Recommended Philippines Regulatory Reforms
Regulatory Assistance Project
May 29, 2001

1. Background

a. RAP (Wayne Shirley) visited The Philippines during the week of April 23, 2001. Meetings were held with the ERB, utilities, co-ops, and others. The purpose of our meetings was to assess existing barriers to increased utility investment in energy efficiency and related regulatory reform options.

b. The Philippines is served by a hundred or so co-ops and a few dozen IOU's. The utilities range in size from 10,000 MWs or so to just a few kWs of system peak. In addition, there are some 8,000 barangays (small local political units composed of as few as 50 to 100 families, though some are large) that have no electric system at all.[1]

Generally, the large utilities have understood sophisticated concepts and seem willing to explore them. Smaller utilities tend to have little understanding of DSM and need significant assistance in understanding how and why it may be to their advantage to embrace DSM.

c. Pursuant to a USAID initiative, the ERB engaged in a collaborative process in the mid-1990s on the subject of DSM. The ERB adopted a "DSM Framework" that outlines the filing requirements for the utilities. This Framework's general structure is sound and very flexible. It requires the filing of a DSM plan by each utility once every two years. It also allows utilities to apply for cost recovery including lost revenues and incentives. The first filings were due in 1998; however, of the 141 utilities required to file, only 38 or so have filed. Eleven of those have completed the approval process at the commission. Generally, the large IOUs have filed their plans, while the co-ops have not.

d. The ERB staff believes the principal reason most of the utilities have not filed their DSM plans is because of a lack of understanding of how to prepare a

[1]Many of these unserved areas may be candidates for micro-grid concepts or pure DG oriented applications. The typical rural off-grid farmer gets lighting from a gas fired lantern (i.e. Coleman style pressurized lantern) and may be paying as much as 200 ($4.00US) pesos a month in fuel for his lantern. Very small PV applications that charge a battery during the day and run a small portable CFL lantern during the evening may meet the needs of these customer more than a hard-wired "socket" installation, because these users need portable lighting to take to their barns, fields, etc.

plan

and how to implement DSM. In addition, they believe that most of the utilities do not understand how costs are to be recovered. Staff also believe that lack of funds prevent utilities from filing and implementing DSM plans.

No significant DSM has actually been implemented pursuant to the filed plans. One is left with the impression that the fundamental structure of the DSM Framework is probably basically adequate, but the staff and the utilities lack the sophistication to effectively implement it. Nonetheless, some improvements in the Framework are warranted, especially in the areas of cost recovery and rate regulation.

2. General

a. The Philippine's utility industry is still vertically integrated, but it is expected that generation will soon be separated and turned into a more competitive business. Our recommendations focus on the distribution utility.

b. The main objective of our recommendations is to suggest regulatory policies and reforms that support increased end-use energy efficiency. Under current regulatory practices, utility profits are significantly reduced if the utility (or customer) invests in cost-effective end-use energy efficiency. The potential for increased energy efficiency is very large and cost-effective. The economic and environmental benefits of increased energy efficiency are likewise very large. Electric utilities in the US and elsewhere have demonstrated their ability to creatively deliver end-use energy efficiency when regulation has been reformed to make energy efficiency profitable.

c. Although our focus is on regulation of the distribution utility, the design of wholesale markets can also determine the role of energy efficiency and load management. The wholesale electricity markets in California and elsewhere have dramatically shown how badly markets can perform when demand response has not been built into the market design and rules. Retail market rules have reduced the energy efficiency incentive for customers as well as retail sellers. See http://www.rapmaine.org/demandside2.html. In addition, Attachment 1 provides our view of the important lessons of the California crisis for The Philippines.

3. Summary of Recommendations

a. Our meetings provided a great deal of information about the facts and circumstances facing the electric industry in the Philippines. One of the most striking facts is the wide range of size and capability of the utilities. This makes it important to fashion DSM related reforms that differ for the large and small utilities.

b. The meetings also revealed many percieved obstacles to DSM. The following are the primary obstacles listed in order of importance. Each of these obstacles can and should be addressed:

i. Lost Revenues - Most of the parties observed that lost revenues are a driver for resistance to DSM. The utilities generally view DSM as a threat to their revenue base, even with the DSM Framework provisions for cost recovery. Parties said it is not clear whether the commission intends to allow recovery of lost revenues.

This is the most significant obstacle to large scale utility investment in DSM. The Philippines appear to be a clear case for revenue cap regulation or Lost Revenue Adjustments. For the larger utilities we suggest adopting stronger and more specific regulatory reforms to make utility investment in cost-effective energy efficiency at least as profitable as investment in new supplies. This adds more specificity to the existing basic policy of the ERB's DSM Framework.

ii. Financing - Most parties believe that financing is major barrier to DSM. There is an expectation, borne out of regulator custom, not law, that the expenses of DSM must be incurred before the commission can allow rate recovery.

