This phenomenon was also observed in the comparison of six models for NEES, which was discussed above (Fig. 7).

Given this range in model performance, how might a utility seeking to maximize its allowed revenues in future years pick among these models? Table 9 shows that Model 4 yields the largest positive error of these eight models, a 5.1% overprediction of sales. Comparing the coefficients of this model with those of Model 8, the other log-log model, shows that Model 4 has a higher electricity-price coefficient and a lower industrial-output coefficient.

If the utility knew, in 1989, that industrial output would grow slowly during the next three years and that the mix of electricity sales would shift to the industrial sector (which pays a lower price than does the residential class), then the utility would pick Model 4 over Model 8. On the other hand, if the utility thought that the economy would grow rapidly and that the mix of sales would not change (or would shift to the residential sector), then it would want to use Model 8. Absent good information on such future trends, the utility has no basis for selecting one model over another.

One can pick any pair of models among these eight and go through the same type of exercise to show the difficulty of selecting a model to achieve a desired outcome. Consider Models 1 and 2 as another example. The state's consumer advocate might like a model that lowered the utility's authorized revenue. So it would prefer, after the fact, Model 1 to Model 2. But in 1989, how would it know whether the number of customers would grow slowly (in which case it would pick Model 2) or whether the summers would be especially hot and the winters unusually mild (in which case it would pick Model 1)? What would the consumer advocate do if it thought that the number of customers would grow slowly (which favors Model 2) *and* that the summers would be mild and the winters harsh (which favors Model 1)?

This examination of alternative models and their simulation results leads to three conclusions:

- It is very difficult — absent reliable information on future changes in the number of customers, the weather, and the economy — to select a model that will achieve a desired outcome. Thus, manipulation is not a problem with SR.

- The range in estimates across these models is quite small, which suggests that SR results are robust.

- The range in estimates increases from one year to the next, which suggests that these models should be re-estimated every few years.

EFFECTS OF PAST UTILITY DSM PROGRAMS

Because the models used in SR are based on historical data, they will automatically include the effects of any past load-building or energy-efficiency programs that the utility might have run. Will the effects of such past programs bias the estimates obtained with the statistical-recoupling models?

Hypothetical Example

To explore this issue, I used the data from PacifiCorp and added the effects of a hypothetical load-building program. This hypothetical program began in 1985, with a first quarter sales increase of 0.15%. The program continued unchanged with each quarter's load increment added to the cumulative effects of all past increments such that sales in 1989 were increased 2.5% because of these load-building efforts. By assumption, this program had no effect on the local economy (i.e., Utah industrial output).

I made two alternative assumptions for the 1990–1992 simulation period: (1) the utility continued its load-building program unchanged during these three years or (2) the utility stopped load-building programs at the end of 1989 (Fig. 9). In both cases, the effects of past load-building programs continued through the simulation period. I used the same linear model formulation of total electricity use shown in Table 6; the coefficients are different because of the load-building effects from 1985 through 1989.

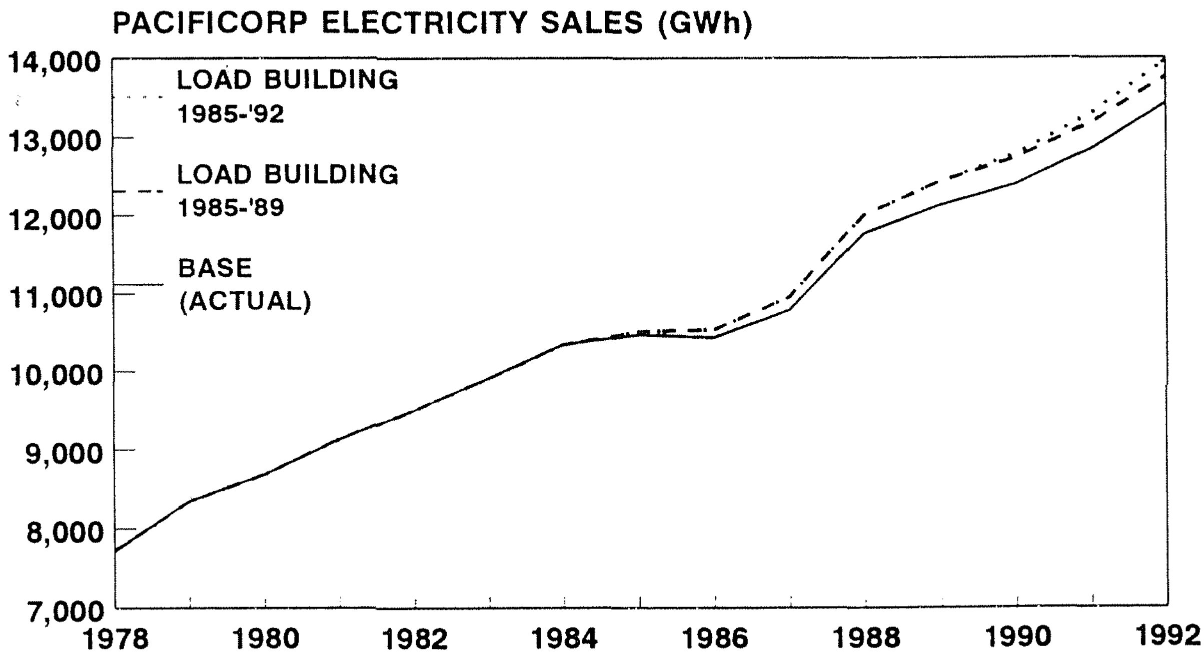

Fig. 9. PacifiCorp retail electricity sales for its Utah service area. The solid line is actual sales. The dashed line assumes that a load-building program was in operation from 1985 through 1989. The dotted line assumes that the load-building program continued to operate through 1992.

The simulation results for the case with continuation of load building are quite similar to those obtained with no load building (compare the first column in Table 9 with the first column in Table 10). However, the errors are consistently more positive for the case when load-building stops at the end of 1989. Over the three-year simulation period, the difference amounts to an extra 2.7% of sales if the utility had stopped its load-building programs at the end of 1989.

Table 10. Simulation errors obtained with a model of total PacifiCorp electricity use with a load-building program that was run from 1985 through either 1989 or 1992[a]

	Load building continued through 1992	Load building stopped in 1989
1990	1.7	2.1
1991	0.3	1.2
1992	-2.4	-1.0
Three-year error	-0.4	+2.3

[a]This load-building program, begun in 1985, increased sales by 2.5% in 1989. The difference between the two cases in 1992 was 1.5% of sales.

These results are expected. The model and its coefficients used to estimate electricity use for 1990, 1991, and 1992 are exactly the same in both cases. Therefore, the estimated results are the same in both cases. The errors are greater in the second case because the "actual" values of electricity use are lower when load building stops at the end of 1989.

These results show that SR overestimates allowed revenues if the utility had load-building programs that were discontinued at the start of the statistical-recoupling implementation period. The reverse is also true. If the utility had run energy-efficiency programs that were cancelled when SR was being implemented, the utility would under-recover. This error in SR may, fortuitously, lead to good policy. The error encourages utilities to stop load-building programs that do not promote economic growth and to continue energy-efficiency programs.

If the statistical models include explanatory variables that capture the effects of the utility's DSM programs (e.g., the utility's quarterly budget for load-building or energy-efficiency programs), this problem might not occur. However, the historical effects of utility DSM programs are likely to be small and difficult to capture in such a simple statistical model.

The practical issue is whether historical load-building programs that do not affect the local economy are likely to have a large enough effect on past and future electricity sales to have measurable effects. If the load-building programs were small, the bias in simulation results obtained with SR would, likewise, be small.

Analysis of Southern California Edison Data

Southern California Edison (1993) calculates, on a quarterly basis, what electricity sales would have been for each sector absent the effects of SCE conservation programs, mandatory appliance and building efficiency standards, and bypass. These adjustments increased from 4% of sales in 1980 to 15% in 1992. Thus, these data provide an opportunity to examine empirically the performance of SR when (1) a utility has DSM programs in place, (2) has estimates of the effects of these programs (as well as other factors) on electricity use, and (3) when the effect of these programs on sales is nontrivial.

I tested different specifications of a model of SCE retail electricity sales with and without a variable that is SCE's estimate of the change in sales caused by the factors listed above. The coefficients of this change variable were always statistically significant at the 99% level; the magnitude of this coefficient ranged from 0.6 to 1.1. A coefficient greater than 1.0 implies that the SCE estimates of the electricity savings caused by these factors was too low, a coefficient of 1.0 implies that the SCE estimates are exactly correct, and so on.

In most cases, the model that included this additional factor had more accurate estimates of actual sales for 1990, 1991, and 1992 than did the model without this variable (Table 11). However, the models that did not include this change variable also had very good predictive powers. So, even in a case where the adjustments are substantial (15% in 1992 for SCE), a model that ignores these effects can perform well.

Table 11. Performance of models of electricity sales for Southern California Edison with and without an explanatory variable for the effects of DSM and other factors

Variables in model	Number of explanatory variables	Number significant at 99%	R^2	Coefficient of estimated electricity savings	Three-year (1990–92) error (%)
Employment, CDD,	3	3	0.988	-	-1.4
and price	4	4	0.991	-1.3	-1.7
Unemployment, CDD,	3	2	0.990	-	-1.3
and price	4	4	0.993	-1.1	-0.6
Unemployment, CDD,	4	3	0.992	-	-1.5
HDD, and price	5	5	0.994	-1.1	-0.4

The statistical recoupling models all deal with electricity use and not demand (GWh and not MW). In addition, the aggregate models (which are simpler to estimate and which perform better than separate models for each customer class) include all customer classes in one equation.

These features of SR raise questions about its accuracy in estimating the net lost revenues associated with DSM programs if (1) these programs affect different customer classes differentially or (2) these programs have different effects on energy use and demand. To explore the performance of SR with different types of DSM programs, I created a hypothetical utility with three customer classes and the rate structures shown in Table 12.

Table 12. Rate structures and electricity use by customer class for a hypothetical utility

	Retail tariffs			Customers	Energy	Demand
	\$/month	¢/kWh	\$/kW-month	(thousands)	(GWh)	(MW)
Residential	5	6.8	0	900	6300	1438
Commercial	30	3.6	10	90	5400	1121
Industrial	150	2.5	8	5	6300	899
Totals	8	4.3	5.3	995	18000	3458

Typical of most utilities, this one has rate structures that differ substantially across customer classes. The residential customers pay no demand charge and have the highest average price (7.7¢/kWh). The commercial and industrial customers pay both energy and demand charges, with the industrial class paying less (leading to average prices of 6.7¢/kWh and 4.0¢/kWh for the commercial and industrial classes, respectively). The utility's total revenue is \$1.1 billion.

Differences in DSM Across Customer Classes

If this utility runs a set of DSM programs that reduce both energy and demand for each customer class by 1.0%, the net lost revenues total \$6.1 million (0.6% of revenue). If the utility's DSM programs, however, emphasize one class over the others, then SR based on an aggregate model will not appropriately compensate the utility for its net lost revenues (Table 13). For example, if the percentage savings from the industrial DSM programs are 50% more than the savings achieved by the residential and commercial programs, then SR will overcompensate the utility, awarding it the same \$6.1 million for its loss of \$5.6 million, a -0.04% error in total revenues. On the other hand, if the residential programs cut electricity use by 50% more than the commercial and industrial programs, then SR would undercompensate the utility, awarding it the same $6.1 million for its loss of $6.4 million, a +0.03% error in total revenues.

A DSM program aimed at only one customer class is the worst-case situation for SR (Table 13). An industrial-only program that cut aggregate energy and demand by the same 1% would result in $3.0 million of lost revenue. But the aggregate SR model would pay the utility $6.1 million, a -0.28% error in revenues. A DSM program that cut energy and demand by residential customers enough to save 1% overall would result in $8.3 million of lost revenue. Once again, the aggregate SR model would pay the utility $6.1 million, a +0.20% error in revenues. Thus, a utility operating under SR with an aggregate model would have an incentive to target industrial customers and neglect residential customers in its DSM programs.

Table 13. Comparison of DSM-induced net lost revenues and the amounts awarded by statistical recoupling[a]

	Net lost revenue (million $)	
	Actual	SR-aggregate[b]
Savings 50% higher in		
Residential class	6.4	6.1 (+0.03)
Commercial class	6.2	6.1 (+0.01)
Industrial class	5.6	6.1 (-0.04)
Savings only in		
Residential class	8.3	6.1 (+0.20)
Commercial class	7.0	6.1 (+0.09)
Industrial class	3.0	6.1 (-0.28)

[a]These cases all involve DSM programs that cut overall energy and demand by 1.0%. The numbers in parentheses are the percentage errors in the amounts of money awarded by the SR model relative to total revenues ($1,096 million).

[b]SR-aggregate refers to use of one statistical model that simulates electricity use for all three classes.

These cases of disproportionate DSM yield three conclusions:

- Use of an aggregate statistical model introduces some error into estimation of the amount of net lost revenues associated with DSM programs; use of statistical models for each customer class avoids this problem.

- The error caused by use of an aggregate model is small. Even in the worst possible situation (a DSM program aimed only at the industrial sector, where the lost revenues per kWh are the lowest), the amount of excess revenue granted the utility, while double the actual net lost revenues, is only 0.3% of total revenues.

- Therefore, states considering SR should either ensure roughly proportionate DSM across customer classes or use individual statistical models rather than the aggregate model.

Differences in Conservation Load Factors

DSM programs can also differ in their effects on customer energy use and peak demands. In the cases discussed above, energy and demand were always reduced by the same percentages, which assumes that the conservation load factor (CLF) is the same as the utility system's load factor.

However, DSM programs typically cut demand by a larger percentage than they cut energy use (i.e., the CLF is less than the system load factor). Consider a set of DSM programs that cut peak demands in each sector by 1% with different percentage reductions in energy use. Because residential customers pay no demand charge, actual net lost revenues equal those computed with SR models. For the commercial and industrial sectors, which pay both energy and demand charges, the SR models underestimate net lost revenues when the CLF of DSM programs is less than the system load factor (60% in this example).

The extent to which the SR models underestimate net lost revenues depends on (1) whether the DSM programs cut peak demands at the time of maximum customer demand (i.e., the relationship between coincident and noncoincident peaks), (2) any nonzero short-term avoided capacity costs, and (3) whether the utility's demand charge includes a ratchet.* In the following analysis, I assume a zero avoided capacity cost and ignore differences between the timing of DSM-program demand reductions and customer peaks; these assumptions represent a worst-case treatment of SR. I treat the monthly demand charge parametrically, with a full 12-month ratchet at one extreme and no ratchet at the other.

If the DSM programs cut demand by 1% and cut energy use by 0.5% (i.e., the CLF is half the system load factor), net lost revenues are $4.1 million with a 12-month ratchet and $3.1 million with no ratchet, but the SR model allows only $3.0 million (a -0.1% error in total revenues with the ratchet and a -0.01% error with no ratchet). Figure 10 shows how the SR-induced error varies with differences in the CLF of the utility's DSM programs. Unlike the situation with different DSM effects across customer classes, the two types of SR models, by class and aggregate, yield the same errors. This error occurs because the SR models estimate electricity sales (GWh) and are silent with respect to demand (MW). Therefore, changes in demand that do not affect sales have no effect on the amounts of net lost revenues estimated with SR models.

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*A demand ratchet has a demand charge ($/kW-month) based on the customer's highest demand during the past n months (where n is often 12), rather than the highest demand during the current month.

Figure 10 shows that the SR estimate of lost revenue is increasingly inaccurate as CLF gets smaller. With a 12-month demand ratchet and a CLF of 0.1, the actual revenues lost are almost triple that calculated by the SR method. With no demand ratchet, the actual revenues exceed the SR estimate by 15%. Figure 10 also shows the SR error as a percentage of total revenues. Because the amount of revenue lost is quite small for programs that save little energy per kW saved, these percentages are quite small. Even for DSM programs with a CLF of 0.1 and a 12-month ratchet, the SR-induced error is less than 0.2% of revenues.

For two reasons, the errors in allowed revenues calculated here are upper bounds. First, I assumed that there is no short-term capacity cost that can be avoided by DSM programs. Second, utility load-management programs typically focus on reducing demands at the time of system peak, which may not coincide with the times of customer peak demands; therefore, the net lost revenue associated with demand charges will be less than assumed here.

