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August 16, 2011

RECEIVED

AUG 17 2011

PUBLIC SERVICE
COMMISSION

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602

RE: Owen Electric Cooperative, Inc.
Case No. 2011-00037

Dear Mr. Derouen:

Please find enclosed the original and ten (10) copies of the responses to the "Commission Staff's Second Information Request" to Owen Electric Cooperative, Inc.

Please contact me with any questions regarding this filing.

Respectfully submitted,

CRAWFORD & BAXTER, P.S.C.

James M. Crawford

James M. Crawford

JMC/mns

Enclosures

cc: Mr. Dennis Howard, Assistant Attorney General

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

AUG 17 2011

PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF OWEN ELECTRIC COOPERATIVE CORPORATION FOR AN ORDER AUTHORIZING A CHANGE IN RATE DESIGN FOR ITS RESIDENTIAL AND SMALL COMMERCIAL RATE CLASSES, AND THE PROFFERING OF SEVERAL OPTIONAL RATE DESIGNS FOR THE RESIDENTIAL RATE CLASSES	)	CASE NO. 2011-00037

COMMISSION STAFF'S SECOND INFORMATION REQUEST TO OWEN ELECTRIC COOPERATIVE CORPORATION

Owen Electric Cooperative Corporation ("Owen"), pursuant to 807 KAR 5:001, is to file with the Commission the original and 10 copies of the following information, with a copy to all parties of record. The information requested herein is due no later than August 17, 2011. Responses to requests for information shall be appropriately bound, tabbed and indexed. Each response shall include the name of the witness responsible for responding to the questions related to the information provided.

Each response shall be answered under oath or, for representatives of a public or private corporation or a partnership or association or a governmental agency, be accompanied by a signed certification of the preparer or person supervising the preparation of the response on behalf of the entity that the response is true and accurate to the best of that person's knowledge, information, and belief formed after a reasonable inquiry.

Owen shall make timely amendment to any prior response if it obtains information which indicates that the response was incorrect when made or, though correct when made, is now incorrect in any material respect. For any request to which

Owen fails or refuses to furnish all or part of the requested information, Owen shall provide a written explanation of the specific grounds for its failure to completely and precisely respond.

Careful attention should be given to copied material to ensure that it is legible. When the requested information has been previously provided in this proceeding in the requested format, reference may be made to the specific location of that information in responding to this request. When applicable, the requested information shall be separately provided for total company operations and jurisdictional operations.

1. Refer to the response to Item 1 of Commission Staff's First Information Request ("Staff's First Request"). Explain why Page 5 of 5 shows residential space heating customers having the lowest average monthly usage in comparison to the non-space heating residential customers' usage and the average residential usage shown on pages 4 and 3, respectively.

2. Refer to the responses to Items 1.d. and 2.d. of Staff's First Request.

a. It is understood that Owen's proposed changes in rates are designed to be revenue neutral, but they are not necessarily bill neutral. Explain whether Owen agrees or disagrees that annual decreases in the energy rate could send a price signal that promotes usage.

b. Explain whether Owen is aware of any published studies which address customers' responses to conservation, energy efficiency or demand response offerings of utilities when the offerings coincide with the type of rate design changes Owen is proposing in this proceeding.

3. Refer to the response to Item 3.a. of Staff's First Request. Explain whether the fact that Owen's proposed rates do not always follow the underlying rates of its wholesale power supplies, East Kentucky Power Cooperative, Inc., puts Owen at some financial risk.

4. Refer to the response to Item 5 of Staff's First Request. Owen states that the rate design in this case has taken considerable time to process, educate and finalize with Owen's Board of Directors.

a. Since Owen's board members are likely more familiar with the electric utility industry and electric utility rates than its member-owners, explain how Owen plans to educate and inform its members as to the reasons for its changes in rates, and communicate to its members how to determine the effect of the changes on their bills.

b. Explain whether Owen has discussed its proposed rate changes in focus groups, or in other meetings with members.

5. Refer to the response to Item 8 of Staff's First Request.

a. Explain the ratings given to the "DSM" method in comparison to those given to the "Cost of Service" method, paying particular attention to the high level of simplicity, transparency, understandability, and equity ascribed to the "Cost of Service" method as opposed to the "DSM" method.

b. The last sentence in the response reads, "We believe the cost of service method offers members superior fairness and equity....because it allocates costs accurately thereby removing cross subsidies and inequity in rates between members." Explain whether any of Owen's rate classes are currently subsidizing other rate classes and, if so, whether Owen is addressing the subsidization in this case.

MS/JA

6. Refer to the response to Item 9 of Staff's First Request. If the customer charge is equal to the full distribution cost to serve and the energy charge exceeds the wholesale cost per kWh, explain whether a throughput incentive still exists.

MS / JBoe

7. Refer to page 2 of the response to Item 10 of Staff's First Request. Provide a brief description of each of the five potential future services and products listed on the page.

MC

8. Refer to the response to Item 11.b. of Staff's First Request. Explain whether any of the Demand-Side Management ("DSM") programs listed in this response are specifically targeted to fixed- and low-income members. If not, explain how many such customers participate in each of the DSM programs listed.

MC

9. Refer to the response to Item 13 of Staff's First Request.

a. Explain why the REM/Rate energy rating tool uses BTUs and not kWh in determining saving for a rural electric cooperative.

b. Provide a detailed list of the materials used, including their costs, and the labor costs that comprise the $16,296 total cost, which equates to an average of $1,810 for the nine homes weatherized under the Button-Up pilot program.

JA/MC

10. Refer to the response to Item 16 of Staff's First Request, which indicates that approximately 28,000 residential customers will experience an increase in their bills, with this number dropping to 9,500 if customers who would benefit from the Inclining Block Rate actually choose it. The Prepared Testimony of James R. Adkins

("Adkins Testimony") at page 6 states that the residential Inclining Block Rate is specifically designed for customers who consistently use 500 kWh per month or less.

a. Explain whether Owen expects approximately 18,500, which equates to one-third, of its residential customers to understand that their bills are likely to increase if they don't change rate schedules. Explain whether Owen plans to directly contact those low usage customers who do not change to the Inclining Block Rate Schedule to advise them of the opportunity to decrease their bills by changing rate schedules. MC

b. Refer to Exhibit 9 of Owen's application, which shows the impact of rate proposals on customers at various usage levels. Explain why Inclining Block Rates bills shown in the last column continue to be lower for usage over 500 kWh even though the last rate step is, as the Adkins Testimony describes, at a premium of three cents per kWh over the energy rate for the previous step. If there is an error in the calculation of the Inclining Block Rates column, provide a revised Exhibit 9.

c. Describe the usage pattern of the 9,500 remaining residential customers who would not benefit from a switch to Inclining Block Rates, and any opportunity available to them to avoid an increase in their electric bill.

ML 11. Refer to the response to Item 17.a. of Staff's First Request. Explain whether some change to Owen's proposed tariffs is required to clarify that one-year commitments are not required, especially in the absence of a written contract.

MP 12. Refer to the response to Item 19 of Staff's First Request. Confirm that during a higher usage month a customer switching to Schedule 1-B1-Farm & Home-

Time of Day tariff could receive a lower bill without shifting usage (the assumptions provided stated that no usage shift from peak to off-peak or -shoulder was assumed).

MP 13. Refer to the response to Item 20 of Staff's First Request.

a. Confirm that, using the information provided for years 2012 through 2015, during a higher usage month a customer switching to Schedule 1-B2-Farm & Home- Time of Day tariff could receive a lower bill without shifting usage (the assumptions provided stated that no usage shift from peak to off-peak or -shoulder was assumed).

b. Explain why the calculated B2 bills provided for 2011 are higher than those provided for 2012 through 2015.

14. Refer to the response to Item 21 of Staff's First Request. Confirm that MP during a higher usage month a customer switching to Schedule 1-B3-Farm & Home- Time of Day tariff could receive a lower bill without shifting usage (the assumptions provided stated that no usage shift from peak to off-peak or -shoulder was assumed).

Aaron D. Greenwell for
Jeff Derouen
Executive Director
Public Service Commission
P.O. Box 615
Frankfort, Kentucky 40602

DATED AUG 05 2011

cc: All Parties

Honorable James M Crawford
Attorney At Law
Crawford & Baxter, P.S.C. Attorneys at Law
523 Highland Avenue
P. O. Box 353
Carrollton, KENTUCKY 41008

Mr. Dennis Howard
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KENTUCKY 40601

Mark Stallons
President
Owen Electric Cooperative, Inc.
8205 Highway 127 North
P. O. Box 400
Owenton, KY 40359

Affiant, James Adkins, states that the answers given by him to the foregoing questions are true and correct to the best of his knowledge and belief.

James R. Adkins
James Adkins

Subscribed and sworn to before me by the affiant, James Adkins, this 17th day of August, 2011.

Notary Melissa K Moore
State-at-Large

My Commission expires April 14, 2015.

Affiant, Mark A Stallons, states that the answers given by him to the foregoing questions are true and correct to the best of his knowledge and belief.

Mark A Stallons

Subscribed and sworn to before me by the affiant, Mark A Stallons, this 17th day of August, 2011.

Notary Melissa K. Moore

State-at-Large

My Commission expires April 14, 2015.

Affiant, Michael Cobb, states that the answers given by him to the foregoing questions are true and correct to the best of his knowledge and belief.

Michael Cobb

Subscribed and sworn to before me by the affiant, Michael Cobb, this 17th day of August, 2011.

Notary Melissa K. Moore
State-at-Large

My Commission expires April 14, 2015.

Affiant, Mary E Purvis, states that the answers given by her to the foregoing questions are true and correct to the best of her knowledge and belief.

Mary E. Purvis
____
Mary E Purvis

Subscribed and sworn to before me by the affiant, Mary E Purvis, this 17th day of August, 2011.

Notary Melissa K Moore
State-at-Large

My Commission expires April 14, 2015.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Provide the following information in a comparative format:

Question:

Refer to the response to Item 1 of Commission Staff's First Information Request ("Staff's First Request"). Explain why Page 5 of 5 shows residential space heating customers having the lowest average monthly usage in comparison to the non-space heating residential customers' usage and the average residential usage shown on pages 4 and 3, respectively.

Response:

Because the residential class is not segmented into space and non-space heating types, the 2009 Residential End Use Survey was utilized to estimate the average annual usage. A cross tab was generated using type of heating system and average annual usage. The non-space heating calculation was taken from those members who answered that the heating system used was either electric furnace, electric heat pump, geothermal, natural gas furnace, bottled gas/propane furnaces or fuel oil furnaces. Space heating usage was calculated from those members who said that they had electric built in units, kerosene space heaters, wood burning fire places, wood/coal stove or something other were used to heat their residence. Space heating usage was slightly lower than non-space heating usage. This fact can be attributed to non-space heating residences have a larger square footage and the annual usage includes air conditioning which is used more often in homes with non-space heating.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Refer to the responses to Items 1.d. and 2.d. of Staff's First Request.

a. Question:

It is understood that Owen's proposed changes in rates are designed to be revenue neutral, but they are not necessarily bill neutral. Explain whether Owen agrees or disagrees that annual decreases in the energy rate could send a price signal that promotes usage.

a. Response:

Owen disagrees that annual decreases in the energy rate could send a price signal that promotes usage for the following reason: Owen believes that member's consumption is driven by their desire for comfort and convenience as well as affected by their household energy budget. The first response of most bill payers is to look at the amount of their bill. If the amount is within their expectations then they pay the bill and move on to the next item on their "to do" list. If the billed amount is outside their budgeted expectations, they begin to explore their options and ask questions of their electric supplier. The primary driver is the billed amount not the mathematical formula to derive the billed amount. The strength in the gradualism approach is that, even within the rate class, the billed amount changes slowly over time and is most likely to be overshadowed by weather, fuel, and environmental price fluctuations.

b. Question:

Explain whether Owen is aware of any published studies which address customers' responses to conservation, energy efficiency or demand response offerings of utilities when the offerings coincide with the type of rate design changes Owen is proposing in this proceeding.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

b. Response:

Owen is not aware of specific studies that address customer's responses to conservation and energy efficiency offerings when the offerings coincide with a cost of service approach to rate design. This approach, however, is widely utilized by cooperatives wishing to promote conservation, energy efficiency, and demand side management initiatives and follows best practice guidelines set forth by the National Rural Electric Cooperative Association ("NRECA"), the National Rural Utilities Cooperative Finance Corporation ("CFC"), rate consultants, and the National Regulatory Research Institute. Copies of rate design guidelines from each of these groups are attached for informational purposes.

National Regulatory
Research Institute

A Rate Design to Encourage Energy Efficiency and Reduce Revenue Requirements

David Magnus Boonin

Principal, Electricity Research & Policy

National Regulatory Research Institute

July 2008

08-08

Acknowledgments

The author thanks Kenneth Costello, NRRI's Director of Gas Research and Policy, for his support and insight throughout this project. Ken is a thought leader in the area of decoupling and energy utility rate design. The author also acknowledges the input of the paper's reviewers, Scott Hempling (NRRI), Andrew Keeler (Ohio State University), and Eric Ackerman (EEI). Finally, the author thanks NRRI's entire staff and all of NRRI's members for making this report possible.

Executive Summary

The search for low-carbon electricity resources intensifies as more attention is paid to greenhouse gases (GHG). If energy efficiency in the electricity sector is to be a major resource in the battle against greenhouse gases, utility regulators need to create an environment that enables and encourages cost-effective energy efficiency. This paper addresses one overlooked method of decoupling a utility's income from sales and offers a complementary set of price signals to consumers that are designed to enhance energy efficiency.[1] The decoupling strategy is a Straight Fixed Variable (SFV) rate design, and the customer price signal is a Revenue-Neutral Energy Efficiency Feebate (REEF).

Rate designers contrast straight fixed variable design with standard two-part rates. The terminology can be confusing because both forms involve two-part rates; the difference between them has to do with how each approach treats fixed costs. Straight fixed variable rate design places all of a utility's fixed costs into a fixed component of a utility customer's bill, thereby recovering only variable costs, such as fuel and purchased power, on a variable (e.g., per kWh or kW) basis. A standard two-part tariff, in contrast, usually collects some fixed costs through a variable charge. The standard approach causes larger users within a class to pay more than the fixed costs they impose on the system, with small users paying less than their share of fixed costs.

Both designs recover variable costs predictably. They differ in the predictability of fixed cost recovery in the context of sales reductions. Because the "standard" method recovers part of the fixed costs through the variable charge, increased customer energy efficiency causes sales reduction, which in turn leads to a gap in fixed cost recovery and income. A straight fixed variable approach, in contrast, insulates the utility's income from changes in sales per customer.

SFV rate design creates a rational model for allocating fixed and variable costs. One criticism, however, is that by moving fixed costs out of the variable charge, the rate design weakens the price signal, thereby reducing a customer's economic incentive to use energy efficiently. That is, the average short-term variable costs left in the variable charge will be less than what had been collected from customers in the variable component under the Standard

[1] Other potential barriers exist to electricity energy efficiency, including whether there is comparability in profitability from the utility's perspective between supply and demand resources in jurisdictions where utilities have a role in delivering energy efficiency services, and numerous consumer-oriented market barriers.

Tariff. Hence, the second component of this paper is a revenue-neutral energy efficiency feebate (REEF) for customers. A revenue-neutral feebate works by charging fees to those who use more than a typical amount of electricity while giving rebates in the same total amount to others in the class who use less than that amount. Feebates can update continuously the targets for efficiency as people change their energy consumption. Feebates have been proposed and implemented to encourage increases in the automobile gasoline efficiency. The utility would see no financial effect, but consumers could see their bills go either up or down depending on their usage relative to similar customers.

Shifting dollars so that fixed costs are fully recovered through fixed charges, with variable fully recovered through variable charges, not only decouples income from sales (eliminating the utility's disincentive to encourage customer efficiency); it also reduces the utility's financial risk associated with variance in sales. Sales variations associated with weather, the economy, price elasticity, and energy efficiency not stimulated by utility-sponsored programs are all eliminated by SFV rate design. This reduction in risk means that that the commissions can reduce the authorized return on equity, thereby lowering rates for all.

This report is available on the NRRI website at: http://nrri.org/pubs/electricity/rate_des_energy_eff_SFV_REEF_july08-08.pdf.

Item No 2
Page 7 of 55

Table of Contents

A Rate Design to Increase Efficiency and Reduce Revenue Requirements

I. Energy efficiency's role in mitigating greenhouse gases

Greenhouse gas reduction through some type of carbon emissions law at the federal and state levels is gaining increasing momentum. Utility power plant emissions will almost certainly be a set of emissions targeted for control. The strategies frequently discussed to reduce carbon emissions for the electricity generation sector are: increased use of natural gas, increased energy efficiency, increased renewable non-emitting generation, new nuclear power plants, and carbon sequestration. These strategies are applicable whether the carbon restrictions take the form of a tax, cap or trade, or source-specific reductions. Neither new nuclear plants nor carbon sequestration will make significant contributions to carbon reductions for at least a decade. This reality leaves gas generation, non-carbon-emitting generation, and energy efficiency.

Utilities have had an inherent financial bias against demand-side resources that reduce sales, since reductions in sales reduce the income of utilities that use the Standard Two-Part Tariff (Standard Tariff). The Standard-Two Part Tariff recovers only a portion of a utility's fixed costs from fixed charges, leaving the residual fixed costs, including income, to be recovered from charges that vary with use. This coupling of sales and income has made utilities reluctant to embrace strategies that reduce sales, regardless of whether the utility is the program implementer or funder, or whether non-utility entities provide these functions. Negawatts instead of megawatts as an energy resource, conservation programs designed to reduce bills in general or make electricity more affordable to low-income households, and energy efficiency programs that are wholly outside of the utility's control—all of these measures have met with utility resistance, partly because of the underlying linkage between sales and income. Decoupling mechanisms that seek to make utilities indifferent to sales variations often encounter implementation and administrative challenges as well as resistance from ratepayers.

The Energy Information Administration's 2007 base case has energy efficiency as the leading strategy for reducing carbon emissions until around 2023, when carbon sequestration takes a leading role. For energy efficiency to occupy this large role, regulators must (1) eliminate the disincentive for energy efficiency that links decreased sales to decreased income, (2) provide customers with energy efficiency incentives, and (3) provide utilities with financial incentives to promote energy efficiency as a resource comparable to supply resources in places where regulators expect utilities to play a role in implementing or funding energy efficiency initiatives.

This paper starts by focusing on one decoupling approach, a Straight Fixed Variable (SFV) rate design. Straight Fixed Variable rate design is a rational way to recover fixed and variable costs because it aligns pricing with variable and fixed cost causation, thereby removing the utility's profit sensitivity to reduced sales. The problem with SFV is that it reduces the variable charge to short-term variable cost, which is likely to be lower than the economically efficient level of long-term marginal cost, leading to over consumption. To address this problem, an economic incentive for consumer energy efficiency is needed. This paper therefore proposes to discuss the SFV rate design with revenue-neutral energy efficiency feebates. Feebates are a combination of fees and rebates.

II. Straight fixed variable rate design

A. Overview of the concepts

A Straight Fixed Variable Tariff is designed to assign all fixed costs to fixed charges and only variable costs to variable charges. Fixed costs do not change with changes in output, whereas variable costs do change with output. Economic theory would have the price of electricity based upon long-term marginal cost.[2] Given regulators' general use of embedded cost pricing for utility ratemaking, allocating fixed costs to fixed charges and variable costs to variable charges is a reasonable second-best solution from an economic rationality and equity perspective.

The Standard Two-Part Tariff, by allocating some fixed charges to the variable rate, causes large users to pay for fixed costs in excess of their load share. SFV rate eliminates this characteristic. Assume there are two off-peak water heating customers, each with the same contribution to system peak use, except that one uses a lot more hot water. The user of more hot water under a Standard Tariff will pay a disproportionate share of the fixed costs, relieving the other customer of a portion of its share. Although the fixed costs needed to serve each customer are the same, they bear different cost shares.

