FINAL REPORT

COSTS, BENEFITS, AND IMPACTS OF THE ARIZONA ENVIRONMENTAL PORTFOLIO STANDARD

Prepared by the

Cost Evaluation Working Group*

Submitted to:

Arizona Corporation Commission

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* *This report is the work of the Cost Evaluation Working Group. Although Staff chaired the working group meetings and participated in subcommittee meetings, this is not a Staff Report. The Utilities Division neither endorses nor opposes the report.*

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EXECUTIVE SUMMARY

In February 2001, the Arizona Corporation Commission (Commission) adopted the Environmental Portfolio Standard (EPS) to further the development of renewable resources in producing electricity for Arizona consumers. Starting with 0.2 percent in 2001, the EPS portfolio percentage increases on January 1 of each year, so that by 2007, Load-Serving Entities (LSEs) should provide 1.1 percent of total retail energy sales from solar or other environmentally friendly resources.[1] The EPS provides that the Commission would continue the annual increase in the portfolio percentage after 2004 only if the cost of environmental portfolio electricity has declined to a Commission-approved cost/benefit point. Otherwise, the retail energy percentage will remain 0.8 percent from 2004 through 2012. The EPS recognizes that Arizona's most ubiquitous and abundant renewable resource is the sun as the EPS requires that at least 60 percent of the energy needed to meet the EPS come from solar electric technologies. Funding for the EPS is provided through a per-kWh Surcharge assessed on retail customers, subject to caps with the cap amount depending on the class of customer. Also, in the case of two utilities, existing System Benefits Charges were reallocated to the EPS programs.

The EPS implementation schedule originally intended that a longer time to collect data from operating projects would be available before performing a formal evaluation of the policy. Therefore, this evaluation is based on only 18 months of project data rather than the 30 months planned. This evaluation was conducted by the Cost Evaluation Working Group (CEWG) over eight months and reviewed costs, benefits, and economic impacts of completed renewable energy projects. Projects used to meet EPS renewable energy goals in place at the end of 2002 include almost 6 MW of various solar photovoltaic (PV) installations, a 5 MW landfill project and a large, solar hot water system displacing about 200 kW of peak electric demand. As a direct result of the EPS, Arizona utilities already have a greater installed capacity of large, utility-scale PV systems than any other investor-owned electric utilities in the United States. The benefit of these large systems is that Arizona utility employees now have some of the best levels of experience and expertise in the nation in the installation, operation, and maintenance of utility-scale PV systems.

The vast majority of the information on costs and benefits of projects under the EPS was obtained from Arizona's two largest investor-owned utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP).

Costs: Since 2001, APS and TEP have developed over 5 MW of solar electric generation projects, sufficient from which to draw credible cost conclusions. Over 95 percent of the capacity installed is in large, utility-owned, grid-tied systems greater than 10 kW in capacity, but about 139 small, customer-sited systems have also been completed. For the large projects, total installed system costs are now in the $5.00-5.50 per watt-dc range or simple cost premium of $0.120 to $0.134 per electrical kWh. Overall, a decline in cost is the predominant trend for solar installations.

Benefits: The EPS benefits are both quantifiable and non-quantifiable. The analysis of quantifiable benefits (amounting to $0.03 per kWh of solar electric generation) identified the following:

- displaced or avoided conventional energy costs,

[1] adjusted for extra credit multipliers.

- displaced or avoided conventional capacity costs,
- avoided emissions,
- significant reductions in Balance of System (BOS)[2] costs by TEP and APS, and
- other benefits.

Significant non-quantifiable benefits include:

- Willingness of the Rural Utilities Service (RUS) to approve loans to rural electric cooperatives for PV facilities because of the EPS Surcharge funding source,
- Evaluation of solar system intermittency characteristics,
- Avoidance or delay of distribution and transmission line upgrades,
- Reduction in water use,
- Creation of additional public/private partnership opportunities, and
- Meeting federal pollution mandates.

Economic Impacts: The EPS economic impacts are the Arizona output, earnings, and employment that can be attributed to construction and operation of projects to meet the EPS plus multiplier effects. The resulting impacts do not take into account avoided or foregone impacts of conventional power plant construction or operation that might have happened in the absence of the EPS. The construction of solar energy projects through 2002 contributed $28.2 million of Arizona output of goods and services, $8.6 million of Arizona earnings, and 274 person years of Arizona employment to the economy of Arizona.

Implementation: The Arizona EPS has attained regional and national importance due to its utility-based funding collection and project selection processes. However, given the limited revenues available under the EPS rule, no utilities will be able to meet the annual renewable energy targets established by the EPS on the existing timeline. Nevertheless, it is likely that at least one utility will meet the EPS annual renewable energy percentage goal of 1.1 percent by 2012 or earlier – a primary objective of the Commission in adopting the Rule. With this one exception, there are not sufficient funds to meet the renewable generation targets set forth in the Rule. Further, the actual potential for attaining the Rule targets depends on which utility is being evaluated. Utility-specific factors in place at the start of the Rule have a significant effect on the ability of the utilities to meet the EPS, such as access to inexpensive generation from other renewable technologies and whether use of System Benefit funds has been authorized by the Commission.

One attribute of the utilities' response to the EPS has been a diversity of types of projects, both solar and nonsolar, that the utilities have initiated or expanded. Some promising new PV and solar thermal technologies have good potential for cost reduction, but may not be the least-cost today. It is beneficial for the utilities to be allowed to continue to support new products and technologies when they choose to, so that further cost reductions may be found.

Recommendations: When adopted, the EPS and the Commission decision that approved the EPS contemplated a review of the costs and benefits associated with the program in 2003 to make recommendations about an acceptable portfolio electricity cost/benefit point or portfolio kWh cost

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[2] BOS costs are defined as all costs for the installed PV system other than the PV panel. These costs normally include: electrical system; support structures; inverters, software, and infrastructure; ground preparation and grid interconnection; data collection, metering, and internet connection costs.

impact maximum. Per the EPS, the CEWG was formed to prepare this Report and recommendations. Although there was not consensus reached on all issues discussed by the CEWG, there was general consensus on the following matters:

- Although the EPS has been in effect for only 18 months, it is producing significant benefits within Arizona including improved environmental impacts, increased experience in installing renewable capacity, development of in-state renewable resource infrastructure, and job creation.

- Costs associated with solar electric technologies have declined substantially from costs prior to adoption of the EPS.

- The costs for non-solar renewable technologies—including geothermal, wind, biomass, and landfill gas—are generally lower than the costs of solar generation, and participating utilities have identified projects incorporating these technologies that will make progress towards meeting the EPS. In some cases these costs are competitive with traditional fueled generation. However, opportunities for cost-effective non-solar renewable energy projects in Arizona are resource limited. Because of the size and ubiquitous availability of Arizona's solar resource, it can represent a major contribution to the long-term energy future of the state and support a large industry creating in-state jobs and economic and environmental benefits.

- The current EPS model, where utilities are responsible for collecting and controlling EPS funds, has a significant policy value because it enables utilities to eliminate financing costs for capital intensive renewable generation projects. This expensing feature is essential to the success of the EPS and should be continued. This model also allows the LSEs to pursue multiple technologies, continue assessment of least cost opportunities, and continue a strong diversity of solar renewable energy development and implementation until solar generation development costs become competitive with traditional resources.

- The two options recommended for Commission consideration are in no particular order:

    1. Take no action at this time and leave the annual renewable energy target at 0.8 percent of retail energy sales for all LSEs until a future review determines that either EPS funding is sufficient, or solar generation costs have declined to the point for EPS program success for all LSEs at the 0.8 percent level, then increase the program percentage to 1.1 percent.

    2. Continue the renewable energy requirement increase to 1.1 percent by 2007.

Recommendations:

1. The CEWG recommends that the Commission use the Portfolio net simple cost premium number of $0.11 per kWh, defined in the Recommendations section of this report, as a reference point or benchmark for evaluating future costs and cost reductions resulting from the EPS. This net simple cost premium may be used by the Commission as a general benchmark to evaluate in the aggregate the future progress in achieving cost reductions in solar photovoltaic projects by the LSEs as a result of their efforts to comply with the goals of the EPS Rules. It should be noted, however, that this net simple cost premium is based on a set of assumptions and the current funding method of the projects. As noted in the Recommendations section, to the extent the assumptions change, the benchmark would have to be adjusted for items such as financing or operating costs.

2. The CEWG recommends that the Commission recognize that considerable progress has been made in just 18 months and that the EPS should be continued with two possible options:

    - <u>Option 1</u>: Take no action at this time and leave the annual renewable energy target at 0.8 percent of retail energy sales for all LSEs until a future review determines that either EPS funding is sufficient, or solar generation costs have declined to the point for EPS program success for all LSEs at the 0.8 percent level, then increase the program percentage to 1.1 percent.

    - <u>Option 2</u>: Continue the renewable energy requirement increase to 1.1 percent by 2007

I. INTRODUCTION

In May 2000, the Commission approved the Environmental Portfolio Standard (EPS) and referred it for a rulemaking in Decision No. 62506 (May 4, 2000). The Commission approved the EPS rule, A.A.C. R14-2-1618, in Decision No. 63364 (February 8, 2001) which was later modified by Decision No. 63486 (March 29, 2001).

The EPS provides that 0.2 percent of total retail energy sold in 2001 by a Load-Serving Entity (LSE) be generated from new solar resources or certain other environmentally friendly renewable technologies. The EPS also provides that, after considering various extra-credit multipliers, the portfolio goal consists of at least 60 percent solar electric energy and no more than 40 percent of energy from solar hot water heating and other renewable resources. The overall EPS portfolio percentage increases on January 1 of each year after 2001, so that by 2007, LSEs should provide 1.1 percent of total retail energy sales from qualifying sources.

The EPS is partially funded through a surcharge (EPS Surcharge) of $0.000875 per kWh on customers' bills. There is a surcharge cap of $0.35 per month per service for residential customers, $13.00 per month per service for non-residential customers, and $39.00 per month per service for non-residential customers with demand of 3,000 kW or more. The surcharge has been implemented through tariffs filed by the covered incumbent utilities.

Rule 1618 provides for an evaluation of the costs and benefits of the EPS to determine whether to continue to increase the portfolio percentage after 2004. Rule 1618(B)(2) provides:

> The Commission would continue the annual increase in the portfolio percentage after December 31, 2004, only if the cost of environmental portfolio electricity has declined to a Commission-approved cost/benefit point. The Director, Utilities Division shall establish, not later than January 1, 2003, an Environmental Portfolio Cost Evaluation Working Group to make recommendations to the Commission of an acceptable portfolio electricity cost/benefit point or portfolio kWh cost impact maximum that the Commission could use as a criteria for the decision to continue the increase in the portfolio percentage. The recommendations of the Working Group shall be presented to the Commission not later than June 30, 2003. In no event, however, shall the Commission increase the surcharge caps as delineated in R14-2-1618(A)(2).

Additionally, the Commission addressed the role of the Cost Evaluation Working Group (CEWG) and the 2003 review of the EPS in Decision No. 63364:

> Neither the Load-Serving Entities affected by the Rule nor the Commission will know the true cost of the EPS for several years, which is why the EPS Rule incorporates the "off ramp" provision of R14-2-1618.B.2. It is the intent of this Rule that the surcharge will cover the cost of the mandate. It is not the Commission's intent that the ratepayers of Arizona pay the surcharge and also be faced with high deferred costs if it turns out the surcharge is not sufficient to allow an utility that is taking prudent measures to meet the portfolio percentage. However, neither do we wish to encourage utilities to ignore their obligation under the EPS Rule to meet the required percentages. The Commission will re-examine

the required percentages, appropriate surcharge and the amount of the deficiency payment in 2003 based on actual experience.[3]

This report was prepared pursuant to the requirements in Rule 1618(B)(2) and Decision No. 63364.

To prepare for the CEWG and the report required by Rule 1618(B)(2) and Decision No. 63364, the Commission Staff formed an Advisory Committee to assist in organizing the CEWG, selecting members, and implementing the CEWG process. A report was submitted to the Director of the Utilities Division in July 2002 recommending that the CEWG be formed as soon as possible to provide sufficient time to collect data and provide both quantitative and qualitative information on the EPS.

The Director of the Utilities Division appointed 20 members to the CEWG from companies and groups that had participated in the rulemaking process for the EPS. Most of the members of the CEWG have been actively involved in workshops relating to the EPS, in implementing the EPS, or in renewable energy policy and technical matters generally. A list of CEWG members is provided in Appendix 5.

The CEWG determined that three subcommittees should be formed to evaluate different issues for inclusion in this Report. A Cost Subcommittee was formed to determine the cost per kWh of projects and technologies funded or authorized for the EPS. A Benefits Subcommittee was formed to determine the benefits, both quantitative and qualitative, resulting from the EPS. And an Impacts Subcommittee was formed to determine economic impacts of the EPS on Arizona. Each subcommittee report, following review by the CEWG, is included in this Report.

In reviewing this report, it is important to note that the implementation schedule for the EPS was delayed due to an appeal after the EPS was first passed and by some other implementation issues. The appeal was ultimately settled, but the delay has affected the implementation of the EPS by the utilities and the collection of data to support this Report. This delay has both reduced the time available for the utilities to construct projects and the time over which to collect data on those projects.

The consensus conclusions and recommendations of the CEWG are provided in the final section of this Report as well as the Executive Summary.

[3] Decision No. 63364 at p. 4. The deficiency payment provisions were deleted from the EPS rule in Decision No. 63486.

Background Information

Goals of the Environmental Portfolio Standard

The genesis of the Environmental Portfolio Standard goes back to the Integrated Resource Planning (IRP) process that the ACC conducted from 1990-1996.

The Commission's first IRP process, which ran from December 1989 through October 1991, included extensive discussion of renewable energy resources. IRP Decision No. 57589 required that the utilities: consider solar power plants as an alternative to intermediate and peaking power plants; ordered the three largest utilities to provide information to potential line extension customers in remote areas about possible use of stand-alone photovoltaic systems; and ordered Arizona Public Service (APS) to study the use of photovoltaics in transmission and distribution systems.

> The present Rule includes objectives developed during years of hearings and negotiations.

The Commission's second major IRP decision (No. 58643) ordered utilities to develop comprehensive renewable resource plans, and the Commission set renewable goals of a total of 19 MW of renewables to be met by four utilities [APS, Tucson Electric Power (TEP), Citizens, and Arizona Electric Power Cooperative (AEPCO)] by December 31, 2000.

As part of the Commission consideration of possible retail electric competition rules, renewable energy was discussed extensively resulting in the Solar Portfolio Standard (SPS) Rule portion adopted in December 1996. This short-lived Rule required that new, competitive suppliers of retail electricity (APS, TEP, and other LSEs were exempt) include renewable energy in their generation portfolios. However, the 1996 Rule is the basis of many of the goals found in the present Rule which apply to all LSEs. The original objectives of the 1996 Portfolio Standard were:

> Initial goals stressed adoption of clean technologies that would diversify Arizona's electricity generation portfolio by exploiting its extensive solar energy resource.

- Increase utility fuel diversity,
- Allow utilities to gain actual experience with solar technologies to eventually move away from fossil fuel power plants to clean distributed solar generation, and
- Encourage the sustained orderly development of the solar technologies to bring down the future price of the equipment.

The 1996 order established a number of working groups. The Solar Portfolio Standard Subcommittee met from May through September 1997 and developed revised objectives of the Solar Portfolio Standard. Those objectives were:

> Later efforts emphasized utility benefits gained from deploying renewable energy projects; driving down project costs through large-scale deployment; and encouraging a state solar electric industry.

- Encourage use of solar electric technologies to increase fuel diversity in the electricity generation mix;
- Increase utility expertise and experience in the procurement, installation and operation of solar electric systems or in the purchase and transmission of solar electricity from other sources;

- Encourage new solar electric technologies as a reasonable percentage of competitive retail electric sales;
- Encourage use of modest-sized, distributed solar generators to reduce existing transmission line loads and reduce the need to build new, expensive transmission lines as electricity demand increases;
- Support solar electric technology commercialization to decrease solar electricity costs for Arizona customers; and
- Contribute to economic benefits by encouraging an Arizona-based solar industry.

In 1999, the Commission decided to reconsider the scope of the SPS to broaden the standard to include other renewable technologies. The 1999 EPS hearing process led to the addition of some new objectives:

- Open the portfolio to additional renewable technologies with similar clean-fuel characteristics;
- Allow other solar technologies, such as solar water heating, and solar air conditioning to be included in the portfolio; and
- Allow utilities to include other renewable technologies to diversify the portfolio.

