ORIGINAL

0000084873

RECEIVED

BEFORE THE ARIZONA CORPORATION COMMISSION

2008 MAY 13 P 3: 53

AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS
MIKE GLEASON – Chairman
WILLIAM A. MUNDELL
JEFF HATCH–MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-07-0594 **NOTICE OF FILING**

Tucson Electric Power Company ("TEP" or the "Company"), through undersigned counsel, hereby submits the following documents in compliance with Decision No. 70314 (April 28, 2008):

(i) The TEP REST Implementation Plan;

(ii) The TEP REST Tariff;

(iii) The TEP Renewable Energy Credit Purchase Program ("RECPP"); and

(iv) The TEP Customer Self-Directed Renewable Energy Option Tariff (the "TEP Customer Self-Directed Tariff").

RESPECTFULLY SUBMITTED this 13th day of May 2008.

TUCSON ELECTRIC POWER COMPANY

By: Michelle Livengood

Michelle Livengood
Tucson Electric Power Company
One South Church Avenue, Suite 200
Tucson, Arizona 85701

Arizona Corporation Commission
DOCKETED
MAY 13 2008
DOCKETED BY

and

Michael W. Patten
Roshka DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

Attorneys for Tucson Electric Power Company

Original and 13 copies of the foregoing filed this 13th day of May 2008 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copy of the foregoing hand-delivered/mailed this 13th day of May 2008 to:

Chairman Mike Gleason
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner William A. Mundell
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner Jeff Hatch-Miller
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner Kristin K. Mayes
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner Gary Pierce
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Janice M. Alward, Esq.
Chief Counsel, Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Brian Bozzo
Compliance, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

By: Mary Ippolito

Exhibit 1

Tucson Electric Power Company's Renewable Energy Standard & Tariff Implementation Plan 2008 - 2012

TABLE OF CONTENTS

ATTACHMENTS

I. EXECUTIVE SUMMARY

Tucson Electric Power Company ("TEP" or "Company") has prepared an Implementation Plan for the five-year period 2008-2012 (the "Implementation Plan"), in compliance with the Renewable Energy Standard and Tariff ("REST") Rule filing schedule. The Implementation Plan uses the REST Rule Sample Tariff energy rate amount of $0.004988 per kWh, and caps the monthly payment for a residential customer at $2.00, a small commercial customer at $39.00 and a large commercial customer as defined in the REST Rule at $500.00. The Implementation Plan describes the renewable energy resources capacity that may be added during the next five years, the annual energy expected to be produced from these resources, estimated customer funding and tariff amounts required to support acquisition of those resources in 2008 and a 2008 program budget. The REST annual renewable energy requirement begins at 1.75% of total retail sales in 2008 and requires a minimum of 10% of the renewable energy to come from distributed energy sources, of which at least 50% - 5% of total renewable energy - must be from residential customer sources.

As a separate document associated with this Implementation Plan, the Company is filing a Renewable Energy Credit Purchase Program ("RECPP"), attached as Exhibit 3 to the Compliance Filing, which includes nearly all of the preliminary recommendations reached by an informal Uniform Credit Purchase Program Working Group established by Commission Staff during 2006. The RECPP addresses the participation process for a wide range of customers, incentive levels, eligible technologies and system requirements.

TEP currently estimates the cost of the Implementation Plan to comply with the REST to be $8.8 million for the seven remaining months of 2008 and increasing to $55.6 million by 2012, for a five-year total of $173.5 million. REST funding is intended to cover the cost of utility-scale renewable generation in excess of the market cost of conventional resource alternatives, incentive payments for distributed energy resources, marketing expenses, and program implementation and administration costs. The above-market costs for renewable generation are based upon TEP's current understanding of that market as derived from bids received as a result of a Request for Proposals ("RFP") for renewable energy as well as extensive discussion with renewable energy vendors and installers. The costs for distributed generation incentives and the program budget are based upon incentives developed as part of the Commission Staff's Working Group and TEP's best estimations of market uptake for the various technologies available to its customers.

Annual increases in the program budget are driven mainly by the annually increasing energy targets. TEP requested and received approval to transfer all unused EPS funding, expected to be about $0.6 million, for the purpose of funding REST programs.

II. IMPLEMENTATION PLAN COMPONENTS

A. Renewable Energy Requirements

This Implementation Plan has been created in response to the requirements of Arizona Administrative Code R14-2-1801 through R14-2-1815, formally known as the REST Rules. The Implementation Plan's main purpose is to present the renewable energy purchase and development plan as TEP's Implementation Plan portfolio, and cost recovery mechanisms for the REST. Pursuant to Commission Decision No. 69568, the Company is hereby filing its REST compliance programs in this separate docket. In filings for consideration in Decision No. 69568, several parties, including the Commission Staff, stated a preference to consider the ultimate cost recovery of such a program through an adjustor mechanism in the context of a greater rate case proceeding. Therefore, the Company has filed information regarding the adjustor mechanism in that separate rate proceeding, as well as part of this REST program filing. TEP has prepared this Implementation Plan for the five-year period 2008-2012. The REST requires that affected utilities satisfy an annual renewable energy requirement by providing a percentage of their retail electric energy sales from renewable resources. The required annual renewable energy percentage for the first year of implementation, 2008, begins at 1.75% and increases to 3.50% in 2012.

Renewable resources under this rule include "renewable generation" projects, which are constructed solely to export their energy production to the utility, and renewable distributed generation ("DG"), which is a renewable resource application acquired, installed, and operated by customers on their premises that is used to displace the customer's energy consumption. As part of the REST, the energy generated or displaced by the DG is applied towards the percentage of the utility's distributed renewable energy requirement. To determine compliance with the REST, the metric used to track energy in kilowatt hours ("kWh") derived from renewable resources is the Renewable Energy Credit ("REC"), with one kWh equaling one REC.

Meeting the REST requirements presents all of the affected Arizona utilities, including TEP, with a number of uncertainties going forward. Given the needs of our neighboring states to meet their renewable energy mandates there could be intense competition for renewable energy sources over the next several years. This competition will add to the other challenges TEP faces in meeting the REST annual energy requirements. These include the timely completion and energy production from contracted renewable energy sources, availability of qualified contractors to install renewable DG facilities, the number of customers who will opt to participate in renewable DG projects, and the further development of technology to make renewable energy sufficiently affordable and reliable to be of primary interest to electric utility customers. Risks also include issues such as: the availability, level and consistency of federal, state and local incentives; the availability of renewable energy projects executed by financially and technically sound developers; the availability of adequate transmission resources to deliver new renewable energy resources to TEP load; the availability of renewable energy projects matching TEP's anticipated cost profiles; the timing of new resource availability; and the ability of DG technologies and technology providers to serve the needs of customers. TEP acknowledged the risks identified above and attempted to account for them in its Implementation Plan. The timely delivery of energy from renewable resources is critical to TEP's compliance with the energy targets; development of these types of projects typically requires between two to five years. Recent experience across the nation indicates renewable generation projects suffer from high levels of project failure, broadly summarized as the inability to meet contract energy delivery dates. These failures and delays can be attributed to a broad range of issues, but are generally attributed to the immature nature of the renewable resource markets. Published experience with renewable energy projects in California suggests that a minimum overall contract failure rate of 20-30% should generally be expected for large solicitations. TEP has attempted to develop an implementation plan that assumes a slightly lower level of project failure rate to that observed in California. As a way to buffer against these risks, TEP's experience with both renewable energy projects and with conventional energy technologies suggests that careful project screening can reduce, but not eliminate, some of the risk associated with project failures. Consequently, the Implementation Plan is general in nature and not specific with regard to the mix of resources to be used to meet the REST requirements in 2008.

Utilities such as TEP that are affected by the REST Rules are required by A.A.C. R14-2-1813(A) to file an Implementation Plan each year for review and approval by the Arizona Corporation Commission ("Commission"). The Implementation Plan must describe the procurement of renewable energy resources for the next five calendar years that will meet the requirements of the REST. This description must identify the considered technologies, the expected schedule for the resource incorporation on a year-by-year basis, and a description of the kilowatts ("kW") capacity and kWh of energy that are expected to be added to the TEP generation portfolio by the incorporation of those renewable energy resources. This is TEP's proposed initial Implementation Plan.

B. <u>Development of Renewables in TEP's Service Territory</u>

1. Resource Planning

TEP has historically recognized that long-term resource planning is an essential element in determining both supply and demand-side elements of energy production and delivery when making decisions regarding construction of new generation and transmission assets. Beginning in 1994, TEP has studied numerous cost-effective alternative energy sources to meet the growing energy needs of its customers. TEP's long-term resource planning process is an integral part of the renewable energy planning and goal setting process. The forecast of annual kWh of energy and kW of capacity from renewable energy resources by technology to meet the REST goals is listed in Attachment 1.

TEP initially considers self-build renewable energy options in the cost evaluation portion of the planning process, but does not include them as a criterion in determining the need for renewable generation options. Purchased renewable power allows for greater flexibility in use of scarce financial resources in developing renewable generation resources, which are typically priced above the Market Cost of Comparable Conventional Generation ("MCCCG"). Purchase of renewable energy allows TEP to more effectively use its resources in developing renewable energy for its customers through partnering with renewable energy developers. It is thus an essential element in the Company's generation portfolio. However, cost-effective self-build renewable energy options will be pursued as an alternate to purchased renewable energy if necessary. At this time in this Implementation Plan, TEP plans to purchase all of its non-DG renewable energy needed beyond that energy from its existing fleet of wind and solar generation systems and its landfill gas to energy facility. TEP may, as a last resort if purchased renewable energy supplies are insufficient to meet REST requirements, purchase RECs from its bank, created during the EPS program, to meet REST requirements.

TEP uses an Independent Monitor to review the RFP evaluation criteria and process to ensure that a fair and equitable RFP evaluation is performed in comparing bids against each other as well as against the MCCCG.

2. Market Cost of Comparable Conventional Generation ("MCCCG")

MCCCG, as used in the evaluation of renewable energy bids and as used in the context of determining the above MCCCG costs of purchased renewable energy for recovery in the REST Adjustor Mechanism calculation, is determined from market costs based on bids received from our pending purchases of conventional energy sources, RFP process and/or the cost of TEP's generation. This depends on the type of purchased renewable generation resource (firm, non-firm, dispatchable, etc.) and the market conditions at the time of the renewable purchase.

This MCCCG portion of purchased renewable energy resources is recovered under the REST Tariff as determined in the REST Adjustor Mechanism calculation, whereas the portion of the cost of the renewable energy purchased that is at, or below, the MCCCG is recovered in the base generation rates. It is therefore important for the proper allocation of generation costs that the MCCCG of the purchased renewable generation be known with precision.

An MCCCG definition and matrix document, Attachment 2, was developed to determine the applicable market conditions and the type of the purchased renewable generation resource for which the MCCCG is to be evaluated. The matrix is based on the renewable energy technology type employed and the market conditions, along with dispatch conditions at the time of the production of the renewable energy under evaluation. The MCCCG calculation will be dependent on the hour of the day, the season of the year and the month. The MCCCG will be evaluated for true up as part of the REST Adjustor Mechanism calculation at the end of each year by running TEP's PROMOD model software against the purchased renewable generation costs. As discussed above, the cost of the purchased renewable generation above the MCCCG costs will be included in the REST Tariff as determined in the REST Adjustor Mechanism calculation.

TEP undertook a study that applied the matrix to the 2006 actual generation market conditions and proposed generation profiles of wind generation and a round-the-clock generation bids received in 2007 to determine the MCCCG of the renewable energy options. The evaluation resulted in MCCCG values for each of TEP's meter billing periods. These hourly MCCCG values were then applied against the hourly generation profiles for the three lowest cost option renewable generation proposals offered in response to TEP's 2007 RFP for renewable generation.

3. Transmission

All of the wind renewable energy resources evaluated for MCCCG are located at least 150 miles from Tucson. Thus, transmission on existing or new lines will be required to bring the energy from these resources to the customer loads in Tucson. Nevertheless, TEP believes the REST goals for 2008 through 2010 are not of large enough magnitude to require additional transmission to support purchased renewable power delivery to TEP planned under the Implementation Plan. However, it is very likely that the resources needed to meet the 2011 and future REST goals of TEP will require additional transmission between the windy areas of Arizona north of the Mogollon Rim and the Tucson population center. It is important that the transmission planning process include the needs for moving renewable energy from the resource sites to the population centers. It is also important that the Commission determine an appropriate transmission expense recovery method in advance of the need to build these transmission lines to ensure investor confidence in financial support of the transmission line construction. It is not yet clear if additional transmission will be required or, if it is required, what would be the appropriate venue in which to recover the expenses of such transmission. In some cases, as discussed below, strategically located energy storage could mitigate the need for additional transmission. Consequently, we do not propose any expense recovery mechanism for transmission in support of renewable energy resources at this time, but reserve the right to propose such recovery in future years.

As TEP transitions to a low-carbon, sustainable generation portfolio with energy storage over the next 100 years, while supporting continued customer growth and the transition of transportation technologies from a base of fossil fuels to electric energy based sources, there may be an increased need for additional transmission capacity from the more remote areas of Arizona, where wind generation and central solar generation is most cost effective, to the population centers. However, effective use of optimally located energy storage in combination with the location of central solar generation at the sites of existing power plants and customer sited renewable generation could reduce the need for additional transmission. Further study and evaluation is needed in this area. For this reason, TEP does not recommend any specific additional transmission needs at this time.

4. Renewable Generation Integration Management

There are costs associated with the integration and load balancing of intermittent renewable resources such as solar or wind. The current lowest cost renewable energy resource available to TEP is wind generation. Many studies have been published regarding the costs of integrating wind generation into a utility generation portfolio, most recently by Idaho Power citing a cost of over $10 per MWh for integration using hydro generation resources for balancing. Studies performed by TEP, which have been recognized by a recent $100,000 grant award from the Department of Energy to develop evaluation methods for determining the capacity value of solar generation to utilities, indicate that solar generation without some integrated energy storage – both central plant and distributed – has a much greater time variant percentage fluctuation in output than wind generation over the same time frame. Preliminary studies by TEP and Carnegie Mellon University indicate geographic diversity is not as effective in reducing the high level of variation in the output of solar generation as it is for the output of wind generation. While the cost study for integration of solar energy into a utility generation portfolio is not yet complete, TEP does not expect that the cost of managing the integration of both time variant renewable generation sources, solar and wind, will be more than an insignificant factor until the year 2011, based on the lower initial REST annual energy percentages in the early program years. TEP will use the data taken in the years prior to 2011 to evaluate the cost impact of integrating wind and solar generation with its existing fueled generation portfolio. After 2011, TEP expects to include a factor for recovery of integration costs in its REST Tariff through the REST Adjustor Mechanism, and thus requests approval of that factor, not the amount of the charge, at this time.

5. Distributed Generation

The REST requires that affected utilities satisfy a percentage of their annual renewable energy requirement through the addition of distributed energy resources. The required DG percentage for the current implementation period begins at 10% of the 1.75% total requirement in 2008, and increases to 30% of the 3.5% total requirement in 2012. That percentage remains at 30% of the total renewable energy requirement through 2025.

Considerable public discussion has surrounded the DG targets described in the REST. This discussion has centered on questions related to the magnitude of customer interest in DG, the effect of introducing many new distributed technologies, the ability of the technology suppliers and installers to meet the potential customer demand, long-term reliability of these technologies and, ultimately, the total cost of incentives required to drive the required customer participation to meet REST compliance. The extent of customer participation is the primary driver of DG results and it is simply unknown and unknowable at this time. TEP's six years of experience with its SunShare Incentive Program demonstrated that changes in public policy affecting the program (i.e., state and federal tax incentive increases) and changes in program incentives can have dramatic impacts on customer participation, in some cases beyond those anticipated, and positive results can be location specific. There is virtually no way to accurately predict whether the amount of incentives being offered will motivate customers in all parts of the service territory to participate at the necessary rate for full REST compliance. This is particularly germane, because even with availability of significant incentives, customers must still provide significant personal funding in order to have DG systems installed on their homes or businesses. Today, the typical residential distributed photovoltaic system costs about $21,000 to install, attracts about $10,000 in government and utility incentives, and requires a customer investment of about $11,000.

TEP recognizes that DG is an important component of the renewable energy goals of the REST. TEP recognizes that uncertainty exists with respect to the proposed incentive levels and the total number of RECs that they will generate; however, in order to comply with the DG targets, TEP believes this funding level is necessary if consumer demand for DG is to be sufficient to meet the REST DG annual energy requirements. The assumptions used to build the DG program budget are based on incentives developed as part of Commission Staff's UCPP Working Group, market insights from those same meetings, and TEP's experience with its SunShare Program modeled with customer payback term scenarios with current federal and state incentives. TEP expects in this Implementation Plan to purchase all REST DG credits through its GreenWatts SunShare program offerings, as described in the RECPP program below.

TEP believes that customer-sited renewable DG systems are part of the long-term goal of a sustainable, Arizona self-sufficient energy supply for its customers. Thus, a Renewable Energy Credit Purchase Program incentive program, the TEP Renewable Energy Credit Purchase Program ("RECPP"), is to be offered for our customers who install and operate renewable DG systems.

TEP implemented Arizona's first true net metering program, approved by the Commission in 2000, in combination with Arizona's first utility-sponsored solar energy system rebate program, SunShare, approved by the Commission in January 2001. While development of distributed renewable generation will reduce TEP's need to produce electric energy from fossil fuels to meet its customers' energy needs, central or distributed solar and wind generation have demonstrated over five years of TEP renewable energy production and SunShare experience that they are not able alone to meet the firm capacity or voltage control requirements essential in providing safe, reliable electricity service to all of our customers. Historic data indicates there is nearly zero firm capacity benefit on an annual basis from the installation by Tucson based customers of distributed solar and wind generation systems to TEP at the time of annual peak loads due to typical monsoon conditions that drive the peak loads, yet generally cover the sky with clouds as the load's peak.

There are both additional benefit factors as well as additional cost factors to TEP from customers installing and operating renewable DG systems at their homes or businesses. Distributed Generation can provide benefits to both the customers owning the DG as well as to the utility in whose distribution system the DG has been installed. There are also costs from the installation of DG to both the owner of the DG and the utility. If the DG output is not time-variant, the benefits are demonstrably higher and the costs lower to both the DG owner and the utility. However, if the output is time variant or is a function of weather patterns which can affect peak utility system demand, such as monsoon cycles, the benefit of the DG for firm capacity support is significantly reduced. Other benefits include: (1) reduced line losses, (2) increased life for current induced heating devices like transformers, (3) reduced water consumption at generating plants, (4) reduced emissions from conventional generating plants, and (5) reduced impact from the recovery and transportation processes used to provide fossil fuels for conventional generating plants.

Costs of DG to the owner include the cost of any required fuel, operation and maintenance costs ("O&M"), initial installation costs and ownership costs including financing, taxes and insurance associated with ownership of a generation system. There are also costs to the utility, including: (1) the increased need for rapid response automatic voltage control and load management devices in the distribution systems, (2) increased hardware to provide proper protection to distribution circuits with high percentages of DG installed, (3) additional repair time after a storm to clear DG sources prior to start of work, (4) increased outage recovery time from uncontrollable (to the utility) DG resources that start generating automatically in an unpredictable manner, and (5) lost revenue from the reduced sales of electricity with consumption only based rate structures. The quantification of these benefits and costs is very much utility-specific and of fairly low magnitude at the low levels of DG penetration expected in 2008 through 2010. While accurate, valid data is also difficult to obtain at low levels of DG penetration. Over time, as DG installations increase, the data quality and quantity will improve and benefits and costs of renewable DG will be accurately quantified.

Net metering programs provide an added benefit to the DG owner by providing a credit at the retail rate for generation output produced in excess of use over a given time period. For time variant non-dispatchable DG systems like solar or wind, this can be a large benefit as DG output cannot be easily scheduled by the owner to match demand. Utilities can positively impact a decision to install DG by offering net metering programs for time variant DG systems, and by eliminating or reducing the cost of the interconnection to the utility grid. Utilities can also positively support installation of DG by eliminating or reducing backup capacity and energy fees charged to a DG customer when the DG system is not operational for planned or unplanned reasons. Utilities positively support renewable DG systems, such as solar generation, through providing rebate programs to reduce the initial cost of a DG system or through providing production based REC purchase programs to provide an ongoing revenue stream for the owner to offset O&M and ownership costs.

Utilities receive a benefit from DG systems primarily from dependable reductions in peak annual demand from the generation output of DG systems during high load demand hours. Firm, guaranteed reductions in peak demand allow utilities to reduce requirements for building generation, transmission and distribution capacity. However, if the DG generation is not firm and guaranteed to a very high degree of confidence over many annual load cycles, the utility cannot reduce its planned capacity requirements from customer installation of DG. Utilities will benefit from fuel use reductions and reductions in distribution losses through DG installation, effectively the variable portion of energy production expenses. There can also be a benefit to utilities from an increase in operational life for various distribution components, such as transformers and underground cables whose life is reduced by operation at elevated temperatures, created in part by high electrical loads. However, this benefit is also heavily dependent upon the ability of the DG to provide firm, highly reliable output during the highest load demand hours of the year. Thus, to a utility, the benefit of DG is a very large function of the capacity credit assigned a generator based on its proven ability to provide electrical generation output during the peak load demand hours of the year for that utility.

The costs of renewable DG to a utility include the direct cost of any rebates or production payments made for renewable generation, as well as internal and external labor or consultant costs of reviewing interconnection plans and providing interconnection devices to DG installers. However, in many cases, the largest cost to a utility from installation of DG systems is lost revenues from energy-only based utility rates as a DG system reduces the energy consumption of the owner. The DG owner still must have a distribution drop to their premises, the distribution, transmission and generation capacity must still be available to support demand, the meter must still be read and bills prepared, remittances processed and administration of the utility provided. A time variant DG system does reduce utility annual fuel use and line losses in the distribution system. However, since the energy based utility rate DG owner uses less energy per billing cycle, that owner will be providing reduced amounts of revenue to the utility to compensate for those services which the utility is obligated to continue providing and the DG owner requires for continuity of service. This can be addressed through partial requirements tariffs, backup service charges, an increase in the monthly fixed service charge and other rate mechanisms designed to provide a decoupling of the fixed cost of providing electrical service from energy production-based related charges. Decoupling of rates from consumption can reduce this negative impact and more closely align the financial interests of customers and utilities for support of self-generation.