In addition to correcting for the disproportionate recovery of fixed costs, placing all fixed costs into the fixed charge decouples per-customer sales volume from a utility's income. The table below provides a simplified comparison of the effect of a reduction in sales on a utility's income when using a Standard Two-Part Tariff versus an SFV rate design. Standard Two-Part Tariffs and SFV tariffs can have the same basic components (e.g., customer, demand, and energy charges), with the only difference being that there are no fixed costs in the variable portion of the SFV tariff.

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[2] See Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions, Volume I* (Cambridge, MA: MIT Press, 1988), Chapter 4.

Table 1: Effect on Income Associated with Reduced Sales

	Standard Two-Part Tariff (No Decoupling Adjustment)		Straight Fixed Variable Tariff	
	Base Case	**Energy Efficiency Case**	**Base Case**	**Energy Efficiency Case**
Key Assumptions	100 customers 1000 kWh/customer Fixed charge $15/customer Variable Charge $0.075/kWh	100 customers 950 kWh/customer Fixed charge $15/customer Variable Charge $0.075/kWh	100 customers 1000 kWh/customer Fixed charge $50/customer Variable Charge $0.04/kWh	100 customers 950 kWh/customer Fixed charge $50/customer Variable Charge $0.04/kWh
Revenues				
Revenues from Fixed Charges*	$1,500	$1,500	$5,000	$5,000
Revenues from Variable Charges	$7,500	$7,125	$4,000	$3,800
Total Revenues	**$9,000**	**$8,625**	**$9,000**	**$8,800**
Expenses				
Fixed	$4,000	$4,000	$4,000	$4,000
Variable ($0.04/unit)	$4,000	$3,800	$4,000	$3,800
Total Costs	**$8,000**	**$7,800**	**$8,000**	**$7,800**
Income	**$1,000**	**$825**	**$1,000**	**$1,000**

* Fixed charges are here presented without any adjustment for Return on Equity in SFV cases to reflect reduced risk.

In the example above, the utility experiences a decrease from the base level of sales set in the rate case, from 1,000 units per customer to 950 units per customer. The effect on income of a 5% reduction in sales when a Standard Tariff is used is a decrease in income of 17.5%. Under the SFV tariff, income is not changed by the decrease in sales. The larger the change in income related to a change in sales under an existing Standard Tariff, the greater the need for rate redesign and the greater impact the change will have on the utility's behavior.

B. Major reasons for regulatory reluctance to implement an SFV rate design

Straight Fixed Variable rate design is not a new idea, nor is decoupling of income from sales. SFV rates are used for gas utilities in North Dakota, Georgia, Oklahoma, and Missouri. The author is not aware of any place where an SFV rate design is used to recover the costs of an electric utility. The apparent unpopularity is likely based on the following concerns:

1. Moving revenue from the variable component of a standard two-part tariff to the fixed charge can reduce a customer's economic incentive to conserve.
2. Larger users should be allocated more of the utility's fixed costs.
3. Moving revenue from the variable component of a standard two-part tariff to the fixed charge adversely affects small users within a class, including possibly low-income customers.
4. There are differences of opinion about which costs are fixed and which are variable.

Each of these concerns is addressed below.

1. SGV reduces consumers' incentive to conserve energy

As explained in Part II.A above, recovering fixed costs solely through fixed charges is an economically reasonable second best solution when rates do not reflect the long-run marginal cost of electricity. But the reduction in the variable charge arising from a shift of fixed costs to the fixed charge can reduce the customer's economic incentive to conserve. Reduced savings on the customer's bill that are associated with SFV rate design in certain situations can extend the payback period, from the customer's perspective, of a customer-funded energy-efficiency investment. The example on the next page sets forth two cases from the consumer's perspective and compares the payback period for the same customer-funded energy efficiency investment.

Table 2: Comparison of Payback on Energy Efficiency Investments

Reduction of Monthly Customer Usage from 1000 to 900 Units Energy Efficiency Investment of $200		
	Standard Two-Part Tariff **$15 Fixed Charge** **$0.075/unit**	**Straight Fixed Variable** **$50 Fixed Charge** **$0.04/unit**
1,000 units	Fixed $15.00 Variable $75.00 Total $90.00	Fixed $50.00 Variable $40.00 Total $90.00
900 units	Fixed $15.00 Variable $67.50 Total $82.50	Fixed $50.00 Variable $36.00 Total $86.00
Savings	**$7.50/month or $90/year**	**$4.00 or $48/year**
Payback Period w/o adjustment for decoupling	**2.2 years**	**4.2 years**
Payback Period after $1.66/month adjustment for decoupling[3]	**2.9 years**	**4.2 years**

[3] Based on assumptions used in Table 1, where a $175 income shortfall would need to be recovered from all customers in the class.

The above example shows that consumers would have a shorter payback period with the Standard Tariff than an SFV tariff. Absent other modifications, the SFV thus would discourage some customers from making an investment; they would see a payback in 4.2 years rather than 2.9 years.

There are several responses to the assertion that SFV provides less of an economic incentive for customers to conserve than a Standard Two-Part Tariff.

a. If everyone conserved to exactly the same degree and a decoupling adjustment clause were used to recover the utility's lost income, then the bill to the consumer under either a Standard or an SFV tariff would be the same. See Table 3 on the next page, where the customer's bill is $88 under either tariff. Table 3 demonstrates that when the utility's income is protected from erosion due to reduced sales, and when all customers in a class reduce usage by the same percentage, the bills before and after the sales reduction under either tariff are the same. When all customers conserve proportionally equally, there is no conservation disincentive associated with SFV rate design compared to the Standard Tariff with a decoupling tracker. The issue is, therefore, not that SFV reduces the conservation incentive; rather, it is that customers may behave differently from each other even when offered the same opportunities to conserve.

Table 3: Effect on Customer Bill

Across-the-Board 5% Reduction in Usage and a Decoupling Adjustment		
	Standard Tariff **$15 Fixed Charge** **$0.075 Variable Charge** **$.001842 Decoupling Fee**	**SFV** **$40 Fixed Charge** **$0.04 Variable Charge** **Decoupling Fee N/A**
1,000 Units	Fixed $15.00 Variable $75.00 Total $90.00	Fixed $50.00 Variable $40.00 Total $90.00
950 Units	Fixed $15.00 Variable $71.25 Decoupling[4] $1.75 Total $88.00	Fixed $50.00 Variable $38.00 Decoupling N/A Total $88.00

b. When the Straight Fixed Variable rate design is used in conjunction with the Revenue-Neutral Energy Efficiency Feebate (REEF), the regulator can reflect long-term marginal costs and the costs of externalities in a customer's price signal without upsetting the embedded cost-based revenue requirement calculation for the utility. The REEF concept is discussed at Section III.

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[4] The Decoupling Fee was calculated by dividing the $175 income shortfall from Table one by the 95,000 units (100 customers x 950 units), or $0.001842/unit.

2. Larger users' share of the utility's fixed costs

Some oppose straight fixed variable because it would reduce large users' share of the utility's fixed costs. The argument of SFV is that it aligns the customer's cost share with the burden that the user places on the system. No user – large or small -- should pay more than its appropriately allocated share of fixed costs. If all customers within a class place the same fixed costs (costs that do not vary with usage) on the system, then all customers within that class should pay the same amount in fixed costs. Costs that are not fixed and vary with usage should be recovered from the variable charge. Variable charges should recover charges such as RTO capacity charges, variable demand charges associated with purchased power, and the variable portion of depreciation charges.

The allocations between fixed and variable costs in an SFV rate design occur within a customer class. Creating homogeneous membership within customer classes is a first step towards reducing misallocations among customers within a class. Stratification of customers into more homogeneous groups allows for better assignment of costs under any ratemaking approach.

3. SFV places a greater burden on small and low-income customers than do Standard Tariffs

SFV tariffs do charge low-usage customers within a customer class more than a Standard Two-Part Tariff. If a utility incurs the same fixed costs by having two customers connected to the system who are able to take as much power as they want whenever they want, then each customer should pay the same in fixed charges, because assigning fixed costs within a specific tariff to a fixed charge is fair to all customers.

The Revenue-Neutral Energy Efficiency Feebates discussed in Part III below are designed to shift revenue responsibility from small users to large users within a customer class, without distorting the rate design. The shift in revenue responsibility associated with REEF addresses the issue that low-usage customers would bear more costs due to a move from a Standard Tariff to an SFV tariff.

The effect that an SFV tariff would have on low-income customers is far from conclusive. The literature is not consistent regarding whether low-income customers use more or less electricity than the average customer. Consumption often depends on demographics other than income, such as family size; quality of housing stock; owners versus renters and whether the renter pays the electric bill directly; end uses such water heating, cooking, and space heating; appliance efficiency; and age of householders. There are many other ways of addressing low-income customers' energy affordability issues besides allocating fixed costs to variable charges that may or may not be beneficial to low-income customers. These strategies include, in part, low-income usage-reduction programs where the utility may make investments in the low-income housing stock to increase energy efficiency (note that SFV rate design creates no disincentive for low-income usage reductions programs, in contrast to the Standard Tariff), rate discounts targeted directly to low-income customers, maximum bills as a percentage of a customer's income, and federal low-income energy assistance grants.

4. Difficulties in determining which costs are fixed and which are variable

It is not always transparent which costs vary with sales. Examples of costs which do not vary with sales include administrative overhead such as rent, office building depreciation, or interest on long-term debt. The depreciation of a generating plant, however, has a fixed component and a variable component; i.e., the more the power plant is used to meet demand, the faster it depreciates. The variable component of depreciation should be assigned to the variable component of the SFV tariff and booked as incurred. Labor is predominately a fixed cost, but a portion may be variable, such as overtime for power plant maintenance or customer service, during high-usage summer periods. Commissions that decide to consider an SFV as a decoupling tool may wish to allocate additional time and resources to the rate design portion of the rate case where the SFV concept is first developed.

C. Benefits of SFV

SFV rate design provides a rational allocation of and recovery mechanism for fixed and variable costs, and decouples sales from income. SFV reduces the risk to utility investors. SFV protects a utility's income from externalities associated with variance in sales such as weather, the economy, price elasticity, and energy efficiency. With a reduced variance in income, risk to investors is reduced. Reduction in risk should be linked to a reduction in the allowed return on equity (ROE). A lower ROE reduces the cost to all customers.

Another benefit of an SFV tariff is that it also makes a utility indifferent to the meter running backwards for net metering of demand-side renewable resources. The removal of losses associated with net metering allows a utility to promote smaller solar and wind technologies.

With an SFV rate design as the decoupling mechanism, nothing other than the base tariff need be posted on the bill, unless the variable charge includes some type of an adjustment mechanism. This method is simpler than a Standard Tariff with decoupling adjustment mechanism, which if implemented to track all changes in revenues from each part of the tariff could have separate adjustments for the customer, energy, and demand components as well as ongoing reconciliation adjustments. The SFV rates are set within a rate case without the decoupling adjustment mechanism associated with a Standard Tariff and without the accompanying recurring audits and hearings to ensure that the decoupling adjustment has been accurately recovered.

III. Revenue-Neutral Energy Efficiency Feebate

The Revenue-Neutral Energy Efficiency Feebate (REEF) allows regulators to promote energy efficiency beyond the average cost price signals provided by the variable portions of most rate designs. Regulation normally looks at embedded costs and then divides costs by usage to get prices that are average-cost-based. This method ignores avoidable long-term costs that have not occurred and may not occur if the need for additional resources is avoided by changes in customer behavior. Marginal cost pricing is difficult to achieve when revenue requirements are based on embedded costs. State commissions have used inverted block rates to try to achieve this goal, but those rates aggravate the decoupling problem discussed above, because the movement towards marginal cost pricing is accomplished by shifting more of the embedded fixed cost to the marginal charges in the inverted block rates.

A REEF enhancement to an SFV rate design allows regulators to adjust pricing to reflect long-run marginal costs without affecting a utility's total revenues. Feebates combine rebates and fees into a single program to encourage behavior. The fees fund the rebates, thus making the price incentives revenue-neutral for the utility. The combination of SFV rate design and feebate thus creates an income-neutral environment for energy efficiency.

A. REEF—a general description

The REEF is an intra-class adjustment in which customers who use more than some typical amount pay a fee, while customers who use less receive a rebate. The fees and the rebates offset each other fully, leaving the utility revenue-neutral. These fees and rebates can be designed to induce certain behaviors, such as off-peak conservation (thus reducing coal generation) or on-peak summer conservation (to avoid peak-related future generation costs). The benchmarks used to determine rebates and fees are continuously adjusted by the changes in actual usage to reflect changes in the consumption of different customer classes, whether associated with the weather or with a reaction to the REEF.

The REEF can be designed to reflect long-term marginal costs and to provide customers with price signals relating to externalities. This redesign is an improvement on standard utility pricing, which uses only average embedded costs. For example, average embedded cost pricing would reflect the cost of carbon credits at current prices but would not reflect future carbon costs or long-term marginal costs

Price incentives based upon avoidable costs usually affect total revenues collected and therefore affect the embedded cost ratemaking math. A post-revenue requirement adjustment to rate design that is revenue-neutral allows the regulator to sharpen the price signals without changing the underlying total revenues earned by the utility. In addition to targeting avoidable long-term costs and carbon emissions, the feebate can be designed to maintain the conservation incentives that existed under the Standard Tariff for some period so as not to penalize customers who relied on that pricing paradigm and made energy-efficiency investments.

Every rebate paid to a customer is funded by a customer-paid fee from the same class of customer. It is, therefore, important to have homogeneous customer classes. It might also be necessary to create benchmarks within some classes to normalize usage targets (e.g., in a commercial class, setting the benchmarks based upon usage per square foot of retail space rather than total usage). Customers will quickly see that they can earn credits by using energy more efficiently. It may be more acceptable in some cases to limit the application of REEF to relatively homogeneous classes while not applying it to classes that are particularly heterogeneous.

B. REEF—implementation issues

1. Keep REEF adjustments within a class

A REEF should be designed to keep the adjustments within a class of customers. Customer classes should be defined so that customers are as homogeneous as possible (e.g., heating customers separate from non-heating customers). Classes can generally follow rate classes. Revenue-neutral adjustments will occur within each class. It may not be practical or necessary to have a REEF for each class. The heterogeneity among large industrial customers may make using rate classes impractical and require other comparison techniques, such as looking at the same customer's usage over time. The lack of heterogeneous rate classes for a portion of a utility's customers is not a reason to reject the REFF for other customers.

2. Determine and apply the benchmark

The benchmark should focus on goals that the regulator finds important and that are not adequately addressed by the underlying pricing structure. The benchmark could be based solely on energy, if the focus is carbon; on demand, if the focus is avoiding the need for future generating capacity; or on off-peak energy only, if the strategy is to focus energy efficiency when coal is on the margin. The benchmark could also be based on another goal or combination of goals. The benchmark(s) within a class would be determined for each REEF calculation period so that as customer behavior and exogenous factors (e.g., the weather) change, the benchmark changes also. Once a benchmark for the period is determined, it would be compared to the actual usage of customers in that class for that period to determine the fee or rebate due to each customer.

The feebate program could be developed such that customers that are within a certain percentage or standard deviation of the benchmark would have no adjustment. This "null zone" approach would eliminate noise around the middle, applying adjustments only to customers who are either considerably more or less energy efficient than their class members. Null zones create simplicity but also dampen price signals, because of the exclusion of units within the null zone.

3. Determine the size of the fee and rebate

The strength of the REEF as a price signal is related to the size of the fees and rebates. The regulator need only set the fee; the rebate for each customer will result from allocating all the fees received to those who have earned a rebate. Commissions generally have a great deal of discretion, as long as the methodology for establishing the fees is consistent with public interest goals and reasonably based upon underlying costs associated with those goals. These costs may be understood as either actual avoided costs (e.g., the real-time cost of electricity) or potentially avoidable costs (e.g., long-term marginal costs or externalities not currently internalized to the utility's costs), with no effect on the utility's current revenue requirement. The rebate is calculated by allocating the total fees charged to the customers whose usage was below the benchmark (e.g., proportionally based upon usage below the target level). A customer's current bill would be adjusted with a fee or rebate as established above, rather than through a lagging adjustment as in a decoupling adjustment. There is an actual dollar amount and actual usage used in this calculation, unlike the decoupling adjustment that uses the next period's usage to recover the lost revenues. This actual cost and usage method keeps usage and fees/rebates synchronized, eliminating any need for reconciliation or true-ups.

The actual size and design of the fee needs to be determined based upon the facts such as long-term marginal costs or avoidable costs in individual cases. The size of the feebate can create an energy efficiency signal that is stronger than the standard tariff's signal (see Table 5 for an example). The design of the rebate need not be consistent between rate classes and can even have increasing blocks (e.g., the biggest energy hogs pay ever-increasing fees).

4. Target the REEF

A REEF can be used to target usage that is aligned with the public policy goals of the regulator. If the goal is to shed coal generation that is on the margin only during off-peak hours, the target would be off-peak usage. Conversely, if carbon dispatch is being used instead of economic dispatch by the RTO, or if the market for carbon credits is very expensive, then coal might be on the margin during on-peak hours. More than one public policy goal may be targeted at the same time as long as they do not conflict.

5. Set the REEF adjustment period

The application of the REEF requires that there be a period over which usage data is collected and compared. There are a few ways to define the adjustment period. The first is to have an adjustment for each billing cycle. Every customer within a customer class would have a REEF calculated based upon meters that are read on the same day for the same billing period. The benefit of this approach is that it provides analytical rigor, as all customers will have been billed for consumption in the same period, with the same number of weekdays and weekends and with the same weather. The calculation of fees and rebates is easy to manage; all the data comes in at the same time and an adjustment is placed on the subsequent bill. Using the billing cycle breaks the class into about 20 subgroups (number of billing cycles within a month), and therefore might cause a situation where the groups are too small to prevent the behavior of a small number of customers from having too much influence on the feebate calculation.

Another approach is to gather all customers' data during a set period, such as reading all meters in June. Periods of between several days and a month can be considered. The longer the period, the more customers there will be within the adjustment group. On the other hand, a longer data-gathering period increases the chance that anomalies may occur among the customers because of exogenous changes, such as weather. If a month is chosen and one customer's data is for the 30-day period May 3 through June 1, while another's period is June 1 through June 30, the weather conditions might be much different between these two periods.

Using weekly rather than monthly groups reduces the incentive group size by about 75%, but avoids the problems associated with two-month spans in weather changes.

6. Billing

The REEF, either the rebate or the fee, would be posted on the customer's next bill as a specific amount with a clear explanation such as "Your usage was 50 kWh less than this month's energy efficiency benchmark of 750 kWh; you are being awarded a rebate in recognition of your commitment to using energy efficiently and improving the environment," or "Your usage was 50 kWh greater than this month's energy efficiency benchmark of 750 kWh, and you are being charged an energy efficiency fee. To reduce or eliminate this premium or earn an energy efficiency credit, pleases consider how you can use energy more efficiently and improve our environment. Call 1-800-555-SAVE." The message could be different depending on the Commission's explicit public policy goal and rate class.

Instilling the most transparency, flexibility, and confidence in a REEF requires frequent, timely, and accurate actual meter reads. Automatic meter reading enhances this potential. Estimated meter readings reduce confidence that the right customers are paying the correct fees and receiving the correct rebates.

C. REEF—an example

A REEF can be developed in many ways to enhance the SFV rate design. The REEF's design depends on many underlying issues. This example assumes that, after considering the long-term marginal cost of electricity and the potential future cost of carbon credits, regulators determined that the variable cost of electricity should be \$0.09/kWh. This unit price is higher than either the \$0.04 under the SFV or the \$0.075 for the Standard Tariff, as shown in Table 1, and creates a \$0.05/kWh fee for excess usage under the SFV rate design. The \$0.09/kWh rate would be based upon factors not included in the current embedded costs that regulators find appropriate to provide as price signals to consumers about the true cost of electricity. This example assumes that costs do not vary by time of day or time of year. The benchmark usage is 1000/kWh/customer. The table shows how credits and premiums would be allocated among the five customers in this class. A null zone has not been included.