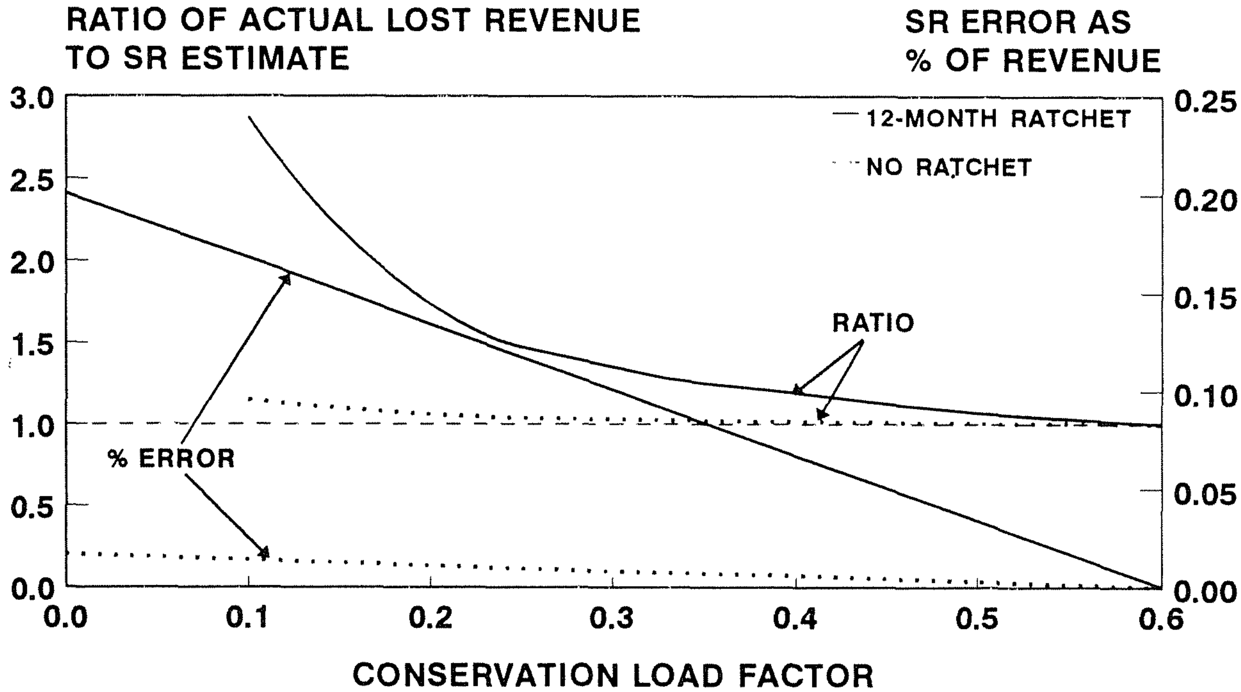

Fig. 10. Errors in the SR estimates of DSM-induced net lost revenue as functions of conservation load factor. (The system load factor is 0.60.) The graph shows two sets of curves, both with a 12-month ratchet and without a ratchet. The first set shows the ratio of actual lost revenues to the SR estimate, and the second set shows the SR error as a percentage of total revenues.

SHIFTS IN ELECTRICITY USE AMONG CUSTOMER CLASSES

As discussed above, the models of aggregate electricity use perform better than does the combination of models of each customer class. In addition, it takes less time and is simpler to estimate one model than to estimate separate models for the residential, commercial, and industrial classes.

Although the mix of electricity use and demand across sectors changes from year to year, SR based on an aggregate model should produce unbiased estimates of allowed revenue. The variables that capture electricity use, number of customers, and electricity price all account for changes in the mix of sales, customers, and revenues across customer classes. Also, the proportions of electricity sales by customer class change only slowly over time (Fig. 11). Therefore, any errors caused by aggregate SR are likely to be quite small.

Even in Massachusetts, where the economy has been poor during the past few years, the shifts in electricity sales among classes have been slight. Between 1988 and 1992, for example, the share of NEES, sales to the industrial sector declined from 27.6% to 25.7%, a two-percentage point change in four years.

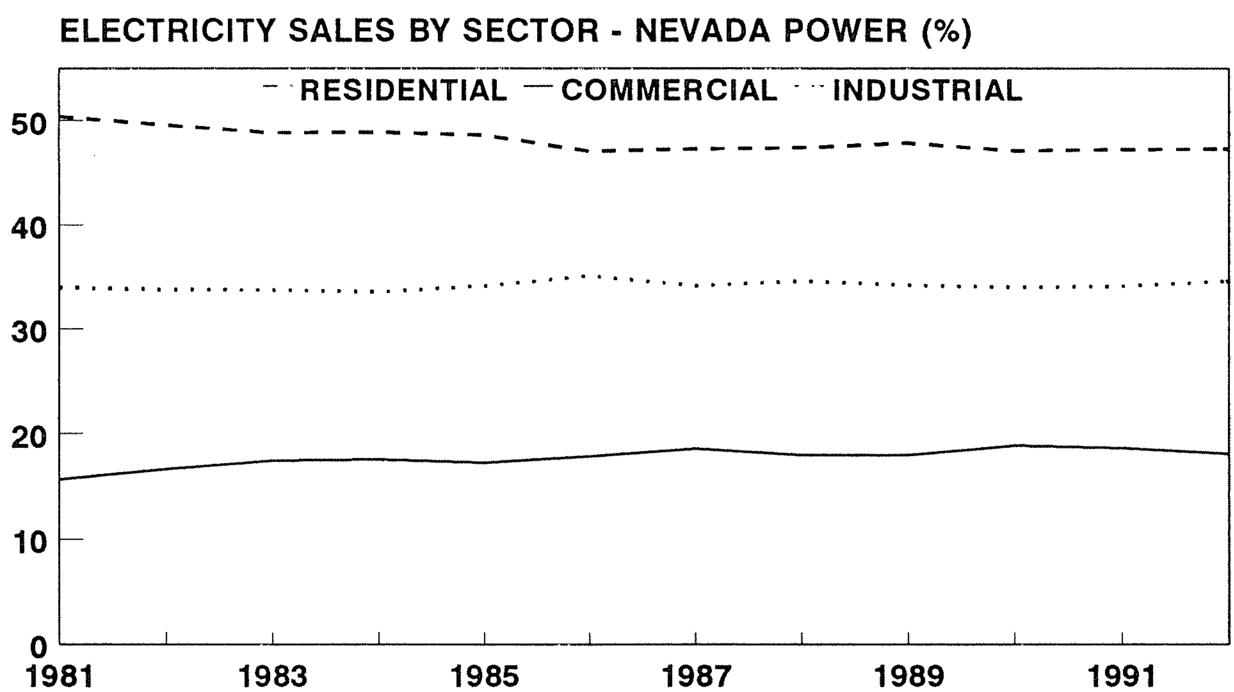

Fig. 11. The percentage contributions to total electricity sales by customer class for Nevada Power.

EXCLUSION OF SOME CUSTOMER CLASSES

In this analysis of data from five utilities, I estimated models for the same three major customer classes, residential, commercial, and industrial. What are the consequences of ignoring electricity sales and revenues for the other customer classes, including street and highway lighting, other public authorities, and railroads and railways?

National data (Edison Electric Institute 1992) show that the three major classes accounted for more than 95% of total retail electricity sales during the past decade. Of course, the contributions of these classes to total sales differ across utilities. Among the five in this sample, the three classes account for anywhere from 93 to 99% of total retail sales.

These data suggest that SR, based on inclusion of only the three major customer classes, can proceed in one of two ways. The utility can adjust electricity prices for all retail customer classes (including those excluded from the SR analysis), which will reduce slightly the SR-induced price changes. This approach makes sense if the utility's DSM programs affect these excluded customer classes. Alternatively, the utility could adjust electricity prices for only those classes that are explicitly included in the SR analysis. Because the three major customer classes account for such a large fraction of total retail sales, the difference between these two approaches is very small.

CONCLUSIONS

COMPARISON OF STATISTICAL RECOUPLING WITH OTHER MECHANISMS

Statistical recoupling is only one of several methods that can be used to remove the disincentives that utilities face, under current regulation, to implement energy-efficiency programs. These approaches include explicit net-lost-revenue adjustment mechanisms and three forms of decoupling. The decoupling mechanisms include ones that recouple revenues to the determinants of fixed costs (e.g., California's Electric Revenue Adjustment Mechanism), to growth in the number of customers (revenue-per-customer decoupling), or to the determinants of electricity sales (SR). Not surprisingly, these methods have different strengths and limitations (Table 14).

All four approaches remove the disincentive to utility promotion of improved customer energy efficiency. With an NLRA, a utility's shareholders are compensated for the between-rate-cases net lost revenues caused by the utility's DSM programs. With decoupling, utility revenues are independent of sales levels.

The three decoupling methods, but not NLRAs, remove the incentive to promote load growth. Whether utilities should be encouraged to build load is a controversial issue. Some argue that, in a competitive environment, the utility (like other private companies) should earn more money if it sells more of its product. Others believe that, as part of integrated resource planning, the utility should earn more money for implementing its preferred resource plan, which likely will include both demand and supply resources. SR compensates utility shareholders for load growth that is a consequence of economic growth but not for "undifferentiated" load growth.

One of the concerns raised with decoupling is that it allows the utility to become less competitive and to worry less about controlling costs, promoting economic development, and providing top-notch customer service. Because NLRAs are narrowly focused on DSM programs, such mechanisms have no effect on the utility's competitive behavior. In principle, the decoupling approaches, because they affect utility *revenues* rather than *earnings*, should not affect a utility's efforts to control costs. However, decoupling removes the incentive for load building, which removes the incentive for economic development that increases loads. Thus, utilities with ERAM or RPC decoupling might devote less effort to economic development in their service areas, although utilities with RPC decoupling have an incentive to add customers whose costs are less than that allowed in the RPC mechanism. SR, on the other hand, contains an explicit incentive for utilities to promote economic growth. This incentive is a consequence of the explanatory variable(s) used in the SR model(s) that capture local employment, industrial output, income, or gross state product.

Table 14. Comparison of alternative methods to treat DSM-induced net lost revenues

Criterion	NLRA	ERAM	RPC	SR	Current regulation
Removes disincentive to energy-efficiency programs	Yes	Yes	Yes	Yes	No
Removes incentive to build load	No	Yes	Yes	Yes	No
Retains utility incentives to					
- Control costs	Yes	Yes	Yes	Yes	Yes
- Promote economic development	Yes	No	Some	Yes	Yes
- Improve customer service	Yes	Yes	?	Yes	Yes
Simple to					
- Understand	No	No	Yes	No	Yes
- Administer	No	No	Yes	Yes	Yes
Difficult to manipulate	No	Yes	Yes	Yes	Yes
Minimizes volatility of electricity prices	Yes	No	No	Yes	Yes
Maintains current risk allocation between customers and utility	Yes	No	No	Yes	Yes

Because RPC decoupling pays the utility a fixed amount per customer, the utility may have no incentive to encourage growth in the number of large customers (i.e., those for whom the cost of service is above the average). Although there was no evidence of this phenomenon occurring in Maine or Washington, some customers are concerned about this disincentive. However, RPC decoupling could be implemented separately for each customer class. Because the concept of revenue *per customer* is not part of either ERAM or SR, there is no reason for a utility to pay less attention to its large commercial and industrial customers. Thus, service quality is no more, nor less, of a problem with ERAM or SR than it is with traditional regulation.

Establishing and overseeing an NLRA can be very time consuming and complicated. On the other hand, this effort to establish an adequate DSM-program monitoring and evaluation system is needed anyway for good program management, for regulatory oversight, and for resource planning. California's ERAM is also complicated. On the other hand, RPC decoupling is very simple. SR may be difficult to understand, but it is straightforward to design and implement. With RPC decoupling, it may be necessary to agree on an estimate of per-customer growth in electricity use (expressed in %/year). SR has no predetermined growth-rate factor that remains constant between rate cases.

One of the complications with an NLRA is the ease with which the utility can manipulate samples, data, analytical methods, and evaluation results. Because of the enormous information asymmetry between the utility and the PUC, monitoring the fairness of the NLRA's implementation can be difficult. The decoupling approaches are much less susceptible to manipulation.*

An NLRA, because of its narrow focus on DSM programs, will have minimal effects on electricity prices. ERAM and RPC decoupling can lead to larger swings in prices. SR, because it seeks to mimic closely current regulation, should have only small year-to-year changes in electricity prices. However, SR relies on the accuracy of statistical models that are based on historical data. To the extent that the future is different from the past, SR will lead to errors in the amounts of money transferred to or from the utility. Thus, SR is vulnerable to major structural shifts in energy demand (e.g., tough new building or appliance standards or a new electrotechnology that sweeps the market).

ERAM and RPC decoupling transfer some risks from the utility to customers, those associated with sales fluctuations caused by changes in the weather and the economy. NLRA mechanisms shift DSM-program performance risks from a utility to its customers. The risks associated with weather and the economy remain with the utility under SR. With SR, customers bear the risk only for changes in revenues associated with those factors that affect sales and are not appropriately included in the SR equations.

In summary, statistical recoupling is similar to other forms of decoupling in that it eliminates the between-rate-cases incentive to build load and the disincentive to run energy-efficiency programs. However, SR does not shift the revenue and price risks associated with weather and economic changes from utilities to customers. Thus, SR is likely to involve much smaller price changes than do other types of decoupling.

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*Three reviewers of this report believe that development of the models for statistical recoupling will be contentious because people will assume that these models can be manipulated. Because the amounts of money at stake are large relative to earnings (although very small compared to revenues), they think that smart analysts will find ways to manipulate the models. These people were not convinced by the examples summarized in Table 9 and Fig. 8.

FINAL THOUGHTS

Whether or not SR is a good idea depends on two key factors. First, one has to believe that electric utilities can and should play a major role in helping their customers improve efficiency of electricity use. Second, one must believe that the between-rate-cases disincentive to DSM in current regulation is an important deterrent to aggressive and innovative utility DSM programs.

Acceptance of these two propositions leads to a commitment to remove from regulation the incentives for load growth and the disincentives for energy efficiency. As discussed here, utilities and regulatory commissions have several options to choose from in addressing this problem. These options include net-lost-revenue adjustments, various forms of decoupling, annual rate cases, alternative rate designs, and command-and-control regulation.

Compared with other approaches, SR offers important advantages. Its key strength is its ability to break the link between electric revenues and sales with minimal deviations from current ratemaking. In particular, SR shifts few risks from utilities to customers; therefore, the price swings caused by SR should be less than those caused by other decoupling approaches. SR should be easy to design and implement, primarily because it uses the same data and analytical techniques that utilities have used for years in developing short-term forecasting models. SR should be simple for regulators to oversee because its application is uncomplicated and it is difficult to manipulate the system. SR should serve utilities and their customers well in an era of increasing competition because SR retains an incentive for utilities to promote local economic growth. The major uncertainty with SR is the possibility that the determinants of electricity use will be different during the application period than during the historical period on which the models were based. If the structure of electricity use changes dramatically during the few years that SR is applied, then this approach could lead to nontrivial price changes.

On balance, statistical recoupling offers much potential to completely break the link between revenues and sales and therefore to free utilities to run ambitious and creative DSM programs. Statistical recoupling is easy to design, implement, and oversee; it should yield only small (much less than 2%/year) changes in electricity price; and it retains the traditional incentives for utilities to control costs, promote economic development, and improve customer service.

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ALTERNATIVE MODELS OF TOTAL ELECTRICITY USE FOR PACIFICORP

The models summarized in Table 9 and Fig. 8 are presented below. These tables are the outputs from Forecast Pro, the software used to estimate these time-series models. CTOT is the number of customers, PTOT is the average retail electricity price in real (1987) dollars, HDD and CDD are heating and cooling degree days, INDOUT is Utah industrial output, EMPMFG is manufacturing employment in Utah, _CONST is the constant term, _AUTO[-1] is the first-order autoregressive term, and Ln refers to the logarithmic form of the variable. R-square and Adjusted R-square show the percentage of variation explained by the model. BIC is the Bayes information criterion. The Durbin-Watson d-statistic and the Ljung-Box test check for autocorrelation in the residual terms. MAPE is the mean absolute percentage error. And RMSE is the root-mean-squared error.