Revised objectives kept greatest emphasis on solar electric technologies to build a viable state infrastructure of generation and industry but allowed other renewable energy technologies to participate.

Limited Time Available for the Evaluation

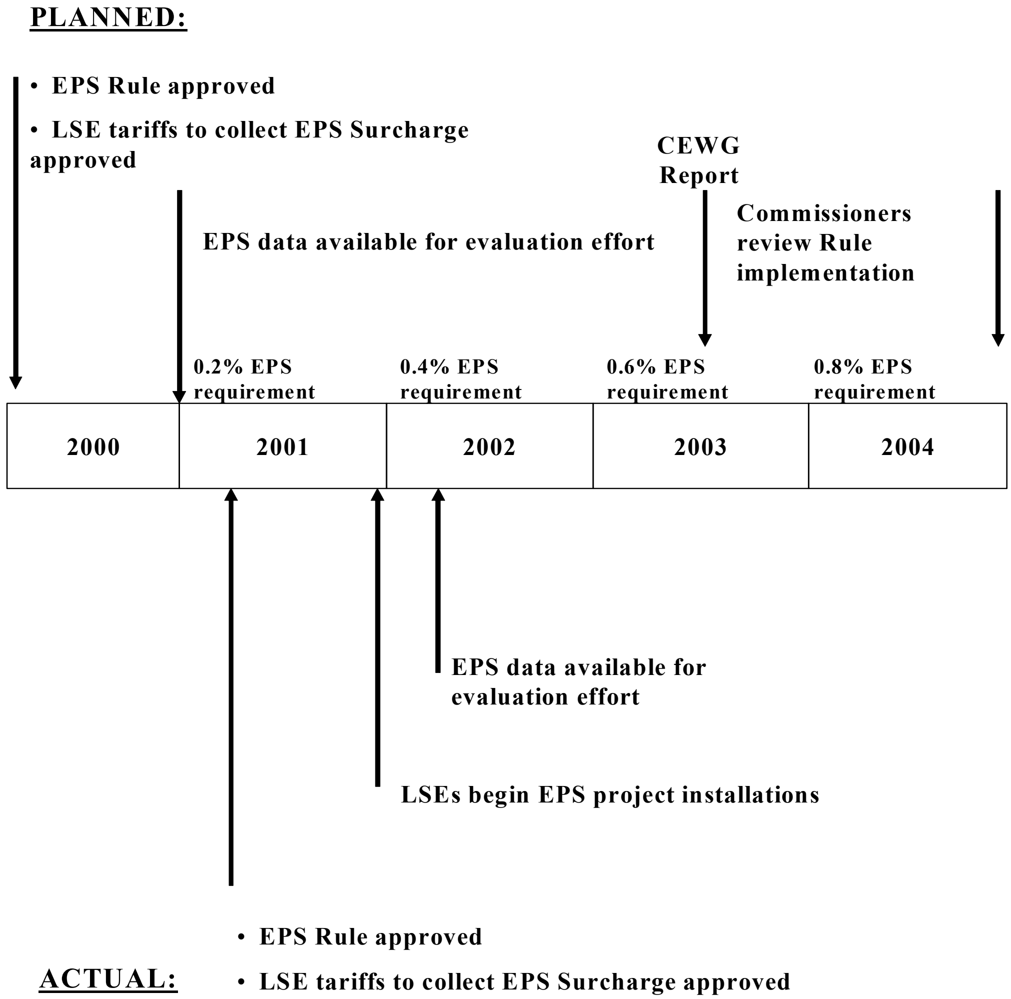
Some procedural factors contributed to delays in adopting the Rule and approving tariffs for the LSEs to collect EPS Surcharge funds from which they would enact programs. Another factor that delayed EPS implementation was the an appeal of the Commission Rule approval. The result of the litigation and procedural factors was that although the LSEs began collecting EPS Surcharge funds after the February approval date, most did not actually begin using the funds to install projects until the fourth quarter of 2001. Although solar electric and environmentally-friendly renewable technologies have much shorter design and installation timelines than fossil-fired or nuclear electricity generation plants, some LSE decisions on deploying Rule projects did not occur until the first quarter in 2002.

The original EPS implementation schedule allowed a longer time to collect data from operating projects before performing a formal evaluation of the policy.

In effect, the EPS was designed to start in early 2000, but the generation percentages were not adjusted to reflect the later start date. The Rule allowed LSEs to begin collecting an EPS Surcharge as part of rate charges from residential, commercial, and industrial customers. The implication is that LSEs would have collected and used Portfolio Surcharge and other funds in 2000 to be able to have projects on-line and capable of meeting the 0.2 percent requirement during 2001. In effect, although the original plan for implementation of the Portfolio Standard would have evaluated thirty months of project data derived from the policy, some procedural and litigation factors reduced the evaluation period to less than eighteen months. This effect is described graphically in Figure I-1 which shows the original schedule on top and the actual implementation dates on the lower half.

Figure I-1.

Environmental Portfolio Standard Cost Evaluation Working Group Schedule



II. STATUS OF ENVIRONMENTAL PORTFOLIO STANDARD IMPLEMENTATION

This section provides an overview of how the EPS policy is being implemented. It includes viewpoints of the utilities who are ultimately accountable to the Commission for implementation and those of the renewable energy industry who have worked for years with the utilities on the policy formulation to create a viable, sustainable, renewable resource-based industry in Arizona.

> <u>EPS Renewables installed in Arizona</u>
>
> 6 MW photovoltaic projects
> 5 MW landfill gas
> 200 kW solar hot water system

Among existing state portfolio standard policies, the Arizona approach is unique in that it relies on a surcharge collected and controlled by utilities; utility planning for program projects; utility selection of projects; and utility installation of a major portion of the generation capacity required by the Rule. In that context, the policy has attained a regional and national significance because the other major Renewable Portfolio Standard (RPS) efforts in the Southwest all differ from the Arizona approach. For example, California, Nevada, and Texas all rely on "top-down" RPS policies that require Public Utility Commissions or the Energy Commission in California to collect RPS funds and determine how the funds are used to pay for renewable energy projects. California is in the process of changing its RPS to a policy closer to the Arizona model.

> The Arizona EPS has attained regional and national importance due to its utility-based collection and project approval process.

For both utilities and the renewable energy industry, the EPS creates a higher degree of solar energy market certainty than was possible without the EPS Rule. Annual EPS Surcharge funds will increase slightly through 2012 as the number of customers increases, providing LSEs a growing revenue base to support project capital costs for developing public/private partnerships and for joint efforts with the state renewable energy industry. The continuing availability of EPS Surcharge funds can also help an LSE justify other renewable energy investments. And, as the revenue from EPS project generated electricity increases over the duration of the EPS, it provides an additional source of funds for LSE deployment of renewable energy projects.

> The EPS provides a greater degree of market certainty for both utilities and the renewable energy industry.

<u>Approaches to Implementing the Environmental Portfolio Standard through 2002</u>

There were several perspectives among the members of the CEWG on how the EPS should be implemented. The predominant two perspectives presented to the CEWG, not in any order of preference, are:

a) A small distributed generation approach in which small, customer-sited projects comprise a large portion of the projects installed (i.e., serving load with small generation projects located at or near the load as opposed to feeding the energy output directly into the distribution or transmission system);

b) A large distributed generation approach (per FERC definitions of distributed generation systems) in which most of the capacity is installed in relatively large, central-station type facilities that feed the energy output directly into the distribution or transmission system or use the energy in a large, distributed generation project to support subsystem operation at central stations and thereby offset otherwise needed fossil-fueled generation.

LSEs are using a major portion of EPS funds to install large distributed generation projects.

The utilities believe that, since they are ultimately accountable for compliance with the EPS Rule, they need to be allowed flexibility in their implementation efforts, which is given under the EPS rules. They have pursued a combination of both approaches, with the emphasis on large projects. Solar industry representatives advocate more emphasis on small, customer-sited projects that they believe make greater use of leveraging Surcharge funds to provide additional resources for meeting the Rule generation goals. The utilities contend that when all distributed generation program costs such as administration, marketing, and follow-up with residential and small commercial customers are included, and when lost revenues and PV system operation and maintenance costs are considered, the large project approach is a more advantageous use of EPS Surcharge funds. Based on their experience with both approaches to date, TEP plans to offer incentives from EPS Surcharge funds for customers to install up to 200 kW of small distributed generation capacity per year, and APS plans to offer Surcharge fund incentives for customers to install up to 600 kW of distributed generation capacity per year as part of its EPS program.

<u>Sources of Environmental Portfolio Standard Funds and Use of Funds</u>

Most of the EPS projects rely directly or indirectly on rates levied on consumers to accomplish the goals of the EPS. Tables A1-1 and A1-2 in Appendix 1 present summaries of EPS Sources and Uses of Funds for APS and TEP.

EPS Surcharge funds are derived almost entirely from residential and small commercial ratepayers.

Much discussion took place during hearings on the EPS Rule related to the responsibility of each customer class for paying the Surcharge. Customer responsibility under the EPS rule is limited by caps placed on monthly payments. The following two tables for TEP and APS show that the majority of the Surcharge portion of funds available for EPS activities is being paid by the residential and small commercial categories. The large commercial and industrial category contributes relatively little to pay for EPS projects in light of the MWh of energy consumed annually by these large customers.

Table II-1
Summary of TEP Environmental Portfolio Standard Program Revenues

Description	2002 Revenues	2002 TEP Retail Energy Sales to Customer Category, MWH
GreenWatts Total	$67,573	-
Reallocation of DSM Total	$2,010,000	-
Residential Surcharge Total	***$1,205,956.46***	3,188,726
Small Commercial Surcharge Total	***$1,202,430.52***	1,867,007
Large Commercial Surcharge Total	***$31,746.00***	2,956,684
Renewables Surcharge Total*	***$2,440,132.98***	8,012,417

* Renewables Surcharge Total includes only the Residential, Small Commercial and Large Commercial Surcharge Totals.

Table II-2
Summary of APS Environmental Portfolio Standard Program Revenues

Description	2002 Revenues	2002 APS Retail Energy Sales to Customer Category, MWH
Green Pricing Program Total	$259,628	-
Reallocation of DSM Total	$6,000,000	-
Residential Surcharge Total	***$3,101,375.20***	10,447,596
Small Commercial Surcharge Total	***$3,439,219.20***	10,338,456
Large Commercial Surcharge Total	***$31,150.60***	2,575,703
Renewables Surcharge Total*	***$6,571,745.00***	23,361,755

* Renewables Surcharge Total includes only the Residential, Small Commercial and Large Commercial Surcharge Totals.

Meeting the Rule Percentage Generation Goals

The EPS renewable energy percentage goals are difficult to meet in the early years of the program given the level of revenues from the surcharge and other sources authorized by the Commission. In particular, the EPS maximum annual renewable energy percentage goal is reached in 2007 while EPS Surcharge funding is collected through 2012 from an increasing number of customers. Thus, EPS revenues do not directly match the timing of expenditures needed to meet the energy percentage goals.[4]

In 2001, APS achieved nearly 100 percent of the EPS goal of 0.2 percent renewable energy from systems installed since 1997 when all extra credits are included. This was primarily due to extra credits that the utility had achieved for early, in-state, solar installations for the solar component of the EPS mandate and the purchase of EPS credits from another utility for the non-

[4] APS and TEP have been granted Commission approval to use System Benefits Charge (SBC) funds for EPS purposes to provide a closer match between revenues and generation capacity installed requirements (expenditures).

solar component. In 2002, APS achieved 59 percent of the portfolio standard. One hundred percent of its mandated non-solar goal was met through the purchase of EPS credits and 29 percent of the solar requirement from its own system installations and the purchase of EPS credits from customer-owned solar systems.

In 2001, TEP achieved 72 percent of the 0.2 percent goal and in 2002, TEP achieved nearly 80 percent of the portfolio standard requirements for that year, which was 0.4 percent of retail sales. This reflects meeting 100 percent of the non-solar component from its landfill gas generating facility and 60 percent of its solar requirement from its own solar facilities. These levels were achieved by spending 72 percent more than revenue provided by the EPS surcharge and System Benefit Charge funding moved from demand-side management (DSM) programs.

Navopache met 50 percent of its EPS requirements in 2001 and 2002 through the purchase of landfill gas credits from TEP. As discussed in the Benefits and Impact sections of this report, Navopache is planning to construct PV systems as well.

TEP Approach

Independent analytical efforts by the Renewable Energy Leadership Group with the Arizona Clean Energy Industries Alliance and TEP concluded that it is likely the solar electric generation goal in the Rule can be met by TEP on or before 2012, primarily due to use of numerous renewable energy assets and revenue sources for the EPS program beyond the EPS Surcharge and SBC funds.[5] Results are shown in Figure II-1. This conclusion is based on the following assumptions:

- Continued use of an existing landfill gas electricity generation system to produce all non-solar EPS credits needed through the full term of the EPS and to generate additional revenue through sales of extra EPS non-solar credits to other Arizona utilities. The output of the landfill gas facility is assumed constant after 2002.
- A shift of a majority of System Benefits Charge funds from DSM to EPS programs.
- Use of Global Solar manufacturing credits to displace the maximum amount of solar generation credits allowed by the EPS Rule; Global Solar is an affiliate of TEP.
- Extrapolation of EPS cost and performance levels and trends through the first quarter of 2003 to predict future program costs.
- Continuation of existing market values of excess credits sold by LSEs.
- Continuation of balance of system cost reductions demonstrated at Springerville.
- Reasonable assumptions on use of Extra Credit Multipliers.
- Industry predictions on reductions of PV module costs that are generally in agreement with TEP forecasts through 2006 but which represent a very aggressive reduction of costs after 2006.
- Electricity sales and wholesale electric price escalation rates of 2.5 percent per year. The value of solar generated energy is returned to TEP's EPS program at the wholesale value of market energy at the time the energy was produced.

[5] The TEP analysis has some assumptions which are different from the Renewable Energy Leadership Group/Arizona Clean Energy Industries Alliance analysis. However, the effects of the differences cancel each other so the analytical conclusions in 2012, at the end of the EPS program, are very similar.

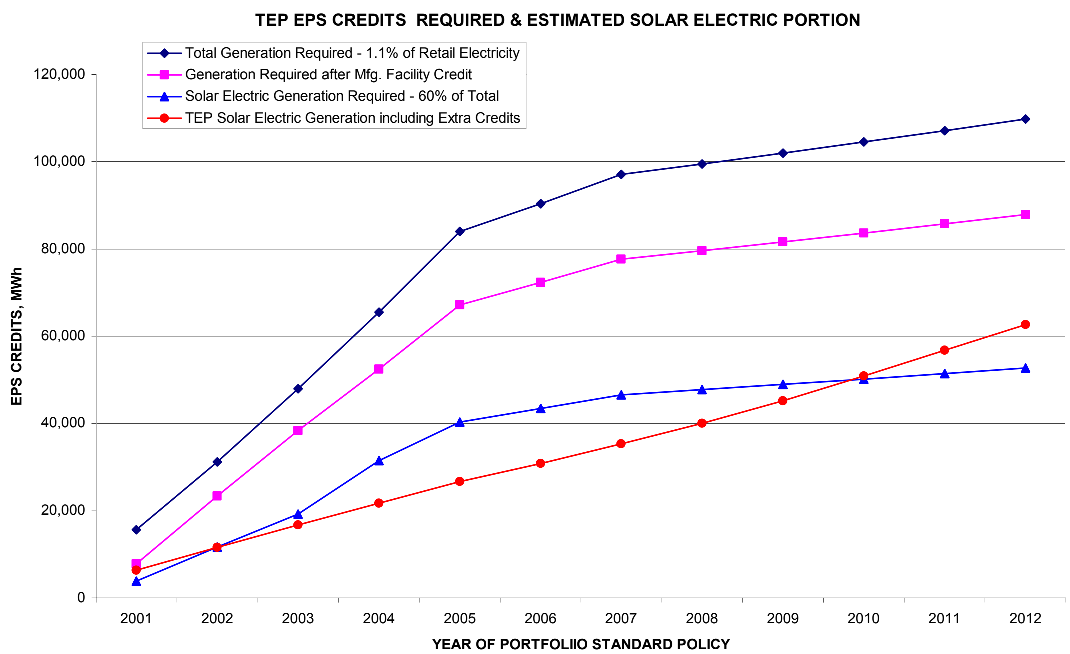
- Use by the EPS program of federal investment tax credits from installation of about 1,100 kW DC per year of solar generation equipment. No Federal production tax credit will be available over the period of analysis.

