SOUTHER INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH)

DIRECT TESTIMONY
OF
AHMAD FARUQUI

PRINCIPAL
THE BRATTLE GROUP

ON BEHALF OF VECTREN SOUTH

ON

SMART GRID

SPONSORING PETITIONER'S EXHIBITS AF-1 THROUGH AF-3

DIRECT TESTIMONY OF AHMAD FARUQUI

Q. What is your name and affiliation?

A. My name is Ahmad Faruqui. I am a Principal with The Brattle Group ("Brattle") located in the firm's San Francisco office.

Q. What is the purpose of your testimony?

A. My testimony summarizes the work that I have done to analyze the benefits of demand response ("DR") associated with the deployment of advanced metering infrastructure ("AMI") in Vectren South's service territory.

Q. What are your qualifications?

A. I have three decades of research and consulting experience in the design and evaluation of customer-side programs. Most recently, I led a team of consultants in conducting a state-by-state assessment of the potential for demand response programs for the Federal Energy Regulatory Commission. The report was filed with Congress in June of 2009. Last year, I worked on a national assessment of energy efficiency programs for the Electric Power Research Institute and wrote a whitepaper for the Edison Electric Institute on quantifying the benefits of dynamic pricing. Since the power crisis in the Western states, I have worked for several utilities, ISOs/ RTOs and state/provincial commissions in assessing the benefits of DR by designing pilot programs and conducting cost-benefit analyses. I hold a doctoral degree in economics from The University of California at Davis. Additional details are contained in my resume, which I sponsor as <u>Petitioner's Exhibit No. AF-2</u>.

Q. Please describe the professional services that Brattle provided to Vectren South.

A. I was hired by Vectren South to develop a bottom-up assessment of the impacts of AMI-enabled DR on their system. This first involved the development of several types of dynamic rates, which would require an advanced metering system to be deployed on a full scale basis. I then simulated the impacts of these rate designs on customer consumption patterns using a model that has been used in several other AMI business case filings. The dynamic pricing impacts were then converted to financial benefits using well-established industry practices for quantifying avoided costs. My work originally began in early 2008 and has been ongoing since.

Q. What other exhibits are you sponsoring in this proceeding?

A. I am also sponsoring Petitioner's Exhibit No. AF-3, which is a presentation summarizing the details of my analysis. The report is titled "Quantifying the Impacts of Dynamic Pricing on Vectren South's System."

Q. Please summarize the type of benefits Vectren South and its customers should realize as a result of the proposed AMI deployment and related dynamic pricing tariffs.

A. I have concluded that the potential benefits of DR to the Vectren South system could be quite significant, depending on the type of program that is offered. At a high level, Vectren South's dynamic pricing tariffs will benefit customers by introducing price elasticity into the regional electricity market. Primarily, this will result in a direct benefit of lowering generation resource costs by reducing or offsetting the amount of capacity and energy that Vectren South must procure or produce. This reduction in resource costs is likely to persist over the long haul. Additionally, Vectren South's programs can be expected to improve system reliability, enhance market competitiveness by mitigating the market power of generators, reduce price volatility, reduce transmission and distribution losses, encourage adoption of new smart grid technologies, and accommodate new electric end-uses and the proliferation of small-scale renewable generators.

Over a 20 year forecast horizon, I have estimated that the AMI-enabled DR programs proposed by Vectren South could lead to reductions in system peak demand of approximately 37 MW. Over this same twenty year period, the peak reductions translate into a present value of financial benefits of approximately $24 million. These direct financial impacts are a result of avoiding or deferring resource costs.

Q. What were your key assumptions and how do you justify them?

A. I developed my analysis using historical Vectren South system data. Where projections were needed (for example, the peak demand forecast or expected customer growth rates) I relied on information that was provided to be by Vectren South.

The first step in my analysis was to develop cost-based dynamic rates for Vectren South's system. I developed four rate types: time-of-use (TOU), critical peak pricing (CPP), real time pricing (RTP), and a CPP rate layered on top of a TOU rate (CPP/TOU). These rates have a peak period from noon to 4 pm, when Vectren South's system peak is most likely to occur. Further, they only apply in summer months (June through September). The differential between the peak and off peak period rates is mostly driven by the cost of building generating capacity to meet peak demand. The rates are all revenue neutral, meaning that in the absence of any change in consumption patterns, the average customer's bill would remain unchanged when moving from the existing tariff to any of the new dynamic rates. The rate design process is described in more detail later in my testimony.

The next step was to estimate individual customer DR to the dynamic rates. In other words, how much load would customers shift from the higher priced peak period to the lower priced off-peak period? By how much would their bills decrease as a result? To answer these questions, I used the Price Response Impact Simulation Model (PRISM). The PRISM modeling framework was initially developed through the California Statewide Pricing Pilot and has subsequently been updated with results of other recent dynamic pricing pilots. This model formed the basis for the analysis we carried out for FERC. By tailoring PRISM to Vectren South's system using inputs such as central air-conditioning saturation, weather data, customer load shapes, and the Vectren South-specific rate designs that I described previously, the model produces estimates of peak demand reductions, total consumption changes, and bill changes for the average Vectren South customer. The impacts simulation process is described in more detail later in my testimony.

Once the customer-level DR estimates were developed, I extrapolated them to the system level. I did so using assumptions about customer participation rates. The dynamic pricing programs could be offered on an optional, default, or universal basis.