1. Forecast Model: Total Utah Sales (GWh)

Term	Coefficient	Standard error	t-statistic	Significance
CTOT	0.006603	0.001354	4.875088	0.999982
PTOT	-61.723168	31.555730	-1.956005	0.942527
HDD	0.113035	0.013195	8.566718	1.000000
CDD	0.346906	0.035360	9.810710	1.000000
INDOUT	176.921646	111.595417	1.585385	0.879246
_CONST	-563.573372	334.283099	-1.685916	0.900402
_AUTO[- 1]	0.415613	0.148275	2.802979	0.992229

Sample size 47	Number of parameters 7
Mean 2496	Standard deviation 326.9
R-square 0.968	Adjusted R-square 0.9632
Durbin-Watson 1.981	Ljung-Box(18)=19.99 P=0.6664
Forecast error 62.69	BIC 77.04
MAPE 0.01869	RMSE 57.83

Three-year simulation errors

1990	+1.7%	
1991	+0.7%	
1992	-1.9%	Total error = 0.5%

2. Forecast Model: Total Utah Sales (GWh)

Term	Coefficient	Standard error	t-statistic	Significance
CTOT	0.007429	0.000649	11.440181	1.000000
PTOT	-69.018620	23.089086	-2.989231	0.995235
HDD	0.112369	0.013876	8.098222	1.000000
CDD	0.349962	0.037579	9.312740	1.000000
EMPMFG	8.787764	3.887644	2.260434	0.970693
_CONST	-1351.119893	276.522568	-4.886111	0.999983
_AUTO[- 1]	0.275579	0.161422	1.707200	0.904463

Sample size 47
Mean 2496
R-square 0.9698
Durbin-Watson 1.921
Forecast error 60.88
MAPE 0.01841

Number of parameters 7
Standard deviation 326.9
Adjusted R-square 0.9653
Ljung-Box(18)=21.34 P=0.7373
BIC 74.81
RMSE 56.16

Three-year simulation errors

1990	+2.8%	
1991	+1.4%	
1992	-2.0%	Total error = 2.2%

3. Forecast Model: Total Utah Sales (GWh)

Term	Coefficient	Standard error	t-statistic	Significance
CTOT	0.007213	0.000944	7.636736	1.000000
PTOT	-62.397034	30.292397	-2.059825	0.954037
HDD	0.113102	0.013115	8.623676	1.000000
CDD	0.346624	0.035132	9.866210	1.000000
INDOUT/CTOT	86.535951	50.657948	1.708240	0.904658
_CONST	-861.035894	255.838531	-3.365544	0.998304
_AUTO[- 1]	0.417843	0.148038	2.822545	0.992613

Sample size 47
Mean 2496
R-square 0.9683
Durbin-Watson 1.985
Forecast error 62.4
MAPE 0.01858

Number of parameters 7
Standard deviation 326.9
Adjusted R-square 0.9636
Ljung-Box(18)=20.31 P=0.6844
BIC 76.68
RMSE 57.56

Three-year simulation errors

1990	+1.6%	
1991	+0.5%	
1992	-2.2%	Total error = 0.1%

4. Forecast Model: Total Utah Sales (GWh) (Log transform)

Term	Coefficient	Standard error	t-statistic	Significance
Ln(CTOT)	1.238864	0.213670	5.798027	0.999999
Ln(PTOT)	-0.153025	0.069808	-2.192072	0.965745
HDD	0.000047	0.000005	8.540861	1.000000
CDD	0.000142	0.000015	9.663676	1.000000
Ln(INDOUT)	0.102805	0.077822	1.321033	0.806002
_CONST	-8.148596	2.663202	-3.059699	0.996056
_AUTO[- 1]	0.370750	0.152165	2.436505	0.980625

Sample size 47 Number of parameters 7
Mean 7.814 Standard deviation 0.1328
R-square 0.9686 Adjusted R-square 0.9639
Durbin-Watson 1.983 Ljung-Box(18)=17.57 P=0.516
Forecast error 0.02522 BIC 76.72
MAPE 0.01915 RMSE 58.61

Three-year simulation errors
1990 +2.7%
1991 +2.3%
1992 +0.1% Total error = 5.1%

5. Forecast Model: Total Utah Sales per Customer (kWh)

Term	Coefficient	Standard error	t-statistic	Significance
PTOT	-94.840847	64.463149	-1.471241	0.851140
HDD	0.262514	0.028798	9.115726	1.000000
CDD	0.793193	0.076713	10.339750	1.000000
INDOUT	560.396888	100.023316	5.602663	0.999998
_CONST	4699.238795	510.335709	9.208132	1.000000
_AUTO[- 1]	0.492139	0.140957	3.491423	0.998835

Sample size 47 Number of parameters 6
Mean 5707 Standard deviation 350.8
R-square 0.8512 Adjusted R-square 0.833
Durbin-Watson 2.059 Ljung-Box(18)=20.77 P=0.7086
Forecast error 143.3 BIC 171.2
MAPE 0.01933 RMSE 133.9

Three-year simulation errors
1990 +2.0%
1991 +0.9%
1992 -1.5% Total error = 1.4%

6. Forecast Model: Total Utah Sales per Customer (kWh)

Term	Coefficient	Standard error	t-statistic	Significance
PTOT	-77.908581	63.924633	-1.218757	0.770097
HDD	0.260320	0.030097	8.649273	1.000000
CDD	0.790214	0.080359	9.833496	1.000000
EMPMFG	38.238323	7.111025	5.377329	0.999997
_CONST	2137.989280	886.464513	2.411816	0.979565
_AUTO[- 1]	0.465573	0.145612	3.197345	0.997328

Sample size 47
Mean 5707
R-square 0.8421
Durbin-Watson 2.001
Forecast error 147.7
MAPE 0.02031

Number of parameters 6
Standard deviation 350.8
Adjusted R-square 0.8228
Ljung-Box(18)=18.96 P=0.6057
BIC 176.3
RMSE 137.9

Three-year simulation errors

1990 +2.6%
1991 +0.4%
1992 -3.9% Total error = -0.9%

7. Forecast Model: Total Utah Sales per Customer (kWh)

Term	Coefficient	Standard error	t-statistic	Significance
PTOT	-87.482583	77.156850	-1.133828	0.736547
HDD	0.265101	0.027561	9.618740	1.000000
CDD	0.788912	0.073277	10.766149	1.000000
INDOUT/CTOT	351.254641	78.939624	4.449662	0.999935
_CONST	4215.013094	710.312774	5.934024	0.999999
_AUTO[- 1]	0.586401	0.131043	4.474858	0.999940

Sample size 47
Mean 5707
R-square 0.8485
Durbin-Watson 2.157
Forecast error 144.6
MAPE 0.01923

Number of parameters 6
Standard deviation 350.8
Adjusted R-square 0.83
Ljung-Box(18)=22.25 P=0.7791
BIC 172.7
RMSE 135.1

Three-year simulation errors

1990 +1.6%
1991 +0.1%
1992 -2.4% Total error = -0.7%

8. Forecast Model: Total Utah Sales per Customer (kWh) (Log transform)

Term	Coefficient	Standard error	t-statistic	Significance
Ln(PTOT)	-0.118210	0.066328	-1.782202	0.917877
HDD	0.000047	0.000005	9.028772	1.000000
CDD	0.000140	0.000014	10.158988	1.000000
Ln(INDOUT)	0.184214	0.031288	5.887621	0.999999
_CONST	8.655771	0.129577	66.800403	1.000000
_AUTO[- 1]	0.461057	0.143213	3.219389	0.997486

Sample size 47
Number of parameters 6
Mean 8.648
Standard deviation 0.06107
R-square 0.8485
Adjusted R-square 0.8301
Durbin-Watson 2.074
Ljung-Box(18)=20.39 P=0.6886
Forecast error 0.02518
BIC 171.3
MAPE 0.01931
RMSE 133.4

Three-year simulation errors

1990	+2.2%	
1991	+1.3%	
1992	-2.1%	Total error = 1.4%

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DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

PSC STAFF'S FIRST DATA REQUEST DATED JULY 25, 2007

RESPONSIBLE PERSON: Geoffrey M. Young

Request 6.

Refer to the Young Testimony, page 22 of 41. Mr. Young states that "Statistical recoupling appears to be the decoupling approach that would be most beneficial for Kentucky."

Request 6a.

Is Mr. Young's conclusion based solely on the articles he has referenced in his testimony? Explain the response.

Response 6a.

No. In addition to the articles cited in my testimony, I have thought about the problem of perverse financial incentives for many years now. I have not seen or heard about a ratemaking approach that succeeds in decoupling revenue from sales yet at the same time creates as few unintended side effects as does SR.

Request 6b.

Has Mr. Young any personal experience in the development or application of the statistical models or formulas required under the statistical recoupling approach? If yes, describe Mr. Young's experience.

Response 6b.

I have taken a couple of Econometrics courses during my academic years and developed some regression models for course assignments. The implementation-related concepts and issues that Eric Hirst discussed in his report are not particularly daunting. If the Commission were to adopt the particular SR model provided in response to request 9c below, which was based on the model Hirst described in Chapter 6 of his report, the only remaining tasks would be to obtain quarterly data for the pertinent variables for the past 15 years and run the regression. The Commission might find it preferable, however, to follow the suggestion Eric Hirst made at the beginning of Chapter 6 (page 33). "Implementation involves two steps," he wrote. "In the first step, the utility, working with other interested parties, develops alternative statistical models. After review of these models, the company and other parties agree on a particular model to use, subject to approval by the public utilities commission (PUC)... The second step involves application of the model to compute allowed sales and revenues..."

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

PSC STAFF'S FIRST DATA REQUEST DATED JULY 25, 2007

RESPONSIBLE PERSON: Geoffrey M. Young

Request 7.

Refer to the Young Testimony, page 22 of 41. Mr. Young states that as a not-for-profit cooperative, EKPC can return excess net income to its customers and has done so in the past. Specifically identify when EKPC has previously returned excess net income to its customers.

Response 7.

I was thinking of the year 1995, when EKPC lowered its rates to its member cooperatives, thereby returning excess net income to its customers. However, that event came about through a general rate case and was not an example of the generation and transmission (G&T) cooperative returning excess net income to its member cooperatives on a one-time basis. My statement at page 22, line 15 was apparently not well founded. Although EKPC may have made such distributions in the past, as its bylaws allow, I am unable to specify when it may have occurred. I believe, however, that my basic point is still valid – that there is virtually no likelihood that the implementation of SR will lead to massive "over-recovery" of revenue by EKPC.

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

PSC STAFF'S FIRST DATA REQUEST DATED JULY 25, 2007

RESPONSIBLE PERSON: Geoffrey M. Young

Request 8.

Refer to the Young Testimony, pages 23 and 24 of 41. Explain the methodology of the measurement and verification protocols.

Response 8.

The complete manual is available at the following web site:

http://www.eere.energy.gov/buildings/info/documents/pdfs/29564.pdf

A copy of the first 8 pages of Chapter 3, Basic Concepts and Methodology, is provided below.

Chapter 3 Basic Concepts and Methodology

3.1 Introduction

Energy or demand savings are determined by comparing measured energy use or demand before and after implementation of an energy savings program. In general:

$$\text{Energy Savings} = \text{Baseyear Energy Use} - \text{Post-Retrofit Energy Use} \pm \text{Adjustments} \qquad \textbf{Eq. 1}$$

The "Adjustments" term in this general equation brings energy use in the two time periods to the same set of conditions. Conditions commonly affecting energy use are weather, occupancy, plant throughput, and equipment operations required by these conditions. Adjustments may be positive or negative.

Adjustments are derived from identifiable physical facts. The adjustments are made either routinely such as for weather changes, or as necessary such as when a second shift is added, occupants are added to the space, or increased usage of electrical equipment in the building.

Adjustments are commonly made to restate baseyear energy use under post-retrofit conditions. Such adjustment process yields savings which are often described as "avoided energy use" of the post-retrofit period. The level of such savings are dependent on post-retrofit period operating conditions.

Adjustments may also be made to an agreed fixed set of conditions such as those of the baseyear or some other period. The level of savings computed in this situation is unaffected by post-retrofit period conditions, but reflects operation under a set of conditions which must be established in advance.

There are many other considerations and choices to make in determining savings. Chapter 3.4 describes four basic Options, any one of which may be adapted to a particular savings determination task. Chapter 4 gives guidance on common issues such as balancing costs and accuracy with the value of the energy savings program being evaluated. Chapter 5 reviews metering and instrumentation issues.

3.2 Basic Approach

Proper savings determination is a necessary part of good design of the savings program itself. Therefore the basic approach in savings determination is closely linked with some elements of program design. The basic approach common to all good savings determination entails the following steps:

1 Select the IPMVP Option (see Chapter 3.4) that is consistent with the intended scope of the project, and determine whether adjustment will be made to post-retrofit conditions or to some other set of conditions. (These fundamental decisions may be written into the terms of an energy performance contract.)

2 Gather relevant energy and operating data from the baseyear and record it in a way that can be accessed in the future.

3 Design the energy savings program. This design should include documentation of both the design intent and methods to be used for demonstrating achievement of the design intent.

4 Prepare a Measurement Plan, and a Verification Plan if necessary, (commonly together called an "M&V Plan"). The M&V Plan fundamentally defines the meaning of the word "savings" for each project. It will contain the results of steps 1 through 3 above, and will define the subsequent steps 5 through 8 (see Chapter 3.3).

5 Design, install and test any special measurement equipment needed under the M&V Plan.

6 After the energy savings program is implemented, inspect the installed equipment and revised operating procedures to ensure that they conform with the design intent defined in step 3. This process is commonly called "commissioning." ASHRAE defines good practice in commissioning most building modifications (ASHRAE 1996).

7 Gather energy and operating data from the post-retrofit period, consistent with that of the baseyear and as defined in the M&V Plan. The inspections needed for gathering these data should include periodic repetition of commissioning activities to ensure equipment is functioning as planned.

8 Compute and report savings in accordance with the M&V Plan.

Steps 7 and 8 are repeated periodically when a savings report is needed.

Savings are deemed to be statistically valid if the result of equation (1) is greater than the expected variances (noise) in the baseyear data. Chapter 4.2 discusses some methods of assessing this noise level. If noise is excessive, the unexplained random behavior of the facility is high and the resultant savings determination is unreliable. Where this criterion is not expected to be met, consideration should be given to using more independent variables in the model, or selecting an IPMVP Option that is less affected by unknown variables.

The balance of this document fleshes out some key details of this basic approach to determining savings.

Once a savings report has been prepared, a third party may verify that it complies with the M&V Plan. This third party should also verify that the M&V Plan itself is consistent with the objectives of the project.

3.3 M&V Plan

The preparation of an M&V Plan is central to proper savings determination and the basis for verification. Advance planning ensures that all data needed for proper savings determination will be available after implementation of the energy savings program, within an acceptable budget.

Data from the baseyear and details of the ECMs may be lost over time. Therefore it is important to properly record them for future reference, should conditions change or ECMs fail. Documentation should be prepared in a fashion that is easily accessed by verifiers and other persons not involved in its development, since several years may pass before these data are needed.

An M&V Plan should include:

- A description of the ECM and its intended result.
- Identification of the boundaries of the savings determination. The boundaries may be as narrow as the flow of energy through a pipe or wire, or as broad as the total energy use of one or many buildings. The nature of any energy effects beyond the boundaries should be described and their possible impacts estimated.
- Documentation of the facility's *baseyear conditions* and resultant *baseyear energy data*. In performance contracts, baseyear energy use and baseyear conditions may be defined by either the owner or the ESCO, providing the other party is given adequate opportunity to verify it. A preliminary energy audit used for establishing the objectives of a savings program or terms of an energy performance contract is typically not adequate for planning M&V activities. Usually a more comprehensive audit is required to gather the baseyear information relevant to M&V:
  - — energy consumption and demand profiles
  - — occupancy type, density and periods
  - — space conditions or plant throughput for each operating period and season. (For example in a building this would include light level and color, space temperature humidity and ventilation. An assessment of thermal comfort and/or indoor air quality (IAQ) may also prove useful in cases where the new system does not perform as well as the old inefficient system. See Volume II.)
  - — equipment inventory: nameplate data, location, condition. Photographs or videotapes are effective ways to record equipment condition.
  - — equipment operating practices (schedules and setpoint, actual temperatures/pressures)
  - — significant equipment problems or outages.

