Attachment 1

EES Consulting Report for PWP
Regarding EPACT 2005 Compliance

PASADENA WATER AND POWER

EES Consulting

FINAL

ENERGY POLICY ACT OF 2005
Requirements and Impacts for Pasadena Water & Power

May 2007

EES Consulting

May 21, 2007

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SUBJECT: Energy Policy Act of 2005—Requirements and Impacts for Pasadena Water & Power

Dear Mr. Lyn:

Please find attached the final report prepared by EES Consulting on the Energy Policy Act of 2005.

Thank you for the opportunity to assist PWP with this evaluation of EPAct 2005. Please contact me if you have any questions.

Very truly yours,

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Introduction

EES Consulting (EESC) was retained by the City of Pasadena Water and Power (PWP) to review the Energy Policy Act of 2005 and compare its requirements with the current provisions of PWP. The Energy Policy Act of 2005 (EPAct 2005) amended the Public Utility Regulatory Policies Act of 1978 (PURPA) to require state regulatory commissions and unregulated utilities with annual retail sales in excess of 500,000 megawatt-hours to conduct assessments regarding the implementation of time-based meters and rates. Specifically, EPAct 2005 added language to PURPA which effectuates the following actions:

- Utilities are required, upon request by any customer it serves, to ***interconnect*** onsite generation facilities to the local distribution facilities.

- Utilities are required to make ***net metering*** available to electric customers, upon request.

- Utilities are required offer ***time-based rate schedules*** that reflect the variance, if any, in the utility's cost of generating and purchasing wholesale electricity.

- If utilities offer time-based rate schedules, utilities must then offer ***smart meters*** to customers who request them.

- Utilities must consider developing a ***fuel sources plan*** that minimizes dependence on one fuel source and ensures that the energy sold to customers is generated using a diverse range of fuels and technologies.

The PURPA language states that the utility must *consider* each of these actions and then make a determination concerning whether or not it is appropriate to implement the standard. Therefore, unregulated utilities and state commissions are **not required to adopt the standards, only consider them**. However, if declined, the utility must state in writing their reason for the decision in a public document.

PWP must make a determination on whether implementation of the new PURPA (EPAct) standards is appropriate. PWP may implement any standard or decline to implement any standard. However, if PWP declines, it is required to state in writing the reason for the decision and make that statement available to the public. PWP could chose to adopt all, part, or a modified version of the standard.

EES Consulting was asked to provide a gap analysis of each of the areas to determine the EPAct 2005 requirements, the current PWP status for each item and any required action needed to comply with the EPAct 2005 requirements.

Interconnection

Based on a review of PWP interconnection agreements, it is EESC's opinion that PWP can meet the requirement of EPAct 2005 regarding interconnection standards without any changes to the Interconnection agreements in place.

EPACT 2005 Requirements

Section 1254 of the EPAct 2005 requires public utilities to offer customers with on-site generation interconnection to the power grid. The EPAct 2005 added language to PURPA which states that "utilities must, upon request, provide interconnection service to any customer that it serves". Interconnection service refers to service to any customer with an on-site generating facility that is connected to the distribution system.

The Act specifies that the interconnection service must be offered based on the IEEE Standard 1547. The group that developed IEEE 1547 is still active and will continue to review and revise the standard. The Act recognizes this and is intentionally flexible indicating that "...Standard 1547...may be amended from time to time." Standard 1547 itself is designed to protect all parties connected to the grid, from small residential applications to the grid as a whole. Standard 1547 also addresses product quality, interoperability, design, engineering, installation and certification.

Current PWP Interconnection Standards

PWP currently has in place the following interconnection standards:

- Distributed Generation Interconnection Requirements – Regulation 23 (Manual)

The DG Interconnection Requirements manual, Regulation 23, was adopted by Council Resolution #8304 on October 12, 2003. The document describes the interconnection, operating and metering requirements for DG units to be connected the electric grid. This 30+ page manual describes the regulations, process, requirements, cost responsibilities, metering requirements, dispute resolution, application review process, and testing and certification criteria. In the manual's Scope and Purpose section it states that the requirements of Regulation 23 are "...intended to be in accordance with the latest revision of the following regulation, but are not intended to be a substitute for said regulations:

- Rule 21, Generating facilities Interconnections
- Underwriters Laboratory (UL) 1741
- Institute of Electric and Electronic Engineers (IEEE) P1547"

Regulation 23 is specifically written to meet or exceed IEEE 1547, Rule 21, and UL 1741.

