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UTILITIES COMMISSION

Residential Time-of-Use Pricing Viability Study

Report to the
Idaho Public Utilities Commission

IDAHO POWER
An IDACORP Company

September 12, 2002

BACKGROUND

In Order No. 28894 the Idaho Public Utilities Commission ("the Commission") directed Idaho Power Company ("the Company") and the Energy Efficiency Advisory Group ("the EEAG") to consider implementing a time-of-use metering pilot program. In Order No. 29026 the Commission reaffirmed its directive that Idaho Power and the Energy Efficiency Advisory Group "evaluate and report to the Commission on the viability of a Time-of-Use residential metering program by September 12, 2002".

To assist in evaluating the feasibility of residential time-of-use (TOU) pricing, Idaho Power engaged the services of Christensen Associates. Christensen Associates is an economic consulting firm that has been providing consulting services to the energy industry for more than 25 years and is well known in the industry for its work with time-of-use and real-time pricing and market-based interruptible load programs.

This report is comprised of the following sections:

- An overview of residential time-of-use pricing provided by Christensen Associates
- An analysis performed by Christensen Associates assessing the potential benefits of residential time-of-use pricing for Idaho Power
- Issues relating to the implementation of time-of-use pricing which are specific to Idaho Power
- Input from the Energy Efficiency Advisory Group
- Conclusions on the viability of residential time-of-use pricing at this time

Christensen Associates Overview

An Overview of Residential Time-of-Use Pricing – *Problems and Potential*

Steven Braithwait
Christensen Associates

July 15, 2002

The Idaho Public Utility Commission has asked Idaho Power to investigate the viability of time-of-use (TOU) pricing for its residential customers. This memorandum serves as the first step in assisting Idaho Power to conduct that assessment. It provides an overview of residential TOU pricing, including the following topics:

- an historical perspective,
- a discussion of potential problems that can limit the benefits of residential TOU to utilities,
- a description of new types of TOU pricing that show promise in addressing some of those problems, and
- a summary of evidence on customer price responsiveness.

1. Background and historical perspective

The issue of market design, and the current disconnect between wholesale and retail power markets, has been the focus of intense discussion in recent months. It has been generally acknowledged that hourly wholesale power costs vary substantially across hours, days and seasons, while most customers face fixed retail prices. Thus, customers have no incentive to cut back usage during periods of high wholesale costs, which would provide needed relief from wholesale price pressures. As a result, various *demand response* mechanisms have been suggested to remedy this problem. One category of demand response mechanisms is *dynamic pricing*, in which customers face retail prices that directly reflect conditions in the wholesale market. The most common example of dynamic pricing is real-time pricing (RTP) for large commercial and industrial customers. However, interest in the general topic has renewed discussion of the potential value of TOU pricing for residential customers.

TOU pricing has been studied in some detail, in a variety of pilot and permanent programs, over the past twenty-five years, but has never achieved widespread use for small customers. Over that time, utility rate designers, regulators, academics, and consultants have debated the fundamental principles of retail electricity rate designs. Traditional utility rate design has focused largely on recovering allowed costs, and on methods for allocating those costs fairly across various customer types. A relatively low priority has been given to establishing prices that reflect differences in the incremental, or marginal cost of generating and delivering electricity in different time periods.

The principal argument in favor of TOU pricing has always been *economic efficiency – i.e.*, TOU prices reflect differences in the average cost of generating and delivering power during particular time periods, thus providing more appropriate price signals to customers than do flat rates. Customers can achieve benefits under TOU pricing if they can shift sufficient consumption from peak-period hours, in which the price exceeds the standard flat price, to lower-price off-peak hours. Utilities can realize net gains from those same load shifts by avoiding some peak period sales whose cost exceeds the revenue generated, and selling more during low-cost off-peak periods. However, these TOU benefits must be traded off against higher metering and administrative costs.

Estimates of that benefit-cost tradeoff have generally not been favorable. Two main factors have weighed against the benefits of TOU pricing for residential customers. First, TOU prices do not reflect the variability of wholesale power costs with sufficient accuracy. For example, peak period prices (*e.g.*, $.12/kWh) are generally designed to represent an average across expected wholesale costs during peak-period hours in a given season (*e.g.*, summer).[1] However, wholesale power costs can range widely from moderate to very-high levels, depending on actual load levels and supply conditions. In many hours, TOU peak period prices substantially exceed the actual cost of power (*e.g.,* a TOU price of $.12/kWh versus a wholesale cost of $.04 to $.06/kWh). However, in the very hours in which costs reach their highest levels, the peak period price is likely to fall far short of that level (*e.g.,* $.12/kWh versus costs of $1.00/kWh or more). Thus, while TOU prices do a better job than a flat price of reflecting cost differences on average, the price signal is still not very accurate. When TOU customer reduce load during those peak hours in which costs are actually low, utilities' revenue can be reduced by more than their costs.

Second, the relatively low usage level of residential customers, combined with the first factor of inaccurate prices, limits the overall magnitude of potential *benefits* from customer response to TOU prices. These benefits must be traded off against the additional *cost* of metering and billing.

TOU rates have generally not been mandated, or established as the default tariff for residential customers. Most TOU programs have been offered as voluntary programs, typically targeted at customers with high usage levels, or ownership of major appliances such as central air conditioning or pool pumps. As a result, most residential TOU tariffs have relatively few customers.

Two recent programs promoted by Puget Sound Energy (PSE) in Washington State, and Gulf Power in Florida, provide indications of potential renewed interest in

[1] To cover expected costs, TOU prices actually need to reflect a *load-weighted average* of hourly wholesale costs, where the weights represent the load pattern of the customers expected to take service under the rate.

residential TOU. PSE has undertaken an ambitious program to install advanced interval meters for all of its residential customers, along with software and communication devices that give customers the ability to monitor their energy usage and PSE's wholesale power costs online. PSE has assigned all customers with the new meters to a TOU rate, although customers have the right to opt out and return to a flat rate. PSE claims that a large share of the cost of the metering and communications system may be covered by improved meter reading and billing efficiency, even before accounting for the benefits associated with customer load response to TOU prices. PSE has also discussed a range of potential advanced pricing approaches that they may consider offering to take advantage of the metering and communications capabilities.

Gulf Power has recently announced a planned expansion of their pilot Residential Service Variable Price (RSVP) program, which combines advanced interval metering, and communication and control technology with a TOU rate that includes a dispatchable "critical peak price." This program, described in more detail in section 3, has the potential to solve a number of the problems with traditional TOU pricing.

2. Problems with traditional residential TOU pricing

Traditional TOU pricing has typically been characterized by two or three fixed price levels (*e.g.*, peak, shoulder and off-peak) for two seasons (*e.g.*, summer and non-summer). The prices are designed to represent the average cost of generating and delivering power to a class of customers during those periods. Potential problems associated with traditional TOU pricing include the following:

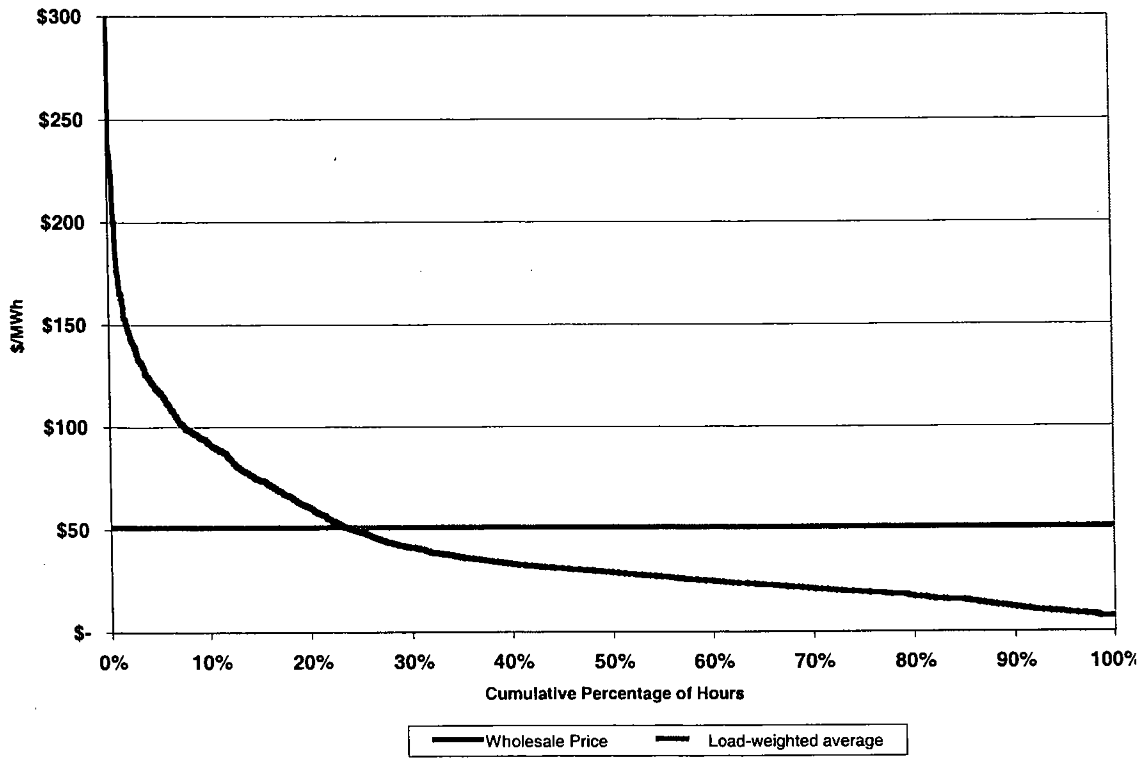
- inaccuracy of TOU prices;
- revenue attrition due to overall reductions in consumption;
- revenue attrition due to customer self-selection in voluntary rates; and
- inadequate benefits relative to costs.