  The extent of the information to be recorded is determined by the boundaries or scope of the savings determination. The baseyear documentation typically requires well documented audits, surveys, inspections and/or spot or short-term metering activities. Where whole building Option is employed (Chapter 3.4.3 or Chapter 3.4.4), all building equipment and conditions should be documented.
- Identification of any planned changes to conditions of the baseyear, such as night time temperatures.
- Identification of the post-retrofit period. This period may be as short as a one minute test following commissioning of an ECM, or as long as the time required to recover the investment cost of the ECM program.
- Establishment of the set of conditions to which all energy measurements will be adjusted. The conditions may be those of the post-retrofit period or some other set of fixed conditions. As discussed in the introductory remarks of Chapter 3, this choice determines whether reported savings are "avoided costs" or energy reductions under defined conditions.
- Documentation of the design intent of the ECM(s) and the commissioning procedures that will be used to verify successful implementation of each ECM.

- Specification of which Option from Chapter 3.4 will be used to determine savings.
- Specification of the exact data analysis procedures, algorithms and assumptions. For each mathematical model used, report all of its terms and the range of independent variables over which it is valid.
- Specification of the metering points, period(s) of metering, meter characteristics, meter reading and witnessing protocol, meter commissioning procedure, routine calibration process and method of dealing with lost data.
- For Option A, report the values to be used for any stipulated parameters. Show the overall significance of these parameters to the total expected saving and describe the uncertainty inherent in the stipulation.
- For Option D, report the name and version number of the simulation software to be used. Provide a paper and electronic copy of the input files, output files, and reference the weather files used for the simulation, noting which input parameters were measured and which assumed. Describe the process of obtaining any measured data. Report the accuracy with which the simulation results match the energy use data used for calibration.
- Specification of quality assurance procedures.
- Quantification of the expected accuracy associated with the measurement, data capture and analysis. Also describe qualitatively the expected impact of factors affecting the accuracy of results but which cannot be quantified.
- Specification of how results will be reported and documented. A sample of each report should be included.
- Specification of the data that will be available for another party to verify reported savings, if needed.
- Where the nature of future changes can be anticipated, methods for making the relevant non-routine *Baseline Adjustments*[1] should be defined.
- Definition of the budget and resource requirements for the savings determination, both initial setup costs and ongoing costs throughout the post-retrofit period.

When planning a savings measurement process, it is helpful to consider the nature of the facility's energy use pattern, and the ECM s impacts thereon. Consideration of the amount of variation in energy patterns and the change needing to be assessed will help to establish the amount of effort needed to determine savings. The following three examples show the range of scenarios that may arise.

- **ECM reduces a constant load without changing its operating hours.** Example: Lighting project where lamps and ballasts in an office building are changed, but the operating hours of the lights do not change.
- **ECM reduces operating hours while load is unchanged.** Example: Automatic controls shut down air handling equipment or lighting during unoccupied periods.

1. The terms in italics are defined in Chapter 6.1

- **ECM reduces both equipment load and operating hours.** Example: Resetting of temperature on hot water radiation system reduces overheating, thereby reducing boiler load and operating periods.

Generally, conditions of variable load or variable operating hours require more rigorous measurement and computation procedures.

It is important to realistically anticipate costs and effort associated with completing metering and data analysis activities. Time and budget requirements are often underestimated leading to incomplete data collection. It is better to complete a less accurate and less expensive savings determination than to have an incomplete or poorly done, yet theoretically more accurate determination that requires substantially more resources, experience and/or budget than available. Chapter 4.11 addresses cost/benefit tradeoffs.

Typical contents of four M&V Plans are outlined in the four examples shown in Appendix A.

3.4 Methods

The Energy Use quantities in Equation 1 can be "measured" by one or more of the following techniques:

- Utility or fuel supplier invoices or meter readings.
- Special meters isolating a retrofit or portion of a facility from the rest of the facility. Measurements may be periodic for short intervals, or continuous throughout the post-retrofit period.
- Separate measurements of parameters used in computing energy use. For example, equipment operating parameters of electrical load and operating hours can be measured separately and factored together to compute the equipment's energy use.
- Computer simulation which is calibrated to some actual performance data for the system or facility being modeled, e.g., DOE-2 analysis for buildings.
- Agreed assumptions or stipulations of ECM parameters that are well known. The boundaries of the savings determination, the responsibilities of the parties involved in project implementation, and the significance of possible assumption error will determine where assumptions can reasonably replace actual measurement. For example, in an ECM involving the installation of more efficient light fixtures without changing lighting periods, savings can be determined by simply metering the lighting circuit power draw before and after retrofit while assuming the circuit operates for an agreed period of time. This example involves stipulation of operating periods, while equipment performance is measured.

The Adjustments term in equation (1) can be of two different types:

- **Routine** Adjustments for changes in parameters that can be expected to happen throughout the post-retrofit period and for which a relationship with energy use/demand can be identified. These changes are often seasonal or cyclical, such as weather or occupancy variations. This protocol defines four basic Options for deriving routine adjustments. Table 1 summarizes the various Options.

- **Non-routine** Adjustments for changes in parameters which cannot be predicted and for which a significant impact on energy use/demand is expected. Non-routine adjustments should be based on known and agreed changes to the facility. Chapter 4.8 presents a general approach for handling non-routine adjustments, commonly called "baseline adjustments.

Table 1: Overview of M&V Options

M&V Option	How Savings Are Calculated	Typical Applications
A. Partially Measured Retrofit Isolation Savings are determined by partial field measurement of the energy use of the system(s) to which an ECM was applied, separate from the energy use of the rest of the facility. Measurements may be either short-term or continuous. Partial measurement means that some but not all parameter(s) may be stipulated, if the total impact of possible stipulation error(s) is not significant to the resultant savings. Careful review of ECM design and installation will ensure that stipulated values fairly represent the probable actual value. Stipulations should be shown in the M&V Plan along with analysis of the significance of the error they may introduce.	Engineering calculations using short term or continuous post-retrofit measurements and stipulations.	Lighting retrofit where power draw is measured periodically. Operating hours of the lights are assumed to be one half hour per day longer than store open hours.
B. Retrofit Isolation Savings are determined by field measurement of the energy use of the systems to which the ECM was applied, separate from the energy use of the rest of the facility. Short-term or continuous measurements are taken throughout the post-retrofit period.	Engineering calculations using short term or continuous measurements	Application of controls to vary the load on a constant speed pump using a variable speed drive. Electricity use is measured by a kWh meter installed on the electrical supply to the pump motor. In the baseyear this meter is in place for a week to verify constant loading. The meter is in place throughout the post-retrofit period to track variations in energy use.
C. Whole Facility Savings are determined by measuring energy use at the whole facility level. Short-term or continuous measurements are taken throughout the post-retrofit period.	Analysis of whole facility utility meter or sub-meter data using techniques from simple comparison to regression analysis.	Multifaceted energy management program affecting many systems in a building. Energy use is measured by the gas and electric utility meters for a twelve month baseyear period and throughout the post-retrofit period.
D. Calibrated Simulation Savings are determined through simulation of the energy use of components or the whole facility. Simulation routines must be demonstrated to adequately model actual energy performance measured in the facility. This option usually requires considerable skill in calibrated simulation.	Energy use simulation, calibrated with hourly or monthly utility billing data and/or end-use metering.	Multifaceted energy management program affecting many systems in a building but where no baseyear data are available. Post-retrofit period energy use is measured by the gas and electric utility meters. Baseyear energy use is determined by simulation using a model calibrated by the post-retrofit period utility data.

Options A and B focus on the performance of specific ECMs. They involve measuring the energy use of systems affected by each ECM separate from that of the rest of the facility. Option C assesses the energy savings at the whole facility level. Option D is based on simulations of the energy performance of equipment or whole facilities to enable determination of savings when baseyear or post-retrofit data are unreliable or unavailable.

An example of the use of each of the four Options is contained in Appendix A.

3.4.1 Option A: Partially Measured Retrofit Isolation

Option A involves isolation of the energy use of the equipment affected by an ECM from the energy use of the rest of the facility. Measurement equipment is used to isolate all relevant energy flows in the pre-retrofit and post-retrofit periods. Only partial measurement is used under Option A, with some parameter(s) being stipulated rather than measured. However such stipulation can only be made where it can be shown that the combined impact of the plausible errors from all such stipulations will not significantly affect overall reported savings.

3.4.1.1 Option A: Isolation Metering

Measurement equipment must be used to isolate the energy use of the equipment affected by the ECM from the energy use of the rest of the facility. The isolation metering should reflect the boundary between equipment which the ECM affects and that which it does not affect. For example, a lighting load reduction often has a related impact on HVAC system energy use, but the boundary for measurement may be defined to encompass only the lighting electricity. However if the boundary of the savings determination encompasses HVAC effects, measurement or stipulation will be required for both the lighting and HVAC energy flows.

Chapter 5 discusses metering issues.

3.4.1.2 Option A: Measurement vs. Stipulation

Some, but not all parameters of energy use may be stipulated under Option A. The decision of which parameters to measure and which to stipulate should consider the significance of the impact of all such stipulations on the overall reported savings. The stipulated values and analysis of their significance should be included in the M&V Plan (See Chapter 3.2).

Stipulation may be based on historical data, such as recorded operating hours from the baseyear. Wherever a parameter is not measured in the facility for the baseyear or post-retrofit period it should be treated as a stipulated value and the impact of possible error in the stipulation assessed relative to the expected savings.

Engineering estimates or mathematical modeling may be used to assess the significance of stipulation of any parameter in the reported savings. For example if a piece of equipment's operating hours are considered for stipulation, but may be between 2,100 and 2,300 hours per year, the estimated savings at 2,100 and 2,300 hours should be computed and the difference evaluated for its significance to the expected savings. The impact of all such possible stipulations should be totaled before determining whether sufficient measurement is in place.

The selection of factor(s) to measure may also be considered relative to the duties of a contractor undertaking some ECM performance risk. Where a factor is significant to assessing a contractor's performance, it should be measured, while other factors beyond the ESCO's control should be considered for stipulation.

3.4.1.3 Installation Verification

Since stipulation is allowed under this Option, great care is needed to review the engineering design and installation to ensure that the stipulations are realistic and achievable, i.e. the equipment truly has the potential to perform as assumed.

At defined intervals during the post-retrofit period the installation should be re-inspected to verify continued existence of the equipment and its proper operation and maintenance. Such re-inspections will ensure continuation of the potential to generate predicted savings and validate stipulations. The frequency of these re-inspections can be determined by the likelihood of change. Such likelihood can be established through initial frequent inspections to establish the stability of equipment existence and performance. An example of a situation needing routine re-inspection is a lighting retrofit savings determination involving the sampling of the performance of fixtures and a count of the number of fixtures. In this case the continued existence of the fixtures and lamps is critical to the savings determination. Therefore periodic counts of the number of fixtures in place with all lamps burning would be appropriate. Similarly, where the performance of controls equipment is assumed but subject to being overridden, regular inspections or recordings of control settings are critical to limiting the uncertainty created by the stipulations.

3.4.1.4 Option A: Measurement Interval

Parameters may be continuously measured or periodically measured for short periods. The expected amount of variation in the parameter will govern the decision of whether to measure continuously or periodically.

Where a parameter is not expected to change it may be measured immediately after ECM installation and checked occasionally throughout the post-retrofit period. The frequency of this checking can be determined by beginning with frequent measurements to verify that the parameter is constant. Once proven constant, the frequency of measurement may be reduced.

If less than continuous measurement is used, the location of the measurement and the exact nature of the measurement device should be recorded in the M&V Plan, along with the procedure for calibrating the meter being used.

Where a parameter is expected to be constant, measurement intervals can be short and occasional. Lighting fixtures provide an example of constant power flow, assuming they have no dimming capability. However lighting operating periods may not be constant, for example outdoor lighting controlled by a photocell operates for shorter periods in seasons of long daylight than in seasons of short daylight. Where a parameter may change seasonally, such as this photocell case, measurements should be made under appropriate seasonal conditions.

Where a parameter may vary daily or hourly, as in most heating or cooling systems, continuous metering may be simplest. However for weather dependent

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Request 9.

Refer to the Young Testimony, page 24 of 41.

Request 9a.

Has Mr. Young developed and run the statistical models required in conjunction with his recommendation that statistical recoupling be adopted for EKPC? Explain the response.

Response 9a.

I have developed one such model in order to enable the Commission to evaluate the concept, but I have not obtained the data for the input variables or run the model. Please refer to my responses to request 6b above and 9c below.

Request 9b.

Has Mr. Young provided the statistical models and formulas that would be required as part of the implementation of statistical recoupling for EKPC in this case? Explain the response.

Response 9b.

One possible model for the Commission to consider is provided in response to request 9c below.

Request 9c.

Has Mr. Young provided proposed revisions to EKPC's existing tariffs reflecting his proposed adoption of statistical recoupling? Explain the response.

Response 9c.

For purposes of illustration, I have provided a proposed new tariff below that would implement SR for EKPC. The particular SR formula provided below is based closely on the model described in Chapters 4 and 6 of Eric Hirst's report. Please note that the values of the model's coefficients – A, B, C, D, E and F – would be calculated by running the regression model using the past 15 years of historical quarterly data. To reduce the potential for gaming, I would suggest that these coefficients be updated relatively infrequently, e.g., not more often than every three years or every time EKPC has a general rate case.

The SR formula would be used each quarter to derive EKPC's predicted quarterly energy use (EPRED). If EPRED is larger than the actual energy use (EACT), the amount flowing into the ESF Balancing Account would be positive. The amount flowing into the ESF Balancing Account could be negative if EPRED were smaller than EACT and the difference between the two were larger than the sum of that quarter's DSM program costs plus EKPC's shared savings incentive. After each quarterly use of the SR formula to adjust the amount in the balancing account, the Commission and EKPC would divide that amount by three and make a small percentage adjustment for the next three months in the energy and demand charges of each underlying rate schedule (i.e., rate sections A, B, C, E, and G, and the special contract rates of those large industrial customers that have not opted out of participation in DSM programs). By the time the SR formula was used again three months later to determine the allowable revenue for the next quarter, the amount in the ESF Balancing Account – whether it had been a positive or a negative number – would have been reduced to zero.

EAST KENTUCKY POWER COOPERATIVE, INC.

RATE ESF – EFFICIENCY SAVINGS FACTOR
APPLICABILITY

Applicable to all sections of this rate schedule; this rate shall apply to each member system.

AVAILABILITY

This rate schedule shall apply to EKPC rate sections A, B, C, E, and G. It shall also apply to all special contracts unless the special contract customer has met the requirements to opt out that are specified in KRS 278.285, Section (3) and has opted out of demand-side management programs offered by EKPC and its member cooperatives. Adjustments in rates pursuant to this tariff shall be subject to the approval of the Commission.

RATE

The Efficiency Savings Factor shall provide for monthly adjustments based on a percent of revenues equal to one-third (1/3) of the amount in EKPC's ESF Balancing Account. The amount flowing into the ESF Balancing Account each calendar quarter is the sum of the program costs of EKPC's Commission-approved demand-side management (DSM) programs, a shared savings incentive, and the difference between EKPC's actual revenue and its allowed revenue.

ESF Balancing Account = DSMPC + SSI + PF*(EPRED – EACT)

where:
(a) DSMPC is the quarterly DSM program costs;
(b) SSI is a shared savings incentive equal to 10% of the measured savings accruing to the ultimate customers on EKPC and its member systems as a result of DSM programs;
(c) PF is the fixed-cost component of the retail electricity price;
(d) EPRED is the predicted quarterly energy use calculated by the using Statistical Recoupling (SR) formula below; and
(e) EACT is the actual quarterly energy use.

PF is calculated according to the following formula:
PF = (Retail revenue – Revenue from customer charges)/(Retail sales) - PV

where PV is EKPC's variable cost, which consists primarily of the costs of fuel and purchased power.