Item NO 2
Page 22 of 55

Table 4: REEF Example

	650 kWh	900 kWh	1000/kWh	1200 kWh	1250 kWh
SVF Tariff	$76.00	$86.00	$90.00	$98.00	$100.00
REEF Adjustment	-$17.50	-$5.00	$0.00	$10.00	$12.50
SVF plus REEF	$58.50	$81.00	$90.00	$108.00	$112.50
Standard Tariff	$63.75	$82.50	$90.00	$105.00	$108.75

In this example, the REEF-SFV combination shifts costs from larger customers to smaller customers more strongly than did the Standard Tariff, even though the fixed costs have been removed from the variable charge of the SFV tariff. Only at the typical usage point of 1,000 kWh are the bills under the Standard Tariff and the SFVR-REEF combination equal. A consumer using 650 kWh saved an additional $5.25 (8.2%) under the SFV-REEF tariff, and a consumer using 1,259 kWh paid $3.75 (3.4%) more than the Standard the Tariff. A stronger conservation incentive has been provided.

The REEF is self-adjusting. As consumers become more energy efficient, the REEF standards become stronger. Table 6 provides an example which takes into account reduced average usage.

Table 5: REEF Example – Step 2

	650 kWh	850 kWh	900/kWh	1000 kWh	1100 kWh
SVF Tariff	$76.00	$84.00	$86.00	$90.00	$94.00
REEF Adjustment	-$12.50	-$2.50	$0.00	$5.00	$10.00
SVF plus REEF	$63.50	$81.50	$86.00	$95.00	$104.00
Standard Tariff	$63.75	$78.75	$82.50	$105.00	$108.75
Decoupling Adjustment	$2.53	$3.32	$3.51	$3.90	$4.29
Std Tariff + Decoupling	$66.28	$82.07	$85.51	$108.90	$113.04

The bill for the 650 kWh-customer is higher than in the earlier case ($63.50 vs. $58.50). This change in the bill is because all consumers are now more energy efficient, reducing the total fees collected, and this consumer did not change his consumption.

There are many ways to structure a REEF other than the one shown in this example. A REEF can be applied to all components of a tariff, to the demand or energy components alone, or to on-peak rather than off-peak usage, depending on the objective of the price signal. Benchmarks could compare the customer's behavior to his own previous usage when there is no reasonable comparison group with credits shared with other heterogeneous customers within the customer class.

IV. Comparison of SFV-REEF Tariff with other decoupling tools

A. Overview of other decoupling tools

1. Revenue decoupling tracker

This automatic adjustment clause increases or decreases rates depending on how actual sales compare to base sales established in a rate case. There are many implementation issues, including setting base usage figures for each rate class and for each tariff component. In implementing this type of a decoupling mechanism, income neutrality requires adjustment only for revenues associated with fixed costs (net revenues) and not gross revenues. Net revenues are gross revenues net of variable costs. Income neutrality is not achieved (see the following table) when gross revenues are used as the basis because the variable portion of gross revenues is already adjusted by the change in sales.

Table 6: Net vs. Gross Revenue Adjustments

Assumptions: Rate Structure - $15 fixed charge plus $0.075/kWh; Variable Cost $0.04/kWh; 100 customers; Base sales of 1000 kWh/customer; Actual Sales of 950 kWh/customer

	Base Case	Actual w/o Decoupling Adjustment	Actual with Adjustment for Gross Revenues[5]	Actual with Adjustment for Net Revenues[6]
Revenue				
Fixed Charge	$1,500	$1,500	$1,500	$1,500
Variable Charge	$7,500	$7,125	$7,125	$7,500
Decoupling Adj.	N/A	N/A	$375	$175
Total	**$9,000**	**$8,625**	**$9,000**	**$8,800**
Costs				
Fixed	$4,000	$4,000	$4,000	$4,000
Variable	$4,000	$3,800	$3,800	$3,800
Total	**$8,000**	**$7,800**	**$7,800**	**$7,800**
Income	**$1,000**	**$825**	**$1,200**	**$1,000**

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5 Adjustment calculated by subtracting total base revenues from total actual revenues.

6 Adjustment calculated by netting out reduction in variable cost from gross revenue adjustment.

Failure to net out revenue changes designed to recover variable costs from the adjustment leads to an unintended increase in utility income of 20 percent. The same mechanism would cause an unintended decrease in income if adjusting for an increase in sales.

Decoupling trackers require recurring audits and a reconciliation mechanism. The use of a revenue decoupling tracker could require several line items on a bill, making the bill more complicated and possibly causing customer resistance to the approach. A decoupling tracker can create revenue neutrality, but requires considerable administrative effort to execute accurately.

2. Lost revenue recovery adjustment

The lost revenue recovery adjustment (LRRA) creates an explicit revenue adjustment for particular actions taken by a utility. For example, if a utility replaces a light bulb with a compact fluorescent, a specific lost revenue adjustment would be recovered from ratepayers. The LRRA targets utility-driven energy efficiency-related losses in revenues—not those changes in revenues associated with fluctuations in factors such as the economy, the weather, or non-utility energy efficiency programs. It can be difficult to quantify either the action or the effect on revenues of softer yet important programs. Harder-to-quantify utility-sponsored programs include energy efficiency customer education, or fluorescent bulb distribution, as it is hard to know whether distributed compact fluorescent light bulbs get and stay installed. There is a natural tendency for utilities to want to overstate the effect on revenue of a particular action; likewise, ratepayer advocates tend to understate the increase or decrease in the associated revenue adjustment. Continuous measurement and monitoring is required to ensure that estimated savings are reasonable approximations of actual savings. Lost revenue recovery adjustments should also be designed to reflect changes in net revenue versus gross revenue, as discussed at the section on revenue trackers The LRRA takes a good deal of administrative effort to implement, audit, and reconcile.

B. Other decoupling tools compared to the SFV-REEF rate design

Table 7 compares SFV-REEF rate design to other decoupling tools. This comparison utilizes three indicators in addition to the underlying economic premise that variable fixed cost should be recovered solely through fixed charges.

1. Effectiveness and accuracy as a decoupling tool: This comparison addresses how well income neutrality is achieved by each method (i.e., how well the approach decouples income from sales).

2. Effectiveness as an energy efficiency incentive: This comparison addresses whether the method provides signals to the utility and the customer to save energy.

3. Ease of administration and billing.

Table 7: Comparing SFV-REEF to Other Decoupling Tools

	Revenue Decoupling Tracker	**Lost Revenue Recovery Adjustment**
Effectiveness in Decoupling Revenues and Income	Can achieve same decoupling as SFV but only if net revenues are used as the adjustment rather than gross revenues. Use of gross revenues can produce unintended income rather than income neutrality. Unlike SFV, can adjust for changes in sales associated with the number of customers.	Targets only revenue losses associated with utility programs. Does not make utility indifferent about lost revenues associated with other energy efficiency programs. Difficult to measure softer measures such as education or full or sustained implementation of each action. Tendency by stakeholders to under-or overstate adjustment factors.
Effectiveness in Encouraging Energy Efficiency	Underlying Standard Tariff may include more customer incentive for energy efficiency than SFV as more dollars are recovered through variable charges. Difference disappears if all customers conserve the same amount. Existing Standard Tariffs may not provide accurate price signals. Inclusion of REEF allows regulators to better target specific customer behavior and reflect long-run marginal costs. Both methods eliminate the disincentive to utilities associated with energy efficiency but do not provide a profit incentive.	Underlying Standard Tariff may include more customer incentive for energy efficiency than SFV as more dollars are recovered through variable charges. Difference disappears if all customers conserve the same amount. Existing Standard Tariffs may not provide accurate price signals. Inclusion of REEF allows regulators to better target specific customer behavior and reflect long-run marginal costs. Does not achieve the same breadth of energy efficiency decoupling as SFV. May make utility opposed to non-utility energy efficiency initiatives.
Ease of Billing And Administration	SFV easier to bill and administer. No extra lines on bill. SFV requires no tracking, audits or reconciliation that is required by tracking mechanism. SFV may require an income tracking protocol to ensure excessive earnings do not occur. REEF introduces some additional administration for billing. No reconciliation is necessary.	SFV easier to bill and administer. No extra lines on bill. SFV requires no tracking, audits or reconciliation that is required by lost revenue recovery mechanism. Lost recovery mechanism requires ongoing measurement and monitoring of estimated and actual savings. SFV may require an income tracking protocol to ensure excessive earnings do not occur. REEF introduces some additional administration for billing. No reconciliation is necessary.

The SFV-REEF tariff is fundamentally superior to the other decoupling mechanisms. It decouples income from sales almost as completely as one method and better than the other, provides better price signals, and is much easier to bill and administer. For all of these reasons, in a time when energy efficiency must become a growing part of the resource mix to meet carbon standards and fight greenhouse gases, a Straight Fixed Variable Rate design supplemented by a Revenue-Neutral Energy Efficiency Feebate should be considered by regulators across the country.

V. Conclusions and Recommendations

Energy efficiency is a resource that requires more attention as regulators, utilities and consumers of electricity set off to engage in the battle against greenhouse gases. The following actions, together, will create a regulatory environment more conducive to improving the natural environment.

1. ***Eliminate the disincentive associated with the current coupling of sales and income.*** Coupling has discouraged utilities from employing strategies that reduce sales, by implementing a straight fixed variable rate design as a decoupling tool. This paper suggests that the SFV rate design is superior to the standard two-part tariff from an economic theory perspective, provides broad decoupling, and is much easier to implement and administer than other decoupling tools. An SFV rate design reduces a utility's financial risk, which should lead to a decrease in the allowed rate of return and total revenue requirements and rates.

2. ***Supplement the SFV rate design with a Revenue-Neutral Energy Efficiency Feebate program.*** The REEF allows regulators to provide targeted price signals that reflect costs such as long-term marginal costs and externalities that have not been internalized to a utility's cost structure. The REEF ameliorates concerns that some may have with an SFV rate design and allows regulators to carefully target incentives for specific customer behavior without changing the utility's overall revenue requirement.

This type of regulatory package puts downward pressure on rates while improving the regulatory environment for energy efficiency.

JI Item 1.4.2
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Rate Strategies for 21st Century Challenges

A GUIDE TO RATE INNOVATION FOR COOPERATIVES

EXECUTIVE SUMMARY

National Rural Electric Cooperative Association

National Rural Utilities Cooperative Finance Corporation

Item No 2
Page 30 of 55

Executive Summary

This Executive Summary provides an overview of the guide "Rate Strategies for 21st Century Challenges: A Guide to Rate Innovation for Cooperatives" developed by NRECA and CFC as a helpful resource for electric cooperatives to begin their own rate design process. Please refer to the complete guide, available only to our electric cooperative members, for more in-depth information.

Between 1983 and 2000, cooperatives enjoyed a period of rate stability when the U.S. cooperative average total revenue per kilowatt-hour (kwh) hovered around 6.8 cents and inflation-adjusted rates actually fell. Since 2000, inflation-adjusted rates have risen, and the cooperative average total revenue per kilowatt-hour reached 9.3 cents in 2008—indicating a significant increase in costs. Unfortunately, it appears these increases are part of a long-term trend. Preliminary data from CFC's latest KRTA analysis indicate that rates increased by about 4 percent in 2009.

Over the next decade, cooperatives can expect continued escalation in power supply costs resulting from:

- A new power plant construction cycle and rapidly rising construction costs;
- Potential climate change mandates that, if implemented, are likely to impose additional costs on fossil-fueled generation;
- Increased volatility in fuel costs and wholesale market prices; and
- Political, environmental and regulatory pressures on utilities to achieve societal goals, such as increased reliance on renewable resources and energy efficiency.

While cooperative loads are expected to grow faster than those of investor-owned companies due to population shifts and a greater dependency of rural residential consumers on electricity to meet energy needs, increases in energy efficiency, conservation, demand response and distributed generation are still likely to result in a reduced rate of growth in kilowatt-hour sales. In addition, emerging technology for new uses of electricity, new generating resources, and control and management of the electric system will create new risks and opportunities. These factors may make it more difficult for systems with traditional rates to recover their costs and margins.

To help cooperatives address these issues, CFC and NRECA have jointly prepared this rate guide for the consideration of member cooperatives. It provides information about the ratemaking process in general and the specific concerns facing cooperatives today. The guide reflects input received from a focus group and panels at the CFC Forum in June 2009, rate consultants and panels at the NRECA Rate Summit in July 2009, the NRECA Innovative Energy Strategies Task Force, panels and participants in the 2009 regional meetings, and panels and participants at the CFC Independent Borrowers Executive Summit in November 2009.

While cooperatives have much in common, each system faces unique issues and circumstances. Therefore, each cooperative's approach to rates must be grounded in its unique circumstances, including its financial targets, power cost expectations, member acceptance, and regulatory and competitive issues.

With full respect for the wide diversity among electric cooperatives and an understanding that one size does not fit all, we offer the following suggestions for the consideration of electric cooperative management and boards.

Key Points

- Over the next decade, cooperatives can expect significant increases in the cost of power and slower load growth.
- Slower growth in future sales in conjunction with energy efficiency, conservation and environmental legislation may make it harder for cooperatives with traditional rates to recover their costs and margins.
- Emerging technology will create new risks and opportunities for cooperatives.

Item No 2
Page 31 of 55

1. Integrate Rates with the Business Plan

Cooperatives should consider including rate objectives as a key component of integrated business plans that address the new challenges facing the electric industry

Rates are not distinct from other aspects of a cooperative's efforts to meet its strategic goals and should not be addressed in isolation. Each cooperative should consider having an integrated business plan that addresses the new challenges facing the energy industry and provides guidance to staff and consumers. A business plan typically identifies specific objectives and actions that will help the cooperative continue to provide members with safe, reliable, affordable power while also maintaining the cooperative as a viable business and preserving and ultimately returning members' patronage capital. Rates usually should be a part of that plan, and cooperatives should adopt rate policies and tariffs that are consistent with their business goals. Technology, power supply, communications, non-rate programs, member services and financial goals are normally addressed as well. This is critical to responding effectively to current industry conditions and will require more extensive advance planning than the traditional load forecasts, construction work plans and annual budgets that cooperatives have relied on in the past.

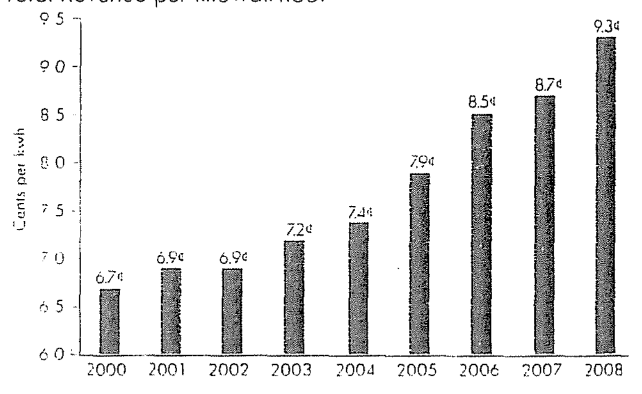
Establishing a common vision that helps all branches of the cooperative work together toward common goals creates synergies that will result in a greater impact than if each functional area pursues its goals individually. Integrating rates with business plan objectives provides an opportunity for cooperatives to develop new, more cost-effective ways to serve their members.

Key Point

- *Every cooperative should consider having an integrated business plan that establishes how the cooperative will implement rate and other policies to achieve key strategic goals.*

Rates Have Increased 39% Since 2000

Total Revenue per kilowatt-hour



Source: EIA and CFC December 2009

Item No 2
Page 32 of 55

2. Adopt a Rate Policy Statement

Cooperative boards, working with management, should consider adopting a rate policy statement that provides specific objectives for rates that support the cooperative's strategic goals.

Strategic Goals

- Provide safe, reliable power at the lowest cost consistent with good business practices.
- Maintain the cooperative as a viable business and preserve and ultimately return members' patronage capital

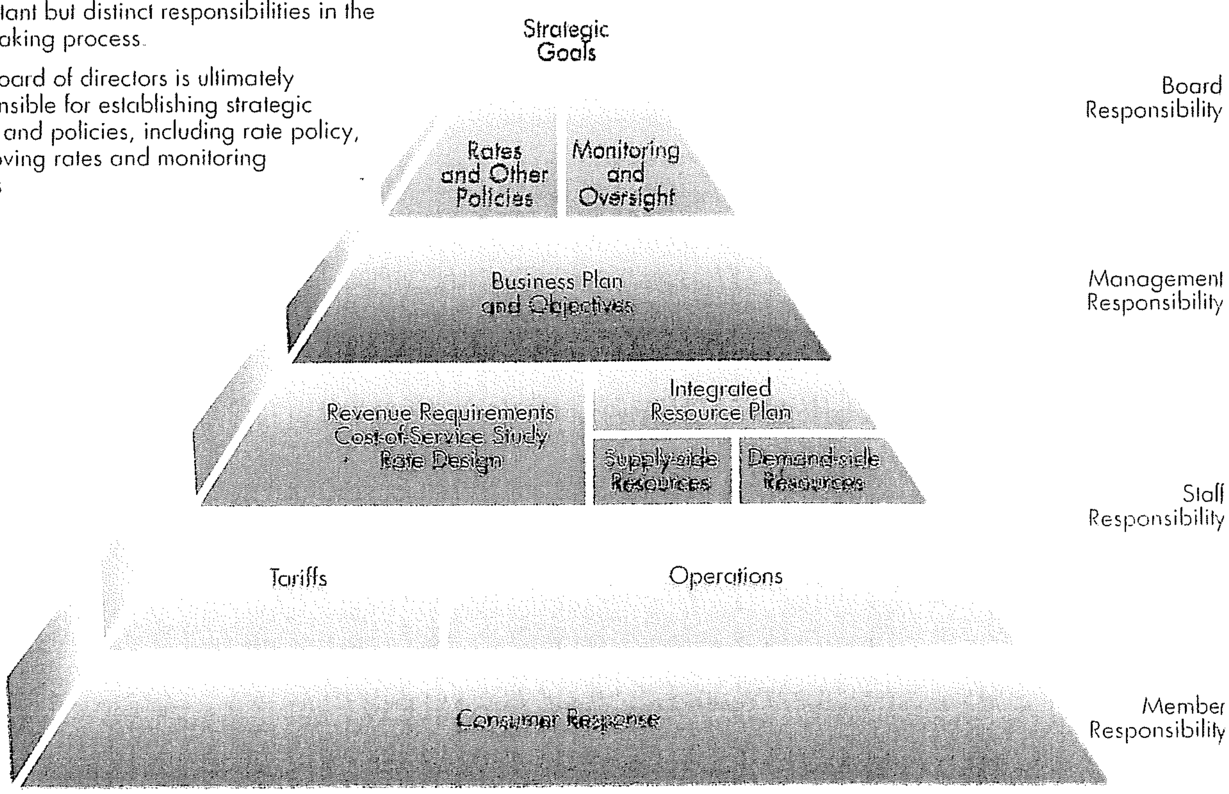
A cooperative's board of directors has an obligation to see that the cooperative provides safe, reliable power at the lowest cost consistent with good business practices. It also has the fiduciary responsibility to maintain the cooperative as a viable business and to preserve and ultimately return members' patronage capital. Establishing rate policies and approving rates are basic duties that largely determine whether the cooperative meets its strategic goals.

Before beginning the rate process, the board and management should evaluate the cooperative's business plan to determine how rates relate to its other business activities, such as its technology planning and economic development efforts, and how rates can support broader strategic goals. A review of current financial policies and targets in light

Rates and rate policy provide important support for a cooperative's strategic goals.