The results of the Renewable Energy Leadership Group and Arizona Clean Energy Industries Alliance analysis shown graphically in Figure II-1 are appropriate for only TEP and cannot be applied to any other Arizona utility due primarily to differences in the amount and type of existing renewable generation portfolio resources at the beginning of the EPS in 2001 and to treatment of tax credits.

> Independent analysis by CEWG members indicates TEP will meet EPS generation requirements by 2012, although it will not meet the annual energy percentage goals during the early years of the EPS Rule.

In closing, the positive effects of the EPS policy discussed in the Benefits section indicate that, from a status of implementation perspective, the utilities are implementing programs that result in significant growth in the installed capacity of renewable generation in the state.

Figure II-1



APS Approach

APS projects it will meet the current 0.8 percent goal by 2010 and the 1.1 percent goal by 2017. Figure II-2 represents APS' projections for achieving the EPS goals. This graph is based on a number of assumptions. APS actual performance and success will vary based the assumptions below and on consistent economic and operational conditions throughout the term of the EPS. These assumptions are made based on APS' past experience and represent its best efforts at predicting the future. It is highly likely that these conditions will change.

The assumptions used in APS' projections are for APS use only and are estimates that may vary for numerous reasons including markets and technology uncertainty:

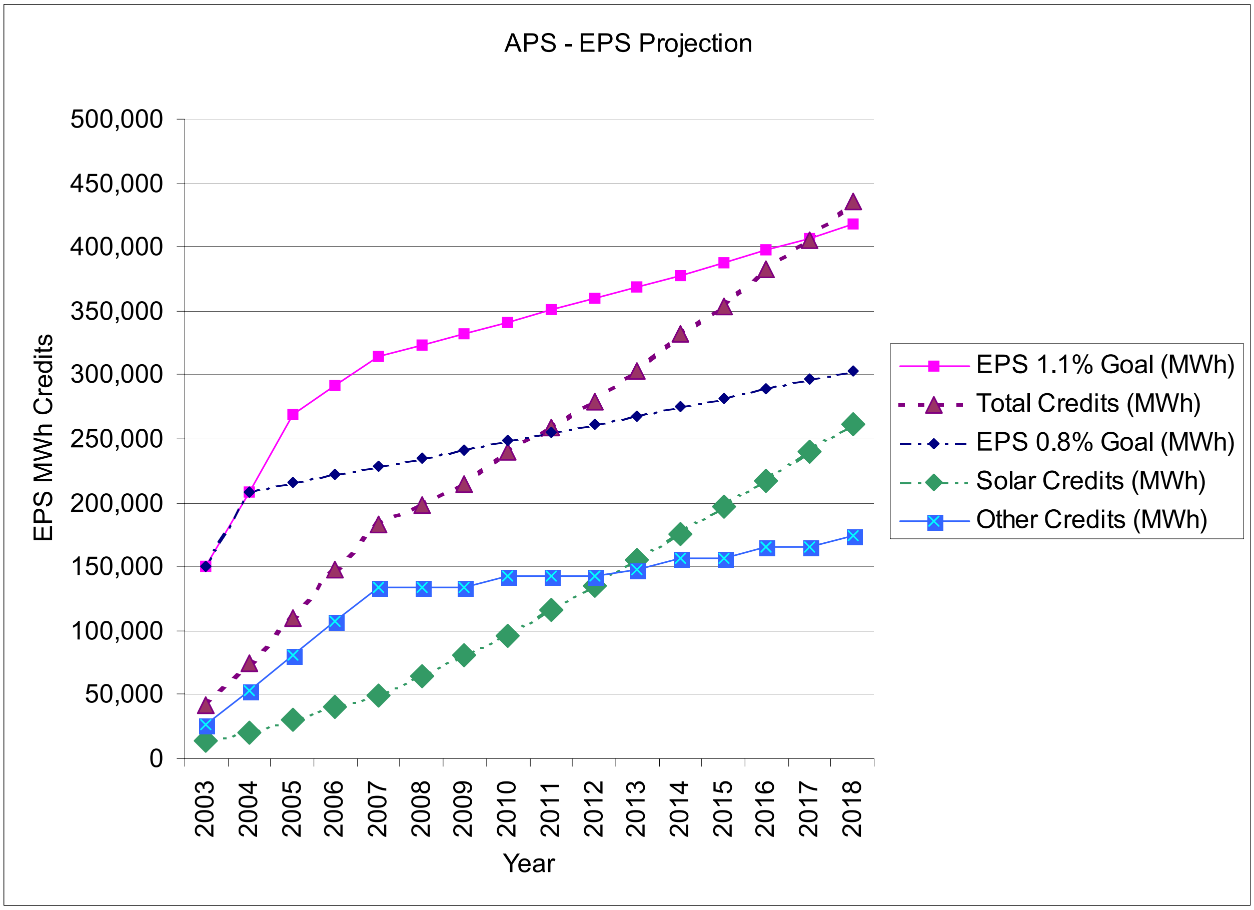
- Installation costs for large scale solar begin at $6.00 per watt and decline to $2.80 per watt by 2015, approximately linearly, with a 22 percent capacity factor.
- Annual solar installations grow from 1.2 to 5 MW per year as prices decrease and available funding for solar increases as non-solar goal are met.
- The average EPS credit multiplier for analysis is 2.0 for solar and 1.2 for non-solar.
- APS will reach the 40 percent non-solar goal by 2007 by averaging 3 MW per year after which all funds will be used for solar except those required for load growth.
- Cost of non-solar technologies is estimated at $1.50 per watt with 85 percent capacity factor.
- APS will make EPS Credit purchases only for investment in and support of new renewable technologies.
- Estimates includes $6 million per year in SBC funds.
- EPS Surcharge caps remain in place beyond 2012.
- Although exploring solar module manufacturing opportunities, no credits are included for solar module manufacturing.
- BOS and integration costs decline along with installed costs.
- ACC approves on-going operating and maintenance (O&M) recovery in base rates rather than through EPS funding – effective 7/1/04.
- APS doesn't pay itself avoided costs of generation since customers have already paid for this through the EPS and SBC funding.
- APS interprets the IRS tax code regarding Federal Investment Tax Credits, section 48, to preclude public utility property.
- No Federal production tax credit will be available over the period of analysis.
- 2.5 percent annual load growth.

APS met 99.1 percent of the 0.2 percent EPS goal in 2001 and 59.8 percent of the 0.4 percent requirement in 2002. This represents a total installed solar capacity of 1.62 MW in 2001 and 3.17 MW in 2002, including EPS solar credits from nearly 600 kW of customer solar systems installed by customers. The 2001 and 2002 APS levels of achievement were partially a result of credits received for early installation of PV systems from 1997 through 2001 and the purchase of non-solar EPS credits from TEP.

APS will continue to pursue its strategy of installing new and emerging PV and renewable energy technologies that have the potential to become cost-effective alternative energy resources for the future. APS anticipates, based on recent experience for the development of these new technologies and reductions in the associated costs, that it will meet the combined 0.8 percent goal in 2010 and the 1.1 percent goal by 2017, assuming current funding and the 60 percent solar and 40 percent non-solar resource mix. This includes using all expected EPS Surcharge funds, currently available SBC funds, and additional solar revenues from green pricing and commercial solar programs.

The timing of the current funding will allow APS to meet the non-solar component of the EPS by 2007 by installing and supporting the installation of a combination of new biomass and landfill gas electrical generation projects throughout Arizona. Towards meeting the more costly 60 percent solar generation goals APS has developed cost trends that project future prices dropping below $4 per watt once installations reach 5 MW per year and eventually reaching $2.80 per watt by 2015. Within the current EPS funding, APS will install one to five megawatts annually of a variety of new and most promising solar generation technologies including large-scale tracking and high-concentration photovoltaics, solar thermal trough generation, dish-engine

Figure II-2



technology, and the purchase of solar credits from customer photovoltaic and solar thermal installations. The rate of solar installations will increase once the 40 percent non-solar generation goal is reached and additional funds can be directed to solar installations and as the price of solar installations decrease in future years.

III. COSTS OF THE ENVIRONMENTAL PORTFOLIO STANDARD

The cost section of the CEWG report discusses the costs of implementing the EPS as well as general cost trends for the major technology used so far to make progress towards the goal of achieving 1.1 percent of energy sales from renewable resources by 2007 (adjusted for extra credit multipliers).

The CEWG decided to limit its analysis of costs to projects that were actually constructed in Arizona to meet the EPS requirements. There were no projects built by private developers, so information about developer bids responding to various utility RFPs or solicitations were not included. Similarly, the CEWG chose not to include costs from renewable projects in other states.

This section of the report will review primarily photovoltaic (PV) systems because they have been the dominant technology deployed since the EPS became effective. This section will also briefly discuss a large solar thermal project used to help meet EPS requirements and a landfill gas project from which TEP obtains energy and EPS credits. Credits from the solar thermal and landfill gas projects have been purchased by utilities to help meet their EPS requirements.

Costs in this section reflect actual installed costs of PV systems and are presented in terms of dollars or dollars per kW of installed generating capacity. In addition, rates expressed as dollars per kWh are developed by dividing total installed cost by estimated lifetime kWh production of the system to provide comparison of the cost of energy for these technologies. These energy costs do not represent what a project developer would charge for energy from a PV project because the costs do not include financing costs, the cost of capital, or operation and maintenance costs based on long-term experience. The cost of capital is not considered because the portfolio standard is funded through a combination of System Benefits Charges (SBC) and customer surcharges to pay for the programs, and program costs are expensed. Consequently, the energy costs per kWh developed in this study are not comparable to rates per kWh calculated in studies which assume that there is both a return of capital and a return on capital. Further, the costs presented do not generally include standard utility costs such as overhead, transmission and distribution support, customer support, and human resources for these renewable energy systems. These cost estimates may also vary by utility.

Overview

Since 1997, APS and TEP have spent more than $59 million on renewable energy programs and development, installing almost 6 MW of solar generation and 5 MW of landfill gas generation. Sources of these funds include the EPS Surcharge collected since 2001, system benefits charges, and some additional funds expended by APS and TEP since 1997. Since the EPS began in 2001, APS and TEP have spent over $35 million installing the majority of Arizona's solar generation capacity of more than 5 MW. Over 95 percent of the power represented by these installations, 5.6 MW at 23 sites, is the result of large, utility-owned grid-tied systems greater than 10 kW installed by APS and TEP. Additionally, over 139 small, customer-sited systems, either grid-tied or off-grid, have been installed or supported financially through EPS funds.

Table III-1
1997-2002 Photovoltaic Installation Summary

			Simple $/watt			Simple $/kWh			Simple $/EPS credit	
Category	**Installations**	**Total kW-dc**	**Average cost per watt**	**Low cost per watt**	**High cost per watt**	**Average cost per kWh**	**Low cost per kWh**	**High cost per kWh**	**Average cost per EPS credit**	**Average EPS multiplier**
large grid-tied non-tracking*	26	2760	**$6.17**	$4.31	$8.28	**$0.131**	$0.06	$0.17	**$0.106**	2.22
large grid-tied tracking	9	1917	**$5.69**	$4.77	$7.50	**$0.128**	$0.10	$0.17	**$0.118**	2.13
large grid-tied concentrating	7	644	**$7.16**	$5.91	$8.73	**$0.159**	$0.13	$0.20	**$0.172**	2.20
large grid-tied integrated	4	270	**$5.65**	$4.76	$6.51	**$0.202**	$0.16	$0.26	**$0.201**	2.13
large off-grid utility-owned	2	54	**$20.50**	$17.16	$24.12	**$0.410**	$0.33	$0.51	**$0.392**	2.09
small grid-tied utility-owned	17	59	**$8.93**	$4.44	$17.63	**$0.224**	$0.05	$0.54	**$0.214**	2.27
small off-grid customer**	65	122	**$13.28**	--------	--------	**$0.281**	--------	--------	**$0.294**	2.17
EPS small grid-tied cust. (TEP)***	29	61	**$4.48**	--------	--------	**$0.265**	--------	--------	**$0.305**	2.17
EPS small grid-tied cust. (APS)**	5	11	**$8.75**	--------	--------	**$0.185**	--------	--------	**$0.194**	2.17
EPS small off-grid cust. (APS)**	23	46	**$12.61**	--------	--------	**$0.267**	--------	--------	**$0.280**	2.17
Utility EPS credit purchase cost****			**$2.00**	--------	--------	**$0.042**	--------	--------	**$0.041**	2.17

Simple cost per kWh = installation cost divided by estimated kWh over 25-year life.
Simple cost per EPS credit = installation cost or EPS credit purchase cost divided by estimated EPS credits created through 2012.
Estimated EPS credits created through 2012 = EPS years of service multiplied by annual expected kWh multiplied by EPS credit multiplier.
* EPS credit amount includes avoided cost of generation of $0.03085 per kWh credit.
** Cost per kWh based on estimate of 1890 kWh per year per kW. Cost per EPS credit derived from total system cost.
*** Net cost to customer based on actual meter reads averaging 676 kWh/kW. EPS credit includes estimated O & M and administrative costs.
**** Actual cost to utility for purchase of solar EPS credits assuming $2/watt and 1890 kWh/kW/yr.

Table III-2
APS & TEP Annual Revenue and Expenditures for Renewable Energy Programs
($1,000)

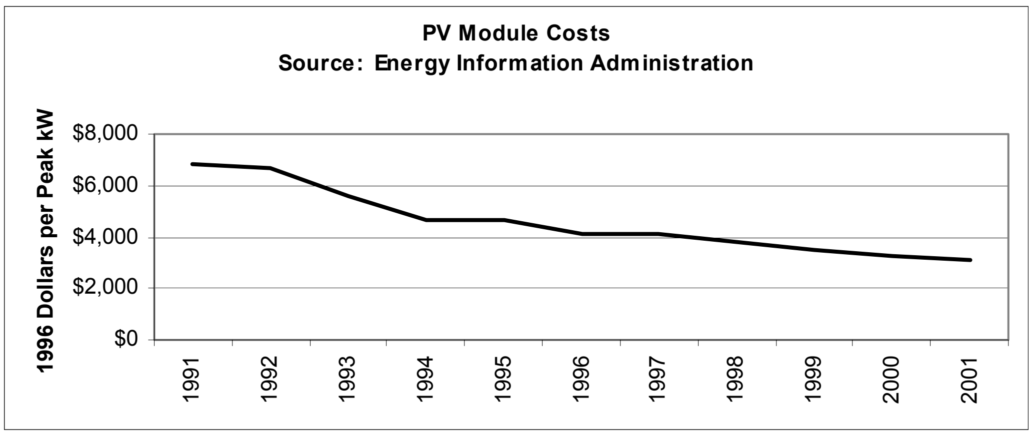
	1997	1998	1999	2000	2001	2002	Total
Annual Total Revenues							
APS	$3,870	$3,690	$3,568	$7,657	$11,491	$13,613	
TEP	$210	$210	$210	$1,796	$5,436	$6,264	
	$4,080	$3,900	$3,778	$9,453	$16,927	$19,877	$58,015
Annual Total Expenditures							
APS	$3,789	$4,483	$4,101	$6,526	$9,799	$12,980	
TEP	$194	$214	$264	$1,638	$8,684	$6,489	
	$3,983	$4,697	$4,365	$8,164	$18,483	$19,469	$59,161

Note: Revenues represent a combination of SBC, EPS Surcharge and renewable program income.

The information presented below shows that, in general, the cost of solar power is declining. These price decreases are primarily a result of recent reductions in the price of photovoltaic panels (Figure III-1) and associated electrical components, which convert the energy to alternating current for use by customers. Additionally, as utilities build larger systems, they experience economies of scale in purchasing, site preparation, and installation, which also assist with lowering the overall price. This section will also demonstrate that larger systems typically produce more energy per dollar invested than small systems.

The chart below demonstrates that photovoltaic module costs have been declining for a number of years. The wholesale prices of photovoltaic modules have fallen nearly 25 percent from 1997 to 2002 (in constant 1996 dollars).