It would be useful to allow the use of a balancing account in conjunction with a small addition to rates prior to the expenditures as a way to get DSM off the ground. Another approach would be to identify the DSM revenue stream recovery in a way that allows them to "securitize" a DSM revenue stream, making it a "bankable" resource for purposes of bank financing of DSM programs. This is similar to the widespread securitization of stranded cost in the US.

iii. Retail Tariff Issues - There is a problem with rate design for very small users. Generally, there is a minimal bill for customers who use 10 kWh or less per month. As a result, these customers cannot save any money by reducing their usage.

Some mechanism should be employed to deliver savings to these customers. Two possibilities would be to eliminate the minimum bill or to give those who install CFL's a lower minimum bill.

iv. DSM costs appear on bills. The ERB requires the utilities to disclose DSM costs as a separate line item on the bill. As a result, many of the utilities believe that the public would resist DSM.

Showing DSM costs on bills tends to mislead customers by failing to show the cost savings associated with the DSM investment. Cost-effective energy efficiency saves more money than it costs. Thus, we suggest that DSM costs not be shown as a separate line item. If DSM costs are shown as a separate line item it should be the DSM's net cost (cost minus the savings) which will show as a DSM credit as opposed to a DSM cost.

v. Pilot Project Syndrome - It appears that nearly every utility is going through the low-level learning curve of understanding how DSM really saves money. As a result, there is a tendency to have every utility engage in its own pilot program, each in its turn reinventing the same wheel.

There is a clear need for the learning experience to be shared among the utilities from the very beginning.

vi. Excess Capacity - A number of people believed that the existence of excess capacity presented an obstacle to DSM. When pressed, however, the extent and persistance of excess capacity was not well known.

We heard anecdotal stories of very small island utilities that have been given "hand-me-down" surplus diesel generators that in some cases are 5 to 10 times greater than the load on the system. The operators of these systems believe that they do not need DSM, because they have large amounts of excess capacity. However, large diesels running at low loads are very inefficient and have running costs well in excess of the cost of DSM. Also, because most of the loads of these small island utilities are residential lighting loads (one or a few light bulbs and maybe a radio or television), they could achieve great reductions in system peak with the use of CFL's. Were this done, the 2 or 3 MW loads might be reduced to a few hundred kW of load, in which case a very small generator might be installed to serve the community and keep the lights on all day long.

The bigger systems may have 20-30% reserve margins, but growth rates are very high. Any current excess is likely to be absorbed within a very few years.

In our view, excess capacity generally means that marginal, or avoided, cost is low. However, large amounts of energy efficiency costs less than the operating cost of existing generation. This means excess capacity, even if it exists, should not present an obstacle to DSM.

c. Other recommendations

i. For larger utilities we suggest the ERB adopt minimum DSM goals based on reasonably achievable DSM. DSM incentives would be available only if the DSM goals were achieved.

ii. For smaller utilities we suggest the ERB adopt simple default DSM and cost recovery plans for utilities that choose not to file utility specific plans.

4. Large Utilities

a. Fix the incentives

i. Every system of regulation creates incentives for and against particular behavior. Unfortunately for DSM, regulation in the Philippines is similar to traditional US regulation. For the purpose of this report, the most important features of existing regulation are 1) cost-of-service methods are used to set prices, 2) rate reviews occur on an as needed basis, and 3) automatic clauses flow all (prudent) fuel and purchased power costs to consumers.

The result of these provisions is the utility's revenue (non-fuel) increases as sales increase, the marginal cost of fuel and purchased power to the utility is zero, and profits increase.[2] Conversely, as sales decrease due to energy efficiency, revenues go down, the marginal fuel and purchased power savings are zero, and profits go down. The effect on utility profits becomes more pronounced when restructuring separates generation from the distribution utility. For example, for distribution utilities, a 1% reduction in sales can cut utility profits by 20% or more!

We have very little doubt that there are substantial, unrealized end-use energy efficiency gains that could be realized in the Philippines. There is also very little doubt that electric utilities can very effectively deliver energy efficiency services. However, electric utilities may also present major barriers and obstacles to the realization of increased end use energy efficiency. The role and effectiveness of utilities depends directly upon whether the utility's financial interests are consistent with the successful delivery of cost-effective energy efficiency.

ii. Reconciling utility financial interests with successful deployment of cost-effective energy efficiency is a two step process.

(1) **DSM program cost recovery.** Recovery of direct DSM program costs is a necessary first step. With one exception, existing ERB practices for recovery of direct DSM program costs do not appear to be a problem. Utilities have asserted that their financial condition makes it difficult to budget for DSM investment. To address this concern, it may be desirable to adopt a balancing account approach to allow collection of DSM costs to occur in advance of costs being incurred.

