GUNSTER

ATTORNEYS AT LAW

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January 6, 2011

BY HAND DELIVERY

Ms. Ann Cole
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: **Docket No. 100459-EI - Petition for authority to implement a demonstration project consisting of proposed time-of-use and interruptible rate schedules and corresponding fuel rates in the Northwest Division on an experimental basis and request for expedited treatment, by Florida Public Utilities Company.**

Dear Ms. Cole:

Enclosed for filing, please find the original and five (5) copies of Florida Public Utilities Company's responses to Staff's First Data Requests in this proceeding. Also included with this filing are 6 copies of the consultant's report referenced in the Company's responses.

Thank you for your assistance with this filing. If you have any questions whatsoever, please do not hesitate to let me know.

Sincerely,

Beth Keating

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cc: Robert Scheffel Wright, Esquire (via email)

FLORIDA PUBLIC UTILITIES COMPANY
RESPONSES TO
STAFF'S FIRST DATA REQUEST
DOCKET NO. 100459-EI

1. Please explain how and when FPUC will allocate savings to non-participants, i.e., customers that will not take service under the time-of-use (TOU) or interruptible program, resulting from the expected reduction in the demand ratchet provision.

   Company Response: The Company, through the amended Agreement for Generation Services with Gulf Power Company (the "Amended Agreement"), has negotiated a reduction in the Capacity Purchase quantity and, therefore, the Monthly Capacity Payment provision that will result in lower costs (savings) regardless of any actions from customers. The Amended Agreement savings were not projected in the Company's Fuel and Purchased Power Cost Recovery Clause filing for rates that were approved for 2011. As such, absent any action on behalf of the Company, the Amended Agreement savings, holding everything else equal, would show up as an over-collection in its 2011 fuel adjustment true-up for the Marianna Division. This over-collection would help reduce the fuel rates in 2012, as would the inclusion of the lower Capacity Purchase quantity in the projection calculations.

2. Please refer to paragraph 18 of the petition, which states: "[i]t is important to note that if customer participation in the demonstration program is below that established maximum levels, then all remaining targeted annual savings will benefit non-participants." Please explain how non-participants will benefit if customer participation is below the participation levels.

   Company Response: The Company has allocated a portion of the total Amended Agreement savings to the TOU rate classifications, and established the participation level and the on-peak and off-peak rates to achieve the target savings amount. If, for example, the proposed maximum number of participants in the Residential TOU rate classification (940 participants) does participate, then the amount of Amended Agreement savings allocated to this class would be enjoyed by said participants (holding all other assumptions equal). Therefore, if fewer customers participate, then the level of savings for the Residential TOU rate classification will be lower. As stated in response to Question 1 above, the total Amended Agreement savings are fixed and will occur, so, in this example, the non-participants will receive more savings if fewer TOU customers participate in the program. Because the Company is proposing to cap the number of participants in the TOU program, there is no scenario where non-participants can be harmed or otherwise negatively impacted (pay more than they otherwise would) by this program.

3. With respect to the $900,000 annual savings, please state in dollars: (a) the savings allocated to the proposed TOU rate, (b) the savings allocated to the proposed interruptible rate, and (c) the savings allocated to non-participants.

Company Response: The $900,000 annual savings is an average per year over the remaining, extended Amended Agreement term. The Company has allocated for 2011 approximately 50% of the annual savings to the TOU rate classifications, 5% to the Interruptible classification and 45% to non-participants.

4. Is FPUC proposing to lower the 2011 levelized fuel factors that have been approved in Docket No. 100001-EI to reflect any savings resulting from the expected reduction in the demand ratchet provision?

Company Response: The Company is not proposing to lower the 2011 levelized fuel factors approved in Docket No. 100001-EI at this time.

5. Please provide the workpapers that show the calculation of the proposed on- and off-peak fuel factors.

Company Response: Please see the attached report from Christensen Associates Energy Consulting ("Christensen"). See Tables 9 through 12 for the analysis of the proposed rates located on pages 22 through 25.

6. The petition states that FPUC has allocated approximately 50 percent of the expected savings resulting from the amended Agreement to the proposed TOU fuel rates. Does that allocation of savings result in customers being able to save on the TOU rate even without modifying their consumption behavior?

Company Response: As stated in the Petition, the Company does not have customer-specific data regarding hourly consumption for either on-peak or off-peak periods. The Company engaged Christensen to analyze the available data (most of which is recorded at the interconnection points with Gulf Power) and their previous experience with other utilities to derive an estimate of customer behaviors. Christensen utilized this data to project customer usage patterns under the standard fuel rates and projected changes under the TOU rates. As shown on Tables 9 through 12, there is a behavioral change required to achieve the targeted level of savings per customer. If customers do not change their behaviors, then the TOU rates could result in higher monthly bills compared to the standard rates.

7. Please provide the workpapers that show the calculation of the proposed on- and off-peak fuel factors for interruptible rate. Please also include a discussion as to how customers are being compensated for choosing to take service on a non-firm rate.

Company Response: For Interruptible service, the on-peak period, as shown on First Revised Sheet No. 39.0, is the entire calendar months of May through September. This matches the Amended Agreement's Peak Season which determines the Capacity Purchase quantity and Monthly Capacity Payment. The Company has proposed an on-peak rate that is lower than the approved 2011 levelized fuel factor for those customers that are eligible for this service, as shown on First Revised Sheet No. 38.0. The on-peak rate was derived from the expected number of KWh's for the customer electing this service during May through

September and the allocation of approximately 5% of the annual savings from the Amended Agreement.

8. Please state and describe the administrative and operational costs the Company is proposing to absorb.

Company Response: The Company is proposing to absorb the following administrative and operational costs, including but not limited to: 1) Billing system administration – the existing billing system has a module for time-of-use rates that is currently inactive. The Company will need to activate the module and test it to ensure that it works properly with the proposed rates; 2) the Company will need to train its Customer Care staff on TOU rates so that they can assist customers who are interested in the TOU experimental rates; 3) the Company will need to administer the "Open Enrollment" process including preparation of educational materials, postage and other costs associated with this process; 4) the Company will need to investigate and make modifications, if any, to the hand-held meter reading devices and processes to ensure accurate reads are transmitted into the billing system; 5) the Company will need to purchase TOU meters for each participant, program the meters and install the meters at the customers location; and 6) administer the terms and conditions of the Interruptible Special Contract. There may be additional administrative and operational costs incurred that are not listed here.

9. What is the basis for the summer on-peak period to be from noon – 6 pm? (for the other IOUs the summer on-peak period is noon – 9:00 pm)

Company Response: Please see Section 2 (pages 2 through 5) of the Christensen report attached for the basis for the summer on-peak period of noon – 6 pm.

10. How many customers does FPUC - Marianna serve under the GSLD rate?

Company Response: The Company currently serves thirteen (13) customers under the GSLD rate classification.

The following questions refer to the amended agreement FPUC and Gulf Power have agreed to in principal:

11. Besides the reduction in the Capacity Purchase quantity, are there any other changes both parties agreed in principal to amend? If yes, please describe each amendment in detail.

Company Response: The parties have agreed in principal to extend the current Agreement by two (2) years (through December 31, 2019) and have established the capacity rates for 2018 and 2019 (these rates are confidential). The Amended Agreement also includes language so that if the City of Marianna does not renew, extend or replace the franchise at the current expiration date, then, under certain conditions, the Capacity Minimum may be reduced by the Marianna Load Amount beginning January 1, 2018 (the beginning of the two year extension). The Company expects to file the Amended Agreement with the Commission for approval within the next two or three weeks.

12. Will the term of the original agreement be extended? If yes, please explain and identify the number of years.

Company Response: Yes, the agreement will be extended for two (2) years. The current agreement expires on December 31, 2017 and the Amended Agreement, if approved, will expire on December 31, 2019.

13. Will the agreement for transmission services be affected by the amendment of the agreement? If yes, please explain.

Company Response: No.

14. Has the negotiation to amend the contract been concluded?

Company Response: Yes, however, the City of Marianna has the right to review any amendment and they are still in their review process. The amendment has not yet been executed by either the Company or Gulf Power.

15. When will FPUC file for Commission approval of the amended agreement?

Company Response: The Company expects to file for Commission approval within the next two to three weeks, if the amendment is executed.

16. Please explain in detail what happens if the discussions with Gulf Power end unsuccessfully or the Commission denies the amended agreement.

Company Response: The Company and Gulf Power have agreed in principle to the Amended Agreement. The Company is waiting on the City of Marianna to finish its review before executing the Amended Agreement. Although the Company is not predicting what the Commission will do with respect to the Amended Agreement, because the result of the amendment is a savings from the existing Commission-approved agreement, the Company believes that the probability is very high that the Commission will approve the Amended Agreement.

17. Please refer to proposed Tariff Sheet No. 40.0, Terms and Conditions. The first sentence states " . . . after execution of a Special Contract which will be subject to approval by the Commission." Is FPUC proposing that the Commission approve a contract for every customer taking service under the IS-EXP rate?

Company Response: The experimental Interruptible rate proposed limits participation to one (1) customer. If the Company enters into discussions with a potential customer interested in the IS-EXP rate classification, the Company expects that there will be specific requirements that the customer needs in order to participate. These needs are likely to be operational and may deviate from the standard tariff provisions, since the Company does not currently offer any kind of interruptible service. As such, the Company believes that it was prudent to require

a Special Contract between the parties so that all of the details would be clearly defined and agreed to by the parties and approved by the Commission.

18. Please refer to proposed Tariff Sheet No. 41.0. The on-peak fuel charge for the IS-EXP rate class is lower than the off-peak fuel charge. Is that correct?