Key Points

- Directors, management, staff and members have important but distinct responsibilities in the ratemaking process.
- The board of directors is ultimately responsible for establishing strategic goals and policies, including rate policy, approving rates and monitoring results



Item No 2
Page 33 of 55

of the current operating environment can guide the adoption of any needed changes. Management should make sure that those who will be involved in the ratemaking process are familiar with all applicable legal requirements related to ratemaking, including federal tax law principles, antitrust law and consumer protection requirements.

While a cooperative's management, staff, consultants and even members have important roles in the ratemaking process, the board of directors is ultimately responsible for establishing rate policy. While these policies are best developed in cooperation with management, a written board policy statement can help link the cooperative's rates to its strategic goals by providing clear guidance on rate issues. In crafting rate policy, directors have a responsibility to:

- **Establish targets to meet the cooperative's strategic financial goals.** It is appropriate for the board to set targets for financial performance, including times interest earned ratio (TIER), modified debt service coverage (MDSC) and equity level, and for managing patronage capital through the cooperative's equity management plan. These guidelines are an important component of determining the cooperative's revenue requirements, which are collected through rates.
- **Set objectives for rate design.** The most important objective, and one all cooperatives have in common, is to collect revenue sufficient to meet the cooperative's strategic financial goals. Beyond that, depending on the cooperative's strategic goals, the board may establish complementary objectives intended to manage costs and meet other member needs. These may include requiring all members to provide a margin, decoupling revenue from sales, reducing peak demand, reducing energy requirements through conservation, encouraging energy efficiency, promoting renewable resources and/or accommodating distributed generation.
- **Examine the fairness of rates between classes of customers and within customer classes.** To ensure the cooperative operates "at cost" as required under federal tax law, subsidies between or within classes of customers should be minimized. In some circumstances, a board may determine that certain allocations of cost from one class to another are unavoidable or otherwise justifiable. For example, a reduced economic development rate that attracts a new business or industry to the cooperative's service territory, improving the cooperative's load factor, creating jobs in the community, etc., may offer benefits to a community. If a board of directors adopts rates partially allocating the costs of serving one rate class to another rate class, then it should recognize the possibility of perceived inequity and failure to operate "at cost."
- **Identify any issues other than the cost of service that should be taken into consideration.** Competition at some level is a reality for most cooperatives. A board may feel it needs to consider the cooperative's current rates, those of neighboring utilities or the cost of alternative fuels in setting rates. For example, the level of the customer charge needed to recover actual customer costs may be significantly higher than what a cooperative or its neighbors are currently charging. The board should determine whether there is a valid reason to continue a low (but still cost-based) customer charge. If not, it should balance the greater long-term interest of consumers in a rate design that more fully achieves recovery of actual customer costs through the customer charge compared to the degree that such a change is overly disruptive, given competitive and other considerations, including member acceptance. The board also may consider whether to implement higher rate components in stages over a period of

time. Again, the important point is that this should be a conscious decision based on an understanding of the issue and a careful consideration of alternatives.

- **Provide other necessary direction to staff.** The policy should clearly state the requirements for developing the specific information and analysis needed for rates, including a cost-of-service study and cost allocation methods that allocate costs to the rate classes that cause the costs to be incurred. It also should provide guidance for issues such as:
  - rate design principles—for example, recovering costs in the way they are incurred;
  - internal coordination across department lines;
  - coordination with power supplier;
  - conservation, energy efficiency and programs for demand-side management;
  - investments in technology; and
  - guidelines for monitoring and reviewing rates.

A sound rate policy helps ensure that rates are aligned with the strategic goals and business objectives of the cooperative.

Key Points

- Management is responsible for ensuring the completion of key tasks in the ratemaking process.
- A load research program provides valuable insight into consumer behavior that can help the cooperative design more effective rates.
- To ensure compliance with federal tax law and cooperative principles, rates should be based on actual costs incurred by each customer class and should not unduly discriminate between or among customer classes.
- There are many widely accepted ways of devising rates that are cost based and consistent with a cooperative's rate policy.

3. Support Financial and Other Strategic Goals Through Effective and Complementary Rate Design

Retail rates should be designed to:

- Consistently produce sufficient revenue to recover the cost of providing service to consumers, including its margin targets,
- Give price signals to consumers that are aligned with the strategic objectives embodied in the cooperative's business plan,
- Minimize abrupt changes in rates through use of a purchased power adjustment mechanism, which provides smaller, more frequent rate changes, and
- Assure compliance with legal and tax requirements

The basic process for setting rates is the same, whether a cooperative is regulated by a state public service commission or is locally regulated by its board of directors. Management is responsible for ensuring completion of the key tasks needed to:

- **Determine the cooperative's revenue requirements**, the amount of revenue needed to conduct the cooperative's business and meet its strategic financial goals. Revenue requirements must be sufficient to recover the cooperative's operating expenses, provide a return on capital and achieve the cooperative's equity goals.
- **Prepare a cost-of-service study, if needed**, to establish how much revenue different rate classes of members should contribute toward the recovery of costs. A load research program is a valuable tool for determining how, when and why consumers use electricity, information that can be used to allocate costs equitably.

- **Develop a rate design for each class of consumers** to collect revenue in a way that aligns price signals with the goals of the cooperative. Ideally, rates should be based on costs incurred by each customer class and should not unduly discriminate between or among customer classes. A number of proven rate designs are available to implement the cooperative's rate policy.
- **Activate a rate implementation plan** to put new rates into effect in a positive and proactive manner.

While cost recovery is central to achieving strategic financial goals, cooperatives have the opportunity to use the price signals expressed in rates to manage their costs and keep rates affordable to members. A cooperative's rate design should reflect the financial, power supply, environmental, regulatory and member relations' objectives embodied in its business plan as well as tax requirements for operating on a cooperative basis to maintain exempt status. Depending on the cooperative's situation, these objectives may include:

- Encouraging consumers to conserve or become more energy efficient.
- Encouraging consumers to refrain from using electricity during peak periods in order to reduce or delay the need for additional transmission, generation and distribution facilities.
- Enabling the cooperative to interrupt or directly control certain loads.
- Minimizing fuel costs, wholesale market costs and risks, and
- Ensuring that rates are fair and affordable for members

4. Consider Decoupling Revenue and Sales

Cooperatives should consider moving, to the extent practicable, toward recovering costs in the way they are incurred. Under such an approach, fixed costs and margins would be recovered through fixed charges, and variable costs through variable charges. To the extent that this cannot be fully achieved due to competitive pressures, cooperatives should consider adopting an adjustment mechanism that permits the recovery of fixed costs and appropriate margins regardless of the level of sales

Rates are a critical tool for recovering costs, maintaining a healthy financial performance and controlling and shaping loads to keep costs down. One of the basic values of cooperatives is that members share equitably in the benefits and the costs of participating in the cooperative. Each member should, as nearly as possible, pay for the costs it imposes on the system.

Cost-based rates provide a pricing structure where consumers in each rate class, such as residential, commercial or industrial, pay their fair share of the cooperative's costs so that there are minimal subsidies between classes of consumers. To the extent possible, each individual consumer within the class also should pay for the costs imposed on the system in a way that reflects the origin of the costs. This sends the right messages about costs to

Key Points

- To the extent possible, consumers should pay for the actual costs they create for the cooperative in a way that reflects the origin of the costs.
- Cooperatives can protect themselves from potentially slower sales by adopting rates that ensure they collect enough revenue to recover the cost of service and meet their financial goals regardless of sales levels.
- Adjustment mechanisms help the cooperative recover costs that fluctuate frequently without a major ratemaking procedure

Overall, almost half of cooperatives now have a purchased power adjustment clause, according to a 2009 CFC survey.

consumers and assures compliance with legal and tax requirements. Ideally, the appropriate costs would be collected through separate customer, demand and energy charges.

Decoupling of revenue and sales is an approach to rates that ensures that a reduction in kilowatt-hour sales will not adversely affect the recovery of fixed costs. It allows a cooperative to promote conservation and energy efficiency without financially harming itself or its members. Cooperatives can move toward decoupling by adopting rates that, to the extent practical, collect enough revenue to recover the cost of service and meet financial targets regardless of sales levels. There are a number of ways to move in this direction, but they typically involve:

- Adopting rate designs that recover a greater portion of fixed and demand costs and margins through fixed charges, such as the customer charge, and/or
- Adopting a separate adjustment mechanism providing for rates to automatically increase and decrease in order to ensure cost recovery by maintaining margin, TIER or other financial indicators within specifically defined boundaries as kilowatt-hour sales rise or fall.

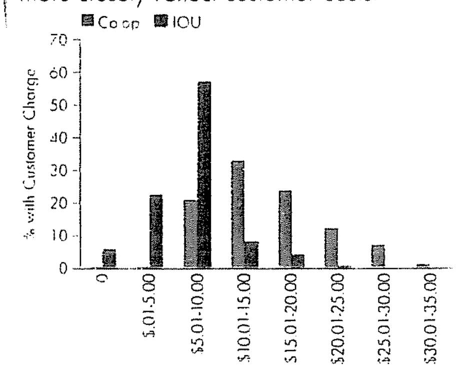
Adjustment mechanisms are used to recover costs fluctuations without going through a major ratemaking procedure. While decoupling adjustment mechanisms are a relatively new concept, fuel and purchased power adjustments are widely accepted in the utility industry. The most simple and effective action a cooperative can take to stabilize margins is to implement a purchased power cost adjustment mechanism.

For many systems, a good step toward decoupling is to implement a customer charge that as fully as possible recovers customer costs. There is a trend in this direction, and cooperatives are leading investor-owned utilities in this regard.

Rates that send a clear price signal to consumers in a way that is easy for them to understand can affect consumer patterns of electric use. The right signal will encourage consumers to make changes that help the cooperative manage and shape its loads.

Cooperative and Investor-Owned Utility (IOU) Customer Charges

Cooperatives lead investor-owned utilities in implementing customer charges that more closely reflect customer costs.



The example above is based on a sample of 371 distribution cooperatives and 163 IOUs.

Source: CFC, NRECA

Cooperatives Can Decouple Revenue and Sales by Aligning Costs and Charges.

Costs	Components	Charges
Customer	Consumer Accounting/Sales Portions of A&G, Distribution O&M, Depreciation	Fixed Monthly Charge per Customer
Demand	Wholesale Power Bill Demand Components Transmission O&M Portions of A&G, Distribution O&M, Depreciation	Metered Demand
Energy	Wholesale Power Bill Energy Charges	Variable per kilowatt-hour Charge

5. Align Wholesale and Retail Rates with Wholesale Cost Drivers

G&Ts should consider designing rates that reflect wholesale cost drivers, and G&Ts and distribution systems should consider coordinating rate policies in order to align both wholesale and retail rates to send appropriate price signals to consumers

Wholesale power costs, which are affected by the load characteristics of distribution systems served by the wholesale power supplier, account for approximately 65 percent of a typical cooperative consumer's electric bill. Wholesale rates should reflect wholesale cost drivers, and any distribution cooperative seeking to minimize its overall costs must work closely with its power supplier to make sure that happens. When a G&T's rates and other non-rate programs are designed to accurately reflect its costs and send accurate price signals to its member distribution systems, the distribution systems can adopt rates and programs that then pass correct price signals through to consumers. Effective approaches can include time-varying rates and non-rate programs for conservation, energy efficiency and demand response. Successful coordination in this manner can potentially:

- Delay the need for new generating capacity,
- Delay the need for new transmission and distribution capacity,
- Reduce exposure to high fuel prices and high wholesale market prices for electricity,
- Reduce coincident peak demand,
- Develop energy efficiency and demand response as capacity resources,
- Better utilize technological capabilities and
- Help consumers control their bills.

Mutual cooperation is the key to maximizing the benefit of innovative rate and demand-side management initiatives. It is in the long-term interest of everyone—the G&T or other power supplier, its member distribution systems and the ultimate consumer—for wholesale rates and non-rate demand-side programs to properly reflect the wholesale cost drivers and for the distribution systems' rates to send the right price signals to consumers.

Key Points

- The wholesale power bill is the largest component of total costs for most distribution systems
- Coordination between distribution systems and their power supplier is necessary for consumers to receive accurate price signals

Item No 2
Page 38 of 55

6. Develop a Rate Implementation Plan

Rate implementation plans assist a cooperative to achieve member, community and regulatory acceptance of rate changes and continued satisfaction with the cooperative. A key aspect of such a plan is internal coordination of rate objectives and activities among a cooperative's functional lines

Key Points

- The way a cooperative implements a rate change can affect how consumers, regulators and others react to the change.
- It is important to have adequate technology and other resources to implement preferred rates.
- Coordination of rate policies and strategies among all departments enables employees to work more successfully toward achieving the cooperative's goals
- A long-term technology plan can support this coordination

Rates send a powerful signal to consumers, but the manner in which a rate change is implemented has a powerful impact on how it is perceived. A comprehensive rate implementation plan can help the cooperative prepare members and other interested parties for changes and ensure a smooth transition.

The ultimate goal of the rate implementation plan is to achieve member acceptance of and positive response to rate changes, and continued satisfaction with the cooperative. It should foster member understanding of the cooperative's objectives and how the cooperative will provide reliable supply and acceptable costs for the consumer on a long-term basis. The plan should address:

- A schedule for the ratemaking process.
- Assigned roles and responsibilities for successfully implementing the rate change.
- An approach to educating key audiences.
- Technology, software, staff, training and other resources required to implement the change smoothly,
- Timing of rate adjustments,
- Ways to help members manage their energy usage,
- Timely review of rate schedules to ensure intended result and
- Adequate budget support.

An important aspect of the ratemaking and rate implementation process is the internal coordination of rate policies and strategies across functional lines within the cooperative When all departments and all employees understand the cooperative's rate policy and objectives, it can generate synergies that save time and money and enable employees to work more successfully toward achieving the system's goals. A unified approach across department lines will enhance financial performance, member relations, communications, business development, system engineering and operations, long-term technology acquisition and other cooperative functions.

Being proactive in presenting the changes to members in an informative and positive way increases the likelihood of member buy-in. To that end, the rate message should be consistent across the cooperative's communications channels, including its newsletter, website and community activities. Every director and employee should be fully informed of all significant aspects of any rate change and should be prepared to answer questions when asked. However, in most implementation plans, typically the CEO or other senior staff member assumes the role of spokesperson for the cooperative regarding the rate change.

Item No 2
Page 39 of 55

7. Review Rates at Least Annually

An annual review of rate strategies and policy is recommended—more frequently if a significant change occurs

The rate implementation plan often includes reviewing rates at least once a year to determine whether revenue is meeting financial targets—and more frequently in the event of a significant internal or external event affecting revenue requirements. The review includes an evaluation of consumer response to rates and a determination of whether the rates are helping to achieve the cooperative's strategic goals. Rates should be revised when revenue differs significantly from revenue requirements; there is a significant change in cost of service, such as a change in wholesale power costs; or the rate design is not achieving the desired consumer response.

Cooperatives should avoid delaying rate increases for many years only to have to introduce a larger increase, a course that may ultimately alienate members. Implementing smaller adjustments more frequently can help consumers better understand and accept rate changes and respond to the cooperative's cost drivers.

Key Point

- Setting rates is an ongoing process.

For More Information

Additional information is available online at www.cooperative.com/ratedesign.

21st Century Rate Strategies for 21st Century Challenges

A Director's Guide to Rate Innovation

National Rural Electric Cooperative Association
A Touchstone Energy® Cooperative

National Rural Utilities Cooperative Finance Corporation

NRECA and CFC are developing a new guide for distribution system directors to encourage cooperatives to take a fresh look at their rate strategies and to provide guidance on the challenging rate issues they face. The guide makes specific recommendations for cooperative actions, discusses goals for the [illegible] process and provides guidelines for rate design. This four-page document is a preview of the full guide that will be released in early 2010.

A cooperative's board of directors has a fiduciary responsibility to maintain the cooperative as a viable business and to preserve and ultimately return members' patronage capital. Cooperatives also have an obligation to provide safe and reliable power at the lowest cost consistent with good business practices. Establishing rate policies and setting rates are basic duties that largely determine whether the board meets those twin responsibilities.

Today, cooperatives are facing new challenges that are likely to increase costs significantly, making it more difficult to achieve financial goals. In this climate, rate practices that served well in the past may not assure continued success in the future, and many cooperatives will need to reevaluate their rate strategies. The new rate guide is intended to help directors answer the following questions:

In a climate of rising costs, members want to know what their cooperative is doing to keep rates at an acceptable level and to help them control their bills.

- Why do changes in the energy industry require new approaches to ratemaking?
- How can innovative rate policies help a cooperative achieve its goals?
- What are the key elements of the ratemaking process?
- Why is there a need for active director participation?
- How can we implement a rate adjustment in ways that support consumer acceptance?

Rates send a powerful message to consumers. Rate policies that foster member understanding of the cooperative's strategies and how they can help the cooperative provide reliable electricity at affordable costs in the future will encourage member acceptance and continued satisfaction.

Changes in the Energy Industry Are Raising Power Costs

Between 1983 and 2000, cooperatives enjoyed a period of rate stability when the cooperative U.S. average total revenue per kilowatt-hour hovered around 6.8 cents and inflation-adjusted rates actually fell. Since 2000, inflation-adjusted rates have risen, and the national cooperative average total revenue per kilowatt-hour exceeded 9.3 cents in 2008. This indicates cooperatives have experienced a significant increase in costs, and, unfortunately, it appears these increases are part of a long-term trend.

During the next decade, cooperatives can expect continued escalation in costs as a result of:

- *A new power supply construction cycle and rising construction costs.* Cooperatives are engaged in a strong construction program to ensure their members have the power they need. A recent survey conducted by NRECA and the G&T Accounting & Finance Association found that 27 G&Ts plan to add 18,106 mw of new capacity by 2019 at a cost of about $50 billion—an investment of more than $4,800 for each of the 11 million consumers served by those cooperatives in 2007.

Continued on Page 2

Item No 2
Page 41 of 55

- *Increased volatility in fuel costs and wholesale market prices.* Since 2002, natural gas and, to a lesser degree, coal prices have both trended upward and fluctuated widely. Competitive wholesale markets, which affect power costs for many cooperatives, have experienced significant market price volatility.
- *Political, environmental and regulatory pressures on utilities to achieve societal goals.* Nineteen states have set utility goals for energy efficiency while 30 states require electricity providers to generate or acquire certain percentages of generation or mw of capacity from renewable resources. The federal government and other states are considering similar actions.
- *Pending federal climate change legislation likely to impose additional costs on fossil-fueled generation.* Thirty-six states already have adopted climate change mitigation plans, including 16 states that have imposed mandatory regulations. About 60 percent of the electricity sold by cooperatives comes from coal and another 10 percent from natural gas. Those kilowatt-hours will be subject to the cost burden of whatever approach is ultimately adopted by the federal government.

As a result of these factors, many cooperatives could see their power costs increase significantly over the next 10 years.

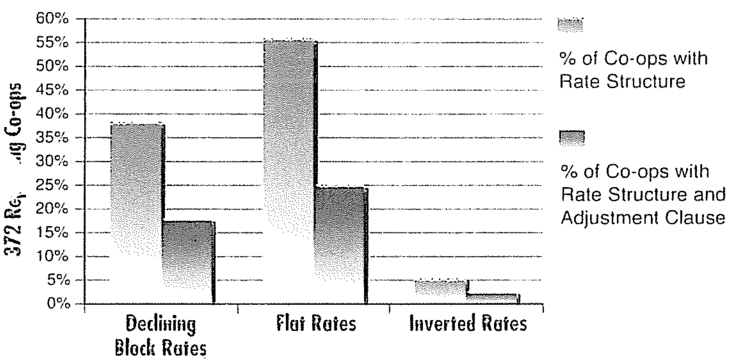
Key Recommendation
Integrated Rate Strategies

Each cooperative should include its rate strategies as a key component of an integrated business plan that addresses the new challenges facing the electric industry and the new technology for metering and managing the electrical system

So far, cooperatives are continuing to experience robust load growth. The minimum projected load growth through 2030 is 1.6 percent per year for cooperatives, compared to the U.S. annual growth rate of 0.9 percent per year. The continued expansion of information and communications technology and a potential shift from petroleum-based fuels to electricity in the transportation industry could significantly increase the demand for power. On the other hand, distributed generation and energy efficiency could become increasingly attractive options for consumers as the relevant technologies mature, government incentives increase and electric rates rise. These changes could lead to significantly lower per-capita usage levels for some classes of consumers. Cooperatives need to prepare for those scenarios by implementing rate structures that assure cost recovery, regardless of the level of sales.