(2) **Lost revenue recovery.** Under existing regulatory practices, reduced sales due to DSM reduce utility revenues and profits. Correcting this problem can be done in several ways, although the third may only be partially effective.

(a) Adopt performance–based regulation (PBR) which

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[2]The marginal cost of fuel and purchased power is a cost to consumers, not the utility. Any under-recovery of fuel and purchased power costs can be recovered from consumers when the adjustment clause is invoked.

relies on revenue caps as opposed to price caps.
(b) Adopt lost revenue adjustment (LRA) mechanisms that allow utilities to recover the lost margins relating to energy efficiency program reductions in sales.
(c) Reform the accounting mechanisms used for fuel and purchase power clause adjustment mechanisms. Each of these options is described more fully below.

Our preference is for the PBR approach, although the LRA approach, with or without fuel accounting reforms, can be effective. It is also possible to use a mix of the approaches with revenue based PBR for residential and small commercial customers and LRA for the larger customer classes.

Finally, for smaller utilities the easiest option may be to develop a default DSM plan that includes specific cost recovery provisions. The small utility DSM approach is described in section 3. The following discussion relates to the larger utilities.

iii. <u>Revenue Based PBRs</u>. Every system of regulation creates incentives that encourages certain behavior and discourages other behavior. The Philippines now uses the same type of cost-of-service regulation used in the US and elsewhere. Cost-of-service regulation and price cap forms of regulation have similar incentive properties. Both provide strong incentives to cut costs, but they also provide utilities with very powerful incentives to promote electric use and equally strong disincentives for energy efficiency.

Correcting this problem requires the adoption of revenue, as opposed to price-based PBR. This approach is also referred to as revenue caps. Revenue caps and price caps produce the same costs, but revenue caps eliminate the incentive to increase sales and the disincentive for energy efficiency.

A description of the theory and mechanics of revenue cap PBR is shown in attachment 2.

iv. <u>Lost Revenue Adjustments</u>. Lost revenue adjustments (LRA) are much more limited in scope and effectiveness. With a LRA, DSM program evaluations are used to quantify the revenues lost due to the implementation of utility sponsored DSM programs. Adjustments begin with an evaluation of the energy and capacity savings of DSM. The revenues lost due to the energy and capacity savings are then based on retail tariffs for each affected customer class. Revenue losses are reduced by any identifiable or estimated cost savings associated with the implementation of DSM programs. Because fuel and purchase power are subject to separate and automatic adjustment clauses, these savings do not factor into this calculation and, instead, are passed back to customers through normal operation of the fuel and purchase power adjustment clauses.

In principle, both the revenue-based PBR and LRA approaches address the existing disincentive to utility DSM, but the results from the two approaches are different. LRA limits itself to changes in revenues resulting from specific DSM measures. The PBR approach is applied to all changes in utility sales and therefore removes the utilities' incentive to promote new sales. LRAs are not capable of removing existing incentives to increase sales.

Because revenue-based PBR separates profits from fluctuating sales levels **regardless** of the cause of the changed sales volumes, it addresses efficiency impacts resulting from **all** effects including:

- rate design
- all utility-sponsored DSM activities
- energy efficiency achieved through standards and other means
- energy efficiency measures undertaken by consumers or ESCOs directly, without any utility involvement.

Attachment 3 summarizes the characteristics of each of the approaches.

v. Fuel Revenue Accounting. Under existing practices one can think of every kWh sold as having associated with it an average amount of revenue attributable to fuel and purchase power costs. If sales increase by 1 kWh, fuel costs will increase by the marginal cost of fuel, while fuel revenue will increase by the average amount of fuel and purchase power reflected in the existing fuel adjustment clause. The shortfall between marginal and average cost of fuel and purchase power will be made up in the course of the next fuel adjustment proceeding. Existing retail tariffs minus the average fuel and purchase power clause provides a measure of the incremental addition to the bottom line profits of each incremental kWh sold. Under existing accounting practices this means high priced kWhs contribute more to utility profits than low priced kWhs. This produces the perverse result of having on-peak kWh sales be more profitable than off-peak kWh sales and tail block rates (assuming an inverted block rate structure, such as exists for Meralco) produces greater margins than off-peak kWh sales. Utilities thus have an incentive to shift customer use from off-peak periods to on-peak periods. Clearly, this is not desirable.

It is possible through accounting changes to alter this relationship. One could attribute a greater portion of the fuel revenue to high priced kWhs (on-peak) than low priced (off-peak) kWhs. The ultimate goal with these revenue accounting approaches would be to make average kWh sales and on-peak kWh sales less profitable than off-peak kWh sales. For example, the following illustrative table based on Meralco's approximate prices and rate structure shows a before and after view of the accounting changes.