Company Response: Yes, the Company is providing a discounted price during the period that the customer would be subject to interruption (they are no longer receiving firm service).

ASSESSMENT OF IMPACTS

TIME-OF-USE PILOT PROGRAM FOR CUSTOMERS OF THE NORTHWEST DIVISION

for consideration of
Florida Public Utilities Company

prepared by
Robert J. Camfield
Bruce R. Chapman
Christensen Associates Energy Consulting

December 2010

1. Introduction

This study report ("Report") presents an assessment of the time-of-use ("TOU") pilot program proposed by Florida Public Utilities Company ("FPU" or "Company"). A TOU rate option constitutes time dependent pricing, where prices are differentiated according to timeframe, including peak and off-peak periods. The TOU pricing pilot will be implemented for the four main retail rate classes of the Northwest Division, consisting of the Residential, General Service, General Service-Demand, and General Service Large Demand categories.

The process of designing a TOU program poses several key questions, as follows:

- What are the appropriate timeframes for differentiated TOU prices?
- What considerations should guide the determination of prices, and what should the TOU on-peak and off-peak prices be?
- What are the likely impacts that arise from the introduction of TOU options, in view of the sensitivity of retail consumers to prices?[1]

Christensen Associates Energy Consulting has conducted a technical evaluation ("Study") of the potential impacts of two pricing alternatives for FPU's TOU pilot program. This Report presents the findings of the Study.

Section 2 of the Report begins by discussing the economic cost considerations and load patterns, which are highly specific to timeframe, and thus provide the basis to determine TOU pricing periods and levels. Section 3 reviews two TOU pricing perspectives: a Summer-Only TOU approach, and an All-Year TOU program proposed by the Company. Summer-Only TOU pricing hews closely to the economic cost patterns associated with retail electricity services provided by FPU's Northwest Division. The second

[1] Impacts to prices can include numerous metrics. For purposes of the immediate discussion, "impacts" refers to several key measures including the level of consumer participation, load response including load shifting from peak to off-peak periods, peak load impacts, revenue impacts on the Northwest Division, and net benefits realized by participating consumers.

perspective, All-Year TOU, incorporates tariff design constraints pertinent to the market context of the Northwest Division at present. Section 4 describes the methodology used to analyze impacts that are likely to result from proposed TOU prices, while Section 5 presents our estimates of the impacts of the two approaches. Section 6 concludes the Report with a summary of the Study findings. We also provide an appendix focused on principles for interruptible rate design options.

2. Cost Basis for TOU Tariff Options

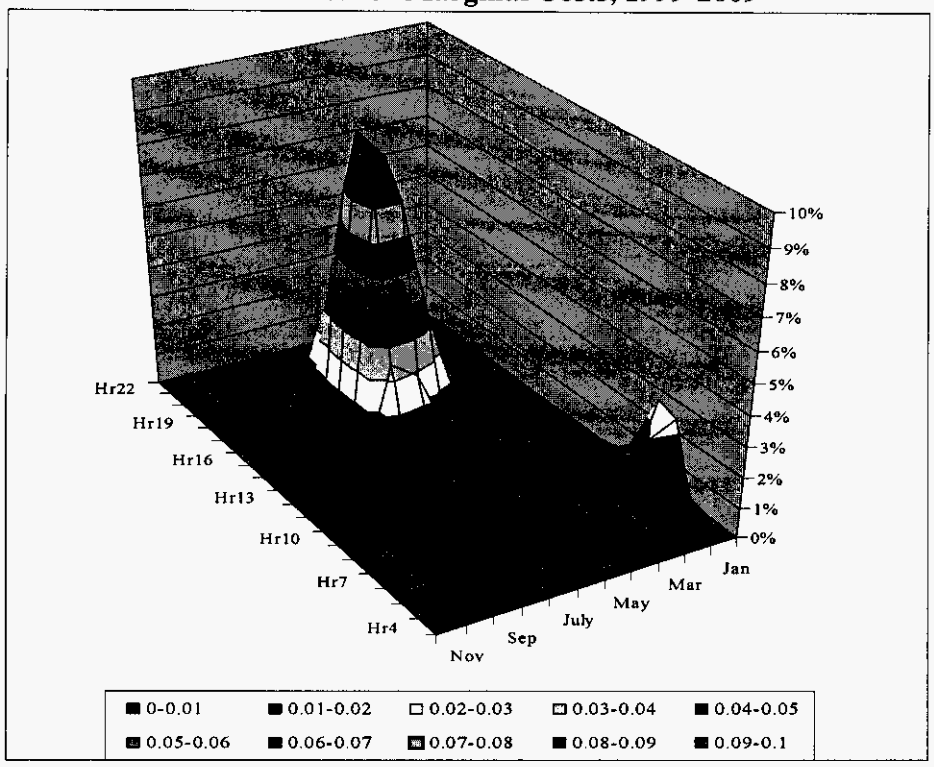
The design of TOU tariff options involves two cost metrics: financial costs (embedded costs), and marginal costs associated with incremental changes in consumption. The general purpose of TOU pricing is to provide customers with prices that more closely match economic costs than do conventional, non-seasonal tariffs, where the end result is improved resource efficiency. However, TOU tariff options should also ensure that revenue flows adequately cover financial costs. Covering embedded costs is a main design objective of revenue sufficiency: subject to regulatory validation, FPU's TOU tariff options must provide revenues that cover financial costs. Second, TOU prices should also reflect the underlying pattern of load-related economic/marginal costs of providing electricity services.

Time-differentiated pricing works best when peak and off-peak prices reflect the relative marginal costs of the corresponding peak and off-peak time periods. To this end, the Study begins by developing an hourly marginal cost profile based on volumetric costs. Volumetric costs include the prices of the Northwest Division's purchased power contract (*i.e.*, $/kWh energy charges, $/kW demand charges) as well as transmission charges, proxies for marginal distribution capacity costs, and marginal distribution line losses. Demand charges (generation, transmission) and distribution capacity costs are concentrated in hours where system loads are closest to system peak load levels.[2] This "proximity to peak" approach to determining hourly demand- or capacity-related charges, is the basis for time varying hourly economic costs, and results in a cost pattern with high concentrations of costs during summer months, as the summer season is when peak loads tend to determine demand charges in total. This is shown in the figure below, where the cost pattern represents the likelihood of setting new peak demands. The graph presents hours of the day running from right to left, and the months of the year running from back to front. The concentration of costs during summer afternoons is self evident.

As mentioned, $/kW-year demand charges are distributed to individual hours on a relative load basis, with the result that the annual, incremental demand-related costs are just covered over an annual period. Note also that a modest share of demand-related marginal costs, stated annually, occur during morning hours of winter days.

[2] While other methods are available, such an approach is appropriate as it recognizes that the hour in which peak loads occur cannot be known with certainty. However, similar hourly load patterns for individuals are easily discerned year over year. Peak loads consistently occur within several specific hours within days; these hours are closely clustered within a narrowly defined timeframe. This timeframe is the basis for determining the peak period for TOU tariff options.

Figure 1
PATTERN OF MARGINAL COSTS
Probabilities for Marginal Costs, 1999-2009



The Study evaluated an array of alternative peak periods with respect to the concentration of marginal costs, and selected preferred peak periods accordingly. Table 1 below presents concentrations for alternative starting and ending definitions of peak periods of days for specific months. Each row represents the time interval covering the stated month through to September, the last summer (billing) month.[3] Each cell presents the proportion (% share) of the expected annual demand-related cost within each defined timeframe.

Placing *all* the capacity costs within on-peak periods is generally inappropriate. Such an approach mixes low-cost hours in with high-cost hours; the end result is the inclusion of months and hours that have little chance of actually being the timeframe in which peak loads occur.[4]

[3] The data in these tables were generated using hourly load data from 1999 through 2009 (excluding 2005 because data were lacking for part of the summer). The probability of peak was calculated for each hour of each year, in isolation from other years. Such an approach recognizes that each year is a 'random' draw from history. In essence, loads for each year were treated as a sample of potential load patterns that might occur.

[4] In many circumstances, high energy costs across a broader peak interval give rise to a longer duration on-peak timeframe. However, the contract for generation services between FPU and Gulf Power Company specifies a uniform energy price, thus obtaining uniform marginal energy costs for across hours. As

We also suggest "staggering" the TOU peak periods for residential and business consumers ("Commercial and Industrial" or "C&I") by one hour in order to minimize the likelihood that load shifting would create a new peak load outside the defined peak period. Shoulder or transition hours of the peak period have lower expected costs than hours central to the peak period, but higher than hours which are fully external to peak period definitions. This staggered peak period approach may constitute a preferred design feature, as it helps to maintain comparatively narrow peak periods for individual customer groups, thus facilitating load shifting toward off-peak periods.

While a "uniform" peak periods approach is suitable for pilot programs, staggered TOU periods are likely to become increasingly important as customer participation and the share of system load served under the TOU options increases. On the other hand, it may be advisable to use a staggered approach from the start if the transition from a pilot program (with uniform peak periods) to a permanent program (with staggered periods) introduces a degree of disruption to pricing terms to which customers have become accustomed. That is, some customers who had planned for specific TOU periods may have to shift operations/consumption patterns to match altered periods.