Vectren South has proposed an optional rate offering. For that scenario, I have assumed that the participation rate is 15 percent in the first three years of the forecast (during the AMI deployment period), and then ramps up to 20 percent linearly over the following five years. This reflects the relatively low customer enrollment that is expected when customers must proactively sign up for a new rate. Alternatively, customers could be automatically enrolled in a dynamic rate, with the option of reverting back to their existing rate. Or the rate could be offered on a universal basis, without the option to opt-out. These are scenarios that I discuss later in my testimony.

All but one of my scenarios assumes that 60 percent of the eligible customers will be equipped with an "enabling technology." In the case of the residential class, the technology is the programmable communicating thermostat (PCT), a device that can receive a signal from the utility and automatically turn down the customer's central air conditioner. I assumed that the same percentage of eligible C&I customers would be equipped with a system which is similar in concept but extends to more end-uses by interacting with the facility's energy management system (EMS).

Finally, I multiply the system impacts into estimates of avoided generating capacity and energy costs. Capacity costs begin at roughly $73/kW-year and grow to $109/kW-year by the end of the 20 year forecast horizon (in nominal dollars). Average annual energy costs begin at roughly $50/MWh and grow to $98/MWh over that same timeframe. The result is an annual stream of avoided cost benefits.

Q. Are there additional benefits of DR that you have not quantified?

A. Yes. Other benefits will include (1) improved reliability; (2) enhanced market competitiveness; (3) reduced rate volatility; and (4) reduced transmission and distribution losses.

Demand reduction programs can reduce the probability and extent of rolling blackouts. In a supply-inadequate scenario, demand response would help prevent intolerably low reserve margins with likely blackouts and would allow the system to operate reliably. Reliability also has economic value. Monetizing reliability benefits requires estimating the effect of demand response on the expected loss of load, and then applying an economic value to each megawatt-hour of lost load.

During high-load periods, electricity markets suffer from structural problems that increase the incentive and ability for generators to exercise market power. Market power is exacerbated if most customers are not enrolled in DR programs, so they have no incentive to reduce even their lowest-value consumption when spot prices spike, leading to a demand curve that is almost completely inelastic. DR programs would increase the elasticity of demand and thereby increase the competitiveness of the market. Simple game-theoretic models suggest that doubling the elasticity of demand – not an overly-ambitious goal, given the nascence of DR programs – would enhance competitiveness as effectively as a 50% reduction in market concentration.

Many customers are risk-averse and value rate stability, for example because they need to be able to forecast their costs accurately for budgeting purposes. Hence, there is value to reducing the price variance, not just reducing expected prices.

Retail electricity prices can fluctuate in response to spot prices (for customers on real-time pricing) or in response to expected wholesale prices. To the extent that demand reduction reduces volatility in the spot market, it improves overall electricity price stability for at least some customers. Dynamic pricing reduces volatility by preventing the market from becoming as tight during normal peaks in load. This mitigating effect is greatest under extreme conditions, when rates are highest and when rate relief would be the most valuable.

Q. How do the programs you analyze on behalf of Vectren South compare with those programs that have been offered by utilities in other jurisdictions?

A. Currently, AMI is deployed for five percent of the nation's 142 million customers, up from just one percent just two years ago. Based on current projections, another 40 to 50 million customers will be included by AMI deployments that have already been advanced or at fairly advanced stages of business case development. This additional deployment is expected to take place over the next decade. Deployment is expected to take place at a faster pace after SGIG awards are made.

The dynamic rates that I have analyzed for Vectren South are consistent with the "best practices" that I have observed through my review of demand response programs around the U.S. The rates are cost-based, with sufficiently strong price signals to provide customers with the opportunity and incentive to reduce their bills (and overall system costs) by shifting demand from peak period to the off peak period.[1]

Q. Did you also perform a DR assessment for FERC that featured state-by-state results?

A. Yes. I led a team of consultants in a study that assessed state-level DR potential under four scenarios of DR program market penetration. The study concluded in June of 2009, when "A National Assessment of Demand Response Potential" was submitted to U.S. Congress. The report and accompanying model can be found on the FERC website at: http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential.asp.

Q. Have you surveyed the empirical evidence on DR associated with dynamic pricing from other jurisdictions that have carried out pilot programs?

A. Yes, I have surveyed the results of more than a dozen pilots on dynamic pricing. The results of that survey are summarized in a whitepaper titled "Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence." It can be found at the following link: http://www.hks.harvard.edu/hepg/.

Q. What have been the conclusions from your survey?

A. AMI-enabled dynamic pricing is receiving great interest in the United States and Canada. More than a dozen experiments involving several thousand customers have been carried out in these two countries and there is convincing evidence that customers do respond to dynamic pricing by reducing peak loads during critical times. Utilities and state commissions are engaged in serious deliberations about how best to deploy dynamic pricing, once AMI deployment has occurred. In California, the Public Utilities Commission has ordered that dynamic pricing should be made the default pricing

[1] For more information on the principles of dynamic rate design, see Ahmad Faruqui and Ryan Hledik, "Transitioning to Dynamic Pricing," *Public Utilities Fortnightly*, March 2009.

structure once AMI is deployed for all customer classes (unless it is so prevented by legislation).