EPRED is calculated by using the following Statistical Recoupling (SR) formula:

EPRED = A + B*CTOT + C*HDD + D*CDD + E*PTOT + F*INDOUT + AUTOREG

where:

(a) CTOT is the number of customers served by EKPC and its member systems;
(b) HDD is the number of heating degree-days in the quarter;
(c) CDD is the number of cooling degree-days in the quarter;
(d) PTOT is the retail electricity price;
(e) INDOUT is Kentucky's industrial output; and
(f) AUTOREG is a first-order autoregressive term to improve the accuracy of the SR formula.

Request 9d.

If none of the items outlined in parts (a) through (c) above have been provided, explain in detail how the Commission can evaluate the reasonableness of the proposal to adopt statistical recoupling for EKPC.

Response 9d.

Not applicable; the information provided above, in conjunction with Eric Hirst's report, should provide a sufficient basis upon which the Commission could evaluate the reasonableness of the Sierra Club's proposal to adopt statistical recoupling for EKPC.

Please note that the precise form of the regression equation provided above is not the only form it could reasonably take. The particular equation could vary somewhat if the Commission were to engage in a process such as that described above in my response to information request 6b.

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Request 10.

On page 24 of 41, Mr. Young states,

> Following the example of the decoupling pilot programs that were tried by LG&E, KU, and ULH&P, the Commission could approve a new tariff for EKPC that would add a single line to customers' bills. In order to communicate the purpose and function of this element to customers in the clearest possible way, I propose that this item on customers' bills be called either the "Efficiency Savings Factor" or the "Efficiency Shared Savings Factor."

Request 10a.

As proposed by Mr. Young, would this "single line" be added to the power bills from EKPC to the 16 member coops or be added to the bills from the 16 member coops to their member consumers?

Response 10a.

Both. It is clear that for the two levels of the EKPC system to operate together in an effective manner, both EKPC and its member coops need to have the same set of financial incentives in place. It would be counterproductive for the Commission to establish one set of incentives, e.g., the incentives created by the use of SR as proposed above and in my testimony, for EKPC, while leaving in place the traditional incentive for the member coops to sell more energy at all times. A complex web of competing incentives would be created that would only serve to cause disagreements between EKPC and its member coops and would do little to further the interests either of the EKPC system as a whole or its ultimate customers.

Request 10b.

Was Mr. Young aware that the rate changes approved in this case will be to the power bills received by the 16 member coops from EKPC?

Response 10b.

Yes.

Request 10c.

Was Mr. Young aware that the 16 member coops have filed applications to pass through the change in the rates from EKPC under the provisions of KRS 278.455?

Response 10c.

Yes. The fact that the 16 member coops currently have rate cases before the Commission presents an excellent opportunity to implement the Sierra Club's proposed rate structure at both levels of the EKPC system.

If the Commission deems it advisable for the purpose of introducing information about the rate structures of the member coops, the Sierra Club would be very willing to discuss the possibility of applying for full or partial intervenor status in the general rate cases of the 16 member coops.

Request 10d.

Was Mr. Young aware that KRS 278.455(2) provides that a distribution cooperative may change its rates to reflect a change in the rate of its wholesale supplier if the effects of an increase or decrease are allocated to each class and within each tariff on a proportional basis that will result in no change in the rate design currently in effect?

Response 10d.

Yes. The Commission may find it necessary or advisable, however, to refer to Kentucky statutes other than KRS 278.455 in order to effect the appropriate changes in the rate structure of the member coops.

Request 10e.

If Mr. Young's recommendation for a customer bill line item called "Efficiency Savings Factor" or "Efficiency Shared Savings Factor" is aimed at the member consumers of the 16 member coops, does Mr. Young believe that this recommendation is beyond the scope of this rate case and the provisions of KRS 278.455(2)? Explain the response.

Response 10e.

The Sierra Club's testimony in this proceeding has been directed to EKPC's rate structure because that is the subject of this rate case. Please refer to the responses to requests 10a through 10d above.

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Request 11.

Refer to the Young Testimony, page 25 of 41. Concerning Mr. Young's recommendation that EKPC phase out the Electric Thermal Storage ("ETS") program,

Request 11a.

Since the ETS program shifts loads to off peak times, would Mr. Young agree that this shift provides for an improved utilization of EKPC's existing generating facilities? Explain the response.

Response 11a.

It is clear from the information provided by EKPC and reproduced in Attachment A of my testimony that one major effect of the utility's two ETS programs is to build load. EKPC reported that its energy usage in 2006 was 44,906 MWh higher than it would have been in the absence of the ETS programs.

The effects of the ETS Propane program were combined with those of the ETS Electric Furnace program in the data provided by EKPC. It is therefore not clear how many of the ETS systems installed over the years have displaced propane heating systems and how many have displaced electric furnaces. To the extent that ETS systems are installed in homes that have electric furnaces, I would agree that the peak-shifting effect allows EKPC to use its existing generating facilities at a more constant level during the course of the day and night.

Request 11b.

If the ETS program actually shifts loads from on peak to off peak times, explain in detail how this results in boosting energy consumption.

Response 11b.

To the extent that the ETS system replaces propane heating systems, it is a load-building program that boosts energy consumption. One reason the ETS programs have been so popular with the member coops over the past couple of decades is that they enable the coops to sell more energy. Because the traditional rate structure rewards increased energy sales with higher revenues and net revenues, the member coops have been willing to give their customers a significant price break for energy purchased during off-peak hours.

Request 11c.

If Mr. Young has relied on independent analyses or studies to reach the conclusion the ETS program should be phased out, provide printed copies of these analyses or studies. If the analyses or studies are more than 7 years old, also explain the relevance of the analyses or studies to today's situation.

Response 11c.

My conclusion that the ETS program should be phased out is based on the data for the year 2006 provided by EKPC, combined with my knowledge that there are much more cost-effective ways to shift energy consumption from peak periods to shoulder and off-peak periods than the ETS concept. Real-time pricing (RTP) for large customers, for example, can be an extremely cost-effective and economically efficient way to shift peak loads. EKPC may wish to consider the idea of RTP for residential customers as well.

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Request 12.

Refer to the Young Testimony, page 32 of 41. Concerning the referenced case study at lines 19 through 23,

Request 12a.

Provide printed copies of the referenced report.

Response 12a.

The entire report is 91 pages long. A printed copy of the first twelve pages is provided below. The referenced report is available at the following web site: http://www.nrel.gov/docs/fy00osti/28053.pdf If the entire report were essential to elucidate key issues in this proceeding, I would have no hesitation about providing copies of the complete printed report. However, the Sierra Club's budget for this proceeding is limited, and to provide the required number of copies of the additional pages would add approximately $70 to the cost of responding to this information request. If online access to the report is insufficient, it would be available for inspection at my home office in Lexington during reasonable business hours. Anyone wishing to review the complete printed copy is invited to call me at 859-278-4966 to arrange a time to view the document.

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Making Connections

Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects

R. Brent Alderfer, M. Monika Eldridge
Competitive Utility Strategies, LLC
Doylestown, Pennsylvania

Thomas J. Starrs
Kelso Starrs & Associates, LLC
Vashon, Washington

NREL Technical Monitor: Gary Nakarado
Prepared under Subcontracts No. CXE9-29093-01 and CXE9-29092-01

National Renewable Energy Laboratory

1617 Cole Boulevard
Golden, Colorado 80401-3393

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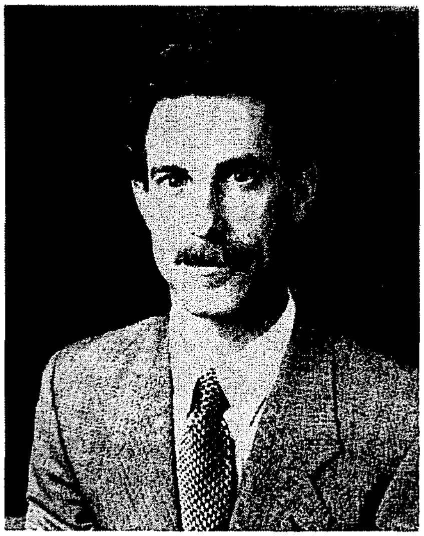
Foreword



Today there is growing interest in distributed electricity generation, particularly onsite generation. This interest is stimulated by the reliability, power quality, and environmental needs of businesses and homeowners, as well as the availability of more efficient, environmentally-friendly, modular electric generation technologies, such as microturbines, fuel cells, photovoltaics, and small wind turbines.

This report documents the difficulties faced by distributed generation projects seeking to connect with the electricity grid. The distributed generation industry has told us that removing these barriers is their highest priority. The case studies treated in this report clearly demonstrate that these barriers are real. They are, in part, an artifact of the present electricity industry institutional and regulatory structure which was designed for a vertically integrated utility industry relying on large central station generation.

It is essential that energy and environmental policy reform accompany continued technological improvement in order to bring the many benefits of distributed power systems to our Nation. The challenge for us today, as the authors of this report suggest, is to seize the opportunity offered by the current restructuring of the electricity industry to create a new electricity system that supports, rather than stymies, distributed generation.

We in the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy look forward to working with our many stakeholders in meeting this challenge.

Dan W. Reicher
Assistant Secretary of Energy
Office of Energy Efficiency and Renewable Energy

Executive Summary

Environmentally-friendly renewable energy technologies such as wind turbines and photovoltaics and clean, efficient, fossil-fuel technologies such as gas turbines and fuel cells are among the fleet of new generating technologies driving the demand for distributed generation of electricity. Combined heat and power systems at industrial plants or commercial buildings can be three times more efficient than conventional central generating stations. When facilities such as hospitals and businesses with computers or other critical electronic technology can get power from either the grid or their own generating equipment, energy reliability and security are greatly improved.

Distributed power is modular electric generation or storage located close to the point of use. It can also include controllable load. This study focuses primarily on distributed generation projects. Distributed generation holds great promise for improving the electrical generation system for the United States in ways that strongly support the primary energy efficiency and renewable energy goals of the U.S. Department of Energy (DOE). Distributed generation offers customer benefits in the form of increased reliability, uninterruptible service, energy cost savings, and onsite efficiencies. Electric utility operations can also benefit. Smaller distributed-generation facilities can delay or eliminate the need to build new large central generating plants or transmission and distribution lines. They can also help smooth out peak demand patterns, reduce transmission losses, and improve quality of service to outlying areas.

However, overlaying a network of small, non-utility owned (as well as utility-owned) generating facilities on a grid developed around centralized generation requires innovative approaches to managing and operating the utility distribution system, at a time when actual or anticipated deregulation has created great uncertainty that sometimes discourages adoption of new policies and practices.

In December 1998, DOE sponsored a meeting of the stakeholders in distributed generation. The need to document the nature of the entry barriers for distributed power technologies became clear. Customers, vendors, and developers of these technologies cited interconnection barriers—including technical issues, institutional practices, and regulatory policies—as the principal obstacles separating them from commercial markets. Industry and regulatory officials are also beginning to examine the nature and extent of these barriers and to debate the appropriate responses.

This report reviews the barriers that distributed generators of electricity are encountering when attempting to interconnect to the electrical grid. The authors interviewed people who had previously sought or were currently seeking permission to interconnect. This study focuses on the perspective of the project proponents. No attempt was made to assess the prevalence of the barriers identified.*

By contacting people known to be developing distributed generation projects or to be interested in these projects, and then gathering referrals from those people, the authors were able to identify 90 potential projects for this study. Telephone interviews were then conducted with people involved with those 90 projects. For smaller projects, this was usually the customer or owner of the project. For larger projects, this was usually a distributed generation project developer building the facility for the customer. The authors obtained sufficient information about 65 of the 90 projects to develop full case studies for these projects. The sizes of the projects represented by the case studies range from 26 megawatts to less than a kilowatt.

Most of the distributed power case studies experienced significant market entry barriers. Of the 65 case studies, only 7 cases reported no major utility-related barriers and were completed and interconnected on a satisfactory timeline. For the remaining case studies, the project proponents expressed some degree of dissatisfaction in dealing with the utility. They believed that the utilities' policies or practices constituted unnecessary barriers

* The purpose and value of the study was simply to confirm that barriers do exist, to provide illustrative examples of current case studies, and to initially identify the kinds of barriers. The authors made no attempt to obtain a statistically valid or unbiased sample. Also, the use of referrals to select case studies for identifying barriers likely skewed the selection toward cases where there were barriers.

Findings

This report focuses on cases where barriers were present and does so from the project proponents' perspective. Nonetheless, the study offers the following findings about current barriers to interconnection of distributed power generation projects.

- A variety of technical, business practice, and regulatory barriers discourage interconnection in the US domestic market.
- These barriers sometimes prevent distributed generation projects from being developed.
- The barriers exist for all distributed-generation technologies and in all regions of the country.
- Lengthy approval processes, project-specific equipment requirements, or high standard fees are particularly severe for smaller distributed generation projects.
- Many barriers in today's marketplace occur because utilities have not previously dealt with small-project or customer-generator interconnection requests.
- There is no national consensus on technical standards for connecting equipment, necessary insurance, reasonable charges for activities related to connection, or agreement on appropriate charges or payments for distributed generation.
- Utilities often have the flexibility to remove or lessen barriers.
- Distributed generation project proponents faced with technical requirements, fees, or other burdensome barriers are often able to get those barriers removed or lessened by protesting to the utility, to the utility's regulatory agency, or to other public agencies. However, this usually requires considerable time, effort, and resources.
- Official judicial or regulatory appeals were often seen as too costly for relatively small-scale distributed generation projects.
- Distributed generation project proponents frequently felt that existing rules did not give them appropriate credit for the contributions they make to meeting power demand, reducing transmission losses, or improving environmental quality.

to interconnection. As of completion of the report, 29 of the case study projects had been completed and interconnected; 9 were meeting only the customer's load and were not sending any power to the grid; 2 had disconnected from the grid; 7 had been installed, but were still seeking interconnection (and may be operating independently in the interim); 13 were pending; and 5 projects had been abandoned.

For purposes of this analysis, the barriers encountered in the case studies were classified as technical, business practice, or regulatory.

Technical barriers consist principally of utility requirements to ensure engineering compatibility of interconnected generators with the grid and its operation. Most significant of the technical barriers are requirements for protective equipment and safety measures intended to avoid hazards to utility property and personnel, and to the quality of power in the system. Proponents of potential distributed generation systems often stated that the required equipment and custom engineering analyses are unnecessarily costly and duplicative. Such requirements added $1200 or 15% to the cost of a 0.9 kW photovoltaics project, for example, plus an additional $125 per year for relay calibration. Newer generating equipment already incorporates technology designed specifically to address safety, reliability, and power-quality concerns.

Business-practice barriers arise from contractual and procedural requirements for interconnection and, often times, from the simple difficulty of finding someone within a utility who is familiar with the issues and authorized to act on the utility's behalf. This lack of utility experience in dealing with such issues may be one of the most widespread and significant barriers to distributed generation, particularly for small projects. Utilities that set up standard procedures and designate a point of contact for distributed generation projects considerably simplify and reduce the cost of the interconnection process both for themselves and for the distributed generation project proponents.

Other significant business-practice barriers included procedures for approving interconnection, application and interconnection fees, insurance requirements, and operational requirements. Many project proponents complained about the length of time required for getting projects approved. Seventeen projects—more than 25% of the case studies—experienced delays greater than 4 months. Smaller projects often faced a lack of uniform standards, procedures, and designated utility points of contact for determining a particular utility's technical requirements and review processes. This led to prohibitively long and costly approvals. Proponents of larger projects sometimes formed the perception that the utility was deliberately dragging out negotiations. Application and interconnection fees were frequently viewed as arbitrary and, particularly for smaller projects, disproportionate. Utility-imposed operational requirements sometimes resulted in direct conflicts between utility and customer needs. For example, utilities often ask to control the facility so that, among other things, they can shut down the facility for safety purposes during power outages. This requirement would preclude the customer using the facility for emergency backup power—a key advantage of distributed generation.

Regulatory barriers were principally posed by the tariff structures applicable to customers who add distributed generation facilities, but included outright prohibition of "parallel operation"—that is, any use other than emergency backup when disconnected from the grid. The tariff issues included charges and payments by the utility and how the benefits and costs of distributed generation should be measured and allocated. Also, several project proponents reported being offered substantial discounts on their electrical service from the utility as an inducement not to build their planned distributed generation facilities.