Table 1
CONCENTRATION OF MARGINAL COSTS
Percent of Annual Capacity Costs Within Defined Peak Periods

	Ending 5:00 pm			Ending 6:00 pm			Ending 7:00 pm		
Starting Periods	11am	12pm	1pm	11am	12pm	1pm	11am	12pm	1pm
May	97.5%	96.0%	87.7%	99.8%	98.3%	90.1%	99.8%	98.3%	90.1%
June	**97.4%**	95.9%	87.7%	99.8%	**98.3%**	90.1%	99.8%	98.3%	90.1%
July	88.2%	86.8%	78.9%	90.3%	88.9%	81.0%	90.3%	88.9%	81.0%

By inspection, a peak period covering June to September results in inclusion of almost all capacity costs. As shown, excluding June appears to result in a significant reduction in coverage of capacity costs. Thus, to the degree that TOU periods are based on costs, a seasonal definition of June through September appears sensible. Regarding time of day, ending the peak period at 7:00 pm provides virtually no benefit since the peak period ending at 6:00 pm captures virtually an identical share of total capacity costs. In contrast, excluding the hour ending 6:00 pm appears to reduce coverage measurably. Similarly, initiating the peak period at 1.00 pm excludes significant potential cost savings from the on-peak period.

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discussed above, hourly costs vary as a result of demand charges for generation services (contract with Gulf Power Company), transmission charges (Southern Company's OATT), and distribution costs including proxy marginal capacity costs and line losses. Hourly costs covering demand charges (generation, transmission) plus distribution are the only basis for temporally differentiated costs. As hourly costs are driven by peak loads, which occur in narrowly concentrated timeframes, costs are similarly concentrated. Furthermore, it is the overall summer peak that matters for generation-related demand charges, which are by far the dominant non-energy charge.

In summary, the analysis of marginal costs indicates that a peak period beginning at either 11:00 am or 12 noon provides the best coverage. Accordingly, for a permanent or pilot TOU program, we recommend the two highlighted cells in Table 1 for the peak period, as described above:

- Residential customers: noon to 6:00 pm.
- Business customers: 11:00 am to 5:00 pm.

As discussed above, summers are characterized by broad sets of hours with load levels that consistently approach peak levels, and thus present a very high probability of setting new peaks. Although winter peaks can rival those of the summer, they are not as systematic as summer peak periods. Rather, winter peaks occur as narrow "spikes" and tend to apply to short intervals that "move around" across years, reflecting random, extreme weather events. As a result, it is neither efficient nor effective to impose static peak-period pricing on entire months or non-summer seasons, for highly intermittent event.

However, we recognize that high winter peak loads may, on occasion, present a significant load management issue for the Company's Northwest Division. For winter peaks, a useful approach is to explore "dynamic" pricing tools that signal extreme cost conditions on short notice.[5] A well-known application of this approach is interruptible service options offered to larger business customers. To assist the Company in its investigation of this option, the Appendix provides guidelines for the design of interruptible service options, and recommendations.

3. Alternative TOU Structures and Tariff Options

The analysis of time periods and costs discussed above suggests that a Summer-Only TOU package best reflect marginal cost patterns, providing that such an approach can be priced in a manner that satisfies revenue targets and other objectives including acceptance by key stakeholders. Because of market and institutional context, FPU wishes to explore the impacts of an All-Year TOU program, a formulation commonly used in other jurisdictions. Thus, the Study evaluates two TOU tariff structures, as follows:

- Summer-Only TOU, where prices are designed to reflect economic costs.
- All-Year TOU, as proposed by the Company.

Each of the two alternatives is discussed below.

Summer-Only TOU Design

Based on the Company's economic cost patterns, the Summer-Only approach implies TOU periods that cover the four months of summer (June – September), and where the

[5] Generally speaking, TOU service options are simply too imprecise to capture adequately the cost variability, including extreme cost consequences, associated with randomly occurring winter peak load events. Interruptible service, where dynamic price or quantity control signals are delivered to participating customers on short notice, offers the potential to manage isolated winter extremes, and is the better approach.

peak and off-peak prices are largely determined according to the commercial terms of FPU's contract with Gulf Power for generation services. As mentioned above, the contract implies significant cost differentiation during the summer, with virtually no cost variation during non-summer months.[6]

The objective of the Summer-Only TOU approach is to bring prices in line with costs, thereby signaling to customers when electricity is relatively costly and, alternatively, when it is comparatively inexpensive. Such an approach tends to induce customers to shift load away from summer on-peak hours, including hours in which the annual peak demand of the Northwest Division is likely to be set. By reducing customer loads in these high-cost hours, TOU participants lower costs for themselves and for other customers as well, as system peak demands are reduced.

Table 2 below presents a set of TOU price terms. The price terms are expressed as *additions to* (rather than replacements of) the existing terms in the Rate Adjustment Rider (RAR) of the Company's retail tariffs – essentially, incremental prices during the peak period and decremental prices during the off-peak period, when compared to the standard tariffs. The RAR would remain unchanged in all other respects. A non-summer discount provides a bill reduction to reflect expected reductions in the cost of power under FPU's wholesale contract with Gulf Power Company.

Table 2
RATE ADJUSTMENT RIDER ADDITIONS, SUMMER-ONLY TOU

	RS	GS	GSD	GSLD
Energy Premium/Discount ($/kWh)				
On-peak	$0.20	$0.20	$0.20	$0.20
Off-peak	$(0.0603)	$(0.0628)	$(0.0628)	$(0.0628)
Non-Summer	$(0.0223)	$(0.0340)	$(0.0292)	$(0.0192)
Demand Charge ($/kW)				
On-peak	Not applicable		*None presently*	*None presently*
Off-peak			*None presently*	*None presently*

All-Year TOU Design

The Company's proposed All-Year TOU design involves setting TOU prices in the same manner as the Summer-Only design – premium and discount prices administered through the RAR – but covering the entire year. The All-Year TOU approach uses a two-part peak period for the non-summer months, reflecting cost patterns during winter months. For the seven non-summer months, the peak period occurs on non-holiday weekdays, and

[6] Economic (marginal) cost patterns incorporated in the Study have comparatively small levels of marginal distribution capacity costs and transmission demand charges (which inherently cover transmission capacity costs) during the winter. As mentioned above, transmission charges are OATT-based transmission charges, which are expected to approximate $2.54/kW-month in 2012, not including line losses. T&D cost levels taken in isolation are not sufficient to warrant cost-based TOU during non-summer.

is split between the four morning hours of 6:00-10:00am, and the four evening hours of 6:00-10:00pm. Under the Company's proposed TOU approach, the TOU prices have on-peak to off-peak price ratios of about 2.0 to 2.5 across the four service classes, RS, GS, GSD, and GSLD. Table 3 below presents the price premiums and discounts for each tariff. As with Summer-Only TOU, these values reflect tariff price changes *vis-à-vis* the standard tariff, and are *additions to* (rather than replacements of) the existing terms of the RAR.

Table 3
RATE ADJUSTMENT RIDER ADDITIONS, ALL-YEAR TOU

	RS	GS	GSD	GSLD
Energy Premium/Discount ($/kWh)				
On-peak	$0.084	$0.040	$0.040	$0.060
Off-peak	$(0.039)	$(0.050)	$(0.0325)	$(0.030)
Demand Charge ($/kW)				
On-peak	Not applicable		*None presently*	*None presently*
Off-peak			*None presently*	*None presently*

As can be seen, the All-Year approach provides a smaller on-peak price premium and off-peak price discount than the Summer-Only approach. As a result, the on-peak to off-peak price ratios are narrowed, when compared to Summer-Only price ratios.

In brief, the Summer-Only TOU approach sets prices according to economic costs, communicates costs to customers through prices, and thus obtains load reductions during times of peak demand. The Company's proposed All-Year TOU recognizes these design concerns while also striving to satisfying broader objectives. As expressed, these objectives are as follows:

1. Advance TOU prices which approximately match relevant TOU prices in the region.
2. Realize net gains (reduced bills) for TOU participants over the course of the pilot program, where overall participation is sizable though, as a practical matter, necessarily constrained.
3. Provide sufficient price incentives, where the end result is measurable load relief to the benefit of all customers of the Northwest Division.
4. Allocate fairly, to retail customers of the Northwest Division, cost relief resulting from the renegotiated wholesale prices for generation services.
5. Acquire real-world experience, as contained in observed load data, in order to better understand the load response behavior of customers under TOU, where prices are differentiated by timeframe.
6. Build market experience and cement in long-term load response within the customer base of the Northwest Division.

The Company recognizes that working toward satisfying multiple objectives implies rate designs that may not obtain the most beneficial level of load relief during high-cost timeframes. The task at hand is to examine alternative TOU pricing designs and, through analysis, select a TOU design and prices that best meet FPU's multiple objectives.

Common Features: The two approaches to TOU pricing have common elements. *First*, both approaches follow the Company's proposed method for apportioning lower purchased power costs on a going-forward basis to the TOU pilot program.[7] However, each design takes a different approach to distributing the TOU share of reduced power costs. The Summer-Only approach reduces overall prices only during non-summer months, while the All-Year approach distributes the price reduction evenly across the entire year.

The essential difference is that, under Summer-Only TOU, prices approximate economic costs, resulting in substantial peak – off-peak price differentials. Conversely, in view of the constraints facing the all-year approach, the proposed peak – off-peak TOU price differences are (must be) significantly narrowed. The end result is that the Summer-Only TOU package will obtain, by definition, larger load response than the All-Year package, during the timeframe that load response matters, summer peak load periods.

The All-Year TOU approach, in which the TOU prices depart from non-summer cost patterns, will likely result in load changes without corresponding cost savings.[8] In addition, All-Year TOU may induce some customers to participate where the end result is reduced net margins for FPU, and lower benefits overall. The level of potential foregone

[7] Lower costs of power are a direct result of renegotiated terms of the Company's wholesale contract with Gulf Power.