Consideration

To further the development of Distributed Generation resources, EPAct 2005 requires utilities to consider offering its customers the ability to interconnect onsite generation to the grid in accordance with the Institute of Electrical and Electronics Engineers: IEEE 1547.

One of the significant issues facing a customer planning to install a Distributed Generation (DG) technology it the interconnection of the device to the electric utility system. The lack of common standards for interconnecting DG devices into the utility system is considered an important barrier to the wide acceptance and installation of DG technologies. In addition, if the interconnection policy is not tailored to different sizes and types of generators, the requirements may be too difficult for a customer to implement. Interconnection policy should, in general, address interconnection issues in a balanced manner to address the size of the generation facility and the unique capability of DG. The current PWP interconnection requirements accomplish this objective by allowing simplified interconnection for qualifying DG facilities.

Summary and Conclusions

It is EES Consulting's opinion that PWP already complies with the interconnection portion of EPAct 2005 through Regulation 23 by requiring its customers to adhere to PWP's interconnection agreement which meet or exceed IEEE 1547.

Net Metering

Based on a review of PWP net metering policy, it is EESC's opinion that PWP can meet the requirement of EPAct 2005 regarding net metering without any changes to the policy in place. The following section outlines the EPAct 2005 requirements and further provides a discussion of typical net metering issues and policies.

EPACT 2005 Requirements

The EPAct 2005 states that utilities must make net metering service available to any customer that makes a request. Net metering is required when energy generated by a customer from an on-site generating facility is delivered to the distribution system and used to offset energy provided by the utility to the customer.

Current PWP Net Metering Rules

PWP offers mandatory net metering to all customers with self-generation or cogeneration through rate schedule SG: Self-Generation Service, as referenced under the Pasadena Municipal Code 13.04.178 - Section B.

In August 2006, California SB 1, Section 6 amended the California Public Utilities Code "Section 2827 (c) (1)" to state the following:

> "Every electric service provider shall develop a standard contract or tariff providing for net energy metering, and shall make this contract available to eligible customer-generators, upon request, on a first-come-first-served basis until the time that the total rates generating capacity used by eligible customer-generators exceeds 2.5 percent of the electric service provider's aggregate customer peak demand."

PWP provides the net metering requirement through a separate rate class for self-generators of all sizes to facilitate the interconnection and billing of these customers. Conditions of the rate class specify "customers shall sign an interconnection agreement with PWP" and "customers shall comply with Regulation 23."

At this time, PWP has approximately 45 residential solar customers and 5 commercial solar customers, 6 Distributed Generation customers, and 1 cogeneration customer on schedule SG: Self-Generation.

Net Metering Issues and Considerations

Net metering allows small customers to offset their electricity consumption by sending extra energy generated to the interconnected utility. A bi-directional meter registers electrical flow in both directions. This type of metering enables a monetary exchange based on net customer generation and consumption.

A net metering customer uses distributed generation to generate part of their load and the utility for the remaining load requirements. However, issues arise with the possibility of the customer generating more electricity than they use. The primary question is how this excess energy should be valued if it is returned to the interconnected utility. Opinions range from a minimum rate based on the cost for the utility to purchase wholesale power to a maximum rate based on the full retail energy rate to the customer. Issues associated with net metering, include:

- The energy portion of the utility tariff may contain fixed charges and costs. If so, the full retail rate may over-compensate the customer for the energy delivered back to the utility and, in turn, hurt the utility's non-participating customers.

- The energy rate is an average rate over the whole year; therefore it may not correctly value the energy. Wholesale energy rates vary throughout the year and the retail energy rate accounts for these fluctuations. This means that the customer could be providing power to the utility during high or low value times.

PWP has already addressed these issues in rate schedule SG, but may want to clarify some of these issues in detail, if any future amendments are made to rate schedule SG.

Compatibility with SB 1

PWP has a net metering agreement, "Interconnection and Metering Agreement" that enables net metering for customers with solar or wind generating devices on their properties. This agreement, however, was developed prior to the passage of SB 1 in 2006. The primary change in SB 1 was to increase the allowable capacity of net metering from 0.5% of peak to 2.5% of peak. Table 1 below shows a comparison of selected stipulations of SB 1 and compared with the requirements of PWP through Regulation 23 and the Interconnection and Metering Agreement.