Time variant DG output would appear to a utility control system as variable negative load. If the amount of DG output variance exceeded the amount of load variation normally experienced by the utility, it could result in the need for additional high ramp rate peaking generation or storage capacity, beyond what would be required without the time variant DG installations. The cost of installation and operation of natural gas-fired, high ramp rate capability firming generation, or electrical energy storage is an additional cost to a utility for support of time variant DG sources in its service territory. The installation of rapid change, time variant DG, coupled with the current inability of solar generation systems to provide reactive power, may also adversely impact the ability of existing utility voltage control devices, primarily slow response capacitor banks, to adjust reactive power flows to support local distribution system voltage in a sustainable, reliable manner during cloud passing events. Additional grid regulation support requirements, such as low voltage ride through, droop support and frequency stability regulation are not currently provided by grid-connected solar generation systems and will consequently need to be provided in greater quantities by utilities in the future, with the associated cost of installation, maintenance and operation of these control devices.

Due to the relatively small amount of renewable DG installed in any North American utility service territory, there is not sufficient verified cost data to accurately and unambiguously determine the costs or benefits of renewable DG to TEP. Therefore, TEP does not propose an allowance for indirect costs or benefits of renewable DG be applied to increase or decrease the expenses TEP will incur in offering a renewable DG incentive program at this time. The REST Adjustor Mechanism will reflect recovery of all actual direct expenses of the renewable DG program. In the future, as verifiable cost and benefit data is available from renewable DG programs with significant participation in the TEP service territory, the Company will apply those indirect factors to the REST Adjustor Mechanism value calculation.

C. <u>Required Program Funding</u>

The Implementation Plan is estimated to cost a total of $173.5 million over the five-year period covered by this Implementation Plan. This Implementation Plan is designed to achieve compliance with the REST requirements. The cost for the first program year (seven months of 2008) is estimated to be approximately $8.8 million and increases to $55.6 million in 2012, driven mainly by the increasing energy targets. In this Implementation Plan, TEP is requesting a REST Tariff to recover only the estimated seven months of 2008 costs of approximately $8.2 million. In each succeeding year, as part of its Implementation Plan, TEP will request a reset of the adjuster to collect the estimated costs for the following calendar year and true up revenue received and expenses incurred for prior REST program years.

Several of the attachments to this Implementation Plan include pricing estimates that have been made by TEP in development of the program costs. Some of the pricing included in this Implementation Plan is pricing from existing confidential proposals. The price estimates are necessary to allow TEP to provide the information sought by the Commission as part of the background and support for the Implementation Plan. In addition, summary expenditures and energy requirements for generation provided on a year-by-year basis could be used to infer much of the confidential pricing information. TEP believes it is in the best interest of the Company and its customers to ensure that future suppliers of renewable resources compete for the right to supply renewable energy without a pre-conceived notion of the pricing assumptions or confidential pricing in this Implementation Plan.

This Implementation Plan makes reasonable assumptions concerning renewable energy resources, and as TEP gains more experience with renewable resources, future plans will account for the realities TEP encounters in the actual implementation of the REST.

III. TEP REST IMPLEMENTATION PLAN

A. Energy

The minimum annual percentage of a utility's retail sales that must be obtained from renewable resources is identified in the REST; the Implementation Plan's first-year target for 2008 is 1.75%. The renewable resource targets required to meet TEP's targets for each year of the Implementation Plan are detailed in Attachment 1. The REST targets are described in two categories - renewable generation and distributed generation resources.

Renewable generation consists of projects that export their energy production to the utility. These projects are typically large-scale facilities that use renewable resources such as wind, solar, geothermal, biomass, and biogas to generate electricity. Energy produced from those resources is delivered through transmission and distribution systems and, ultimately, to the utility's customers.

Distributed generation resources represent technology applications that are physically installed on the customer's property. These applications are usually designed specifically for the distributed setting. Distributed applications under the REST would include a wide range of technologies; these technologies are currently most frequently represented by photovoltaic and solar water heating systems. The DG displaces some of the customer's energy needs, and can be tied to the existing TEP distribution system or installed as a remote application independent of the TEP distribution system. TEP does not plan to install DG at customers' properties other than through our GreenWatts-funded community leadership sited projects; rather, the installation of DG is facilitated by providing customers with financial incentives for the installation of such resources by licensed contractors.

B. Capacity

There are no capacity (in kW) requirements in the REST targets, but rather requirements are energy-based (kWh) only. However, this Implementation Plan utilizes historical based generation capacity assumptions to forecast compliance with the energy targets. When one is equating energy targets to planned capacity levels, it is important to recognize that the capacity factors for various renewable generation technologies vary significantly. Some technologies, such as biomass and geothermal, are predictable and can produce energy at capacity factors of approximately 80-90%, similar to conventional-base load generation. Other renewable generation technologies, such as solar, are less predictable and have inherently low capacity factors of 15-30%, which are driven by daily fluctuations such as the availability of solar radiation and are influenced by location. There are other renewable generation technologies, such as wind, which are less predictable on a real-time basis. On an annual basis, however, wind will generally produce capacity factors in the range of 25-35%, depending upon the characteristics of the wind resource in a specific location.

A key factor in reaching a target, therefore, is the combination of technologies utilized, and the ultimate mixture will dictate the additional capacity required to achieve the energy targets. Attachment 1 provides the level of capacity for the specific mixture of technologies assumed in the Implementation Plan for the coming five years. This Attachment is not intended to be an exact representation of the resources TEP intends to acquire, but rather is offered as an example of a potential resource mix, based upon TEP's current understanding of the marketplace. The economics of a particular technology or resource will ultimately determine the extent to which any one technology is employed as part of the overall portfolio's content.

C. <u>Renewable Generation</u>

This Implementation Plan has been designed for sufficient flexibility in order to provide the maximum opportunities to meet or exceed the REST target at a reasonable cost. The following sets forth descriptions of the expected resource additions over the next five years:

1. Existing Renewable Generation

TEP presently has no purchase power agreements ("PPA") for renewable generation resources. However, TEP owns and operates approximately 5 MW of solar capacity and has a contract to purchase landfill gas in amounts up to 10 MW equivalents.

2. Renewable Generation Procurement Plan and Process

Energy required to meet the TEP targets and the anticipated demand for renewable rates in each of the next five years is outlined in Attachment 1 to the Implementation Plan. Generally speaking, two to five years is required from the initiation of a project via a RFP to the point at which energy can flow into the TEP system from a completed renewable generation project. The development and construction of the project itself accounts for the majority of that time period; therefore, an RFP process started in 2007 may realistically be expected to result in producing renewable energy applicable to the renewable resource target in 2009 at the earliest.

TEP estimates that it will need additional amounts of renewable energy commencing in 2008, in addition to that which has already been built. As a result, TEP implemented a competitive procurement process in 2005, 2006 and most recently in 2007. The competitive procurement process consists of, but is not limited to, the issuance of RFPs, negotiated bilateral supply contracts, and other competitive solicitations seeking long-term renewable resources. Implementing an effective competitive procurement process will ensure a fair and unbiased procedure that will efficiently incorporate a full range of renewable resource alternatives from the marketplace.

During the evaluation of submitted bids during the competitive procurement process, TEP's review of proposals will include analysis of: energy production; capacity value; deliverability; technical characteristics; operational performance; reliability; efficiency; credit worthiness; grid impact mitigation; and respondent experience. The procurement and project selection procedure employed by TEP has been documented and certified to be fair and appropriate by an independent auditor as required by the REST.

TEP's Implementation Plan attempts to fully acknowledge the reality that PPAs and project development methods will not necessarily conform to required delivery schedules and planned quantities. Renewable generation projects, like other generation projects, may fail to achieve scheduled commercial operation. A recent review of renewable projects in California stated that utilities should expect that 20-30% of renewable contracts would experience termination or major delays. Delays or failures of that magnitude could cause TEP to fall short of its renewable energy targets. Thus, such risks require TEP to design and employ contingency measures. In order to prevent energy shortfalls resulting from these risks, a procurement goal of 120% of the target energy for three to five years into the future will be employed.

3. Identifying Renewable Generation Requirements

The renewable resource targets an increase from 1.75% in 2008 to 3.50% in 2012 during the five-year period of this Implementation Plan. The Implementation Plan focuses on existing and planned renewable resource projects to meet those targets. It is also contemplated that new renewable generation will be contracted for and developed during that five-year period. It should be noted that TEP has based its program's budget and energy procurement on several assumptions that are mentioned in the discussion that follows.

a. Costs of Renewable Generation

The costs of renewable generation are based for the purposes of resource and budget planning upon the portion of the renewable energy cost that is above the Market Cost of Comparable Conventional Generation ("MCCCG"). The value amount above TEP's cost for comparable generation was established at the time the bids of proposed contracts were evaluated, and that value is applied to the total proposed purchased power cost for the planning year. For future contracts, the price is estimated based upon existing renewable generation contracts, recent market experience, and general trends observed in renewable generation project development. Subsequently, these numbers will be re-evaluated during subsequent five-year planning periods. All renewable resource costs are described in terms of dollars per megawatt hour ("MWh") above TEP's comparable conventional generation values.

b. Planned Resource Additions

The REST renewable targets' annual increases suggest that renewable generation resources can be developed and procured in increments sized to match annual increases. However, a utility's ability to add renewable resources in amounts that specifically match the requirement is unlikely. Therefore, in some years the renewable generation procured will exceed that specifically targeted; these excess additions are sometimes referred to as "non-linear additions." The schedule of resource additions provided in Attachment 1 to the

Implementation Plan identifies specific targeted additions of renewable resources. The planning model incorporates an assumed-capacity factor for each renewable technology. The modeled capacity factors are based on TEP's review of technical performance data for each technology, discussions with project developers, and a review of published information related to currently operating commercial renewable resources.

D. Distributed Generation

TEP has identified distributed generation ("DG") as an important component of the renewable energy goals of the REST, and, as part of this Implementation Plan, TEP proposes a funding level Commission Staff proposed as necessary for compliance in 2008 to support the DG program. TEP recognizes that uncertainty exists with respect to the proposed incentive levels and the total number of generated RECs; however, in order to comply with the DG targets, TEP believes that the proposed funding level is necessary to accommodate required consumer demand for DG.

As a result, TEP has requested a level of funding for its first REST Tariff Adjustor Mechanism necessary to recover only the seven months of 2008 estimated expenses for the DG program. Increases in the adjustor will be required in future years for TEP to meet the DG requirements in the REST. TEP believes that adjusting the funding annually allows TEP, working with the Commission, to implement a flexible program with a clear understanding of program performance and costs without over-collecting funds from customers in the near-term or compromising the overall resource goals of this Implementation Plan and the REST.

The Commission Staff initiated the UCPP Working Group described in A.A.C. R14-2-1810 in June 2006, and TEP participated in all of the working group's efforts. TEP has generally used the approach developed by the UCPP Working Group for the Company's proposed DG incentive program, the RECPP. The Working Group has made significant progress toward identifying program workflows, technology-sensitive incentive structures and levels, and technology-specific requirements and limitations. The efforts of the Working Group also provided TEP with insight into the anticipated potential contributions from technologies not previously included in TEP's SunShare programs. Planning models, implementation strategies, and budgeting for the DG program were all designed with specific consideration for the UCPP Working Group's recommendations. In addition, TEP relied on over six years' experience with its SunShare Program, as well as on continuing dialogue with many industry and consumer stakeholders.

1. Anticipated DG Program Outcomes

TEP has developed a set of planning tools to help anticipate DG program outcomes, both from energy and budgetary perspectives. In developing the anticipated program outcomes for this Implementation Plan, a number of assumptions about technologies and customer preferences were first necessitated. The assumptions included the anticipated number of categorical projects requesting incentives and the anticipated energy contribution from each DG project. Anticipated energy contribution is calculated by utilizing assumptions on average project size and average project production. The detailed assumptions were required for purposes of budget and planning, but are not intended to reflect allocations, funding caps, or preference for any one technology.

The energy production assumptions are set forth in Attachment 1 to this Implementation Plan.

Included in the TEP RECPP are incentives drawn from the draft UCPP Working Group efforts. The RECPP is a separate document submitted in general compliance with A.A.C. R14-2-1810.B. The RECPP, as generally described herein, details different incentive types for use in the DG program. For planning purposes, assumptions about customer preference for the variety of incentive alternatives were utilized. The RECPP is attached as Exhibit 3 to the Compliance Filing.

The TEP-proposed DG budget, combined with these planning assumptions, results in specific outcomes as noted in Attachment 1 to the Implementation Plan. The actual results of program implementation may well be different from those anticipated by TEP's planning efforts, as customers learn more about the variety of technologies and applications available as a result of TEP's program marketing, advertising, and partnership-development efforts.

2. Key Components of the Proposed DG Administration Plan

TEP's DG program is detailed in the RECPP. The following describes several key common components of TEP's program as set forth in the RECPP.

a. Administration

Project funding is not guaranteed until a reservation confirmation is provided by TEP for each project. To receive a reservation and an incentive, applicants must follow the established reservation, installation, and inspection procedures.

b. Equipment and Installation Requirements

The installed DG systems will be required to adhere to generally accepted industry standards, federal, state and local codes, all applicable regulatory requirements, and manufacturer recommendations for installation and operation. Systems must be installed and warranted by an Arizona licensed contractor holding an active certification for the technology being installed, or in some cases by a residential homeowner if he is willing to accept a lower level of incentive.

c. Incentives

Incentives are designed to defray some of the costs of a system designed to offset a typical load of a customer. Systems qualifying for DG incentives cannot qualify for other utility incentives.

> Residential - Customers applying for residential incentives may apply for a one-time payment based upon the DG system's capacity, or based upon the estimated first-year savings provided by the DG system, dependant upon the technology used. This type of incentive is referred to as an Up-Front Incentive ("UFI"). Residential customers can also apply for a production-based incentive ("PBI") as an option, or if their warranty conditions are not sufficient to meet the UFI qualifications.

Non-Residential - Non-residential customers will either receive a UFI or a PBI, which is paid out over time. Projects receiving PBI payments are paid based on system energy output rather than on system capacity. Projects with a capacity less than or equal to 20 kW can elect to receive a one-time capacity based UFI; all others will receive incentives based upon production (a PBI).

d. Non-Conforming Projects

Those DG projects that fall outside of the standard administrative, equipment, or incentive requirements for RECPP projects, or projects that are solicited by TEP to achieve specific program goals, may be eligible for incentives as non-conforming projects. These projects must be comparable to conforming projects in financial efficiency in order to be considered eligible for incentives.

e. Customer Self-Directed Option

Per the REST Rule, certain interested eligible customers are required to apply and declare the amount of the self-directed funding requested before May 1st of the year prior to the request for funding payment, effectively at least 60 days before the Implementation Plan is filed for the upcoming year. These projects must be comparable to conforming projects in financial efficiency to be considered for incentives. The amount of funds allocated to customer self-directed projects will be disclosed in the Implementation Plan for the next program year. For 2008, there will be no funds available for self-directed projects as no funds for such programs are expected to be collected under the REST Tariff in 2007.

3. Distributed Generation Incentive Budgets

TEP's initial DG incentive budget for the five-year planning window is described in Attachment 3 to the Implementation Plan. The incentive budget for the Implementation Plan allocation is designed to result in half of the distributed energy to be from residential installations and half from non-residential. Annual increases in program budget are designed to accommodate both an increase in the DG energy target and to account for the increasing levels of commitment to PBIs, which are used primarily for non-residential DG resources. The incentive matrices incorporated as part of the RECPP describe incentive reductions every two years of the program. Those planned reductions were designed by the UCPP Working Group to reflect the anticipation that DG technologies will decline in cost as market penetration and product availability increases. Three specific allocations are described in the RECPP for the Implementation Plan; they include: non-residential UFIs; non-residential PBIs; and residential UFIs.

The RECPP describes potential funding for customer self-directed projects. As part of the RECPP, a budgetary earmark is required in order to fund projects meeting the criteria of customer self-directed projects. No funds have presently been paid to TEP as part of the REST, and therefore no projects currently qualify for customer self-directed funds or would in 2008. Consequently, no allocation for self-directed or non-conforming projects has been established in this inaugural Implementation Plan.

The annual funding level for DG incentives was established based upon the estimates of the renewable energy needed for compliance, anticipated consumer demand, projected sales and development time frames, variations in the levels of technology maturity, and availability of equipment for installation. Should it happen that funds collected for use in the DG incentive program are not fully subscribed within a program year, those funds will be applied to the next program year and allocated to achieve the required energy outcome between residential and non-residential projects. Those over-collected funds would reduce the amount of the REST Tariff in the subsequent year.

4. Marketing, Advertising and Partnership Development

TEP is committed to conducting an action-oriented marketing campaign that will not only inform and educate consumers about the importance of renewable DG and its potential benefits to customers and the community at large, but also spur them into investing in renewable energy.

Education and community awareness are the catalysts for the shift in public attitude required to jump-start the robust solar energy market envisioned by political leaders and DG advocates. Information is the prerequisite in achieving real movement toward alternative energy solutions. But fostering enhanced knowledge on the subject is not enough; ultimately, the goal is to proliferate solar and renewable energy DG in the Tucson metropolitan area.

The marketing campaign will take a three-pronged strategic approach: 1) identify key stakeholders and analyze their specific interests; 2) educate those stakeholders (such as residential customers, business owners, students and opinion leaders) about the nature and benefits of DG; and 3) create marketing messages that encourage customers to take action, while promoting incentives designed to make DG an attractive choice for customers to reduce their carbon footprint.

The following key marketing components are designed to bring DG into the mainstream:

- Create an actionable campaign that focuses on the benefits, improved reliability and environmental impact of DG; cause consumers to see DG in a whole new light.

- Utilize media that will best reach our various stakeholders through both paid and public service messages, as well as earned media.

- Develop collateral pieces for both residential and non-residential customer acquisition.

- Heavily promote the DG program on tep.com and through customer communication vehicles such as bill inserts, e-newsletters and bill messaging.

- Maximize participation in green expos and other targeted community-wide events.

- Create and promote solar-based educational programs for the schools.

- Identify and solicit the support of "change agents" in the community who can effectively influence key stakeholder groups.

- Partner with various media outlets and vendors to develop co-promotions based around distributed generation; provide supporting collateral such as site signage and counter displays for added promotional support.

- Expand partnerships with area solar installers by continuing to provide technical expertise and collateral materials as well as sharing industry news and product updates.

- Escalate TEP's involvement in the community dialogue about energy sustainability, lending expertise and experience through existing networks, ranging from classroom presentations and demonstration projects to interaction with environmental organizations and homeowner associations.

TEP has been widely recognized for many years as a leader in the development and installation of solar energy systems. As a byproduct of that leadership, TEP has cultivated relationships, and acquired industry intelligence, that can now be applied to the propagation of DG in the Tucson area.

The previously described marketing components are based on currently available data. As the campaign proceeds, TEP staff will monitor and analyze results, and will consider modifications to the campaign that mitigate deficiencies or capitalize on successes.

E. Implementation and Administration

As part of the development of a strategy and budget for REST implementation, a logical separation was created between 1) those elements required to support the renewable generation portion of the program and 2) the DG portion of the program. Renewable generation involves expertise in utility-scale technologies, competitive procurement and evaluation processes, project siting, utility integration, transmission- and distribution-related issues, complex contract negotiations, and contract management. The DG program will be a mass-market program involving thousands of individual interactions requiring customer communication, interconnections, inspections, customer billing, and a sophisticated system to monitor REC production. Certain TEP resources will be used to support both portions of the REST, as discussed below.

1. Resources Required for the Renewable Generation Program

A renewable generation program requires knowledge-area experts to identify those aspects of renewable generation procurement, engineering, and market analysis that are unique from those same areas in conventional energy operation, and to coordinate with the impacted operational areas of TEP in order to seamlessly integrate renewable resource management into TEP's standard utility business practices. These experts comprising the renewable generation administrative team include the personnel necessary to manage the program, which incorporates establishing policies and procedures, procuring renewable generation, handling contract administration and construction management, managing benchmarking and resource integration studies, and performing program monitoring and compliance reporting.

There are also TEP employees supporting the program that are neither part of the administrative nor the implementation teams. These personnel are considered "non-incremental" and are required to support the general operations of the utility and have responsibilities that are not directly related to the DG program. These would include, but would not be limited to, employees within TEP's regulatory, pricing, accounting, legal, contract administration, and meter reading areas.

2. Resources Required for the Distributed Generation Program

The implementation strategy for the DG program was developed with the following goals:

- Develop an accurate, efficient and customer-friendly process.
- Integrate the program's processes into the general business operations.
- Create a measurable process that responds to adjustments in the volume of program participation.
- Support the strategic marketing efforts of the program.

In order to accomplish these goals, a significant investment in program implementation and management is needed. The DG program represents a significant number of individual transactions, and each transaction impacts numerous parts of TEP's business infrastructure. Thus, implementation costs for the DG program are significant.

a. Program Resources

The program's personnel team is comprised of the human resources necessary to execute the DG incentive program. This includes the fixed-payroll personnel required to administer the reservation and interconnection applications and agreements, review system design for conformance with RECPP and interconnection requirements, process incentive payments, answer customer and installer questions about the program, and perform field inspections. It also includes the variable-payroll personnel required to program and install net or performance meters, label utility equipment to identify potential backfeed sources, and provide billing support to net-metering customers. Further needed are the employees required to manage the execution of the program, develop and execute the marketing and advertising programs, and provide ongoing program monitoring and compliance reporting. The number of implementation team members required is proportional to both the number of applicants at any one time and the number of program participants. Additionally, just as in the case of renewable generation resources discussed above, many non-incremental employees will also be needed to support the DG program.

b. Material Costs

In order to measure the actual amount of kWh returned to the grid by DG facilities, a DG performance meter as well as a standard utility meter must be utilized in TEP's system. The incremental cost charged to the REST is the total cost of the performance meter in addition to the incremental cost of any net meters added as replacements for the standard utility meter.