Inaccuracy of TOU prices

Utility planning and operations staff have always recognized the variability of electricity costs. However, prior to the deregulation of wholesale power markets, these costs were largely internal to individual utilities, and not visible in public markets. As wholesale power markets have opened up, time-varying power generation costs have become reflected in wholesale energy prices. The increasing opportunities for trading power in wholesale markets make these prices the opportunity cost of power for most utilities, regardless of their mix of generation resources.

In spite of the variability of wholesale power costs, traditional utility rate design has focused largely on recovery of allowed costs through fixed retail prices, using methods designed to allocate those costs fairly across various customer types. Figure 1 illustrates the resulting disconnection that can exist between varying wholesale energy costs and fixed retail prices. The curved line in the figure shows hourly wholesale prices in the PJM East region for the summer of 2000, arrayed from high to low. The flat line shows the load-weighted average of these prices, which turns out to be approximately $50/MWh (or $.05/kWh). This value represents a typical flat seasonal energy price that might be offered to customers in this region. If charged in all hours, it would recover the same amount of revenue as if the actual variable costs were charged in each hour. Note, however, that in more than 70 percent of the hours of the summer, wholesale electricity costs were less than the average price (sometimes much less), while in more than 5 percent of the hours, electricity costs were more than twice as high as the average.

Figure 1. Disconnect Between Wholesale Energy Costs and Retail Prices
(PJM East – Summer 2000)



Competitive markets for other commodities tend to produce prices that reflect production costs. The frequent wide differences between wholesale electricity costs and retail prices suggest extensive foregone opportunities for economic gain. That is, in an important but relatively small number of hours, the cost of producing electricity far exceeds customers' value of consuming it, as reflected in the price they willingly pay. Reductions in usage during these hours would save costs far in excess of customers' forgone value of power. However, it is also important to recognize that typical retail tariffs give customers no access to the relatively low-cost power that is available in the vast majority of hours. Increased usage during these periods would produce value to consumers that exceeds the cost of generating that power.

The figure above shows costs in all hours compared to a single fixed average price. Similar figures could be constructed to illustrate the distribution of costs in peak and off-peak periods. While the results would undoubtedly be less extreme, the wide distribution shown suggests that a fixed peak-period price would exceed costs in many hours, but lie below wholesale costs during the few, but important hours of highest costs. If customers reduce load in all peak periods, then during low-cost hours, utilities lose more revenue than they save in avoided costs; and during high-cost hours, utilities face costs that exceed revenues.

Section 3 describes two types of innovative TOU price structures that allow closer matching between TOU prices and actual market costs.

Revenue attrition due to overall reductions in consumption
Under standard utility rate design methods, TOU prices are typically constructed to be revenue neutral for customers in a particular rate class at the at the average usage pattern for that class under standard rates. That is, the average monthly bill under TOU prices, at the same consumption pattern used to design the flat rate, would remain the same as under a standard flat price. Customers then have an opportunity to lower their bill if they shift load from peak to off-peak periods under TOU pricing. However, one typical finding from studies of customer response to TOU prices is that in addition to shifting load from peak to off-peak periods, customers tend to reduce overall consumption somewhat. This reduction can cause utilities to recover less revenue than planned.

This revenue attrition is largely the result of bundled tariffs that are designed to recover transmission and distribution costs, as well as energy costs, through a volumetric (per kWh) price. That is, overall reductions in energy consumption lead to corresponding reductions in the cost of energy, though not in T & D costs, which are largely fixed. One potential solution to this revenue attrition problem is to redesign TOU tariffs to recover a larger portion of T & D costs through monthly customer charges, where the size of the charge may vary by customer size.

Revenue attrition due to customer self selection under voluntary rates
Calculating appropriate TOU prices is a reasonably straightforward exercise if the rate is *mandatory* for a particular customer class, or group of customers (*e.g.*, all residential customers with both electric space heating and water heating). In that case, the expected loads, and thus the expected load-weighted energy costs, can be calculated based on existing load research data and information on expected power costs.

However, the situation is more complicated in the case of an *optional* TOU rate. The problem is caused by two factors – the diversity of customers' usage patterns, and a lack of hourly or TOU metered data for all customers. Regulated electricity prices for residential customers are typically fixed across a broad range of customers. The prices are set to recover the costs to serve the customers in the class, based on metered usage data for a load research sample of customers.

However, the *actual* cost to serve different types of customers in the class can vary widely, depending on the percentage of their usage that occurs in the relatively high-cost peak period. The average cost to serve some customers may be substantially lower than the tariff price, while the cost to serve others may be much higher. However, without metered data, the energy supplier cannot easily distinguish between the costs to serve individual customers.

Two possible approaches for setting the regulated prices of an optional TOU rate illustrate the potential problems involved with traditional designs. In the first approach, TOU prices are set to be revenue neutral to the standard tariff for the average customer in the class (*i.e.*, the TOU prices are set to recover the same revenue as under the standard tariff, at the class-average level of usage). In the second approach, the TOU prices are designed to be revenue neutral *for those customers that the utility expects are most likely to select the TOU rate* (*i.e.*, the TOU prices are set to recover the same revenue as under the standard tariff, after accounting for the lower-cost usage patterns of the customers most likely to accept the TOU rate).

In the first case, the customers most likely to choose the TOU rate are "instant winners" who would see lower bills than under the standard tariff, even without changing their usage pattern, since their peak-period usage is less than average. This outcome, however, would leave the utility with less revenue than before, and is thus not revenue neutral across both the standard and TOU tariffs.

In the second case, the customers most likely to choose the TOU rate are those with peak-period usage that is lower even than the average of those customers targeted for the rate. As a result, relatively few customers are likely to choose the TOU rate, and those that do are still likely to see lower bills (and hence lower revenue to the utility) than if they had remained on the standard tariff, even before any load shifting.

Possible solutions to self-selection problems

One solution to the revenue attrition dilemma posed by these two approaches is to treat both the TOU rate and the standard tariff as optional once TOU is offered. Each rate is then priced to reflect the expected cost to serve the customers likely to select it. That is, the TOU prices are set to recover the *lower* expected cost of serving the customers most likely to accept the TOU rate, and the standard tariff prices are set to reflect the *higher* expected cost to serve the remaining customers. With such designs, the utility is more likely to recover its allowed revenue, while achieving greater participation in the TOU rate.[2] This is also the natural approach and outcome that will be followed by competitive energy suppliers offering alternative pricing options to customers in a broad market.

[2] This design is arguably more fair in that it produces less intra-class cross subsidy than a single flat rate.

Another approach to addressing the revenue erosion problem is to attempt to limit the applicability of the TOU rate to particular customer types whose readily identifiable characteristics are likely to imply costs to serve that are lower or higher than average (*e.g.,* customers with electric space heat and water heating). Yet another approach is to use a *two-part pricing* mechanism, with a customer-specific baseline level of usage, similar to the method used in two-part real-time pricing programs. This approach maintains revenue by billing each customer's baseline usage level at their standard rate, and applying TOU prices to differences between their actual and baseline usage. It gives each customer an incentive to respond to the TOU prices, but provides bill stability if they maintain their usage at baseline levels. Two potential weaknesses of this approach for residential customers are a lack of information on individual customers' baseline usage patterns, and a perception of greater complexity compared to a standard TOU rate.

A final solution is to install advanced interval meters for all customers, and charge prices, either flat or TOU, that reflect each customer's actual costs.