Note
(1) Before the accounting changes the higher tail block sales are twice as profitable (3.4 versus 1.7) than initial block sales.
(2) After the accounting reforms tail block sales are less profitable than initial block sales.
(3) Actual prices consumer's see are not affected by the reforms.

	Before Accounting Reform	After Accounting Reform
first 50 kwh base	1.7	2.5
fuel	1.2	0.4
total	2.9	2.9
Next 100 kwh base	3.4	1.5
fuel	1.2	3.1
total	4.6	4.6
Avg PPA	1.2	1.2

b. If the ERB is not inclined to reform the regulatory practices to reconcile utility financial interests with DSM, the second class of options either impose specific DSM plans on the utilities or view the utility as a vehicle to collect funds which would be administered by others whose interests are consistent with the successful implementation of energy efficiency programs. Based on our experience, trying to force utilities to design and implement energy efficiency programs that are at odds with the utility's financial interest is a very difficult task. We have, however, found that some utilities support the need for increased energy efficiency but prefer that they not be the entity that designs and implements energy efficiency programs. These utilities have supported the creation of a System Benefits Charge with the funds collected and administered by a separate entity.

The most recent example of this approach is in the State of Vermont. Vermont established an energy efficiency utility that has the responsibility of designing and implementing all statewide energy efficiency programs. The efficiency utility is funded through surcharges on the bills of Vermont's electric utilities.

The early experience of the Vermont efficiency utility is very promising. See http://www.efficiencyvermont.com/about/annualreport.pdf

Thus, ERB rules could give large utilities the option of 1) filing revenue-based PBR plans which must be approved by the ERB together with DSM plans or 2) file tariffs that collect funds for DSM programs which would be administered by a separate independent entity that has an interest in the successful implementation of the DSM programs.

5. Small utilities

   a. In addition to other recommendations, the ERB should consider the adoption of a Default DSM Plan. Many utilities in The Philippines are very small, and the time and resources to develop a DSM filing may be prohibitive. Developing a uniform DSM plan that focuses on proven DSM technologies and programs may be one way to reduce the administrative and regulatory costs. The default plan can also address cost recovery and incentive issues.
   b. Attachment 4 describes an approach currently being used in the Pacific Northwest of the United States for a similar purpose. The Bonneville Power Administration (BPA) is a wholesale power supplier to approximately 120 electric utilities. These range in size from investor-owned utilities with peak demands in excess of 4,000 megawatts to small rural cooperatives with peak demands of less than 10 megawatts. The basic approach is if the utility spends at least a specified amount on approved energy efficiency measures, it receives a discount on its wholesale purchases roughly equal to the cost of the DSM measures. This provides a simple yet effective incentive for the small utilities to invest in basic energy efficiency measures.
   c. There are three principal lessons which can be applied from the BPA program to the requirement for small utilities to invest in DSM in the Philippines.
      i. For very small utilities, the amount of savings achievable may be so small that it is not efficient to require any formal tracking of expenditures. For these utilities, a requirement of informational programs, including financing information, combined with a set of just a few pre-approved energy efficiency measures, may be a reasonable requirement.
      ii. For all utilities over a minimum threshold, having a large list of pre-approved efficiency measures available is desirable. Utilities can simply make investments in the approved measures list, report their expenditures, and meet their obligations by showing a sufficient level of expenditures on the deemed cost-effective measures.
      iii. Finally, some sort of evaluation protocol should be available for utilities desiring to invest in unique measures or measures with location-specific or application-specific savings.
   d. In the Philippines, two approaches to cost recovery can be pursued. The simplest may be for the ERB to combine the list of pre-approved measures with pre-approved cost recovery. Each measure would have an associated cost recovery could consist of a pre-approved program cost plus a utility specific distribution margin. The second option is for the National Power Corporation to have a program that mirrors the BPA program.

6. In addition to the basic reforms of regulatory practices there are a few other energy efficiency related issues we wish to alert the ERB to.

   a. Wholesale and Retail Market Structure and Rules

As stated at the outset, the design of wholesale and retail markets can also determine the role of energy efficiency and load management. The wholesale electricity markets in California and elsewhere have dramatically shown how badly markets can perform when demand response has not been built into the market design and rules. Retail market rules have reduced the energy efficiency incentive for customers as well as retail sellers. See http://www.rapmaine.org/demandside2.html

b. Energy Service Companies

As a general matter, restructuring has not been a positive development for ESCOs. The ability of energy service companies to have a role in the restructured power sector depends on many issues. The most important step is to adopt the regulatory reforms described above. Aggressive DSM programs administered by utilities have been a successful driver of the ESCO industry. It is also important that wholesale and retail market design and rules allow ESCOs to realize the full value that energy efficiency delivers to wholesale and retail markets.