[8] There may be practical reasons to retain the standard tariff structure of prices in non-summer months for the TOU tariff options. First, All-Year TOU may impose increased revenue risks on the Company. For example, All-Year TOU can induce customers to reduce on-peak loads, resulting in sizable revenue reductions without offsetting cost savings. Conversely, load increases may occur in off-peak hours with revenue increases not fully covering cost increases.

Second, by maintaining standard prices in the non-summer period, the choice by customers of whether to adopt the TOU option comes down to summer impacts exclusively. Such an approach negates the undesirable outcomes that we have observed in other service territories: selection of TOU service options by customers primarily because of favorable bill impacts (and, hence reduced utility revenues) in non-summer months. Summer-Only TOU negates this potential result; customers select TOU on the basis of the benefits obtained in summer only. Additionally, it is worth noting that customer acceptance contributes significantly to the overall success of the Company's TOU package. Customers appreciate clarity and predictability. Confining the TOU pricing pattern to summer helps to clarify the decision for customers and reduce the bill uncertainty.

Third, in the absence of reducing prices in order to disburse reduced wholesale costs of generation, non-summer TOU would also reduce the likelihood of participation on the TOU option for some customers. Customers who cannot readily shift loads during off-peak seasons may pay higher bills under non-summer TOU. Such losses, in the form of higher bills and reduced customer value, offset benefits realized during the summer. Because of reduced total expected benefits, customers have a reduced likelihood of participation. In short, confining time-differentiated prices to the timeframes where costs actually vary helps to ensure that revenue changes from customer load modifications follow associated cost changes. As will be seen below in the analysis section, reduced bills ensure high rates of participation. The challenge then becomes to find those customers who are likely to shift load in the summer among many volunteers who will have interest in participating in the pilot program.

value (reduced cost savings, lower consumer benefits) is an empirical issue, depending on customer mix and the extent of load response to price. If FPU offers an All-Year TOU package, we recommend that the Company implement TOU prices with comparatively low on-peak – off-peak price ratios during non-summer seasons, as comparatively narrow price differences tend to mitigate load shifting during non-summer, thus minimizing lost net margins.

Second, the two approaches utilize a common set of summer TOU periods with respect to time of day, although the All-Year approach also incorporates May in the summer period.

Third, as discussed above, a practical TOU implementation approach is to retain the current tariff, and offer the changes to the Rate Adjustment Rider (RAR) proposed by FPU. Thus, customers would have the option to remain on their current tariff, or select the TOU option as set out in the RAR. The option can be expressed as two additional price lines applicable to the standard tariff: the first line would specify the *price premium* for the on-peak summer period; the second line would define the price discount for the off-peak period—all other summer hours. In the case of the Summer-Only design, a third line would set out the discount for non-summer months.

Implementation Concerns, RAR: As mentioned above, TOU prices can be expressed as peak and off-peak price premiums and discounts, respectively to the standard tariff price. Alternatively, the RAR could provide a matrix of prices combining the two existing residential tariff prices (arising from the block boundary at 1,000 kWh) with the premium and discount values. However, this second tariff specification is potentially confusing.

In addition, the separate listing of premium and discount prices has a useful counterpart on customer bills. That is, bills could be constructed to contain lines for billings at the premium and discount prices. This approach provides the customer with a direct measure of the bill differential with respect to the standard tariff, decreasing customer uncertainty about whether to convert to TOU service and, arguably, enhance recruiting. Bills can be set up so that they show all customers what their bill would be on the TOU tariff option, and thus how much they might save before modifying usage for further gains. This direct feedback would induce a number of the 'winners' to select the option even if they had not been thinking about the offer. This feedback would be almost unique in the industry and would assist in obtaining industry-leading participation rates in the future when bill reductions from the wholesale cost reductions have dissipated and standard tariff bills and TOU bills are more nearly comparable.

For General Service (GS), the TOU option could proceed in a manner similar to that for Residential TOU. That is, the base GS tariff is not changed, while the RAR includes a TOU price premium (on-peak) and discount (off-peak) with respect to the standard tariff. The price premium and discount values would provide an immediate indication of the expected gains realized by customers from selecting the TOU option.

For larger customers served under General Service Demand (GSD) and General Service Large Demand (GSLD) tariffs, important detailed information on the hourly pattern of consumption is not readily available. Therefore, we advance specific concepts for the long term, and for the near term. For the long term, FPU could work toward a TOU tariff for GSD and GSLD customers that includes a summer peak period demand charge which

parallels the high wholesale demand charges paid by FPU, and thus by its customers.[9] For the near term, though, this approach is hampered by limited information about the timing of customers' peak usage. Once the Company has accumulated interval usage data from initial TOU offerings, it will have the capability to better specify demand charges with assurance of anticipated revenue recovery.

In the near term, then, we suggest that FPU consider offering TOU service to GSD and GSLD customers in the same fashion as for RS and GS customers: a premium and discount applied to energy prices. In the case of Summer-Only TOU in particular, such prices provide well founded signals for the underlying resource costs of energy in the respective peak and off-peak periods.

4. Evaluation Methods

The Study utilizes quantitative analysis tools to approximate likely customer hourly usage patterns. The methodology estimates customers' load responses to each TOU tariff option, and their willingness to participate in the TOU option. Participation is driven by estimates of customer perceived benefits, which are a combination of bill impacts from 1) changes in prices, and 2) the benefits of load shifting.[10]

Load Changes, Revenue Impacts, and Customer Net Benefits: We utilize a formal model of customer behavior to determine customer load shifting. The model estimates customer bills (including load shifting) and customer value impacts which, together, translate into customer net benefits. Inputs used in the model include 1) hourly historical loads; 2) retail prices under the standard tariff; 3) projected TOU prices; and 4) customer price responsiveness parameters (elasticities of electricity demand). The model outputs include load shifts and the resulting load shape, and various other results including bill changes (revenues), and net benefit realized by customers (including but not limited to bill impacts).

TOU Product Selection: The above analysis is conducted for sample customers under a set of parameters. Estimates of the net benefits to customers then serve as inputs into a choice model which, in turn, determines customer selection of the TOU option. Individual customers elect to participate with a certain probability, which is based on model parameters that reflect customer preferences for the option (*e.g.*, TOU service).[11] Selection is estimated for each sample customer; and then scaled up to represent a share

[9] However, we do not intend to imply that the demand charge for customers should apply to all hours. Because of the strong correlation of usage and costs across days and season, it is almost certain that the summer FPU maximum demand will occur on a summer weekday afternoon. Thus, targeting this period is both more efficient and more effective. It is more efficient because shifting loads away from the on-peak window reduces supply costs; it is more effective because it is easier for customers to shift load away from a more compact window.

[10] Customers shift loads because doing so reduces electricity bills. Such benefits (reduced bills) are greater than the foregone customer value (value given up) under load shifts.

[11] The simulation of customer participation incorporates key features inherent to model parameterization: 1) customers have a degree of *status quo* bias regarding a new TOU option, and 2) customers have complete information regarding potential net benefits realized under the TOU option, and 3) the perceived benefits by customers, measured in terms of consumer surplus, is the basis for selection decisions.

of the population of customers. Summing across customers after scaling to the population yields aggregate revenue and cost impacts for FPU, and total load impacts also. Once set up, this combination of customer response simulation and choice modeling provides a means to assess numerous alternative TOU pricing configurations in quick succession.[12]

For the immediate analysis, we used data for the three-year period October 2007 to September 2010, a period with significant variation in loads due to weather variability, changes in overall price levels, and the effects of the late-2007 – 2009 recession. In the absence of hourly customer load data, we constructed representative loads from system load information, with adjustments to reflect class differences in load profiles. We then scaled these representative loads to each sample customer's size and produced multiple possible scenarios of on-peak energy shares for each sample customer.[13] While load shifting is more or less proportional across load scenarios for each individual month for each sample customer, the variety in the monthly pattern of usage and in on-peak share of consumption produces a varied scale of net benefits and, hence, varying propensities to participate in TOU service.

5. Analysis Results

Summer-Only TOU Design

The expected impacts of the Summer-Only TOU tariff package discussed in Section 3 above are reported below, with separate reviews for each of the four tariff classes including residential (RS) and C&I (GS, GSD, GSLD).

Residential Summer-Only TOU

Table 4 below presents estimates of the impacts that can be expected to result from Summer-Only TOU prices. The rows in table 4 set out the several dimensions of the impact of the TOU prices; the columns present levels, changes in levels, and percentage changes. The top panel presents load impacts, while the bottom panel records economic impacts.

The columns of the table present three perspectives on impacts. The first panel shows impacts assuming that all customers who would select the TOU service option actually participate. The second panel presents impacts scaled to the target level of pilot participation, as determined by FPU. The third panel reports imports for the participation necessary to achieve the desired revenue reduction.

The analysis suggests that, in the absence of participation constraints, this particular TOU price configuration would obtain virtually full participation by residential customers,

[12] By way of illustration, the simulation model runs results for a specific rate design in about ten minutes.

[13] Peak and off-peak energy shares sum to unity. So, for each scenario of on-peak energy share, the corresponding off-peak energy share is equal to (1 – on-peak energy share).

reflected as energy totals in the upper left corner of Table 4. The energy totals reflect class energy sales prior to load changes induced by the TOU prices.[14]

The second panel reflects the case in which FPU recruits a target number of 940 customers. This level of constrained participation yields a reduction in summer peak demand of 205 kW, which constitutes about 7.5% of participating customer peak loads and about 0.7% of the total energy of the residential class.[15] We are relatively cautious about estimates of peak demand impacts, as observed sample load shapes for the Company's four classes are not available for use in the Study. Future analysis when hourly metered data become available will provide the basis for improved estimates of changes in peak loads.