Critical peak pricing has achieved load reductions in the 10 to 20 percent range without enabling technologies (per participating customer) and in the 20 to 50 percent range when accompanied with enabling technologies. This is based on a review of 15 pricing pilots from around the globe that involved more than 15,000 customers over the past several years. These findings are consistent with the results of my analysis for Vectren South.

Q. Do you think dynamic pricing is an important part of Vectren South's Smart Grid initiative?

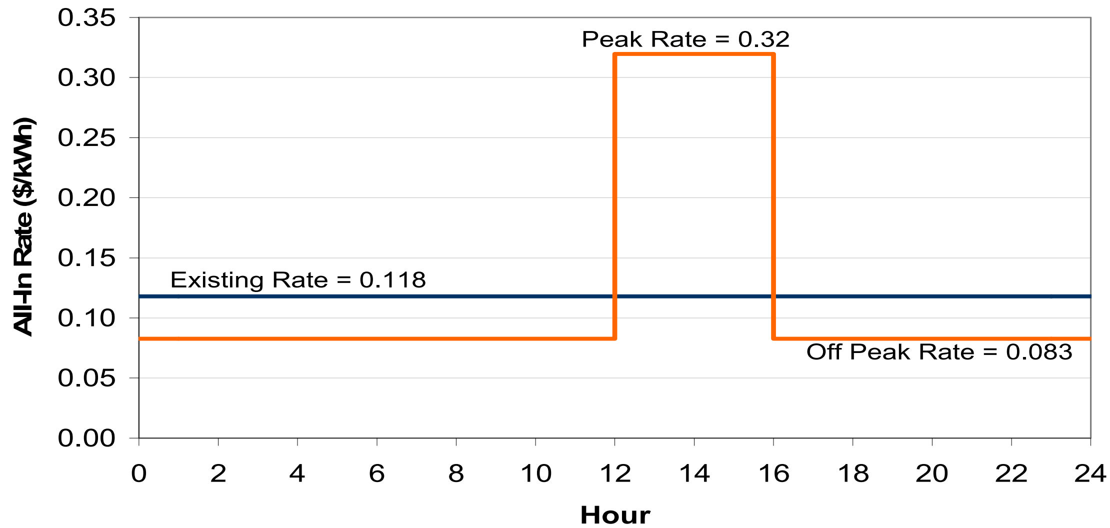
A. Yes. I believe that dynamic pricing should be a core component of Vectren South's Smart Grid initiative. Efficient pricing of electricity not only leads to peak demand reductions and the benefits that I have described previously; it can also encourage the long-run adoption of new smart grid technologies such as energy storage, plug-in hybrid electric vehicles (PHEVs), and solar installations. For example, a well designed TOU rate would encourage residential solar installations by charging customers a lower price during off-peak hours when they are buying electricity from the grid (rather than generating it directly from the solar panels). This rate would also work well with PHEVs, which would need to charge during the nighttime hours.

Q. What potential types of dynamic rates did you develop for Vectren South?

A. In my analysis, I have developed four time-varying rate designs: TOU, CPP, CPP/TOU, and RTP. These rates can be offered individually or in combination to customers. Factors such as customer education and likely response to a rate must be considered in determining which rates to offer.

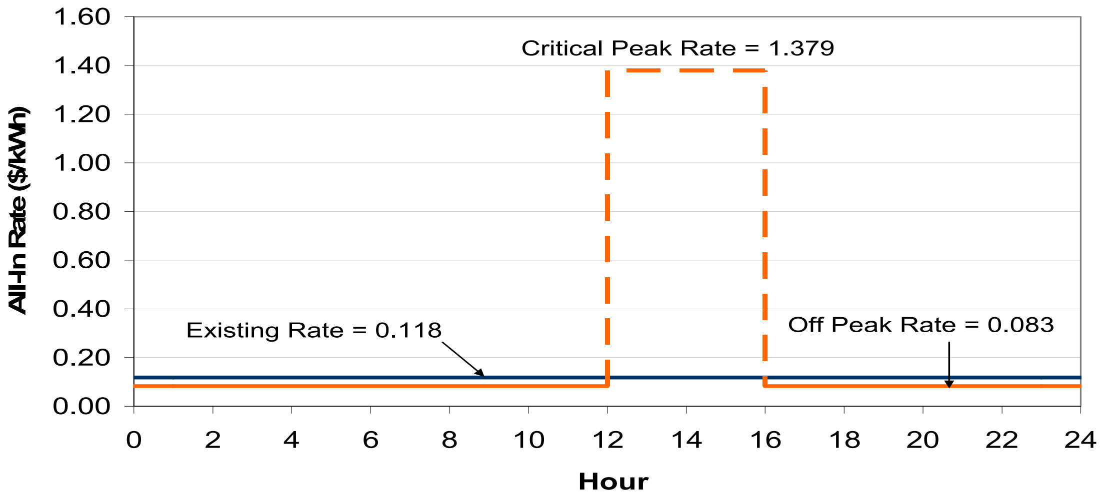
A static TOU rate divides the day into time periods and provides a schedule of rates for each period. In this case, the peak period is defined as the period from 12 pm to 4 pm on summer weekdays, with the remaining summer hours being off-peak. The rate is higher during the peak period and lower during the off-peak, mirroring the variation in the cost of supply. There is no uncertainty as to what the rates would be and when they would occur. For an illustration of the residential TOU rate, see Figure AF-1 below.