3. Innovative new types of residential TOU pricing

As noted in Section 2, a fundamental problem with traditional TOU pricing is the inaccuracy of TOU prices in reflecting wholesale power costs. Two new types of TOU pricing designs show substantial promise for addressing this problem. Both designs involve some form of variable, dispatchable pricing, in which one or more of the TOU prices may be modified on a day-ahead, or shorter notice basis to reflect expected wholesale market prices. One version, sometimes called "critical-peak" pricing, involves a feature in which the peak-period price can be increased to a higher than normal "critical" level in response to high-cost conditions in the wholesale market. The other, exemplified by Electricity de France's (EdF) *Tempo* tariff, consists of multiple sets of TOU prices that apply to different day types, which are designated and announced a day in advance.

Recent examples of the critical price TOU approach have combined variable pricing with *communication and control technologies*. The communication device allows the utility to signal a different price depending on wholesale price conditions. Rate structures of this type have typically taken the form of a standard three-tier TOU rate (*e.g.*, peak, off-peak and shoulder periods), with the addition of a *critical price* that applies only occasionally when wholesale prices or reliability conditions reach certain critical levels (critical price levels appear to have ranged from approximately \$.25 to \$.50/kWh, and many programs limited the number of critical price hours to no more than 2% of all hours). Under this approach, the *standard* peak period price may be set at a level substantially below typical TOU peak-price levels, because it does not have to cover the relatively few, but high-cost hours in which the critical price applies.[3] The lower peak price and occasional critical price allow a better match between TOU prices and wholesale costs. This feature may be particularly valuable to utilities in the Pacific Northwest, where extensive hydroelectric

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[3] For example, Gulf Power Company's standard peak period price is \$.087/kWh, which contrasts with values of \$.15 to .20/kWh for traditional TOU programs at other utilities.

resources keep costs low much of the time, but where infrequent tight reserve conditions can drive wholesale market prices much higher than normal.

In addition to the communication feature of the technology, a control device gives customers the ability to pre-set their response to both the standard and critical prices. This feature, similar to a programmable thermostat, has been shown to amplify the degree of customer price responsiveness, which adds to the potential benefits of this type of TOU rate structure. Gulf Power Company in Florida has tested a pilot critical price TOU tariff (Residential Service Variable Price, or RSVP), and has received approval to expand the program to a target of 50,000 customers.

EdF's Tempo tariff consists of three sets of peak and off-peak TOU prices for three *day-types* (*e.g.*, low, moderate, and high-cost), in each of two seasons. Customers are notified of the next day's day-type by eight p.m. (through the meter). The utility allocates a limited number of high (22) and moderate (43) days throughout the year. Like the critical price approach, this type of rate design allows lower peak period prices on the low and moderate-cost day-types than under typical TOU rates, and provides strong incentives for customers to reduce load during the relatively few high-cost peak periods (see Section 4 for empirical evidence).

4. Evidence of TOU price responsiveness

Traditional TOU

Numerous studies have investigated how residential customers respond to TOU prices. Many of the studies were conducted in the late 1970s and early 1980s as part of a series of TOU experiments at a number of U.S. utilities under sponsorship of the predecessor of the U.S. Department of Energy. Faruqui and Malko (1983) reviewed the findings from a variety of studies arising from these experiments. A useful synthesis of the findings on customer response to TOU pricing can be found in Caves *et al* (1984), which reports on an EPRI study of the consistency of price response across experiments.

Caves *et al* found a striking consistency across the TOU experiments in the estimated value of one typical parameter used to measure price responsiveness – the *elasticity of substitution*, with average values centering on approximately 0.14.[4] The estimated values also varied in sensible ways with certain household characteristics. For example, price responsiveness was smaller (0.07) for customers with no major appliances, and larger (0.21) for customers that had all major appliances, and thus a greater incentive and ability to respond. In a related study, Caves and Christensen (1980) showed that an elasticity of substitution of 0.17 was consistent with *partial* and *total* peak-period own-price elasticities of approximately –0.5 and –0.3 respectively.

Analysts at the Salt River Project in Arizona estimated a peak-period own-price elasticity of approximately -.30 for a TOU experiment in the late 1980s (see Kirkeide [1989]). This estimate focused on the response of relatively high usage residential

[4] See the appendix for a definition of various price elasticity concepts.

customers during the few hours coincident with system peak demands during the summer months.

Voluntary TOU

Two more recent studies reported findings of customer responsiveness to *voluntary* TOU rates. First, Caves *et al* (1989) found a relatively large substitution elasticity of 0.37 among customers who volunteered for a TOU rate at Pacific Gas and Electric Company. In contrast, Baladi *et al* (1998) found that the volunteers for an experimental TOU rate at Midwest Power responded quite similarly (0.17) to customers in the original non-voluntary TOU experiments.

Variable-price TOU

A few studies have reported price response findings for TOU programs in which the utility may dispatch different TOU prices depending on market conditions. American Electric Power (1992) reported significant load shifting from the "high" and "critical" price tiers to the "low" and "medium" tiers, but did not estimate formal price elasticities. They also reported peak demand reductions ranging from 2 to 3 kW per customer at "high" prices, and 3.5 to 6.6 kW at "critical" prices. The latter values represented as much as 60% of customers' peak load during a winter period. AEP also reported overwhelming customer satisfaction with the program.

Braithwait (2000) analyzed a similar pilot program at GPU Energy. Analysis of participant and control group load data indicated that customers modified their usage patterns substantially in response to the TOU prices, *reducing* consumption during peak periods and some shoulder periods, and *increasing* consumption during certain off-peak and shoulder periods. Summer peak-period load reductions averaged about .5 kW, or 25% of control group loads, while response during critical price periods ranged from .6 to 1.24 kW. Estimated elasticities of substitution exceeded those in most previous studies of traditional TOU programs, indicating strong customer price responsiveness. Specifically, the study estimated an elasticity of substitution of 0.31 for a constant elasticity of substitution (CES) demand model, while substitution elasticities between peak and off-peak periods of as large as 0.40 were found using a more flexible Generalized Leontief model.

These results illustrate the importance of two key factors that influence the degree of customer response to time-varying prices. First, relatively high peak period and critical prices ($0.25 and $0.50/kWh, respectively) provided strong *incentives* to respond. Second, the interactive communications equipment provided the *ability* to respond easily, without customers having to remember to make manual adjustments.

Finally, Aubin, et al (1995) reported finding strong price responsiveness and substantial net economic benefits in the experimental phase of the EdF Tempo tariff, which they referred to as residential real-time pricing.

The overwhelming evidence from the literature is that residential customers do respond to TOU prices, in a significant, and reasonably consistent and predictable manner. The primary question is whether the net benefits to customers and utilities from this load response are sufficient to outweigh the additional metering costs.

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Christensen Associates Analysis

Assessing the Potential Benefits of Residential Time-of-Use Pricing at Idaho Power Company

Steve Braithwait
Christensen Associates

September 11, 2002

The Idaho Public Utility Commission has asked Idaho Power Company (IPC) to investigate the viability of time-of-use (TOU) pricing for its residential customers. In a July 15, 2002 memorandum, Christensen Associates provided an overview of residential TOU pricing, including the following topics:

- an historical perspective on TOU pricing,
- a discussion of potential problems that can limit the benefits of residential TOU to utilities and their customers,
- a description of new types of TOU pricing that show promise in addressing some of those problems, and
- a summary of evidence on customer price responsiveness.

This report describes the results of a quantitative analysis designed to estimate the potential benefits to Idaho Power and its customers of offering alternative types of residential TOU pricing.

Summary

The fundamental principle of time-of-use (TOU) pricing is to charge retail prices that vary by time period (*e.g.*, summer peak and off-peak) to reflect differences in the average cost of generating and delivering power during those periods. Billing customers for their consumption under TOU pricing requires the installation of meters that record energy usage during specific blocks of time. As metering technology has advanced and become less expensive, a number of utilities are considering the installation of advanced interval meters that record hourly usage, and thus allow more refined pricing strategies that send high prices only during infrequent periods of high power costs (*e.g.*, extremely hot summer afternoons on which transmission constraints limit Idaho Power's access to wholesale power from outside of its service area). This study assessed the potential benefits to Idaho Power and its customers of both conventional TOU pricing and a form of "critical peak" TOU pricing that would involve interval metering, and communication and control technologies that would allow Idaho Power to send occasional critical prices to residential customers.

This assessment involved the use of data on Idaho Power's residential customer energy use and its hourly costs of supplying power. The analysis was conducted using customer demand model software that simulates customers' load response to TOU pricing, and calculates changes in consumer and utility benefits. Our primary conclusions may be summarized as follows:
Conventional TOU pricing offers relatively small potential benefits. The primary reason for this result is that Idaho Power's supply costs are generally low on most days, but they rise steeply during a few hours on a limited number of days in the summer. TOU prices that remain fixed on all days send price signals to customers that are too high on most days, but too low on the critical few high-cost days.