The RECPP will capture an annual meter read for all DG systems generating electricity for compliance verification and program evaluation purposes. TEP believes that many customers may also be interested in the ability to track total kWh generated by their system. To facilitate both the meter-read capture requirement and to assist customers tracking the kWh production by the DG system, TEP plans to install and read the system performance meter for all participants in the program. The only costs charged to the REST are those costs associated with providing the second meter to record system production. There are also incidental material costs associated with the program including, but not limited to, system locks, tags, inspection tools and transportation for inspection personnel.

TEP may also install an interval-recording meter on a certain number of sites that will be used by load research to conduct studies on the coincidence of solar output vs. TEP system load. The only material cost charged to the REST Implementation Plan Program will be the incremental costs of the interval recording meter.

c. Technological Improvements Required

For TEP to effectively and efficiently implement the DG incentive program, it will be necessary to integrate with its existing systems, including customer billing, the program and operations databases, accounting systems, and dispatch and scheduling tools. This investment is required to ensure integrity and support the scale of the program as it is described in the Implementation Plan. The technology tools to support the distributed incentive program that TEP will develop and integrate into existing systems include:

Agreement-processing and workflow-management tools — These tools will provide an interface through the tep.com website to allow customers and vendors to complete and submit all program forms and agreements on-line with data to be stored in a central database. They will include an integrated workflow-management component to provide status tracking, work orders, and scheduling. The tools will also integrate into all major systems, including the billing system, and the operations and accounting databases.

- Performance information tools — The readings from the system performance meter will be integrated into the TEP billing system.

- Meter Database Management — The readings from the bi-directional meter will be integrated into the TEP billing system. The credit for the energy sold back to the TEP system will be calculated within the billing system and will appear on the customer's standard TEP bill.

- Reporting and maintenance — Data capture necessary for ongoing program monitoring and compliance reporting will be facilitated by developing standard reports and a reporting tool for *ad hoc* queries.

F. Renewable Technology Commercialization and Integration

TEP includes a budget allocation in the Implementation Plan for studies related to commercialization and integration of renewable resources. The purpose of this budget allocation is to enhance and accelerate the development, deployment, commercialization, and utilization of renewable resources for the benefit of TEP customers

Commercialization and integration studies to help meet the accelerated REST goals for renewable resources will be prioritized. As part of TEP's long-standing commitment to renewable resources, several studies related to commercialization and integration are already underway. Those studies and ongoing experience with renewable resources will help identify additional study subjects necessary to develop the tools needed to achieve program goals.

The activities undertaken as part of this program may be supported either by TEP solely, or in partnership with other organizations and entities including private industry, public research institutions, and government laboratories. TEP intends to take full advantage of opportunities to leverage state and federal research and development efforts, and support funding opportunities when planning and funding these activities. TEP will also strive to increase coordination efforts with other utilities, the U.S. Department of Energy ("DOE"), the Arizona Department of Commerce Energy Office, and national laboratories to realize greater investment of federal research funds in Arizona, and more specifically, the Tucson service territory. TEP also intends to coordinate more closely with Arizona universities to better utilize those resources.

Studies presently underway that are currently funded by the EPS include:

- Arizona Renewable Resource Study — Jointly funded by the Arizona Public Service Company ("APS"), Salt River Project ("SRP"), and TEP/UNS Electric, the study represents an independent analysis of potential renewable resources in Arizona. The analysis is being conducted by a leading energy engineering consulting group Black and Veatch, and will effectively establish a baseline understanding of renewable energy resources presently perceived as available within the state. In addition, the study will define renewable energy technology applications, associated cost structures, as well as identify renewable energy market opportunities, which should encourage the development of renewable energy projects in Arizona. This study is complete.

- TEP Solar Capacity Value Study — This study drives extensive research that leverages available high resolution solar generation data within Arizona and evaluates the potential for reliably incorporating utility scale and customer sited distributed solar generation into TEP's system. DOE has awarded TEP a $100,000 grant to develop a specific solar capacity value evaluation method TEP proposed based on the data noted above.

- Joint Utility Market Study — This joint effort will result in a statewide market study evaluating consumer receptiveness to the installation of distributed renewable energy equipment, particularly photovoltaic. Participants include APS, SRP, TEP/UNS Electric and the Arizona Cooperative Utilities.

- Concentrating Solar Power Project Studies — TEP/UNS Electric, in conjunction with several regional utilities, has formed a Joint Development Group ("JDG") to explore the possibility of issuing a joint-RFP for energy from a large-scale (250MW) solar plant. This effort is intended to provide project developers with energy and capacity levels large enough to drive cost-effective economics into the development of solar resources, in an attempt to make solar generation more cost competitive with non-solar resources. The efforts of the JDG will require investment in project siting studies, along with specialized support for the development of an RFP. In determining whether to fund new studies related to commercialization and integration, TEP/UNS Electric will consider three key functional areas:

- Renewable technologies and available resources: These include studies of the attributes, characteristics, and costs of renewable energy technologies and the availability and viability of renewable energy resources in the state of Arizona and the western United States. Specifically, TEP/UNS Electric believe it is valuable to explore geothermal resources, monitoring and forecasting of wind resources and evaluate attributes specific to solar sites for development.

- Transmission and system integration impacts: These studies would be designed to provide TEP/UNS Electric with a better understanding of the operational impacts, costs of integration, and the identification of opportunities with renewable energy resources in the TEP/UNS Electric generation, transmission and distribution systems. TEP/UNS Electric recognize the critical importance of transmission in the success of the expansion of renewable generation. Any significant increase in renewable generation must be integrated into the long-term planning for transmission to be successful.

- Distribution system impacts: These studies will examine the impacts of distributed generation resources on the power distribution system. Specific areas of study would include impacts on the general distribution system, design and construction, operations and maintenance, voltage stability, safety, power quality, and load forecasting.

IV. COSTS OF PROGRAM IMPLEMENTATION

The TEP Implementation Plan's cost is comprised of two key cost segments, renewable generation and distributed generation. A summary of the costs of those segments and the major components for each segment are included in Attachment 3 to this Implementation Plan. As seen in Attachment 3, TEP currently estimates the cost to comply with the REST at $8.8 million for the seven months of 2008. Future annual increases are driven mainly by the annually increasing energy targets.

The REST funding is intended to cover the cost of utility-scale renewable generation in excess of the market cost of conventional resource alternatives; incentive payments for distributed energy resources, marketing expenses, and program implementation and administration costs. The costs for renewable generation are based on TEP's most current insights into that market. The costs for DG incentives and the program budget are based on incentives developed as part of the Commission Staffs UCPP Working Group and TEP's best estimations of market uptake for the various technologies available to consumers.

TEP is presently requesting REST Tariff funding of $8.2 million for the seven months of 2008 under the Implementation Plan. The requested REST Tariff amount, with approval to use the estimated $0.6M of unexpended EPS funds for REST programs, would total the $8.8 million of funding needed to provide a reasonable opportunity, but certainly no guarantee, for compliance with the REST requirements in the seven months of 2008. It is TEP's intent to request additional funding in each successive year for the following calendar year's estimated REST compliance cost. To illustrate, in 2008 TEP will request funding for the 2009 calendar year as part of its 2009 Implementation Plan, and carry forward that methodology in succeeding calendar years. The estimates contained in Attachment 3 to this Implementation Plan would be updated each year to determine the necessary level of funding from TEP's customers.

V. CONCLUSION

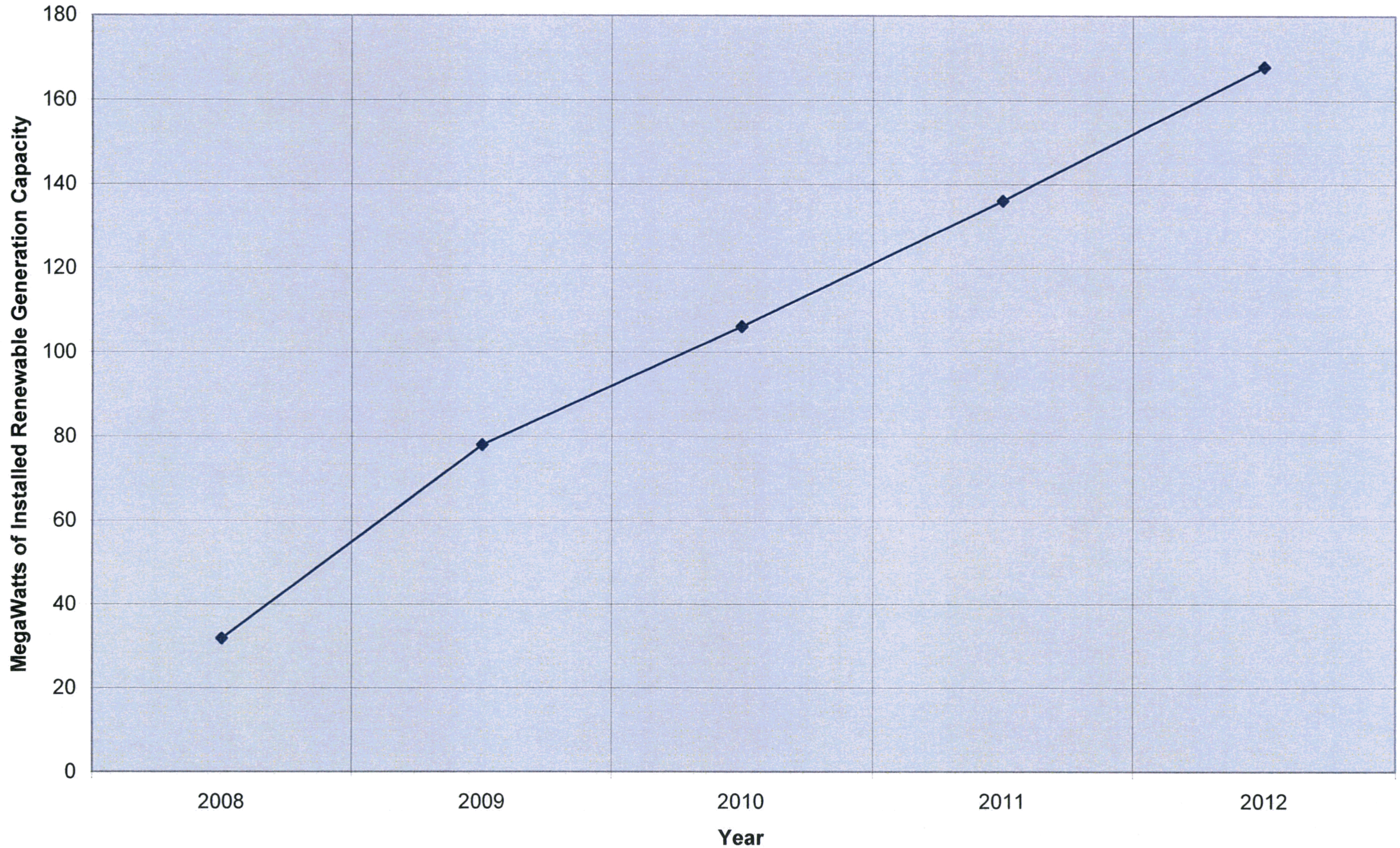
Arizona is beginning the transition from a fossil-fuel based primary energy foundation to a sustainable primary energy based foundation. The transition is needed to ensure that future generations of Arizona citizens have a long-term supply of safe, affordable, convenient energy on demand. As with all transitions, the first steps are the most expensive, difficult and uncertain. Currently, all Arizona sources of renewable energy come at a cost greater than any current fossil-fuel energy source. However, due to increased use of renewable energy, the cost difference is closing and in a decade or less, renewable energy may be at economic parity with fossil fuel sources. Technical challenges to the seamless integration of time variant renewable energy sources with dispatchable generation sources have been found. But, with proper planning, continuous data analysis and deliberate technology management, the challenges can be converted to opportunities and the path to sustainable energy integration can be smooth.

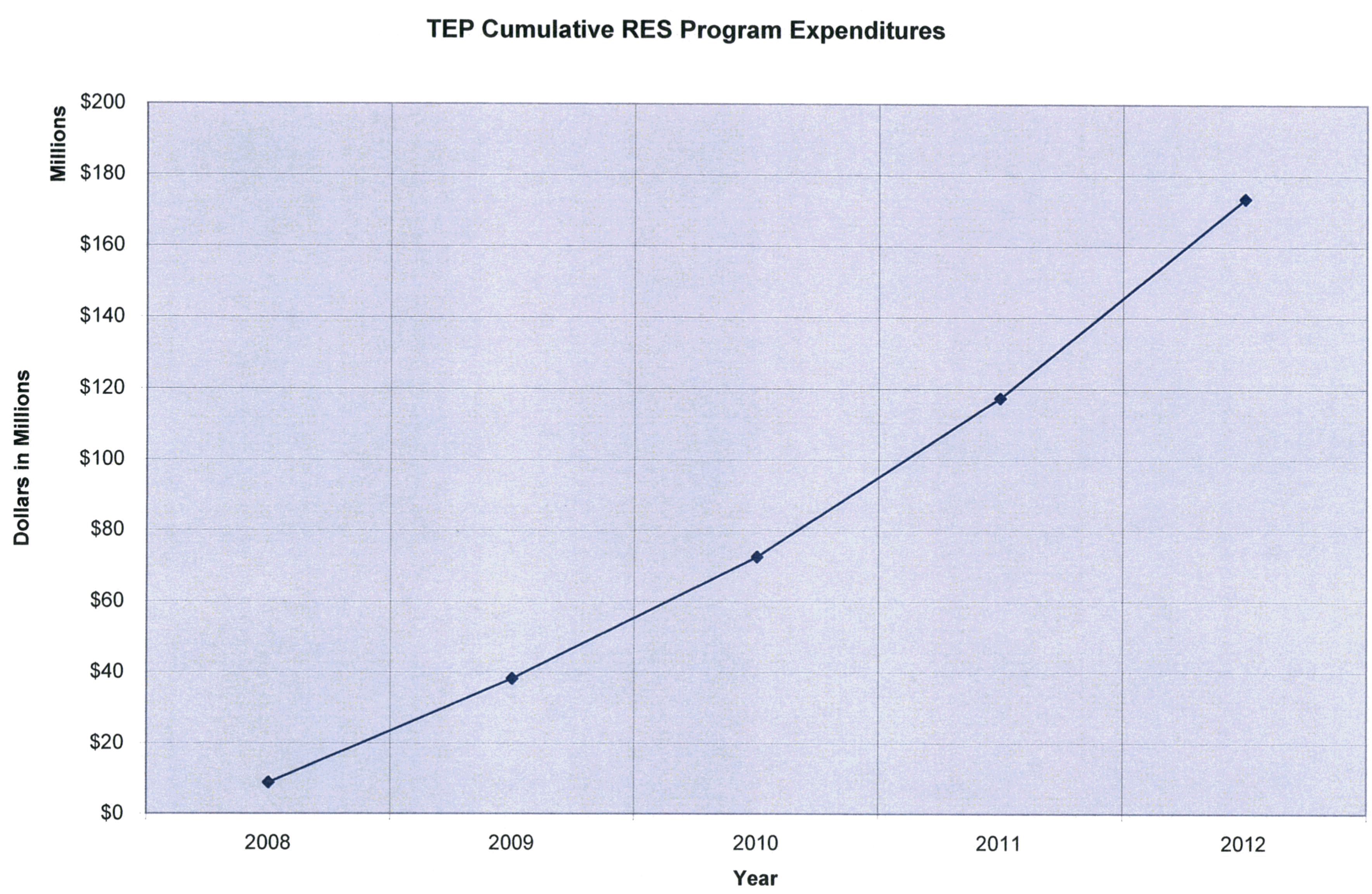
The EPS adopted by the Commission in 2001 provided TEP with the opportunity, and, just as importantly, sufficient funding, to develop appropriate amounts of solar technologies, both in partnership with customers and at utility scale, to understand the basic tools that will need to be developed over the next decade to fully integrate solar energy into its generation portfolio. TEP's REST Implementation Plan and REST Tariff continue that transition to sustainable energy sources by setting a definitive, sustainable timeline and providing sufficient funding to support 15 percent of annual energy needs from renewable resources by 2025.

Arizona has the nation's best solar energy resource, wherein only 0.5 percent of Arizona's land surface, if covered with ten-percent-efficient solar generation and combined with efficient, inexpensive, reliable energy storage, could provide all of Arizona's current annual electric energy needs. Solar energy is Arizona's energy future. In 2100, we expect that future Arizonans will look back in history from their end of the timeline and wonder why there was a time when solar energy was not the energy source of choice. At our end of the timeline we know that the economics and technologies are not yet fully capable of economically and reliably supporting 100 percent of Arizona's energy needs from renewable resources. Commission approval of the REST Implementation Plan and its appropriate funding through the proposed REST Adjustor Mechanism and the REST Tariff will challenge TEP to continue its sustainable energy transition at an accelerated pace for the next two decades. TEP looks forward to working with the Commission in fulfilling the promise of the REST Implementation Plan and REST Tariff, in working with its customers to develop DG projects throughout the Tucson service area, and in developing renewable energy as a whole.