Backup or standby charges were the most frequently cited rate-related barrier. Unless distributed generation customers want to disconnect completely from the grid and invest in the additional equipment needed for emergency backup and peak needs, they will be depending on the utility to augment their onsite power generation. This is a principal reason for interconnection, but it can also impose a burden on the utility because it may be required to maintain otherwise unnecessary capacity to meet the distributed generation customers' occasional added demand. Charges for these services varied widely. Standby charges ranged from $53.34/kW-yr to $200/kW-yr for just the case study projects located in the state of New York, for example. Project proponents often felt that the charges were excessive and that utility concerns could be addressed through scheduling and other procedures. Other frequently disputed charges included transmission and distribution demand charges and exit fees (charges to disconnecting customers that will no longer be supporting the payoff of the utility's sunk or "stranded" cost in generation equipment). Furthermore, the charges imposed often do not reflect the benefits to the grid the distributed generation might provide.

For small customers, net metering (where the meter runs backwards when power is being contributed to the grid—prescribed by law in about 30 states) provides credit at the retail rate. For large distributed generation facilities, however, the typically much-lower wholesale rate paid (or uplift charge assessed for using transmission and distribution systems to sell power to third parties in deregulated states) was often seen as unfair, especially if no credit was given for on-peak production. Project proponents felt that utilities were not giving them credit for their contribution to helping meet peak demands.

Environmental permitting was not a focus of this report, but many project proponents did cite it as a regulatory barrier. Inconsistent requirements from state to state and site to site were frequently listed as barriers. The length of time and cost of testing to comply with air quality standards was often seen as burdensome and unfair. Proponents also felt that permitting processes should give credit for the replacement of older, more polluting, facilities by the distributed generation projects (e.g. a gas turbine instead of a central station coal-fired plant) as well as the increased efficiencies, for example, of a combined heat and power facility.

The case studies identified a wide range of barriers to grid interconnection of distributed generation projects. These barriers unnecessarily delay and increase the cost of what otherwise appear to be viable projects with potential benefits to both the customer and the utility system. They sometimes even kill projects. There are, however, several promising trends. Uniform technical standards for interconnection are being developed by the Institute of Electrical and Electronics Engineers. Individual state regulatory agencies are adopting rules to address barriers to distributed generation. In 1999, the New York and Texas public utility commissions adopted landmark rules on interconnection, and ambitious proceedings on distributed generation are now underway in California. Individual utilities have adopted programs to promote distributed generation. These trends indicate the potential for resolution of barriers to interconnection of distributed generation projects.

Much more must be done in order to create a regulatory, policy, and business environment which does not create artificial market barriers to distributed generation. The barriers distributed generation projects face today go beyond the problems of technical interconnection standards or process delay, which are more immediately apparent to the market. They grow out of long-standing regulatory policies and incentives designed to support monopoly supply and average system costs for all ratepayers.

In the present regulatory environment, utilities have little or no incentive to encourage distributed power. To the contrary, regulatory incentives drive the distribution utility to defend the monopoly against market entry by distributed power technologies. Revenues based on throughput and system average pricing are optimized by keeping maximum loads and highest revenue customers on the system. But, as in any competitive market, those are the customers that gain the most by switching to new, more economic, efficient, or customized power alternatives. In addition, current tariffs and rate design as a rule do not price distribution services to account for system benefits that could be provided by distributed generation.

Resolution on a state-by-state basis will not address what may be the biggest barrier for distributed generation—a patchwork of rules and regulations which defeat the economies of mass production that are natural to these small modular technologies. Although regulatory proceedings and legal challenges eventually would resolve most of the identified barriers, national collaborative efforts among all stakeholders are necessary to accelerate this process so that near-term emerging markets for the new distributed generation technologies are not stymied.

Distributed generation promises greater customer choice, efficiency advantages, improved reliability, and environmental benefits. Removing artificial barriers to interconnection is a critical step toward allowing distributed generation to fulfill this promise

A Ten-Point Action Plan For Reducing Barriers to Distributed Generation

Reduce Technical Barriers

(1) Adopt uniform technical standards for interconnecting distributed power to the grid.

(2) Adopt testing and certification procedures for interconnection equipment.

(3) Accelerate development of distributed power control technology and systems.

Reduce Business Practice Barriers

(4) Adopt standard commercial practices for any required utility review of interconnection.

(5) Establish standard business terms for interconnection agreements.

(6) Develop tools for utilities to assess the value and impact of distributed power at any point on the grid.

Reduce Regulatory Barriers

(7) Develop new regulatory principles compatible with distributed power choices in both competitive and utility markets.

(8) Adopt regulatory tariffs and utility incentives to fit the new distributed power model.

(9) Establish expedited dispute resolution processes for distributed generation project proposals.

(10) Define the conditions necessary for a right to interconnect.

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SECTION 1. INTRODUCTION AND METHODOLOGY

1.1 Introduction

Distributed power is modular electric generation or storage located close to the point of use. It can also include controllable load. This study focuses primarily on distributed generation projects. The sizes of the projects described in this report ranged from 26 megawatts to less than a kilowatt.

The convergence of competition in the electric industry with the arrival of environmentally friendly microturbines, fuel cells, photovoltaics, small wind turbines, and other advanced distributed power technologies has sparked strong interest in distributed power, particularly in on-site generation. This convergence of policy and technology could radically transform the electric power system as we know it today. Like the revolution that took us from mainframe computers to PC's, this transformation could take us from a power system that relies primarily on large central station generation to one in which small electric power plants located in our homes, office buildings, and factories provide most of the electricity we use. The resulting major improvement in electric power reliability could save billions of dollars now lost each year because of power disruptions. The impressive efficiency and environmental gains offered by distributed power technologies have the potential to contribute significantly to mitigation of air pollution and global climate change. However, these distributed power technologies face an array of market entry barriers, which are the subject of this report.

At a Department of Energy (DOE) meeting of industry and public stakeholders in December 1998, the need to document the nature of the entry barriers for distributed power technologies became clear. Customers, vendors, and developers of these technologies cited interconnection barriers, including technical and related institutional and regulatory practices, as the principal obstacles separating them from commercial markets. As witnessed by the landmark rules adopted in 1999 by the New York and Texas public utility commissions, and the ambitious proceedings taking place in California, industry and regulatory officials are beginning to examine the nature and extent of these barriers, and to debate the appropriate response.

This study serves to document the reality of market entry barriers across the spectrum of distributed power technologies by providing case studies of distributed power projects that have been impacted by these market barriers. However, the focus is on barriers to interconnection with utility systems, and other important issues such as environmental permitting are not examined in detail in this report.

1.2 Methodology

Identifying Case Studies

The first challenge of the study was to identify grid-connected distributed power projects that would serve as subjects for the case studies. Representatives from trade associations, equipment manufacturers, distributed power project developers, utilities, utility regulators, state energy officials, and others in the distributed power industry were asked to identify projects that might be candidate case studies. Case study contacts also identified other possible case studies. Altogether more than 150 individuals were contacted during the course of this project.

These contacts identified more than 90 possible projects covering a broad range of fuel types, technologies, and sizes. For smaller projects, the information source was typically the project owner/electricity customer. For larger projects, it was typically a project developer. In a few cases, the equipment manufacturer was the source. The projects varied from those in the planning stages to those that were already in operation. Also included were projects that ultimately did not interconnect with the utility's grid or which were abandoned. Many of the projects were in the process of negotiation with the utilities for final interconnection. Some of projects were not included in this report because of a lack of complete or reliable information. Of the 90 projects, sufficient information was collected on 65 to treat them as case studies. The findings and analyses of this report are based on these 65 case studies.

NOTE: Given the scope of this project and the manner of locating the distributed power cases discussed, no claims are made as to the likelihood that the cases represent any particular scale of problem, nor that the categories in which we have placed individual cases are statistically valid in any formal sense. Rather, the cases report situations encountered in the marketplace today and convey, where available, the participant's suggestions about how to correct situations that hindered distributed power development.

Conducting Interviews

With assistance from the DOE and other distributed resource experts, an interview survey form (inserted on pages 3-4) was designed and used to document the 65 case studies that form the basis of this report.[1] Using this survey form to guide the conversation, we interviewed project information sources by telephone. The completed form was then E-mailed or faxed to the interviewee for verification when possible. Of the 65 case studies, we selected 26 as being representative of the barriers encountered and having sufficient information available to tell an illustrative story. These 26 cases are presented in detail in Section 3 of this report. To respect confidentiality concerns and to avoid undue emphasis on the specifics of any single case study, the names of distributed power owners, specific facility locations, equipment vendors, and interconnecting utilities are excluded from the case study narratives. This report focuses on the nature and scope of interconnection barriers in the U.S domestic market, rather than practices of any particular utility or stakeholder.

Utility Verification

For each of the 26 projects detailed in Section 3, the interconnecting utility was contacted—first to validate information provided by the owners or developers, and second to document the utility's opinions and recommendations. In instances where the project developer or owner desired to remain anonymous, the details of these projects were not discussed with the utility. Instead, generic questions regarding the utility's distributed power practices were asked to compare and confirm the utility's position as reported by the project owner or developer. In addition, tariff information and copies of interconnection procedures and applications were requested. In some cases, there was no response from the utility. Thus, these case studies primarily represent the developers' views of the situations they encountered in seeking to interconnect these facilities. Therefore, the cases reported here may not reflect what might be a very different utility position with respect to some of the cases. (See additional discussion at introductory discussion of case studies.)

Throughout this document, "the utility" typically refers to the utility responsible for the distribution system with which the distributed generation installation sought to interconnect. This includes investor-owned utilities (IOUs), municipals, and cooperatives. In some cases, it may refer to a generation and transmission (G&T) utility that placed restrictions on the distribution utility.

Analyzing and Synthesizing Data

Finally, an attempt was made to summarize the barriers encountered in the case studies and demonstrate the real impact these barriers can have on a distributed power project. Section 2 includes the summary and analysis of the barriers represented in the case studies. Section 2.5 is an initial attempt at quantifying the barrier-related costs of interconnection. Section 2.6 presents findings and conclusions, including suggested actions for reducing barriers. Section 3 provides narrative descriptions of 26 of the individual case studies.

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[1] The authors thank Joseph Galdo, Program Manager, Office of Power Technologies, and Richard DeBlasio and Gary Nakarado of the National Renewable Energy Laboratory for their leadership in setting up this study. Joe Iannucci of Distributed Utility Associates was the most notably included of several experts who played key roles in the conceptualization, organization, and review of this study. Our biggest thanks, however, go to the many projects developers, owners, and utilities who participated in the survey and follow-up interviews.

SURVEY FORM

Please Complete and Return ASAP To:

M. Monika Eldridge PE
Competitive Utility Strategies
meldridge@uswest.net
303/494-7397

1. CONTACT INFORMATION MUST BE PROVIDED!!

UTILITY, PROJECT DEVELOPER, AND CUSTOMER NAME WILL BE KEPT CONFIDENTIAL UPON REQUEST

CONFIDENTIALITY REQUESTED: ____ YES _____ NO

INTERVIEWER:
DATE of INTERVIEW:

CONTACT INFORMATION:
NAME:
ORGANIZATION NAME:
PHONE NUMBER(S):
EMAIL:
MAILING ADDRESS:

PROJECT NAME:

LOCATION / UTILITY or FRANCHISE:
[County Name]
[Utility Name]

TYPE OF RESOURCE /TECHNOLOGY TO BE INTERCONNECTED:

GENERATOR [SYNCHRONOUS, INDUCTION, INVERTER]:
RATED GENERATION CAPACITY (kW):
CAPACITY FACTOR or DUTY CYCLE:

INTENDED START DATE (month/year):

DATE PROJECT BROUGHT ON LINE (if project abandoned so indicate):

TYPE OF POWER APPLICATION (power quality, reliability, peak clipping, energy production, green market supply, CHP):

DESIGN/CONFIGURATION (on what site, connected to what facilities, to run under what conditions):

PROJECT OWNER (Residential Customer, Industrial, etc.):

END USE CUSTOMER(S):

POTENTIAL BENEFITS (renewable, onsite generation, etc.):

TYPE OF BARRIERS ENCOUNTERED:

1. Technical Interconnection
2. Interconnection Practices (delay, customized application etc)
3. Commodity Price (including monopoly buy-back rates)
4. Monopoly Distribution (including monopoly discounting, backup tariffs, uplift tariffs, and franchise rules)
5. Market Rules (size limits, transmission charges, ISO rules, ancillary service charges, scheduling, and loss imputation)
6. Competition Transition Charges
7. Local Permitting
8. Environmental Permitting
9. Other

PIVOTAL BARRIER:

DESCRIPTION OF PIVOTAL BARRIER:

OTHER BARRIERS:

COST TO OVERCOME THE BARRIER COMPARED TO COST OF PROJECT WITHOUT THE BARRIER:

ESTIMATED ECONOMIC LOSS TO SUPPLIER AND CUSTOMERS:

OTHER COMMENTS/CONCERNS, POSITIVE OR NEGATIVE:

LESSONS LEARNED and PROPOSED SOLUTIONS: (suggestions and ideas for the future)

REGULATORY JURISDICTION (State, Regional ISO, etc):
[Local]
[State]
[Federal]

CUSTOMER/INSTALLER CONTACT:

UTILITY/MUNICIPALITY CONTACT:

1.1 SUGGESTED OTHER CONTACTS FOR OTHER PROJECTS:

FOR INTERVIEWS WITH UTILITIES INVOLVED:

Utility Name:
Utility Contact Name:
Phone # (s):
email:
utility website: www.

Study Participants in the utility's service area:
CONFIDENTIAL:___ YES __ NOName:
CONFIDENTIAL:___ YES __ NOName:
CONFIDENTIAL:___ YES __ NOName:

Interviewer:
Date of interview:

_____Interconnect Agreement coming
_____All relevant tariffs coming
_____All original interview questions verified (UNLESS CONFIDENTIAL)

Notes:

Request 12b.

Mr. Young states that "of 65 case studies for which sufficient information existed to include in the report, 58 projects encountered utility-related barriers." Was Mr. Young aware that the authors of this case study acknowledge the case study focuses on cases where barriers were present based on the perspective of distributed generator project proponents?

Response 12b.

Yes. The authors of the report included the following statement in the Executive Summary (page i):

> This report reviews the barriers that distributed generators of electricity are encountering when attempting to interconnect to the electrical grid. The authors interviewed people who had previously sought or were currently seeking permission to interconnect. This study focuses on the perspective of the project proponents. No attempt was made to assess the prevalence of the barriers identified.* (footnote: *The purpose and value of the study was simply to confirm that barriers do exist, to provide illustrative examples of current case studies, and to initially identify the kinds of barriers. The authors made no attempt to obtain a statistically valid or unbiased sample. Also, the use of referrals to select cease studies for identifying barriers likely skewed the selection toward cases where there were barriers.)

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

PSC STAFF'S FIRST DATA REQUEST DATED JULY 25, 2007

RESPONSIBLE PERSON: Geoffrey M. Young

Request 13.

Refer to the Young Testimony, page 33 of 41.

Request 13a.

How much electricity is represented by 5 percent of the rolling average of EKPC's highest monthly coincident peak demand in each of the prior three 12-month periods?

Response 13a.

According to EKPC's most recent integrated resource plan, filed in Case No. 2006-00471, the highest actual coincident peak demands during the last three years were as follows:

2004: 2,610 MW

2005: 2,719 MW

2006: 2,477 MW

5% of these figures are 130.5 MW, 136.0 MW, and 123.9 MW, respectively.

Request 13b.

How much electricity for each of the 16 member coops is represented by 15 percent of the rolling average of each member coop's highest monthly coincident peak demand in each of the prior three 12-month periods?

Response 13b.

I do not have the requested data.

Request 13c.

How much electricity is currently available in Kentucky from qualifying facilities and distributed generation?

Response 13c.

According to the report, "Kentucky's Electric Infrastructure: Present and Future," published by the Commission on August 22, 2005, there are four cogeneration facilities currently operating in Kentucky. A copy of the relevant page from that report [page 18] is attached.