Figure III-1
PV Industry Cost Trend



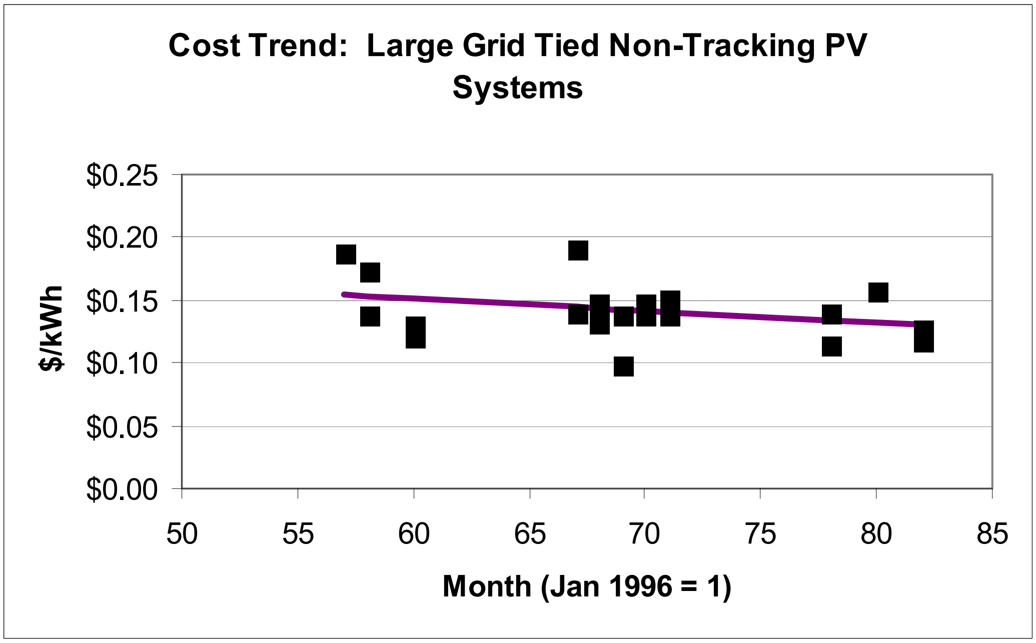
The systems analyzed are grouped by type of photovoltaic system to reflect major differences in system design and output (Table III-1). The primary comparisons will be for grid-tied systems and off-grid or stand alone systems. Grid-tied systems are categorized by large utility scale solar power systems that produce energy which is added to the grid and customer-sited systems, typically small systems installed on a customer's residence or business. Off-grid systems are systems that usually replace a generator or a line extension for remote customers.

Large Systems

The large grid-tied systems installed since 1997 represent utility-owned solar power plants and fall into four categories: fixed or non-tracking, single-axis tracking, concentrating tracking, and integrated covered-parking installations. These systems represent in excess of 5.6 MW of solar generating capacity and 94 percent of the solar energy generated for the EPS in 2002. Many of these systems represent new technologies and first-time installations.

The **large, grid-tied non-tracking solar systems** analyzed are systems installed by TEP in Tucson and Springerville representing 2,760 kW-dc. Table III-1 shows the average cost per watt installed as well as the range of costs incurred. For large systems, costs are now in the $5.00 per watt-dc range. The total installed cost divided by estimated lifetime kWh generated is $0.134 per kWh. When the extra credit multipliers allowed by the EPS are taken into account, the cost of meeting the portfolio standard with large grid-tied non-tracking systems has been $0.106 per EPS kWh credit. The graph (Figure III-2) for large grid-tied non-tracking systems shows a wide scatter of costs, but there is a downward trend in costs over time of about $0.0116 per kWh per year.

Figure III-2



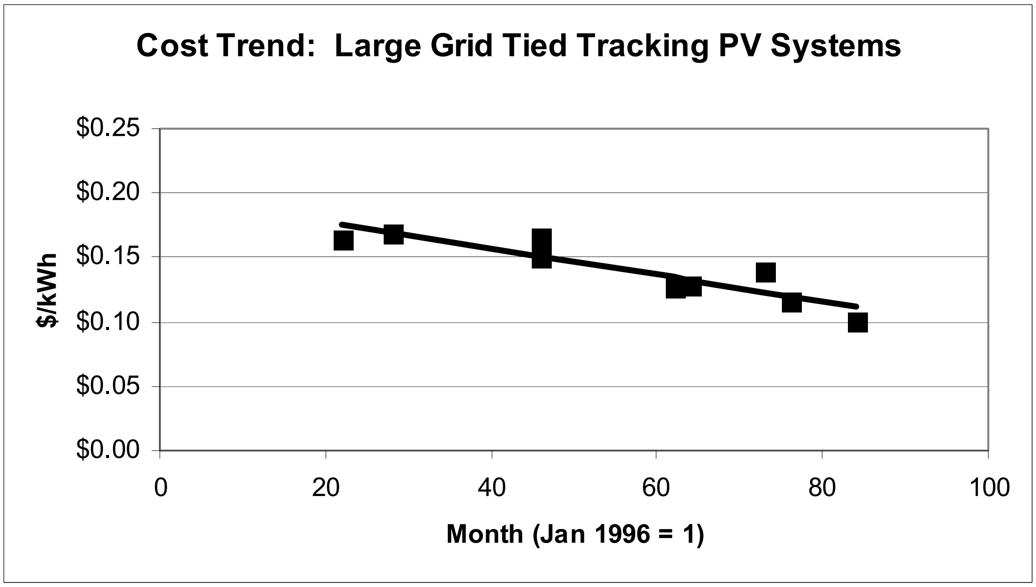
Slope is statistically significant at 0.10 level. Adjusted R squared = 0.095

The **large, grid-tied tracking system** installations represent systems installed by APS since 1997. These systems have been installed in Flagstaff, Prescott, Phoenix, Scottsdale, Glendale, Gilbert, and Yuma and have capacities from 85 kW to 735 kW for a total of 1,917 kW. Costs have ranged from $7.50 per watt-dc to $4.76 per watt-dc. For these tracking technologies, average prices are now in the $5.50 per watt-dc range. With the limited available data, we can estimate that the simple cost per kWh for these systems will generate electricity for about $0.12 per kWh in 2002. While the average cost per watt is slightly higher than for non-tracking systems, the additional performance gained by adding tracking reduces the cost per kWh. The EPS credits will, as in the fixed system, be valued at an estimated $0.118 per credit.

These system costs represent a downward trend over the last five years of about $0.0121 per kWh per year. Both costs per installed kW and, as Figure III-3 represents, cost per kWh have declined.

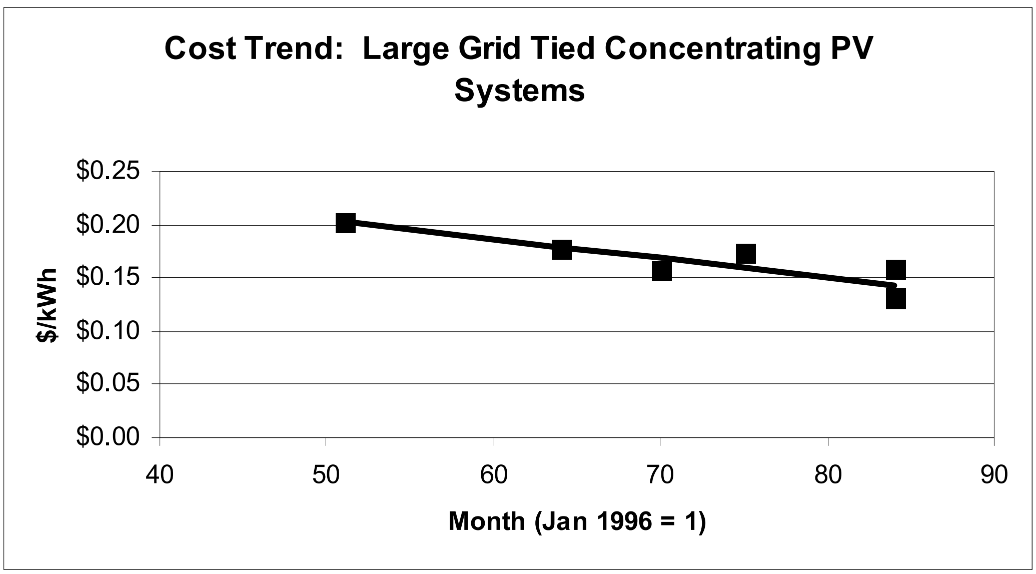
Large scale concentrating PV system prices are also coming down representing reduction in energy cost of about $0.0214 per kWh per year (Figure III-4). APS has installed 644 kW of these systems, primarily at its Solar Test and Research Center in Tempe. These systems are still in their developmental stage, but since beginning exploration of this technology, costs have fallen from $8.73 per kilowatt-dc to $5.91 per kilowatt-dc. The energy generated from these systems is currently estimated to compare favorably with the fixed and tracking systems at $0.13 per kilowatt-hour in 2002 due to increased output achieved from tracking.

Figure III-3



Slope is statistically significant at 0.01 level. Adjusted R squared = 0.787

Figure III-4



Slope is statistically significant at 0.01 level. Adjusted R squared = 0.731

The small number of installations prevents the development of an accurate trend for these costs. However, the cost of the components as well as the installation costs continue to trend downward as these systems are installed in larger quantities.

Large integrated systems are systems where the solar panels are integrated into the building or structure on which they are installed. The systems analyzed represent PV systems integrated by APS into covered-parking structures. This type of installation allows systems to take advantage of an existing structure to lower the overall cost of the installation. On these installations, the solar panels are mounted horizontally on the roof of the parking structure. The costs for these installations have also fallen, to as low as $4.76 per watt-dc excluding the shade structure. However, these systems produce fewer kWh of AC electricity per installed watt of solar because of their mounting orientation. As a result, these systems produce electricity for a higher cost at $0.20 per kWh.

Large utility off-grid systems represent installations for customers who lack access to the power distribution system. These systems require a combination of solar panels, battery storage, backup generation, and the affiliated infrastructure to deliver the energy to the customer's facility. Data are available for two systems installed by APS for customers in remote areas. While more expensive than other types of solar installations, with an average of $20.50 per kW with energy costs of $0.41 pr kWh, they do represent the most cost-effective alternative when comparing the installation to the cost of a line extension or operating a generator full time.

Small Systems

Small utility grid-tied systems under 10 kW are installed primarily for testing and developmental purposes. These systems represent a wide variety of installation sizes from several hundred watts to 10 kW. Prices for these systems are highly variable and therefore trends are impractical to determine.

PV system costs are determined not only by the size of the system but also by various factors including location, application, orientation, specific technology, installation, and other factors which can be highly variable.

Small off-grid systems represent systems sold or leased by APS through its remote solar electric service program. Costs of these systems have also dropped as a result of lower priced panels and inverters. The systems averaged $13.28 per watt. The higher prices are due to additional equipment needed for remote solar installations such as batteries to store energy for use at night and backup power supplies such as generators. The basic cost of energy for these systems is estimated to be $0.28 per kWh.

Small grid-tied systems are installed by customers who wish to remain tied to the grid but who choose to generate a portion of their own electricity needs at their home. These systems are tied to the grid and are grid synchronized to ensure they will not feed electricity back onto the grid should the grid fail to protect customers and service personnel.

EPS Small grid-tied systems (TEP) represent systems purchased by customers through TEP's SunShare program. These systems are subsidized by TEP and sold to customers at a reduced cost and installed by the customer to TEP's specifications. The average cost to customers was $4.48 per watt-dc. The average cost per kWh for these systems is $0.27 per kWh. This is higher than the other small grid-tied systems because TEP records actual customer system performance as measured by a meter on each system. Performance for these small customer-sited PV systems can be highly variable and may not reach theoretical performance levels. Making accurate inferences about energy production and cost per kWh will require additional information on costs and performance. The cost per EPS credit for these systems is $0.305.

EPS Small grid-tied systems (APS) represent systems that have been installed by APS customers who applied for the APS EPS Credit Purchase program. In this program, customers are paid $2.00 per watt-dc for use by APS towards meeting APS' EPS requirements. These systems have an average installation cost of $8.75 per watt-dc before the APS EPS credit purchase. APS does not require its small grid-tied systems under 5 kW to have their energy reported to APS on a regular basis. To determine the value of the EPS credits, APS uses an estimate of 1,890 kWh per kW for each system installed.

The systems in the APS EPS Credit Purchase program cost an average $8.75 per watt installed. The cost per estimated kWh of the energy generated by these systems is estimated to average $0.185 per kWh excluding finance and maintenance. After the APS EPS Credit Purchase program, which provides customers $2.00 per watt-dc for the use of the system as part of the EPS program, the systems average $6.75 per watt. With less than one year's worth of data available from these systems and using estimated annual performance, the estimated cost per kWh, excluding financing and maintenance, is $0.14 at the reduced customer cost.

Anecdotal data show that these system costs have also fallen for the same reasons as larger systems – lower cost solar panels, lower cost inverters, and improving installation knowledge.

EPS Small off-grid customer (APS) installations are also part of the APS EPS Credit Purchase program. This program provides customers $2.00 per watt-dc for off-grid systems. These systems are used in remote areas where power lines are unavailable. Costs appear to have dropped as a result of lower priced panels and inverters. The systems averaged $12.61 per watt. The higher prices are due to additional equipment needed for remote solar installations such as batteries to store energy for use at night and backup power supplies such as generators. The basic cost of energy for these systems is estimated to be $0.27 per kWh with the EPS credits having a cost to APS of $0.28 per EPS credit.

Utility EPS Credit Purchase Cost represents the cost to APS of purchasing EPS credits from the customer. Under this program, APS pays a customer $2.00 per rated watt DC for the right to use the customer's system towards meeting APS' EPS goals. This allows the utility to both financially support the customer's installation of a solar power system as well as obtain the EPS credits. The simple cost for obtaining these credits is calculated at $0.041 per EPS credit over the expected life of the EPS.

Other Systems

In addition to the solar energy systems evaluated, there was a single non-solar renewable energy project completed between 1997 and 2002. In 1999, TEP began injecting methane gas from a City of Tucson landfill into one of its coal-fired generating units at the Irvington power plant to reduce the use of coal in electricity generation at the site. This system, rated at 5 MW, has provided low cost renewable energy. The landfill gas project was installed by an independent developer and is owned by that developer. TEP purchases landfill gas at a price that is approximately equal to the cost of the coal displaced by the landfill gas.

In another project supported by EPS funds, Industrial Solar Technology (IST) installed a solar hot water system at the Federal Correctional Institution in Phoenix in 1999. Tradable credits from this facility are purchased by APS to help meet the EPS. IST states that the hot water system displaces about 1.1 million kWh per year of electricity and reduces peak electrical demand by 200 kW. The construction cost of the system was about $560,000. Thus, the cost per electric kW avoided would be about $2,800.

Conclusion

Since the beginning of the EPS program in early 2001, over 5 MW of solar energy systems have been installed in Arizona that are directly attributable to the EPS program. There are currently over 6 MW of solar power systems installed. A 5 MW landfill gas project has also been used to help meet the EPS requirements. In addition, a solar hot water system displacing 200 kW of peak electrical demand is being used to help meet the EPS requirements. Numerous customer installations are also being supported with EPS funds.

Utilities in the state have spent nearly $40 million since the EPS began in 2001 and over $60 million since 1997 on renewable energy development and implementation in the state of Arizona. While significant progress is being made, the current EPS funding is not sufficient for Arizona utilities to meet the EPS goal of 1.1 percent of retail energy sales by 2007.

There is a great deal of variability in system design, application, performance and cost in photovoltaic systems, but in general, the costs of photovoltaic systems have declined. While the evidence suggests that the costs for solar energy systems will continue to decline, the solar energy industry is still growing rapidly and going through significant change, making long-term cost projections difficult.

As the EPS matures, and the number and types of renewable energy system installations increase, it will be possible to obtain additional information on which systems perform best in each type of application. Continuing the EPS program will allow the industry to identify and pursue the best and most cost-effective solutions in the future subject to constraints on funding. Future investments may include solar, biomass, landfill gas, wind, and geothermal generation facilities.

Continuing the EPS with the appropriate combination and balance of funding and energy goals will allow additional renewable generation of all types to be installed. It will also allow the industry, the state, utilities, and customers to obtain the additional valuable information on the performance of these technologies and to begin to realize the benefits from these technologies. Ongoing monitoring will demonstrate which systems perform best and which are most cost-effective and will help determine the appropriate long-term goals for the state.