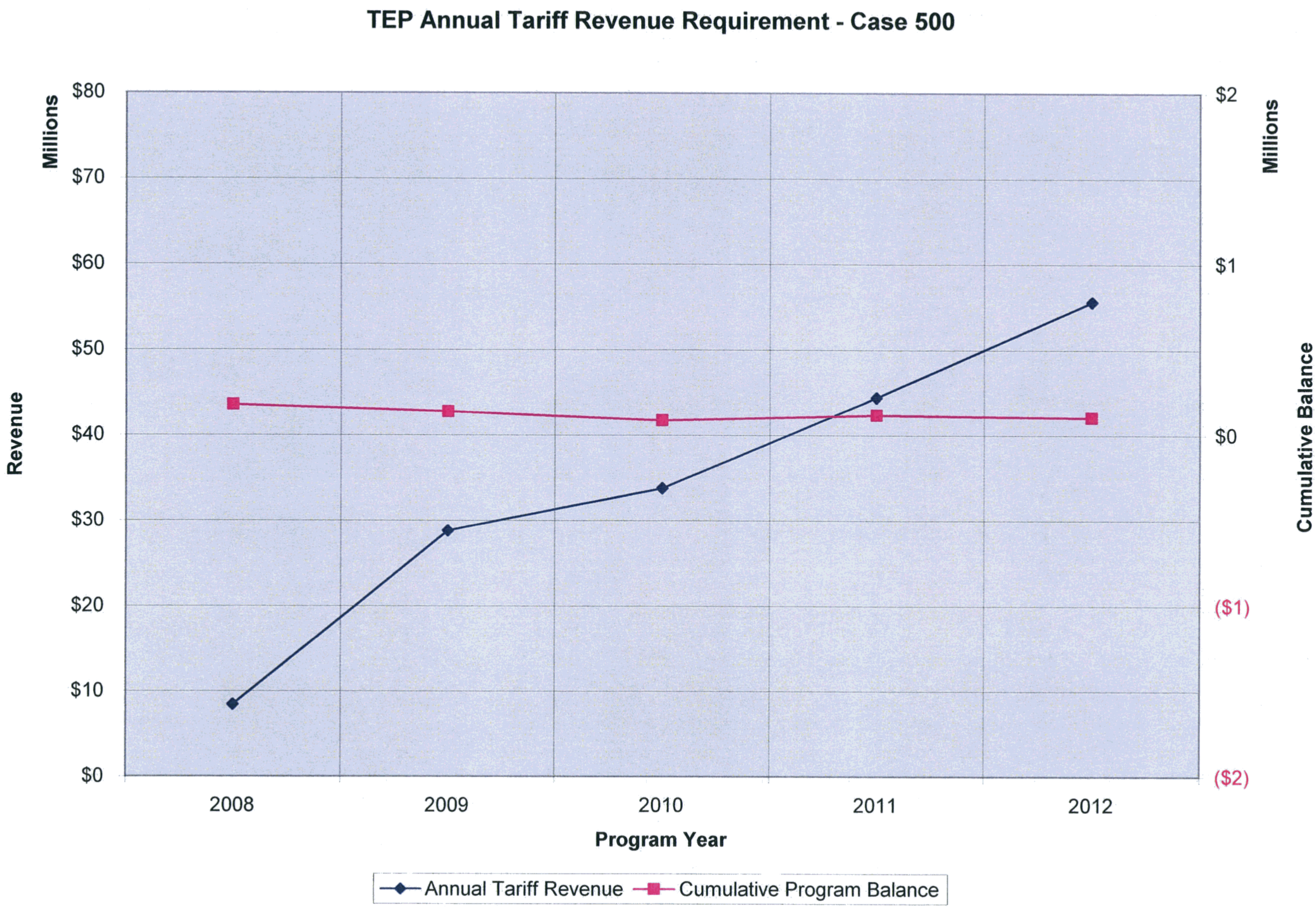
Attachment 1
to Exhibit 1

TEP Total Cumulative Renewable Generation Capacity

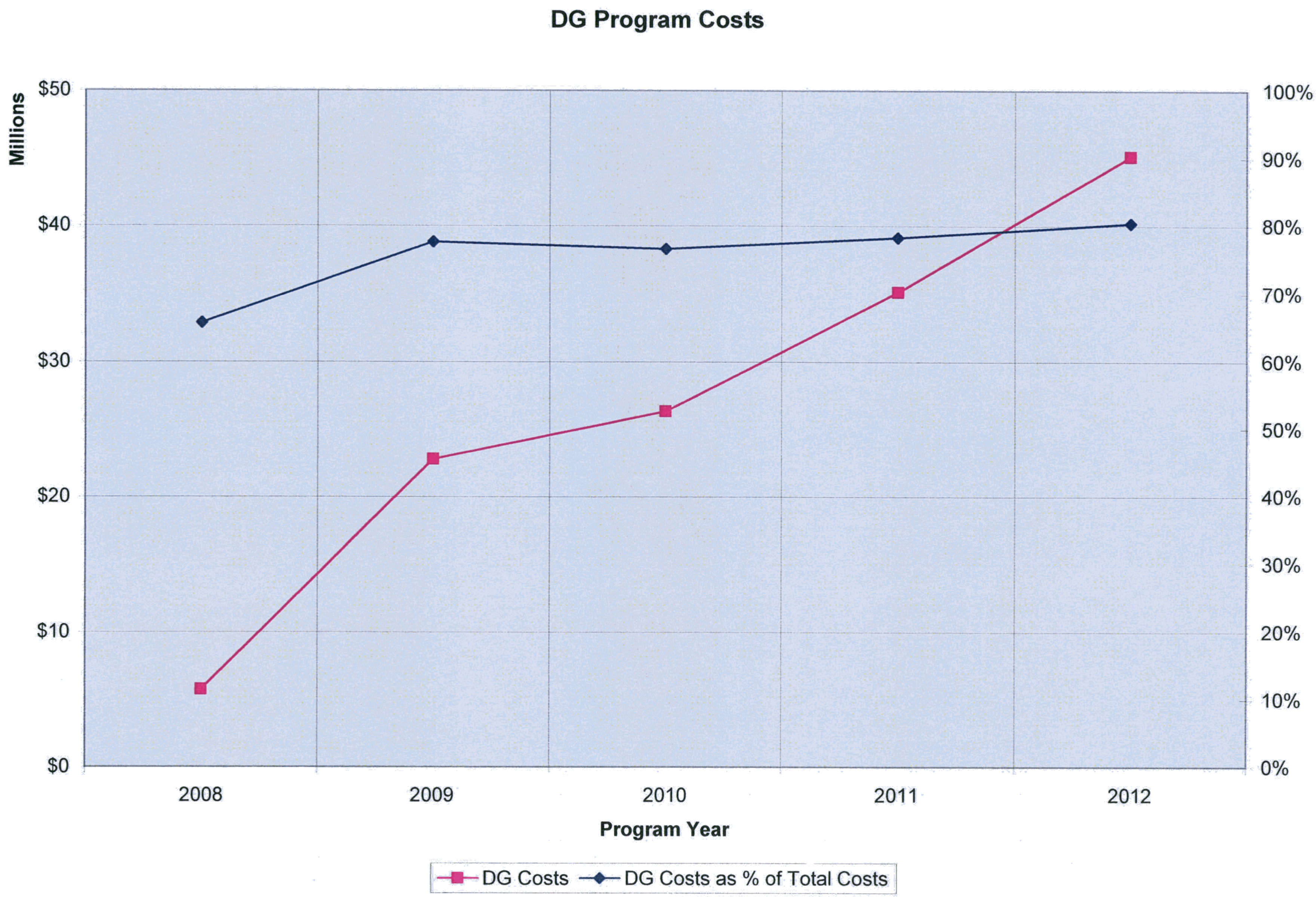




TEP Cumulative RES Program Expenditures
Millions
Dollars in Millions
$200
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
2008
2009
2010
2011
2012
Year



TEP Annual Tariff Revenue Requirement - Case 500
Revenue
Millions
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cumulative Balance
Millions
$2
$1
$0
($1)
($2)
2008
2009
2010
2011
2012
Program Year
Annual Tariff Revenue
Cumulative Program Balance



DG Program Costs
Millions
$50
$40
$30
$20
$10
$0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
2008
2009
2010
2011
2012
Program Year
DG Costs
DG Costs as % of Total Costs

Five Year Renewable Energy and Capacity Forecast with Cost Estimates

TEP-2008

Section	Item	2008	2009	2010	2011	2012
TEP & REST Program Factors	RES Annual Renewable Energy Percentage	1.75%	2.00%	2.50%	3.00%	3.50%
	Energy Sales - MWh Growth @ 1.52%/yr	Seven Months 5,713,342	9,935,957	10,135,006	10,325,861	10,519,779
	Expected DSM Program Annual Energy Reductions	31,384	63,837	97,308	131,815	167,496
	Expected DG Program Annual Energy Reductions	0	9,943	29,587	50,041	76,080
	Net Retail Energy Sales in MWh per Year	5,681,958	9,862,177	10,008,111	10,144,005	10,276,203
	Renewable Energy - MWh	99,434	197,244	250,203	304,320	359,667
	Minimum Distributed Energy %	10.00%	15.00%	20.00%	25.00%	30.00%
	Minimum Distributed Energy MWh	9,943	29,587	50,041	76,080	107,900
	Minimum Residential Distributed Energy %	5.00%	7.50%	10.00%	12.50%	15.00%
	Minimum Residential Distributed Energy MWh	4,972	14,793	25,020	38,040	53,950
	Maximum Commercial Distributed Energy %	5.00%	7.50%	10.00%	12.50%	15.00%
	Maximum Commercial Distributed Energy MWh	4,972	14,793	25,020	38,040	53,950
Renewable Resource Energy and Power Conversion	Residential Distributed Generation - MWp Total New 60% Solar PV	0.448	4.814	9.359	15.145	22.217
	Residential Distributed Energy - MWp Total New 40% Solar Hot Water/Space Heating & Wind	1.989	5.917	10.008	15.216	21.580
	Commercial Distributed Generation - MWp Total New 75% Solar Electric PV in 2008, 25% after	2.193	2.175	3.679	5.594	7.934
	Commercial Distributed Generation - MWp Total New 25% in 2008, 75% after, Non Solar Electric @ ave 50% CF	0.284	2.533	4.284	6.514	9.238
	Distributed Solar Elect MWp Old With Multipliers	1.76	1.76	1.76	1.76	1.76
	Utility Solar Elect MWp Old With Multipliers	11.11	11.11	11.11	11.11	11.11
	Utility Fueled Generation - MWp Old With Multipliers	3.938	3.938	3.938	3.938	3.938
	Utility Generated @ 80% NonDispatchable Energy - MWp New No Multipliers - Wind	15.004	47.489	60.997	72.666	82.444
	Utility Generated @ 20% Fueled - MWp New No Multipliers	0.824	2.609	3.351	3.992	4.529
	Resulting Total Solar Electric Capacity in MW	8.792	13.139	19.188	26.890	36.300
	Resulting Total Solar Electric Annual Energy in MWh	14,404	20,267	28,960	40,026	53,550
	Incremental Solar Capacity Watts Installed per Year per Person	3.302	5.434	7.562	9.627	11.764
	Resulting Total Distributed Solar Water Heating Capacity in MW	3.232	9.616	16.263	24.726	35.068
	Resulting Total Distributed Solar Water Heating Annual Energy in MWh	3,232	9,616	16,263	24,726	35,068
	Resulting Total Distributed Non Solar Electric Dispatchable or Displaced Generation Capacity in MW	0.568	1.689	2.856	4.342	6.159
	Resulting Total Distributed Non Solar Electric Dispatchable or Displaced Generation Annual Energy in MWh	2,486	7,397	12,510	19,020	26,975
	Resulting Total Wind Electric Generation Capacity in MW	15.004	47.489	60.997	72.666	82.444
	Resulting Total Wind Electric Generation Annual Energy in MWh	28,883	91,416	117,420	139,882	158,704
	Resulting Total Biomass Electric Generation Capacity in MW	4.249	6.034	6.776	7.417	7.954
	Resulting Total Biomass Electric Generation Annual Energy in MWh	37,221	52,854	59,355	64,971	69,676
	Total Renewable Generating Annual Energy in MWh	**86,226**	**181,549**	**234,508**	**288,626**	**343,972**
	Total Renewable Generating Capacity in MW	**31.844**	**77.966**	**106.081**	**136.041**	**167.924**
Annual Credit Balances MWh	Residential Distributed Electric Credit Balance	3,483	3,483	3,483	3,483	3,483
	Commercial Distributed Energy Credit Balance	0	0	0	0	0
	Utility Generated Electric Credit Balance	118,600	117,100	115,500	113,800	112,000
Assumption	Residential Distributed Generation Solar Electric %	60.00%	60.00%	60.00%	60.00%	60.00%
Residential Solar Electric Up Front Subsidy Payment UCPP Plan	Residential Distributed Genration Up Front Solar Electric Subsidy Program $/Watt DC	$3.00	$3.00	$3.00	$3.00	$3.00
	Additional Residential Distributed Solar Electric Capacity Needed in MWp this given Year	0.448	4.365	4.545	5.787	7.071
	Subtotal Cost of Residential Distributed Solar Electric Subsidies	$1,345,351	$13,095,402	$13,636,018	$17,359,656	$21,213,394
Distributed Solar Hot Water & Wind Up Front Subsidy Payment UCPP Plan	Residential Distributed Solar Hot Water & Wind Up Front Subsidy Program $/Watt AC Equivalent	$0.5000	$0.5000	$0.5000	$0.5000	$0.5000
	Additional Residential Distributed Solar Hot Water & Wind Capacity Needed in MWp this given Year	1.989	3.929	4.091	5.208	6.364
	Subtotal Cost of Residential Distributed Solar Hot Water & Wind Subsidies	$994,343	$1,964,310	$2,045,403	$2,603,948	$3,182,009
Assumption	Distributed Generation Solar Electric %	75.00%	25.00%	25.00%	25.00%	25.00%
...ed Generation Solar Feed In Tariff Plan - ...o all non residential ...ic in all years. UCPP	SubTotal Cost of Distributed Solar Electric Generation Feed In Tariff	$671,181	$1,601,283	$2,350,199	$3,890,820	$5,752,098
	Unit Built in 2008	$671,181	$671,181	$671,181	$671,181	$671,181
	Unit Built in 2009		$665,697	$665,697	$665,697	$665,697
	Unit Built in 2010			$1,013,321	$1,013,321	$1,013,321
	Unit Built in 2011				$1,540,621	$1,540,621
	Unit Built in 2012					$1,861,277
	Unit Built in 2013					
	Unit Built in 2014					
	Unit Built in 2015					

Distribute Electric F Applies tc solar electr	Unit Built in 2016					
	Unit Built in 2017					
	Unit Built in 2018					
	Unit Built in 2019					
	Unit Built in 2020					
	Feed In Tariff Rate for 20 years $/kWh	$0.1800	$0.1800	$0.1620	$0.1620	$0.1380
Distributed Generation Non Solar Electric Energy Feed In Tariff Plan - Solar Thermal, Solar Cooling, Wind, Biomass & Daylighting. Applies to all non residential solar electric in all years. UCPP	SubTotal Cost of Non Solar Electric Distributed Energy Feed In Tariff	$62,146	$641,376	$1,461,328	$2,745,179	$4,363,681
	Unit Built in 2008	$62,146	$62,146	$62,146	$62,146	$62,146
	Unit Built in 2009		$554,747	$554,747	$554,747	$554,747
	Unit Built in 2010			$844,434	$844,434	$844,434
	Unit Built in 2011				$1,283,851	$1,283,851
	Unit Built in 2012					$1,618,502
	Unit Built in 2013					
	Unit Built in 2014					
	Unit Built in 2015					
	Unit Built in 2016					
	Unit Built in 2017					
	Unit Built in 2018					
	Unit Built in 2019					
	Unit Built in 2020					
	Feed In Tariff Rate for 20 years $/kWh	$0.0500	$0.0500	$0.0450	$0.0450	$0.0400
TEP Generated Renewabl e Power	Above Market Premium of Self Generated or Purchased Renewable Power Including Transmission After 2009	$0.0455	$0.0455	$0.0455	$0.0465	$0.0465
	Cost of Self Generated or Purchased Renewable Power	$3,007,725	$6,564,285	$8,043,273	$9,525,670	$10,619,669
Other RES Program Costs	Grid Integration Rate in $/MWh	$0.00	$0.00	$0.00	$2.00	$3.00
	Large Scale Grid Integration Costs in $	$0.00	$0.00	$0.00	$228,240	$377,650
	Administrative Costs & Integration Costs & Outreach and Advertising & Net Metering costs	$2,584,956	$5,355,422	$6,695,787	$8,630,410	$10,865,010
GreenWatts Projects	Distributed non-residential community sited PV UFI projects funded with GreeWatts proceeds	$118,577	$127,047	$135,517	$143,987	$152,456
DG Program Subtotal	Distributed Generation & DG Admin and DG Integration Program Costs	$5,776,555	$22,784,840	$26,324,252	$35,145,759	$45,150,997
Distributed Program % of Total Program	Percent of Total REST Program Costs	65.76%	77.63%	76.60%	78.28%	80.41%
Total Program Expenses	Total REST Program Cost	$8,784,279	$29,349,125	$34,367,525	$44,899,670	$56,148,316
Program Revenue Streams	Credit Sales MWh	0	0	0	0	0
	Green Sales MWh	1,400	1,500	1,600	1,700	1,800
	Credit Sales $/MWh	$0	$0	$0	$0	$0
	Green Sales $/MWh	$85	$85	$85	$85	$85
	Renewable Product Sales Income - GreenWatts for Community Sited Commercial UFI PV only	$118,577	$127,047	$135,517	$143,987	$152,456
	EPS Carryover Revenue	$0	$0	$0	$0	$0
	REST Surcharge/Sample Tariff Income	**$8,456,063**	**$28,800,000**	**$33,800,000**	**$44,400,000**	**$55,600,000**
	Value of TEP PV Energy at $50/MWh (incl SGSSS)	$429,250	$429,250	$429,250	$429,250	$429,250
	PV O&M Exp @ $50/MWh	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)
	Investment Tax Credit	$0	$0	$0	$0	$0
	Finance Cost @ 10% or Investment @ 5%	$0	($8,981)	($6,890)	($4,408)	($5,866)
	Total EPS Program Revenue	$8,963,890	$29,307,316	$34,317,877	$44,928,829	$56,135,841
Annual Program $ Balance	Total EPS Program Annual Balance (Subsidy Program)	**$179,611**	**($41,809)**	**($49,649)**	**$29,159**	**($12,475)**
Cumulative Program $ Balance	**Cumulative Gain (Loss) (Subsidy Program)**	**$179,611**	**$137,802**	**$88,154**	**$117,313**	**$104,838**
Cumulative Program Cost	**Cumulative REST Program Expenditures**	**$8,784,279**	**$38,133,404**	**$72,500,930**	**$117,400,599**	**$173,548,915**

Variable Assumptions	Landfill Gas MWp	5 MWp	
	Central Solar Conversion Rate	1700 MWh/MWp	
	Distributed Solar Conversion Rate	1350 MWh/MWp	
	Distributed Renewable Conversion Rate	1000 MWh/MWp	OG Energy Rate
	Solar Thermal Conversion	2840 MWh/MWp	
	Dispatchable Conversion Rate	8760 MWh/MWp	
	Wind Conversion Rate	1925 MWh/MWp	

Program Assumptions

Assumptions:
TEP manages the Distributed Generation Program
60% of residential distributed is solar electric. The other 40% is solar hot water and wind. Paid for with up front subsidy through 2012
25% of Commercial distributed is solar electric. The other 75% is solar hot water heating, solar cooling, wind, biomass or daylighting. Paid for with a 20 year locked feed in tariff after 2007 through 2030.
The Springerville Solar System will not continue to be credited as commercial distributed generation, but multipliers count..
All banked landfill gas credits, including those from multipliers, will be useful in subsequent years for meeting REST needs or GreenWatts needs or for sale.
The cost of renewable energy purchased through RFPs and generated by TEP in the future initially will be $0.0455 per kWh above the market price for energy purchased at the same time the renewable energy was generated.
The cost of transmission after 2012 to bring the needed amounts of 50% wind to Tucson will be based on a transmission cost of $0.035 cents per kWh on a 20% capacity factor line, in 2013 with reduction to market in 2030.
All renewable generation sources for TEP can be integrated into the existing transmission structure through 2012.
This scenario does not include reductions from Global Solar credit production.
Energy sales and subsidy revenue growth is 1.52% per year: Assumes the REST reduces customer energy load growth due to the new generation installe and DSM reduces load growth also.
Annual energy production rates for the various technologies are based on historical data from the first five years of the TEP EPS programs.
The Feed In Tariff program has less risk of problems associated with customer generation production than the Up Front Subsidy Program given that there
Grid Integration Costs based on Xcel/Minnessota Dept of Commerce Report of 2004, Idaho Power Report of 2007 and British report of 2006.
Other REST Program Costs include: Interconnection application review costs, net metering costs, application processing costs, initial inspections, annual hearing costs.
There is no energy storage anticipated during the 2008 through 2015 time frame. Storage will be needed after 2015 if unpredictable energy sources like
Administrative costs assume one person per 500/kWp per year of new commercial or residential solar installations and two technical gurus for all levels of
Ongoing annual inspection and repair work will be contracted out.
Creation of a database with online access for customers and installers will add some cost in future.

Attachment 2
to Exhibit 1

Market Cost of Comparable Conventional Generation for the Renewable Energy Standard and Tariff

Consistent with the Renewable Energy Standard Tariff ("REST") Rules passed by the Arizona Corporation Commission ("Commission"), Tucson Electric Power Company's ("TEP") Renewable Energy Standard and Tariff Implementation Plan contemplates recovery of expenses in excess of the Market Cost of Comparable Conventional Generation ("MCCCG"). The Commission provided guidance on defining MCCCG in the context of its REST Rules and identified the MCCCG as "the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal and long term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs." R14-2-1801.11.

The great bulk of Renewable Energy Standard program expenses are expected to be from procurement of renewable energy generation sources, both customer sited distributed generation and remote utility scale sources through purchased power agreements. There may be some internal renewable generation production sources built if the cost of purchased renewable energy is higher than self built options. The recovery of all expenses through the REST Tariff revenues will, to a very large degree, be affected by the methodology used to derive the MCCCG amount, expected to be an annual number. This document is intended to define the methodology for purchased power or for internally owned renewable generation sources. It may also be used as a comparison point for customer sited distributed renewable generation resource cost recovery.

The proposed method assumes that an annual revenue requirement figure will built up as a sum from a series of 8,760 (8,784 in a leap year) hourly figures comparing actual renewable generation resource costs for each renewable energy resource purchased or self produced in each hour of the year against the MCCCG in those same hours. The comparable hourly MCCCG may be different for different renewable sources, taking into account the firmness of the renewable generation resource, the curtailability of the renewable generation resource and whether native load requirements were met by internally owned or contracted generation resources or if market purchases were required to meet native load requirements. The following table provides a MCCCG evaluation matrix. The hourly MCCCG cost determination criteria is listed in the box selected by comparing the types of Purchased Renewable Generation with the Market Condition and Dispatch Type. This method of cost determination is very data intensive and will be evaluated at the end of each year by running TEP's PROMOD model software against the purchased renewable generation. The cost of the purchased renewable generation above MCCCG costs will be included in the REST Adjustor Mechanism and REST Tariff.

MCCCG Cost Determination Matrix

<table>
<tr><th colspan="6">Types of Purchased Renewable Generation</th></tr>
<tr><td rowspan="6">Market Condition and Dispatch Type</td><td></td><td>Dispatchable Firm Renewable Generation: Fuel/Solar hybrid, Wind/Hydro hybrid, Biomass</td><td>Must Run Firm Renewable Generation: Dedicated Landfill Gas or Biogas</td><td>Must Run Non-Firm Renewable Generation: Run of Canal or River Hydro</td><td>Curtailable Non Firm Renewable Generation: Wind or Solar without firming storage</td></tr>
<tr><td>Selling to Market from In House Real and Contracted Generation Sources</td><td colspan="4" rowspan="2">MCCCG Cost Based on Incremental Production/Purchase Cost of Base Load Generation for that hour</td></tr>
<tr><td>No Market Transactions from/to In House and Contracted Generation Sources</td></tr>
<tr><td>Purchasing from Day Ahead Market, but not Spot Market, to meet Native Load Requirements</td><td colspan="4">MCCCG Cost Based on Average Day Ahead Market Price of Purchased Power for that hour</td></tr>
<tr><td>Purchasing from Spot Market to meet Native Load Requirements</td><td colspan="4">MCCCG Cost Based on Average Spot Market Price of Purchased Power for that hour</td></tr>
</table>

Incremental Production / Purchase of Base Load - The cost of the next kWh (incremental) amount of load that has to be provided by TEP generation sources and/or purchased power. This will be dependent on the season, month and time of day.

If Day Ahead Market or Spot Market purchases are being used to provide for reliability support capacity to meet native load requirements by freeing up in house or contracted generation resources for regulation or spinning reserve purposes for support of native load requirements, that would still represent a Market Purchase for purposes of determining which matrix box is applicable.

Attachment 3
to Exhibit 1

Tucson Electric Power Company Renewable Energy Standard and Tariff Budget
Cost Recovery Factors Definition for 2008

Total REST (TEP's Implementation Plan) Budget 2008: $15,584,066 ($9 million Jun - Dec)

	TEP's Implementation Plan (Jun 08 - Dec 08)
Purchased Renewable Energy:	
Above Market Cost of Conventional Generation calculated annually on hourly data per MCCCG Matrix [1]	$3,017,103
Non project cost associoced with Purchased Renewable Energy [2]	$70,000
Total	**$3,087,103**
Customer Sited Distributed Renewable Energy:	
Up front subsidy payment to customers cost [3]	$2,523,358
Annual production based performance payment to customers cost [4]	$735,017
Non - project costs associed with Customer Sited Distribution Renewable Energy [5]	$1,855,324
Total	**$5,113,698**
System Costs (Customer and Energy Management)[6]	$375,000
Net Metering[7]	$50,345
Reporting[8]	$80,208
Outside Coordination and Support[9]	$72,829
Renewable Energy Hardware[10]	$29,167
Grand Total	**$8,808,351**

Notes:

Note 1: 66,310 MWh @ $45.50 per MWH above cost of MCCCG – Purchased Power. Contracts are in addition to existing power purchase contracts, costs are incremental and caused by renewable purchased power contracts. Includes GreenWatts proceeds projects which are UFI community sited PV projects, non-residential.