Attachment 1

California Crisis - Lessons for Regulation

The California crisis provides a useful example of what can happen if restructuring fails to fully incorporate a country's goals and constraints including energy efficiency, environmental, and economic development goals. California's experience also shows the problems that can occur if the regulatory agency does not have the authority to fix problems. We begin with a description of the cause of the California crisis.

The Causes of the Crisis

The causes of the California energy crisis are widely misunderstood so many of the most important lessons have not been learned. Five factors contributed most to the California crisis:

7. A shortage of supply from the Pacific Northwest's vast hydroelectric system due to drought conditions,
8. Rapid increases in the price of natural gas,
9. Increased cost of meeting air pollution requirements that were designed before restructuring,
10. The exercise of market power by generating companies, and
11. A market structure that lacked of a demand response, the ability of consumers to respond to increasing high wholesale prices with lower demand.

These five factors explain most of the reason spot electricity prices increased dramatically in California. Next, under California's market structure practically all electricity was traded or priced at spot market prices. This made the problem very wide spread.

Common Misunderstandings

There are many inaccurate impressions of the cause of California crisis. The four most common errors are as follows:

1. Retail rate freeze. The four-year retail rate freeze was not a cause of the crisis. First, the price freeze was not imposed on unwilling utilities. Rather, it was part of a complex negotiated restructuring plan that included give and take on all sides. Without full utility support, the California restructuring law would not have passed the California legislature on a unanimous vote. It was a deal that went well for more than two years and then turned very bad. The utilities were free to insist that their exposure to certain risks be limited; for whatever reasons they did not do so.

Second, eliminating the price freeze might have helped the financial health of the utilities but it would not have addressed the underlying problems. If wholesale prices were passed onto consumers immediately the financial problem for the local distribution company may have been solved but the public and political problems would have been at least as bad as it is today. Any developing (or developed) country that faces a rapid run-up in fuel prices and the exercise of market power on the scale seen in California will have a crisis with or without a rate freeze.

2. New plant construction. There have been very few new generation plants constructed to serve California over the past eight years, but the licensing issues are not the problem. Low energy prices for the first two and a half years and uncertain market rules meant there were no significant proposals to build power plants. During the past 10 years California regulators approved every proposal that was filed. The California utilities were so certain that excess capacity would persist that In 1995 they asked the federal government (FERC) to overturn a California PUC order requiring the California utilities to buy 1500 MW of new capacity. The FERC approved the utility requests and the capacity was not built.

3. **Strict Environmental Laws.** Other regions with siting and environmental laws as strict as California's have had little trouble attracting, siting, and building new plants.

4. Load growth. There is a lot of discussion about increased electrical demand, but demand this year is well below last year. California is a national leader in energy efficiency. Unfortunately, the other western states have not invested in energy efficiency and as a result their growth in electricity use has been very rapid.

The sudden decrease in supply of hydropower is also an important factor. The loss, beginning with the May 22 Northwest River Forecast Center stream flow announcement, was about 6,000 average megawatts. Replacing this energy with natural gas production caused a huge (57% through October) increase in natural gas demand.

<u>Lessons to be Learned</u>

Lessons from the California crisis are quite clear.

1. Keep the size of the spot market small. The size of the spot market should probably be limited to 10% or 15% of total generation. In the case of California it was almost 90%. Keeping the size of the spot markets small does not mean the spot market will work well. Small spot markets mean that if there are problems in the market the problems will be limited in size.
2. Incorporate demand response in the wholesale market design. Demand response by consumers, distribution companies, and energy service companies should be built directly into the structure of wholesale markets. This was one of the strongest lessons to come out of California and other markets that have suffered similar kinds of price level and price volatility problems.
3. Retail competition has not been successful so far. Retail competition has caused more problems than it cured. One critical, but overlooked, aspect of retail competition is that with retail access electricity prices are much more volatile that with more traditional approaches. If increased price volatility is unacceptable to the public, retail access may not be a practical option.
4. Do not split regulatory jurisdiction. In California, jurisdiction was too divided between various state and federal agencies. As a result, once the problem occurred, nobody was in a

position to solve the problem. Instead, each regulatory agency points to the other as the culprit.

5. Regulate transmission and distribution utilities in a fashion to encourage end use energy efficiency as well as improvement and expansion of the transmission and distribution system. Every reform will create a new set of incentives, some of which will be intended and some unintended. Our experience shows that there are two basic options: price caps and revenue caps. Price caps promote increased electricity sales and discourage utility investment in end-use energy efficiency. Revenue caps encourage cost reductions without the incentive to increase sales.
6. Incorporate environmental and economic goals in the restructured markets. Market rules and market structure need to be consistent with the increased use of renewables and reformed environmental rules. Without specific consideration of the environment, restructuring is likely to lead to increased use of the oldest and most polluting sources.
7. Another lesson from California relates to what they did correctly. California's restructuring included continued and very substantial investment in end use energy efficiency and renewables. Without the energy efficiency and renewable programs that California pioneered years ago and continued through restructuring process, the California crises would have been much worse. Clifornia has responded to the crisis by doubling the investment in energy efficiency because theis is the fastest and lowest cost solution to the problem

<u>Applying California's Lessons to The Philippines</u>

The Philippines and California are clearly very different places and The Philippines will not experience the same problems seen in California. However, there are several aspects of the power sector that could lead to similar problems.