Critical peak TOU pricing has the potential to produce substantial benefits. If implemented on a mandatory basis, such a pricing strategy could produce peak load reductions on high-cost days of nearly 200 MW. Estimated benefits to customers would exceed $1 million annually. Estimated benefits to Idaho Power depend critically on assumptions about the costs that it avoids when customers reduce load during critical price periods. If avoided capital costs of new peaking capacity are considered, then the cost reductions associated with the 200 MW load reductions under mandatory CP TOU pricing could reach $12 million per year.

Under mandatory TOU pricing, the wide range of usage patterns across all residential customers implies that, before accounting for load response, some customers could face bill increases of up to $20 per year, while others could face bill reductions of similar amounts.

Implementing critical peak TOU pricing would require substantial investment in new metering and communication equipment, and changes to Idaho Power's billing systems. The cost of those investments has not been investigated in this study.

If TOU pricing were offered on a voluntary basis, the customers most likely to switch to TOU would be those that would experience an immediate bill reduction even before changing usage patterns. This would produce a revenue shortfall to Idaho Power without rate design changes to address this "self-selection" problem.

1. Introduction

The principal argument in favor of TOU pricing has always been *economic efficiency – i.e.*, TOU prices reflect differences in the average cost of generating and delivering power during particular time periods, thus providing more appropriate price signals to customers than do flat rates. Customers can achieve benefits under TOU pricing if they can shift sufficient consumption from peak-period hours, in which the price exceeds the standard flat price, to lower-price off-peak hours. Utilities can realize net gains from those same load shifts by avoiding some peak period sales whose cost exceeds the revenue generated, and selling more during low-cost off-peak periods. However, these TOU benefits must be traded off against higher metering and administrative costs.

Estimates of that benefit-cost tradeoff have generally not been favorable. Two main factors have weighed against the benefits of TOU pricing for residential customers. First, TOU prices do not reflect the variability of wholesale power costs with sufficient accuracy. For example, peak period prices (*e.g.*, $.10/kWh) are generally designed to represent an average across expected wholesale costs during peak-period hours in a given season (*e.g.*, summer).[1] However, wholesale power costs can range widely from moderate to very-high levels, depending on actual load levels and supply conditions. In many hours, TOU peak period prices substantially exceed the actual cost of power (*e.g.*, a TOU price of $.10/kWh versus a wholesale cost of $.03 to $.05/kWh). However, in the very hours in which costs reach their highest levels, the peak period price is likely to fall far short of that level (*e.g.*, $.10/kWh versus costs of $.50 to $1.00/kWh or more). Thus, while TOU prices do a better job than does a flat price of reflecting cost differences on average, the price signal is still not very accurate. When TOU customers reduce load during the many peak hours in which costs are actually relatively low, utilities' revenue can be reduced by more than their costs.

Second, the relatively low usage level of residential customers, combined with the first factor of inaccurate prices, limits the overall magnitude of potential *benefits* from customers' responses to TOU prices. These benefits must be traded off against the additional *cost* of metering and billing.

TOU rates have generally not been mandated, or established as the default tariff for residential customers. Most TOU programs have been offered as voluntary programs, typically targeted at customers with high usage levels, or ownership of major appliances such as central air conditioning or pool pumps. As a result, most residential TOU tariffs have relatively few customers.

Two recent programs promoted by Puget Sound Energy (PSE) in Washington State, and Gulf Power Company in Florida, provide indications of potential renewed interest in residential TOU. PSE has undertaken an ambitious program to install advanced interval meters for all of its residential customers, along with software and communication devices that give customers the ability to monitor their energy usage and PSE's wholesale power costs online. PSE has assigned all customers with the new meters to a TOU rate, although customers have the right to opt out and return to a flat rate. PSE claims that a large share of the cost of the metering and communications system may be covered by improved meter reading and billing efficiency, even before accounting for the benefits associated with customer load response to TOU prices. PSE has also discussed a range of potential advanced pricing approaches that they may consider offering to take advantage of the metering and communications capabilities.

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metering, and communication and control technology with a TOU rate that includes a dispatchable "critical peak" price. This program, a version of which is assessed in this report, has the potential to solve a number of the problems with traditional TOU pricing.

Our understanding is that Idaho Power Company currently faces a situation of increasing demand and transmission constraints that limit access to generation resources to the west. As a result, the company is considering plans to build additional peaking capacity. Thus, a dynamic pricing program that provided load reductions during key peak demand periods could provide valuable cost savings.

2. Overview of Quantitative Assessment

This report describes the analyses that we have conducted to assess the viability of residential TOU pricing at Idaho Power. We have analyzed variations on two general types of TOU pricing strategies – a conventional TOU tariff and a "critical peak" (CP) TOU tariff which consists of a standard TOU rate plus the ability of the utility to send a "critical" price on a limited number of days during the peak period, with day-ahead notice. We considered *mandatory* and *voluntary* versions of these two general TOU pricing strategies.

2.1 Analytical Tools and Data

Calculating the benefits of TOU pricing requires certain types of analytical tools and data. The principle benefits from TOU pricing result from customers' demand response to the TOU prices relative to their former flat price. Thus, developing estimates of TOU benefits requires an analytical model of customer demand for electricity by time period. In this study, we have calculated the benefits to customers and the utility using customer demand model software (implemented in Excel spreadsheets) that characterizes customers' hourly demands for electricity (relative to a reference load) as a function of TOU prices relative to prices from a reference period.[2] The model first calculates hourly *changes in loads* in response to changes in TOU prices, then calculates the *changes in customer benefits* (technically, *consumer surplus*) and *utility net benefits* (changes in revenue less changes in cost) associated with those load changes, and finally adds up the changes over all hours in the period of analysis.[3] In cases where TOU pricing is voluntary, customers may choose the TOU tariff if they believe that they would be better off facing TOU prices. To simulate this choice, the demand model contains a simple choice model, in which customers' probability of selecting the TOU rate depends on their estimated benefits from TOU pricing, scaled as the percentage change relative to their base bill under the flat rate.

The demand model requires several types of input data and behavioral parameter assumptions. The data include *historical* hourly customer loads and wholesale

[2] A technical description of the customer demand model is provided in an appendix.

[3] In the case of regulated utilities such as Idaho Power, the benefits to the utility may largely be thought of as benefits to all of the utility's customers. For example, load reductions that produce avoided costs that exceed foregone revenue imply that retail rates in the future will be less than would otherwise be the case.

costs, and *forecasts* of wholesale costs for the period of analysis. The parameters include price elasticities that characterize the extent to which different types of customers respond to time-varying and overall electricity prices, and parameters that represent customers' likelihood of accepting TOU pricing if offered on a voluntary basis. Christensen Associates has extensive experience in both estimating price response parameters for customers facing TOU pricing, and in compiling literature reviews of parameter values estimated in other studies.

Historical load and wholesale cost data

For purposes of this analysis, we used historical data from 1999 on customer loads and wholesale costs. This was the most recent year that was not "contaminated" by the extreme conditions that held in the West due to the California crisis of 2000-2001. Idaho Power provided hourly load research sample data for 1999. After exclusions for missing data, we were left with high quality data on hourly loads for a random sample of 94 customers that represented the wide range of usage patterns of Idaho Power's residential customers.

Constructing historical wholesale cost data required several steps. In principle, we wished to represent Idaho Power's hourly opportunity cost of generating, purchasing or selling power. IPC staff suggested using Mid-Columbia wholesale prices to represent those values. However, IPC only maintained historical records of the daily average peak and off-peak prices for 1999. To allocate those prices to hours of the day, we applied hourly patterns of the California day-ahead PX prices for each day in 1999. Finally, we decided that it was appropriate to smooth out certain uncharacteristic seasonal price patterns in the historical data by using expected seasonal patterns from wholesale price forecasts provided by IP.

Figure 1 illustrates the variability of IP's power costs. The curve shows the distribution of daily (weekday) five-hour peak average wholesale costs during June through September 1999 (*e.g.*, the average cost for hours 14 through 18). The solid flat line shows the overall average summer peak-period cost, which would normally serve as the basis for a peak period TOU price. The classic asymmetric shape of the price distribution illustrates one of the typical problems of TOU pricing – a TOU peak price based on the average cost across all days exceeds the actual cost of power on more than two-thirds of the summer days, while on the dozen days of the highest costs, the actual cost of power exceeds the average cost by more than fifty percent. When customers reduce load in response to peak TOU prices on days of relatively low costs, the utility loses more in revenue than it avoids in cost. Only on the relatively few high cost days does the utility save more in avoided cost than it loses in revenue from the load reductions.[4]

[4] The utility also potentially loses revenue from the non-energy portion of the rate if consumers reduce load by more in the peak periods than they increase usage in off-peak periods. This suggests that a larger portion of non-energy costs be recovered through customer charges rather than energy charges, particularly to the extent that the costs are fixed and not affected by changes in energy consumption.