Note 2: Non project costs such as costs associated with the independent auditor, labor for RFP preparation, contract administration and negotiation and annual analysis of hourly delivery intermittencies on grid stability.

Note 3: Residential – 60% will be PV. 0.45 MWDC of PV in 2008. @ $3.00 per watt DC = $1.36M. 40% will be SDWH. 1.99 MW of SDWH in 2008. @ $0.500 per watt = $1.0M.

Note 4: Commercial PBI – 75% * 3,737 MWh/yr/ @ $0.18 = $0.673M. The other 25% commercial as thermal – 25% * 1,245 MWh @ $0.05/kWh = $0.063M. '08 total = $735,017

Note 5: Non project cost such as labor associated with Distributed Generation such as meter reading, acceptance testing, application processing and customer support. Outreach and marketing costs.

Note 6: Cost associated with system enhancements to for renewable energy Customer database for DG programs and system upgrades to the Energy Management System / Energy Settlements.

Note 7: Cost associated with net metering including meter cost, labor to install and customer upgrades to CC&B.

Note 8: Cost associated with program reporting - annual compliance and implementation filings.

Note 9: Cost to support information to outside reasearch groups, association and membership fees, training and travel for employees.

Note 10: Cost associated operating and maintainig renewable energy hardware and new technology development.

Exhibit 2

Tucson Electric Power
The Energy People

Renewable Energy Standard and Tariff Surcharge
REST-TS1
Renewable Energy Program Expense Recovery

APPLICABILITY

Mandatory, non-bypassable surcharge applied to all energy consumed by all customers throughout Company's entire electric service area.

RATES

For all energy billed which is supplied by the Company to the customer, the price shall be $0.004988 per kWh of metered monthly energy consumption on all kWh consumed per meter that month up to and including a monthly cap of:

For residential customers:	$2.00 per month.
For small commercial customers:	$39.00 per month.
For large commercial customers:	$500.00 per month

A large commercial customer is one with monthly demand in excess of 3,000 kW for the three consecutive months preceding the current billing period.

For non-metered services, the lesser of the load profile or otherwise estimated kWh required to provide the service in question, or the service's contract kWh shall be used in the calculation of the surcharge.

This charge will be a line item on customer bills reading "Arizona Corporation Commission Renewable Energy Standard & Tariff"

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

Exhibit 3

Tucson Electric Power Uniform Credit Purchase Program

Renewable Energy Credit Purchase Program

(RECPP)

Definition

Tucson Electric Power Renewable Energy Credit Purchase Program (RECPP)

Tucson Electric Power Company is committed to assisting our customers develop their own renewable generation resources, through a balanced and supportive renewable energy distributed generation incentive program. Our goal is to create a program that will provide incentives for affordable, environmentally sensitive, customer-sited renewable energy generation systems to supplement TEP customer's energy needs. A properly designed system, matched to a customer's energy use, will provide a reduction in utility bills through the use of renewable resources. This program reflects our commitment to reduce the cost of developing renewable energy resources in partnership with our customers and help provide our customers with clean energy options.

Defined Terms

ACC – Arizona Corporation Commission.

AZROC – Arizona Registrar of Contractors.

Applicant –Utility customer of record for the Utility Revenue Meter located at the installation site; a builder of the structure (residential or non-residential) who will reserve and install the Qualifying system; or for an off-grid Qualifying System, the property owner for the installation site located within a Utility's service territory.

Arizona Business License – A business license issued by the ACC.

Cancelled – Reservation Status indicating that a Reservation has been terminated, funding is no longer allocated, and the utility has removed the reservation from the funding queue.

Cancellation – The termination of the Reservation.

Commissioned – Qualifying System certified to be in operation.

Commissioning Package – Written verification signed by the installer and the customer confirming that the system has been installed in conformance with the approved reservation and that the system is ready for operation.

Conforming Project – Any project utilizing a renewable technology listed in Attachment D.

Conformance Inspection – Inspection performed by the utility to verify that the system has been installed and operates in conformance with the Reservation application.

Customer -- Utility customer of record for the Utility Revenue Meter located at the installation site or a builder of the structure (residential or non-residential) who will reserve and install the Qualifying System.

Extension – The extension of the Reservation Timeframe.

Installer – The entity or individual responsible for the installation of a qualifying system.

Interconnection Inspection – Inspection performed by the utility to confirm that the system can be safely interconnected to the power grid.

Non-Conforming Project – Non-conforming projects include, but are not limited to, projects with staged completion dates, multi-customer or multi-system projects, projects involving more than one technology, projects requiring new or unique agreement terms, projects with technologies for which qualification standards have not been developed or projects requiring non-standard timeframes.

Performance Based Incentive (PBI) – Incentive based on a rate per kWh output or equivalent kWh of energy savings.

Project Costs – System Costs plus financing costs.

Proof of Project Advancement – Documentation demonstrating that a project is progressing on schedule and is staged for Commissioning on or before the end of the Reservation Timeframe.

Qualifying System – Distributed renewable energy systems meeting the qualifications for production of qualified Renewable Energy Credits in Arizona acceptable to the Arizona Corporation Commission as they may be defined for affected utilities to meet any renewable energy standards.

Renewable Energy Credit (REC) – One Renewable Energy Credit is created for each kWh, or kWh equivalent for non-generating resources, derived from an eligible renewable energy resource. RECs shall include all environmental attributes associated with the production of the eligible renewable energy resource.

Reservation – A dollar amount committed by the utility to fund a project if all program requirements are met.

Reservation Status – Indicator relating to approval or denial of a Reservation request. If a Reservation is approved, the Reservation Status is Reserved. If a Reservation request is denied, the Reservation Status is either Cancelled or Wait Listed.

Reserved – Status indicating the acceptance of a Reservation request.

Reservation Timeframe – The duration of the utility's funding commitment for a Reservation.

System Costs -- Costs associated with the Qualifying System components, direct energy distribution, system control/metering, and standard installation costs directly related to the installation of the Qualifying System.

Up Front Incentive (UFI) – One time incentive payment based on system capacity or estimated energy kWh production rather than on measured system output.

Wait List – Status indicating Applicant has met program requirements, but the Utility has insufficient funding to commit to funding the project.

Tucson Electric Power Renewable Energy Credit Purchase Program (RECPP)
Review Panel

TEP will participate in a RECPP Review Panel for ongoing review and modification of all Renewable Distributed Generation programs, as prescribed by the ACC. TEP believes that the Review Panel making recommendations to expeditiously modify all TEP renewable programs is critical to its ultimate success. Program elements may need to be adjusted to reflect new information, changing market conditions, incorrect initial assumptions, or technological innovations.

Panel Structure and Function

The Review Panel will be a five member panel created and maintained to provide on-going review of all renewable distributed generation program modifications and to efficiently facilitate incorporation of features that increase program efficacy as more information is gained by program implementation. The panel will make recommendations to the TEP Renewable Energy program management for review and potential program incorporation.

The panel make-up includes one representative from the ACC staff, two representatives from the Tucson area renewable distributed generation industry, and two representatives from TEP. The industry representatives should not exceed one each from a technology type and should reflect the diversity of technologies and consumer types available in the Tucson area.

No renewable distributed generation industry representative shall serve more than one four year term.

The Review Panel shall make recommendations for consideration on the following subjects:

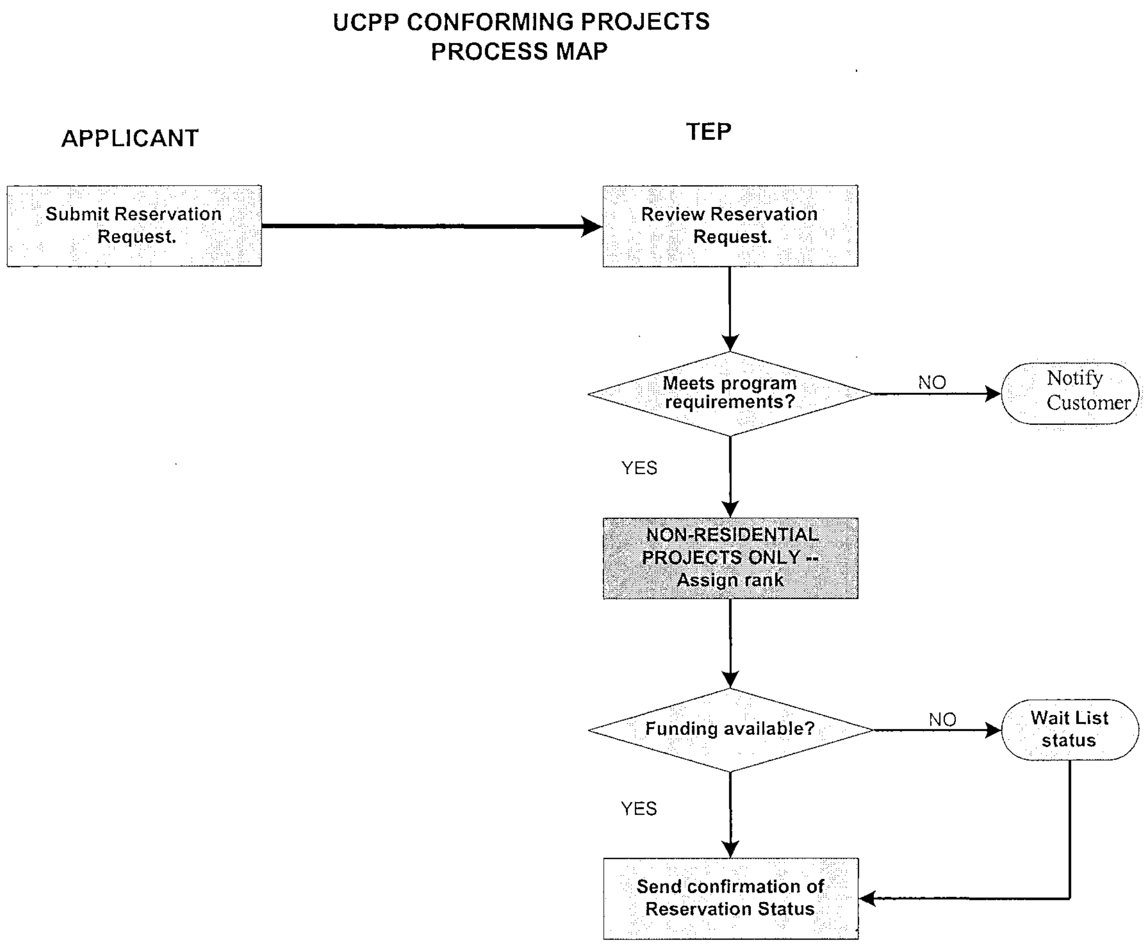
- Adjustment of incentive structures to reflect market response
- Process related issues that affect market function
- Development of new conforming incentives, as necessary
- Arbitration of incentive or program borne conflicts

The Review Panel should meet twice per year (or more often as necessary) to assess the items related to the above-described purpose. The Review Panel will review input from stakeholders on items before it for consideration, and it is anticipated that on occasion stakeholders may be consulted by the Review Panel to provide additional input. Upon full consideration of an item, the Review Panel will vote on adoption of the specified recommendation. A super-majority majority vote of at least four affirmative votes on a subject would result in a recommendation for consideration and potential incorporation into the RECPP.

Process Map – Conforming Projects

TEP mapped the RECPP process for conforming projects to illustrate the flow of information between the applicant and TEP. The following sections reflect the recommended process flow.

Step 1 – Reservation Request and Assignment of Reservation Status



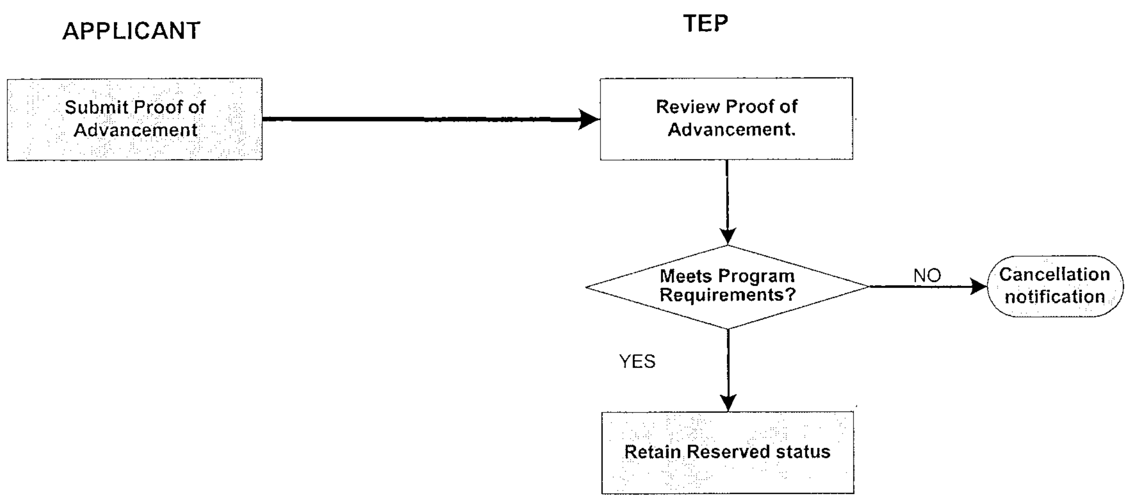
Process Map Description – Step 1

The first input TEP receives from the customer is the reservation request. TEP will review the reservation request to ensure the application conforms to program requirements. Residential reservation requests are processed on a first-come, first-reserved basis. Non-residential reservation requests are assigned a rank based on the lowest expected life cycle credit purchase cost. Additional detail on non-residential reservations is provided in the incentives section of this report.

After reviewing the reservation request, TEP will assign a reservation status. If the reservation request is approved, TEP will send a confirmation to the applicant. If the reservation request is denied because the request is not in compliance with program requirements, TEP will send notification to the applicant of the discrepancies and that the request will be cancelled. Similarly, if the reservation request is denied because funding is not available, TEP will send a notification to the applicant that the request will be placed on a waiting list.

Residential reservation requests will be reviewed within 30 days of the utility's receipt of the request. Non-residential reservation requests will be reviewed within 90 days of TEP's receipt of the request. Further detail relating to reservation periods is provided under the section titled Incentive Allocation.

Step 2 – Proof of Advancement Process Map



Process Map Description – Step 2

The applicant must submit proof of advancement to TEP to retain his or her reservation within the timeframes outlined below. At a minimum, the Proof of Project Advancement documentation for a non-residential application greater than 20 kWac will include:

- A project agreement (between customer and installer);
- An executed installation agreement including all project participants;
- Building and/or construction permits and/or a full set of design development or construction drawings (80% or more complete); and
- An executed interconnection agreement (if applicable).

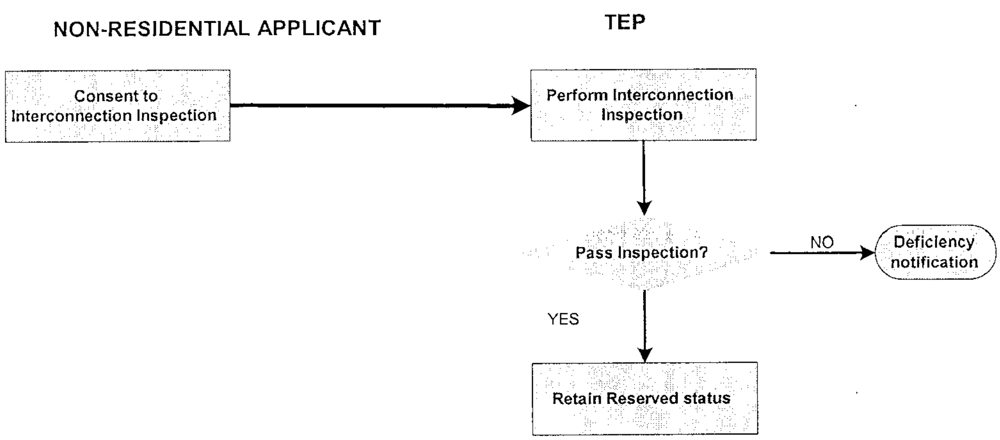
Residential customers and non-residential customers installing a renewable energy system with rated production capacity of 20 kWac or less must provide copies of City/County construction permits to TEP.

The timeline for proof of project advancement is based on the date of reservation confirmation and must be provided by the customer in accordance with the following schedule:

Residential	Non-Residential ≤20,000 watts AC capacity equivalent	Non-Residential > 20,000 watts AC capacity equivalent
60 Days	60 Days	120 Days

If proof of project advancement is not received within the specified timeframe, the customer will be notified that the reservation is cancelled. The applicant has the option to reapply for funding after the reservation has been cancelled. The request will be processed in the same manner as a new project reservation and will be contingent upon availability of funding.

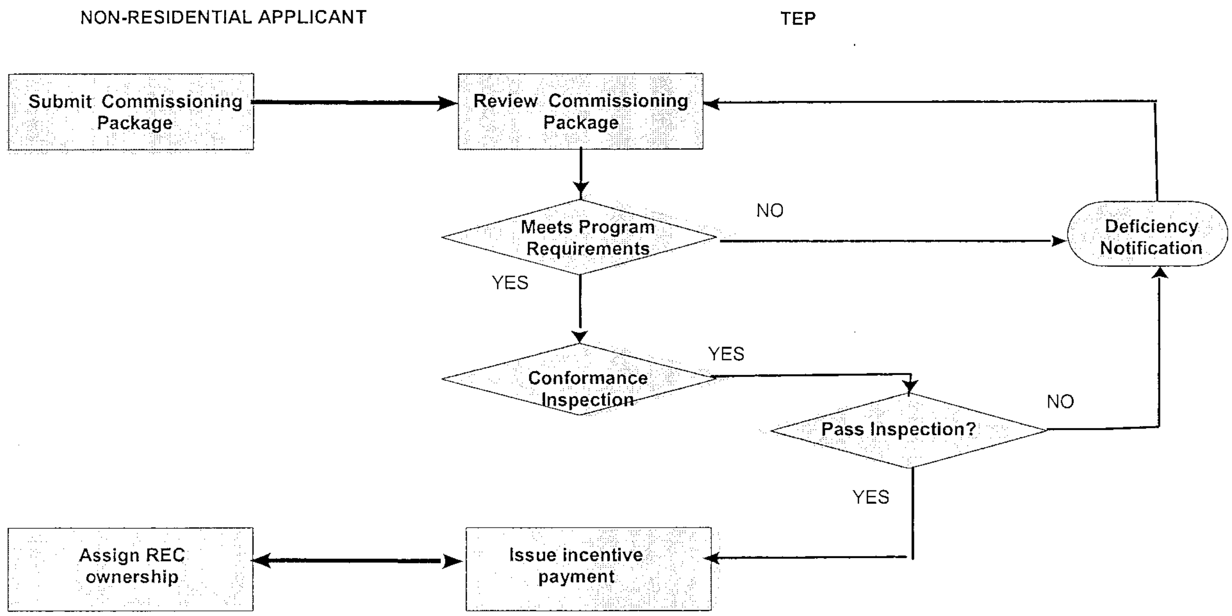
Step 3 – Interconnection Inspection (for Grid-Tied Qualifying Systems with capacity larger than 20 kWac)



<u>Process Map Description – Step 3</u>

Non-residential grid-tied qualifying systems of electrical generating capacity larger than 20 kWac must submit to and pass an interconnection inspection before the system can be commissioned. TEP conducts the interconnection inspection and will notify the applicant of the results of the inspection. If the system passes the inspection, the application retains the reservation. The applicant can keep the reservation even if the system fails the initial inspection, as long as the deficiency is remedied within the defined reservation timeframe described in Step 2.

Step 4 – System Commissioning For Non-Residential Systems with capacity Larger Than 20 kWac



<u>Process Map Description for System Commissioning Non-Residential Customers – Step 4</u>

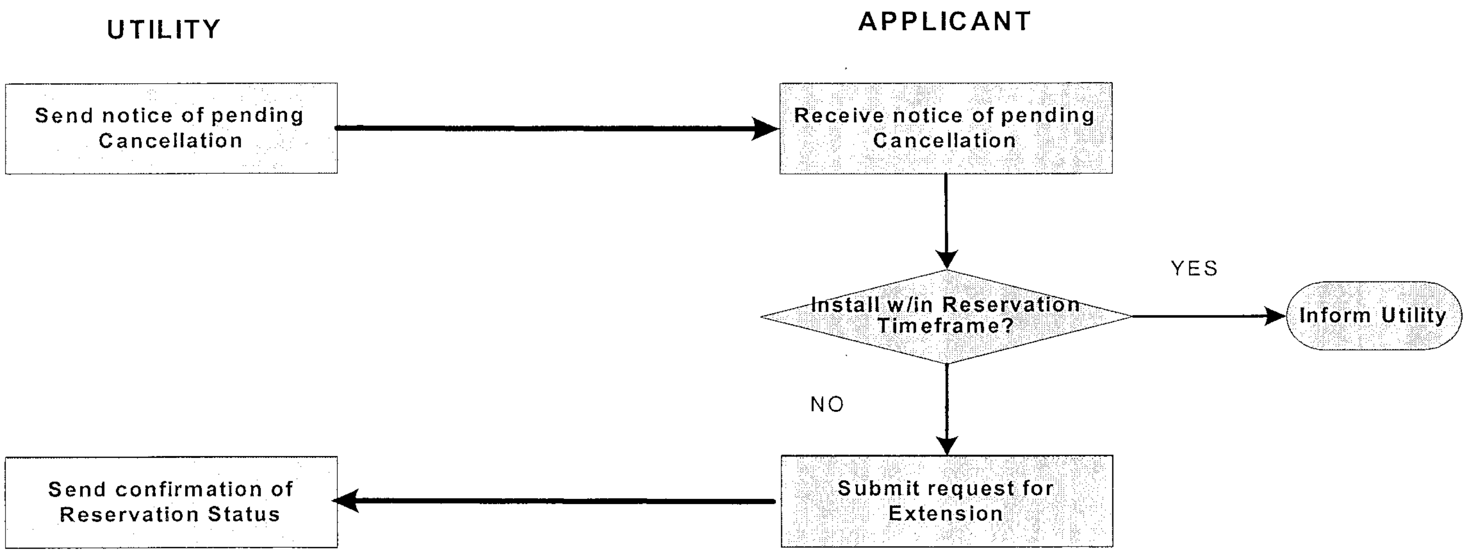
After the Non-Residential system has been commissioned, the applicant must submit a commissioning package to TEP. TEP will review the commissioning package and confirm that all program requirements have been met, including passing the interconnection inspection. For systems with capacity larger than 20 kWac, TEP may, at its discretion, perform a conformance inspection of the system. TEP will notify the applicant of the scheduled conformance inspection and the applicant must make the system available for inspection. In some cases, an incentive payment may not be issued until after a qualifying system has passed the conformance inspection.