Figure AF-1: Illustration of Residential TOU Rate



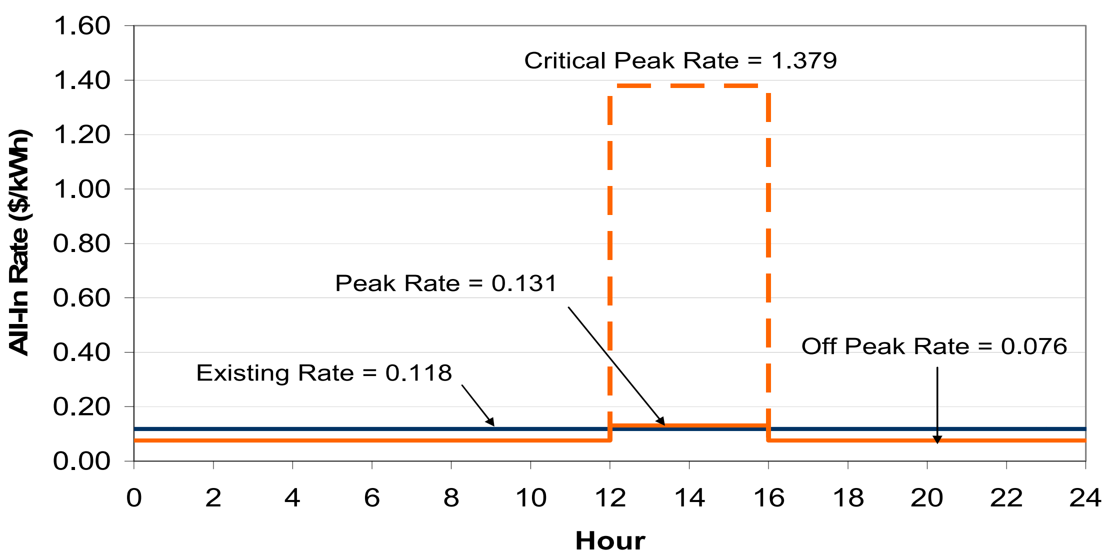
Under the CPP rate, participating customers pay higher peak period prices than they would on their otherwise applicable tariff during peak hours on the few days when wholesale prices are the highest. In return, the customers pay a lower off-peak price that more accurately reflects lower off-peak energy supply costs for the duration of the season (or year). Thus, the CPP rate attempts to convey the true cost of power generation to electricity customers and provides them with a price signal that more accurately reflects energy costs as well as the opportunity to minimize their electricity bills. This rate form is particularly effective when elevated supply costs are limited to only a few (under 100) hours of the year, and their onset is quite predictable. For an illustration of the residential CPP rate, see Figure AF-2 below.

Figure AF-2: Illustration of Residential CPP Rate



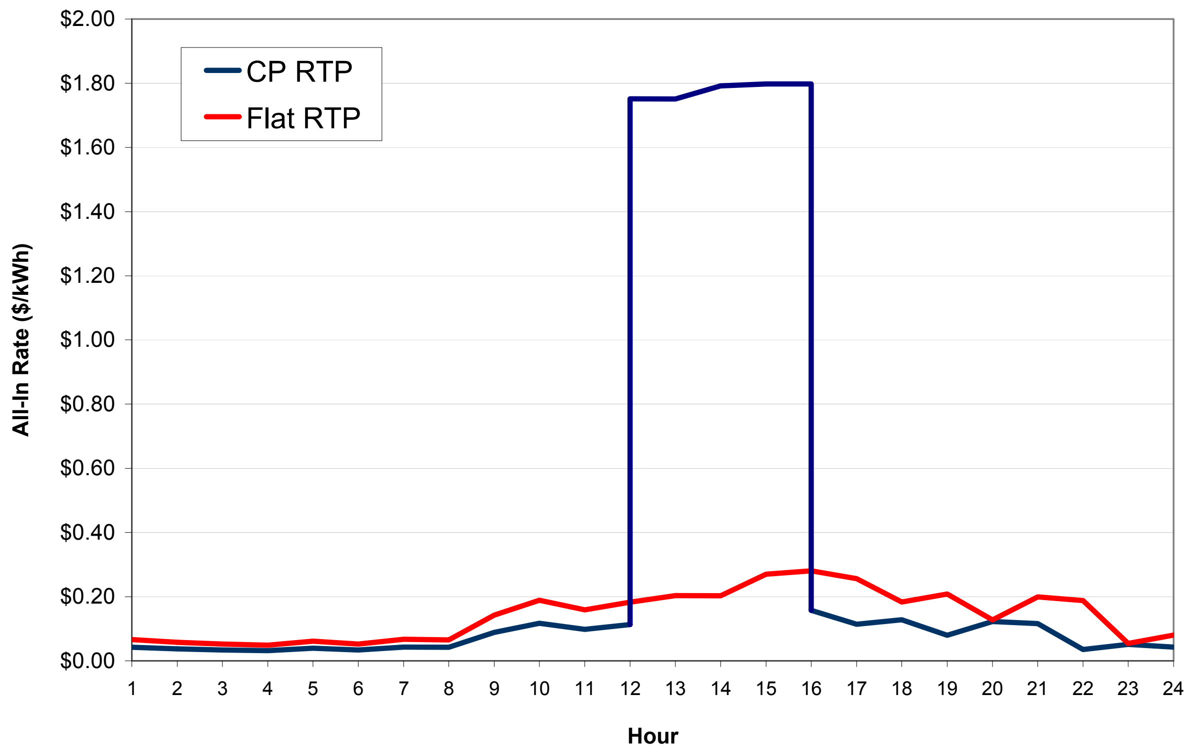
The CPP/TOU rate is simply a combination of the TOU and the CPP, with a smaller peak price applying on non-critical weekdays than on critical weekdays, and a discounted off-peak price during all remaining hours of the summer. For an illustration of the residential CPP rate, see Figure AF-3 below.