Energy impacts are modest overall: the price reduction results in an increase in consumption of about 2.2% for TOU participants. However, summer peak period energy consumption declines by about 5.7%, while summer off-peak consumption experiences an increase of about 5.1% of participant load.

The bottom panel of Table 4 presents the economic impacts of residential customer participation in TOU service. These impacts consist of 1) net revenue impacts for FPU; 2) customer net benefits that arise from bill changes and load shifting; 3) social net benefits, equal to the sum of utility and participating customer net benefits (change in consumer surplus); and 4) immediate revenue impacts (prior to load shifting). Note that immediate revenue impacts are equivalent to immediate customer benefits. Utility net benefits arise from the combination of revenue impacts and cost reductions that result from TOU service.[16] It is not unusual for revenue attrition from customers adopting TOU service to overwhelm cost savings due to load modification. In this case, this tendency is reinforced by the Company's planned reduction in revenue level due to renegotiated contract terms; net revenues thus decline by $174,000.

The immediate revenue impact provides a guide as to the degree to which FPU's prices and target participation achieve the target revenue reduction. For this case, it appears that the removal of the blocking in the RS-TOU tariff adds slightly to the revenue reduction, producing an instant reduction of about $194,000, assuming that 940 customers are recruited.

GS Summer-Only TOU

The summer-only GS-TOU design yields virtually full expected participation for the same reason as the RS-TOU design: anticipated bill reductions for customers. For a

[14] Totals for the class are equal to the sales quantities reported by FPU for the period October 2009 to September 2010.

[15] Note that these impacts refer to the influence of the TOU rate introduction only and exclude the impacts of overall class rate reduction to disburse the remainder of the forecasted cost reduction. These latter rate reductions will be modest and will have a modest positive influence in consumption in all hours.

[16] The revenues of the simulation are not scaled to precisely the revenues of FPU's records. This occurs in part due to the precise matching to billed load totals but the discrepancies between the estimated load profile and the (unknown) actual load profiles. However, it is the change in revenues that matters, so minor errors in scale are typically inconsequential for analytical purposes.

target pilot participation of 150 customers, the peak demand reduction is estimated to be about 45 kW, a reduction of about 7.9% of participant peak demands.[17]

Energy impacts are similar to the results for RS-TOU, including modest overall consumption increases (4.4% of participants' overall consumption), summer peak reductions of about 6.1%, and summer off-peak increases of about 5.9%.

The economic impacts at the target participation include immediate revenue reductions close to the target level, and customer net benefits that exceed FPU's net losses sufficient to result in an $8,000 societal net benefit.

GSD Summer-Only TOU

The Summer-Only GSD-TOU targets 25 customers out of a population of 457. In the absence of participation constraints/limits, the pricing plan again results in virtually complete willingness to participate in the TOU pilot program by GSD customers. The recruited target customers produce an estimated 88 kW of peak demand reduction.

Energy consumption among the target customers increases by about 5.0%, with the usual differentiation between summer peak and off-peak consumption changes. On-peak consumption decreases by about 4.3% with a corresponding off-peak consumption increase of about 7.5%.

The Summer-Only design yields immediate benefits of about $93,000 for participating customers, with a parallel revenue reduction by the Northwest Division. Overall net revenue impact is estimated at a reduction of about $89,000, offset by an increase in customer net benefits of about $102,000. The social net benefits are thus positive, at about $13,000.

GSLD Summer-Only TOU

Table 7 below presents the results for the GSLD rate class, which consists of 13 large customers. As with other Summer-Only TOU tariff designs, desired participation is universal and must, therefore, be constrained in order to satisfy target limits. FPU hopes to attract one of these customers to the TOU pilot program. The estimated result, as simulated, is a peak demand reduction of about 76 kW, which is about 7.7% of the sole participant's peak demand. The third panel, with participation targeted to revenue, reports results for a slightly scaled-up customer.

Energy consumption is estimated to increase by about 4.1% overall, while summer on-peak consumption declines by about 4.4%, offset by a summer off-peak rise in energy consumption of about 7.7%.

The economic impact of recruiting a single (typical) GSLD customer to Summer-Only TOU service includes an immediate revenue reduction of $47,000, and an overall net

[17] Customer target participation in this scenario is double that of the All-Year GS-TOU scenario reported below. This change arises from the need to avoid large price reductions in the summer peak period. The summer off-peak price discount for this class is still well above that of the other classes. Doubling the target participation still leaves a participation percentage of load below that of the Residential TOU design.

revenue reduction of about $52,300. The customer net benefits are estimated to be about $62,000, with resulting net social benefits of just under $10,000.

(see table on the following page)

Table 4
IMPACTS OF SUMMER-ONLY RESIDENTIAL TOU PRICING
Summer Premium/Discount: +$0.20, -$0.0603; Non-Summer Discount: $0.0223

	Unconstrained Participation					Participation Targeted to Customers				Participation Targeted to Revenue			
		TOU Participants		Percent Change		TOU Participants		Percent Change		TOU Participants		Percent Change	
Load Impacts	Total Class*	Baseline Level	Change**	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants
Energy (MWh)	144,457	144,447	3,208	2.22%	2.22%	13,444	299	0.21%	2.22%	12,794	284	0.20%	2.22%
Summer	64,294	64,288	1,690	2.63%	2.63%	5,984	157	0.24%	2.63%	5,694	150	0.23%	2.63%
Peak	14,530	14,529	-835	-5.74%	-5.74%	1,352	-78	-0.53%	-5.74%	1,287	-74	-0.51%	-5.74%
Off-Peak	49,764	49,759	2,525	5.07%	5.07%	4,631	235	0.47%	5.07%	4,407	224	0.45%	5.07%
Non-summer	80,163	80,159	1,517	1.89%	1.89%	7,461	141	0.18%	1.89%	7,100	134	0.17%	1.89%
Peak Demand (MW)													
TOU pricing only	29.1	29.1	-2.20	-7.55%	-7.55%	2.71	-0.205	-0.70%	-7.55%	2.58	-0.195	-0.67%	-7.55%
Participation (% of load)		100.0%				9.3%				8.9%			
Customers (est'd/target)	10,100	10,099				**940**				895			
		TOU Participants				TOU Participants				TOU Participants			
Economic Impacts ($000s)	Total Class*	Baseline Level	Change**	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue	
Revenue	21,046	21,044	-2,019			1,959	-188			1,864	-179		
Cost			-154				-14				-14		
Net Revenue			-1,866	-8.9%			-174	-8.9%			-165	-8.9%	
Customer Net Benefits			2,030	9.6%			189	9.6%			180	9.6%	
Net Social Benefits			165	0.8%			15	0.8%			15	0.8%	
Instant Revenue	-2,080	-2,079				-194				**-184**			

* Includes TOU; ** for TOU Participants only

Table 5
IMPACTS OF SUMMER-ONLY GS TOU PRICING
Summer Premium/Discount: +$0.20, -$0.0628; Non-Summer Discount: $0.0340

	Unconstrained Participation					Participation Targeted to Customers				Participation Targeted to Revenue			
		TOU Participants		Percent Change		TOU Participants		Percent Change		TOU Participants		Percent Change	
Load Impacts	Total Class*	Baseline Level	Change**	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants
Energy (MWh)	28,183	28,157	1,245	4.42%	4.42%	2,033.2	89.9	0.32%	4.42%	1,816.1	80.3	0.28%	4.42%
Summer	14,445	14,426	431	2.98%	2.99%	1,041.7	31.1	0.22%	2.99%	930.4	27.8	0.19%	2.99%
Peak	3,478	3,473	-212.246	-6.10%	-6.11%	250.8	-15.326	-0.44%	-6.11%	224.0	-13.690	-0.39%	-6.11%
Off-Peak	10,968	10,953	643	5.86%	5.87%	790.9	46.4	0.42%	5.87%	706.5	41.5	0.38%	5.87%
Non-summer	13,737	13,731	814	5.93%	5.93%	991.5	58.8	0.43%	5.93%	885.6	52.5	0.38%	5.93%
Peak Demand (MW)													
TOU pricing only	8.0	7.9	-0.62	-7.84%	-7.86%	0.57	-0.045	-0.57%	-7.86%	0.51	-0.040	-0.51%	-7.86%
Participation (% of load)		99.9%				7.2%				6.4%			
Customers (est'd/target)	2,078	2,077				**150**				134			
		TOU Participants				TOU Participants				TOU Participants			
Economic Impacts ($000s)	Total Class*	Baseline Level	Change**	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue	
Revenue	4,133	4,129	-468			298.2	-33.8			266.3	-30.2		
Cost			2				0.1				0.1		
Net Revenue			-470	-11.4%			-33.9	-11.4%			-30.3	-11.4%	
Customer Net Benefits			581	14.1%			42.0	14.1%			37.5	14.1%	
Net Social Benefits			111	2.7%			8.0	2.7%			7.2	2.7%	
Instant Revenue	-523	-523				-37.8				**-33.7**			

* Includes TOU; ** for TOU Participants only

Table 6
IMPACTS OF SUMMER-ONLY GSD TOU PRICING
Summer Premium/Discount: +$0.20, -$0.0628; Non-Summer Discount: $0.0292