1. The Philippines' electricity sector is undergoing very rapid growth. Any perception that the country is currently in a surplus capacity condition quickly evaporates when one looks at the rate of growth of electricity use. This is the time to begin designing and implementing aggressive end use energy efficiency programs.
2. It appears market power may be a problem as The Philippines moves toward a more competitive generation market. Most counties plan to limit generation ownership of any single company to no more than 20-25% of the total generation. One of the lessons in California is that this level of concentration is far too great to avoid market power problems, particularly during periods of low reserves.
3. Finally, like the original restructuring in California, it appears that the important goals and practical constraints may not yet be fully reflected in the power sector reforms. Environmental, energy efficiency, and economic development goals should be important factors in designing the specific rules of the restructured power sector.

Attachment 2

The Theory of Revenue-Based PBR

How do utilities make money? The answer to this basic question explains why mosy utilities do not invest in energy efficiency. The process begins with the tariff setting rate case. The rate case process itself, however, creates no meaningful incentives. Rate cases involve an exhaustive examination of the "reasonableness" of costs, disputes about the "prudence" of investments, and "rate of return" debates over the costs of capital and its structure (debt/equity ratio). One might be led to believe that rate case decisions on a particular cost, on the rate of return, and on revenue requirements actually create some incentives for utilities. They do not.

Once the rate case is completed and prices are set, everything said in the hearing process is irrelevant to the fundamental question of how utilities make money. (Meralco specifically noted the difference between the "allowed" return and the return actually earned.) From the day prices are set, utility profits are ruled by a simple formula:

PROFIT = REVENUE - COSTS

The REVENUE part of the formula is easily computed, but it has nothing to do with the line from the rate case order labeled "revenue requirement" or "allowed revenue." The utility's actual revenue is governed by the following formula:

REVENUE = PRICE * QUANTITY

Prices set at the end of the rate case are fixed until the end of the next rate case. In arithmetic terms, price is a constant, so revenue is directly related to quantity, or sales. Ignoring for the moment the subtleties of rate design (*i.e.*, the structure of prices ─ energy charges, demand rates, and customer charges), if sales go up two percent, revenues will go up by the same percentage.

The COST part of the profit equation is more complicated, but reduced to its simplest form the short-run marginal cost for distribution utilities (excluding fuel and purchased power) is essentially zero. Stated another way, statistical analysis of distribution utility costs (or vertically integrated utility costs excluding fuel and purchased power) has consistently shown that there is no meaningful relationship between non-fuel costs and kWh sales in the short run.

For distribution companies, the fact that costs do not vary with sales has profound effects on how distribution utilities make money. Recall the basic profit formula:

PROFIT = REVENUE - COSTS

Revenues are directly related to sales, and costs are independent of sales. This means profits and sales are directly related. If sales go up two percent, revenues go up two percent, and profits go up two percent. Likewise, if sales drop, revenues and profits drop. This produces a very powerful disincentive for energy efficiency and a very powerful incentive to increase sales.

The Mechanics

The mechanics of revenue caps can take two forms: an absolute cap on revenues or a cap on revenue-per-customer. The following description applies to the revenue-per-customer approach.

Following a typical rate case which determines the cost-or-service (revenue requirement) and the number of customers served, an allowed revenue-per-customer (RPC) is set at a reasonable level. The allowed revenue-per-customer can be an average for the utility or separate averages can be used for each customer class. What differentiates these two options are decisions on how to handle the risk that the mix of customers will change and who should bear the risk. (If the customer mix stays the same, there is no arithmetic difference between the options.) The revenue-per-customer PBR formula then becomes:

$$(\mathrm{RPC})_{\mathrm{Year\ 1}} = (\mathrm{RPC})_{\mathrm{Year\ 0}} * (1+(i-x)) +/- z$$

Where RPC is revenue-per-customer, i is a measure of inflation, x is a productivity adjustment, and z refers to items that are excluded from the PBR.

Notice that this formula mirrors the structure of typical price cap approaches. The revenue-per-customer is calculated, but it plays no direct role in setting charges for individual customers. Customers are billed for service as usual, using any combination of pricing elements including customer, energy, and demand charges. Charging customers based on existing rate designs accomplishes several purposes, among them assuring that large- and small-volume users contribute their fair shares to total revenues and that customers do not experience significant changes in their monthly bills.