IV. BENEFITS OF THE ENVIRONMENTAL PORTFOLIO STANDARD

Background

The Advisory Committee formed to provide advice to the Utilities Division Director for organizing the CEWG identified a number of benefits in its recommendations to the Director. In addition to that list, the three subcommittees of the CEWG identified other benefits during their analysis of EPS data and projects in Arizona. All these benefits were analyzed for two purposes:

- To quantify, if possible, EPS benefits; and
- To consider other EPS benefits in a qualitative manner to provide additional information for the Commissioners in the final CEWG report.

Environmental Portfolio Standard Projects and Facilities

Projects used or in final planning stages by APS, TEP, and Navopache Electric Cooperative, Inc. (NEC) to meet the EPS requirements through 2002 included:

- Photovoltaic (PV) projects, consisting of 5,944 kW (DC) of PV generating capacity. Of this generating capacity, 5,645 kW is in large grid-tied and off-grid projects. An additional 299 kW of PV capacity is installed in 139 small projects. The PV projects were installed from late 1997 through 2002.
- A 5 MW landfill gas project installed in 1999 at the Los Realos Landfill in Tucson. The landfill gas is piped into TEP's Irvington Power Plant and used as a substitute for coal.
- A solar hot water system at the Federal Correctional Institute in Phoenix. This project was installed by Industrial Solar Technology (IST) in 1999. IST rates the project at 200 kW.

As a result of the EPS Rule implementation, TEP and APS are beginning to deploy an infrastructure of renewable energy generation, primarily PV systems, that is unequaled by any investor-owned utility in the United States. NEC is also in the advanced planning and funding stages for a substantial grid-connected PV electric generation project. This project is the first of its kind in the nation for a rural electric transmission and distribution cooperative. These installations represent a diversity of project size, location (i.e. rural and urban), and technologies (primarily different solar electric cell materials). Data from these projects on design, operation, maintenance, and system and component costs will be useful in the future development of Arizona's primary renewable resource - solar.

> As a result of the EPS, Arizona LSEs have a greater installed capacity of large, utility-scale photovoltaic systems than any other investor-owned electric utilities in the United States.

There have been fewer small, distributed generation type projects installed as a result of the EPS than originally anticipated by some parties. Such projects are typically developed, designed, and installed by small company integrators of renewable energy systems. About 139 PV projects for residential and commercial applications (most less than 10 kW in generation capacity) have been completed. Contractors who install small PV systems attribute this "slow start" to a lack of consumer awareness of the opportunity to reduce system cost for homeowners and small commercial businesses caused by the Rule.

In terms of the deployment or installation date, TEP, APS and small integrator company PV projects can be characterized in two time periods: 1997 through 2000, and 2001 through 2002. Because the Rule includes a provision that allows early installation credits, some projects from 1997 through 2001 are included in the electricity generation and capacity tables in the Cost Section although no EPS Surcharge funds were used for these projects. The projects shown in the tables from late 2001 through 2002 are essentially funded by the combination of EPS Surcharge funds and reallocation of System Benefit Charge funds (allowed in the Rule as a source of funds to meet the EPS renewable energy generation requirements).

The Cost Section tables, viewed in the context of the Source and Use of Funds Tables (in Appendix 1 of this report) for the two major LSEs, provide a context for evaluating how Arizona utilities are using EPS Surcharge and other funds to reach generation goals required by the Rule.

Benefits of the Environmental Portfolio Standard

The benefits of renewable resources include:

Overview of Benefits

- Avoided cost of conventional energy
- Avoided cost of conventional capacity
- Avoided air emissions
- Meeting federal pollution mandates
- Price stability
- Cost reductions in renewable energy technology
- Federal government loan approvals
- Assembly of solar energy data
- Cost-effective substitution of renewable energy for distribution and transmission upgrades
- Reduction in water use
- Creation of beneficial partnerships

- **Avoided costs of conventional energy**. When energy is produced from renewable resources, LSEs can reduce consumption of natural gas or coal at power plants, reduce wholesale purchases of electricity, and avoid variable operating costs of conventional gas and coal-fired power plants.
- **Avoided costs of conventional capacity**. Renewable resources have capacity value, although the capacity value of intermittent resources is generally less than their nameplate capacity. In the current Arizona market, LSEs are seeking capacity offers from the wholesale market. Renewable energy projects can contribute to meeting the need for generating capacity. Solar generated energy is especially economical during the sunniest and hottest times of the year as peaking generators when demand and the price of energy are greatest.
- **Avoided air emissions**. By reducing consumption of fossil fuels and by substituting landfill gas for coal, LSEs reduce emissions of carbon dioxide, sulfur dioxide, nitrogen oxides, carbon monoxide, and particulate matter.
- **Meeting federal pollution mandates**. The EPS is one of the key pollution prevention measures that will be included in the Arizona State Implementation Plan to address regional haze concerns.
- **Price stability**. Natural gas and short-term wholesale purchases of electricity have been subject to extreme price volatility. Energy from renewable resources, such as solar energy, is not subject to commodity market price variability because the costs are largely up-front, fixed, capital costs, and for solar electric, there is no fuel cost. The market value of price stability relative to price volatility can be gauged from financial transactions that are intended to gain price stability in a volatile market situation.
- **Cost reductions in renewable energy technology**. Arizona LSEs have been the beneficiary of worldwide trends in cost decreases for solar energy. But Arizona LSEs have also caused significant reductions in the prices of balance of system components and

the integration of those components. Cost decreases attributable to Arizona LSE efforts to optimize design and installation of PV subsystems are direct benefits from the EPS.

- **Federal loans made available to fund renewable energy projects**. The Rural Utilities Service (RUS) has shown that it is willing to approve loans to Arizona's rural electric cooperatives for construction of PV generating facilities under the EPS. For example, the RUS has approved a $3.1 million loan request by NEC for the co-op to construct 300–400 kW of PV facility generation capacity under the EPS.
- **Collection and analysis of solar energy data**. Installation of nearly 6 MW of solar energy facilities to date allows the LSEs to better understand how the intermittency of solar resources affects system reliability. A TEP analysis of capacity and energy effects of large-scale renewable energy projects is shown in Appendix 2. APS has analyzed numerous PV installations prior to and as a result of the EPS. These installations have provided significant benefits to APS and the solar industry and are presented in Appendix 2 under "Arizona Public Service Company - Benefits of the Environmental Portfolio Standard."
- **Cost-effective substitution of renewable energy for distribution and transmission line upgrades.** In some instances, grid-connected solar generating stations are a cost-effective alternative to distribution and transmission line upgrades. This is especially true in large rural areas where more miles of distribution line is required to serve relatively few customers. NEC is implementing such an approach as part of its renewable energy development program under the EPS – specifically, a cost-effective PV project in lieu of a conventional transmission upgrade; i.e., transmission line and substation.
- **Reduction in water use**. As conventional energy generation is offset, associated water withdrawals and consumption are also reduced.
- **Creation of beneficial partnerships**. LSEs can develop partnerships with municipal governments and other agencies to create mutually beneficial renewable energy projects and leverage EPS funds. The EPS also contributes to more competitive pricing and design changes and improvements by renewable energy equipment vendors.

Quantifiable Benefits of the Environmental Portfolio Standard.

This section discusses EPS benefits that the CEWG could analyze and describe in monetary terms. The other benefits are analyzed in the following section.

1. Estimated Benefits of the Environmental Portfolio Standard.

Tables IV-1 and IV-2 present the dollar value of the EPS benefits in 2002 which can be reasonably monetized. These benefits are: displaced or avoided conventional generation costs, displaced or avoided conventional capacity costs, avoided carbon dioxide (CO_2) emissions, avoided sulfur dioxide (SO_2) emissions, and the value of gaining price stability relative to volatile natural gas prices. The benefits are standardized for one full year of operation of renewable energy projects so that projects installed in 2002 (and operating less than a full year) were given full credit. The following sections describe how these benefits were calculated. Table IV-1 assumes a low value for the benefits of CO_2 reductions and Table IV-2 assumes a higher value for the benefits of CO_2 reductions.

The tables also show the costs of each technology and the net benefits of each technology (benefits minus costs). The costs (in dollars per kWh) of the projects are the 2002 fuel costs for the landfill gas project divided by the 2002 landfill gas generation, and the initial cost of the solar energy projects divided by the estimated lifetime kWh of solar energy production using the method set forth in the cost section.[6]

The quantifiable benefits of the EPS in 2002 were between $1.127 million and $1.351 million, depending on the value of the benefits of carbon dioxide reductions. TEP's landfill gas project supplies the majority of the benefits. Both the landfill gas project and the IST solar hot water project exhibit positive net benefits. As expected by the Commission at the time the EPS was adopted, the cost of PV systems results in negative net benefits for PV projects at present. Overall, the quantifiable net benefit of the EPS is between negative $0.022 per kWh and negative $0.027 per kWh.[7] Thus, to the extent that the benefits can be quantified, and based on the installed capacity and technologies as of the end of 2002, there is a premium of between $0.022 and $0.027 per kWh for deploying renewable energy facilities.

The following discussion presents more details on the analysis of the benefits derived from the EPS.

2. Avoided Conventional Energy and Capacity Costs.

Solar Projects. The PV and solar hot water projects displace energy that would otherwise have been produced by conventional generation. In addition, these projects displace generation capacity that might otherwise have to be purchased from the market under the Commission's competitive solicitation process. The avoided conventional energy and capacity costs for 2002 were about $351,000 for solar projects. Details are provided in Tables IV-1 and IV-2. The assumptions underlying the estimate of avoided conventional energy and capacity costs for solar projects are presented below.

TEP believes that, at the current level of PV production, its PV facilities primarily reduce coal-fired generation at the Springerville power plant. The avoided energy cost is therefore calculated using the average cost of coal at Springerville in 2001 and the average heat rate at Springerville in 2001. These data were taken from FERC Form 1 and were the most recent data available to the public. Because some of TEP's PV facilities were installed in 2002 and did not operate for the entire year, the partial year output was scaled up to represent a full year of PV energy generation.

APS believes that its PV facilities displace average system energy, i.e., the existing mix of all energy resources relied on by APS to meet customer needs. Therefore, the avoided energy cost was estimated as APS' 2001 operation costs per kWh for its generation (obtained from FERC Form 1) applied to PV kWh generation. The APS operation cost per kWh was also applied to the energy displaced by the IST solar hot water facility.

6 TEP also incurred a cost of $85,000 for burner modifications. The annual cost was estimated as the initial cost per lifetime kWh of landfill gas production.

7 The overall net benefit is a weighted average of the net benefits of each technology, where the weights are the kWh generated for the full year 2002.

The PV projects are assumed to have a capacity value of about 26 percent of nameplate DC capacity based on TEP's analysis of its Tucson-area PV systems. The IST solar hot water system is valued by its supplier as having a capacity value of 200 kW.

This report assumed that avoided capacity costs are the annualized fixed costs of new combustion turbines. These are the marginal power plants offered in the current wholesale market for capacity. The avoided capacity costs can be calculated to be $68.87 per kW per year.[8]

Landfill Gas Project. The landfill gas project displaces energy that would otherwise have been produced by conventional generation. No capacity value is associated with the TEP landfill gas project because the project substitutes landfill gas for coal as a fuel at the existing Irvington power plant. The avoided conventional energy costs for 2002 were about $730,000. The assumptions underlying the estimate of avoided conventional energy costs for TEP's landfill gas project are presented below.

TEP's landfill gas project displaces coal as a fuel at the Irvington power plant. TEP pays a rate for the landfill gas that is approximately the equivalent of its cost for coal. Therefore, there are no avoided fuel costs on net. The gross avoided cost at Irvington was estimated by applying the average cost of coal at Irvington in 2001 and the average heat rate at the Irvington coal unit in 2001 using data from FERC Form 1.

3. Avoided Air Emissions

Generation of electricity from solar energy or displacement of conventionally generated electricity by solar hot water systems reduces the emissions of carbon dioxide, sulfur dioxide, nitrogen oxides, particulate matter, and carbon monoxide. In addition, because TEP's landfill gas project displaces burning of coal there are net reductions in the amount of air emissions. The volume of avoided air emissions is presented in Appendix 2 of this report.

It is possible to put dollar values on the reductions in emissions for carbon dioxide and sulfur dioxide. In 2002, the benefit of reducing carbon dioxide and sulfur dioxide was between $43,000 and $267,000. Assumptions for estimating the air emissions benefits of the EPS are presented below.

APS estimated system emission factors (pounds per MWh) for SO_2 and CO_2 over the period 1997 though 2001 for its generating system. These emission factors were applied to APS' estimate of full-year kWh production from its PV facilities to determine avoided emissions. As noted above, APS believes that the conventional energy displaced by its PV projects is represented by its system average resource. The same emission factors were applied to IST's kWh equivalent production to estimate avoided air emissions.

8 Cost assumptions are from the Energy Information Administration, *Annual Energy Outlook 2002* for new power plants. Capital costs are $446 per kW for combustion turbines. Fixed O&M costs are $9.16 per kW per year for combustion turbines. A 12 percent interest rate and 20-year time horizon were assumed.

TEP estimated SO_2 and CO_2 emissions displaced by its actual 2002 PV energy production, including facilities which operated only part of the year because they were installed throughout 2002. To make all the cost and benefit data comparable, these avoided emissions were scaled up to reflect a full year of PV generation. The avoided emissions attributable to TEP's landfill gas project were also estimated by TEP.

Market values for SO_2 and CO_2 emissions avoided by EPS projects were estimated as follows. The cost of acquiring an SO_2 allowance is roughly $100 per ton,[9] and this cost was used to estimate the benefits of sulfur dioxide reductions attributable to the EPS. With regard to CO_2, there may be future climate change regulation of CO_2 emissions. Estimates of the costs of avoiding, reducing, or offsetting CO_2 emissions vary greatly. Given the uncertainties about future carbon regulation, markets that trade in carbon credits discount the future, attempting to take into account the verifiability of carbon reductions, the likelihood of future carbon regulations, the likelihood that a particular carbon reduction or offset will be accepted by regulators, and perhaps other factors. Therefore, a range of values was used: $1 per metric ton of CO_2 as the low value and $9 per metric ton of CO_2 as the high value.[10] (Note that actual costs of complying with carbon regulation are likely to be much higher if U.S. regulations are adopted).

The air emissions benefits presented in Tables IV-1 and IV-2 derive from reductions in conventional energy production for retail sales displaced by EPS projects. To the extent that utilities generate and sell the displaced energy on the wholesale market, the air emissions benefits are diminished on net.

4. Hedge Value of Solar Energy

Natural gas prices exhibit great volatility. In contrast, solar energy (as well as wind and geothermal energy) generally have low variable costs and fixed capital costs and are not subject to commodity market price volatility. There is some value to ratepayers and utilities of gaining price stability by hedging volatile natural gas prices with solar energy. In 2002, the benefits from the hedge value of solar energy were judged to be about $3,000. Details of the analysis are presented below.

For the portion of displaced conventional energy which comes from natural gas power plants, substitution of solar energy can result in price stabilization. However, displacement of coal resources is not likely to result in much additional price stability since coal prices are relatively stable. Further, the price of TEP's landfill gas is pegged to the price of coal, so there is no price stability associated with the landfill gas project.

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9 See Barry D. Solomon, "Five Years of Interstate SO2 Allowance Trading: Geographic Patterns and Potential Cost Savings," *The Electricity Journal*, May 1998: 58-70, page 65.

10 Natsource, *Assessment of Private Sector Anticipatory Response to Greenhouse Gas Market Development,* prepared for Environment Canada, 2002, estimated prices up to $11 per metric ton of CO_2. See also Urs Springer and Matthew Varilek, "Estimating the Price of Tradable Permits for Greenhouse Gas Emissions in 2008-12," *Energy Policy* (forthcoming). Jack D. Cogen, CEO of Natsource, quoted permit costs of $3 to $8 per metric ton of CO_2 in a news article on April 10, 2003. Cantor Environmental Brokerage and CO2e.com, www.emissionstrading.com/marketp.htm, accessed April 21, 2003, estimated a range of $1 to $8 per metric ton of CO_2 equivalent depending on the vintage year, risk guarantees, volume, and contract structure.

The only projects to directly displace natural gas are, therefore, the IST solar hot water system and the APS PV projects. Because APS assumes that the average system generation is displaced by its PV projects, the proportion of system energy generated by APS in 2001 using natural gas (about 8 percent) was used to determine the kWh subject to a price stabilization effect for the APS PV projects and the IST facility.