	Unconstrained Participation					Participation Targeted to Customers				Participation Targeted to Revenue			
		TOU Participants		Percent Change		TOU Participants		Percent Change		TOU Participants		Percent Change	
Load Impacts	Total Class*	Baseline Level	Change**	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants
Energy (MWh)	93,648	93,648	4,660	4.98%	4.98%	5,123.0	254.9	0.27%	4.98%	5,012.1	249.4	0.27%	4.98%
Summer	43,546	43,546	2,058	4.73%	4.73%	2,382.2	112.6	0.26%	4.73%	2,330.6	110.2	0.25%	4.73%
Peak	10,265	10,265	-442	-4.31%	-4.31%	561.6	-24.2	-0.24%	-4.31%	549.4	-23.7	-0.23%	-4.31%
Off-Peak	33,281	33,281	2,501	7.51%	7.51%	1,820.6	136.8	0.41%	7.51%	1,781.2	133.8	0.40%	7.51%
Non-summer	50,102	50,102	2,601	5.19%	5.19%	2,740.8	142.3	0.28%	5.19%	2,681.5	139.2	0.28%	5.19%
Peak Demand (MW)													
TOU pricing only	20.9	20.9	-1.61	-7.73%	-7.73%	1.14	-0.088	-0.42%	-7.73%	1.12	-0.086	-0.41%	-7.73%
Participation (% of load)		100.0%				5.5%				5.4%			
Customers (est'd/target)	457	457				**25**				24			
		TOU Participants				TOU Participants				TOU Participants			
Economic Impacts ($000s)	Total Class*	Baseline Level	Change**	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue	
Revenue	11,589	11,589	-1,519			634.0	-83.1			620.2	-81.3		
Cost			111				6.1				5.9		
Net Revenue			-1,630	-14.1%			-89.2	-14.1%			-87.2	-14.1%	
Customer Net Benefits			1,867	16.1%			102.1	16.1%			99.9	16.1%	
Net Social Benefits			237	2.0%			13.0	2.0%			12.7	2.0%	
Instant Revenue	-1,707	-1,707				-93				**-91**			

* Includes TOU; ** for TOU Participants only

Table 7
IMPACTS OF SUMMER-ONLY GSLD TOU PRICING
Summer Premium/Discount: +$0.20, -$0.0628; Non-Summer Discount: $0.0192

	Unconstrained Participation					Participation Targeted to Customers				Participation Targeted to Revenue			
		TOU Participants		Percent Change		TOU Participants		Percent Change		TOU Participants		Percent Change	
Load Impacts	Total Class*	Baseline Level	Change**	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants
Energy (MWh)	58,173	58,173	2,376	4.08%	4.08%	4,474.8	182.7	0.31%	4.08%	5,037.5	205.7	0.35%	4.08%
Summer	26,670	26,670	1,296	4.86%	4.86%	2,051.6	99.7	0.37%	4.86%	2,309.6	112.2	0.42%	4.86%
Peak	6,258	6,258	-273	-4.37%	-4.37%	481.4	-21.0	-0.34%	-4.37%	541.9	-23.7	-0.38%	-4.37%
Off-Peak	20,413	20,413	1,569	7.69%	7.69%	1,570.2	120.7	0.59%	7.69%	1,767.7	135.9	0.67%	7.69%
Non-summer	31,502	31,502	1,080	3.43%	3.43%	2,423.2	83.0	0.26%	3.43%	2,728.0	93.5	0.30%	3.43%
Peak Demand (MW)													
TOU pricing only	12.9	12.9	-0.99	-7.66%	-7.66%	0.99	-0.076	-0.59%	-7.66%	1.11	-0.085	-0.66%	-7.66%
Participation (% of load)		100.0%				7.7%				8.7%			
Customers (est'd/target)	13	13				1				1			

		TOU Participants				TOU Participants				TOU Participants			
Economic Impacts ($000s)	Total Class*	Baseline Level	Change**	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue	
Revenue	6,878	6,878	-650			529.1	-50.0			595.6	-56.3		
Cost			30				2.3				2.6		
Net Revenue			-680	-9.9%			-52.3	-9.9%			-58.9	-9.9%	
Customer Net Benefits			804	11.7%			61.9	11.7%			69.7	11.7%	
Net Social Benefits			124	1.8%			9.6	1.8%			10.8	1.8%	
Instant Revenue	-615	-615				-47				-53			

* Includes TOU; ** for TOU Participants only

Combined Results

Table 8, below, summarizes the results for the summer-only TOU designs at the target levels of participation. The reduction in peak demand across all classes is 414 kW. The table reports energy impacts that differ from those of the individual results reported above by focusing on the overall class and system impacts instead of the participant consumption impacts. For the pilot program the overall effects are quite modest, as should be expected in a pilot. The overall energy consumption impact is projected to be just 0.28%, while summer on-peak consumption declines by 0.38% and summer off-peak consumption rises by 0.48%. As increasing numbers of customers join these rates over time, the impacts will expand proportionately, given retention of the simulated prices.

The economic impacts are close to those targeted by FPU. An instant revenue reduction of about $372,000 occurs, with the main departure from the original target due to the need to allow for the removal of blocking in the residential tariff. Aside from instant effects, all the TOU rates result in net revenue reductions for FPU that are just offset by customer net benefits. Based on marginal cost estimates discussed above in Section 2, a societal net benefit of about $46,000 can be expected.

Table 8
SUMMARY OF SUMMER-ONLY TOU PRICING IMPACTS

	RS	GS	GSD	GSLD	Total
Load Impacts					
Energy (MWh)	0.21%	0.32%	0.27%	0.31%	0.28%
Summer	0.24%	0.22%	0.26%	0.37%	0.28%
Peak	-0.53%	-0.44%	-0.24%	-0.34%	-0.38%
Off-Peak	0.47%	0.42%	0.41%	0.59%	0.48%
Non-summer	0.18%	0.43%	0.28%	0.26%	0.28%
Peak Demand (MW)					
TOU pricing only	-0.205	-0.045	-0.088	-0.076	-0.414
Participation (% of load)	9.3%	7.2%	5.5%	7.7%	7.4%
Customers (target)	940	150	25	1	1,116
Economic Impacts ($000s)					
Revenue	-187.9	-33.8	-83.1	-50.0	-354.9
Cost	-14.3	0.1	6.1	2.3	-5.8
Net Revenue	-173.6	-33.9	-89.2	-52.3	-349.1
Customer Net Benefits	189.0	42.0	102.1	61.9	395.0
Net Social Benefits	15.3	8.0	13.0	9.6	45.9
Instant Revenue	-193.5	-37.8	-93.4	-47.3	-372.0

All-Year TOU Design

The expected impacts of the Company's All-Year TOU tariff package, discussed in Section 3 above, are reported below. Results are reported separately for each rate class, residential (RS) and C&I (GS, GSD, GSLD).

Residential All-Year TOU

Table 9, below, presents results for the prices presented in the RS column of Table 3 above. This all-year price configuration yields almost universal participation (99.8%). Participation constrained to FPU's target of 940 customers in the first year of service yields a predicted peak demand reduction of 90 kW, with a revenue reduction of $124,000. Peak demand reduction is influenced both by the peak period price increase of $0.084/kWh, and by the revenue reduction implicit in all prices. On-peak summer consumption decreases by more than 3% while off-peak summer consumption increases by about 4%. Non-summer consumption increases by just under 2%. The extent of non-summer shifting is similar to that for the summer period, in view of the similarity of the peak – off-peak price ratios for summer and non-summer seasons.

According to this TOU pricing package, conferring the full planned revenue reduction of $184,000 would occur if the participating sample of customers were to be increased to 1,404 customers. This change would provide 134 kW of load reduction.

GS All-Year TOU

Table 10, below, presents results for the All-Year TOU design for GS customers. As expected the pricing configuration selected results in universal participation, as simulated.

The results for GS customers are similar to those of the RS class, except that the decline in peak demand induced by the TOU pricing scheme (load shifting) is wholly offset by the increase in usage induced by the overall price decrease designed to achieve the targeted revenue reduction of $34,000. The Company's target participation of 75 customers achieves actual instant revenue reduction of $28,000. Increasing participation to 92 customers achieves the desired target level. Peak demand impacts remain at zero kW, a result that follows directly from the long-run price response to lower overall prices over the course of the year.

GSD All-Year TOU

The All-Year TOU tariff design also induces full participation by GSD customers, as shown in Table 11 below. Targeted participation of 25 customers yields a peak load reduction of 10 kW and a revenue reduction of about $72,000. To achieve the target reduction of about $91,000 requires expanding the participating number of customers to 32, about 7% of the 457 customers in the class. Simulation models used in the Study suggest that increased participation would result in a corresponding larger reduction in peak load of about 13 kW.

GSLD All-Year TOU

All-Year TOU service calls forth full participation by GSLD as well. Focusing on the targeted participation of a single customer, the simulation analysis estimates a peak load

reduction of 25 kW, with revenue reduction of about $32,000. To achieve the Company's target reduction of about $53,000 requires a second participating customer, with a resulting peak load reduction of about 41 kW. As mentioned above, this estimate is conservative and less reliable than other estimates due to a couple of factors. First, the Northwest Division's total population of large customers is limited. Technical particulars among customers will strongly influence willingness to participate and capability to obtain load reductions or to shift load in response to the TOU prices. Second, the absence of customer load profile data might lead to comparatively large model errors in estimating peak demand in view of the market context – a modest yet diverse number of large customers on GSLD.

In other respects, price response is similar to that of the Company's customers served under the other tariffs, with load shifting from the peak period taking place, along with modest overall consumption increases.

The economic impacts of TOU for GSLD customers are similar to those of other classes. Utility net benefits involve revenue reductions almost offsetting customer net benefits. Net social benefits are, in consequence, small, estimated at about $4,100.

