the state of Illinois. Evaluation costs are one of those required cost components, and for consistency it will be included in this net benefits assessment also.

Results

Data was gathered on the costs and benefits for the PSP program years of 2008 and 2009 following the methodology outlined above. For simplicity, these are one-year snapshots of net benefits. There is no consideration of the benefits and costs related to continuation of the program in future years. The forecasting of benefits and costs will be added to the 2010 assessment of net benefits, along with a consideration of associated probabilities and risks. We are focusing on simplicity of method here to build a solid understanding of the assumptions embedded in the basic net benefits assessment methodology.

Table 21 provides a preview of the one-year net benefits assessment for program years 2008 and 2009. Actual data was used as much as possible.

These preview results show positive net benefits of $501,091 in 2008 which grow to positive net benefits of $1,577,707 in 2009. The growth in positive net benefits comes mainly from the large increase in avoided energy cost benefits in 2009 (bill savings for participants).

Table 21. Preview of One-Year Net Benefits Assessment for 2008 and 2009

	2008	2009
Non-Participant Benefits: Reduction in MISO Price	$978,664	$758,700
Participant Benefits: Avoided Capacity Costs	$10,928	$8,915
Participant Benefits: Avoided Energy Costs	$207,375	$1,735,400
TOTAL BENEFITS	$1,196,967	$2,503,015
Program Implementation Costs - CNT	$420,458	$491,619
Program Implementation Costs - AIU	$211,418	$351,689
Evaluation Costs	$64,000	$82,000
TOTAL COSTS	$695,876	$925,308
NET BENEFITS	**$501,091**	**$1,577,707**

Detailed calculations to support these values can be found in Appendix E.

One of the important issues in the net benefits assessment is quantification of the benefits being received by non-participants. This is important in the determination of how program costs should be allocated between participants and non-participants. These results show that non-participants are receiving substantial benefits from the program in reduced energy prices during the top 50 hours of each year. While the initial reaction is that these results support non-participant contributions toward program costs, it must be remembered that the non-participants are all MISO customers, not just AIU customers. Fair allocation of program costs across all beneficiaries will likely remain an issue even after non-participant benefits are quantified.

Section III » Conclusions

This report is the 2009 assessment of the Power Smart Pricing program. Program evaluation work will be concluded after the end of calendar year 2010, providing the opportunity to refine and update the assessment that was done this year with an additional year of program participation data. The following conclusions highlight the major findings presented in this 2009 report.

Number of Customers using Hourly Pricing

CNT Energy's marketing and enrollment efforts resulted in 7,422 active Power Smart Pricing participants as of December 31, 2009. This was a 136% increase over the participant count of 3,147 at the end of 2008. New participants in the program had higher average energy use than the existing participants. This is considered to be a result of a successful targeted marketing campaign used in 2009 to attract high use customers to the program.

Changes in Customers' Energy Use Patterns

Elasticity modeling done for 2009 shows that Power Smart Pricing participants continued to respond to variation in hourly prices during the summer season, even though 2009 electricity prices were much lower than 2008 prices. The overall own-price elasticity was –2.3%, meaning they reduced their electric usage by 2.3% for every 100% increase in the price of electricity.

Additional analysis revealed that customers show a much higher response to price when prices are above a given threshold. For example, during the summer season the own-price elasticity is -1.0% when prices are below 13 cents per kWH, but when prices rise above 13 cents the own-price elasticity jumps to -24.8%.

There were no High Price Alert days in 2009. However, on regular summer weekdays in 2009 PSP participants showed an average load reduction of 0.13 kW per hour between the hours of Noon and 5 p.m. when compared to a control group. This is similar to the load reduction of 0.18 kW per hour found for regular summer weekdays in 2008. Survey data reinforced the observation that PSP participants were continuing to shift their summer energy usage out of the high price afternoon period even though 2009 energy prices were much lower than 2008 prices.

In addition to shifting energy during the summer, participants also showed an overall reduction in energy use. Power Smart Pricing participants reduced their average energy use by 5.1% during the summer season and by 0.6% during the shoulder months. However, they did not show any energy savings during the winter months. This created an overall annual energy savings of 1.2% per year which is similar to the annual savings of 1.5% found in 2008.

Value of the Program to Participants

In 2008, the aggregate savings for PSP participants was $1,388,996 which represented a 23.6% total savings compared to what the same bills would have been under the standard rate. Average annualized

savings were $304.98 or 24.4%.[16] These percentage savings are three times greater than what was seen in 2008, largely due to the low market prices for electricity.

This estimate of bill savings does not include the additional savings that comes from the conservation effect of the program. Including an annual decrease in consumption of 151 kWh per customer at roughly ten cents/kWh for energy and distribution, there is an additional $15.10 that the average PSP participant avoided paying in 2009. If that savings had been included, the average annualized savings would have risen from 24.4% to 25.6%. For 6,652 participants, that represents an additional annualized aggregate bill savings of $100,445.

VALUE OF THE PROGRAM TO NON-PARTICIPANTS

A thorough assessment of the net benefits from the Power Smart Pricing program will be presented in the 2010 Annual Report to the Commission after the program has completed several years of operation. Plans are in place for the 2010 Annual Report to contain a summary of all the costs and benefits related to the PSP program, including a probabilistic risk assessment of the net benefits.

This 2009 report includes a preview of what the basics of the 2010 net benefit assessment will look like. It looks at actual benefits and costs estimated for the years 2008 and 2009. This includes estimation of non-participant benefits from reduced MISO prices that are a consequence of the PSP program demand reductions. This preview offers the opportunity for a full year of review and discussion on refinement of the methodology before the final net benefit assessment results need to be completed in 2010. It is expected that this opportunity for careful thought and sharing of ideas will lead to a very robust final assessment.

[16] Due to the growing enrollment levels over the course of the year the overall savings percentage and the annualized average savings percentage are not the same. Annualized savings represent what the average customer would have paid if they were on the program for all 12 months of 2009.

Appendix A » 2009 PSP Operational Report and Audit Report

This appendix presents a complete copy of the 2009 Power Smart Pricing Operational Report prepared by CNT Energy, followed by an independent auditor's report on CNT Energy's direct expenses for the Ameren PSP project.

CNTEnergy_PSP2009 _Annual _Report_FIN

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