Residential customers and non-residential customers with systems of capacity 20 kWac and less will notify TEP that their installation is complete. TEP will perform an acceptance test to verify installation and system performance after receiving copies of City/County permit.

Residential customers and non-residential customers with systems of capacity 20 kWac and less, who are receiving a UFI payment, and have met all program requirements, will receive the incentive payment within thirty days of successful acceptance. After TEP issues the UFI payment to the applicant, TEP is assigned exclusive rights to all the RECs associated with the generation produced from the qualifying system for a period of at least twenty years.

Systems receiving PBI payments will report production, receive payment, and release all RECs in conformance with the detail described in this report under the sections titled *Procedures for Production Based Incentives and Distributed Generation Incentives.*

Conditionally Required Step - Cancellations



Process Map Description – Cancellations

Unless an extension is granted, as described below, a reservation request will be cancelled if all program requirements have not been met with the reservation timeframe.

The reservation timeframe is determined in accordance with the following schedule:

Residential	**Non-Residential ≤ 20,000 watts ac capacity equivalent**	**Non-Residential > 20,000 watts ac capacity equivalent**
180 Days from Reservation Confirmation Date	180 Days from Reservation Confirmation Date	365 Days from Reservation Confirmation Date

TEP will notify the applicant of the pending cancellation in accordance with the following schedule:

Residential	**Non-Residential ≤ 20,000 watts ac capacity equivalent**	**Non-Residential > 20,000 watts ac capacity equivalent**
30 Days Prior to Cancellation	30 Days Prior to Cancellation	60 Days Prior to Cancellation

Extensions

TEP will grant an extension for up to 90 days following timely receipt of a customer's request for extension. TEP may approve written extension requests detailing the conditions for delay for periods beyond 90 days under extenuating circumstances.

Operations Monitoring

All customers receiving renewable energy self-generation incentives are obligated to report system production to TEP in accordance with the reporting schedule established in the program agreement between TEP and the customer. TEP, at its option, may perform periodic inspection of the system for operation, metered production, and reporting purposes.

Procedures for Production Based Incentives

Each project eligible for a PBI requires a project agreement between the applicant(s) and TEP that will detail the assignment of energy and RECs and the assignment of payment. All PBI Project Agreements will include the following requirements:

1. Meters certified according to the TEP standards that provide readings in kWh will be provided by TEP as part of the system commissioning package.
2. Quarterly meter reads will be performed by TEP and quarterly payments will be made to the assigned payee within 30 days, based on quarterly kWh production. If the payment due is less than $25.00, it will be held for the next payment period.
3. PBI payments will begin with the first quarterly production following receipt of the completed system commissioning package and commissioning test, if required, and continue for the life of the agreement term. As part of this provision, it is understood that systems commissioned mid-quarter will receive payment only for the production of that partial quarter.

Installer Qualifications

All systems receiving incentives under the RECPP must be installed by a qualified installer. The following requirements must be submitted by the applicant as part of the reservation request. TEP will verify that the installer meets the following minimum qualifications prior to confirming a reservation request:

1. The installer must possess a valid license on file with the AZROC with a license classification appropriate for the technology being installed or the installer must identify use of a contractor

holding an appropriate license on file with the AZROC for the technology being installed. A copy of the AZROC license must be provided as part of the reservation request.

2. The installer must possess an Arizona business license that is active and in good standing.

Installers may request that the above information be retained on file with TEP; however, under this option the installer must certify that the information on file remains current with the submission of each reservation request. Information on file must be renewed yearly.

Installations By Customer (Residential Photovoltaic and Wind Only)

Residential customers may self-install photovoltaic and wind generators of capacity not to exceed 10 kWac providing they adhere to all applicable codes and standards. The customer installed systems are eligible for an incentive equal to 70% of the standard UFI, as otherwise listed in the incentive table, Attachment D. TEP reserves the right to withdraw this self-install qualification condition at any time in the future, if TEP finds self-installations are not adhering to the applicable codes and standards or are found to be of poor quality workmanship.

Energy Reporting

TEP will report on the productivity of all RECPP distributed renewable energy resource systems within the format of the annual renewable energy Compliance Report to the ACC. For PBI systems, TEP will report on the actual metered production of each system as reported by the customer and confirmed by TEP. For systems receiving a UFI, TEP will report on the total installed capacity and metered production.

System Removal

If receiving a UFI, customer shall not remove the Qualifying System or any components thereof from the premises until December 31st of the 20th full calendar year following completion of system installation of the renewable energy system, without express agreement of TEP. If receiving a PBI, customer shall not remove the Qualifying System or any components thereof from the premises until the last day of the final month of the final full calendar year of the applicable incentive payment term in the Agreement following completion of system installation of the renewable energy system, without express agreement from TEP. If customer removes the Qualifying System in violation of this provision, customer shall immediately reimburse TEP all incentive amounts paid by TEP to customer or on behalf of customer to an authorized third party.

In addition, if a Qualified System is removed, TEP shall monitor that specific customer site to ensure that an additional incentive is not provided for any new distributed renewable energy resource system on that site until the REC contracted operational life of the original system has been completed.

TEP shall attempt to monitor the number of missing or non-working distributed generation systems and shall summarize its observations in its annual Compliance Report.

Qualifying Distributed Renewable Energy Resource Technologies – Technology Criteria

The following technology criteria are not intended to preclude the participation of any renewable energy technology approved for implementation under the RECPP. These criteria are aimed at detailing those technologies or application segments within a technology which have been reviewed in detail by TEP and were accepted as eligible conforming projects for the RECPP. In addition, the following sections provide detail on those criteria required by participating technologies.

<u>General Criteria</u>

TEP acknowledges that many regulations and site specific requirements may apply to the installation of any one renewable energy technology. TEP agrees that no requirement imposed by these technology criteria shall be imposed in conflict with any other governmental requirements. Any RECPP based requirement which is in conflict with a site specific governmental requirement shall be detailed in the reservation request. All qualifying systems must adhere to the following requirements in addition to the RECPP program requirements:

- The project must comply with applicable local, state, and federal regulations.
- Products must be installed according to manufacturers' recommendations.
- Installations must meet applicable governmental statutes, codes, ordinances, and accepted engineering and installation practices.
- Systems must be permitted and inspected by the jurisdiction having authority over construction projects in the customer's locale.
- All major system components must be new and must not have been previously placed in service in any other location or for any other application.
- All renewable electricity generation systems must include a dedicated performance meter (provided by TEP) which allows for measurement of system energy production. Certain other non-electric renewable energy production systems, noted below, will require customer supplied metering for PBI payment calculation purposes.
- If the qualifying system is grid-tied, the system must meet Arizona Corporation Commission Interconnection Requirements for Self-Generation Equipment.

<u>Referenced standards</u>

Some technology-specific criteria reference third party standards. The requirements of those standards are fully applicable when referenced as part of technology specific criteria. TEP notes that rapid growth in national and international renewable energy programs is resulting in greater need for the development of standardization in such areas as; design, implementation, performance measurement, system integrity, and installation. TEP recognizes that new standards are likely to develop in the near future for technologies included in the RECPP and recommends that the new standards are examined for application in this program definition as they become available. The following standards or standard development bodies are referenced as part of the recommended technology criteria:

- The Active Solar Heating Systems Design Manual developed by the American Society of Heating, Refrigerating, and Air Conditioning Engineers, Inc. (ASHRAE) in cooperation with the Solar Energy Industries Association (SEIA) and the ACES Research and Management Foundation (the Design Manual).
- Arizona State Boiler Regulations (see R4-13-406).
- The select technology specific qualification developed by the California Energy Commission (CEC).
- Solar Rating and Certification Corporation (SRCC). The SRCC criteria and ratings can be viewed at www.solar-rating.org.
- The Underwriters Laboratory (UL).
- IEEE -929 standard for utility interconnection of PV systems

Technology Specific Criteria

The following equipment qualifications listed are mandatory requirements which must be met at the time of project commissioning to receive a RECPP incentive. The installation guidance is intended to provide consumers with information on installation and operation practices which are most likely to support achieving the system's designed output. Installation guidance is mandated in order for a project to receive a RECPP incentive, as it does reflect both industry and TEP concurrence on those practices which are important for a technology to best achieve the designed output. In the future, additional installation guidance items may be considered for inclusion as part of the equipment qualifications.

Biomass/Biogas, Hydro or Geothermal Electric

Equipment Qualifications

- Biomass/Biogas, Hydro or Geothermal system installations involving a regulated boiler or pressure vessel are required to comply with all Arizona state boiler regulations; provide a qualifying boiler inspection identification number; and keep all applicable permits in good standing.
- System must include a dedicated performance meter to allow for monitoring of the amount of electricity produced.
- Pre-operational/or pre-commissioning energy savings and design output for the system will be verified by submitting either a testing certification for a substantially similar system prepared by a publicly funded laboratory or by submitting an engineering report stamped by a qualified registered professional engineer. The engineering report shall provide a description of the system and major components, design criteria and performance expectations, applicable standards and/or codes, and a brief history of components in similar applications.
- The system will have a material and labor warranty of at least five years.
- The system must meet Arizona DEQ environmental standards.

Installation Guidance

Because of the individual nature of biomass/biogas hydro or geothermal systems, care should be taken to make sure the system complies with all applicable permitting and regulatory requirements including, but not limited to, air emission standards and air permit regulations.

Biomass/Biogas or Geothermal Space Heating, Process Heating or Space Cooling

Equipment Qualifications

- Biomass/Biogas or geothermal system installations involving a regulated boiler or pressure vessel are required to comply with all Arizona state boiler regulations; provide a qualifying boiler inspection identification number; and keep all applicable permits in good standing.
- Energy savings and designed output for the system will be verified by submitting either a testing certification for a substantially similar system prepared by a publicly funded laboratory or by submitting an engineering report stamped by a registered professional engineer. The engineering report shall provide a description of the system and major components, design criteria and performance expectations, applicable standards and/or codes, and a brief history of components in similar applications.
- Energy production for space heating, space cooling and process heating will be calculated as one kWh of energy per 3,415 Btu of useful heat delivered by the system as measured by a dedicated heat delivery measuring meter and used by the building space or process.
- The system will have a material and labor warranty of at least five years.
- The system must meet Arizona DEQ environmental standards.

Installation Guidance

Because of the individual nature of biomass/biogas or geothermal systems, care should be taken to make sure the system complies with all applicable permitting and regulatory requirements including, but not limited to air emission standards and air permit regulations.

Solar Non-residential Daylighting

Equipment Qualifications

All systems shall include the following components as part of the daylighting system:

- A roof mounted skylight assembly with a dome having a minimum 70% solar transmittance.
- A reflective light well to the interior ceiling or a minimum 12" below roof deck in open bay areas.
- An interior diffusion lens.
- A minimum of one thermal break/dead air space in the system between the skylight dome and the interior diffuser.
- If artificial lighting systems remain a part of the installation, the system shall include automated lighting control(s) which are programmed to keep electric lights off during daylight hours of sufficient solar insolation to provide minimum design illumination levels.

- The system must provide a minimum of 70% of the light output of the artificial lighting system which would otherwise be used for all of the claimed period of energy savings as measured in foot-candles in the workspace 36 inches above the floor.
- Energy savings and designed output for the system will be verified by submitting either a testing certification for a substantially similar system prepared by a publicly funded laboratory or by submitting an engineering report stamped by a registered professional engineer or accredited AEE Measurement and Verification professional. The engineering report shall provide a description of the system and major components, design criteria and performance expectations, applicable standards and/or codes, and a brief history of components in similar applications.
- The system will have a material and labor warranty of at least five years.

Installation Guidance

All systems should be installed such that the skylight dome is substantially unshaded and have substantially unobstructed exposure to direct sunlight between the hours of 9 a.m. and 3 p.m.

Small Wind Generator

A small wind generator is a system with a nameplate capacity rating of one MW or less. The technology criteria described below are intended for small wind generators with a nameplate rating of 100 kW or less. Larger systems will be required to submit a detailed package describing site selection, energy production modeling, and an engineered system design and installation report.

Equipment Qualifications

- Eligible small wind systems must be certified and nameplate rated by the CEC[1]. See www.consumerenergycenter.org/erprebate/equipment.html for a list of certified generators. For grid tied or off-grid wind generators where an inverter is used, the CEC listed nameplate rating of the wind generator will be multiplied by the CEC approved weighted efficiency percentage listed for the inverter in the "List of Eligible Inverters" at www.consumerenegycenter.org/cgi-bin/eligible_inverters.cgi to calculate the wind turbine nameplate rating for use in determining the UFI payment.
- Grid connected inverters used as part of the system shall carry a UL listing certifying full compliance with Underwriter's Laboratory ("UL")-1741
- A system must include a dedicated performance meter (provided by TEP) installed to allow for measurement of the amount of electricity produced.
- The performance meter and utility disconnect for grid tied systems will be installed in a location readily accessible by TEP during normal business hours.
- Off-grid systems of capacity less than 10 kWac will not be metered. Compliance reporting production will be based on an annual 20% capacity factor.
- The tower used in the installation must be designed by an Arizona registered engineer and must be suitable for use with the wind generator. Tower installation must be designed and supervised by individuals familiar with local geotechnical conditions.

[1] TEP recommends review of the SWCC standards for rating small wind generators once they become available for purposes of supplanting the CEC requirement in this Technology Criterion.

- To receive a UFI, the wind generator and system must be covered by a manufacturer's warranty of at least ten years. Otherwise the system will qualify for a PBI. In all cases the wind system will have a material and labor warrantee of at least five years.

Installation Guidance

- Location: a wind turbine hub should be at least 20 feet above any surrounding object and at least 28 feet above the ground within a 250-foot radius. Wind generators should be installed in locations with an elevation at or above the general elevation of the surrounding terrain.
- Lot Size: should be one-half acre at minimum. Municipalities and public facilities such as schools and libraries are exempt from the minimum lot size requirements.
- The proposed system for which application is made should be demonstrated by support information to obtain at least a 15% annual capacity factor. The following are readily available methods for helping to demonstrate the potential for a 15% capacity factor, but other methods may be used. The installation location should have a demonstrated average annual wind speed of at least 10 MPH as measured at a height of no more than 50 feet above the ground. Average annual wind speed can be demonstrated by wind speed records from an airport, weather station, or university within 20 miles of the proposed wind generator location, or by a 50 meter wind power density classification of Class 2 "Marginal" or higher on the State of Arizona Average Annual Wind Resource Map dated July 16, 2005, or later as published by Sustainable Energy Solutions of Northern Arizona University. Northern Arizona University provides detailed wind resource maps as well as other resource services. For more information contact Northern Arizona University at http://wind.nau.edu/maps/.

Photovoltaic Systems

Equipment Qualifications

All Systems

- All UFI based systems shall be installed with a horizontal tilt angle of 0 degrees to 60 degrees, and an azimuth angle of +/- 100 degrees of due south. Installation configurations for some systems receiving a UFI will not be eligible for the full RECPP incentive. The reduction will be determined by the TEP developed de-rating chart, Attachment B of this document, and as discussed further in this report under the section titled Conforming Project Incentives.
- A system must include a dedicated performance meter (on grid tied systems, supplied by TEP) to allow for monitoring of the amount of electricity produced.
- Qualifying systems using Building Integrated Photovoltaic (BIPV) modules of total array capacity of 5 kWdc or less shall receive 90% of the UFI incentive value for PV systems listed in Attachment A. Systems using BIPV module of total array capacity of greater than 5 kWDC shall only receive a PBI.
- Photovoltaic modules must be covered by a manufacturer's warranty of at least 20 years.
- Inverters must be covered by a manufacturer's warranty of at least ten years to receive a UFI and at least five years to receive a PBI.

Grid-Connected Systems

- The minimum PV array size shall be no less than 1,200 Wdc
- All photovoltaic modules must be certified by a nationally recognized testing laboratory as meeting the requirements of UL Standard 1703.
- All other electrical components must be UL listed.
- The inverter must be certified as meeting the requirements of IEEE-1547 - Recommended Practice for Utility Interface of Photovoltaic Systems and it must be UL 1741 certified.
- The utility meter, inverter, and utility disconnect will be installed in a location readily accessible by TEP during normal business hours.
- UFI based systems shall meet the requirements of Attachment A or Attachment C as appropriate.

Off-Grid Systems

- The minimum PV array size shall be no less than 600 Wdc and the maximum PV array size shall not exceed 2,000 Wdc.
- All photovoltaic modules must be certified by a nationally recognized testing laboratory as meeting the requirements of UL 1703.
- Off-grid systems will not be metered. Compliance reporting production will be based on an annual 20% capacity factor using nameplate DC rating for capacity.
- All other electrical components must be UL listed.

Installation Guidance

The Customer will be directed to the following resources to gain information regarding industry reference documents for system installation and performance forecasting:

The California Energy Commission's Guide to Buying a Photovoltaic Solar Electric System at http://energy.ca.gov/reports/2003-03-11_500-03-014F.PDF

The Arizona Consumers Guide to Buying a Solar Electric System at www.az**solar**center.com/design/az**guide**-1.pdf

Solar Space Cooling

Equipment Qualifications

- The minimum cooling capacity of the system will be 120,000 BTU (10 tons) per hour.
- Solar collector panels used will have a Solar Rating and Certification Corporation ("SRCC") OG-100 rating or laboratory documentation showing the panel energy output under controlled and replicable test conditions.
- Energy savings and designed output for the system will be verified by submitting either a testing certification for a substantially similar system prepared by a publicly funded laboratory or by submitting an engineering report stamped by a registered professional engineer. The engineering report shall provide a description of the system and major components, design criteria and performance expectations, applicable standards and/or codes, and a brief history of components in similar applications.

- System must include a dedicated performance meter to allow for monitoring of the amount of heat input to the thermal cooling device or system. Energy production will be calculated at one kW-hr per 3,415 Btu of metered heat delivered to the thermal cooling device or system.
- The system will have a material and labor warranty of at least five years.

Installation Guidance

- The horizontal tilt angle of the collector panels should be between 20 and 60 degrees and an azimuth angle should be between +/- 45 degrees of south.
- All systems should be installed such that the energy collection system is substantially unshaded and should have substantially unobstructed exposure to direct sunlight between the hours of 9 a.m. and 3 p.m.
- The system installation should comply with the design manual.

Non-residential Solar Water Heating and Space Heating

Equipment Qualifications

- Solar collector panels used will have a SRCC OG-100 certification or laboratory documentation showing the panel energy output under controlled and replicable test conditions.
- If annual energy production is expected to exceed 10,000 kWh or equivalent, the system must include a dedicated performance customer supplied meter to allow for monitoring of the amount of useful heat produced. Otherwise, compliance reporting production will be based on the design energy savings submitted at time of application.
- Energy savings and designed output for the system will be verified by submitting either a testing certification for a substantially similar system prepared by a publicly funded laboratory or by submitting an engineering report stamped by a registered professional engineer. The engineering report shall provide a description of the system and major components, design criteria and performance expectations, applicable standards and/or codes, and a brief history of components in similar applications.
- The solar collector, heat exchangers and storage elements shall have an equipment warranty of at least 10 years to qualify for a UFI and at least five years to qualify for a PBI
- The system will in all cases have a material and full labor warranty of at least five years.

Installation Guidance

- The horizontal tilt angle of the collector panels should be between 20 and 60 degrees (30 and 60 degrees for space heating applications) and an azimuth angle +/- 45 degrees of south.
- All systems should be installed such that the energy collection system is substantially unshaded and should have substantially unobstructed exposure to direct sunlight between the hours of 9 a.m. and 3 p.m.
- The system installation should comply with the design manual.