There is little information on the market value of price stability in a volatile market. One approach is to estimate the value of price stability resulting from use of solar energy based on premiums paid for fixed price natural gas contracts relative to forecasted varying market prices of natural gas for the same time period. One such study found a market premium of about $0.005 per kWh to hedge away natural gas price risk over a ten-year period using financial swaps.[11] This hedge value was used to estimate the benefits of displacing natural gas-fired generation. The creation of additional uncertainty in the price of fuel used to firm intermittent generation resources was not quantified due to lack of information.

5. Balance of System Cost Reductions

One of the benefits inherent in the table of costs and benefits is the decrease in balance of system (BOS) costs achieved by TEP. A target cost of $3 per Watt has been proposed in the industry as a level at which PV generation becomes competitive.[12] Typically this $3/Watt target is composed of several cost elements, but two, PV module cost and balance of system (BOS) cost, are the major factors. Goals established by both the solar electric industry and Department of Energy (DOE) system integration experts are in agreement that the BOS portion of this value must be $1/Watt or less for the $3/Watt goal to be attained.

Examples of Balance of System Element <u>Cost Decreases</u>

- Design of systems to reduce wiring costs, such as use of smaller current carrying capacity and reduction of use of expensive large copper cables.
- Design of systems to minimize voltage drops on long runs of DC wiring.
- Simplified design of support structures.
- Use of readily available construction components.
- Use of standardized inverters.
- Use of modular construction of large PV projects. Elements of modular construction include surface preparation, underground conduit, concrete foundations, high voltage wiring, transformers, and grounding.

TEP, in a major accomplishment by a U.S. utility, has met this $1/Watt BOS goal at its SGS facility in 2003. The box identifies some of the actions taken by TEP to reduce balance of system costs. More detail on the TEP BOS cost reductions can be found in Appendix 2.

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11 Mark Bolinger, Ryan Wiser, and William Golove, "Quantifying the Value that Wind Power Provides as a Hedge against Volatile Natural Gas Prices," Lawrence Berkeley National Laboratory, June 2002, LBNL-50484.

12 See: U.S. Photovoltaics Industry PV Technology Roadmap Workshop, National Center for Photovoltaics, June 23-25, 1999, Chicago, IL, and Photovoltaic Systems: An End-of-Millennium Review, Progress in Photovoltaics Research and Applications, John Wiley & Sons, 1999.

Table IV-1
Summary of 2002 EPS Benefits
Low Value of Carbon Dioxide Benefits
(adjusted to reflect a full year of energy production)

Benefits and Costs	IST Solar Hot Water	APS PV	TEP PV	TEP Landfill Gas	Total
Avoided conventional energy costs	$23,000	$117,000	$90,000	$730,000	$961,000
Avoided conventional capacity costs	$14,000	$55,000	$51,000	$0	$120,000
Avoided carbon dioxide	$1,000	$3,000	$5,000	$19,000	$28,000
Avoided sulfur dioxide	-	$1,000	$1,000	$13,000	$15,000
Hedge value (price stabilization)	-	$2,000	$0	$0	$3,000
Benefits subtotal in 2002	**$38,000**	**$179,000**	**$148,000**	**$762,000**	**$1,127,000**
Annual fuel costs				$730,000	$730,000
Total benefits minus annual fuel costs	$38,000	$179,000	$148,000	$32,000	$397,000
2002 kWh (full year of operation)	1,100,000	5,531,341	5,109,406	31,661,430	43,402,177
Benefits minus fuel costs, $ per kWh	$0.035	$0.032	$0.029	$0.001	$0.009
Initial cost, $ per kWh	$0.025	$0.150	$0.136	$0.0001	
Net benefits, $ per kWh	**$0.009**	**-$0.117**	**-$0.108**	**$0.001**	**-$0.027**

Table IV-2
Summary of 2002 EPS Benefits
High Value of Carbon Dioxide Benefits
(adjusted to reflect a full year of energy production)

Benefits and Costs	IST Solar Hot Water	APS PV	TEP PV	TEP Landfill Gas	Total
Avoided conventional energy costs	$23,000	$117,000	$90,000	$730,000	$961,000
Avoided conventional capacity costs	$14,000	$55,000	$51,000	$0	$120,000
Avoided carbon dioxide	$6,000	$29,000	$45,000	$173,000	$252,000
Avoided sulfur dioxide	-	$1,000	$1,000	$13,000	$15,000
Hedge value (price stabilization)	-	$2,000	$0	$0	$3,000
Benefits subtotal in 2002	**$43,000**	**$204,000**	**$188,000**	**$916,000**	**$1,351,000**
Annual fuel costs				$730,000	$730,000
Total benefits minus annual fuel costs	$43,000	$204,000	$188,000	$186,000	$621,000
2002 kWh (full year of operation)	1,100,000	5,531,341	5,109,406	31,661,430	43,402,177
Benefits minus fuel costs, $ per kWh	$0.039	$0.037	$0.037	$0.006	$0.014
Initial cost, $ per kWh	$0.025	$0.150	$0.136	$0.0001	
Net benefits, $ per kWh	**$0.014**	**-$0.113**	**-$0.100**	**$0.006**	**-$0.022**

Other Benefits

As with any new, regulatory policy initiative, the Arizona EPS exists within a complex set of policies at the state and federal levels affecting conventional electricity generation and the renewable generation alternatives. As LSEs plan for compliance, private industry works to exploit the new market, and as other entities including federal regulatory agencies are affected by the dynamics of the new market, a set of additional benefits is becoming apparent as a result of the Rule implementation. Many of these additional benefits are qualitative in nature, and it will take some time to be able to better quantify their effects.

Significant benefits not anticipated during deliberations on the Rule are occurring.

In addition to the quantitative benefits listed in the Advisory Committee recommendations, the Benefits Subcommittee has tried to capture these qualitative benefits from experience developed since the Rule implementation. These additional benefits identified to date include the following:

- LSEs are better able to evaluate solar system intermittency effects,
- The Rural Utilities Service (RUS) has shown that it is willing to approve loans to Arizona's rural electric cooperatives for the construction of photovoltaic generating facilities under the EPS,
- Grid-connected PV facilities at strategic points along distribution and transmission lines are a cost-effective alternative to expensive line upgrades,
- Water use is reduced, and
- Additional public/private partnership opportunities have been created.

1. Evaluation of solar system intermittency characteristics

Because the installed generation capacity of EPS solar electric projects in Arizona is still less than 10 MW (small in comparison to utility-installed generation capacity statewide) there has been no actual experience in wheeling large amounts of intermittent renewable energy. However, there is significant benefit to the collection and analysis of data on Arizona renewable resource availability and the variation in that availability over time. Through system modeling, the analyses consider the effects of intermittency on generation and transmission systems. LSEs are starting the process of developing the tools to use the intermittent renewable resource data in their system models. Among other benefits, the EPS allows for the long-term funding needed to assure collection, analysis and system model integration of the renewable resource data for Arizona-based resources. TEP recently conducted an analysis of the hypothetical renewable generation resources producing an annual 10 percent of retail energy assuming proposed Federal energy legislation was adopted. A summary of the analysis is presented in Appendix 2.

EPS projects are accelerating LSEs' ability to understand the integration of renewable energy technologies into their generation and transmission systems.

2. Avoiding or delaying the need to perform expensive upgrades to distribution and transmission lines

A 1996 study performed for NEC concluded that a solar electric distributed generation project, strategically located on the existing distribution line may be a significantly better economic choice to the co-op than upgrading a 36-mile distribution line within NEC's service area to a transmission line and substation.

The analysis is based on comparison of upgrading the existing three-phase distribution line from the Wagon Wheel substation to the town of Cibecue. This circuit to Cibecue is characterized as a winter-peaking feeder with the highest historical peak loads occurring in January, December, and February. Historical load data demonstrated the peak loads occurred between the mid-day, daylight hours during the winter and were primarily caused by demand from a lumber mill.

> Navopache Electric Cooperative, Inc. has identified a grid-connected PV project which can provide distribution service improvements in lieu of conventional line upgrades at a lower cost than conventional upgrades.

A long-range plan from the mid-80s proposed a $4.2 million upgrade of the 14.4 / 24.9 kV distribution line to a 69 kV transmission line. However, the NEC-sponsored analysis showed a proposed grid-interconnected PV system was a lower-cost option. The proposed system will provide sufficient voltage support for the Cibecue load approximately 85 percent of the time. The analysis also showed additional measures such as load control or small amounts of battery storage can provide the required voltage support during the few hours the PV system output is not sufficient.

Based on the needs identified in the long-range plans and the 1996 study, the RUS has approved a $3.1 million loan request by NEC for the cooperative to construct 300-400 kW of PV facility generating capacity under the EPS.

3. Reduction in water used to generate electricity

Drought in the Southwest has begun to seriously strain water resources in the region. Even if the drought lessens, continued population growth given existing water usage policies and cost structures suggests continuing pressures on regional water resources. Although large quantities of water are used to cool portions of conventional, fossil-fuel electricity generation plants, this water is a small portion of total Arizona water use – less than 2 percent. While geothermal and biomass renewable energy projects do consume water for operation, solar electric and wind electricity generation systems do not. Since fossil-fueled generation plants consume an average of 0.5gal/kWh, this water consumption would be eliminated by deployment of solar electric and wind energy systems.

4. Public/Private Partnership Opportunities Created by Environmental Portfolio Standard Policy

Adoption of the EPS Rule by the Arizona Corporation Commission has provided a funding mechanism for LSEs that can be used to develop long-term renewable energy projects with municipal and other governmental partners. These projects and the long-term funding implicit in the EPS gives the LSEs leverage to develop pricing and component design relationships with specific PV component and system vendors by reducing market uncertainty.

The EPS also provides a source of funds that allows LSEs to take a more aggressive financial stake in public/private partnerships. These Arizona EPS funds can be used to leverage scarce public funds to provide a much better return on dollars invested by the cities than would have been possible without the EPS policy.

LSEs can develop partnerships with municipal governments and other agencies to create mutually beneficial renewable energy projects and leverage EPS funds. The EPS also contributes to more competitive pricing and design changes and improvements by renewable energy equipment vendors.

The EPS Rule and its Surcharge funds have made possible a number of creative joint venture activities among Arizona cities and LSEs. It is likely such collaborations will become a large part of EPS projects as more cities learn of the opportunity to leverage Surcharge funds, and the LSEs use the these joint ventures to meet their EPS solar electric and other environmentally friendly technology generation requirements. As examples of such collaboration, TEP has completed the following joint ventures:

a. The City of Tucson was able to avoid the cost of installing a flare and collection system at the City's Los Realos Landfill - the City's largest landfill. The City of Tucson was required by the Environmental Protection Agency (EPA) to have a flare and collection system installed at this landfill. An agreement was structured in which the City made landfill gas available to a developer that has a contract with TEP to supply landfill gas. The agreement required the developer (formerly ZAPCO – now U.S. Energy) to supply the necessary gas collection, flare, processing, pipeline and some boiler modifications at no up-front cost to the City or TEP. The agreement was beneficial to TEP because the project reduced coal consumed at a coal-fired generation plant; the installation allowed the utility to meet its renewables goal for 2000 set during the 1993 integrated resource planning process; and there were substantial long-term environmental benefits. Although the project became operational before the EPS Rule was approved, TEP planning activities anticipated using the Landfill Gas project kWh generation and EPS credits to meet Rule requirements. Anticipated Rule compliance and an existing contract with the developer were factors TEP considered in deciding to participate in the agreement. Also, TEP has been able to sell tradable credits from the landfill gas project to other LSEs to help them meet their EPS requirements.

   Benefits to the City include avoiding a capital expense of an estimated $1,500,000 as well as annual operating and maintenance expenses of $70,000. The agreement includes a provision for the City to pay the developer a fee of $125,000 annually for a 20-year period offset by a requirement that the City receive a refund depending upon actual landfill gas production. The refund amounts to date total $25,000.

b. TEP EPS-related efforts also helped the City of Tucson complete a large PV project at the Hayden/Udall Water Treatment facility. As a participating utility in a DOE-sponsored program, TEP helped the City of Tucson win a grant for $75,000 from the Solar Electric Power Association (SEPA). The existence of the EPS policy was used by TEP and the City to leverage funds originating from the federal government using a smaller amount of City funds. TEP used Surcharge funds to provide inverters necessary for operation of the project and thereby gained access to the kWh generated from the project and extra credit multipliers specific to this project. These efforts by

TEP related to the EPS directly benefited the City of Tucson in its environmental and renewable program development efforts.

APS has collaborated with a number of agencies on innovative projects to deploy additional PV generation capacity including the following:

a. The City of Scottsdale provided access to an existing covered parking structure to demonstrate new thin-film PV technology and develop the first PV-covered parking in the state. The technology was eventually moved to the roof of a new multilevel parking structure that integrated the original PV modules and doubled the system size to over 90 kW. The PV integrates the modules into a channel structure that simplifies wiring and installation of the solar electric generation system.

b. One constraint on deployment of PV in developed urban areas is cost of land. APS partnered with Scottsdale on an innovative project to deploy 300 kW of PV at the Water Campus in North Scottsdale using the concrete cover of the water tanks to mount a tracking system and modules. Modules from three different PV module manufacturers are deployed on a common tracking system at the site. The City's participation was limited to providing access to the concrete tank covers, and APS takes the power generated directly into an adjacent distribution system for retail sale.

c. In another innovative design approach that uses restricted land for PV deployment, the City of Glendale partnered with APS by providing land at the Glendale Airport for a 204 kW concentrating PV system using a tracking design.

d. APS has also collaborated with numerous city, state, federal, and educational facilities to deploy PV in the most cost-effective manor possible as detailed in Appendix 3.

V. ECONOMIC IMPACTS OF THE ENVIRONMENTAL PORTFOLIO STANDARD

This section describes the Arizona economic impacts resulting from implementation of the EPS. The economic impacts are the Arizona output, earnings, and employment that can be attributed to the construction and operation of renewable energy facilities installed to help meet the EPS. These impacts are composed of expenditures in Arizona to construct and operate renewable energy facilities plus multiplier effects.

Impacts measure aspects of the level of economic activity attributable to the EPS. Impacts should not be interpreted as economic benefits. The impacts described in this section take into account only the effects of constructing and operating facilities to meet the EPS. The analysis does not take into account the foregone impacts of conventional power plant construction or operation that might have happened in the absence of the EPS. Nor does the analysis take into account what would have happened if consumers had not paid the surcharge to support the EPS but instead decided how to spend that money themselves.

The projects used by APS, TEP, and Navopache Electric Cooperative to meet the EPS requirements through 2002 are:

- PV projects, consisting of 5,944 kW (DC) of generating capacity installed throughout Arizona between late 1996 and 2002. Of this generating capacity, 5,644 kW is in large grid-tied and off-grid projects. In addition, 300 kW of PV capacity are in 139 small installations.
- A landfill gas project installed in 1999 at the Los Realos Landfill in Tucson. The landfill gas is piped into TEP's Irvington Power Plant and is used as a substitute for coal. The generating capacity of the landfill gas project is about 5,000 kW.
- A solar hot water system at the Federal Correctional Institute in Phoenix. This project was installed by Industrial Solar Technology (IST) in 1999. The solar hot water system displaces, on net, about 1.1 million kWh per year of electricity consumption.

Arizona Impacts of Construction of Solar Energy Projects through 2002

$28.2 million of Arizona output of goods and services
$8.6 million of Arizona earnings
274 person years of Arizona employment

The economic impact of the construction of solar energy systems in Arizona through 2002 which are used to meet the EPS requirements is summarized in the box. Because TEP did not construct the landfill gas project from which it obtains landfill gas and because the landfill gas project data are proprietary, no impact analysis has been conducted on the construction of that project.[13]

[13] TEP did not construct the landfill gas project (except for modifications to the burners at the Irvington power plant) nor does it operate the landfill gas project. TEP burns landfill gas at the Irvington power plant in lieu of coal, and the cost to TEP of burning landfill gas is intended to be the same as the variable cost of burning coal. In addition, the City of Tucson indicated that, in the absence of the landfill gas project, the City would have had to collect and flare methane from the landfill. The avoided capital costs were estimated by the City to be about $1.5 million and the avoided operating and maintenance costs were estimated to be about $70,000 per year.

The remainder of this section provides more detail on the impact analysis and presents impacts from additional projects.