The potential value of the CP TOU pricing approach can be seen in the dashed flat line, which shows average costs after excluding the twelve highest-cost days. In that case, the peak price provides a better approximation of normal peak-period costs, and the higher critical peak price on the highest-cost days encourages greater load response on those days.

Wholesale cost scenarios

We produced results for two alternative wholesale cost scenarios. One used the actual costs that occurred in 1999. The other was designed to represent a high-cost scenario, in which the costs for the 100 highest-cost hours were increased by gradually greater amounts such that the highest price equaled $500/MWh, rather than the actual historical maximum of approximately $200/MWh.

Customer price responsiveness

The customer demand model represents customers' price responsiveness by two main types of parameters – *elasticites of substitution* that represent customers' willingness to shift load from high-price to low-price time periods, and an *overall price elasticity* that represents customers' propensity to change their overall electricity consumption due to any change in the overall average price of electricity. Since the focus of this study was on customer response to time-varying prices, we set the overall price elasticity equal to zero.

We applied a range of elasticity of substitution values across the customers in the load research sample, where the values were based on two key factors that have been observed in previous analyses. First, reasonably consistent values of these elasticities have been found in a variety of conventional TOU pricing studies, with average values ranging from approximately .05 to .15, and higher values typically estimated for customers with major electricity-consuming devices such as central air conditioning, and electric space and water heating. Second, we have found substantially greater price responsiveness among customers facing critical price TOU programs, particularly for those in which the program involves communication and control technology that allows customers to pre-specify their response to TOU and critical prices, as in raising air conditioning thermostat settings. In one study, we found elasticities of substitution that approximately doubled the estimates under conventional TOU pricing.

We incorporated these findings in the following way. First, we assigned elasticities to the sample customers in a random fashion, after adjusting each customer's probability of receiving a given value such that customers with greater (less) than average annual usage had a greater (less) chance of receiving a larger elasticity parameter. Second, the parameters assigned for the CP TOU case were approximately double those of the Base TOU case. For the latter case, the assigned values ranged from .05 to .17, while for the CP case, they ranged from .09 to .30.

2.2 TOU Pricing Strategies

The TOU prices were calculated according to two principles. First, the ratio of peak to off-peak energy prices was set to reflect the ratio of the load-weighted average wholesale power cost in those time periods. Second, the actual price levels were calculated so as to generate the same revenue as under the standard flat tariff price, at the customers' baseline level of consumption. Only the energy portion of the standard tariff price (*i.e.*, the unbundled power supply and PCA rate component) was adjusted to reflect time-varying costs; the remaining portion of the tariff price, which represented about half of the total price, remained constant across time periods.

For the CP TOU strategy, we assumed a CP energy price of $.20/kWh, and assumed that it would be implemented on average during 60 hours of the year.[5] To calculate the TOU prices that apply during the remaining hours of the year, we first subtracted the revenue generated in the assumed 60 critical hours, then calculated the price ratios and revenue-neutral prices for the remainder of the revenue requirement.

For purposes of this relatively high-level analysis, we felt that it was appropriate to focus only on *peak* and *off-peak* pricing periods. A more comprehensive analysis could examine a third set of "shoulder" period prices as well. Analysis of the wholesale power costs across hours suggested that the optimal peak period for the June through September summer period was the five hours of 1 p.m. to 6 p.m. (*i.e.*, hours ending 14 through 18), while for the remaining months it was 14 hours from 7 a.m. to 9 p.m.[6] Table 1 summarizes the relevant prices.

Table 1: TOU Prices

	Summer Prices (cents/kWh)			Winter Prices (cents/kWh)	
	Peak	Off-peak	Critical	Peak	Off-peak
Flat	-	5.12	-	-	5.12
Base TOU	6.78	4.99	-	5.35	4.76
Critical Price TOU	5.94	4.88	22.45	5.23	4.66

[5] For reference, GPU Energy used a critical price of $.50/kWh in a pilot CP TOU program in 1997, and Gulf Power has set its critical price at $.29/kWh. We used a somewhat lower price in view of IPC's generally lower costs.

[6] The optimal peak periods minimize the variability of prices within the period, while maximizing the difference between the average variability between the two periods.

3. Effects of TOU Pricing

3.1 Analysis of Changes in Energy Consumption and Benefits

As described above, the customer demand model first calculates changes in customer usage patterns under TOU pricing. These load changes are then used to calculate changes in consumer benefits, and changes in utility net revenues. In the case of voluntary TOU, the changes in consumer and utility benefits are calculated only for that percentage of customers that are estimated likely to adopt TOU pricing.

Before turning to the quantitative results, we first summarize the source of and method for calculating consumer benefits from TOU pricing. It is instructive to illustrate changes in consumer benefits in two stages. First, consider the bill changes induced by the revenue neutral (at average baseline usage) TOU design, as shown in Figure 2. The higher prices during the peak periods, and the lower prices during off-peak periods, relative to the flat price, imply peak-period *bill increases* and off-peak *bill reductions.* For the average pattern of baseline usage, these bill changes offset each other completely, leaving no net annual bill change (*i.e.*, revenue neutrality) before accounting for any load response. However, the wide range of usage patterns in the residential class implies that some customers (*e.g.*, those with a greater than average share of peak period usage) will experience overall bill increases, while others (*e.g.*, those with a less than average share of peak period usage) will see bill reductions even before undertaking any load response.

To illustrate, Figure 3 shows the distribution across customers of annual bill changes before load response for the Base TOU pricing case. The distribution is reasonably symmetric, with relatively small bill changes ranging from approximately $20 bill reductions, to $20 bill increases per year. (Note that under the current flat price those customers with relatively less usage during the higher-cost summer peak periods cost less to serve than the average customer, and are thus effectively subsidizing customers with relatively high usage during those periods).

Figure 4 illustrates how customers can benefit from load changes in both peak and off-peak periods. Economists traditionally measure changes in consumer benefits due to price changes as changes in *consumer surplus*, which can be thought of as the difference between what consumers are *willing to pay* for a certain amount of a product (as reflected in their demand curve) and the market price that they actually *have to pay.* A conventional downward sloping demand curve reflects the *value* that consumers attach to a product or service; it implies that consumers are willing to purchase more of a product as its price falls, or less of it as its price rises. The right panel of Figure 4 shows that the average consumer who purchased Q^0_{OP} in the off-peak period at the flat price, P_F, increased consumption to Q^{TOU}_{OP} at the lower off-peak price, and experienced an increase in benefits equal to the triangular area under the demand curve and above the off-peak price, P_{OP}.

The left panel shows that during the peak period the average consumer who purchased Q^0_P in the peak period at the flat price, reduced consumption to Q^{TOU}_P at the now higher peak price, P_P. By reducing consumption, he reduced his bill by the rectangular area bounded by the two price lines and the amount of the load reduction. However, he also lost some value from the foregone consumption (*e.g.*, experienced some discomfort after raising the air conditioner thermostat setting on a hot day), as indicated by the triangular area under the demand curve. The net result is a gain in value equal to the bill reduction less the foregone value.[7]

3.2 Estimates of TOU Pricing Impacts

Table 2 summarizes the estimated changes in various key electricity consumption, financial, and customer benefit variables for each of the pricing strategies examined in this analysis. The following are comments on specific results, starting from the left-most columns.

1. *Load changes.* The first set of columns shows changes in demand (in MW). Two values are shown. The first is the change during the hour of maximum demand (regardless of wholesale cost) for the entire class. The second shows the change in the hour of highest wholesale cost. The Base TOU case produces the greatest impact in the coincident peak hour, while the load response for the CP TOU cases is much larger during the important high-cost hour. The mandatory version of CP TOU suggests a maximum potential of nearly 200 MW of load reductions at times that critical prices apply.[8]

2. *Utility impacts.* The second set of columns shows effects on Idaho Power's *revenues, costs, and net revenues* of the load shifting induced by the TOU pricing, under both the base and high-cost scenarios. For the two mandatory cases, the reductions in *revenue* occur as a result of customer load changes. Under the voluntary cases, the revenue reductions occur as a result of both "instant" bill reductions for participating customers as well as their load reductions.