Figure AF-3: Illustration of Residential CPP/TOU Rate



Participants in RTP programs pay for energy at a rate that is linked to the hourly market price for electricity. Depending on their size, participants are typically made aware of the hourly prices on either a day-ahead or hour-ahead basis. Typically, only the largest customers — typically above one MW of load — face hour-ahead prices. These programs post prices that most accurately reflect the cost of producing electricity during each hour of the day, and thus provide the most granular price signals to customers. I have created two variations of the RTP rate. The first, called the "Flat RTP," allocates the cost of capacity proportionally over all hours of the summer. The second, called the "Critical Peak RTP" (or "CP RTP"), allocates the cost of capacity only to the critical peak hours, thus producing a higher rate during those times. For an illustration of the residential RTP rates, see Figure AF-4 below.

Figure AF-4: Illustration of Residential RTP Rates



These rates were developed for five customer classes: Residential, Electric Heat, DGS, OSS, and Large Power. The rates are summarized in Figures AF-5 and AF-6 below.

Figure AF-5: Summary of TOU, CPP, and CPP/TOU Rates

All-In CPP Rate Comparison (cents/kWh)

	Residential	Electric Heat	DGS	OSS	Large Power
Existing Rate	11.8	9.8	8.0	7.6	6.2
Critical Peak Rate	137.9	137.6	136.2	131.7	129.5
Off Peak Rate	8.3	6.5	4.5	4.3	3.0

All-In TOU Rate Comparison (cents/kWh)

	Residential	Electric Heat	DGS	OSS	Large Power
Existing Rate	11.8	9.8	8.0	7.6	6.2
Peak Rate	32.0	30.0	27.7	26.8	25.5
Off Peak Rate	8.3	6.5	4.5	4.3	3.0

All-In CPP/TOU Rate Comparison (cents/kWh)

	Residential	Electric Heat	DGS	OSS	Large Power
Existing Rate	11.8	9.8	8.0	7.6	6.2
Critical Peak Rate	137.9	137.6	136.2	131.7	129.5
Peak Rate	13.1	12.8	11.4	6.9	4.7
Off Peak Rate	7.6	5.6	3.5	3.9	2.8

Figure AF-6: Summary of RTP Rates

All-In Flat RTP Rate Comparison (cents/kWh)

	Residential	Electric Heat	DGS	OSS	Large Power
Existing Rate	11.8	9.8	8.0	7.6	6.2
Max Hourly Rate	135.4	97.5	80.7	75.5	79.1
75th Percentile Rate	13.7	9.8	8.0	7.2	7.8
50th Percentile Rate	7.4	5.3	4.2	3.8	4.1
25th Percentile Rate	5.1	3.6	2.8	2.5	2.7
Min Hourly Rate	0.6	0.4	0.1	-1.6	0.1

All-In CP RTP Rate Comparison (cents/kWh)

	Residential	Electric Heat	DGS	OSS	Large Power
Existing Rate	11.8	9.8	8.0	7.6	6.2
Max Hourly Rate	191.5	142.8	114.1	146.1	110.0
75th Percentile Rate	8.6	6.3	4.9	3.6	4.8
50th Percentile Rate	4.7	3.4	2.6	1.9	2.5
25th Percentile Rate	3.3	2.4	1.8	1.2	1.7
Min Hourly Rate	0.6	0.4	0.1	-0.8	0.1

Q. How did you develop the dynamic pricing rate schedules for Vectren South?

A. All rates are designed to be revenue neutral. In other words, if customers were to enroll in the new rate, then in the absence of any load shifting some bills would decrease and others would increase, but the average customer's bill would not change. Additionally, in developing the rates, only the generation component of the tariff is made to vary with time. The other charges on the existing tariff remain unaffected.

To determine the peak price of each rate design, the cost of a peaking plant (roughly $73/kW-year) is spread equally across the peak hours and added to the average energy rate. Because the peak period of the TOU rate includes more peak hours than the CPP rate, this results in a lower peak price of the TOU rate. The one exception to this approach is case of the Flat RTP rate, for which the capacity price is spread out over all hours of the summer.

In the case of the CPP and TOU rates, the off-peak rate is simply solved to maintain revenue neutrality. This is done separately for each of the five customer classes, since the average load shape varies from one class to the next. In the case of the CPP/TOU rate, the peak period of the TOU is set equal to the first tier of the existing rate, and the off-peak rate is then solved for revenue neutrality. For the two RTP rate designs, the hourly energy prices (LMP plus capacity) are all scaled up or down proportionally to produce a revenue neutral rate for the summer season.[2]

Vectren South is proposing to offer a CPP/TOU rate to its customers. I support this decision, because the CPP/TOU encourages permanent load shifting (through the TOU component of the rate) but is also dynamic and can be used curtail demand specifically during unexpected reliability events or in response to economic conditions. The two period rate design is simpler for customers to understand and respond to than the RTP, which has hourly price variability. And the CPP/TOU has been proven to produce significant customer response and bill savings through several pricing pilots.