Electric Generation in Kentucky

Non- Jurisdictional Generation

Merchant Generation

Dynegy

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dynegy – Foothills	Lawrence	two	460	gas	2002
Dynegy - Riverside	Lawrence	three	690	gas	2001
Dynegy – Bluegrass	Oldham	three	624	gas	2002

Western Kentucky Energy

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Reid	Webster	one	65	coal	1966
Coleman	Hancock	three	455	coal	1969-1972
HMP&L Station 2	Webster	two	405	coal	1973-1974
Reid CT	Webster	one	65	fuel oil	1976
Green	Webster	two	454	coal	1979-1981
Wilson	Ohio	one	420	coal	1986

Cogeneration Generation

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Cinergy – Silver Grove	Campbell	one	20	gas	2001
Weyerhauser – Ky. Mills	Hancock	one	88	wood waste	2001
Cox – Waste to Energy	Taylor	one	4	wood waste	1995
Air Products – Calvert City	Marshall	one	27	gas	2000

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

PSC STAFF'S FIRST DATA REQUEST DATED JULY 25, 2007

RESPONSIBLE PERSON: Geoffrey M. Young

Request 14.

Refer to the Young Testimony, page 34 of 41. Mr. Young states, "Given the set of incentives faced by member cooperatives as a result of EKPC's wholesale tariffs, it would be reasonable to assume that a typical distribution co-op would be willing to pay a cogenerator or small power producer a rate approximately equal to the wholesale rate that the co-op pays to EKPC."

Request 14a.

Explain in detail why it would be "reasonable to assume" any of the 16 member coops would make such a purchase from a co-generator or small power producer if the rates are approximately the same as EKPC's wholesale rate.

Response 14a.

If we assume that the member coops are rational economic actors that are seeking to minimize their costs, and that the electricity provided by EKPC is equivalent to that provided by a qualifying facility (QF) in all respects, then a given member co-op would be indifferent between the two suppliers if each were to offer electricity at the same price.

In reality, however, the member co-op may find the value of the electricity provided by the QF to be higher than that provided by EKPC. There are many factors that could enter into such a valuation, including many of the 207 economic benefits of small distributed generation resources listed in the book, *Small Is Profitable*. [Sierra

Club testimony, June 29, Attachment D] A given member coop could come to the conclusion, based on an analysis of its distribution system, that one or a combination of several of these benefits would merit a price premium above EKPC's wholesale rate.

Request 14b.

Since the 16 member coops are the owners of EKPC, explain in detail why any of the member coops would be willing to purchase electricity from a cogenerator or small power producer if the rate was approximately equal to the EKPC wholesale rate.

Response 14b.

Please refer to the response to request 14a above.

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

PSC STAFF'S FIRST DATA REQUEST DATED JULY 25, 2007

RESPONSIBLE PERSON: Geoffrey M. Young

Request 15.

Refer to the Young Testimony, page 35 of 41, lines 7 through 22.

Request 15a.

Is Mr. Young aware of any existing tariffs approved by any state regulatory commissions that pay qualifying facilities in the manner he discusses?

Response 15a.

Not precisely, but I am generally aware that several states have established generous avoided cost numbers and correspondingly high payments to qualifying facilities (QFs) that use relatively nonpolluting generation technologies.

The web site, www.dsireusa.org, provides state-by-state information about a range of incentives, policies, tariffs, and statutes that states use to encourage energy efficiency and clean renewable energy generation. By way of illustration, a copy of a small subset of that information is provided below and includes incentives and policies enacted by Maryland, Missouri, North Carolina, Oregon, and New York. Many states encourage small-scale renewable energy generation by applying net metering rules to technologies such as photovoltaics, wind power, solar water heating, solar thermal electricity, biomass, anaerobic digestion of animal wastes on farms, landfill gas, small-scale hydroelectric power, and biomass.

DSIRE

Maryland

Maryland - Net Metering

Incentive Type:	Net Metering Rules
Eligible Renewable/Other Technologies:	Photovoltaics, Wind, Biomass, Anaerobic Digestion
Applicable Sectors:	Commercial, Residential, Schools, Local Government, State Government, Fed. Government
Limit on System Size:	2 MW
Limit on Overall Enrollment:	1,500 MW
Treatment of Net Excess:	Credited at retail rate and carried over to customer's next bill; granted to utility at end of 12-month period with no compensation for the customer
Utilities Involved:	All utilities
Interconnection Standards for Net Metering?	Yes
Authority 1:	Md. Public Utility Companies Code § 7-306
Date Enacted:	1997; amended, 2004, 2005, 2006, 2007
Website:	http://www.energy.state.md.us/programs/renewable/solarroofs/index.html

Summary:

Maryland's net-metering law has been expanded four times since it was originally enacted in 1997. The most recent amendments, enacted in April 2007 along with an enhanced state renewable portfolio standard (RPS), raised the maximum capacity of all eligible systems from 200 kilowatts (kW) to two megawatts (MW). Systems owned or leased by residents, businesses, schools or government entities that generate electricity using solar, wind or biomass resources are eligible for net metering. In addition, the April 2007 amendments expanded the law as follows:

- Net metering is available statewide until the aggregate capacity of all net-metered systems reaches 1,500 MW. (The previous aggregate limit on net metering was 34.7 MW.)
- Net excess generation (NEG) is carried over at the utility's retail rate to the customer's next bill for 12 months. Any NEG remaining in a customer's account after a 12-month period is granted to the utility with no compensation for the customer.
- Customers own and have title to all renewable-energy credits (REC) associated with electricity generation by net-metered systems.
- For customers with facilities sized to produce energy in excess of the customer's consumption, the Maryland Public Service Commission (PSC) must consider the capacity of a customer's system when determining whether to require a customer to install a dual meter. (A dual meter may be required only if a customer sizes a system to generate electricity in excess of the customer's consumption.)
- The PSC must file with the Maryland General Assembly detailed annual reports describing the status of the state's net-metering program.

Utilities must install a single, bi-directional meter at a customer's facility (if necessary), and must offer net metering at no additional charge (including standby charges) or increased electricity rate. Customers with systems that meet all applicable safety and performance standards established by the National Electrical Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), Underwriters Laboratories (UL) and any other PSC requirements may not be required by utilities to install additional controls, to perform or pay for additional tests, or to purchase additional liability insurance.

The PSC has developed a credit formula for systems designed to generate more electricity than a customer consumes. The formula excludes recovery of transmission and distribution costs, and provides that the credit may be calculated "using a method other than a kilowatt basis, including a method that allows a dollar-for-dollar offset of electricity supplied by the grid compared to electricity generated by the customer."

Contact:

Tim LaRonde
Maryland Energy Administration
1623 Forest Drive, Suite 300
Annapolis, MD 21403
Phone: (410) 260-7539
Phone 2: (800) 723-6374
Fax: (410) 974-2250
E-Mail: meainfo@energy.state.md.us

PSC Staff Request 15
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Maryland

DSIRE

Fuel Mix and Emissions Disclosure

Incentive Type: Generation Disclosure
Eligible Renewable/Other Technologies: Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Municipal Solid Waste, Anaerobic Digestion
Applicable Sectors: Utility
Fuel Mix: Renewable Energy Resources (listed above), Coal, Natural Gas, Oil, Nuclear
Emissions: SO2, NOx, CO2
Distribution & Frequency: Bill insert or separate mailing
Twice a year
Standard Format Required?: Yes
Authority 1: MD Code §7-505
Date Enacted: 1999
Effective Date: 7/00
Authority 2: MD PSC Case 8738, Order 76241
Effective Date: 2000

Summary:

As part of its 1999 electric utility restructuring legislation, Maryland included provisions for the disclosure of fuel mixes and emissions by all retail suppliers of electricity in the state. Beginning July 1, 2000, this data must be provided in a standard format to customers every six months. Fuel mix data should be based on annually updated historical data. Emissions information must be provided by electric suppliers on a pound per megawatt-hour basis, of pollutants identified by the Commission, or disclosure of a regional fuel mix average. In addition, each energy supplier must submit an annual report to the Maryland Public Service Commission disclosing the annual totals for fuel mix and emissions and whether it had violated any of the terms of agreement for the last year.

Contact:

Mike Li
Maryland Energy Administration
1623 Forest Drive, Suite 300
Annapolis, MD 21403
Phone: (410) 260-7655
E-Mail: mli@energy.state.md.us
Web site: http://www.energy.state.md.us/

DSIRE

Missouri

Renewable Energy and Energy Efficiency Objective

Incentive Type: Renewables Portfolio Standard
Eligible Efficiency Technologies: Yes; specific technologies not identified
Eligible Renewable/Other Technologies: Solar Water Heat, Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Hydrogen, Anaerobic Digestion
Applicable Sectors: Investor-Owned Utility
Standard: 11% by 2020
Technology Minimum: To be determined by Missouri PSC
Credit Trading: To be determined by Missouri PSC
Authority 1: SB 54 of 2007
Date Enacted: 6/25/2007
Effective Date: 1/1/2008

Summary:

Missouri created a renewable energy and energy-efficiency objective for the state's investor-owned utilities in June 2007. Each utility must make a "good-faith effort" to generate or procure electricity generated by an eligible renewable-energy resources, so that by 2012, 4% of total retail electric sales is generated by eligible renewables. The goal increases to 8% by 2015, and to 11% by 2020.

Eligible renewable-energy resources include solar (photovoltaics, concentrating solar power technologies and low-temperature solar collectors); wind; hydropower; hydrogen from renewable resources; biomass; and other renewable-energy resources approved by the Missouri Public Service Commission (PSC) and the Missouri Department of Natural Resources (DNR). Cofiring is permitted, but only the percentage of electricity generated by an eligible renewable resource can be counted toward a utility's renewable energy and energy-efficiency objective. Existing renewable-energy facilities -- owned, controlled or purchased by investor-owned utilities -- that are operational are eligible, as long as the facility continues to generate electricity. The PSC is authorized to create a weighted scale to encourage certain renewable-energy resources and/or instate generation.

Credit towards the objective also may be achieved through energy efficiency that includes utility and consumer efforts to reduce the consumption of electricity. "Energy efficiency" is defined as "verifiable reductions in energy consumption, or verifiable reductions in the rate of energy consumption growth" (as defined by the PSC) as a result of measures implemented by utilities and electricity consumers, which may include "pricing signals, electronic controls, education, information, infrastructure improvements, and the use of high-efficiency equipment and lighting."

By July 1, 2008, the PSC must adopt rules that integrate into its resource planning rules the renewable energy and energy-efficiency objective, and the criteria and standards by which the commission will measure a utility's efforts to meet that objective to determine whether the utility is making the required good-faith effort. Specifically, the PSC must develop criteria and standards that:

- Protect against adverse economic impacts, including the costs of any transmission investments necessary to access eligible renewable-energy technologies, on the ratepayers and shareholders;
- Protect against undesirable impacts on the reliability of each utility's system;
- Consider environmental compliance costs, present and future, of each source evaluated; and
- Consider technical feasibility, providing for flexibility in meeting the objective in the event utilities are, for good cause shown, unable to meet in aggregate the objective of this section.

Each utility must submit to the PSC a biennial report by December 31, beginning in 2009, on its plans, activities and progress with regard to the objective, demonstrating to the commission that the utility is making the required good-faith effort.

Contact:

Pat Justis
Missouri Department of Natural Resources
Energy Center
P.O. Box 176
Jefferson City, MO 65102
Phone: (314) 416-2960
Fax: (314) 416-2970
E-Mail: pat.justis@dnr.mo.gov
Web site: http://www.dnr.mo.gov/energy/

DSIRE

TVA - Green Power Switch Generation Partners Program

Incentive Type: Production Incentive
Eligible Renewable/Other Technologies: Photovoltaics, Wind
Applicable Sectors: Commercial, Residential
Amount: $500 (residential only) plus $0.15/kWh (residential/small-commercial) or $0.20/kWh (large commercial) for 10 years
Terms: $500 payment available only until the program capacity reaches 150 kW
Website: http://www.gpsgenpartners.com

Summary:

Participating power distributors in TVA's Green Power Switch Generation Partners program offer production-based incentives for solar photovoltaics (PV) and wind projects to residential/small-commercial customers and incentives for PV projects to large commercial customers. The energy generated from participating projects will be counted toward the green power resources for TVA's green pricing program, *Green Power Switch*.

Under the residential/small-commercial contract, TVA will purchase the entire output of a qualifying system at $0.15/kWh through a participating power distributor, and the consumer will receive a credit for the power generated. In September 2004, larger commercial customers were included in the program. Under the larger commercial contract, TVA will purchase the output at $0.20/kWh. Participation in this program is entirely up to the discretion of the power distributor. As of August 2006, 30 distributors have signed up for the program. Thus far, the program includes several residential solar participants, a 20-kW wind project, a 50-kW commercial solar system, and a 10-kW commercial solar system.

Qualifying sources for residential/small-commercial projects include photovoltaic and wind turbine systems with a minimum output of 500 watts AC and a maximum of 50 kW. For commercial consumers, qualifying sources are restricted to PV only. Although the maximum output for commercial generation systems remains at 50 kW, the power distributor may elect to permit larger systems with mutual agreement of TVA on a case-by-case basis. Qualifying systems must be used primarily to provide all or part of the energy needs at a particular site and must not have previously generated into the grid. Installations must also comply with local codes and adhere to specific interface guidelines established by the program

Until a total capacity of 150 kW has been reached, the owner of a qualifying residential system will receive a $500 payment when the site is connected to the grid. The goal for the entire program is 5 MW. The credit of $0.15/kWh is available for a minimum of 10 years from the signing of the contract, regardless of the amount produced. Payment is made in the form of a credit issued by the local power distributor on the monthly power bill for the home or business where the generation system is located. TVA retains sole rights to any renewable energy credits.

Customers of TVA distribution utilities who are interested in this program should contact their utility customer services representative.

Contact:

S. Jolyn Newton
Tennessee Valley Authority
Green Power Switch Generation Partners
26 Century Blvd.
OCP 2-F, NST
Nashville, TN 37229
Phone: (615) 232-6409
E-Mail: sjnewton@tva.gov
Web site: http://www.greenpowerswitch.com

DSIRE

North Carolina - Net Metering

Incentive Type: Net Metering Rules
Eligible Renewable/Other Technologies: Photovoltaics, Landfill Gas, Wind, Biomass, Anaerobic Digestion, Small Hydroelectric
Applicable Sectors: Commercial, Industrial, Residential
Limit on System Size: 20 kW for residential systems; 100 kW for non-residential systems
Limit on Overall Enrollment: 0.2% of each utility's North Carolina retail peak load for the previous year
Treatment of Net Excess: Credited to customer's next bill at retail rate; granted to utility (annually) at beginning of each summer season
Utilities Involved: Investor-owned utilities (Progress Energy, Duke Energy, Dominion North Carolina Power)
Interconnection Standards for Net Metering? Yes
Authority 1: NCUC Order, Docket No. E-100, Sub 83
Date Enacted: 10/20/2005
Authority 2: NCUC Order, Docket No. E-100, Sub 83
Date Enacted: 12/27/2005
Authority 3: NCUC Order, Docket No. E-100, Sub 83
Date Enacted: 7/6/2006

Summary:

In October 2005, the North Carolina Utilities Commission (NCUC) adopted an order requiring the state's three investor-owned utilities -- Progress Energy, Duke Energy and Dominion North Carolina Power -- to make net metering available to customers that own and operate systems that generate electricity using photovoltaics (solar-electric energy), wind or biomass resources. Micro-hydro systems became eligible for net metering under terms of an NCUC order adopted in July 2006. Systems must be interconnected and operated in parallel with the utility's distribution system. (The NCUC adopted interconnection standards in March 2005.)

The maximum capacity of net-metered residential systems is 20 kilowatts (kW); the maximum capacity of net-metered nonresidential systems is 100 kW. Net metering is available on a first-come, first-served basis in conjunction with the utility's interconnection standards, up to an aggregate limit of 0.2% of the utility's North Carolina jurisdictional retail peak load for the previous year. Utilities may not charge customer-generators any standby, capacity or metering fees, or other fees and charges in addition to those approved for all customers under the applicable time-of-use demand-rate schedule. The NCUC's July 2006 order extended net metering to eligible renewable-energy systems with battery storage. Previously, system owners with battery storage were not allowed to net meter. (The NCUC noted that "gaming" a net-metering arrangement by using battery storage to manipulate a time-of-use tariff is not allowed.)