   The reductions in *cost* result from the energy costs avoided by customers shifting load on net from high-cost to low-cost hours. Under the base assumption of the costs that occurred in 1999, the cost reductions in most cases are less than the revenue reductions. Under the high-cost scenario, cost reductions in the two mandatory TOU cases exceed revenue losses, showing the potential net benefits to the utility and its customers. In the two voluntary cases, the revenue losses from voluntary self selection exceed the

[7] The actual amounts of both bill reduction and foregone value from the load reduction include the unshaded rectangle below P_F and between the two quantity levels. However, these changes cancel, leading to the focus on the shaded areas.

[8] The load changes and resulting impacts on utility costs were inflated by an estimate of transmission and distribution *line losses*. We assumed an average value of seven percent. Thus, a 1 MW load reduction measured by meters at the customer level translates into a 1.07 MW reduction in Idaho Power generation requirements.

cost reductions. However, it should be pointed out that alternative TOU rate designs can be used to address the revenue attrition problem caused by customer self selection.[9]

Finally, Idaho Power may be able to count an additional benefit of the TOU load reductions to the extent that they allow the utility to avoid or postpone the need for additional peaking capacity. For example, under an assumption of a capital cost for peaking capacity of $500/kW for a unit that is expected to run for approximately 50 hours per year, and an annual capital charge rate of 12%, then a 100 MW load reduction during the same number of hours could be considered to avoid the cost of $60/kW * 100 MW * 1000 kW/MW = $6 million per year. Thus, the 200 MW load reduction of the mandatory CP TOU would produce $12 million in capital cost savings.

3. *Customer benefits.* The third set of columns shows changes in consumer net benefits, in both a dollar amount and as a percentage of the total base bill before load shifting. The total change in net benefits is comprised of two components. One is the "instant" bill changes that consumers see from the change to TOU prices (*e.g.*, customers with greater than average energy consumption in the non-summer and off-peak periods receive an immediate bill reduction from the TOU prices). In the mandatory cases, these instant bill changes net out to effectively zero, reflecting the revenue neutrality assumption. The second component represents "load response" gains due to consumers shifting load from peak to off-peak periods. The *percent of base bill* value provides a useful relative measure of the magnitude of benefits. In previous analyses, we have seen gains in net benefits as a percent of base bill range from less than 1% to approximately 2 – 3%. The magnitude of net benefits depends on two key factors – the degree of price variability (*e.g.*, the difference between peak, off-peak and critical prices) and customers' flexibility to change usage patterns.

   Total annual net benefits for each TOU option under each cost scenario may be obtained by adding the total customer net benefits to the utility's net revenue change in the relevant cost scenario. These results provide one key input to the assessment of the viability of TOU pricing at Idaho Power. To arrive at a complete assessment of the benefits and costs of the TOU pricing strategies, one would need to compare the costs of the required metering equipment to a discounted stream of annual net benefits such as those in the table, over a reasonable time period.

4. *Participation.* The next set of columns shows participation rates in the two voluntary options as a percentage of load and of the number of customers.

[9] For example, once the TOU rate is offered as a voluntary rate, the standard flat rate also becomes voluntary. Thus, each should be priced to reflect the costs of the customers most likely to select each rate. This would suggest higher flat prices to reflect the relatively higher cost to serve customers that do not immediately benefit from the TOU prices.

An assumption underlying the relatively small TOU participation rates is that customers have some inertia that tends to make them reluctant to change pricing options, particularly for the relatively small gains reflected in these examples, such that they do not automatically adopt a TOU option even if it appears to deliver positive net benefits. The number of customers participating in the voluntary cases may be calculated by recognizing that Idaho Power had approximately 300,000 residential customers in 1999.

5. The last column shows the percentage of customers that would experience negative net benefits under each case. Under the mandatory cases, approximately half of the customers would gain at the expense of the other half, as seen in Figure 3 above. In the voluntary cases, even some customers that experience bill increases have some probability of volunteering for the TOU price.

4. Conclusions

Conventional TOU pricing applied on a mandatory basis to IPC's residential customers would produce very modest potential benefits. This result is due to the relatively small differential between average peak and off-peak wholesale costs, and thus the retail TOU prices, as well as the general lack of correspondence between average peak costs and the day-to-day variations in those costs. Making TOU pricing voluntary produces somewhat higher consumer benefits, but results in net revenue losses to Idaho Power due to customers self selecting the TOU rate whenever it offers immediate bill (and revenue) reductions.

Critical peak TOU pricing appears to provide the potential for beneficial load reductions and cost savings. It would produce much larger demand reductions during the most important high-cost hours than does conventional TOU. Customer net benefits are also higher due to the greater opportunity for benefits from load reductions during critical price periods. The results for the mandatory case indicate a potential gain of more than $1 million annually. From the standpoint of Idaho Power, however, the key factor affecting potential benefits is the nature of the costs that would be avoided by customers' load reductions. Under the base cost scenario, cost reductions fall short of revenue reductions, yielding a large net revenue reduction.[10] However, cost reductions under the high-cost scenario exceed the revenue reductions, producing net gains to the utility.

In addition, if the load reductions can be credited with avoided capital costs for new peaking capacity, then the value of the load reductions may be substantially higher than the cost reductions shown in Table 2.

A more realistic case might be that CP TOU would be offered on a voluntary basis. In this case, careful rate design would be required to limit the extent of revenue losses from customer self selection. Under the assumptions in our analysis, a

[10] In actual operation, the critical prices might not be dispatched for as many days under the base cost scenario as was assumed in the analysis. This would limit the amount of net revenue losses.

market share of 25% would produce load reductions of approximately 40 MW during critical price conditions.

Finally, any of the above cases of estimated benefits must be traded off against the cost to Idaho Power of installing advanced interval metering equipment and modifying its billing systems to account for TOU pricing.

Figure 1: Distribution of Wholesale Power Costs –
Average Daily Peak-period Values (1 p.m. – 6 p.m.)