Q. Did you tailor the PRISM model for Vectren South?

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[2] For more information on developing dynamic rates, see Ahmad Faruqui and Ryan Hledik, "The Power of Dynamic Pricing," *The Electricity Journal*, April 2009.

A. Yes, my simulations using the PRISM model were tailored specifically to Vectren South's system conditions.[3] The PRISM model was first developed during the California Statewide Pricing Pilot (SPP), a $20 million experiment carried out jointly by the three investor-owned utilities in the state and the two regulatory commissions to assess customer response to dynamic (time-based) rates. This pilot was the largest experimental pilot of its kind, and formed the basis for the AMI business cases that have been filed by all three of the California IOUs with the California Public Utilities Commission. The purpose of the SPP was to measure the change in consumption patterns that customers would exhibit when the structure of their rate was changed from a non-time varying rate to one that was time varying and dynamic, such as CPP. The experiment involved over 2,500 residential and small commercial and industrial (C&I) customers and spanned a period of more than two years. Ultimately, the SPP produced estimates of customer response to dynamic rates. These estimates varied not only with the dynamic rate design (i.e. price level during the critical peak and off peak periods) but also with information about the region's average load profile, weather, and central air conditioning ("CAC") saturation.

In order to yield meaningful information for Vectren South, PRISM was calibrated to Vectren South's system characteristics, such as weather conditions, load profiles, saturation of CAC and existing rates. It is because of this additional functionality that PRISM's estimations of DR can reflect not only California-specific conditions, but also be calibrated to provide an estimate of DR in Vectren South's service territory. The price elasticities in the model are automatically adjusted to reflect these assumptions.

Q. How do you predict financial benefits with this model?

A. Once the model has been calibrated to Vectren South's system conditions, it is used to produce estimates of customer response to each of the rate designs described previously. These customer-level responses are then multiplied into an assumed number of participating customers to arrive at the system level impacts. The system

[3] The model is described in detail in Ahmad Faruqui and Lisa Wood, "Quantifying the Benefits of Dynamic Pricing in the Mass Market," prepared for EEI, January 2008. The model is available on the web at: http://www.eei.org/industry_issues/electricity_policy/advanced_metering_infrastructure.htm. Recent updates to the model are described in the previously described "A National Assessment of Demand Response Potential."

level impacts are multiplied into estimates of avoided capacity and energy costs to arrive at the total annual financial benefits. This process is illustrated in Figure AF-7. Figure AF-8 includes the details of my financial assumptions.

Figure AF-7: Illustration of PRISM Impacts Forecasting Approach

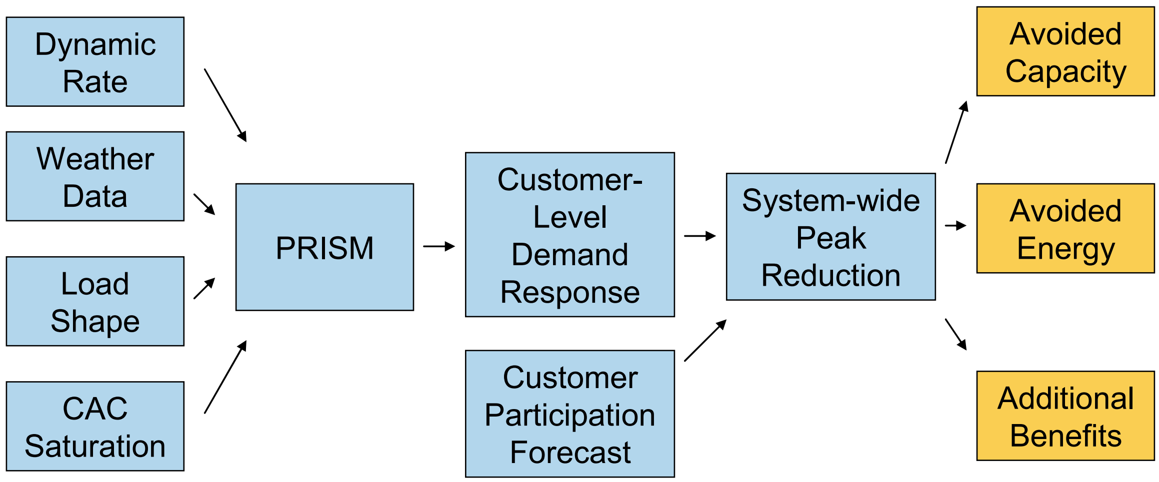


Figure AF-8: Assumptions for Estimating Financial Benefits

- **Forecast Horizon = 20 years**
- **Number of customers in first year (and annual growth rate)**
  - Residential = 94,147 (1.10%)
  - Electric Heating = 27,840 (1.10%)
  - DGS = 8,407 (0.03%)
  - Off Season = 731 (0.03%)
  - Large Power = 104 (-0.01%)
- **Avoided costs**
  - Capacity = $74.88/kW-year in 2010, growing to $109.08/kW-year by 2029
  - Transmission and Distribution = No benefit assumed (see appendix)
  - Average energy price (includes CO2 costs) = $50.41/MWh in 2010, growing to $98.12/MWh by 2029
- **Annual discount rate = 7.32%**
- **Annual inflation rate = 3%**
- **Reserve margin = 15%**
- **Line losses = 5%**