During the PBR term, two key numbers are tracked and then compared on an annual basis. These are actual revenues (the dollars the utility collected from customers) and the allowed revenues (the previously-set RPC times the actual number of customers served by the utility). At the end of each year, any disparity between the allowed revenues and the actual revenues is corrected as either a surcharge or refund to rates during the following year.

The effect of following this approach is that the utility will have a specified amount of money to serve customers' needs. The amount will be approximately the same as the utility would have collected had it charged customers on a fixed price basis. With revenues fixed, profits rise if costs are cut. But profits hinge on cost control, not customer usage. This reduces both the disincentive for DSM and distributed resources and the incentive for load building.

At the end of the PBR period, costs are reexamined, and prices are set based on cost-of-service. The original PBR formula is reviewed and revised if needed.

Table 1. Revenue-Based PBR v. Lost Revenues

	Revenue-Based PBR	Lost Revenues
SALES	Removes sales incentive and all DSM disincentives	Removes some DSM disincentives, does not remove sales incentives.
M&E	Does not require sophisticated measurement and/or estimation	More dependant on measurement and/or estimation.
	Utility does not profit from DSM which does not actually produce savings.	Utility may profit from DSM which does not actually produce savings.
SCOPE	Addresses revenues lost due to: Rate design All DSM programs Customer DSM Efficiency standards	Addresses revenues lost due to utility DSM programs only.
OTHER	Eliminates load forecast gaming.	No direct effect on subsequent rate cases.
	Reduces volatility of utility revenue resulting from many causes.	No effect on the volatility of utility earnings.

Attachment 3

Attachment 4

This attachment discusses an approach currently being used in the Pacific Northwest of the United States for a similar purpose. The Bonneville Power Administration is a wholesale power supplier to approximately 120 electric utilities. These range in size from investor-owned utilities with peak demands in excess of 4,000 megawatts to small rural cooperatives with peak demands of less than 10 megawatts.

Pursuant to federal law, Bonneville is required to encourage its customer utilities to engage in energy efficiency programs. One mechanism Bonneville has developed is called the Conservation and Renewables Rate Discount (C&RD). This mechanism provides a discount from the otherwise applicable wholesale power rate for utilities which undertake independent expenditures for energy efficiency and renewable energy purposes.

The C&RD provides approximately a 2% discount for utilities which invest at least the amount of the discount in energy efficiency measures. The mechanism allows utilities a great deal of flexibility in the choice of efficiency and renewable resources to invest in. For larger utilities, some of whom are entitled to discounts in excess of $1 million per year, detailed reporting of expenditures and cost-effectiveness is required. For small utilities an extremely streamlined approach was developed. Even larger utilities are provided with a very simple mechanism if they prefer not to develop complex program evaluation methods.

The Small Utility Track

The Small Utility Track is designed to make it easy for smaller utilities (those purchasing less than 7.5 MW of energy from Bonneville) to obtain the discount to which they are entitled, without a need to mobilize complex or expensive program administration or program reporting procedures. It consists of the following:

1) The utility shall make available to all residential consumers: information about energy conservation, information about available energy conservation financing, and information about applicable state or federal incentives such as tax credits.

2) Upon request of a consumer, the utility shall provide or arrange for an energy assessment of the consumer's dwelling.

3) The utility may join an energy conservation organization to perform this work, or contract with an energy service provider or another utility to perform this work.

4) Those utilities which are primarily agricultural may provide the information in (1) and (2) to irrigation consumers rather than residential consumers.

5) The utility shall provide an annual letter to Bonneville certifying that these have been done. Upon receipt of the annual letter, Bonneville will apply the appropriate discount. For a customer purchasing 7.5 megawatts of energy from Bonneville, the discount of $.50/mwh would total approximately $33,000.

Larger Utilities

Utilities with larger demands on Bonneville, which are entitled to larger C&RD amounts (i.e., above $33,000 per year), are required to do "full" reporting of their expenditures. However, even these larger utilities have a relatively easy option for securing the full amount of discount to which they are entitled.

First, the amount of funding available to larger utilities is calculated in advance each year by Bonneville, based on forecast loads. The utility is NOT at risk for variances between the forecast amount and actual loads, should actual loads (and therefore the discount to which they are entitled) fall short of the estimate.

Second, the utility is free to invest this money in local conservation and renewable energy programs without interference from Bonneville.