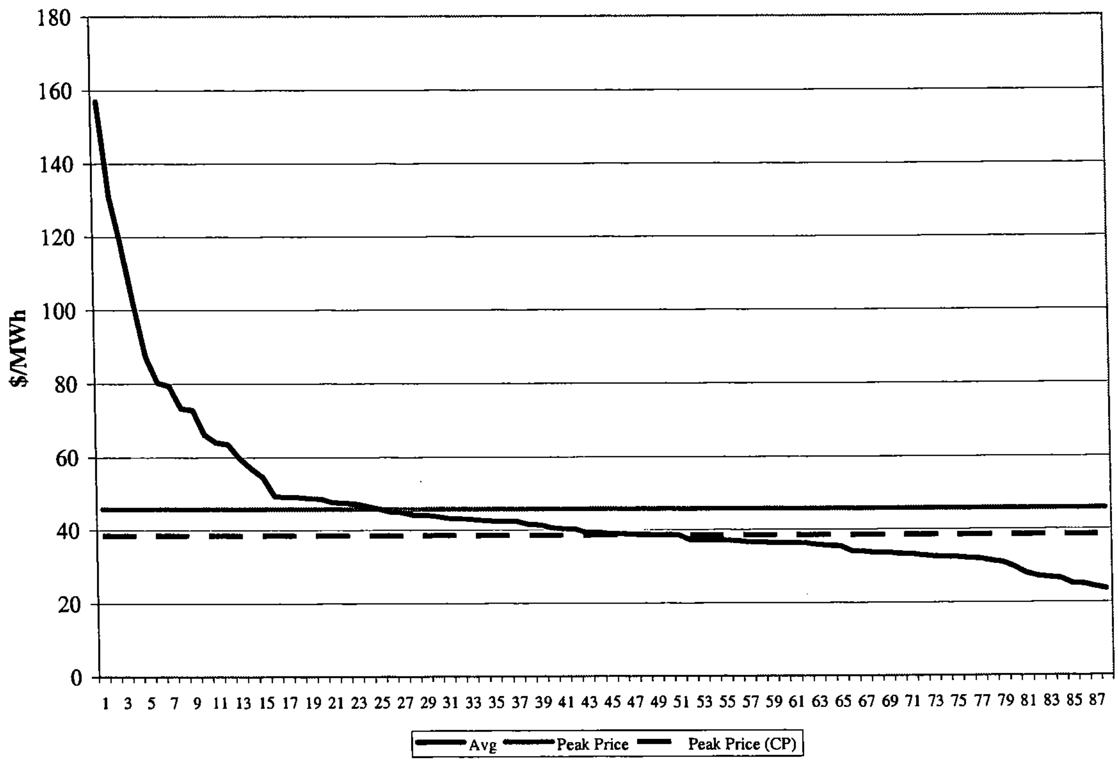

Figure 2: Revenue Neutrality of TOU Prices at Baseline Consumption

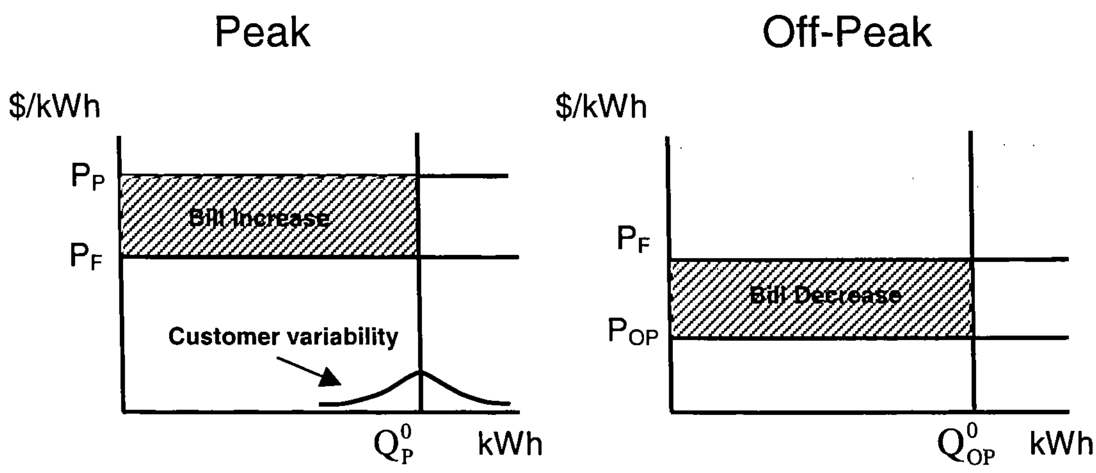

Figure 3: Distribution of Bill Changes Before Load Response
Mandatory Base TOU ($/year)

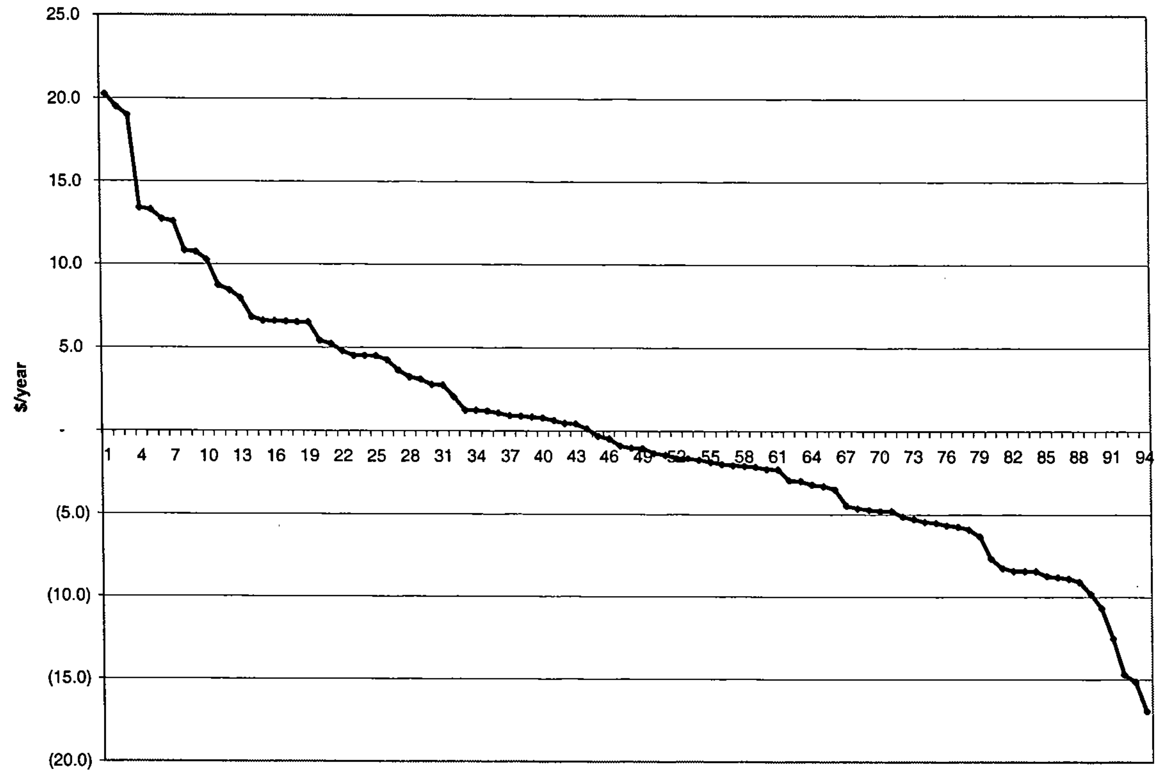

Figure 4: Customer Benefits from TOU Pricing

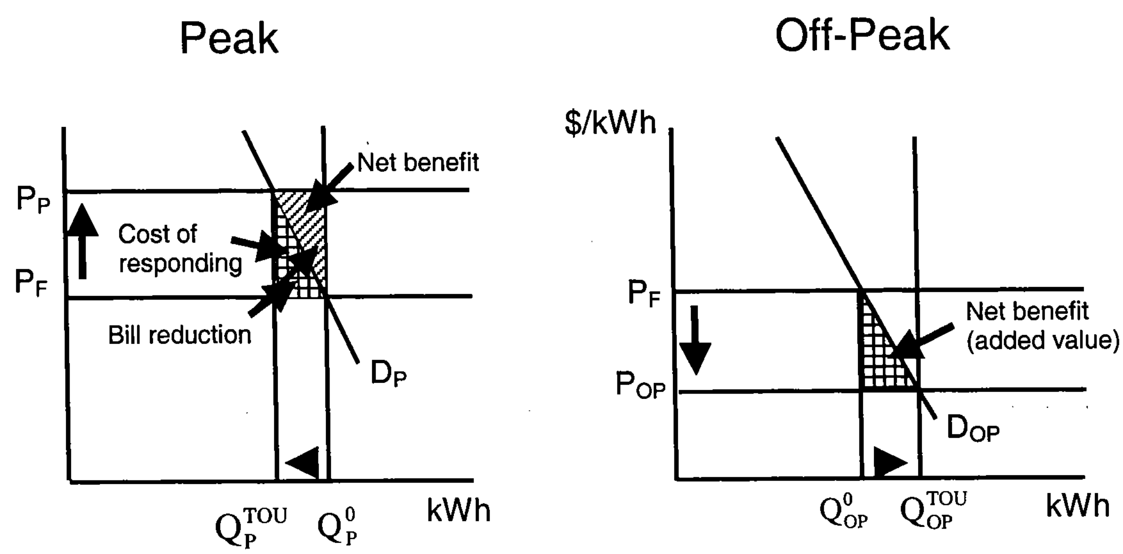

Table 2: Impacts of TOU Pricing – Base Case Costs

Tariff	Change in Demand (MW)		Utility Impacts ($ million)					Customer Benefits ($ million)				Participation		% Cust w/ Neg Benefits
				Base costs		High costs								
	Coin. Peak	Hour of Highest Cost	Rev.	Cost	Net Rev.	Cost	Net Rev.	Instant	LR	Total	% Base Bill	% of load	% of cust.	
Base TOU - Mand.	-25.4	-22.3	-$0.09	-$0.13	$0.04	-$0.25	$0.16	$0.00	$0.09	$0.09	0.04%	100%	100%	53%
Base TOU - Vol.	-3.1	-2.7	-$0.28	-$0.02	-$0.26	-$0.03	-$0.25	$0.27	$0.01	$0.28	0.13%	16%	14%	17%
CP TOU - Man.	-8.8	-198.2	-$1.10	-$0.37	-$0.74	-$1.37	$0.27	$0.00	$1.10	$1.10	0.51%	100%	100%	46%
CP TOU - Vol.	-2.8	-43.2	-$1.15	-$0.09	-$1.06	-$0.31	-$0.84	$0.90	$0.25	$1.15	0.53%	30%	25%	11%

Appendix: Demand Model Documentation

The demand response model incorporated in the spreadsheet software is based on the nested *constant elasticity of substitution* (CES) demand model. The CES functional form has been widely used to characterize customer response to time-varying prices, including both time-of-use (TOU) and hourly prices.

The nested CES (NCES) is derived from a customer cost function that allocates electricity costs separately within and between days. That is, a customer's overall electricity costs are represented by a function of daily price indexes, which in turn are functions of the hourly (or TOU) prices on each day. Customers choose levels of electricity demand that minimize overall costs with respect to the time-varying prices, while maintaining the level of services implied by a historical usage pattern at historical prices. The model allows two levels of customer flexibility to respond to time-varying electricity prices. One level involves the flexibility of customers to shift load between hours or time periods *within* a day; the other level allows the flexibility to shift load *between* days in response to changes in the average price level between different days.