North Carolina is the only state that requires customers to switch to a time-of-use tariff in order to take advantage of net metering. In its July 2006 order, the NCUC clarified that on-peak generation may be used to offset off-peak consumption (but not vice versa). Previously, the utilities' net-metering tariffs and riders only allowed excess on-peak production to be used to reduce on-peak consumption and excess off-peak production to be used to offset off-peak production.

Net excess generation (NEG) is credited to the customer's next bill at the utility's retail rate, and then granted to the utility (annually) at the beginning of each summer season. Any renewable-energy credits (RECs) associated with NEG are granted to the utility when the NEG balance is zeroed out. This provision is designed to limit the size of individual facilities to match on-site power needs, according to the NCUC. Significantly, customer-generators who choose to net meter are not permitted to sell electricity under the NC GreenPower Program.

Utilities must file with the NCUC annual reports indicating the number of net-metering applicants and customer-generators, the aggregate capacity of net-metered generation, the size and types of renewable-energy systems, the amounts of on-peak and off-peak generation credited and ultimately granted to the utility, and the reasons for any rejections or removals of customer-generators from a net-metering arrangement.

Contact:

James McLawhorn
North Carolina Utilities Commission
Public Staff
430 N. Salisbury Street

DSIRE

Oregon - Net Metering

Incentive Type:	Net Metering Rules
Eligible Renewable/Other Technologies:	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Fuel Cells, Anaerobic Digestion
Applicable Sectors:	Commercial, Industrial, Residential, Nonprofit, Schools, Local Government, State Government, Fed. Government, Agricultural, Institutional
Limit on System Size:	Residential: 25 kW; Non-residential customers of PGE and PacifiCorp: 2 MW; Non-residential customers of municipal utilities, electric cooperatives, people's utility districts: 25 kW
Limit on Overall Enrollment:	PGE and PacifiCorp: no limit Municipal utilities, electric cooperatives, people's utility districts: 0.5% of a utility's historic single-hour peak load
Treatment of Net Excess:	Varies by utility (see below)
Utilities Involved:	All utilities (except Idaho Power)
Interconnection Standards for Net Metering?	Yes
Authority 1:	OR Revised Statutes 757.300
Date Enacted:	9/1/1999; amended, 6/7/2005
Authority 2:	Or. Admin. R. 860-039
Date Enacted:	7/24/2007
Effective Date:	7/24/2007
Authority 3:	Or. Admin. R. 860-022-0075
Effective Date:	11/30/2005

Summary:

Oregon has established separate net-metering laws and regulations for its primary investor-owned utilities (PGE and PacifiCorp), and for its municipal utilities and electric cooperatives.

PGE and PacifiCorp Customers

The Oregon Public Utilities Commission (PUC) adopted new rules for net metering for PGE and PacifiCorp customers in July 2007, raising the individual system limit from 25 kilowatts (kW) to two megawatts (MW) for nonresidential applications. (The rules do no apply to customers of Idaho Power, which provides net metering to Oregon customers pursuant to rules adopted by the Idaho Public Utilities Commission.) The limit on individual residential systems is 25 kW. Systems that generate electricity using solar power, wind power, hydropower, fuel cells or biomass resources are eligible. Net-metered systems must be intended primarily to offset part or all of a customer's requirements for electricity. Utilities may not limit the aggregate capacity of net-metered systems.

Net excess generation (NEG) is carried over to the customer's next bill as a kilowatt-hour credit for a 12-month period. Unless a utility and a customer otherwise agree, the annual billing cycle will conclude at the end of the March billing cycle of each year. Any NEG remaining at the end of a 12-month period will be credited at the utility's avoided-cost rate to customers enrolled in Oregon's low-income assistance programs. Customers retain ownership of all renewable-energy credits (RECs) associated with the generation of electricity.

The aggregation of meters for net metering is permitted. There is no limit on the number of net-metering facilities per customer as long as the net-metering facilities in aggregate on a customer's contiguous property do not exceed the applicable capacity limit.

Customers of Municipal Utilities, Cooperatives and People's Utility Districts

Oregon's municipal utilities, electric cooperatives and people's utility districts must offer customers net metering pursuant to OR Revised Statutes 757.300. Systems that generate electricity using solar power, wind power, hydropower, fuel cells or biomass resources are eligible. Net-metered systems must be intended primarily to offset part or all of a customer's requirements for electricity. The aggregated capacity of all net-metered systems is limited to 0.5% of a utility's historic single-hour peak load.

Net excess generation (NEG) is either purchased at the utility's avoided-cost rate or credited to the customer's next monthly bill as a kilowatt-hour credit. At the end of an annual period, any unused NEG credit is granted to the electric utility. This credit, in turn, is then either granted to customers enrolled in the utility's low-income assistance programs, credited to the generating customer or dedicated to an "other use."

Net metering is achieved using a standard bi-directional meter. Utilities may not place any additional standards or requirements on customers beyond those requirements established by the National Electric Code (NEC), National Electrical Safety Code (NESC), Institute of Electrical and Electronic Engineers (IEEE), and Underwriters Laboratories (UL). However, utilities may be authorized to assess a fee or charge if the utility's direct costs of interconnection and administration of net metering outweigh the distribution system, environmental and public-policy benefits of allocating costs among its customers.

Contact:

Christopher Dymond
Oregon Department of Energy
625 Marion Street, NE
Salem, OR 97301-3742
Phone: (503) 378-8325
Phone 2: (800) 221-8035
Fax: (503) 373-7806
E-Mail: christopher.s.dymond@state.or.us
Web site: http://www.energy.state.or.us

Lisa Schwartz
Oregon Public Utility Commission
550 Capital Street, NE
Salem, OR 97310-0335
Phone: (503) 378-8718
Fax: (503) 373-7752
E-Mail:> Lisa.C.Schwartz@state.or.us
Web site: http://www.puc.state.or.us

DSIRE

Oregon

Fuel Mix and Emissions Disclosure

Incentive Type: Generation Disclosure
Eligible Renewable/Other Technologies:
Applicable Sectors: Utility
Fuel Mix: Renewable Energy Sources, Hydroelectricity, Coal, Natural Gas, Nuclear, Other
Emissions: CO2, SO2, NOx, Nuclear Waste
Distribution & Frequency: Bill insert, marketing material
Quarterly basis and with contract
Standard Format Required?: Yes
Authority 1: OR AR 860-038-0300

Summary:

Under Oregon's 1999 electric utility restructuring legislation, electricity suppliers are required to disclose their fuel mix and emissions. Beginning March 1, 2002, disclosure must be supplied using a format prescribed by the Oregon Public Utility Commission. Power source and environmental impact information must be provided to all residential consumers at least quarterly.

Power source information must be reported as the percentages of the total production supply, including coal, hydroelectricity, natural gas, nuclear, and other fuels including but not limited to new renewable resources, if over 1.5 percent of the total fuel mix. Electricity suppliers are to disclose the net system power mix for the current calendar year unless they are "able to demonstrate a different power source and environmental impact." Electricity suppliers with a different fuel mix must base disclosure on projections of the mix to be supplied during the current year. Renewable resources are to be reported as "other fuels" unless they comprise over 1.5 percent of the total fuel mix. Utility mix and emissions are based on the previous calendar year.

Environmental impact information must be reported in pounds per kilowatt-hour (lbs/kWh). Pollutants that must be disclosed include carbon dioxide, sulfur dioxide, and nitrogen oxides. Spent nuclear fuel must be disclosed in milligrams per kilowatt-hour (mg/kWh).

Beginning in April 2003, suppliers making claims of sources other than net system power must file a "reconciliation report" with the Commission detailing the fuel mix of individual products.

Contact:

Phil Carver
Oregon Office of Energy
625 Marion Street, N.E.
Suite 1
Salem, OR 97301-3742
Phone: (503) 378-6874
Fax: (503) 373-7806
E-Mail: philip.h.carver@state.or.us
Web site: http://www.energy.state.or.us/

DSIRE

New York

New York - Net Metering

Incentive Type:	Net Metering Rules
Eligible Renewable/Other Technologies:	Photovoltaics, Wind, Biomass
Applicable Sectors:	Residential, Agricultural
Limit on System Size:	10 kW for solar; 25 kW for residential wind; 125 kW for farm-based wind; 400 kW for farm-based biogas
Limit on Overall Enrollment:	0.1% of 1996 demand per IOU for solar; 0.2% of 2003 demand per IOU for wind; 0.4% of 1996 demand per IOU for farm-based biogas
Treatment of Net Excess:	Credited monthly at retail rate, except for wind greater than 10 kW, which is credited monthly at avoided-cost rate. Accounts reconciled annually at avoided-cost rate.
Utilities Involved:	All utilities
Interconnection Standards for Net Metering?	Yes
Authority 1:	NY Pub Ser § 66-j et seq.
Date Enacted:	8/2/1997; amended 2002, 2004
Website:	http://www.dps.state.ny.us/distgen.htm

Summary:

New York's original net-metering law, enacted in 1997, applied to residential photovoltaic systems up to 10 kilowatts (kW). In 2002, the law was expanded (S.B. 6592) to include qualified farms that generate electricity from biogas produced by the anaerobic digestion of agricultural waste, such as livestock manure, farming waste and food-processing wastes. Farm-based biogas systems with a rated capacity of up to 400 kW are eligible to net meter. In 2004, S.B 4890-E (of 2003) further expanded the law to include residential wind turbines up to 25 kW and farm-based wind turbines up to 125 kW.

Utilities will accept customers into the net-metering program on a first-come, first-serve basis until the total net-metered solar-electric capacity equals 0.1% of a utility's 1996 electric demand.* The limit on aggregate biogas system capacity is 0.4% of a utility's 1996 demand, and the limit on aggregate wind system capacity is 0.2% of 2003 demand. Individual utilities may choose to allow a greater limit in aggregate net-metered capacity.

For solar-electric systems, farm biogas systems and small wind systems (10 kW and less), net excess generation (NEG) in a given month is credited to the next month's bill at the utility's retail rate. At the end of the annual billing cycle, customers are paid at the utility's avoided-cost rate for any unused NEG. However, NEG from wind-energy systems larger than 10 kW is credited to the next month's bill at the state's avoided-cost rate. NEG for these systems will be purchased at the utility's avoided-cost rate at the end of an annualized period.

The New York Public Service Commission (PSC) has developed uniform interconnection rules for net-metered systems. See the PSC web site for more information, including a list of accepted (type-tested) inverters.

** In December 2006, the PSC approved a request by Central Hudson Gas & Electric Corporation to raise the limit on aggregate net-metering capacity for PV systems in its service territory. The PSC's decision increased the limit by 50% -- from 800 kW to 1,200 kW. Central Hudson's net-metering program was the first in the state to approach its limit on aggregate capacity.*

Contact:

Patrick Maher
New York State Department of Public Service
Agency Building 3, Empire State Plaza
Albany, NY 12223
Phone: (518) 486-2574
Fax: (518) 473-2420
E-Mail: patrick_maher@dps.state.ny.us
Web site: http://www.dps.state.ny.us

In general, the idea that a state would enact favorable policies to encourage renewable energy sources has become well-established in this country.

Request 15b.

If yes to part (a) above, provide printed copies of the tariff.

Response 15b.

Not applicable.

Request 15c.

Explain who would determine whether the technology utilized by a qualifying facility is an environmentally-sound generation technology or a highly polluting technology.

Response 15c.

KRS 278.467 Section (1) provides that "The commission shall have original jurisdiction over any dispute between a retail electric supplier and an eligible customer-generator, regarding net metering rates, service standards, performance of contracts, and testing of net meters." Although this provision does not specifically address the question raised in this information request, it indicates that the General Assembly intended to give the Commission a significant amount of discretion in implementing net metering in Kentucky.

Request 15d.

Has Mr. Young provided in this case copies of his revised EKPC qualifying facility tariffs? Explain the response.

Response 15d.

A proposed amended qualifying facility tariff is attached below.

EAST KENTUCKY POWER COOPERATIVE, INC.

COGENERATION AND SMALL POWER PRODUCTION POWER PURCHASE RATE SCHEDULE

AVAILABILITY

Available only to qualified cogeneration or small power production facilities which have executed a contract with East Kentucky Power Cooperative (EKPC) and one of EKPC's member distribution systems for the purchase of electric power by EKPC.

RATES

1. $.01 per kWh is applicable if the energy provided by the cogenerator of small power producer comes from a generating unit that does not have enough pollution control devices to reduce the unit's emissions per kWh to a level significantly below the average emissions per kWh of EKPC's fleet of existing generating units. In case of a disagreement about the environmental cleanliness of a proposed generating technology, the Kentucky Public Service Commission shall have jurisdiction to resolve the dispute.

2. If the energy provided by the cogenerator or small power producer comes from a generating unit which emits significantly less pollution per kWh than the average emissions per kWh of EKPC's fleet of existing generating units, the cogenerator or small power producer shall be entitled to net metering. KRS 278.465 to 278.468 defines net metering to mean "measuring the difference between the electricity supplied by the electric grid and the electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period."

TERMS AND CONDITIONS

1. If the electricity fed back to the grid by an eligible Qualifying Facility (QF) exceeds the electricity supplied by the supplier during a billing period, the QF shall have the option of being credited for the excess energy and power or being paid by EKPC or its member cooperative for the excess energy and power at the retail rate applicable to the QF.

2. If time-of-day, time-of-use, or real-time pricing is used, the electricity fed back to the electric grid by the eligible QF shall be net-metered and accounted for at the specific time it is fed back to the electric grid in accordance with the time-of-day, time-of-use or real-time pricing agreement currently in place.

3. Each net metering contract or tariff shall be identical, with respect to energy rates, rate structure, and monthly charges, to the contract or tariff to which the same customer would be assigned if the customer were not an eligible QF.

4. The electric generating systems and interconnecting equipment used by an eligible QF shall meet all applicable safety and power quality standards established by the National Electrical Code (NEC), Institute of Electrical and Electronics Engineers, and accredited testing laboratories such as Underwriters Laboratories.

5. The QF shall design, construct, install, operate and maintain its generating equipment in accordance with all applicable codes, laws, and regulations.

6. EKPC or its member cooperative shall pay for all costs incurred as a result of interconnecting with the QF.

7. The term of the initial contract between the QF and EKPC and its member cooperative shall be no longer than five years. After the first five years, the contract may be renewed on a year-to-year basis.

8. Any industrial customer-generator making use of the higher rates specified in paragraph (2) of this tariff must not currently be opting out of demand-side management programs offered by EKPC and its member cooperatives, pursuant to the opt-out provisions specified in KRS 278.285, Section (3).

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

PSC STAFF'S FIRST DATA REQUEST DATED JULY 25, 2007

RESPONSIBLE PERSON: Geoffrey M. Young

Request 16.

Refer to the Young Testimony, page 36 of 41.

Request 16a.

Would Mr. Young's definition of an environmentally-sound generation technology recognize the installation and operation of any pollution control equipment, such as scrubbers or selective catalytic reduction equipment, by EKPC? Explain the response.

Response 16a.

Yes. The installation of pollution control equipment by EKPC would be expected to reduce the amount of environmental damage caused by EKPC's existing fleet of generating units. If, for example, EKPC were to add such equipment to one or more of its existing coal-fired power plants, it would decrease the emission of certain pollutants from those plants and would reduce the average emissions per kWh of EKPC's generating fleet.

Request 16b.

Who is "Energy Vortex"?

Response 16b.

According to its web site, EnergyVortex.com is "an open industry energy web site designed to serve as a B2B (business-to-business) community and e-commerce center."

Three attached pages downloaded from the web site show that they maintain an Energy Dictionary with definitions for a large number of terms used in the industry.

Request 16c.

Since 807 KAR 5:054 already defines "avoided costs," explain in detail why it is necessary to consider other definitions of the term.

Response 16c.

The definition I found at the Energy Vortex web site has the advantages that it is more descriptive and more complete than the definition in 807 KAR 5:054, and it specifically refers to one of the legislative intents of the US Congress when it passed PURPA in 1978: to reduce some of the environmental impacts of electricity generation.

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New site:

REDI RENEWABLE ENERGY DEVELOPMENT INSTITUTE

REDI RENEWABLE ENERGY DEVELOPMENT INSTITUE

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Energy Dictionary

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