Table 1 Comparison of SB 1 and PWP Regulation 23		
	California SB 1	PWP Reg. 23 & Net Metering Agreement
Provide Net Metering Service	✓	✓
Solar, Wind, and Hybrid Generator Types	✓	✓
Offered for Up to 2.5% of Customer Peak Demand	✓	N/S
Residential, Commercial, Industrial, Ag Customer Classes	✓	N/S
Capacity Up to 1 MW per Site	✓	N/S
Located at Customer Site; Owned, Leased or Rented	✓	✓
Covers 12-Month Time Period	✓	✓
Single Meter Capable of Measuring Flow in 2 Directions	✓	✓
Meter Cost Responsibility of Customer	✓	✓
Additional Meter Cost Responsibility of utility	✓	✓
Wind Co-Metering (>50 kW)	✓	N/S
Request Processed within 30 Days	✓	N/S
Time-of-use; Co-energy Metering	✓	✓

N/S = Not specified

In general, the PWP agreement covers the SB 1 provisions. The key is to allow up to 2.5% of PWP's capacity be made available for net metering. This limitation is not specified in the documentation and may not need to be. Another requirement of SB 1 is to have the net metering request processed within 30 working days of submittal. A couple other items include the customer class and the unit size limitation, which are indicated in SB 1, but not currently in the PWP agreement. However, as long as these items are part of PWP policy, they do not necessarily need to be identified in the agreement.

Summary and Conclusions

The EPAct requires that the utility consider making net metering available to all customers. PWP is in compliance with this standard, as it offers interconnection and net metering for all customers with cogeneration or self-generation. As such, no change is recommended for PWP net metering program.

Time-Based Rate Schedules

PWP has already implemented time-based rates for most customers. As such, PWP already meets some of the EPACT 2005 requirement for considering time-based rates. The following section outlines the requirement for time based rates stated in EPACT 2005 and describes the additional options that PWP may decide to consider.

EPACT 2005 Requirements

EPAct 2005 requires regulatory entities to conduct an investigation and issue a decision on whether or not utilities should "...offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's cost of generating and purchasing electricity at the wholesale level" (EPAct 2005 Section 1252).

The time-based rate options mentioned in EPAct 2005 include traditional time-of-use (TOU) pricing, critical peak pricing, real-time pricing, and load management credit. Each of these is described below:

- Two Period TOU Pricing - Rates are set in advance and broken into two or three time blocks corresponding to peak, intermediate and off-peak periods. Prices are highest during the peak and lowest during off-peak.

- Critical Peak Pricing (CPP) – Under CPP, TOU Rates are in effect for approximately 95 percent of the hours in a year. However, in the remaining 5 percent of hours of the year which correspond to extreme peak hours of each month, prices are increased substantially to signal the increased value of energy and therefore increased benefit of reducing demand during the extreme peak period.

- Real Time Pricing (RTP) – Rates are set in advance based upon a forecast of hourly real-time wholesale prices. These real-time prices may be updated as frequently as hourly to reflect the actual cost of electricity at the wholesale level in real-time.

- Load Management Credit – Credits for pre-established peak load reductions (customers with large loads) that reduce a utility's capacity obligations.

The objective of this section of the EPAct 2005 is for regulating entities to determine, taking into account special circumstances in their area, if additional time based rate structures should be offered to customers, in order to promote conservation, encourage efficiency of resources and implements equitable rates.

PWP Current Status

PWP currently offers TOU rates to all residential, commercial and industrial customers based on the availability of advanced meters. As such, PWP is ahead of many utilities in the U.S. The PWP TOU rate is designed as an option in the regular rate schedule. For example, Residential Single-Family Service. SCHEDULE R-1, offers two options for energy services charges: Option A – Seasonal Flat Rate, or Option B – Time-of-Use Rate. Option A offers different rates by season only, while Option B offers rates that differ by summer on and off peak and winter on and off peak. Option B is the one that complies with the EPAct 2005. The time periods used for the TOU rate are defined as follows:

- Summer months are defined as June through September
- Summer On-peak hours: 12:00 noon to 8:00 p.m.
- Summer Off-peak hours: 8:00 p.m. to 12:00 noon
- Winter months are defined as October through May
- Winter On-peak hours: 6:00 a.m. to 10:00 p.m.
- Winter Off-peak hours: 10:00 p.m. to 6:00 a.m.
- Weekend and holiday hours are all off-peak

The TOU program was first implemented in July 2002 and to date only 169 commercial and industrial customers have chosen to participate. According to PWP staff, meter availability has not been an issue.

Issues and Considerations Related to Time Based Rates

The primary goals of time of use rates are (1) to reflect the time variation in the wholesale cost to produce electricity, (2) to more accurately match costs with the service being provided to the customer and (3) to encourage customers to eliminate consumption during on-peak periods or shift energy use to off-peak periods allowing utilities to operate more efficiently.