Cooperatives Trending Toward New Rate Structures

The results of a March 2009 survey of 372 distribution cooperatives show that more than 60 percent of the systems reporting have adopted a rate structure different than the traditional declining block structure. In addition, almost half include a power- or fuel-cost adjustment to automatically reflect changes in power or fuel costs in rates.



A cooperative's rate policy can help or hurt its efforts to respond to changes in the industry and its own unique challenges. Every system needs to adopt specific rate strategies as a key component of its integrated business plan for dealing with rising costs while continuing to provide safe, reliable, affordable electricity. The appropriate rate structure can empower consumers to manage their energy consumption in ways that support the cooperative's goals while reducing the member's bill.

Innovative Rate Policies Can Help Cooperatives Achieve Their Goals

A cooperative's rate structure expresses its response to financial, power supply, environmental, regulatory and member issues, and empowers consumers to use electricity in ways that reduce their costs. Cost recovery is the primary goal, but cooperatives may want to consider other goals as well, such as:

- Encouraging consumers to use less energy by conserving or becoming more energy efficient,
- Encouraging consumers to refrain from using electricity during peak periods,
- Enabling the cooperative to interrupt or directly control certain loads,
- Minimizing fuels costs and
- Responding to wholesale market costs and risks.

Rate schedules that send a clear price signal to consumers in a way that is easy for them to understand can persuade consumers to change their patterns of using electricity. The right signal will encourage consumers to make changes that help the cooperative manage and shape its loads to achieve its goals.

Key Recommendation
Core Goals of Rate Strategy

Each cooperative's rates should:

- Consistently produce sufficient revenue to recover the cost of providing service to consumers, meet annual financial goals and preserve the cooperative's long-term financial stability,
- Align price signals to consumers with the strategic goals of the cooperative's business plan and
- Remain at a level that is affordable for most consumers and that minimizes abrupt change through the use of adjustment clauses and more frequent and smaller rate changes.

To the degree that some customers prefer to pay higher prices rather than change the way they use electricity, an appropriately designed rate will ensure that they, not other members of the cooperative, bear the cost of their decision.

Item No 2
Page 42 of 55

For many cooperatives, addressing these issues in a meaningful way will require a shift in thinking. The idea that growth is good and more growth is better has been deeply ingrained in the culture of many utilities. Management and directors may be concerned that any strategy that reduces growth will also erode earnings and lead to financial difficulties for cooperatives. There also may be concerns about consumer acceptance of new rate structures and approaches, particularly as costs rise in the future. These are serious issues that should be carefully considered.

Key Recommendation
Coordination with Power Supplier

Each cooperative should, to the extent possible, coordinate its rate strategies with its G&T or other power supplier in order to align retail rates with wholesale cost drivers and send price signals that empower consumers to take actions that minimize both the consumer's and the cooperative's short- and long-term power costs

Cooperatives can protect themselves from negative effects caused by changes in sales by adopting a rate structure that ensures they collect enough revenue to recover the cost of service and meet financial goals regardless of sales levels. There are many ways to do this, but they all involve two aspects: (1) moving toward rate designs where a greater portion of fixed costs and margins are recovered through fixed charges and (2) adopting purchased power or other adjustment clauses. A consultant can be helpful in determining which approach is best in a particular situation.

It is important for a distribution cooperative to coordinate its rate strategy with its power supplier in order to send appropriate price signals to consumers. One way to do this is for distribution systems to work together with their G&T or other power supplier to develop a coordinated approach to integrated resource planning, rates and energy innovation. In this process, the Integrated Resource Plan establishes the drivers of the G&T costs. The G&T adopts wholesale rates that reflect those costs. The distribution cooperatives can then design retail rates based on the price signals received from wholesale power costs. Consumers can respond to price signals from retail rates by managing their energy usage in ways that allow them to lower their bills by reducing their consumption or shifting their usage patterns. An important part of the planning process is finding a way to:

- Balance the benefits of growth with the benefits of energy efficiency,
- Recognize that some new loads will help the cooperative use its resources more efficiently while others may increase costs and
- Acknowledge the value of demand-side initiatives as well as traditional capacity additions.

If a cooperative can invest in programs that reduce the need for new capacity less expensively than it can add new transmission, generation or distribution facilities, it should do so. Avoiding or delaying the need to add new, higher-cost capacity through any of these measures can result in lower costs to consumers.

Key Recommendation
Internal Coordination

Each cooperative should coordinate the development of rate policies and strategies internally to ensure a consistent approach across departments to achieving the goals of the cooperative's business plan.

An important aspect of the ratemaking process that is sometimes overlooked is internal coordination of rate strategies across department lines. An integrated approach is essential to achieving the cooperative's goals efficiently and cost effectively. For example, coordination between the finance and marketing staff is important to ensure rates offered on new loads are sufficient to recover the additional costs of serving those loads and the cooperative focuses on attracting loads that are compatible with the system's long-term goals. The engineering department may be able to provide information about the impact of usage patterns on system operations, leading to a rate structure that changes usage patterns in a way that reduces future plant investments.

Rate strategy can both drive and be dependent on investments in technology. While some innovative rate structures can be implemented with a standard watt-hour meter, more complicated approaches require advanced metering, communications and software. When innovative rate structures, such as time-of-use rates, were first proposed, it was not cost-effective to invest in the metering needed to implement them for residential and small commercial customers. Technology was the primary barrier to adoption of more complex rate structures. There have been vast improvements in the capabilities of metering systems and in the cost of such systems.

Today, the primary barriers are cultural and political. One way to overcome these barriers is to develop rate strategies in coordination with a long-term technology plan that takes into account the total needs of the system, including information technology, communications, load research and system operations as well as metering and billing. That way, the cooperative can ensure it acquires the technology required to implement its ideal rate strategy and ensure its rates recover sufficient revenue to implement the technology plan effectively.

The Ratemaking Process Requires Active Director Participation

The board of directors is ultimately responsible for approving rates and has an important role in the ratemaking process. Each director has an obligation to understand the economics of the cooperative's operations, its power supply arrangements, the basic process of establishing rates and the role of rates in shaping consumer behavior. Directors should be knowledgeable enough to ask questions and participate in

Continued on Page 4

Item No 2
Page 43 of 55

discussions about setting rates. The board has an obligation to members to perform due diligence on rate decisions and provide informed direction to the management and staff.

The board should adopt a rate policy statement at the beginning of the rate process to give management guidance as to what rates should achieve. A typical rate policy statement sets forth specific objectives, such as:

Key Recommendation
Rate Policy Statement

Each cooperative board should adopt a rate policy that provides specific objectives for rates that match the strategic business objectives of the cooperative.

- The cooperative will implement rates based on an embedded cost-of-service study.
- Rates should be structured to collect fixed costs through fixed charges and energy costs through energy charges.
- All members must provide a margin to the system.
- Costs should be allocated to the rate classes that cause the costs to be incurred.
- Rate subsidies should be minimized.
- Rates should promote energy efficiency.

A sound rate policy helps ensure rates are aligned with the strategic objectives of the cooperative.

The ratemaking process typically includes the following tasks:

- *Evaluate the cooperative's financial goals, policies and strategies* in light of its current operating environment and adopt any needed changes. This is a key board responsibility.
- *Determine the cooperative's revenue requirements* or the amount of revenue needed to conduct the cooperative's business and meet its financial goals. The cooperative's staff, most likely working with a consultant, is responsible for presenting revenue requirements analysis to the board.
- *Prepare a cost-of-service study* to establish how much revenue different classes of members should provide and to allocate revenue to rate classes. The cooperative's staff and consultant, if available, are responsible for conducting the cost-of-service study and presenting the results to the board.
- *Develop a rate design for each class of consumer* to collect revenue in a way that aligns price signals with the goals of the cooperative. The staff and consultant, if available, are responsible for presenting rate alternatives to the board that comply with the board's policy directives.
- *Activate a rate implementation plan* to put new rates into effect in a positive and productive manner. The board, staff and consultants all have responsibilities for implementing rate changes.

The basic process for setting rates is the same, whether the cooperative is regulated by a state public service commission or is locally regulated by its board of directors. Cooperatives should initiate the ratemaking process at least 12 months ahead of the time additional revenue is needed and allocate adequate budget funds and staff resources to support a comprehensive approach.

An Effective Rate Implementation Plan Promotes Member Satisfaction

A rate implementation plan helps to provide a smooth transition to new rate structures and tariffs. The plan should address how the cooperative will:

- Assure it has adequate technological capabilities to support tariffs,
- Introduce rate adjustments at a time that will have the least impact on consumers,
- Explain the cooperative's rate strategy to key audiences,
- Empower consumers to manage energy usage to minimize their bills and
- Provide for timely review and revision of rate schedules.

A sound rate implementation plan helps achieve member acceptance of and positive response to rate changes. It also improves member satisfaction with the cooperative. It should foster member understanding of the cooperative's strategies and how they will lead to reliable supply and acceptable costs for the consumer on a long-term basis.

Key Recommendation
Member Acceptance

Each cooperative should have a rate implementation plan to achieve member, community and regulatory acceptance of rate changes and continued satisfaction with the cooperative.

Key Recommendation
Annual Reviews

Each cooperative should review its strategies and rate policies at least annually—more frequently if a significant change occurs—and make adjustments as necessary.

Being proactive in presenting rate changes to members in an informative and positive way increases the likelihood of member buy-in. To that end, the rate message should be consistent across the cooperative's communications channels, including its newsletter, Web site and community activities.

For More Information

Look for the complete publication, *21st Century Rate Strategies for 21st Century Challenges*, to be issued in early 2010. For more information now, please contact Mike Ganley at NRECA, mike.ganley@nreca.coop, or Richard Larochelle at CFC, rich.larochelle@nrucfc.coop.

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Item No 2 Page 44 of 55

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September 2009

Rate Design – What the Board Needs to Know

This two part series is a reprint of an article which was first published in Management Quarterly in 2005. As cooperatives face the increasingly challenging task of developing and maintaining a meaningful rate policy, we thought it would be appropriate to revisit the basic knowledge required by Boards to make good decisions.

No issue facing a cooperative board is more complex and yet more important than its oversight of the development of effective retail rate policies. No one likes to raise rates. And no one likes sitting in a dark board room staring at a glowing projection screen full of row after row of numbers. Cooperative board members are no exception; yet they must gain a basic understanding of how proposed rates are developed. So how does today's cooperative manager determine the appropriate level of involvement by the board which enables effective decision making without an information overload that can lead to loss of understanding or even paralysis in the rate changing process?

Experience suggests the answer varies from system to system. However, given the potential impact on members, development of properly designed rates requires input from all disciplines within the cooperative, including: accounting, customer service, human resources, engineering, operations and management. As the policy-setting entity and, in some states the rate setting entity, the board is well served to have a solid understanding of the breadth, if not the detailed financial intricacies of the issues. The board also serves as a key communications conduit between the cooperative and the membership.

Every board member at a cooperative implementing a rate increase has no doubt heard questions like these from the members they represent: "Why are you raising my rates?" "Why did you raise my customer charge instead of just the energy charge?" "Why did the rates for residential customers go up five percent while rates for irrigation customers went up seven percent?" Trustees who

See Rate Design on page 2.

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Rate Design

cont. from page 1.

understand industry trends and have a basic understanding of the rationale behind the rate design and the process of setting rates can more effectively answer these questions.

The Rate Change Process

The rate change process generally begins as a result of any number of factors. They include

- a recognized deterioration in the system's financial indicators
- a change in the wholesale cost of power
- response to competitive pressure
- response to environmental and/or energy efficiency concerns
- response to a special contract rate request from a member.

Whether the cooperative is conducting a complete review of its rates, developing a special contract rate for a particular customer or preparing energy efficiency, time of use, demand response or other special rates; the standard process of rate development is essentially the same.

Standing at the beginning of a rate design project and gazing out over the landscape of the information to be reviewed, analyzed and transformed into a meaning report can be overwhelming. One way for a distribution cooperative board to "wrap its arms around" the process is to break it down into five distinct steps:

1. Determine the overall system revenue requirement
2. Develop the class revenue requirements (Cost of Service)
3. Develop the individual customer revenue requirements (Rate Design)
4. Coordinate the line extension policy with the base rate design
5. Monitor and analyze ongoing performance

Development of Overall Revenue Requirement

The board's role in the rate analysis process is to balance two sometimes conflicting duties. This is an essential and often challenging role that cooperative directors must assume: The first duty is to meet the cooperative's financial objectives and maintain satisfactory financial ratios. The second duty is to minimize the impact of costs to members by providing the lowest reasonable rates. If rates are set too low, the cooperative risks not meeting lender mortgage requirements, experiencing decreased cash levels and declining equity levels. If rates are too high, the cooperative risks consumer unrest and noncompetitive rates. The task before the board is to balance the two competing objectives in determining the cooperative's overall revenue requirement.

Setting Rates - Do You Know the Steps?

The first step in the development of the overall system revenue requirement is determining the appropriate level of margin. The financial criteria required to define the level of margin is based on each individual board's objectives associated with:

- Equity Management Plan
- Capital Credit Refund Policy
- General Funds Level Objective
- Coverage Ratio Required by Lenders

There is a margin requirement associated with each criterion noted above. It is critical for the board to understand the relationship between these objectives when determining the overall revenue requirement. The board cannot focus on a single financial objective; it must consider all objectives and how they interact. For example, when considering the equity level established in the equity management plan, it is imperative that the board be mindful of the effect that equity level has on the overall revenue requirement. As investment in new plant increases, the required margin to maintain a specific equity percentage level also increases. If growth in plant is not also accompanied by a sufficient increase in sales it can be a real challenge to maintain the equity objective without an increase in rates. The equity objective also determines the level of debt to be incurred by the cooperative. This directly impacts the level of debt service payments which in turn affects the system's financial coverage ratios. In addition, the rotation of capital credits affects the level of cash reserves, which also affects equity levels and ultimately the cooperative's over all revenue requirement.

A capital planning model or financial forecast prepared by staff and management are valuable tools in the evaluation of the overall system revenue requirement. The results of these types of analysis enable the board to see the relationship between their financial goals and anticipated system performance as those goals are implemented during the next three to five years. The board should be presented with a clear view of the big picture with regard to the cooperative's financial objectives, how the system will achieve those objectives and how those objectives impact rates.

While developing, evaluating and monitoring policy is the board's primary responsibility, it is also important that directors have a working knowledge of the rate change process.

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Item No 2
Page 46 of 55

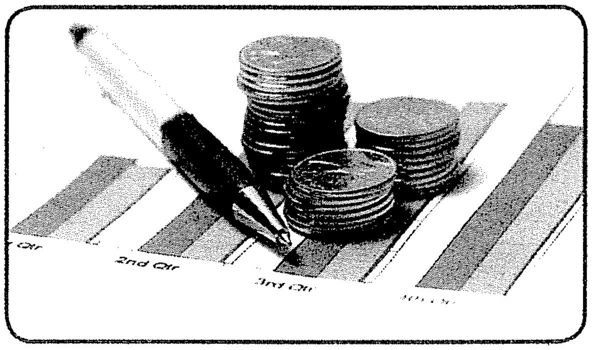
Rate Design Modifications That Encourage Efficiency

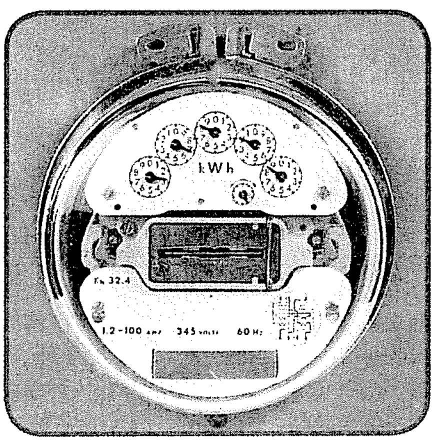
While it is important to create rate designs which encourage efficiency it is equally important to minimize the impact on members.

The Energy Independence and Security Act of 2007 (EISA) contains the requirement for certain qualifying cooperatives to consider four new PURPA standards. One of the standards encourages consideration of rate design modifications that encourage efficiency investments. To comply with this provision cooperatives are to remove any "throughput incentive" and create rate designs which promote energy efficiency for all rate classes. There has been much discussion lately about what these provisions mean and how best to accomplish these provisions.

What is a "throughput incentive?"

A throughput incentive in a rate structure encourages a member to consume energy. The most typical example is the declining block rate. A declining block rate has a higher charge per kWh for the initial block and a progressively lower charges per kWh for remaining block(s). This rate design has been common among cooperatives over the past thirty years. In addition to promoting energy use, the declining block rate design correctly recognized that as consumption increased the capacity cost per kWh to serve declined. That was the environment that existed when excess generation capacity was available but not so now. Today, additional consumption, particularly at peak periods of time, typically increases the generation capacity cost. To encourage efficiency and conservation, many cooperatives are modifying the pricing signal provided to members by eliminating declining block rates and replacing them with flat rates or even inclining block rates.





Why does the cooperative have a disincentive to promote energy efficiency?

The Residential rate at most cooperatives does not recover all of the fixed costs of providing service in the customer charge component. The energy charge component of the rate is higher than necessary in order to recover the fixed costs not recovered in the customer charge. But the cooperative's costs to maintain line and equipment, trim trees, read meters and prepare bills and all other activities related to providing service do not go down if energy usage declines. This situation creates a disincentive for the cooperative with respect to promoting energy efficiency activities. To the extent that kWh consumption is reduced as a result of successful energy efficiency programs, most cooperatives lose the ability to recover fixed costs within the energy charge.

Solutions

The best way to deal with this problem is to increase the fixed charge component of the rate. Eliminating the declining block rate and increasing the customer charge are two examples of rate design modifications that help to promote energy efficiency while reducing the cooperative's financial disincentive to do so. It seems that these would be simple solutions except that both of these rate design changes can create significant increases for individual members. While it is important to create rate designs which encourage efficiency it is equally important to carefully consider the impact on members.

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Item NO 2
Page 47 of 55

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Three Best Practices for Securing Your IT Environment and Meeting NERC CIP Requirements

The North American Electric Reliability Council (NERC) first issued the voluntary Critical Infrastructure Protection (CIP) Cyber Security Standards to safeguard electrical systems in 2003. In 2006, the Federal Energy Regulatory Commission (FERC) approved the Security and Reliability standards proposed by NERC, making the CIP Cyber Security Standards mandatory and enforceable across all users, owners and operators of the bulk-power system throughout North America. Enforcement provisions include on-site and off-site compliance audits, random spot checks, investigations, determination of violations, mitigation plans and substantial fines of up to $1 million per day per infraction for violators. The CIP requirements encompass eight specific standards as shown in Table 1.

Each standard includes significant challenges with respect to achieving and maintaining compliance. Three key best practices for ensuring NERC CIP compliance include:

1. **Defense in Depth Strategy**: Defense in Depth is a strategy to defend a system against various attacks using several, varying methods. While most organizations tend to gravitate toward technology for this defense, the human element is often disregarded. Policies and procedures are critical to an efficient, effective and secure information technology environment.

2. **Gateway Firewall**: Gateway firewalls are technical controls that traditionally (1) prevent or limit an attack, or (2) detect and monitor the IT environment. Not only should you ensure proper configuration and installation of these devices, but ensure that they log to a centralized repository and are regularly reviewed for signs of anomalous behavior.