(see following page)

Table 9
IMPACTS OF ALL-YEAR RESIDENTIAL TOU PRICING
Premium/Discount: +$0.084, -$0.039

	Unconstrained Participation					Participation Targeted to Customers				Participation Targeted to Revenue			
		TOU Participants		Percent Change		TOU Participants		Percent Change		TOU Participants		Percent Change	
Load Impacts	Total Class*	Baseline Level	Change**	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants
Energy (MWh)	144,457	144,165	3,217	2.23%	2.23%	13,444	300	0.21%	2.23%	20,042	447	0.31%	2.23%
Summer	64,294	64,173	1,626	2.53%	2.53%	5,984	152	0.24%	2.53%	8,922	226	0.35%	2.53%
Peak	14,415	14,388	-478	-3.31%	-3.32%	1,342	-45	-0.31%	-3.32%	2,000	-66	-0.46%	-3.32%
Off-Peak	49,879	49,785	2,103	4.22%	4.23%	4,643	196	0.39%	4.23%	6,921	292	0.59%	4.23%
Non-summer	80,163	79,991	1,591	1.98%	1.99%	7,459	148	0.19%	1.99%	11,121	221	0.28%	1.99%
Peak	20,783	20,739	-734	-3.53%	-3.54%	1,934	-68	-0.33%	-3.54%	2,883	-102	-0.49%	-3.54%
Off-Peak	59,380	59,253	2,324	3.91%	3.92%	5,525	217	0.37%	3.92%	8,238	323	0.54%	3.92%
Peak Demand (MW)													
TOU pricing only	29.1	29.1	-0.96	-3.30%	-3.30%	2.71	-0.090	-0.31%	-3.30%	4.04	-0.134	-0.46%	-3.30%
Participation (% of load)		99.8%				9.3%				13.9%			
Customers (est'd/target)	10,100	10,080				940				1,404			
		TOU Participants				TOU Participants				TOU Participants			
Economic Impacts ($000s)	Total Class*	Baseline Level	Change**	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue	
Revenue	21,046	21,002	-1,160			1,959	-108			2,920	-161		
Cost			75				7				10		
Net Revenue			-1,235	-5.9%			-115	-5.9%			-172	-5.9%	
Customer Net Benefits			1,462	7.0%			136	7.0%			203	7.0%	
Net Social Benefits			228	1.1%			21	1.1%			32	1.1%	
Instant Revenue	-1,327	-1,325				-124				-184			

* Includes TOU; ** for TOU Participants only

Table 10
IMPACTS OF ALL-YEAR GS TOU PRICING
Premium/Discount: +$0.04, -$0.05

	Unconstrained Participation					Participation Targeted to Customers				Participation Targeted to Revenue			
		TOU Participants		Percent Change		TOU Participants		Percent Change		TOU Participants		Percent Change	
Load Impacts	Total Class*	Baseline Level	Change**	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants
Energy (MWh)	28,183	28,183	1,442	5.12%	5.12%	1,017.2	52.0	0.18%	5.12%	1,247.2	63.8	0.23%	5.12%
Summer	14,445	14,445	772	5.34%	5.34%	521.4	27.9	0.19%	5.34%	639.3	34.1	0.24%	5.34%
Peak	3,441	3,441	4	0.12%	0.12%	124.2	0.2	0.00%	0.12%	152.3	0.2	0.01%	0.12%
Off-Peak	11,004	11,004	767	6.97%	6.97%	397.2	27.7	0.25%	6.97%	487.0	34.0	0.31%	6.97%
Non-summer	13,737	13,737	670	4.88%	4.88%	495.8	24.2	0.18%	4.88%	607.9	29.7	0.22%	4.88%
Peak	3,742	3,742	-3	-0.07%	-0.07%	135.1	-0.1	0.00%	-0.07%	165.6	-0.1	0.00%	-0.07%
Off-Peak	9,995	9,995	673	6.73%	6.73%	360.7	24.3	0.24%	6.73%	442.3	29.8	0.30%	6.73%
Peak Demand (MW)													
TOU pricing only	8.0	8.0	0.01	0.13%	0.13%	0.29	0.000	0.00%	0.13%	0.35	0.000	0.01%	0.13%
Participation (% of load)		100.0%				3.6%				4.4%			
Customers (est'd/target)	2,078	2,078				75				92			
		TOU Participants				TOU Participants				TOU Participants			
Economic Impacts ($000s)	Total Class*	Baseline Level	Change**	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue	
Revenue	4,133	4,133	-638			149.2	-23.0			182.9	-28.3		
Cost			114				4.1				5.1		
Net Revenue			-753	-18.2%			-27.2	-18.2%			-33.3	-18.2%	
Customer Net Benefits			796	19.3%			28.7	19.3%			35.2	19.3%	
Net Social Benefits			43	1.0%			1.6	1.0%			1.9	1.0%	
Instant Revenue	-763	-763				-27.5				-33.7			

* Includes TOU; ** for TOU Participants only

Table 11
IMPACTS OF ALL-YEAR GSD TOU PRICING
Premium/Discount: +$0.04, -$0.0325

	Unconstrained Participation					Participation Targeted to Customers				Participation Targeted to Revenue			
		TOU Participants		Percent Change		TOU Participants		Percent Change		TOU Participants		Percent Change	
Load Impacts	Total Class*	Baseline Level	Change**	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants
Energy (MWh)	93,648	93,648	2,850	3.04%	3.04%	5,123.0	155.9	0.17%	3.04%	6,472.6	197.0	0.21%	3.04%
Summer	43,546	43,546	1,456	3.34%	3.34%	2,382.2	79.6	0.18%	3.34%	3,009.8	100.6	0.23%	3.34%
Peak	10,125	10,125	-102	-1.01%	-1.01%	553.9	-5.6	-0.06%	-1.01%	699.8	-7.0	-0.07%	-1.01%
Off-Peak	33,421	33,421	1,558	4.66%	4.66%	1,828.3	85.2	0.25%	4.66%	2,309.9	107.7	0.32%	4.66%
Non-summer	50,102	50,102	1,394	2.78%	2.78%	2,740.8	76.3	0.15%	2.78%	3,462.9	96.3	0.19%	2.78%
Peak	13,625	13,625	-180	-1.32%	-1.32%	745.3	-9.9	-0.07%	-1.32%	941.7	-12.5	-0.09%	-1.32%
Off-Peak	36,477	36,477	1,574	4.32%	4.32%	1,995.5	86.1	0.24%	4.32%	2,521.2	108.8	0.30%	4.32%
Peak Demand (MW)													
TOU pricing only	20.9	20.9	-0.19	-0.91%	-0.91%	1.14	-0.010	-0.05%	-0.91%	1.44	-0.013	-0.06%	-0.91%
Participation (% of load)		100.0%				5.5%				6.9%			
Customers (est'd/target)	457	457				25				32			
		TOU Participants				TOU Participants				TOU Participants			
Economic Impacts ($000s)	Total Class*	Baseline Level	Change**	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue	
Revenue	11,589	11,589	-1,106			634.0	-60.5			801.0	-76.5		
Cost			193				10.6				13.3		
Net Revenue			-1,299	-11.2%			-71.1	-11.2%			-89.8	-11.2%	
Customer Net Benefits			1,382	11.9%			75.6	11.9%			95.5	11.9%	
Net Social Benefits			82	0.7%			4.5	0.7%			5.7	0.7%	
Instant Revenue	-1,322	-1,322				-72.3				-91.4			

* Includes TOU; ** for TOU Participants only

Table 12
IMPACTS OF ALL-YEAR GSLD TOU PRICING
Premium/Discount: +$0.06, -$0.03

	Unconstrained Participation					Participation Targeted to Customers				Participation Targeted to Revenue			
		TOU Participants		Percent Change		TOU Participants		Percent Change		TOU Participants		Percent Change	
Load Impacts	Total Class*	Baseline Level	Change**	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants	Baseline Level	Change	Total Class*	TOU Participants
Energy (MWh)	58,173	58,171	1,162	2.00%	2.00%	4,474.8	89.4	0.15%	2.00%	7,375.0	147.4	0.25%	2.00%
Summer	26,670	26,670	632	2.37%	2.37%	2,051.6	48.6	0.18%	2.37%	3,381.2	80.1	0.30%	2.37%
Peak	6,167	6,167	-164	-2.65%	-2.65%	474.4	-12.6	-0.20%	-2.65%	781.9	-20.7	-0.34%	-2.65%
Off-Peak	20,503	20,503	796	3.88%	3.88%	1,577.2	61.2	0.30%	3.88%	2,599.3	100.9	0.49%	3.88%
Non-summer	31,502	31,501	530	1.68%	1.68%	2,423.2	40.8	0.13%	1.68%	3,993.8	67.2	0.21%	1.68%
Peak	8,556	8,556	-264	-3.08%	-3.08%	658.2	-20.3	-0.24%	-3.08%	1,084.8	-33.4	-0.39%	-3.08%
Off-Peak	22,946	22,945	794	3.46%	3.46%	1,765.0	61.1	0.27%	3.46%	2,909.0	100.7	0.44%	3.46%
Peak Demand (MW)													
TOU pricing only	12.9	12.9	-0.32	-2.52%	-2.52%	0.99	-0.025	-0.19%	-2.52%	1.63	-0.041	-0.32%	-2.52%
Participation (% of load)		100.0%				7.7%				12.7%			
Customers (est'd/target)	13	13				1				2			

		TOU Participants				TOU Participants				TOU Participants			
Economic Impacts ($000s)	Total Class*	Baseline Level	Change**	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue		Baseline Level	Change	% of Std Tariff Revenue	
Revenue	6,878	6,878	-371			529.1	-28.5			872.0	-47.0		
Cost			38				2.9				4.8		
Net Revenue			-409	-5.9%			-31.4	-5.9%			-51.8	-5.9%	
Customer Net Benefits			462	6.7%			35.6	6.7%			58.6	6.7%	
Net Social Benefits			54	0.8%			4.1	0.8%			6.8	0.8%	
Instant Revenue	-420	-420				-32.3				-53.3			

* Includes TOU; ** for TOU Participants only

Combined Results

Table 13 below provides a summary of the impacts of the All-Year TOU package and price configurations described above. At the target levels of customer participation the percentage of load on TOU service is about 6.8% across the system, with most customer classes fairly close to this share, the exception being the GS class. The on-peak energy consumption of participants declines by about 0.16% of system usage and the summer off-peak consumption expands by about 0.31%. Overall consumption expands very slightly, by 0.18%, with customers taking advantage of low summer off-peak prices. Impacts are generally smaller than those of the Summer-Only TOU package, chiefly due to the smaller on-peak to off-peak price ratios of the All-Year TOU approach.