The daily price index for day d, D_d, is specified via the CES functional form as a *load-weighted average of elasticity-adjusted hourly prices* P_h in that day:

$$D_d = \left(\sum_{h \in d} \alpha_{hd} P_h^{(1-\sigma_w)} \right)^{1/(1-\sigma_w)},$$

where α_{hd} is a load shape parameter that approximates the fraction of daily load in hour h, and σ_w is the *within-day elasticity of substitution* parameter. Next, the aggregate monthly price index M_m, also given as a CES function, is a load-weighted average of elasticity-adjusted daily prices D_d in that month:

$$M_m = \left(\sum_{d} \beta_d D_d^{(1-\sigma_b)} \right)^{1/(1-\sigma_b)},$$

where β_d is a second load shape parameter that approximates the fraction of aggregate monthly load that occurs in day d, and σ_b is the between-day elasticity of substitution parameter.

The customer's demand for electricity may then be obtained by applying Shepard's Lemma to the above cost functions, differentiating the cost function with respect to the input price. It is most convenient to specify the resulting demand equations *relative to an average reference load*, and in logarithm form as shown in the following:

$$\ln\left(\frac{E_{dh}}{\overline{E}_h^m}\right) = \sigma_w\left[\ln\left(\frac{D_d}{\overline{D}^m}\right) - \ln\left(\frac{P_{dh}}{\overline{P}_h^m}\right)\right] + \sigma_b\left[\ln\left(\frac{M_m}{\overline{M}^m}\right) - \ln\left(\frac{D_d}{\overline{D}^m}\right)\right].$$

E_{dh} represents electricity usage in hour (or time period) h on day d, P_{dh} is the price, and the daily and monthly price indexes are as defined above. The variables in the denominator with the super bar represent averages of the variable for the comparable time period in the reference period (*e.g.*, the average load in hour h on weekdays in a given month. The demand equations have two types of parameters. The *load shape parameters* (α_{hd} and β_d) characterize the inherent shape of the customer's load pattern and are used to construct the daily and monthly price indexes. The *price response parameters* (σ_w and σ_b) characterize how the load responds to changing hourly prices. In this study, we assumed that the two price response parameters take on the same value, *i.e.*, $\sigma_w = \sigma_b$, and refer to that value as the elasticity of substitution.

Given prices and loads in a baseline period, assumptions about price response parameters, and prices in an alternative scenario, the model calculates customer demands in each time period.

ISSUES SPECIFIC TO IDAHO POWER

Two issues which directly affect the viability of time-of-use pricing for Idaho Power are the current status of the Company's metering capability and the PCA treatment of benefits associated with reductions in power supply costs which may result from the shifting of customer loads to off-peak periods. Any potential benefits from time-of-use pricing must be traded off against the costs of the metering equipment and billing system modifications necessary to record and bill interval usage. In addition, any power supply related benefits from time-of-use pricing should flow through the PCA in a manner that is fair and equitable to customers and the Company.

Metering Capability. The analysis performed by Christensen Associates did not include any cost component for the metering equipment necessary to record usage by time period. Idaho Power currently does not have metering equipment in place to record usage by time period for residential customers. There are two options which could be utilized to provide the ability to record usage by time-of-use. First, standard time-of-use meters could be installed. These meters have an internal clock and calendar and are programmed to record usage during the time-of-use periods. Usage data is retrieved monthly during the Company's standard meter reading process. If the hours included in the time-of-use periods change, these meters must be physically reprogrammed through a site visit. In addition, because usage information from several registers must be retrieved when these meters are read, additional administrative costs associated with the increased meter reading time is incurred. Second, an automated meter reading (AMR) system could be installed. With an AMR system, meters are read via the power line or radio frequency depending on the application. Changes to time-of-use periods can easily be made via the remote communication capability of an AMR system. Because an AMR system reads meters remotely, updated usage information can be collected on an "at will" basis, allowing for more timely information to be provided to customers. The average cost to install a standard time-of-use meter for a residential customer would be about $145 per customer or approximately $47 million for all residential customers system-wide. The incremental cost of the TOU meter compared to the standard meter now installed for residential customers would result in an increased charge to customers of about $1 a month. The latest cost estimate to install an AMR system across Idaho Power's service territory is approximately $72 million.

PCA Implications. Benefits result from time-of-use pricing when customers are able to reduce their bills and utilities are able to reduce their costs by an amount greater than the reduction in revenue. Assuming that a time-of-use scenario that successfully addresses the potential revenue attrition problems identified by Christensen Associates could be constructed, a time-of-use scenario cannot be beneficial to Idaho Power without a modification to the manner in which reductions in power supply costs which result from customers' load shifting are treated in the Power Cost Adjustment (PCA) mechanism. Under the current PCA methodology, 90% of the reductions in power supply costs that accrue as a result of customers shifting load from the on-peak to the off-peak period are passed through to customers as a benefit. Idaho Power is able to retain only 10% of the benefit. However, Idaho Power absorbs 100% of the reduction in revenue. The 90/10 sharing of the benefits associated with reduced power supply costs would result in a negative impact to Idaho Power's earnings. The following example, in which it is assumed that customers' load shifting resulted in a decrease in power supply costs greater than the reduction in revenue, illustrates the situation.

<u>Impact for Utility Without PCA Mechanism</u>

Reduction in revenue due to reduced customer billings	$ (90,000)
Reduction in power supply costs due to customers shifting load to off-peak time period	$(130,000)
Impact to Utility's earnings	$ 40,000

In this example, the net impact to the utility's earnings is an increase of $40,000.

<u>Impact for Idaho Power With PCA Mechanism</u>

Reduction in revenue due to reduced customer billings		$ (90,000)
Reduction in power supply costs due to customers shifting load to off-peak time period	$(130,000)	
Idaho Power's 10% share of reduced costs	$(130,000*10%)	$(13,000)
Impact to Idaho Power's earnings		$(77,000)

In this example, the net impact to Idaho Power's earnings is a decrease of $77,000.

The PCA treatment of benefits associated with reductions in power supply expenses that could accrue as a result of customers shifting load in response to time-of-use pricing must be addressed to remove the negative impact to Idaho Power's earnings in order for time-of-use pricing to have the opportunity to be viable.

Energy Efficiency Advisory Group

Input from the Energy Efficiency Advisory Group (EEAG) indicates support for implementing pricing that requires customers to pay what it costs to receive service. The EEAG supported pricing that lets customers who use less energy during the on-peak period pay less and requires customers who use more energy during the on-peak period to pay more. Overall the group was more supportive of increasing the charges for the standard tariff service and making both the standard service and time-of-use service optional than it was of making time-of-use mandatory. Some concern was expressed for those who may have a difficult time paying more for energy used during the on-peak period; however, recognition was made that customers should pay for the service they receive.

The EEAG expressed the sentiment that it appeared to be more sensible to pursue a demand response program than a time-of-use pricing program at this time given the investment in metering equipment that would be necessary to accommodate a wide-scale time-of-use program. A demand response program that targeted a reduction in load during only those high cost hours in which the economics indicated it was beneficial to do so appeared, according to the EEAG, to be an option that might have merit.

Although time-of-use pricing could be offered using standard time-of-use meters, the EEAG believed that it would be important to the program's success to provide customers with the additional information that would be available through an AMR system. In addition, the EEAG indicated customers would be willing to pay more to have the additional information available.

The EEAG discussed the potential of installing time-of-use meters in new subdivisions and housing developments. However, the EEAG did not support mandatory time-of-use pricing for these customers nor did the EEAG support cost shifting of additional meter related costs to non-participants. Consequently, EEAG did not support the suggestion that all new developments be equipped with time-of-use meters.

Conclusions

Some of the new types of time-of-use pricing, particularly the critical peak TOU structure, may have potential as viable pricing options for residential customers at some time in the future. However, any benefits that may result from time-of-use pricing must be balanced against the costs of the equipment necessary to accommodate the pricing. Idaho Power currently does not have a metering system in place to accommodate a large-scale time-of-use pricing program for residential customers. The cost of installing standard time-of-use meters, which would not allow for the "critical peak" or "day type" designs, does not appear to be economic given the potential benefits that might accrue from load shifting given the relatively small loads of residential customers. Until such time as an AMR system is available on Idaho Power's system, and a PCA methodology is devised to remove the negative impact to Idaho Power's earnings due to the unequal treatment of the revenues and expenses impacted by load shifting, residential time-of-use pricing is not economically viable.