Design of Time Based Rates

As discussed, PWP already has in place a TOU rate for all customer classes. EPAct 2005 discusses two additional time based rate structures CPP and RTP. For all three time based rate designs. PWP's hourly power cost needs to be explored and analyzed to determine the appropriate rate design and pricing.

Evaluation of Time Based Rates (TOU, CPP and RTP)

The resulting benefits of a successfully designed TOU program are twofold. First, the electric system load shifts over time, allowing for the potential deferral of capital investments in the distribution system. Secondly, customers and utilities realize reduced power costs due to shifting of consumption. Conversely, implementing TOU rates increase expenditures due to the costs associated with replacing or upgrading metering and billing infrastructure. The costs of these investments vary depending on the TOU program selected by the utility and the current capability of the existing system.

The Energy Policy Act of 2005 (Act) requires that non-regulated and regulated utilities analyze the costs and benefits of implementing retail rates that are designed to reflect the utility's variation in wholesale power costs. The Act also directs utilities to determine a framework for calculating the benefits and the costs that reflect the major sources of benefits that may be realized by a utility and the major sources of costs that a utility is likely to incur. The remainder of this section will lay out a framework for analysis that can be used by PWP to further evaluate time based rates.

Any analysis of time-based rate schedules will need to be performed separately for each rate schedule. Different time-based rates may be appropriate for different customer classes depending on usage patterns and power supply costs. Therefore a separate analysis for each combination of time based rates (TOU, CPP, RTP) and rate schedules (R-1, R-2, S-1, M-1, M-2, L-1, and L-2). Since PWP already offers a TOU rate for all rate schedules. the additional analysis could be limited to the CPP and RTP options.

As part of the analysis of time based rates, PWP would also need to determine if the rate structure is mandatory, i.e. required for all customers in the customer class, or voluntary, as is the case with the current TOU rate offered to PWP customers.

The first step in the analysis of time based rates is the estimation of the gross benefits of implementing the rates. The major benefits of time-based rates to the utility are twofold. Following the implementation of time-based rates, customers will experience higher rates in on-peak periods and lower rates in off-peak periods. This price signal may cause consumption of energy to shift from peak to off-peak periods if the following occurs: (1) customers are capable of shifting load, (2) the price differential between the on-peak period and off-peak period is large enough to provide sufficient benefits for the customers to shift load, and (3) the customers have adequate information about their loads to assess the impact and benefits of shifting their loads. If customers are able to shift energy consumption between the on-peak periods to the off-peak period, the utility could potentially reduce its power costs and transmission costs. Secondly, as customers reduce on-peak consumption it may be possible for utilities to defer future capacity investments in the distribution system. Both of these benefits need to be accounted for in the benefit-cost analysis.

In the calculation of the gross benefits to PWP, the following methodology can be utilized:

- Determination of Net Savings in Power and Transmission Costs
    - Determination of incremental power and transmission cost by on-peak and off-peak rate periods for the TOU rate design, by critical peak, on-peak and off-peak rate periods for the CPP rate design and on an hourly basis for the RTP rate design.
    - Determine the potential shift of usage under new time based rates based on the assumed price elasticity of substitution for PWP customers.
    - Adjust power cost as a result of customers shifting load from on-peak periods to off-peak periods.

- Because retail rates are designed to reflect power costs, reduce retail customers' average rate because it reflects the reduction in average power costs.

- Assume that the retail customer would respond to this reduction in its average retail rate by increasing its overall consumption. This increase in overall consumption offset or reduced some of the calculated benefits achieved from shifting consumption from peak to off-peak.

- Based on the reduction in on-peak energy, calculate the reduced demand consumption.

- Determine transmission cost savings due to reduction in customer demand.

■ Determination of Net Savings in Future Distribution System Capital Additions

- Based on discussions with PWP engineers, determine potential savings in future distribution system capital additions due to reducing the magnitude of peak loads.

- Determine the expected shift in demand from on-peak to off-peak based on the projected reduction in peak loads.

- Determine average distribution capital investment costs per kW either based on PWP historical data or based on a survey of neighboring utilities.

- The avoided distribution cost can be calculated as the estimated kW reduction times the projected cost savings per kW.

Once the gross benefits per customer are determined, the potential savings can be extrapolated to determine total program savings for both a mandatory and a voluntary rate program.

The second step in evaluating time based rates is the estimate of the additional costs of implementing rates. Implementing a time-based rate requires special metering and capability of the Customer Information System to handle multiple rates per period. If only a small number of customers participated in a time-based program, the utility could calculate bills manually for these customers. On the other hand, if more than a handful of customers take service under a time-based rate schedule, major changes to a utility's infrastructure may be required.