Q. Did you test any scenarios in addition to the one which you described previously?

A. Yes. I tested several scenarios using different combinations of assumptions about the participation rate and the type of dynamic rate being offered. Under a default rate offering scenario, I assumed that the participation rate would be 80 percent, reflecting the much higher level of participation that can be achieved when customers are automatically enrolled in a dynamic rate, with the option of reverting back to their existing rate. Under a universal rate offering I assumed that no customers would have the option of going back to the existing rate and therefore 100 percent would be enrolled in a dynamic rate. This is driven by the Department of Energy (DOE) requirement that all recipients of SGIG funds offer a pricing pilot with mandatory participation to test customer price response. It will be interesting to compare customer response across voluntary and mandatory rate offerings, as no pilots to date have explored this aspect of dynamic pricing.

Definitions of the six participation scenarios that I modeled are provided in Figure AF-9 below. The projection of peak impacts over the 20 year forecast horizon range from 12 MW to 184 MW. The resulting present value of financial benefits is between $8 million and $131 million. These results are presented in Figure AF-10 and Figure AF-11 below.

Figure AF-9: Participation Scenarios

Scenario Name	Class	Rate	Participation	Enabling Tech
Optional CPP/TOU	Residential	CPP/TOU	Optional (15%)	Yes
	Electric Heat	CPP/TOU	Optional (15%)	Yes
	DGS	CPP/TOU	Optional (15%)	Yes
	OSS	CPP/TOU	Optional (15%)	Yes
	Large Power	CPP/TOU	Optional (15%)	Yes
Optional TOU	Residential	TOU	Optional (15%)	No
	Electric Heat	TOU	Optional (15%)	No
	DGS	TOU	Optional (15%)	No
	OSS	TOU	Optional (15%)	No
	Large Power	TOU	Optional (15%)	No
Optional CPP	Residential	CPP	Optional (15%)	Yes
	Electric Heat	CPP	Optional (15%)	Yes
	DGS	CPP	Optional (15%)	Yes
	OSS	CPP	Optional (15%)	Yes
	Large Power	CPP	Optional (15%)	Yes
Optional Residential, Universal C&I CPP/TOU	Residential	CPP/TOU	Optional (15%)	Yes
	Electric Heat	CPP/TOU	Optional (15%)	Yes
	DGS	CPP/TOU	Universal (100%)	Yes
	OSS	CPP/TOU	Universal (100%)	Yes
	Large Power	CPP/TOU	Universal (100%)	Yes
Universal CPP/TOU	Residential	CPP/TOU	Universal (100%)	Yes
	Electric Heat	CPP/TOU	Universal (100%)	Yes
	DGS	CPP/TOU	Universal (100%)	Yes
	OSS	CPP/TOU	Universal (100%)	Yes
	Large Power	CPP/TOU	Universal (100%)	Yes
Optional Residential, Default C&I CPP	Residential	CPP	Optional (15%)	Yes
	Electric Heat	CPP	Optional (15%)	Yes
	DGS	CPP	Default (80%)	Yes
	OSS	CPP	Default (80%)	Yes
	Large Power	CPP	Default (80%)	Yes