3. **Backup and Disaster Recovery Plans**: While the scope of a data-backup strategy and the selection of technologies are of obvious importance, less obvious is the critical role of testing and exercising the data backup and recovery plan. Be sure to periodically test and exercise your plan. Doing so can reveal unexpected gaps in a plan, such as trying to recover data stored in obsolete formats and inaccessibility of the off-site storage facility.

The correct combination of procedures, technology and recovery planning will enable your organization to favorably position their compliance efforts as well as provide real-world protection for your critical infrastructure.

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Table 1 - Eight Standards

Critical Cyber Asset Identification	Physical Security
Security Management Controls	Systems Security Management
Personnel and Training	Incident Reporting and Response Planning
Electronic Security	Recovery Plans

Item No 2
Page 48 of 55

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January 2010

Rate Design — What the Board Needs to Know, Part II

This series is a reprint of an article first published in the Spring 2005 Management Quarterly. Part I was printed in the September 2009 issue of the Energy FOCUS. As cooperatives face the increasingly challenging task of maintaining a meaningful rate policy, we thought it would be appropriate to revisit the basic knowledge required by boards to make good decisions.

No issue facing a cooperative board is more complex and yet more important than its oversight of the development of effective retail rate policies. While developing, evaluating and monitoring policy is the board's primary responsibility, it is also important that directors have a working knowledge of the rate change process. Developing the system revenue requirement is like taking a typical cooperative income statement and turning it upside down. Once the required level of margin is determined, the revenue requirement calculation proceeds from the bottom of the income statement to the top. Using a historical twelve-month test year, staff and management identify the known and measurable adjustments to operating expenses, interest expense and non-operating activities. These items are then added to the required margin to determine the overall system revenue requirement.

Determination of Class Revenue Requirements

The second step in the development of rates is the determination of class revenue requirements - determining if each rate class is "pulling its own weight." This is accomplished through a cost of service study. While the cooperative's staff is typically involved in detailed development of the cost of service study, it is important for the board to have an understanding of the process.

The purpose of the cost of service study is to determine the level of margin produced by each rate class under existing rate schedules and to calculate the required change in revenue for each rate class based on the proposed overall system revenue requirement. This is accomplished by developing percentage allocations to spread the plant investment required to serve each class, along with associated expenses.

The board should look for consistency of approach in the development of the cost of service study. Generally accepted methodologies for developing cost allocations should be used rather than developing cost allocations based upon assumptions and methods intended to achieve a predetermined outcome. If the cooperative's rates are regulated by a state utility commission, the methodology is predetermined. If the cooperative is exempt from commission regulation, it should use the same basic methodology as if it were regulated. In either case,

See Rate Design on page 2.

Item No 2
Page 49 of 55

Rate Design
cont. from page 1.

the cooperative has a result that is defensible in the event of questions or challenges from members or other power suppliers.

The board of directors should have a realistic assessment of the cost to serve each rate class and that should be presented in a well prepared analysis. A properly prepared cost of service study provides the information the board needs to determine the appropriate course of action for changes in rates for individual rate classes. For example, the study might show that, while the cooperative as a whole requires a 3% rate increase, the residential rate class requires a 5% increase and the large power class requires a reduction to meet the system average rate of return. The board in this example must carefully weigh the disparity between the classes while balancing member and financial impact.

"...directors should have a realistic assessment of the cost to serve each rate class..."

The summary of the cost of service study should clearly show the level of margins earned from each rate class. Some rate classes will provide higher rates of return than the system average while others will yield lower rates of return. Typically, for cooperatives, large commercial and industrial classes yield higher rates of return than residential or general service classes. This is not uncommon. It is typical for some degree of subsidy to exist among rate classes. This is one of the key issues the board must consider when setting individual class revenue requirements. The board should focus on the level of margin produced by each rate class and the resulting magnitude of subsidy that exists. The board's task is to determine the appropriate class revenue requirement and thus the level of interclass subsidy that will exist in the proposed rate design.

For rate regulated cooperatives, the standard approach used by state utility commissions in the development of the class revenue requirements is to move the rate of return for each class toward the system average. The goal is to eliminate subsidies by requiring that all classes have the same rate of return. Over time, the class rates of return are equalized. Missing from this approach, however, is recognition of the different levels of risk assumed in serving different classes of consumers. Board members should not ignore the concept of risk when determining the individual class revenue requirements as providing service to certain classes of consumers is inherently more risky than others. For example, certain commercial accounts are far more risky to serve than a residential load. Some cooperatives, for example, serve customers whose operations are dependent on government policy — such as ethanol facilities or coal-bed methane facilities that have a limited life. The high levels of plant investment that are often required for such loads, coupled with the high levels of revenue from these commercial consumers, create a higher potential for loss should the consumer substantially reduce consumption or leave the system. As the risk of serving such consumers increases, the board should consider a higher rate of return for this rate class in order to protect other members.

Perhaps the most important single concept for the board to grasp is that any cost of service study should be viewed as a tool for use in determining rate levels for individual classes, not a roadmap to be followed blindly. The board should always consider the impact on consumers in deciding rate levels. The cost of service analysis will identify existing subsidies between rate classes that should be carefully scrutinized. Often, the justifiable correction of these subsidies is of such magnitude that a one-time rate change would be overly burdensome on the members in the affected rate classes. Board members are rightly sensitive to the possible impact on member's bills and must weigh the results of the cost of service study against the impact on consumers of possible rate changes when determining class revenue requirements.

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GUERNSEY Seminars

Texas Electric Cooperatives is offering GUERNSEY's cost of service and rate design, financial forecasting and accounting seminars. The seminars are hosted by the statewide association and will be held at various locations throughout the state. Cooperatives from anywhere in the U.S. are invited to register. For dates and locations, contact Esther Dominguez at Texas Electric Cooperatives at (512) 486-6211 or visit www.chguernsey.com/seminar.

GUERNSEY is also offering its courses in Oklahoma City and Orlando.

Financial Forecasting April 21-22, 2010 - Oklahoma City
Rates & Cost of Service September 15-16, 2010 - Oklahoma City
Rates & Cost of Service October 26-27, 2010 - Orlando, Florida

Item No2
Page 50 of 55

Tough Issues in Wholesale Rate Design

In theory, wholesale rate design should be fairly straightforward and considerably less complex than designing retail rates. But is it?

After all, there are considerably fewer consumers and fewer rate classes. However, as is often the case, nothing is as simple as it might seem. Issues such as load management, pricing signals, and looming environmental concerns are only a few issues which make developing a single wholesale rate structure agreeable for all stakeholders a considerable challenge.

In designing wholesale rates, determining the revenue requirement is the first and generally easiest step. Some debate is common when determining the margin component of the revenue requirement. The margin is generally designed to ensure the G&T (or other wholesale supplier) meets its debt obligations, sustains sufficient cash reserves, and maintains or achieves an appropriate equity level. Once the revenue requirement is determined, the next step is to determine the rate design. Since the rate design for a wholesale rate is typically based on functional cost components, the cost allocation or cost of service study is essential. All rate designs are intended to recover the revenue requirement. However, rate designs may not impact all members the same.

Distinctions among wholesale rate designs often include factors such as high load factor versus low load factor systems high growth versus low growth systems and systems with and without industrial customers. More recent concerns have added to the complexity of wholesale rate design. Hot topics include the impact of load management and energy efficiency programs and greenhouse gas (GHG) emissions, namely carbon dioxide. Restructuring rates to reflect the appropriate pricing signal while addressing the aforementioned may require careful education and consensus building to develop agreeable rates for all stakeholders.

Load management, or load control, is often encouraged through a demand rate pricing signal. The intent is not to reduce load, but shift it from one hour to another. The consumer instituting load control desires to minimize its bill. If a supplier has multiple demand charges with the same billing units (e.g., production demand and transmission), then a controlled load avoids all of those rates. The customer in this case has reduced its power cost far more than the wholesale supplier has reduced its cost, resulting in reduced margins. The wholesale supplier may want to examine alternative cost recovery mechanisms to more closely match its revenue to how its costs are incurred. Demand rates should be reviewed to determine whether they are too high. Is the supplier sending an unintentionally strong signal to promote load control?

> *"...it becomes more important to evaluate the pricing signal sent..."*

Energy efficiency programs reduce overall load, impacting both demand and energy rates. The wholesale supplier sees reduced costs; however, if administrative costs and margins have been included in these rates, then as usage is conserved, the wholesale supplier will not recover its intended revenue requirement. Most distribution cooperatives address this situation by adjusting customer charges. A wholesale power supplier may do the same by keeping fixed costs out of the energy component.

Some wholesale rates are "tilted." This means a portion of the demand or capacity cost of generating and transmitting power is actually being recovered through wholesale energy charges as opposed to demand charges. For wholesale suppliers whose rates include tilt, it is important to consider how it will recover its demand costs as end-use customers conserve energy.

Although GHG legislation is currently being debated in the Senate, the cost impacts of the Waxman-Markey bill approved by the House are being evaluated nationwide. Under Waxman-Markey, utilities as a whole will not receive sufficient allowances to cover their GHG emissions penalties. With the expected increased costs due to GHG emissions penalties, the wholesale supplier must consider cost recovery in its rate design. The supplier is likely to recover the cost (net of any revenues of GHG allowances sold) through either its base rates or its power cost adjustment (PCA). Most PCAs are designed to recover changes in fuel and purchased power costs and would require modification to include GHG costs. From the supplier's standpoint, this is likely to be a more favorable alternative. If these costs are not recovered through the PCA, then it could lead to more frequent changes to the wholesale provider's base rates if the GHG costs vary significantly from year to year.

With the number of issues associated with wholesale rate design increasing, it becomes more important to evaluate the rate signal sent by the G&T to its distribution cooperative and member consumer. The challenge at the wholesale supplier level is to be mindful of these issues while maintaining a fair balance of cost recovery among its members.

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Item No 2
Page 51 of 55

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G&T Credit Metrics Change

Amid a sea of change in the utility industry, modifications to credit ratings methodologies may go largely unnoticed by many distribution managers.

However, it is worth a review as the impact on generation and transmission (G&T) cooperative ratings resulting from one agency's methodology may influence the way we think of the relationship between the distribution cooperative member's financial management and the assigned credit risk of its G&T.

In December 2009, Moody's Investors Service published updates to its methodology framework in assessing the credit risk of U.S. Electric G&T Cooperatives. Moody's credit rating analysis examines five rating factors when determining the creditworthiness of a G&T. The new framework includes modifications to each of the five key factors to "better reflect industry challenges" as well as "simplify the rating methodology." Moody's published its procedures of analyzing the credit risk of G&T cooperatives to "provide more transparency for issuers, investors and other interested parties to assess credit risk for the sector."

Metrics

Moody's five key factors utilized in examining the credit risk of a G&T are:

- Long-term wholesale power contracts and regulatory status
- Rate flexibility
- Member profile
- Financial metrics
- Size

Moody's weights factors based on an assumed relative importance of each measure in determining the utility's rating. One important factor in a G&T's rating is whether or not the G&T and/or its distribution members are jurisdictional to a regulatory service commission. If so, the cooperatives are considered to have less direct control on their ability to recover costs. Moreover, an "unsupportive regulatory jurisdiction" is considered a credit negative. The rating agency views favorably G&Ts whose board or trustees are "proactive in managing the cooperative's rates and cost recovery abilities" including those with long-term wholesale power contracts in place. Other factors contributing to a favorable rating are cooperatives with higher residential sales as a percent of total sales; G&Ts owning larger pools of assets and those possessing economies of scale, i.e., higher megawatt hour sales. The rating agency continues to assign the highest weighting to the G&T's 3-year average financial metrics including TIER, DSC, funds from operations covering interest and debt, and equity as a percent of capitalization.

With much of the focus on the power supplier, distribution cooperatives remain interested in the methodology contributing to their G&T's rating. According to Moody's, G&T plant and equipment are valued at $12 billion dollars with expected additions over the next five years of approximately $8 billion. As the industry faces enormous challenges in the near term, a G&T's ability to access capital will be integral to meeting those challenges. The financial health of the distribution member will be a central part of their G&T's credit rating and ability to access low-cost capital.

For information on Moody's rating methodology of U.S. Electric G&T Cooperatives, visit: chguernsey.com/news/energy.

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Item No 2
Page 52 of 55

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June 2010

Rate Design — What the Board Needs to Know, Part III

This series is a reprint of an article first published in the Spring 2005 Management Quarterly. Part I was printed in the September 2009 issue of the Energy FOCUS and Part II in January 2010. As cooperatives face the increasingly challenging task of maintaining a meaningful rate policy, we thought it would be appropriate to revisit the basic knowledge required by boards to make good decisions.

Customer Revenue Requirement

The next step in the rate process is determining the individual customer's revenue requirement. This is accomplished through the actual design of the per unit charges in the rates. Often, the board is particularly interested in this aspect of the rate process for it is at this point the true impact on individual members becomes most apparent. Comparisons between existing and proposed rate designs should be provided to guide the board in choosing the best alternative. Additionally, it is helpful for the board to have an understanding of the "functionalized" costs which support the rate design.

The cost of service study should identify not only the dollar amount of the costs incurred to provide service to a specific class of customers, but also the type of costs — known as functionalized costs. Functionalized costs include demand-related costs, energy-related costs and customer-related costs.

Demand-related costs are associated with a member's capacity or size requirement. They reflect the demand that the member's load places upon the cooperative's system and the costs of investment in the plant and facilities to serve that demand. Costs associated with transmission facilities, distribution substation and distribution backbone facilities are examples of demand-related costs, along with any demand charges levied by the cooperative's wholesale power supplier. Energy-related costs are those costs that vary based on the quantity of kWh sold. For a distribution cooperative, the only true energy-related costs are those associated with the fuel and energy component of the wholesale power bill. All other delivery costs are either demand-related or customer-related. Customer-related costs are those costs that are required simply to have the member's service in place, regardless of the size of the load or the amount of energy required. Because cooperatives typically have low consumer density, a certain minimum level of distribution lines and other facilities are necessary to provide service. Other customer-related costs include the cost of the service drop, the meter, a portion of the transformer, meter reading costs, customer service and billing costs.

These so-called "functionalized" costs are used as a tool in establishing the charges that go into the tariff established for each rate class. It is important for the board to understand their system's customer-related costs of providing service to each customer class, especially residential consumers. The actual "functionalized" customer-related cost of providing service to each rate class is the basis for each class's customer charge. Typical distribution cooperative residential customer-related costs, for example, range between $20 and $30 per customer per month. In an effort to more closely match the customer charge in their rates with the customer-related costs identified in their cost of service studies, many cooperatives have begun to increase the customer charge in the residential rate to more closely track the functionalized customer-related cost. This trend is a result of increased competition and the cooperative's desire to minimize subsidies.

Cooperative customer charges have historically been much lower

See Rate Design on page 2.

InFOCUS

Rate Design — What the Board Needs to Know, Part III

No issue facing a cooperative board is more complex and yet more important than its oversight of the development of effective retail rate policies.

What's New With Rates?

Developing new rate structures to address conservation, energy efficiency and the recovery of fixed costs is not a new concept. Cooperatives merely need to look to the PURPA Title 1 Standards and not forget the fundamentals of good rate design in an effort to be new and innovative.

GUERNSEY Seminars

See inside for details of upcoming seminar dates.

Item No 2
Page 53 of 55

Rate Design

cont. from page 1.

than the actual customer-related costs. This has created an intraclass subsidy; a subsidy between individual customers within the same class. When the customer charge component of the rate is lower than the actual cost to serve, the energy component or kWh charge must increase in order to recover the total cost for the class. Such a rate structure benefits minimum use and low use customers who do not pay the full required cost. Meanwhile the higher use customers who consume more kWh will pay a greater share of the costs. This is of particular concern to boards whose cooperatives have a high number of minimum bill or seasonal accounts. It is also of particular concern to cooperatives facing retail competition who may be charging the very high-usage customers — who are most coveted by the competition — a higher rate to subsidize low-usage customers.

Balance is again the key in determining the appropriate rate design. Although the cost of service analysis may indicate that a certain level of customer charge is justified, the impact on consumers of implementing that customer charge may be too great. Multiple rate changes over several years may be required to accomplish the board's long-term goals with regard to the customer charge.

The discussion of customer-related costs points out the fundamental principle of rate design; the development and implementation of cost-based rates. Simply stated, the retail rate to the consumer should recover, to the extent possible, the costs of providing service in the manner in which the costs are incurred. This is especially true with regard to recovery of wholesale power costs. A well designed rate reduces the cooperative's risk associated with the wholesale components of costs and accurately reflects recovery of distribution wire costs.

There is no "one-size-fits-all" rate design. There are many different types of rate designs for different purposes. There are seasonal rates to reflect different seasonal power cost differences, declining block or demand rates to reflect the general trend of power cost to decline in volume, time-of-use or interruptible rates to motivate energy efficiency and many other rate structures. The cooperative board and management may want to look at a number of rate alternatives before selecting an option that best meets their individual needs. The benefits and risks of each alternative should be discussed. In reviewing various rate alternatives, the board should be sure that their rate choice recovers all of the costs to provide service and minimizes risk.

Coordinate Line Extension Policy With Rate Design

A key area often neglected in the rate process is the cooperative's line extension policy. Typically, a line extension policy covers how line is extended to provide service to new members and who pays for it. Most cooperatives have some cost sharing built into their policy between the cooperative and the member. Any line extension cost paid by the individual member reduces the cooperative's investment. Any remaining amount is paid, not by the individual member requesting it, but by all members, ultimately through their rates.

Any time changes are made to rates, the board should also review the impact on the line extension policy. Inherent in the development of rates is recovery of the investment costs to provide service to the various customer classes. The revenue received from a new load must be sufficient to cover the cost of the additional investment required to serve that new load.

The cost of service study can help the board with this analysis. The results of the study identify the total dollar amount of line extension investment supported by each rate class at different average usage levels. Cooperative boards can incorporate this information into their line extension policies. Based on the cost of service results for example, the cooperative may agree to pay for the first $1,500 of new line extension to the residential class. Any amount in excess of $1,500 is paid by the prospective member.

The key point for directors to consider with regard to the line extension policy is to not lose sight of the link between rates charged to consumers and the amount of plant or facilities in which the cooperative can afford to invest. The line extension policy should reflect the relative risk and life expectancy of the new load as well. This may require a significant shift in the cooperative's historic philosophy. Many systems have essentially provided line extensions to most new consumers at little or no cost. While no one would recommend that cooperatives forget their roots and abandon the principle of providing fairly-priced service to consumers in areas where it is more costly to serve, it is important that the board balance the cost of providing a certain level of line extension — at no cost to an individual member — with the impact that policy will have on

See Rate Design on page 4.

Item No 2
Page 54 of 55

What's New With Rates?

Probably the most frequently asked question I get these days is, "What new or different rate design should be adopted in response to the various issues facing cooperatives today?"

Of course, the answer is not the same for every situation. In the pressure to be new or "innovative" we should not forget the importance of rate making fundamentals. While not new, they should be considered in all rate designs.

First and foremost, rates should recover the costs of providing service. This was the first of six standards of rate design included in Title 1 of PURPA in 1978. The importance of this fundamental principle is evident. Rates not based on cost put the cooperative's margins at risk and create subsidies between rate classes and between customers in the same rate class. Competition is often cited as the key reason for straying away from the cost of service concept. Designing a rate structure that is both market-based and competitive is certainly achievable. However, if the rate does not recover the full cost to serve, it will not be sustainable and will lead to losses and subsidies.

Other standards included in the PURPA address time-based rates, seasonal rates, interruptible rates and load management rates. It should be noted that the three stated purposes of the PURPA Title 1 standards applicable to utilities since 1978 are to encourage:

1. the conservation of energy supplied by electric utilities,
2. the optimal efficiency of electric utility facilities and resources, and
3. equitable rates for electric consumers.

It is interesting to note that even way back in the '70s there was recognition of the need for conservation, efficiency and fairness. For many years, cooperatives across the country have been designing rates based on these fundamentals. It is somewhat disconcerting that rate making concepts set forth back in 1978 and used in the design of rates by cooperatives for years are now being extolled by some as new and innovative concepts.