Small Domestic Solar Water Heating and Space Heating

Equipment Qualifications

- Domestic Solar Water Heating systems will be rated by the SRCC and meet the OG-300 system standard. Systems that include OG-100 collectors, but are not certified under OG-300, will need to be verified by submitting either a testing certification for a substantially similar system prepared by a publicly funded laboratory or by submitting an engineering report stamped by a registered professional engineer detailing annual energy savings. Solar Space Heating systems will utilize OG-100 collectors.
- Domestic Water Heating systems shall be selected and sized according to the geographic location and hot water needs of the specific application. Reservation requests will include a manufacturer's verification disclosing that the system size and collector type proposed is appropriate for the specific application, including certification that collector stagnation temperature shall never exceed 300 degrees Fahrenheit under any possible conditions at the location of the installation. The manufacturer's verification may be presented as a manufacturer's product specification sheet and will be included in the reservation request. Compliance reporting production will be based on the design energy savings submitted at time of application
- Solar Space Heating systems will be sized in conformance with the Solar Space Heating Incentive Calculation Procedure (Attachment E.) Compliance reporting production will be based on the design energy savings submitted at time of application
- Active, open-loop systems are not eligible for RECPP incentives except for active, open-loop systems that have a proven technology or design that limits scaling and internal corrosion of system piping, and includes appropriate automatic methods for freeze protection and prevents stagnations temperatures that exceed 250 degrees F. under all conditions at the location of installation. Details disclosing conformance with this exception shall be submitted as part of the manufacturer's verification documentation.
- Integrated Collector System (ICS) systems shall have a minimum collector piping wall thickness of 0.058 inches. Details disclosing conformance with this requirement shall be submitted as part of the manufacturer's verification documentation. ICS units shall include certification that collector stagnation temperature shall never exceed 250 degrees F. under any possible conditions at the location of the installation.
- The 'high' limit on all Domestic Water Heating controllers shall be set no higher than 160 degrees F.
- Active thermal storage for solar space heating systems shall use water as the storage element.
- Contractors must provide a minimum of a five year equipment warranty as provided by the system manufacturer, including a minimum warranty period of five years for repair/replacement service to the customer.
- Domestic Water Heating systems that are installed as an addition to an existing system or are submitted as a customer designed system or not certified to OG-300 must be specifically reviewed and approved by the utility
- The solar collector, heat exchangers and storage elements shall have an equipment warranty of at least 10 years to qualify for a UFI and at least five years to qualify for a PBI

Installation Guidance

- The system shall be installed with a horizontal tilt angle between 20 degrees and 60 degrees (40 and 60 degrees for space heating applications), and an azimuth angle of +/- 60 degrees of due south (+/- 20 degrees for space heating applications). It is recommended that collectors be positioned for optimum winter heating conditions at a minimum tilt angle of 45 degrees above horizontal, or as recommended by the manufacturer for the specific collector type and geographic location of installation.
- All systems should be installed such that the energy collection system is substantially unshaded and should have substantially unobstructed exposure to direct sunlight between the hours of 9 a.m. and 3 p.m.
- Heat exchange fluid in glycol systems should be tested, flushed and refilled with new fluid as necessary or at a minimum every five years or sooner per manufacturer's recommendations.
- It is recommended that the anode rod be checked and replaced per manufacturer's recommendations, but no less frequently than every five years.
- It is recommended that the system design include a timer, switch, or other control device on the backup element of the storage tank.
- The collectors and storage tank should be in close proximity to the backup system and house distribution system to avoid excessive pressure or temperature losses.
- It is recommended that in areas where water quality problems are reported to have reduced the expected life of a solar water heater, that a water quality test is performed for each residence to screen for materials that through interaction with the materials of the proposed solar water heating system may reduce the expected operational life of the system components. The customer should consider contacting the manufacturer to determine if warranty or operational life will be affected.
- In areas subject to snow accumulation, sufficient clearance will be provided to allow a 12" snowfall to be shed from a solar collector without shadowing any part of the collector.
- Each system shall have a comprehensive operation and maintenance manual at the customer's site, which includes a spare parts list, data sheets and flow diagrams indicating operating temperatures and pressures, maintenance schedules and description of testing methods and each customer must complete an initial start up and operation training review with the contractor at the time of system start up.
- Ball valves shall be used throughout the system. Gate valves shall not be used.
- Pipes carrying heated fluids shall be insulated for thermal energy conservation as well as personnel protection.

Technologies without Technology Specific Criteria and Non-Conforming Projects

Technology specific criteria have not yet been developed for the following qualifying technologies:

- Fuel Cells
- Non-Residential Pool Heating

For applicants requesting incentives for the above technologies or for applicants requesting installation of a technology with conforming project technology criteria, but where some criteria cannot be met, the applicant will need to submit design and output documentation.

Applicants installing these systems will, at a minimum, need to provide an energy savings and designed output report for the system. The report must include either a testing certification for a substantially similar system prepared by a publicly funded laboratory or an engineering report stamped by a qualified registered professional engineer. The engineering report and/or testing certification shall provide a description of the system and major components, design criteria and performance expectations, applicable standards and/or codes, and a brief history of components in similar applications. Additional information may be required as part of the RECPP requirements.

Distributed Renewable Energy Resource Incentives

Incentive Principles

RECPP incentives can be applied to systems designed to serve only the typical load of the customer with whom the incentive agreement has been established. The assessment of that typical load does not preclude the periodic production of electricity in excess of the customer's demand. Under some circumstances it is understood that select customer installations will be designed to serve loads greater than that of the customer. Under those circumstances, the RECPP incentive will be applied only to the fraction of the generation which is used to serve the typical customer load. Other incentives were developed separate and apart from other RECPP program incentives, such as those for demand side management projects. Systems are not eligible to receive RECPP incentives if other utility incentives are applied.

Up-front incentives (UFIs) are those incentives where the customer receives a one-time payment based on the system's designed capacity or based on the first year energy savings provided by the system. In general, this type of incentive is appropriate for smaller, 20 kWac or less, non-residential installations and all residential installations. The second incentive type is a production based incentive (PBI). The PBI allows the customer to collect incentive payments in direct relation to the actual system production. PBIs are most appropriate where the total system costs are large, of 20 kWac capacity or above.

Incentive funds can be applied to a project, which is the sum of all systems installed at a customer site in a single calendar year. A customer site is the sum of facilities and/or buildings associated with a single utility revenue meter.

A customer site can obtain a UFI for multiple projects, under separate reservations, up to 20,000 Wac capacity equivalent at each customer site. Once the sum of incentives for all project(s) exceeds the 20,000 Wac capacity equivalent limit, described below, incentives for additional projects will take the form of a PBI. This condition only applies to non-residential systems. No partial or split payment types are allowed under one project regarding a UFI or PBI.

All residential systems will be offered only a UFI, unless system warranty conditions will not qualify for a UFI in which case a PBI would apply. Residential customers will receive a UFI up to a cap of 20kWac. If a residential system is installed above 20 kWac, TEP will only provide an incentive payment for the first 20 kWac. Non-residential systems may receive either a UFI or a PBI, depending on the warranty period, technology and the installation size. UFIs were developed for technologies where the average project size results in a total single site renewable capacity equivalent installed less than or equal to 20,000 watts AC. PBIs were developed for technologies where the average project size results in a total single site installed capacity equivalent of more than 20,000 Wac. Both UFIs and PBIs were developed for technologies where projects can range in size. There is no incentive cap for non-residential systems other than annual program funding considerations.

In return for TEP's payment of a UFI, TEP will be given complete and irrevocable ownership of the RECs until December 31st of the 20th full calendar year after completion of installation of the system. Operational life during that time frame must be supported by system warranty or planned maintenance schedules.

TEP's payment of a PBI will assure TEP complete and irrevocable ownership of the REC for the full duration of the PBI agreement. The agreement duration must fully coincide with the PBI payment schedule and the system must be supported by system warranty or planned maintenance schedules for the term of the agreement.

Projects receiving a UFI can receive no more than 60% of the system cost in the total incentive payout. A PBI can not exceed 60% of the real project costs, defined as the undiscounted total system cost plus acceptable financing charges. Acceptable finance charges are finance charges used for the PBI incentive cap calculation and can not exceed the current prime interest rate plus 5%. Financing charges must be disclosed as part of the commissioning package, if not disclosed before.

It is expected that the UFI and PBI incentive caps as a percentage of system cost will decline in the third year of the program to 55%, and the caps will decline to 50% in the fifth year and beyond.

RECPP incentives in combination with other state and federal incentives make it likely that some renewable energy production systems would be free to the customer, or in the extreme, that the customer would realize a net profit from installing a system.

To prevent this result, TEP requires that customers requesting incentives for these systems be required to contribute a minimum of 15 percent of the System Cost in the case of a UFI and of the Project Cost in the case of a PBI. As such, the incentive for all RECPP projects will be calculated as follows: assume the full application of all available incentives, not including the RECPP incentive, and regardless of the customer's ability to fully realize any particular incentive, add the customer contribution (15%), and finally add the RECPP incentive. If the RECPP incentive can be fully applied given the other incentive cap provisions without exceeding the System Cost in the case of a UFI or Project Cost in the case of a PBI, the customer will receive the full incentive amount. If the RECPP incentive cannot be fully applied without exceeding the System Cost in the case of a UFI or Project Cost in the case of a PBI, the RECPP incentive will be capped such as not to exceed the System Cost in the case of a UFI or the Project Cost in the case of a PBI. The incentive amount will be calculated at the time the application is approved for reservation. If federal or state incentives change during the period of time after the reservation approval, the incentive amount reserved will not be changed as long as the reservation is not cancelled.

Conforming Project Incentives

Conforming project incentives were developed to help create or expand incipient markets for distributed renewable energy production facilities, taking into account each technology's specific market conditions, and placing a significant portion of the cost on project owners. The incentives reflect specific input from each technology representative(s). Program incentives were generally not developed with specific consideration for other available state or federal incentives. Incentive caps detailed above were relied upon to account for the impact of multiple incentive sources.

In general, PBI incentive levels were developed first by establishing an incentive for a 10-year agreement. The incentives proposed by TEP are detailed in Attachment D. TEP proposes that the incentive matrix in Attachment D be applied for the first five years of the RECPP. In all cases, incentive values listed in Attachment D are maximum values. Applicants are encouraged to submit applications requesting incentive amounts less than the maximums listed. Applications requesting a lower level of incentive payment than the maximum will have an increased chance of acceptance in the allocation ranking process.

TEP proposes that incentive types should transition to all PBI based incentives after 2012 and incentive levels should continue to decline in future program years. In the long term, incentives should be market based. TEP also recommends that the declining incentives and proposed reductions be carefully reviewed prior to implementation.

Technologies with Special Incentive Considerations

Beyond the requirements of the technology specific criteria and the requirements of the incentive matrix, some technologies require additional project specific adjustment of the available incentives. Those specific requirements are detailed below.

Photovoltaic Systems

The productivity of photovoltaic systems is sensitive to the specifics of the installation method and location. In particular, these systems are impacted by shading, photovoltaic panel horizontal tilt angle and azimuth, and potentially regional conditions. These factors are particularly important as they relate to systems receiving UFI type incentives both in the amount of incentive received by the customer and in the computation of the capacity reported by TEP.

TEP has established a single incentive adjustment table clearly detailing adjustments for each allowable photovoltaic system configuration. TEP will work to assure that the adjustment table is easily interpreted by consumers and installers. The incentive adjustment chart prepared by TEP is included as Attachment B.

Small Domestic Solar Hot Water and Space Heating Systems

Accurately predicting appropriate incentive levels in support of system costs associated with small domestic solar hot water and space heating systems present a challenge. RECPP incentives in combination with other state and federal incentives make it likely that some systems would be free to the customer, or in the extreme, that the customer would realize a net profit from installing a system.

To prevent this result, TEP proposes that customers requesting incentives for these systems be required to contribute a minimum of 15 percent of the system cost. As such, the incentive for small domestic solar hot water and space heating systems will be calculated as follows: assume the full application of all available incentives, not including the RECPP incentive, and regardless of the customer's ability to fully realize any particular incentive, add the customer contribution (15%), and finally add the RECPP incentive. If the RECPP incentive can be fully applied without exceeding the System Cost, the customer will receive the full incentive amount. If the RECPP incentive cannot be fully applied without exceeding the System Cost, the RECPP incentive will be capped such as not to exceed the System Cost.

Example:

$$\text{RECPP Incentive} \leq (\text{System Cost}) - (\text{Total of all Incentives})$$

Where:

Total of all Incentives = Federal Incentives + State Incentives + (15% Customer Contribution)

For purpose of UFI calculation, System Cost for a solar space heating system will not include the cost of any passive thermal storage or the cost of the building heating system itself. It will include the cost of new materials and installation of active thermal storage, expansion tanks, controls, tempering valves, piping, vents, drains, safety valves and all freeze protection.

Small Solar Space Heating System

There are several additional challenges associated with Solar Space Heating Systems. Variability in design for these systems generally suggested a high level of expertise was required to appropriately size and design the systems; yet the overall system cost seemed to require a standardized approach. In order to address this challenge, TEP has adopted a standardized calculation method to support system sizing and incentive payment. The display page of the spreadsheet calculation is presented in Attachment E.

The solar space heating incentive calculation does not suggest or imply that a full energy audit is required to qualify for the solar space heating incentive. The intent is that industry professionals can utilize the calculation tool to aid in facilitating sound system design.

The effective use of the solar space heating incentive calculation is contingent on a Building Design Review. The Building Design Review calculations, inputs and outputs will be determined and specified as part of the reservation request. It is noted that stakeholder acceptance of the proposed calculation tool is conditioned on the future development of standardized design tools, potentially including input tables and charts.

TEP believes that the proposed approach reflects sound design principles and uses inputs which should be available to professionals in this industry segment. TEP does, however, recognize that the approach used in the standardized calculation is not currently universally applied. TEP proposes that continuing efforts be made to develop standard input charts and tables to increase the efficiency of the method's application. In addition, it is the expectation of TEP that the standard calculation can, in most instances, be implemented by practitioners in the solar space heating industry. TEP supports industry collaborative efforts to increase technical knowledge development in this specific area.

RECPP Incentive Allocation

TEP identified two primary program level allocations in conjunction with the RECPP. The first allocation is that associated with RECPP conforming projects. The second is that associated with RECPP non-conforming Projects.

Conforming Project Incentive Allocation

Beyond the allocation made by TEP for purposes of funding conforming projects, TEP also recommends an allocation framework within the conforming project allocation. TEP designed the allocation framework with several key considerations in mind. The factors considered in developing project incentive allocations were as follows:

- Administrative ease
- Economic efficiency
- Consumer clarity and ease of understanding
- Establishment of a high degree of market certainty
- Encouragement of cost reductions in renewable energy technologies
- Flexibility sufficient to allow timely adaptations to changing market conditions
- Capability for making funds available in a timely manner, and
- Avoidance of excessive incentives

These considerations resulted in two different allocation frameworks, one for residential projects and one for non-residential projects. The allocation frameworks are described below.

Conforming Projects – Residential Incentive Allocation – 80% of Distributed Generation funds in 2008.

Funds for conforming residential projects will be divided into four quarters (Jan-Mar, Apr-Jun, Jul-Sep, and Oct-Dec). Funds within each quarter will be made available weekly for reservations on a first-come, first-reserved basis. However, applications received during a given week that request incentive funding levels below the maximum incentive values will receive priority for the allocation of funds available that week based on the lowest expected life cycle credit purchase cost as provided in the application and verified by TEP. Reservation requests can be made throughout each quarter and will be reviewed and approved by the utility weekly as long as the quarterly funding has not been exhausted, assuming all other program requirements have been met.

Funds unused in one quarter will be equally divided among the remaining quarters in that year. Funds allocated to residential projects will not roll forward from one year to the next. If funds in one quarter are fully exhausted, funds for the following quarter will be made available at the start of the following quarter.

Reservations which are rejected as a result of insufficient funds will be offered the opportunity to retain their original reservation date for one additional quarter without the need to resubmit application documentation. If the incentive level has changed from the date of the original reservation to the date when the reservation is approved, the new incentive level shall be applied.

<u>Conforming Projects – Non-residential Incentive Allocation – 20% of Distributed Generation Funds in 2008.</u>

The non-residential incentive allocation framework allows market forces to play a major deciding role in the selection of projects when the volume of proposed projects exceeds the budget for non-residential projects. When the volume of proposed projects is relatively small so that the non-residential program is not fully subscribed, all conforming projects would be selected. In addition, a yearly review will be made to observe and review trends in requested and approved incentive levels. TEP believes this element is important for the on-going management and potential adjustment of incentive levels as needed to respond to market conditions.

Non-residential funds will be equally divided into four quarters (Jan-Mar, Apr-Jun, Jul-Sep, and Oct-Dec). Funds within each period will be made available to projects based on a ranking generated by lowest expected life cycle credit purchase cost as provided in the application and verified by TEP. In the event of a tie in the ranking, when the program would be fully subscribed if both projects were given reservation status, funds will be awarded based on the date of receipt of the completed reservation request.

In each three-month period, reservation requests will be accepted, but they will be reviewed by the utility only after the conclusion of the three month period. Once reservation requests are fully ranked in each reservation period, notification of reservation approvals and rejections will be made in conformance with the rankings and available funding.

Funds unused in one period will be equally divided among the remaining periods in that year. Funds allocated to non-residential projects will not roll forward from one year to the next. Reservations which are rejected as a result of insufficient program funds may elect to carry forward into the next period and retain the original reservation date. The election must be made at the time of the original application.

Within each period, projects submitted to the utility for reservation will be ranked based on a calculated index value for purposes of allocating non-residential funds as proposed in the application and verified by TEP. Lowest lifecycle cost projects will be funded first. Indexing of the non-residential projects will be performed based on the verified incentive values and terms in the application for that project. Projects with higher incentive payments result in a higher expected life cycle credit purchase cost and projects that produce more kWh result in a lower expected life cycle credit purchase cost.

Conforming Projects Fund Contributions Between Residential and Non Residential

Available funding will be split between residential and non-residential project classes. Initially 20% is being allocated to non residential system incentives and 80% is being allocated to residential system incentives. This split will be reapplied each quarter if all funds are not reserved.

Non-Conforming Projects – Allocation: 0% of Distributed Generation Funds in 2008.

Non-conforming projects include, but are not limited to, projects with staged completion dates, multi-customer or multi-system projects, projects involving more than one technology where an interrelated incentive was not developed, projects requiring new or unique agreement terms, or projects requiring timelines differing from those offered to conforming projects. Non-conforming projects also include technologies for which a conforming incentive or technical qualifications were not developed at the time of this plan.

As detailed in the RECPP incentive allocation section of this plan, TEP will disclose the allocation of funds for non-conforming projects in its implementation plan for the next year. TEP will generally, but not always, include a minimum allocation to allow for the potential development of projects with technologies not included on the conforming project incentive matrix.

TEP will apply a minimum of 50% and a maximum of 75% of the non-reserved, non-conforming project allocation to conforming project funding at the end of each calendar quarter. Unreserved non-conforming project allocations will not carry forward from one year to the next.

Incentives used for non-conforming projects must achieve similar economic efficiency as those incentives used in the conforming project category. Incentives applied for non-conforming projects must meet the lower of: 1) the maximum allowable incentive for the proposed technology as described in Attachment D, or 2) the average incentive value of projects accepted by TEP for incentive disbursement for the proposed technology in the previous year.

Some qualifying technologies will not meet either of the previously described economic efficiency measures. Those applicants can negotiate the requested system or project incentive with TEP. In no instance can the incentive exceed the highest calculated appropriate incentive payment value for projects approved by TEP in the previous year.

Under some circumstances a non-conforming project may not identify the customer at project initiation. Regardless of the project design, implementation, or timeline, a customer must be identified at the time of system commissioning. Non-conforming funds will be disbursed upon filing by the customer and acceptance of project commissioning documentation by TEP. For purposes of financing non-conforming projects, funds can be assigned to third parties.

Non-conforming systems must report system capacity (for up-front incentives) or production (for performance-based incentives) in general conformance with those same technologies as described in the conforming project requirements and be covered by similar warranties. For those technologies not described in the conforming project criteria, the reservation documentation must include details related to warranty, system capacity and anticipated annual production. Metering equipment must be made available to TEP during normal business hours for inspection and reporting purposes.

Initially, no funding would be allocated to the Non-Conforming Project class. However, if Non-Conforming Project applications are received, unused funds from the Conforming Project Classes may be allocated to the Non-Conforming Project class. Alternatively, if sufficient interest in developing Non-Conforming Projects is demonstrated, they could be accepted into the Conforming Project class after development and acceptance of technical standards and appropriate incentive values; or TEP could request a special project fund allocation for a specific Non-Conforming Project in its annual REST Tariff Adjustor Mechanism and Implementation Plan filing.

Attachment 1
to Exhibit 3

Application Process
ATTACHMENT 1

System Qualifications

All solar electric generating Customer Systems must meet the following system and installation requirements to qualify for Tucson Electric Power Company's ("TEP" or the "Company") GreenWatts™ SunShare Hardware Buydown Program. Capitalized terms not defined herein shall have the meanings ascribed to them in the GreenWatts™ SunShare Program Hardware Buydown Agreement.

1. A Residential Customer System must have a total solar array nameplate rating of at least 1,200 watts DC and no more than 30,000 watts DC. Any Non-Residential Customer System must have a total solar array nameplate rating of more than 1,200 watts DC.

2. The Customer System components must be certified as meeting the requirements of IEEE-929 - Recommended Practice for Utility Interface of Photovoltaic Systems.

3. The Customer System components must be certified as meeting the requirements of UL-1741 - Power Conditioning Units for use in Residential Photovoltaic Power and be covered by a non-prorated manufacturer's warranty of at least two years.

4. Photovoltaic components must be certified as meeting the requirements of UL-1703 - Standard for Flat Plate Photovoltaic Modules and Panels Systems and be covered by a non-prorated manufacturer's warranty of at least 20 years.

5. The Customer System design and installation must meet all requirements of the latest edition of the National Electrical Code, including Article 690 and all grounding, conductor, raceway, over-current protection, disconnect and labeling requirements.

6. The Customer System and installation must meet the requirements of all federal, state and local building codes and have been successfully inspected by the building official having jurisdiction. Accordingly, the installation must be completed in accordance with the requirements of the latest edition of National Electrical Code in effect in the jurisdiction where the installation is being completed (NEC), including, without limitation, Sections 200-6, 210-6, 230-70, 240-3, 250-26, 250-50, 250-122, all of Article 690 pertaining to Solar Photovoltaic Systems, thereof, all as amended and superseded.

7. The Customer System must meet Company and Arizona Corporation Commission interconnection requirements for self-generation equipment.