Figure AF-10: Comparison of Total Annual Peak Reductions

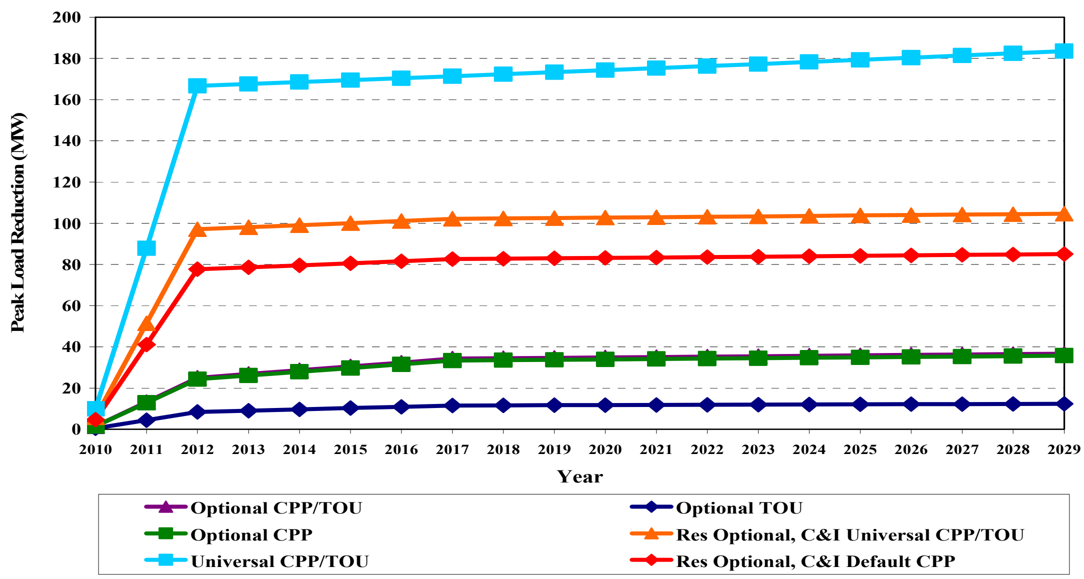
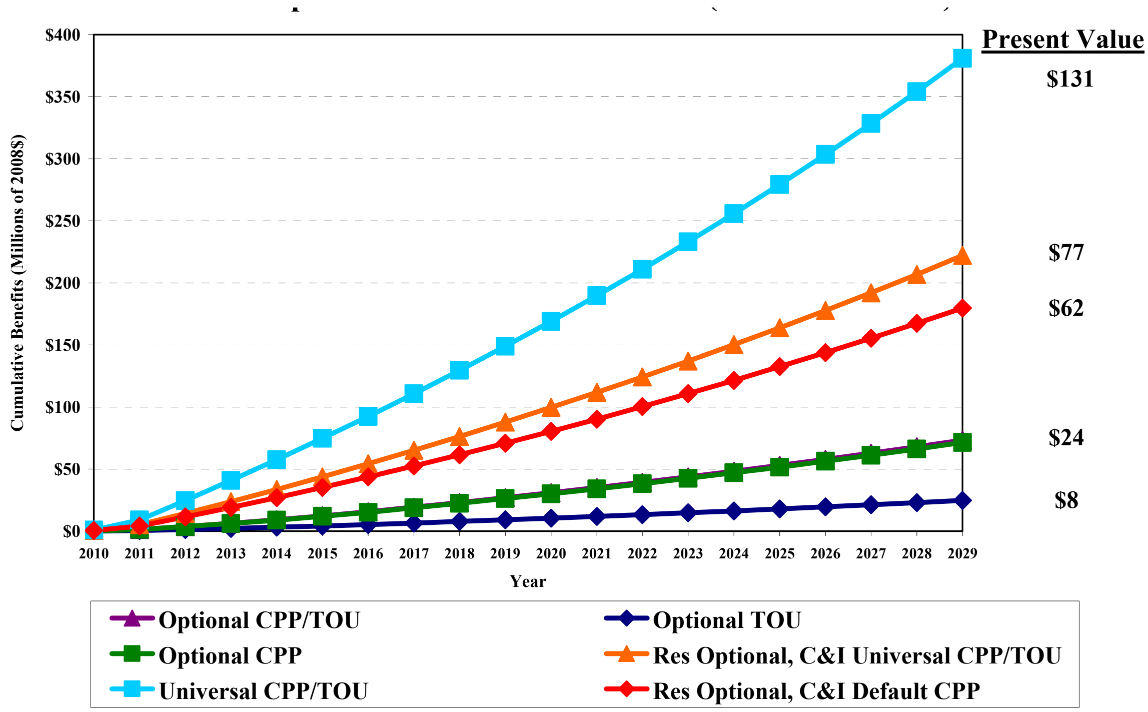


Figure AF-11: Comparison of Cumulative Benefits (Millions of 2009$)



Note: The impacts of the "Optional CPP" scenario and the "Optional CPP/TOU" scenario overlap.

Q. Why is there such large variance in benefits between the optional participation scenarios and the default and universal participation scenarios?

A. Under the optional participation scenario, participation is only assumed to reach 20 percent. This means that only a fraction of Vectren South's customers will be shifting their demand away from peak periods to take advantage of lower off peak prices. Under the universal participation scenario, all customers would be enrolled in a dynamic rate, and a much larger percentage of the population would actively cut back on peak demand as a result. It is this simple distinction that drives the difference in impacts.

My assumed participation rates are based on the best available research on the topic. For more information, see Momentum Market Intelligence, "Customer Preferences Market Research: A Market Assessment of Time Differentiated Rates Among Residential Customers in California," December 2003. The study is based on a survey of residential customers regarding their likelihood to enroll in dynamic pricing. It finds that roughly 20 percent would do so on an opt-in basis. On the other hand, roughly 80 percent would be expected to remain on the rates if offered on an opt-out basis. One of the reasons for developing multiple participation scenarios - as I have done in my analysis - is that there is uncertainty around these estimates and their applicability to other regions.

The types of rates and technologies offered also affect the total impacts. When customers are enrolled in rates with stronger price signals and equipped with technologies that automate their demand reductions, they tend to provide larger peak savings.

Q. Please explain the relationship between dynamic pricing and a direct load control program?

A. Dynamic pricing programs expand the reach of direct load control programs by giving customers an additional incentive to go beyond their use of central air conditioning and reschedule their appliance and lighting loads. Additionally, customers can be offered enabling technologies (like programmable communicating thermostats) which operate like a direct load control program by automatically reducing air conditioning load during critical peak events. In my analysis, I have assumed that 60 percent of eligible customers adopt these types of technologies.[4] Experimental pilots have found that customers who are both equipped with these devices and enrolled in dynamic rates will produce additional incremental impacts well above and beyond those of customers who are enrolled in dynamic rates but do not have the devices. I used the results of these pilots to model an additional incremental impact due to technology for the participating customers.

Q. Does this conclude your prepared direct testimony?

A. Yes, at this time.

[4] Eligible customers are those customers with both AMI and central air conditioning. The 60 percent participation rate is Vectren's target assuming the technologies will be offered at no charge to customers, and that the benefits of the technologies will be marketed along with the dynamic pricing program. This is also the assumed participation rate in the Achievable Participation scenario of the *National Assessment of Demand Response Potential* report.