"Designing a rate structure that is both market-based and competitive is certainly achievable."

For example, what has been coined as decoupling – reducing the potential impact of increased or decreased energy sales on margins – is a great idea. For cooperatives, decoupling is more of a cost of service and fairness issue. It is an effective way to reduce the financial impact of energy efficiency, distributed generation programs and even fluctuations in energy consumption caused by the weather. Yet, this is hardly a new concept. Many of our cooperative clients have been methodically increasing their customer charge in order to recover more of the distribution fixed costs for just these reasons.

It is important not to overreact to the potential negative financial impacts of energy efficiency and distributed generation on cost recovery by increasing customer charges too much too quickly. Potential negative impacts resulting from energy efficiency and conservation measures will be gradual over the next several years. Having a rate strategy that moves the customer charge up over time and provides a reasonable customer impact provides both the stability that the cooperative needs as well as member acceptance.

Likewise, other rate design concepts that are now getting a lot of attention such as time-based rates, inclining block rates, interruptible rates and load management rates have been implemented, refined and improved by many systems over the past thirty years. Much has been learned about how these rates work, how member-consumers accept and respond to such rate designs and the expected impact on consumption and cost. It is vital that the lessons learned be included in the process of developing new rates.

Some of these rate designs may be appropriate at your system. All of them should be considered and studied. However, not all rate designs will be embraced by members. For example, residential members have historically resisted participation in time-based and load management rates. Providing effective member education is as important as the rate design itself in achieving price and cost reduction as well as efficiency and conservation goals. Moreover, the desire of public power utilities like cooperatives to always consider member impact over profits is as innovative today as it was 74 years ago.

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Item No 2
Page 55 of 55

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Owen Electric Cooperative, Inc
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Owenton KY 40359-0400

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Rate Design

cont. from page 2.

rates paid by all members. The more investment costs that are assumed by the cooperative over a period of years, the higher the retail rates will be. Providing service at a reasonable price need not mean unlimited line extension to any location selected by the consumer and subsidized by the other members of the system.

Monitor and Analyze Ongoing Performance

Ongoing oversight is the final step in the rate setting process. It is sometimes overlooked because it does not occur at the same time as the cost of service study or the rate change. It is, however, a critical part of the entire process and should be actively pursued by both the cooperative staff and the board.

Monthly reports should be produced by the cooperative staff to determine how well the financial forecast continues to reflect the cooperative's condition. Are projected sales growth levels being met? Are actual purchased power costs per kWh similar to projections? What about plant additions, interest rates and O&M costs? Are they on target? The forecast should be a living document, with changes made to meet changing conditions and it should be reviewed by the board on a routine basis.

Cooperative boards should also continue to examine their often conflicting obligation to balance the cooperative's financial needs against the financial impact on members. Rate philosophy and policies vary with individual cooperatives. Some cooperative boards feel that, instead of changing rates as seldom as possible (resulting in large, infrequent rate increases), they should adopt more frequent and far smaller changes. Some cooperatives prefer to establish rates that produce TIER or other financial coverage ratios at the lowest possible level while others prefer a reasonable cushion for unforeseen contingencies. Some desire to maximize equity by minimizing borrowing from lenders.

"The forecast should be a living document, with changes made to meet changing conditions..."

Some cooperatives have adopted adjustment clauses for power cost changes or debt cost changes. Boards should consider the adoption of standards for the percentage of total revenue they believe should be permitted from these types of adjustment clauses before an overall rate adjustment is necessary. If a large portion of a member's monthly bill comes from one of these clauses, the tariffs no longer reflect the total cost paid by customers, and rates become increasingly less based on actual underlying costs. Cooperative boards and management should establish monthly reporting mechanisms to track over time the changes in the financial forecast and performance of their rates, including any adjustment factors and line extension contributions. The process of analyzing a cooperative's revenue needs, cost of service allocations and rate design can be a challenge for a cooperative board of directors. However, when the process is clearly defined in a series of understandable steps and time is devoted to the task, the cooperative board will be better positioned to make informed, balanced and fair decisions, and effectively communicate to members the rationale behind the cooperative's rate policies.

David Hedrick
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OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Question:

Refer to the response to Item 3.a. of Staff's First Request. Explain whether the fact that Owen's proposed rates do not always follow the underlying rates of its wholesale power supplier, East Kentucky Power Cooperative, Inc., puts Owen at some financial risk.

Response:

Owen does have some financial risk when it does not follow its wholesale power supplier's underlying rates by having fewer on-peak hours than its wholesale power supplier, East Kentucky Power Cooperative ("EKPC"). However, Owen feels that this risk is very minimal. Owen has reviewed its load profile for its Schedule 1, Farm and Home rate and for its Small Commercial rate and feels very confident about the times it has selected as on-peak and off-peak. Other EKPC members have Time-of-Day rates with hours different from EKPC's hours.

Owen is attempting to provide rate options to its members that allow them the ability to better manage their electric bill consistent with their lifestyle.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Refer to the response to Item 5 of Staff's First Request. Owen states that the rate design in this case has taken considerable time to process, educate and finalize with Owen's board of Directors.

a. Question:

Since Owen's board members are likely more familiar with the electric utility industry and electric utility rates than its member-owners, explain how Owen plans to educate and inform its members as to the reasons for its changes in rates, and communicate to its members how to determine the effect of the changes on their bills.

a. Response:

The majority of time spent developing this rate design case consisted of Owen management personnel developing various rate options, finalizing the smart grid pilot projects, and crafting a comprehensive communication and education plan. While it did take several months to complete this process, once the initiatives were finalized and presented to the board, Owen's board easily understood, and approved the plan within a short amount of time. Owen would agree that currently its board is more familiar with the electric utility industry and electric utility rates that the average member/owner. Owen's board, however, consists of elected members of the Cooperative and represents a cross section of the membership, and we believe that the communication and education plan is adequate to effectively educate and inform the membership of the proposed rate design options and choices.

Owen will engage in education and communications efforts to provide information on rate design strategies and rate options available on an ongoing basis. The message of rate choices will be explained and advocated via billing inserts, newsletter articles, community meetings and other forums. The goal is for the member to become interested and contact the Cooperative to obtain information from a trained CSR. At this point the CSR will discuss the rate choices and direct the member to a rate best suited to their usage pattern. Later, a more targeted approach will be used where members who best fit the rate options will receive direct mailings catered towards a specific optional rate. A rates website page will also be developed and utilized to

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

introduce Owen's rate choices and will incorporate easy to follow narratives and illustrations of each rate.

For additional details pertaining to how Owen Electric plans to educate its member-owners, please refer to Exhibit 14 (Education and Communications Plan) in our original rate application (2011-00037).

b. Question:

Explain whether Owen has discussed its proposed rate changes in focus groups, or in other meetings with members.

b. Response:

Owen has not discussed its proposed rate changes with member focus groups. The rate changes were introduced and presented at Owen Electric's 2011 annual membership meeting. Additionally, Owen's proposed rate changes have been discussed with various groups (i.e. civic clubs, community groups, professional associations etc...) and the response has been favorable. The Time of Day rates will be featured in our smart home pilot and the results (member acceptance, rate impact on energy usage and overall bill amount) will be analyzed. Owen's plan is to utilize the members who are participating in the smart grid pilots as a "focus group" to provide feedback, help the cooperative evaluate and modify existing programs, and develop new programs and offerings, if needed.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Refer to the response to Item 8 of Staff's First Request.

a. Question:

Explain the rating given to the "DSM" method in comparison to those give to the "Cost of Service" method, paying particular attention to the high level of simplicity, transparency, understandability, and equity ascribed to the "Cost of Service" method as opposed to the "DSM" method.

a. Response:

In regards to simplicity, the DSM surcharge method is more complex than the cost of service method as a result of two main factors.

The first is the true up adjustment. The cost of service method requires no true up because the costs are recovered in rates as the costs are incurred. Estimates of costs are not required nor are justifications for variances from the estimated expenses. As a result, the true up process required by the DSM surcharge is much more time consuming, may result in more rate volatility, and is much more complicated than the much simpler cost of service method.

A second complexity of the DSM surcharge is engineering estimates of lost revenues. In the cost of service model, revenues associated with customer related costs are not lost and therefore there is no need to estimate recovery. Any other lost revenues are assumed minimal to the distribution cooperative at the retail level. The process of estimating lost revenue is significant, complex, debatable, and can be contested by experts from many different perspectives and positions. It is much simpler to avoid the need to estimate lost revenues by proactively adjusting to accurate cost of service rates thereby eliminating the need to recover lost revenues.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

In regards to transparency, we are referring to the degree to which the method is easily understood and communicated, thereby building trust with our members. The DSM surcharge, as establish above, is more complicated, requiring a billing true up process that can produce rates swings, requiring rate experts to estimate lost revenues and who may publically disagree over the accuracy of the calculations.

All of the above leads to a complexity that is difficult to communicate, that is not easily understood, can lead to mistrust or lack of faith in the fairness of the process, and as a result is not transparent. The cost of service method is simple, easy to understand, easily verified, and as a result extremely transparent.

In regards to cost recovery we found no significant advantage of one method to the other. As noted above, however, the cost of service method is a much simpler and straight forward approach to cost recovery utilizing fewer estimates and true up mechanisms.

In regards to flexibility we believe the cost of service method allows us to more quickly adjust to member needs and new technology. The DSM surcharge mechanism requires a hearing every six (6) to twelve (12) months while the need for a hearing in the cost of service method is on an as needed basis. As with the FAC and the Environmental Surcharge mechanisms, the opportunities for revisions to the DSM programs will tend to correspond with the hearing dates, as a result flexibility will be reduced to a predetermined timeline as opposed to the needs of the member participants.

In regards to regulatory approval, the DSM surcharge was given a rating of five (5) because it is an existing process being utilized by Investor Owned Utilities in the state and is well defined and understood by the Commission. The Cost of Service method was given a score of four (4) because, although this methodology was advanced by Owen in PSC Case No. 2008-00154 and referenced by the Commission in their order in that Case as an option along with the DSM Surcharge mechanism, it is an approach that has not yet received regulatory approval.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

In regards to Equity, we view the cost of service method as superior to a DSM surcharge for several reasons. First and foremost a customer charge of $11.70 is far below Owen's customer related costs of $27.66. This mismatch means that over 50% of customer related charges are recovered in the energy charge. If one member greatly reduces energy consumption by 15%, they in effect shift recovery of their fair share of the consumer related costs to another member. Cost of service rate design is the only means to ensure an equitable rate structure for all members.

Secondly, we likewise believe that the cost of service method more fairly provides the member making an effort to reduce energy consumption with their actual energy savings. Applying the DSM surcharge with a customer charge of $11.70 per meter in the first step overpays the energy efficiency achiever, then in a second step takes some of the savings back with an engineering estimated lost revenue charge dovetailed into a DSM surcharge. Our solution proposes to proactively allocate costs accurately upfront and avoid the complexity and debate of estimating lost revenue.

Thirdly, a DSM surcharge charges everyone within a rate class for all DSM costs within the rate class whether they participate in the DSM program or not. It also does not allow disaggregation and market segmentation within the rate class. It treats the rate class as a homogenous group, all alike, with the same wants and needs. With cost of service rates, coupled with a tariff specifically targeted toward a market segment within a rate class, the cooperative is easily able to allocate the cost of a program to the members who benefit from the optional tariff. Several excellent examples of this approach are the prepay meter tariff presently in place Jackson Energy, and the How $mart KY tariff program presently in place at cooperatives in Kentucky, South Carolina, and Kansas. Owen is considering using the same approach to implement Smart Home and Beat the Peak programs system wide should the pilots prove to be cost effective.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

In regards to implementing Owen Electric's energy innovation strategy, due to the above reasoning it is Owen's belief that cost of service rates where the customer charge adequately but not completely recovers the customer related expenses provides Owen Electric's members superior fairness, flexibility, transparency, understanding, and simplicity.

b. Question:

The last sentence in the response reads, "We believe the cost of service method offers members superior fairness and equity...because it allocates costs accurately thereby removing cross subsidies and inequity in rates between members: Explain whether any of Owen's rate classes are currently subsidizing other rate classes and if so, whether Owen is addressing the subsidization in this case.

b. Response:

Based upon Owen's last rate case 2008-00054 the rates of return varied, and did indicate cross subsidies between member classes. Using a gradualism approach as embraced by the Commission we will work to reduce the cross subsidies between member classes over a realistic time frame. Owen is not, however, attempting to address this issue in this revenue neutral filing. In this particular rate filing, our goal is to only address the inadequate recovery of consumer related costs in our customer charge for our Farm & Home and Small Commercial classes.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Question:

Refer to the response to Item 9 of Staff's First Request. If the customer charge is equal to the full distribution cost to serve and the energy charge exceeds the wholesale cost per kWh, explain whether a throughput incentive still exists.

Response:

If the customer charge provides for the full distribution revenue requirements, then the energy charge should be equal to the wholesale cost per kWh. In this situation, if the energy charge is greater than the wholesale cost per kWh, then a throughput incentive does exist. In this proposal, Owen is not seeking full recovery of its customer related costs through its customer charge nor is it seeking any distribution demand related costs through its customer charge.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Question:

Refer to page 2 of the response to Item 10 of Staff's First Request. Provide a brief description of each of the five potential future services and products listed on the page.

Response:

How $mart Kentucky on bill financing – In PSC Case 2010-00089, Jackson Energy Cooperative, Grayson RECC, Fleming Mason Energy Cooperative, and Big Sandy RECC partnered with MACED to introduce a two year pilot project designed to provide energy savings to the member at no upfront cost. The project (1) identifies potential household energy systems that can be upgraded to new efficient and less costly systems, (2) provides project management and oversight, (3) finances the cost of the project through the resulting household energy savings, and (4) assigns the household meter with a fixed monthly charge so that the utility can recover the investment. The pilot was developed as a tariff option for residential and small commercial rate class members. Ninety percent of the electric bill savings are used to cash flow the project while ten percent of the savings are returned to the member as an inducement to participate. The project is typically financed over 15 years at 3% interest, tied to the electric meter, and secured to the homeowners property deed to communicate the on line utility bill obligation to a new homeowner. The project template was developed several years ago at Midwest Energy in Kansas where it has been very successful, has been similarly developed by South Carolina Cooperatives, before being piloted by Kentucky Cooperatives and MACED. We have had discussions with fellow Cooperatives, met with MACED, and are investigating joining the pilot. No decision has been made at this time.

Prepay Metering – In Case 2010-00210 Jackson Energy developed the first prepay tariff in Kentucky and are in the early stages of launching the prepay metering program to their members. Our major barrier in moving forward relates to integration issues between vendors that must be resolved to enable prepay to work at Owen.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

At present, our vendors have not indicated when the integration will be in place. We will continue to monitor the integration process, will review the results at Jackson Energy and other Cooperatives, and will make a decision to deploy or not as the integration becomes available.

<u>Smart Home with TOD or CPP</u> – Based upon prepay cooperative results of 12% energy savings (reference Jackson Energy Case 2010-00210) we expect smart home energy savings to approach a similar level and possibly exceed the 12% threshold depending on the user friendliness of the system.

The purpose of the Smart Home with TOD project is to put equipment in the members' home that will allow them to monitor and control all major electrical loads and to allow the member to have Owen Electric, or another third party, to assist them in this endeavor. While the products and services Owen will provide in the future for the Smart Home with TOD or Critical Peak Pricing are still under development with our pilot projects, key components of the project are: to put as many key tools for managing the members' usage of electricity in their hands as we can, educate them on the benefits of those tools, monitor how the members use the system, evaluate the cost benefits of all components, share the results with key stakeholders, and finally develop rates and services that will be cost effective for our members.

The proposed member tools are:

1. Smart thermostat
2. Water heater control
3. Smart switch
4. Smart Appliances – Washer, dryer, stove, dishwasher, refrigerator
5. A Home management system consisting of a display, communication system to all the above devices as well as the meter, software to monitor and control all the above devices, associated hardware and communication to the internet so that the system can be remotely managed via their phone or have OEC or a third party manage their system for them. The communication will also be used for OEC to send energy pricing signals or critical data to the member.
6. Host software at OEC so that our Customer Service Representative can assist members, when requested.
7. Also be able to interface with third parties if the members desired sharing the data or having someone else assisting with managing their energy usage.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Since this is a new and complex project, Owen proposes splitting implementation into four segments. The first segment is to set up the system in two or three homes of Owen employees in order to work out the technical details associated with the implementation. The second step is to implement the system into about five (5) members home in order to develop a member deployment process and get initial feedback. The third step is to deploy to 50 to 100 members for 1 to 2 years for full monitoring and analysis. In the final phase a cost/benefit analysis will be conducted and program development will be done to offer the system to all of our members.

Some of this technology was very new and was not fully developed so we delayed this project as long as possible. The bids received from the seven vendors confirm our concerns regarding the initial development of the technology. Only one vendor is bidding smart appliances and six are proposing that a third party host all the data vs. the homeowner maintaining their own data and only sharing it if they wish. Owen's next step in this process will be to sit down with two or three of the best vendors and either negotiate an acceptable solution, or modify the project to make it acceptable.

Some of the possible products and services Owen could offer as an outcome of this project are:

1. Energy saving incentive rates that are optimum for members' life styles with maximum energy conservation at no additional cost to all other members.
2. Educational tools to demonstrate to our members what is available in the market for energy conservation equipment and systems and cost benefit analysis on them based on other members use of those products.
3. Provide home area network systems to our members, either with or without a third party, similar to the one in the pilot project.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Beat the Peak with CPP – Our Beat the Peak Pilot Project launched in April 2011 without a corresponding rate incentive. A TOD rate structure was deemed to be too complicated for a do-it-yourself Beat the Peak pilot. Instead a critical peak price rate structure was developed consisting of a $25 customer charge, a seven and one half cent ($0.075) off peak energy rate, and a twenty-two cent ($0.2288) on peak energy rate with a maximum of 120 hours. The rate concept is on hold pending the availability of metering software offering such a billing format.

O Power Mailing – O Power was founded in 2007 on the simple premise that "it's time to engage the 300 million Americans who are in the dark about their energy use". The program offers to get members attention to energy usage by comparing a household's energy use to what is "normal" in their neighborhood. The mailings have proven to be an appealing mechanism to grab the members' attention and motivate action. Studies show energy savings in the range of 2%.

The O Power and Beat the Peak options are targeted toward members who do not want a home energy network but who instead prefer a more hands on approach. The prepay option is more aggressive than either the O Power or Beat the Peak options in that it provides a prepay system that informs the member of their ongoing energy budget balance as well as the rate of energy consumption. The prepay option is a home energy budgeting tool. Our smart home option is again another step up the proactive energy management scale in that it employs the use of automated direct load control, smart appliances, and home energy software tools to monitor and manage home energy consumption. Owen Electric's long term energy innovation vision is to provide a range of options, running the gamut from passive to active, and automated energy management tools that offer members choices within a range of options to manage their energy use, budget, comfort, and convenience to match their unique lifestyle.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Question:

Refer to the response to Item 11.b. of Staff's First Request. Explain whether any of the Demand-Side Management ("DSM") programs listed in this response are specifically targeted to fixed- and low-income members. If not, explain how many such customers participate in each of the DSM programs listed.

Response:

Owen's DSM programs are made available to all Owen Electric members and are not specifically targeted to fixed- and low-income members.*

Owen does not ask for proof of income as part its DSM program participation practices.* The DSM program participation rate of fixed- and low-income members is not known.

***Exceptions to the above are**:

Owen's 2009 Button-Up pilot program. All nine of Owen's participants were selected in conjunction with community action agencies and were certified as low-income participants.

Energy workshops. Owen Electric coordinated energy efficiency/conservation workshops with area community action agencies during the 2009-2010 heating season. Approximately 70 LIHEAP (low-income) recipients attended workshops held in Boone, Gallatin, Grant, and Owen Counties. Owen also conducted a workshop in conjunction with the Owen County Senior Citizens for approximately 15 seniors (fixed-income).