The All-Year TOU offerings as priced secure about 133 kW of peak demand reductions, well below the 414 kW estimated for the Summer-Only TOU design. This outcome is to be expected, since the Summer-Only design features much higher on-peak to off-peak price ratios. As noted previously, the estimates of the Summer-Only and All-Year TOU packages should be treated with caution due to 1) the absence of specific customer load profile data, and 2) the uncertainty surrounding the estimate for the small number of GSLD customers. Another consideration arises from the use in the analysis of price response parameters that, while being representative of past experience at other utilities, may understate responsiveness by FPU's Northwest Division customers. Indeed, our studies find that, controlling for changes in the underlying metrics for the regional economy and weather, declines in electricity consumption for 2008 forward follow directly from the exceptional electricity prices experienced by the retail consumers of the Northwest Division. These results indicate possibly greater price response capability than we have assumed in this analysis.

The economic impacts include immediate revenue reductions of about $256,000, somewhat short of the targeted amount. The right-hand panel of the individual tables presented above provides estimates of the increased participation needed to achieve the target. Utility net revenues are reduced by about $243,000 and customer net benefits increase by about $276,000, resulting in about $32,000 in social net benefits. These results are smaller in scale but similar in relative proportion to those of the summer-only TOU package.

(see following page)

Table 13
SUMMARY OF ALL-YEAR TOU PRICING IMPACTS

	RS	GS	GSD	GSLD	Total
Load Impacts					
Energy (MWh)	0.21%	0.18%	0.17%	0.15%	0.18%
Summer	0.24%	0.19%	0.18%	0.18%	0.20%
Peak	-0.31%	0.00%	-0.06%	-0.20%	-0.15%
Off-Peak	0.39%	0.25%	0.25%	0.30%	0.30%
Non-summer	0.19%	0.18%	0.15%	0.13%	0.16%
Peak	-0.33%	0.00%	-0.07%	-0.24%	-0.17%
Off-Peak	0.37%	0.24%	0.24%	0.27%	0.28%
Peak Demand (MW)					
TOU pricing only	-0.090	0.000	-0.010	-0.025	-0.124
Participation (% of load)	9.3%	3.6%	5.5%	7.7%	6.8%
Customers (target)	940	75	25	1	1,041
Economic Impacts ($000s)					
Revenue	-108.1	-23.0	-60.5	-28.5	-220.2
Cost	7.0	4.1	10.6	2.9	24.6
Net Revenue	-115.1	-27.2	-71.1	-31.4	-244.8
Customer Net Benefits	136.4	28.7	75.6	35.6	276.3
Net Social Benefits	21.2	1.6	4.5	4.1	31.4
Instant Revenue	-123.5	-27.5	-72.3	-32.3	-255.7

6. Summary

CA Energy Consulting's evaluation of likely responses to various TOU alternatives for FPU's Northwest Division reveals that the Summer-Only TOU design provides an effective means of communicating economic costs to customers, thus realizing effective peak demand reductions. The pattern of marginal costs clearly indicates that TOU pricing is desirable predominantly during the summer period, where peak period prices cover a six-hour window on non-holiday weekday afternoons.

The All-Year TOU design recognizes broader objectives as identified above and thus trades off some peak demand reduction in order to satisfy other design objectives. As reviewed above, the Company's proposed All-Year TOU package also provides net economic gains, which translate into benefits for all retail customers of the Northwest Division over the long term. Importantly, the Company's proposed All-Year TOU program serves as a platform for the Company and its customers to become familiar with time varying pricing, thus teeing up more advanced pricing methods such as various dynamic pricing approaches that are being widely adopted nationally.

We recommend that customers in all classes be offered a TOU option via a modification in the RAR that conveys a premium for on-peak consumption, and a discount for off-peak consumption. This price configuration is compatible with the mild blocking of the current RAR for residential customers and eliminates the need to modify the existing base tariffs. The overall structure recommends itself due to its simplicity and the ability of customers to evaluate its risks and rewards.

For larger customers in the GSD and GSLD service classes, this basic structure can be modified by the introduction of an on-peak demand charge once the time pattern of peak demands is better known. Additionally, the introduction of these TOU designs does not constrain FPU from modifying its underlying tariffs to better reflect the variation in marginal costs across seasons.

Our quantitative assessment of the two TOU approaches (Summer Only, All-Year) for the particular price configurations simulated, indicates very high levels of participation if not constrained, a natural result in view of the lower overall bills that can be achieved through program participation. FPU plans to select a subset of volunteers within each class for its pilot programs. The Summer-Only package appears to yield more substantial summer peak demand reductions of 414 kW when compared to 124 kW for the All-Year TOU package, a logical outcome of the higher on-peak – off-peak price ratios of the Summer-Only approach.

Several factors suggest caution in the use of these results. In particular, energy consumption by customers of the Northwest Division has proved to be highly sensitive to the comparatively high price levels beginning in early 2008. This recent experience suggests that load response by customers may exceed the levels estimated above.

APPENDIX

Interruptible Service Options

A potential solution to the challenge posed by winter peaks (and by spikes in the summer as well) is to offer interruptible service to large customers. Based on our experience in developing a number of interruptible/curtailable designs, we suggest that FPU consider a design similar to those being introduced or updated in other service territories. These designs serve a couple of purposes, and FPU may wish to explore which purposes are most important.

It is our preliminary impression that avoiding increasing peak demand as recorded by Gulf Power for reasons related to overall customer demand is a top priority, (as opposed to responding to an unforeseen outage) so a product that meets this need may be a first choice for development. However, in contacting large customers who are the likely first target for interruptible service, FPU may encounter cases where short-notice service to meet outages can be provided. This can occur through the availability of on-site generation or particular industrial processes where something akin to direct load control is possible.

A design for a product for the pilot period might include the following:

- **Advance notice of *curtailment.*** Day-ahead notification of curtailment (via electronic means with backup to ensure notice delivery) with perhaps hour-ahead confirmation or cancellation.
- **A Participation Credit.** FPU can offer a modest demand charge credit in summer and winter months when the potential for curtailments is highest. The credit should reflect the expected cost savings from interruption.[18] The credit need not be identical in summer and winter.
- **A set of (high) energy prices specific to hours of actual curtailment.** Customers would pay to exceed a contractual level of consumption and would be paid to reduce consumption below that level. These charges would reflect the expected marginal cost/value to FPU of increases/reductions in demand. In the event of a likely increase in system maximum demand the incremental cost can be very high – well over a dollar per kW-hour.
- **Contract basis for energy pricing during interruption.** Traditional rates specify a Firm Power Level to which a customer must reduce usage. Newer rates tend to specify a contractual level to which the base rate applies. In fact, the contract level can be specified after the fact via statistical analysis. This approach can be found in certain critical-peak pricing (CPP) programs. Departures from this contractual level are priced at the pre-specified energy price for the interruption period.
- **Advance notice of *pricing.*** Advance notice can be "rate case-ahead" (with prices enshrined in a tariff), year-ahead (with prices announced in the same manner as the RAR), season-ahead (to reflect marginal costs with enough time to allow customers who like long lead times to plan) or short-notice (day-ahead or even hour-ahead).

[18] Varying the demand charge credit could be based on short-term load and energy forecasts that, in turn, utilize near-term outlook for the regional economy and the State of Florida, and projected weather.

- **Penalty for failure to curtail.** This is a traditional tool to ensure compliance, developed for rates which did not pay for actual load reduction. If FPU pays for load reduction, as we suggest above, there is little need for a supplemental penalty for failure to curtail.
- **Contract duration.** FPU should offer a modest duration of one or two years. Long contracts used to be preferred since customers were assumed to be replacing peaking capacity. However, long contract duration deters participation. Short duration contracts are compatible with pricing that changes in response to market tightness.
- **Limits on hours of interruption.** Traditionally important prior to the introduction of payments for load reduction, this provision may not be necessary. Consultation with customers will reveal whether such a provision is necessary.
- **The cost basis for credits.** This basis can be determined to meet the degree of advance notice of *pricing*.
    - For instance, for the next year or two FPU's Northwest system may still be significantly below the ratcheted demand of the wholesale contract and hence credits and payments would likely be low. Demand growth will eventually close the gap, resulting in increased likelihood of exceeding the contract demand ratchet value. Prices can be set at a low level initially and then rise progressively with expectations, being modified annually or more frequently to reflect changing forecasts.
    - Even in cases where costs seem likely to be low (with low values for up-front credits) a developing event might indicate much higher costs than previously expected. FPU can explore 'dynamic' pricing, whose values are not necessarily specified in a tariff or even a pre-season update. In fact, almost all successful real-time pricing programs determine prices between an hour and a day ahead. FPU could ultimately consider a curtailment program that is essentially an 'occasional real-time pricing' program, with the energy price in curtailment hours being announced at short notice.