As part of the analysis of time—based rates, PWP needs to examine the potential costs of implementing additional time-based rates. Many of these additional costs have been discussed in the Smart-Meter section, but a summary of the cost components is provided below:

■ Evaluation of the Customer Information System

- Assess the capabilities of the current CIS and billing system. How many billing periods can the system handle? Is it possible to bill for RTP and CPP rate designs?

- If upgrades are needed, determine the cost of upgrading the system to handle RTP and/or CPP rates based on discussions with vendors.

■ Evaluation of Metering Hardware

- Determination of number of meters capable of metering for TOU, CCP and RTP rates by rate class.

- Determination of the cost, including installation, of new meters capable of metering for TOU, CCP and RTP rates by rate class.

- Assessment of communications module needs for each rate option.

■ Determination of Additional Administrative Cost

- Due to meter installation and implementation of time based rates.

- Due to additional customer education and customer service.

■ Evaluation of Customer Impact

- Increase complexity on customer bills
- Potential increase in costs
- Customer inconvenience
- Production interruptions

Once the benefits and costs have been determined for each time-based rate option and for each customer class, the analysis can be concluded by determining if each time-based rate option should be implemented on a cost-benefit basis.

Evaluation of Load Management Credit

Load management has generally been used for large commercial and industrial customers. These programs allow the utility to interrupt or reduce customer loads to respond to high market prices or demand costs. Various control strategies can be implemented to ensure that the load reduction actually occurs. In general, very few utilities have implemented load control for residential or small commercial customers. The most common residential load control programs include air conditioning and water heater programs. These programs are estimated to save approximately 0.1 kW to 1.59 kW per customer per event for air conditioning (depending on location and size of housing) and between 0.2 and 0.65 kW per customer for water heating cycling.

Larger customers, that are able to shift or stop operations, may be able to provide more benefit to the utility and the customer, especially if a price signal is provided. The estimates savings from this program is difficult to establish, since the potential for demand reduction is dependent on the operation of the individual customer site.

For the Load Management Credit, due to the likelihood that this program would be most applicable to large commercial and industrial customers, it is likely that each agreement developed with such customers would be unique based upon the customer's circumstances and therefore a general estimate would not be meaningful. As a result, a generic quantitative cost-benefit analysis is difficult to develop for a Load Management Credit. If a PWP customer is interested in a load management program, it is recommended that the specific costs and benefits for that customer are determined on a stand alone basis.

Case Studies

Time of Use (TOU) rates have been an area of study for utilities for many years. The success of these rate structures has largely depended on the cost of primary sources of power supply and the cost of implementation. TOU rates have been offered in California for several years and have shown some success in particular for large commercial and industrial customers.

In 2004, the California Public Utilities Commission (CPUC) required that investor owned utilities analyze and develop business cases surrounding "Advanced Metering Systems" capable of supporting dynamic tariffs, facilitating operation and other cost reductions, and ultimately reducing peak-energy demand through load control and demand response capabilities. This analysis requires that utilities study the costs and benefits of full deployment or a mandatory program for all of its customers. For a utility such as Southern Cal Edison (SCE), this would involve developing and building an infrastructure capable of serving 5,000,000 customers spread over a 50,000 square mile service territory.

In SCE's evaluation, SCE found that with current technology, even under its most optimistic or "best" full deployment business cases, the results yielded significantly negative net present values (NPV). As a result, SCE began to pursue development of a *next generation* Advanced Metering Infrastructure (AMI) technology. Since that time, SCE has observed significant *potential* improvement in the *next generation* technology. The revised estimate of business case NPV's, incorporating the assumed *next generation* technology improvements, have changed dramatically. While the NPV's are still negative, the improvement has lead SCE to conclude that if these major technology advancements are realized, it no longer can conclude that the full deployment is highly unlikely to result in a net benefit.

Ironically, at the same time that the CPUC has ordered utilities to embark on a study of full deployment or mandatory TOU rate programs, the statewide "20/20" programs for commercial and industrial customers have been criticized for yielding insufficient load reductions for the cost. SDG&E's C&I Peak Day 20/20 program is designed to reward small-commercial and industrial customers with a 20 percent bill reduction in exchange for the customers cutting their demand by 20 percent at certain times. Unfortunately, between 2005 and 2006 the number of customers participating and the amount of load reduction achieved appears to have dropped dramatically. This program has also been criticized for going the way of the other statewide programs by achieving benefits derived from the load reductions that are less than the associated costs.