Overview of Impact Analysis

The **direct impact** of EPS activities on Arizona is the dollar value of expenditures in Arizona to install and operate renewable energy facilities. The **indirect impact** on Arizona is the value of the expenditures in Arizona resulting from the direct impacts. The indirect impact captures the **multiplier effect** due to inter-industry transactions. For example, if a utility spends $1 million on goods and services in Arizona to install PV systems (the direct impact), suppliers of these goods and services and labor will in turn purchase more inputs, some of which come from Arizona suppliers. These Arizona suppliers then purchase some goods and services from Arizona firms and employ Arizona labor. And so forth. The sum of the Arizona economic repercussions resulting from the direct impacts in Arizona is the indirect impact on Arizona. The indirect impacts are determined from the Bureau of Economic Analysis' RIMS II model for Arizona.[14] Continuing with the example, if the indirect impacts were $800,000 of goods and services produced in Arizona, the multiplier effect would be 1.8, calculated by dividing $1.8 million of direct and indirect impacts in Arizona by $1 million in direct impacts in the state.

Impacts are measured as follows:

- Arizona output, i.e., the value of goods and services produced in the region.
- Arizona earnings, calculated as the sum of wages and salaries, proprietors' income, directors' fees, and employer contributions for health insurance less personal contributions for social insurance.
- Arizona employment or jobs, measured in person years of employment.

The data for the direct impacts were provided by APS, TEP, American Solar Electric, IST, and Navopache Electric Cooperative. Each of these entities provided the total costs of each major input into the construction or operation of their projects (e.g., PV modules, inverters, structural supports, engineering services, construction activity, and so forth), and identified the portion of the costs which came from Arizona suppliers.[15]

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14 RIMS II is a regional input-output modeling system which makes use of the most recent survey-based national input-output model of the economy. The input-output model reflects inter-industry patterns of purchases among approximately 500 industries. The national pattern of inter-industry purchases is regionalized using regional purchase coefficients to reflect the geographic pattern of purchases made by industries in a particular region, in this case, the state of Arizona. See Bureau of Economic Analysis, U.S. Department of Commerce, *Regional Multipliers: A User Handbook for the Regional Input-Output Modeling System (RIMS II)*, March 1997. The Bureau of Economic Analysis provides the specific multiplier files for a user-defined region.

15 The entities provided the data in their own formats reflecting the way they maintained their data. The data were then re-organized to conform, as closely as possible, to the RIMS II model requirements. In conducting the impact analyses, costs were disaggregated into a "bill of goods" such as the manufacture of: PV devices, inverters, structural supports, data acquisition systems, motors, wire and conduit, other electrical equipment; engineering services; construction services; distribution services; and transportation.

Impacts are separated into construction phase impacts and operations phase impacts because the economic activities are typically quite different in these two phases. Operations phase impacts are presented for a typical year whereas construction phase impacts are presented for the entire package of construction activities.[16]

Construction Phase Impacts: TEP and APS Photovoltaics Projects

Construction phase impacts were calculated separately for TEP and APS' PV projects. Because the inputs themselves and the geographic origin of inputs are different for the two companies, the impacts are different.

Table V-1 presents the impacts on Arizona of the construction of TEP's Springerville PV systems and APS' PV systems through 2002. TEP obtained modules, inverters and electrical and electronic equipment from out-of-state suppliers. Engineering services, fabrication of structural supports, assembly of junction boxes, and installation of the PV systems were performed mostly in Arizona. Consequently, out of \$15.8 million in TEP's construction phase costs, about \$5.8 million of inputs were obtained from Arizona suppliers and about \$10 million of inputs were obtained from out-of-state. The total (direct plus indirect) Arizona impact of the in-state expenditures associated with TEP's PV projects is production of about \$12.3 million of goods and services in Arizona, about \$3.8 million of earnings within the state, and about 121 person years of employment in Arizona. The TEP-related impacts occurred primarily during 2001 and 2002.

APS obtained modules, inverters and some balance of system components from out-of-state suppliers. Most construction services, all engineering services, and some balance of system equipment were provided by in-state suppliers. Out of \$23.7 million in construction phase costs, about \$6.9 million of goods and services were obtained from Arizona suppliers and about \$16.8 million of inputs were obtained from out-of-state. The total (direct plus indirect) Arizona impact of the in-state expenditures is production of about \$15.3 million of goods and services in Arizona, about \$4.6 million of earnings within the state, and about 147 person years of employment in Arizona. The APS-related impacts occurred primarily during the period 1997 through 2002.

Table V-1 also shows the direct and indirect impacts as multipliers applied to the direct impacts. These multipliers are calculated as the output, earnings or employment per dollar or per million dollars of direct impacts.

[16] TEP's construction activities took place primarily over the period 2000 through 2002. APS' construction activities took place primarily over the period 1997 through 2002.

Table V-1
Arizona Impacts of Construction of TEP Springerville and APS PV Systems
(Installations through 2002)

		TEP - Springerville	APS	Total
kW (DC) of PV included in analysis		**2,428**	**3,093**	**5,521**
MWh (full year of operation)		**4,471**	**5,531**	**10,002**
Installed cost of PV systems		**$15.8 million**	**$23.7 million**	**$39.5 million**
Direct impacts on Arizona (expenditures in Arizona)		**$5.8 million**	**$6.9 million**	**$12.7 million**
Direct and indirect impacts on Arizona	Output	**$12.3 million**	**$15.3 million**	**$27.6 million**
	Earnings	**$3.8 million**	**$4.6 million**	**$8.4 million**
	Person years of employment	**121**	**147**	**268**
Arizona multipliers	Output per dollar of direct impact	**2.14**	**2.22**	**2.18**
	Earnings per dollar of direct impact	**0.65**	**0.67**	**0.66**
	Employment per million dollars of direct impact	**20.98**	**21.28**	**21.14**

Construction Phase Impacts: Small Distributed PV Projects

One of the effects of the EPS is the installation of small, distributed PV systems on consumers' premises. These small systems range in size from less than 1 kW to about 10 kW, although they can be larger when installed on commercial buildings or parking structures. Small distributed PV systems are often paid for in part or entirely by the property owner. Therefore, as these small, distributed PV systems are used to help meet EPS requirements, the utilities do not have to spend utility money for the entire project cost. In other words, the costs of small, distributed PV projects can be leveraged by property owners to help utilities meet EPS objectives.

This section analyzes the economic impacts of small, distributed PV systems based on data provided by American Solar Electric for grid-connected systems installed between September 2001 and December 2002. Because the impacts of any one system are small and to maintain the confidentiality of American Solar Electric's data, this section reports impacts for 100 projects based upon the average system installed by American Solar Electric. Some small PV projects have been included in the utility project data reported in Table V-1, but some small projects were not installed with the assistance of a utility. Therefore, the impacts reported in this section cannot be added to the impacts reported in Table V-1.[17]

[17] The TEP PV program data analyzed above do not include installations of small systems, but the APS PV program data analyzed above do include installations of small systems. In addition, some of the small systems installed by American Solar Electric were not part of utility EPS programs.

Table V-2 presents the potential impacts on Arizona of installing 100 small grid-tied PV systems (without batteries).[18] About half the goods and services used in installing these PV systems come from outside Arizona. American Solar Electric obtained modules, inverters, structural supports, and electrical and electronic equipment from out-of-state suppliers. Some wholesale distribution services were provided by in-state suppliers. All engineering services and various contracting and related services were provided by in-state suppliers. Of course, different PV installers may exhibit different geographic expenditure patterns; for example, some installers may purchase modules from in-state suppliers or may purchase structural supports from in-state suppliers.

Table V-2
Arizona Impacts of Installing 100 Small PV Systems

Estimated kW (DC) of 100 small PV systems		**320**
Estimated MWh per year from 100 small PV systems		**400**
Installed cost of 100 small PV systems		**$2.8 million**
Direct impacts on Arizona (expenditures in Arizona)		**$1.3 million**
Direct and indirect impacts on Arizona	Output	**$2.9 million**
	Earnings	**$0.9 million**
	Person years of employment	**28**
Arizona multipliers	Output per dollar of direct impact	**2.21**
	Earnings per dollar of direct impact	**0.67**
	Employment per million dollars of direct impact	**21.25**

Table V-2 also reports the direct and indirect impacts as multipliers applied to the direct impacts. These multipliers are calculated as the output, earnings or employment per dollar or per million dollars of direct impacts. Because the mix of inputs and geographic origin of those inputs are different than TEP's or APS' patterns of inputs, the multipliers are slightly different than TEP and APS multipliers.

Construction Phase Impacts: Large Solar Hot Water System

This section presents an analysis of the direct and indirect impacts on the Arizona economy of the installation of a solar hot water system at the Federal Correctional Institution in Phoenix. This hot water system was installed by Industrial Solar Technology (IST) in 1999 and tradable credits associated with the project have been sold to Arizona utilities to help them meet their EPS requirements. The solar hot water system provides hot water throughout the day by storing hot water.

Table V-3 presents the impacts on Arizona of the construction of the IST hot water system. The project components (collectors, supports, piping, storage tanks, and controls) were manufactured out-of-state. Some engineering and related activities took place in Arizona, and some were carried out in Colorado. Construction and related activities took place in Arizona and constitute the largest element of the direct impacts on Arizona. Out of $0.56 million in construction phase costs, about $0.26 million of inputs were obtained from Arizona suppliers.

[18] The kW and MWh estimates shown in Table V-2 were estimated based on the performance of TEP's small PV projects and APS' costs of small grid-tied PV projects of $8.75 per DC watt. If 100 small PV systems cost $2.8 million, then about 320 kW of DC capacity could be installed. Assuming performance levels of TEP's small PV systems, the 320 kW of small projects would generate about 400 MWh per year.

The total (direct plus indirect) Arizona impact of the in-state expenditures is production of about \$0.57 million of goods and services, about \$0.17 million of earnings within the state, and about 5.9 Arizona jobs. These impacts primarily occurred at about the time of construction.

Table V-3
Arizona Impacts of Construction of the IST Hot Water System
(Located at the Federal Correctional Institution)

Reduction in peak demand at Federal Correctional Institution (kW)		**200**
Annual net electrical energy displacement (MWh)		**1,100**
Installed cost of hot water system		**\$0.56 million**
Direct impacts on Arizona (expenditures in Arizona)		**\$0.26 million**
Direct and indirect impacts on Arizona	Output	**\$0.57 million**
	Earnings	**\$0.17 million**
	Person years of employment	**5.9**
Arizona multipliers	Output per dollar of direct impact	**2.22**
	Earnings per dollar of direct impact	**0.67**
	Employment per million dollars of direct impact	**23.17**

Table V-3 also reports the direct and indirect impacts as multipliers applied to the direct impacts. These multipliers are calculated as the output, earnings or employment per dollar or per million dollars of direct impacts. Because the mix of inputs and geographic origin of those inputs are different than other companies' patterns of inputs, the multipliers are slightly different than the multipliers shown in the other tables.

Construction Phase Impacts: Navopache's Planned Projects

This section presents an analysis of the direct and indirect impacts on the Arizona economy of the planned installation of PV systems by Navopache Electric Cooperative in response to the EPS. Navopache has recently received funding approval from the Rural Utilities Service (RUS) for construction of approximately 300 kW of PV facilities. Navopache is negotiating a contract with a PV vendor and expects its first PV system to be installed by the end of 2003. The data used in this analysis were provided by the vendor and reflect the pending contract with Navopache. The data also reflect Navopache's work plan associated with its loan application submitted to the RUS.

Table V-4 presents the impacts on Arizona of the construction of Navopache's planned PV systems for projects to be installed from 2003 through 2006. Navopache plans to obtain some modules and inverters from an Arizona supplier and plans to obtain structural supports, wires, electrical equipment, engineering services, and construction services from Arizona suppliers. Out of about \$3.1 million in planned construction phase costs, about \$1.3 million of goods and services are planned to be acquired from Arizona suppliers and \$1.8 million of inputs are planned to be obtained from out of state. The total (direct plus indirect) Arizona impact of the in-state expenditures is production of about \$2.82 million of goods and services, about \$0.85 million of earnings within the state, and about 25 Arizona jobs.

Table V-4 also reports the direct and indirect impacts as multipliers applied to the direct impacts. These multipliers are calculated as the output, earnings or employment per dollar or per million dollars of direct impacts. Because the mix of inputs and geographic origin of those inputs are different than other companies' patterns of inputs, the multipliers are slightly different than the multipliers shown in the other tables.

Table V-4
Arizona Impacts of Construction of Navopache's Planned PV Systems
(Planned Installations 2003-2006)

Installed cost of PV systems		**$3.14 million**
Direct impacts on Arizona (Navopache's expenditures in Arizona)		**$1.32 million**
Direct and indirect impacts on Arizona	Output	**$2.82 million**
	Earnings	**$0.85 million**
	Person years of employment	**24.7**
Arizona multipliers	Output per dollar of direct impact	**2.13**
	Earnings per dollar of direct impact	**0.64**
	Employment per million dollars of direct impact	**18.69**

<u>Operations Phase Impacts</u>

For TEP's PV systems, 2002 operating expenditures in Arizona were about $51,000. These expenditures consisted of vegetation control, module replacement, and small PV system repairs. TEP also incurred insurance costs and taxes, but, on net, these costs are approximately zero because they would be incurred for conventional generation as well. Because the annual operating phase costs are small, no impact analysis of the PV system was conducted. Avoided conventional generation costs are discussed in the section on EPS benefits. In addition, TEP reports that the landfill gas project employs one person as a caretaker on site.

APS spent $3.83 million on operations and maintenance activities for its PV projects over the period 1997 to 2002. In addition, about $1.26 million of construction cost expenditures incurred between 1997 and 2002 are more appropriately classified as operation and maintenance activities.[19] APS did not provide detail on the activities included in operations and maintenance except to note that all the operations and maintenance expenditures took place in Arizona. Because the RIMS II model requires detail on operations and maintenance activities, no operations phase impact analysis is presented. Avoided conventional generation costs are discussed in the section on EPS benefits.

With regard to small PV systems, operations phase expenditures (such as maintenance) have not yet occurred and are therefore not reported.

For the IST solar hot water system, typical annual expenditures for maintenance of the hot water system by Arizona vendors are $6,000. Because this impact is relatively small, no indirect impacts have been estimated.

Finally, Arizona has a PV manufacturing facility, Global Solar, in Tucson employing an average of 100 people during 2002 and currently employing over 150 people. Credits produced by the manufacture of Global Solar material in Arizona are being used by TEP to meet part of its EPS energy percentage goals. These jobs have a positive impact on the economy of Arizona.

[19] These activities are maintenance and repair and marketing and they are not included in the impact analysis of construction activities described above.

VI. RECOMMENDATIONS

As noted in the Introduction, the CEWG is to provide "recommendations to the Commission of an acceptable portfolio electricity cost/benefit point or portfolio kWh cost impact maximum that the Commission could use as a [criterion] for the decision to continue the increase in the portfolio percentage." The CEWG has attempted to answer the following questions:

1) Have the installed simple project costs declined sufficiently to warrant an increase in the EPS?
2) Is funding provided by the EPS sufficient to meet either the 0.8% or 1.1% EPS goal?
3) Can a cost/benefit point or impact maximum be recommended to the Commission for use in its evaluation of the EPS?

In response to the first question, there is agreement among the CEWG participants that significant progress has been made, that renewable energy development life cycle cost reductions have been achieved in the EPS's first 18 months, and that the program should continue. There is consensus that costs have declined substantially from costs prior to adoption of the EPS. Much of this decline has come from the experience gained by TEP and APS installing large, utility-scale projects as described in this report. Also, both utilities expect this decline to continue because of ongoing design, installation, and operation efficiency gains and teamwork with inverter and module manufacturers.

There is no consensus on how the standard should move forward. Therefore, the participants have proposed options on how to move forward for the Commission's consideration. As explained at the end of this section there are two basic options for moving forward, within the scope of the EPS as it is currently written.

In response to the second question, the CEWG's conclusion is that there are not sufficient funds, based on the current costs of solar generation, to meet the renewable generation goals set forth in the EPS. Further, the potential for attaining the EPS goals depends on which utility is being evaluated. Utility-specific factors in place at the start of the EPS have a significant effect on the ability of the utilities to meet the standard, such as access to inexpensive generation and excess credits to sell from other renewable technologies developed prior to the EPS, and whether System Benefits Charges (SBC) funds are allowed in the respective utility's tariff.