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Refer to the response to Item 13 of Staff's First Request.

a. Question:

Explain why the REM/Rate energy rating tool uses BTUs and not kWh in determining saving for a rural electric cooperative.

a. Response:

REM/Rate's function is to evaluate the energy consumed by a home's heating and cooling system. This evaluation is calculated in BTUs as a universal measurement of energy consumed. The BTUs may then be converted to the unit of measurement for the appropriate fuel type (i.e. electric (kWh), natural gas (cubic foot), etc...) in use.

b. Question:

Provide a detailed list of the materials used, including their costs, and the labor costs that comprise the $16,296 total cost, which equates to an average of $1,810 for the nine homes weatherized under the Button-Up pilot program.

b. Response:

The home improvement work conducted for the pilot was performed by a third party—Ideal Homebuilders. The following pages display copies of 3 invoices for the 9 homes completed in Owen's pilot program. The invoices include square feet of upgraded insulation (by location and R-value of insulation), details pertaining to the air sealing completed, and the total cost to Owen Electric. Labor was not itemized separately on the invoices.

IDEAL Homebuilders

INVOICE

Tax I.D. = 61-1396448

To: East Kentucky Power Cooperative
4775 Lexington, Road
Winchester, Ky 40392

page (1)

Invoice No.	Invoice Date	P.O. Number	Vendor No.	Reg. No.	Other
092312	03/24/09				

Date Completed	Description		Amount
3/23/2009	Residence # 1		
Owen Elec.	Air Sealed Homes windows, doors and reduced whole		$1,708.00
	homes air leakage from 4500 cfm to 1800 cfm...		
	Built and sealed attic hatch. Adjusted and applied		
	air locks to windows. Weather stripped doors, Sprayfoamed		
	Band Board and increased attic insulation from R-19 to R-38		
3/23/2009	Residence # 2		
Owen Elec.	Enhanced entire 1154 sq ft basement ceiling from		$2,286.00
	R-0 to R-19. Sealed windows, weather stripped doors.		
	Sealed off interior basement door to create envelope.		
	Sealed all plumbing penitrations through basement ceiling		
	Increased attic insulation from R-19 to R-38.		
3/24/2009	Residence # 3		$145.00
Owen Elec.	Sealed and Weather stripped three doors.		

Subtotal		Shipping	Amount Due	Terms	Pay By
$4,139.00	Sales Tax		$4,139.00		ON RECEIPT
	$0.00				

MAKE ALL CHECKS PAYABLE TO:

IDEAL HOMEBUILDERS
276 BLUE SKY PARKWAY
LEXINGTON, KY 40509-9419

PHONE: 859-221-6363
Fax: 859-264-1371
Email: mmfiscus@aol.com

IDEAL Homebuilders

INVOICE

Tax I.D. = 61-1396448

To: East Kentucky Power Cooperative
4775 Lexington, Road
Winchester, Ky 40392

page (1)

Invoice No.	Invoice Date	P.O. Number	Vendor No.	Reg. No.	Other
092315	04/10/09				

Date Completed	Description		Amount
4/8/2009	Residence # 4		
Owen Electric	Rebuilt & insulated attic hatch. Increased attic insulation		$2,114.00
	from R-19 to R-38 (cable ceiling heat / Delta T increased)...		
	Weather Stripped two exterior doors, clear caulked windows,		
	ceiled below bath tub & plumbing penitrations...		
	Increased entire crawl space from R-0 to R-19...		
4/9/2009	Residence # 5		$2,760.00
Owen Electric	Sealed major duct leakage.. Increased two crawl spaces		
	and entire basement ceiling from R-0 to R-19.... Sealed plumbing		
	penitrations and applied a water heater blanket.. Applied		
	R- 13 and foam board on 320 sq ft of attic knee walls,		
	and sealed off entire basement stairwell...		
4/10/2009	Residence # 6		$1,685.00
Owen Electric	Adjusted and weather stripped front door...		
	Rebuilt and insulated attic hatch.. Sealed leaky supply		
	boots.. Sealed HVAC duct work & plynam...		
	Increased attic insulation from R-19 to R-38....		

Subtotal	Sales Tax	Shipping	Amount Due	Terms	Pay By
$6,559.00	$0.00		$6,559.00		ON RECEIPT

MAKE ALL CHECKS PAYABLE TO:

IDEAL HOMEBUILDERS
276 BLUE SKY PARKWAY
LEXINGTON, KY 40509-9419

PHONE: 859-221-6363
Fax: 859-264-1371
Email: mmfiscus@aol.com

IDEAL Homebuilders

INVOICE

Tax I.D. = 61-1396448

To: East Kentucky Power Cooperative
4775 Lexington, Road
Winchester, Ky 40392

page (1)

Invoice No.	Invoice Date	P.O. Number	Vendor No.	Reg. No.	Other
092318	05/01/09				

Date Completed	Description		Amount
4/27/2009	Residence # 7		$2,114.00
Owen Electric	Sealed off entire homes major air infiltration ares:		
	Family room ceiling, basement plumbing, laundry vent,		
	A.C. unit.... Added water heater blanket, and sealed		
	and put R-0 to R-19 in entire band board... Increased both		
	attics from R-19 to R-38...Sealed hatch and exterior		
	windows....		
4/28/2009	Residence # 8		$1,804.00
Owen Electric	Sealed crawl space HVAC duct work (a lot of leakage)...		
	Weather stripped exterior door... Increased attic		
	insulation from R-19 to R-38....		
4/28/2009	Residence # 9		$1,680.00
Owen Electric	Foamed and sealed plumbing penitrations...		
	Added a water heater blanket... Increased attic		
	insulation from R-19 to R-38.... Weather stripped one		
	door....		

Subtotal		Shipping	Amount Due	Terms	Pay By
$5,598.00	Sales Tax		$5,598.00		ON RECEIPT
	$0.00				

MAKE ALL CHECKS PAYABLE TO:

IDEAL HOMEBUILDERS
276 BLUE SKY PARKWAY
LEXINGTON, KY 40509-9419

PHONE: 859-221-6363
Fax: 859-264-1371
Email: mmfiscus@aol.com

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Refer to the response to Item 16 of Staff's First Request, which indicates that approximately 28,000 residential customers will experience an increase in their bills, with number dropping to 9,500 if customers who would benefit from the Inclining Block Rate actually choose it. The Prepared Testimony of James R. Adkins ("Adkins Testimony") at page 6 states that the residential Inclining Block Rate is specifically designed for customers who consistently use 500 kWh per month or less.

a. Question:

Explain whether Owen expects approximately 18,500, which equates to one-third, of its residential customers to understand that their bills are likely to increase if they don't change rate schedules. Explain whether Owen plans to directly contact those low usage customers who do not change to the Inclining Block Rate Schedule to advise them of the opportunity to decrease their bills by changing rate schedules.

a. Response:

Even with Owen's comprehensive member education and communication plan (please refer to Exhibit 14 - Education and Communications Plan in our original rate application 2011-00037), it is not reasonable to anticipate that every member will immediately understand how the menu of rates would affect their bill. After the initial roll out of the rates, Owen does plan to engage in a targeted approach where members who best fit the rate options will receive direct mailings catered towards a specific optional rate. Low usage members will be identified via billing queries and will be contacted in an attempt to encourage them to consider the optional Inclining Block Rate Schedule.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

b. Question:

Refer to Exhibit 9 of Owen's application, which shows the impact of rate proposals on customers at varios usage levels. Explain why Inclining Block Rates bill shown in the last column continue to be lower for usage over 500 kWh even though the last rate step is, as the Adkins Testimony describes, as a premium of three cents per kWh over the energy rate for the previous step. If there is an error in the calculation of the Inclining Block Rates column, provide a revised Exhibit 9.

b. Response:

Attached as page 3 of this response is revised Exhibit 9 with a correction to the Inclining Block Rates column.

c. Question:

Describe the usage pattern of the 9,500 remaining residential customers who would not benefit from a switch to Inclining Block Rates, and any opportunity abailable to them to avoid an increase in their electric bill.

c. Response:

Please refer to Page 5 of 5, Exhibit 6 in the Application and identified as Bill Frequency Analysis. Those approximately 9,500 customers who would not benefit from the Inclining Block Rate are those customers whose monthly usage is from 850 kWh per month through 1100 kWh per month.

Other opportunities do exist for them through selecting one of the time-of-day rate options or one of the options that may be offered by Owen.

OWEN ELECTRIC COOPERATIVE
CASE NO. 2022-00037

IMPACT OF THE RATE PROPOSALS ON THE AVERAGE CONSUMER

IMPACT OF RATE PROPOSALS UPON CONSUMERS AT VARIOUS USAGE LEVELS							
kWh Usage	Present Rates	2011 Rates	2012 Rates	2013 Rates	2014 Rates	2015 Rates	Inclining Block Rates
0	$ 11.30	$ 15.00	$ 17.50	$ 20.00	$ 22.50	$ 25.00	$ 15.78
50	16.04	19.57	21.96	24.34	26.73	29.11	$ 19.27
100	20.78	24.14	26.41	28.68	30.96	33.23	$ 22.76
150	25.52	28.71	30.87	33.03	35.18	37.34	$ 26.25
200	30.26	33.28	35.32	37.37	39.41	41.45	$ 29.73
250	35.00	37.85	39.78	41.71	43.64	45.57	$ 33.22
300	39.73	42.42	44.24	46.05	47.87	49.68	$ 36.71
350	44.47	46.99	48.69	50.39	52.09	53.79	$ 41.32
400	49.21	51.56	53.15	54.73	56.32	57.91	$ 45.94
450	53.95	56.13	57.60	59.08	60.55	62.02	$ 50.55
500	58.69	60.70	62.06	63.42	64.78	66.13	$ 55.17
600	68.17	69.84	70.97	72.10	73.23	74.36	$ 67.39
700	77.65	78.98	79.88	80.78	81.69	82.59	$ 79.62
800	87.12	88.12	88.79	89.47	90.14	90.81	$ 91.85
900	96.60	97.26	97.71	98.15	98.60	99.04	$ 104.07
1000	106.08	106.40	106.62	106.83	107.05	107.27	$ 116.30
1100	115.56	115.54	115.53	115.52	115.51	115.49	$ 128.53
1200	125.04	124.68	124.44	124.20	123.96	123.72	$ 140.75
1300	134.51	133.82	133.35	132.88	132.42	131.95	$ 152.98
1400	143.99	142.96	142.26	141.57	140.87	140.17	$ 165.21
1500	153.47	152.10	151.18	150.25	149.33	148.40	$ 177.44
1600	162.95	161.24	160.09	158.93	157.78	156.63	$ 189.66
1700	172.43	170.38	169.00	167.62	166.24	164.85	$ 201.89
1800	181.90	179.52	177.91	176.30	174.69	173.08	$ 214.12
1900	191.38	188.66	186.82	184.98	183.15	181.31	$ 226.34
2000	200.86	197.80	195.73	193.67	191.60	189.53	$ 238.57
2250	224.56	220.65	218.01	215.38	212.74	210.10	$ 269.14
2500	248.25	243.50	240.29	237.08	233.88	230.67	$ 299.71
2750	271.95	266.35	262.57	258.79	255.01	251.23	$ 330.27
3000	295.64	289.20	284.85	280.50	276.15	271.80	$ 360.84

Item No 11
Page 1 of 1
Witness: Michael Cobb

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Question:

Refer to the response to Item 17.a. of Staff's First Request. Explain whether some change to Owen's proposed tariffs is required to clarify that one-year commitments are not required, especially in the absence of a written contract.

Response:

It is Owen Electric's contention that the language on the four proposed optional tariffs that stipulates "*One year minimum commitment required*" should remain. This level of commitment is necessary to properly realize the effectiveness and impact of the rates on an annual basis. If a member switches rates multiple times during the year they potentially run the risk of missing seasonal advantages or avoiding seasonal disadvantages associated with the rate selection. This one year commitment would also minimize the potential for members to 'game' the rates structures throughout the year.

As noted in the response to Item 17.a. of Staff's First Request, Owen is not proposing to require a written contract from members who wish to select one of the optional rates. We will be requesting a one-year commitment, for the reasons stated above, but if the member finds during that year that the rate option they have chosen does not meet their needs, the cooperative will work with the member to find an acceptable rate option and will allow the member to change. Owen is committed to providing the best customer service to its member/owners, and does not believe that requiring a contract with rigid terms is in the best interest of its membership.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Question:

Refer to the response to Item 19 of Staff's First Request. Confirm that during a higher usage month a customer switching to Schedule1-B1-Farm & Home-Time of Day tariff could receive a lower bill without shifting usage (the assumptions provided stated that no usage shift from peak to off-peak or –shoulder was assumed).

Response:

Yes, if a customer has usage which is higher than the average, the result is a lower bill. The TOD rate was calculated based an annual analysis not monthly. Therefore, during those shoulder months when usage is lower, the bill is slightly higher, thus balancing out to be revenue neutral over the year.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Refer to the response to Item 20 of Staff's First Request.

a. Question:

Confirm that, using the information provided for years 2012 through 2015, during a higher usage month a customer switching to Schedule 1-B2-Farm & Home- Time of Day tariff could receive a lower bill without shifting usage (the assumptions provided stated that no usage shift from peak to off-peak or –shoulder was assumed).

a. Response:

See response to Question 12.

b. Question:

Explain why the calculated B2 bills provided for 2011 are higher than those provided for 2012 through 2015.

b. Response:

For the 2001 B2 bill, there was an error in the calculation. The correct analysis is attached. The 2011 bill for B2 is revenue neutral.

OWEN ELE(` COOPERATIVE
CASE NO. 2011-00037

RESPONSE TO COMMISSION STAFF'S SECOND
INFORMATION REQUEST

	Current	Average use Proposed	B2
	$ 115.07		
2011		$ 115.07	$ 115.07
2012		$ 115.07	$ 115.07
2013		$ 115.06	$ 115.07
2014		$ 115.07	$ 115.07
2015		$ 115.07	$ 115.07

		2011			2012			2013		
	Avg Use	Current	Proposed	B2	Current	Proposed	B2	Current	Proposed	B2
Jan	1,618	$ 164.63	$ 162.86	$ 152.93	$ 164.63	$ 161.67	$ 152.93	$ 164.63	$ 160.47	$ 152.93
Feb	1,227	$ 127.59	$ 127.15	$ 122.24	$ 127.59	$ 126.85	$ 122.24	$ 127.59	$ 126.54	$ 122.24
Mar	1,040	$ 109.91	$ 110.09	$ 107.53	$ 109.91	$ 110.22	$ 107.53	$ 109.91	$ 110.34	$ 107.53
Apr	877	$ 94.39	$ 95.13	$ 94.90	$ 94.39	$ 95.63	$ 94.90	$ 94.39	$ 96.12	$ 94.90
May	838	$ 90.76	$ 91.63	$ 96.63	$ 90.76	$ 92.21	$ 96.63	$ 90.76	$ 92.79	$ 96.63
Jun	1,071	$ 112.83	$ 112.91	$ 118.28	$ 112.83	$ 112.97	$ 118.28	$ 112.83	$ 113.01	$ 118.28
Jul	1,027	$ 108.67	$ 108.89	$ 114.39	$ 108.67	$ 109.05	$ 114.39	$ 108.67	$ 109.20	$ 114.39
Aug	1,135	$ 118.92	$ 118.78	$ 124.36	$ 118.92	$ 118.69	$ 124.36	$ 118.92	$ 118.59	$ 124.36
Sep	875	$ 94.25	$ 94.99	$ 100.79	$ 94.25	$ 95.50	$ 100.79	$ 94.25	$ 95.99	$ 100.79
Oct	861	$ 92.93	$ 93.72	$ 93.91	$ 92.93	$ 94.26	$ 93.91	$ 92.93	$ 94.79	$ 93.91
Nov	1,011	$ 107.09	$ 107.38	$ 105.93	$ 107.09	$ 107.57	$ 105.93	$ 107.09	$ 107.76	$ 105.93
Dec	1,562	$ 159.34	$ 157.76	$ 149.30	$ 159.34	$ 156.70	$ 149.30	$ 159.34	$ 155.63	$ 149.30
Annual	1,095	$ 1,381.32	$ 1,381.29	$ 1,381.20	$ 1,381.32	$ 1,381.33	$ 1,381.20	$ 1,381.32	$ 1,381.23	$ 1,381.20

RESPONSE TO COMMISSION STAFF'S SECOND
INFORMATION REQUEST

2014			2015			
Current	Proposed	B2	Current	Proposed	B2	
$ 164.63	$ 159.28	$ 152.93	$ 164.63	$ 158.09	$ 152.93	Jan
$ 127.59	$ 126.24	$ 122.24	$ 127.59	$ 125.94	$ 122.24	Feb
$ 109.91	$ 110.46	$ 107.53	$ 109.91	$ 110.59	$ 107.53	Mar
$ 94.39	$ 96.63	$ 94.90	$ 94.39	$ 97.13	$ 94.90	Apr
$ 90.76	$ 93.38	$ 96.63	$ 90.76	$ 93.97	$ 96.63	May
$ 112.83	$ 113.07	$ 118.28	$ 112.83	$ 113.13	$ 118.28	Jun
$ 108.67	$ 109.36	$ 114.39	$ 108.67	$ 109.52	$ 114.39	Jul
$ 118.92	$ 118.50	$ 124.36	$ 118.92	$ 118.42	$ 124.36	Aug
$ 94.25	$ 96.50	$ 100.79	$ 94.25	$ 97.00	$ 100.79	Sep
$ 92.93	$ 95.32	$ 93.91	$ 92.93	$ 95.86	$ 93.91	Oct
$ 107.09	$ 107.95	$ 105.93	$ 107.09	$ 108.15	$ 105.93	Nov
$ 159.34	$ 154.57	$ 149.30	$ 159.34	$ 153.50	$ 149.30	Dec
$ 1,381.32	$ 1,381.26	$ 1,381.20	$ 1,381.32	$ 1,381.30	$ 1,381.20	Annual

RESPONSE TO COMMISSION STAFF'S SECOND
INFORMATION REQUEST

Steps:

To find the average annual bills:

Found average annual kWh by summing total res kWh and dividing by total res customers

Calculated the current bill by adding the customer charge to the product of the average kWh and current rate.

Calculated the proposed rate by adding the annual proposed customer charge to the product of the average kWh and proposed rate for each subsequent year.

Calculated the peak and off peak usage. This was done by summing the total use for the appropriate hours as seen in Exhibit 6 page 1 and dividing by total annual customers.

Calculated the B2 rate by adding the customer charge to the product of the peak kWh and peak rate and the product of the off-peak kWh and off peak rate.

These results assume no usage shift from peak to off peak or shoulder.

To find the monthly average bills:

The monthly average use for the current and proposed were found by summing the total hourly kwh for each month and then dividing by the monthly customers.

The monthly average use for the peak/off peak use was found by summing the monthly hourly data for each time period as seen in Exhibit 6 page 1 and then dividing by the monthly customers.

Calculated the current bill by adding the customer charge to the product of the monthly average kWh and current rate.

Calculated the proposed rate by adding the annual proposed customer charge to the product of the average monthly kWh and proposed rate for each subsequent year.

Calculated the B2 rate by adding the customer charge to the product of the peak kWh and peak rate and the product of the off-peak kWh and off peak rate.

These results assume no usage shift from peak to off peak or shoulder.

OWEN ELECTRIC COOPERATIVE
CASE NO 2011-00037
RESPONSE TO COMMISSION STAFF'S SECOND INFORMATION REQUEST

Question:

Refer to the response to Item 21 of Staff's First Request. Confirm that during a higher usage month a customer switching to Schedule 1-B3-Farm & Home- Time of Day tariff could receive a lower bill without shifting usage (the assumptions provided stated that no usage shift from peak to off-peak or –shoulder was assumed).

Response:

Please see response to Question 12.