A list of "qualified measures" has been developed for Bonneville by the Northwest Power Planning Council's "Regional Technical Forum." This list is designed to be all-inclusive of known and measurable conservation and renewable energy measures. The full list is available for review at: <http://www.nwcouncil.org/energy/rtf/reports.htm>

Within the list, there are both "deemed" measures and "protocol" measures. The "deemed" measures are those which have been defined in sufficient specificity that the estimated cost and energy savings or production are predictable, and the cost-effectiveness of the measures has been calculated. Each "deemed" measure is listed with a benefit-cost ratio computed for the "bulk power" system, for the "utility" system, and on a "societal" basis. An example would be a compact fluorescent light bulb in a typical residential application. The "protocol" measures are generally unique types of installations for which the cost and savings will be application-specific. For these measures, an evaluation protocol is provided to measure the costs and savings on a consistent basis, so that the savings and cost-effectiveness can be compared to the "deemed" measures. An example would be an industrial electroplating technology retrofit.

If the utility chooses to invest the full amount of the discount in measures which are on the "deemed" savings list, and which have societal benefit-cost ratios greater than 1.0, it need only report to Bonneville the measures acquired and the amount spent. It is then entitled to receive its discount. If it chooses to invest in "protocol" measures, it must provide the calculations called for by the evaluation protocols.

The "bulk power" system analysis consists exclusively of savings at the generation and high-voltage transmission level. These are typically benefits that would accrue to Bonneville, as the wholesale supplier. The "distribution system" value includes distribution capacity costs; these are set at a default value of $20/kva/year, with the utility having the option to use a higher value if the installed measures are designed to avoid a specific higher-cost distribution system capacity upgrade. Finally, the societal analysis includes non-energy benefits of the conservation measure, including, for example, avoided replacement light bulbs for a long-lived compact fluorescent lamp. In the societal calculation, avoided carbon dioxide emissions are valued at $15/ton (about $.006/kwh).

The Mechanism In Operation

The "deemed" measure approach for larger utilities is very simple. They can refer to the "deemed measure" list provided in three technical appendices to the RTF Final Report. They may invest in any of the measures listed which have societal benefit-cost ratios greater than 1. They must only report the amount of their expenditures and the number of measures acquired to Bonneville to secure their discount.

For example, the technical appendix shows that residential compact fluorescent lamps have societal benefit-cost ratios of 3.3 to 377, depending on application. Any of these measures will qualify for full reimbursement, up to the limit of allowable C&RD for the utility. Similarly, Energy Start appliances (clothes washers and dishwashers) have societal benefit-cost ratios of 2 - 7. Any expenditures on these measures will be fully reimbursed, up to the limit of allowable C&RD for the utility.

Alternatively, the utility may choose to invest in commercial sector, industrial sector, or agricultural sector efficiency measures. The Appendices provide a detailed list of measures, and have "deemed" savings and pre-calculated benefit-cost ratios for these. Expenditures on cost-effective measures are fully reimbursed, up to the limit of the C&RD for the utility.

For a utility above 7.5 MW, it is very simple to choose measures on the "deemed savings" list which have societal benefit-cost ratios in excess of 1, and make expenditures on these up to the amount of the C&RD for the utility (again, this limit is $.50/mwh for the amount of power purchased from Bonneville). The utility need only report the amount spent and the number of measures acquired. There is no requirement that the utility provide "full" funding, or that it attempt to "leverage" funding by requiring consumer contributions. The amount spent on deemed cost-effective measures is fully reimbursed, up to the level of the C&RD limit.

Investing in Non-Deemed Measures

Some utilities will choose to invest in more complex conservation measures, or provide assistance to industrial customers with application-specific savings opportunities. For these situations, the level of savings are not "deemed" and must be calculated using engineering protocols.
Engineering protocols are provided for both site-specific measures and for "group" measures. Each of these requires some form of field verification of the installations, measurement of the before and after energy consumption, weather normalization, and, for the "group" protocols, some form of sampling.

This option is clearly more complex for the utility, but it provides the flexibility to allow the utility to invest in unique opportunities for energy savings and receive appropriate reimbursement.

Investment in Non-Cost-Effective Measures

The C&RD does not require utilities to choose only cost-effective efficiency measures. Any form of energy efficiency savings or renewable energy production is eligible for the C&RD. Investments in non-cost-effective measures, however, are only partially reimbursed under the C&RD, up to the level of cost-effectiveness.

This approach provides flexibility to utilities to invest in measures such as customer photovoltaic installations, which may not meet a societal benefit-cost test, but are still desirable to stimulate the industry and to provide energy benefits to the utility system.

These measures which are “deemed” and have benefit-cost ratios of less than 1 are reimbursed based on the benefit-cost ratio. For example, a solar photovoltaic installation with a benefit-cost ratio of 0.1, would be reimbursed under the C&RD only up to 10% of the total installed measure cost. If the utility can cause a consumer to invest in such a system by paying only 10% of the measure cost as an incentive, the utility could therefore recover its full level of investment, but the consumer would be left with paying 90% of the measure cost.