8. The Customer System installation must meet the TEP Service Requirements 2000 Edition, Page 1.20, as follows:

   "AN AC DISCONNECT MEANS SHALL BE PROVIDED ON ALL UNGROUNDED AC CONDUCTORS and SHALL CONSIST OF A LOCKABLE GANG OPERATED

DISCONNECT CLEARLY INDICATING OPEN OR CLOSED. THE SWITCH SHALL BE VISUALLY INSPECTED TO DETERMINE THAT THE SWITCH IS OPEN. THE SWITCH SHALL BE CLEARLY LABELED STATING "DG SERVICE DISCONNECT."

9. The Customer System photovoltaic panels and modules must face within +/- 100 degrees of real south, and be completely unshaded from three hours after sunrise to three hours before sunset. System arrays which are facing at an azimuth angle of more than 20 degrees from true south or shaded for more than one hour per day will be subject to a reduced amount of buydown payment per Attachment B.

10. The Customer System photovoltaic panels and modules must be fitted at an angle of 0 degrees to 60 degrees from horizontal. System arrays which are fitted with an elevation angle of less than 20 degrees or more than 35 degrees above horizontal will be subject to a reduced amount of buydown payment per Attachment B.

11. For Residential Customer Systems, Company will provide a meter and meter socket that will be installed in a readily accessible outdoor location by the Customer between the DC to AC converter and the connection to the over-current device in the Customer's electric service panel. For Non-Residential Customer Systems, Company shall provide the meter only, to be installed in a Customer supplied meter socket to be installed in a readily accessible outdoor location by the Customer between the DC to AC converter and the connection to the over-current device in the Customer's electric service panel.

12. Storage Batteries are not allowed as part of the Customer System unless the inverter is a separate component and TEP can locate the Solar Meter at the inverter's output. If configured otherwise, battery losses will adversely reflect in the annual AC metered energy output. Customer's solar energy generation and energy storage system must meet the requirements of 2 and 3 of this Attachment A.

13. Installation must have been made after January 1, 1997.

14. The Customer must be connected to the Company's electric grid, except for approved off-grid systems in conformance with the RECPP.

15. The DC to AC inverter used must provide maximum power point tracking for the full voltage and current range expected from the photovoltaic panels used and the temperature and solar insolation conditions expected in Tucson, Arizona.

16. The DC to AC inverter must be capable of adjusting to "sun splash" from all possible combinations of cloud fringe effects without interruption of electric production.

17. All Customer System installations must be completed in a professional, workmanlike and safe manner.

18. Total voltage drop on the DC and AC wiring from the furthest PV module to the AC meter will not exceed 2%.

19. PV panels and DC to AC inverter will be installed with sufficient clearance to allow for proper ventilation and cooling. At a minimum, manufacturer clearance recommendations will be observed. In no case will PV modules be mounted less than 4 inches above any surface and an additional inch of clearance for each foot of continuous array surface beyond four feet in the direction parallel to the mounting support surface.

Attachment 2
to Exhibit 3

ATTACHMENT 2

SunShare PV Off-Angle & Shading Annual Energy Derating Chart

SunShare PV Off-Angle & Shading Annual Energy Derating Chart

Revised 04/14/2008

Array Azimuth Angle from Due South

EAST — SOUTH — WEST

Array Angle above Horizontal	EAST 100–80	80–60	60–40	40–20	SOUTH 20–20	20–40	40–60	60–80	80–100 WEST
0–10	80%	80%	80%	80%	80%	80%	80%	80%	80%
10–15	80%	80%	85%	85%	85%	85%	80%	80%	80%
15–20	90%	90%	95%	95%	95%	95%	90%	90%	85%
20–25	85%	90%	95%	95%	100%	95%	90%	90%	85%
25–30	85%	90%	95%	95%	100%	95%	90%	85%	80%
30–35	80%	85%	90%	95%	100%	95%	90%	80%	75%
35–40	75%	85%	90%	95%	95%	90%	85%	80%	70%
40–45	75%	85%	90%	95%	95%	90%	85%	75%	70%
45–50	70%	80%	85%	95%	95%	90%	80%	75%	65%
50–55	70%	80%	85%	90%	90%	85%	80%	70%	
55–60	65%	75%	80%	90%	90%	85%	75%	70%	

EAST — SOUTH — WEST

Array Azimuth Angle from Due South

If both off angle and shading conditions apply, multiply the off angle derating factor with the shading derating factor to obtain the array derating factor for the SunShare payment calculation.

Maximum Morning Shaded Hours	0	1	0	1	0	2	1	2	2	0	3	1	3
Maximum Evening Shaded Hours	0	0	1	1	2	0	2	1	2	3	0	3	1
Percentage of Annual Energy =	100%	100%	100%	95%	90%	90%	85%	85%	75%	75%	70%	70%	70%

Attachment 3
to Exhibit 3

ATTACHMENT 3
Supplemental Non-Residential System Qualifications
(Applicable Only for Customer Systems of Capacity Larger than 20,000 watts AC)

1. All solar electric generating Non-Residential Customer Systems must meet the following additional system and installation requirements to qualify for Tucson Electric Power Company's ("TEP" or the "Company") GreenWatts™ SunShare Hardware Buydown Program. Capitalized terms not defined herein shall have the meanings ascribed to them in the GreenWatts™ SunShare Program Hardware Buydown Agreement.

2. The Non-Residential Customer System shall be operating, substantially complete and have produced an AC output at least 70% of the total array nameplate DC rating at PTC as described below.

3. Operation, Maintenance and Repair. The Customer shall be solely responsible for the operation, maintenance and repair of the Non-Residential Customer System and any and all costs and expenses associated therewith. Company will notify Customer of all Non-Residential Customer System repairs the Company determines are reasonably necessary to support proper continued electrical production of the Non-Residential Customer System. The Customer will notify the Company within five (5) business days of its receipt of any such Company repair notice if the repair requires the installation of a new inverter and/or PV module. The Customer shall complete any such repair that affects the Non-Residential Customer System performance and does not require the purchase of a new inverter or PV module(s) within five (5) business days of the Company's notice of the need for such repair. For any such repair that does require the purchase and installation of a new inverter and/or PV module, the Customer shall promptly commence and diligently pursue such repair to completion, provided, in no event shall such repair take more than thirty (30) days to complete. At all times while Company is receiving the environmental credits from the Non-Residential Customer System, Customer shall clean all PV modules in the Non-Residential Customer System as necessary to keep them free from foreign material that would visibly obscure the modules, including any dirt and/or oils.

4. Non-Residential Customer System Security. At all times during and after installation of the Non-Residential Customer System, the Customer shall use commercially reasonable efforts to provide adequate security to prevent damage or vandalism to the Non-Residential Customer System.

5. Company shall provide Customer with a revenue grade AC meter to be installed between the Non-Residential Customer System and the grid interconnection. This meter will not be used for billing, but shall be used for any official Non-Residential Customer System production output data. Company will retain ownership of the meter and be responsible for its repair if needed.

6. Customer shall provide Company with all documentation reasonably requested by Company to demonstrate to the Commission that any environmental credits transferred under the Agreement

were derived from an eligible technology, that the kWh generated are accurately reported and that the environmental credits have not expired or been used by any other entity for any purpose.

7. If certified proof can not be provided of complete galvanic isolation of any and all DC from the AC output of the inverter(s) used in the Non-Residential Customer System through IEEE-1547 certification of the inverter, the Non-Residential Customer System shall include an isolation transformer installed between the inverter(s) and the grid interconnection. The transformer will be rated at full load continuous operation at 50 degrees C. at 125% of nameplate DC array rating and have an efficiency rating at nameplate DC array rating power of at least 98% as tested. The transformer will have at least one tap each of 2.5% and 5% both above and below the nominal voltage tap.

Attachment 4
to Exhibit 3

ATTACHMENT 4

RECPP – CONFORMING PROJECT INCENTIVE MATRIX

2008 and 2009 Program Year

Technology/Application	UP FRONT INCENTIVE [1] 20-Year REC Agreement	10-Year REC Agreement [2] 10-Year Payment ($/kWH)	15-Year REC Agreement [2] 15-Year Payment ($/kWH)	20-Year REC Agreement [2] 20-Year Payment ($/kWH)
BIOMASS/BIOGAS (Electric)	NA	0.060	0.056	0.054
BIOMASS/BIOGAS – CHP (Electric) [3]	NA	0.035	0.032	0.031
BIOMASS/BIOGAS – CHP (Thermal) [3]		0.018	0.017	0.016
BIOMASS/BIOGAS (thermal)	NA	0.015	0.014	0.013
BIOMASS/BIOGAS (cooling)	NA	0.032	0.030	0.029
DAYLIGHTING (Non-Residential)	$0.20/kWH [7] See this note for clarification	NA	NA	NA
GEOTHERMAL – (electric)	NA	0.024	0.022	0.022
GEOTHERMAL – (thermal)	1.00/Watt	0.048	0.045	0.043
GEOTHERMAL – (cooling)	NA	0.032	0.030	0.029
SMALL HYDRO	NA	0.060	0.056	0.054
SMALL WIND (grid-tied) [4]	$2.50/Watt AC	0.145	0.135	0.130
SMALL WIND (off-grid) [4]	$2.00/Watt AC	0.116	0.108	0.104
SOLAR ELECTRIC:				
RESIDENTIAL (GRID-TIED)	$3.00/Watt DC [8]	0.202	0.187	0.180
Non-Residential (Grid-Tied) 20 kW or less	$2.50/Watt DC [8]	0.202	0.187	0.180
NON-RESIDENTIAL (GRID-TIED) More than 20 kW	NA	0.202	0.187	0.180
RESIDENTIAL (OFF-GRID)	$2.00/Watt DC [8]	NA	NA	NA
NON-RESIDENTIAL (OFF-GRID)	NA	0.121	0.112	0.108
SOLAR SPACE COOLING [5]	NA	0. 129	0. 120	0. 115
SOLAR WATER HEATING/SPACE HEATING [5] (Non-Residential)	NA	0. 057	0. 052	0. 051
RESIDENTIAL SOLAR WATER/SPACE HEATING [6]	$750.00 plus $0.25/kWH to a maximum of $1,750.00 [9, 10]	0. 057	0. 052	0. 051
NON-RESIDENTIAL POOL HEATING	NA	0.012	0.011	0.011

RECPP – CONFORMING PROJECT INCENTIVE MATRIX

2010 and 2011 Program Year

Technology/Application	UP FRONT INCENTIVE [1] 20-Year REC Agreement	10-Year REC Agreement [2] 10-Year Payment ($/kWH)	15-Year REC Agreement [2] 15-Year Payment ($/kWH)	20-Year REC Agreement [2] 20-Year Payment ($/kWH)
BIOMASS/BIOGAS (Electric)	NA	0.054	0.050	0.048
BIOMASS/BIOGAS – CHP (Electric) [3]	NA	0.032	0.029	0.028
BIOMASS/BIOGAS – CHP (Thermal) [3]		0.016	0.015	0.014
BIOMASS/BIOGAS (thermal)	NA	0.014	0.013	0.012
BIOMASS/BIOGAS (cooling)	NA	0.029	0.027	0.026
DAYLIGHTING (Non-Residential)	$0.18/kWH [7] See this note for clarification	NA	NA	NA
GEOTHERMAL – (electric)	NA	0.022	0.020	0.019
GEOTHERMAL – (thermal)	0.90/Watt	0.044	0.040	0.039
GEOTHERMAL – (cooling)	NA	0.029	0.027	0.026
SMALL HYDRO	NA	0.054	0.050	0.048
SMALL WIND (grid-tied) [4]	$2.25/Watt AC	0.131	0.121	0.117
SMALL WIND (off-grid) [4]	$1.80/Watt AC	0.105	0.097	0.094
SOLAR ELECTRIC:				
RESIDENTIAL (GRID-TIED)	$3.00/Watt DC [8]	0.182	0.168	0.162
Non-Residential (Grid-Tied) 20 kW or less	$2.25/Watt DC [8]	0.182	0.168	0.162
NON-RESIDENTIAL (GRID-TIED) More than 20 kW	NA	0.182	0.168	0.162
RESIDENTIAL (OFF-GRID)	$1.80/Watt DC [8]	NA	NA	NA
NON-RESIDENTIAL (OFF-GRID)	NA	0.109	0.101	0.097
SOLAR SPACE COOLING [5]	NA	0. 116	0. 108	0. 104
SOLAR WATER HEATING/SPACE HEATING [5] (Non-Residential)	NA	0. 051	0. 047	0. 045
RESIDENTIAL SOLAR WATER/SPACE HEATING [6]	$750.00 plus $0.25/kWH to a maximum of $1,750.00 [9, 10]	0. 051	0. 047	0. 045
NON-RESIDENTIAL POOL HEATING	NA	0.011	0.010	0.010

RECPP – CONFORMING PROJECT INCENTIVE MATRIX

2012 Program Year

Technology/Application	UP FRONT INCENTIVE [1] 20-Year REC Agreement	10-Year REC Agreement [2] 10-Year Payment ($/kWH)	15-Year REC Agreement [2] 15-Year Payment ($/kWH)	20-Year REC Agreement [2] 20-Year Payment ($/kWH)
BIOMASS/BIOGAS (Electric)	NA	0.046	0.043	0.041
BIOMASS/BIOGAS – CHP (Electric) [3]	NA	0.027	0.025	0.024
BIOMASS/BIOGAS – CHP (Thermal) [3]		0.014	0.013	0.012
BIOMASS/BIOGAS (thermal)	NA	0.011	0.011	0.010
BIOMASS/BIOGAS (cooling)	NA	0.025	0.023	0.022
DAYLIGHTING (Non-Residential)	$0.15/kWH [7] See this note for clarification	NA	NA	NA
GEOTHERMAL – (electric)	NA	0.019	0.017	0.017
GEOTHERMAL – (thermal)	0.77/Watt	0.037	0.034	0.033
GEOTHERMAL – (cooling)	NA	0.025	0.023	0.022
SMALL HYDRO	NA	0.046	0.043	0.041
SMALL WIND (grid-tied) [4]	$1.91/Watt AC	0.111	0.103	0.099
SMALL WIND (off-grid) [4]	$1.53/Watt AC	0.089	0.082	0.080
SOLAR ELECTRIC:				
RESIDENTIAL (GRID-TIED)	$3.00/Watt DC [8]	0.154	0.143	0.138
Non-Residential (Grid-Tied) 20 kW or less	$1.91/Watt DC [8]	0.154	0.143	0.138
NON-RESIDENTIAL (GRID-TIED) More than 20 kW	NA	0.154	0.143	0.138
RESIDENTIAL (OFF-GRID)	$1.53/Watt DC [8]	NA	NA	NA
NON-RESIDENTIAL (OFF-GRID)	NA	0.093	0.086	0.083
SOLAR SPACE COOLING [5]	NA	0. 099	0. 092	0. 088
SOLAR WATER HEATING/SPACE HEATING [5] (Non-Residential)	NA	0. 043	0. 040	0. 039
RESIDENTIAL SOLAR WATER/SPACE HEATING [6]	$750.00 plus $0.25/kWH to a maximum of $1,750.00 [9, 10]	0. 043	0. 040	0. 039
NON-RESIDENTIAL POOL HEATING	NA	0.009	0.009	0.008

Notes:

1) Residential projects are eligible for an up front incentive (UFI)). UFI payments can not exceed 60% of the cost of renewable energy equipment.
2) Non-residential under 20 kW is preferably UFI but can be a PBI. Non-residential 20 kW and greater is PBI only. The total of payments under a production based incentive can not exceed 60% of the project costs for any project.
3) The CHP incentives may be used in combination for the appropriate components of one system.
4) This PBI applies to a maximum system size of 100 kW. Larger wind systems may apply for incentives as NCP.
5) The solar space heating and cooling incentives may be used in combination for the appropriate components of one system.
6) This category includes both traditional water heating and those systems combined with residential solar water heating used for space heating. Space heating applications require a report detailing energy saving for the complete system.
7) Rate applies to measured first five years of energy savings only. Payments are made over a five year period.
8) Some UFI based installations will require an adjustment of the incentive as detailed in the PV Incentive Adjustment Chart.
9) Energy savings rating is based on the SRCC OG-300 published rating or the TEP-RECPP Space Heating Calculator. The customer contribution must be a minimum of 15% of the project cost after accounting for and applying all available Federal and State incentives.
10) Rate applies to forecast/measured first year energy savings only.
NA – Not Available

Attachment 5
to Exhibit 3

ATTACHMENT 5

Solar Space Heating UFI Incentive Calculation Procedure.

In Advance, please perform the Design Review and Utility Bill Review (if Applicable) for numbers to enter in Steps #1, #2 and #5.

Elevation Zone Table:

Min Elevation	Max Elevation	Heating Season Days	Daily Panel Heat Output
-1000	1000	105	0
1001	3000	140	0
3001	5000	175	0
5001	7000	210	0
7001	9000	245	0
9001	11000	280	0

Collector Thermal Performance Rating
Data From OG-100 Sheet

Category:	Delta T	Clear Day
A	-9 Deg. F.	0
B	+9 Deg. F.	0
C	+36 Deg. F.	0
D	+90 Deg. F.	0
E	+144 Deg. F.	0

Enter Solar Panel Make and Model Number Selected for Project:

Step #1:	Enter the result of the Design Review of the Design Annual Building Loss =	0	BTU/Year
Step #2:	Enter the result of the Utility Bill Review of the Actual Annual Building Loss: (If not Electric, Natural Gas or Propane Heat, enter 0) =	0	BTU/Year
Step #3:	Calculate the Lesser of the Result in Step #1 & Step #2 = This is the Annual Building Heat Requirement.	0	BTU/Year
Step #4:	Enter Elevation of the Solar Space Heated Building:	0	Feet AMSL
Step #4 cont:	Number of Heating Days per Heating Season from Elevation Zone Table:	105	Days per Year
Step #4 cont:	Calculate Average Daily Building Heat Requirement =	0	BTU/Day
Step #5:	Enter Passive Heat Storage Specific Heat Capacity from Building Design Review:	0	BTU/Deg. F.
Step #5 cont:	Enter Maximum Daily Room Temperature Variation Allowed by Building Occupants: (Max of 10 Degrees F.)	0	Degrees F.
Step #5 cont:	Calculate Maximum Passive Heat Storage Capacity =	0	BTU
Step #5 cont:	Enter Total Active Heat Storage Heat Capacity from Building Design Review:	0	BTU
Step #5 cont:	Calculate Maximum Total Heat Storage Capacity =	0	BTU
Step #6:	Calculate the Lesser of the Average Daily Building Heat Requirement in Step #4 and the Maximum Total Storage Capacity in Step #5. This is the Maximum Useful Daily Solar Heat Input.	0	BTU/Day
Step #7:	Size the Solar Panels based on a total daily solar heat input no greater than the Maximum Useful Daily Solar Heat Input. Enter the single panel SRCC OG-100 Collector Thermal Performance Rating data in the Table Above.	0	BTU/Day per Panel
Step #7cont:	Enter the Total number of solar panels to be installed:	0	# of Panels
Step #7cont:	Calculate the Average Expected Daily Solar Heat Input:	0	BTU/Day
Step #8:	Calculate the Expected Annual Useful Solar KWH Heat Input using the Number of Heating Days times the Average Expected Daily Solar Heat Input / 3415 BTU/KWH:	0	KWH/Year
Step #9:	Enter the UFI per first year KWH UCPP Incentive Rate:	$0.75	$/KWH
Step #9 cont:	Calculate the Total Maximum UFI Payment Subject to Possible Limitation by the 50% of Initial Cost Cap & 15% Minimum Customer Contribution:	$0.00	$
Step #10:	Enter the Total Solar Space Heating System Initial Cost: This should not include costs for Passive Heat Storage or Building Heating System.	$0.00	$
Step #10 cont:	Calculate the Total Expected Federal and Arizona Incentives for this Project:	$0.00	$
Step #10 cont:	Calculate the 15% minimum of the Total Solar Space Heating System Initital Cost to be paid by Customer	$0.00	$
Step #10 cont:	Calculate the Total Actual UFI Payment:	**$0.00**	**$**

Exhibit 4

Tucson Electric Power
The Energy People

Customer Self-Directed Renewable Energy Option
REST-TS2
Renewable Energy Standard Tariff

AVAILABILITY

Open to all Eligible Customers as defined at A.A.C. R14-02-1801.H.

APPLICABILITY

Any Eligible Customer that applies to the Company under this program and receives approval shall participate at its option.

PARTICIPATION PROCESS

An Eligible Customer seeking to participate shall submit to the Company a written application that describes the Distributed Renewable Energy (DRE) resources or facilities that it proposes to install and the estimated costs of the project. The Company shall have sixty (60) calendar days to evaluate and respond in writing to the Eligible Customer, either accepting or declining the project. If accepted, the Customer shall be reimbursed up to the actual dollar amounts of customer surcharge paid under the REST-TS1 Tariff in any calendar year in which DRE facilities are installed as part of the accepted project. To qualify for such funds, the Customer shall provide at least half of the funding necessary to complete the project described in the accepted application, and shall provide the Company with sufficient and reasonable written documentation of the project's costs. Customer shall submit their application prior to May 1 of a given year to apply for funding in the following calendar year.

FACILITIES INSTALLED

The maintenance and repair of the facilities installed by a Customer under this program shall be the responsibility of the Customer following completion of the project. In order to be accepted by the Company for reimbursement purposes, the project shall, at a minimum, conform to the Company's System Qualification standards on file with the Commission. (REST Implementation Plan, Renewable Energy Credit Purchase Program – RECPP, Distributed Generation Interconnection Requirements, Net Metering Tariff, Company's Interconnection Manual)

PAYMENTS AND CREDITS

All funds reimbursed by the Company to the Customer for installation of approved DRE facilities shall be paid on an annual basis no later than March 30th of each calendar year. All Renewable Energy Credits derived from a project, including generation and Extra Credit Multipliers, shall become the property of the Company and shall be applied towards the Company's Annual Renewable Energy Requirement as defined in A.A.C. R14-2-1801.B.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

RELATED SCHEDULES

- REST-TS1 - Renewable Energy Program Expense Recovery