In response to the third question, the CEWG analyzed over 140 projects funded by EPS revenues or used to obtain credits under the provisions of the EPS. All except two of these are photovoltaic installations, which range in size from 0.5 kW residential projects to utility scale projects greater than 2 MW in capacity. The analysis also included two large projects using other renewable energy technologies – an industrial-scale solar hot water facility and a 5 MW landfill gas project.

The benefits analysis carried out by the CEWG quantified, where possible, with certain assumptions, the benefits of photovoltaic, solar hot water, and landfill gas projects, and compares those benefits with project costs experienced through the end of 2002 based on information developed in the Cost section of the report. The benefits analysis also calculated net benefits (i.e., benefits minus costs), and found that the solar hot water and landfill gas projects that were analyzed exhibit positive net benefits while the photovoltaic projects exhibit, in the aggregate, net costs.

The CEWG calculated an approximate $0.11/kWh net simple cost premium for photovoltaic projects installed through 2002. This is an estimate of the premium, based upon actual simple costs incurred by the utilities as presented in the Cost section of this report, for the aggregate of all solar electric projects in excess of quantifiable benefits. Although there are only 18 months of data, the CEWG concludes this figure is a reasonable portfolio cost kWh impact or net cost benchmark for the Commission to use as a tool to evaluate the simple cost of future EPS projects in the aggregate. Our recommendation that this value be used is further based on our conclusion that TEP and APS have acted carefully in the selection, design, installation, and operation of their renewable generation resources, and have reasonably managed EPS financial resources.

However, the above simple net cost premium benchmark does not include any financing costs associated with the photovoltaic projects, since projects have been directly funded by customers through the surcharge and system benefits charge. If the Commission adopts or encourages another financing method, then a premium for the financing costs would have to be added to the above benchmark for comparison. Additionally, the benchmark does not include operating and maintenance (O&M) costs for the renewables since they are currently not available. It may be reasonable to include such costs when information is available.

OPTIONS:

The options below do not quantify cost impacts nor quantify the impact on monthly customer bills. This is essential in the Commission's consideration of any of these options. The options are not listed in any order of priority, nor are all parties that participated in the CEWG in agreement with each of these options. Each option recognizes that considerable progress that has been made in just 18 months and that the standard should continue.

Option 1 – Take no action at this time and leave the annual renewable energy target at 0.8 percent of retail energy sales for all LSEs until a future review determines that either EPS funding is sufficient, or solar generation costs have declined to the point for EPS program success for all LSEs at the 0.8 percent level, then increase the program percentage to 1.1 percent.

With the current funding levels, reductions have been achieved in the simple costs of solar generation over the last 18 months. Further progress will be made in achieving cost reductions in solar generation installations at the current funding levels. Some parties believe that additional funding will not significantly increase the reduction in installed costs.

The costs of solar generation are still considerably above market costs and the level of funding provided by the EPS is insufficient to allow any utilities to meet the 0.8 percent renewable goal within the EPS time frame. While the simple net cost premium benchmark may be appropriate to measure progress in cost reductions in simple terms, it does reflect the true premium that customers would have to pay in rates to support the EPS. Under traditional ratemaking, whether the costs are recovered through base rates, SBC or a surcharge, the rates put in place would recover capital costs, O&M and financing costs (including a reasonable return.). Therefore, the true costs to customers will be considerably more.

In light of this and the goals of the EPS—to achieve fuel diversity, reduce environmental impacts, and reduce the costs of renewables to competitive levels—some parties believe that the benefits realized by customers are not sufficient at this time to warrant an increase in the EPS percentage or the EPS funding. Nor do they warrant incurring any financing or other costs that would further increase the cost of renewable energy generation and costs to customers. Continuing the EPS at the 0.8 percent level will provide continuity and market certainty. Therefore, the current funding from customers and the 0.8 percent annual renewable energy target should be retained under the following guidelines:

- All LSEs should continue to provide their best efforts with available EPS funding to reduce the cost of renewable energy development.
- The EPS program's progress should be reviewed in three years by the Commission to determine if the 0.8 percent annual renewable energy percentage goal should be retained or increased to 1.1 percent and the timeframe for the increase.

<u>Option 2 – Continue the renewable energy requirement increase to 1.1 percent by 2007.</u>

Option 2 is to continue the increase in the EPS percentage requirement to 1.1 percent by 2007. This option recognizes that considerable progress in installing and utilizing renewable energy projects has been made, as summarized below.

The EPS has led to a diversity of renewable energy projects, both in size and technology, and the projects have improved confidence that these technologies can play a significant role in a diversified Arizona energy portfolio. By the end of 2002, the LSEs installed approximately 6 MW of solar electric generation as a direct result of the EPS Rule - more than in the 20 years prior to Rule approval. Under the EPS, the LSEs have plans to expand their solar electric and other renewable energy projects by more than 2 MW in 2003.

The cost and benefit analyses show that the solar hot water and landfill gas projects pursued to date result in positive net benefits. In addition, the extra credit multipliers and tradable credits are working.

The cost analysis has demonstrated that costs of photovoltaic technologies have declined significantly. The CEWG has not identified any persistent obstacle to continued long-term declines in costs. CEWG analyses show the simple cost premium for PV projects is relatively small - only about $0.11 per kWh, taking into account the Surcharge funding mechanism which eliminates utility financing charges (and recognizing there will be some O&M costs in the future). Also, it is significant that by maximizing use of the extra incentives, at least one utility, TEP, has designed a business plan that is likely to achieve the 1.1 percent goal by 2012 or earlier.

The best way to maintain this progress is to continue the percentage increase to 1.1 percent as set forth in the Rule. Further, continuing the percentage increase to 1.1 percent recognizes the importance of building market certainty, which is viewed by some as critical to encouraging a true market-based renewable energy industry, to achieving lower costs, and to Arizona becoming a major renewable energy market.

As discussed in the Status of Implementation section, there is a mismatch between when funds are available to the LSEs and the annual required generation goal. Therefore, to meet the 1.1 percent requirement, some parties believe making other sources of funds available to the LSEs can substantially shorten the time needed to achieve renewable generation goals set forth in the Rule. This approach will ensure that the utilities have options for LSE financial resources beyond the EPS Surcharge, and that prudent use of these funds to meet Rule goals will be encouraged by the Commission. Thus, to enhance the likelihood that the 1.1 percent goal can be achieved, the

Commission should adopt the policies set forth below. Each of these policies can be pursued without modifying A.A.C. R14-2-1618.

- Utilities should be directed by the Commission to actively seek additional leveraging opportunities such as buying down customer-sited photovoltaic facilities or partnering with municipal or other entities to install photovoltaic equipment on their premises. In this way, customers will pay for part of the costs of the facilities, thereby stretching the dollars available from the Surcharge and System Benefits Charge to meet the EPS requirements. In sum, this approach would encourage projects that leverage investment by property owners or project developers.

- If the LSEs remain concerned that Surcharge funds are not sufficient to meet the 1.1 percent requirement, the utilities should have the option to request Commission approval of an accounting order authorizing the utilities to create a deferral account for the inclusion of expenditures of the EPS projects in excess of the current approved funding. An accounting order approving deferrals would allow the utilities to record expenditures in accordance with Generally Accepted Accounting Principles. Surcharge or other revenues received in excess of a given year's costs should be credited against the deferral account. A reasonable return would be included in the provisions for a deferral account. The recovery of the deferred expenditures would be addressed in a future rate case or through the establishment of a Commission-approved surcharge mechanism for the respective utility. If directed by the Commission, Staff could pre-approve new projects for which cost recovery would be allowed.

- To properly account for the costs of meeting EPS requirements, the Commission should recognize that only the costs in excess of capacity and energy costs displaced by EPS resources and included in rates (or recovered through a purchased power and fuel adjustor mechanism) are to be considered as EPS costs. Utilities should recover the costs of conventional energy and capacity through their authorized rates, and the Surcharge and System Benefits Charge should only be put toward recovering EPS costs above the costs already included in rates or to be included in the future.

- To encourage market certainty, the Commission should explicitly allow utilities to enter into long-term purchase obligations having a term of more than four years and provide for cost recovery.

APPENDICES

Appendix 1
SOURCES AND USES OF FUNDS

Table A1-1
APS Revenues and Expenses for Renewable Energy Projects

Utility Annual Funds Usage ($1,000)	1997	1998	1999	2000	2001	2002
Revenues						
Corporate investment (1)	$0	$0	$0	$0	$0	$0
Other agency funds (2)	$0	$0	$0	$0	$0	$0
APS salaries/administration/misc. O&M	$792	$640	$305	$1,238	$449	$762
System benefit charge	$3,000	$3,000	$3,000	$6,000	$6,000	$6,000
EPS Surcharge	$0	$0	$0	$0	$4,694	$6,572
Investment tax credits at 10% of purchases	$0	$0	$0	$0	$0	$0
Sale of landfill gas credits	$0	$0	$0	$0	$0	$0
Green pricing program revenues	$78	$50	$263	$419	$348	$259
EPS system electricity sales revenue	$0	$0	$0	$0	$0	$0
Annual Total Revenues	$3,870	$3,690	$3,568	$7,657	$11,491	$13,593
Running Revenue Total	$3,870	$7,560	$11,128	$18,785	$30,276	$43,869
Expenses						
Large, utility-size project	$1,278	$778	$1,003	$3,189	$6,751	$7,930
Residential & commercial program installations	$722	$624	$768	$1,259	($35)	$424
New technology development	$347	$2,021	$1,660	$61	$997	$544
Loss of revenue from PV self-generation (3)	$0	$0	$0	$0	$0	$0
Additional loss of revenue from PV net metering	$0	$0	$0	$0	$0	$0
Purchase of EPS credits	$0	$0	$0	$0	$518	$1,435
Property taxes	$0	$0	$0	$0	$0	$0
Operations and Maintenance	$650	$421	$366	$745	$1,107	$1,149
Insurance	$0	$0	$0	$0	$0	$0
Other renewable programs (landfill, wind, GreenWatts)	$0	$0	$0	$34	$11	$1,309
Program salaries/administration/misc. O&M	$792	$640	$305	$1,238	$449	$762
Annual Total Expenses	$3,789	$4,483	$4,101	$6,526	$9,799	$13,553
Running Expense Total	$3,789	$8,272	$12,374	$18,900	$28,698	$42,251

Notes:
1. Corporate investment includes purchase or development of companies producing renewable energy products or services, development or investment in renewable energy projects, and matching funds used to gain access to other agency (such as DOE or AZ Energy Office) dollars.
2. Other agency funds includes dollars won through competitive solicitations and should list amounts provided as matching funds.
3. Includes loss of transmission and distribution revenue from generation of electricity by residential/commercial participants.

Table A1-2
TEP Revenues and Expenses for Renewable Energy Projects

Utility Annual Funds Usage ($1,000)	1997	1998	1999	2000	2001	2002
Revenues						
Other agency funds (1)	$0	$0	$0	$86	$0	$5
System benefit charge	$210	$210	$210	$1,710	$1,810	$2,010
EPS Surcharge	$0	$0	$0	$0	$2,025	$2,440
Investment tax credits - 10% capital cost	$0	$0	$0	$0	$990	$702
Sale of landfill gas credits	$0	$0	$0	$0	$379	$765
Green pricing program revenues	$0	$0	$0	$0	$27	$68
EPS system electricity sale revenue	$0	$0	$0	$0	$205	$117
Annual Total Revenues	$210	$210	$210	$1,796	$5,436	$6,107
Running Revenue Total	$210	$420	$630	$2,426	$7,862	$13,969
Expenses						
Large, utility-size project	$0	$0	$0	$1,410	$8,439	$7,018
Residential & commercial installations	$35	$90	$50	$13	$15	$64
Revenue loss - PV self-generation (2)	$4	$4	$4	$5	$5	$6
Revenue loss - PV net metering	$0	$0	$0	$0	$0	$0
Purchase of EPS credits	$0	$0	$0	$0	$0	$0
Property taxes	$0	$0	$0	$0	$0	$20
Operations and Maintenance	$0	$0	$0	$0	$0	$51
Insurance	$0	$0	$0	$0	$0	$9
Other renewable programs (3)	$85	$0	$85	$30	$40	$72
Annual Total Expenses	$124	$94	$139	$1,458	$8,499	$7,240
Running Expense Total	$124	$218	$357	$1,815	$10,314	$17,554
Administration salaries - estimated	$70	$120	$125	$180	$185	$230

Notes:
1. Other agency funds includes dollars won through competitive solicitations and should list amounts provided as matching funds.
2. Includes loss of transmission and distribution revenue from generation of electricity by residential/commercial participants.
3. Landfill gas, wind, and green power programs

Appendix 2
BENEFITS SECTION

Avoided Air Emissions Data

Table A2-1
TEP System Emission Factors

	lb/MWh-net					
Year	SO_2	NO_x	CO_2	PM	CO	Net MWh
1997	6.5550	4.6700	2,207	0.1324	0.2767	10,608,243
1998	5.9545	4.6528	2,238	0.1025	0.2563	10,849,048
1999	5.2503	4.4748	2,193	0.1128	0.2673	11,231,626
2000	5.0731	4.3773	2,152	0.1533	0.2671	11,936,146
2001	4.8197	4.3651	2,150	0.0889	0.2711	12,151,804
Wtd. Avg.	5.4992	4.5013	2,187	0.1179	0.2677	11,355,373

Note: All generation from fossil fuels.

Table A2-2
TEP Emissions Deferred by Renewable Generation (tons)

Landfill Gas Generation

Year	SO_2	NO_x	CO_2	PM	CO	Net MWh
1999	57	0	2,106	0	0	14,646.62
2000	171	0	20,489	0	0	43,036.27
2001	184	0	30,617	0	0	46,445.12
2002	129	0	21,529	0	0	31,661.43
Total	541	0	74,741	0	0	135,789

Solar Electric Generation

Year	SO_2	NO_x	CO_2	PM	CO	Net MWh
1999	0.192	0.158	77	0.004	0.009	70.00
2000	0.240	0.196	95	0.005	0.012	87.23
2001	3.144	2.574	1,250	0.067	0.153	1,143.46
2002	10.231	8.375	4,068	0.219	0.498	3,721.00
Total	13.808	11.302	5,490	0.296	0.672	5,022

TEP does not take any credit for reductions in NO_x, PM, or CO emissions from burning landfill gas instead of coal. While there has been a very small apparent reduction in NO_x when burning landfill gas instead of coal, the level is less than the noise of measurement.

Table A2-3
APS System Emission Factors

	lb/MWh-net					
Year	SO_2	NO_x	CO_2	PM	CO	Net MWh
1997	3.1643	3.0792	1,256	0.1755	0.2002	20,663,958
1998	2.8966	3.2491	1,262	0.1749	0.2148	21,639,281
1999	2.5324	3.0490	1,274	0.1783	0.2251	22,482,044
2000	2.2277	3.2378	1,324	0.1857	0.2680	24,133,941
2001	2.3086	3.2077	1,324	0.1831	0.2809	25,503,933
Wtd. Avg.	2.6012	3.1675	1,290	0.1798	0.2401	22,884,631

Table A2-4
APS Emissions Deferred by Renewable Generation (tons)
Solar Electric Generation

Year	SO_2	NO_x	CO_2	PM	CO	Net MWh
1997-2000	2.133	2.597	1,058	0.147	0.197	1,640
2001	1.878	2.287	932	0.130	0.173	1,444
2002	3.856	4.696	1,913	0.267	0.356	2,965
Total	7.867	9.580	3,902	0.544	0.726	6,049

TEP Analysis of Capacity and Energy Effects of
Large Scale Renewable Energy Projects

Although the Arizona EPS has only been in effect a short time, projects installed as a result of the policy are allowing the LSEs to assess the integration of renewable energy into the generation and transmission systems serving Arizona based on actual experience. Among the important questions the LSEs are now able to better investigate are:

- How much generation capacity can intermittent renewable resources contribute to the generation and transmission system?
- How does the intermittent quality of renewable energy generation affect the amount of conventional generation needed to maintain system reliability?
- What amount of intermittent renewable resource capacity could be installed before such generation resources would begin to affect overall system operation?[20]

In addition to the analyses of renewable energy projects on operational capacity and reliability, the LSEs are now able to analyze the effects of national policy on Arizona utilities. Although the EPS projects are small relative to the conventional generation systems serving TEP and APS, they are large in comparison (especially in Arizona) to other renewable energy only projects installed to date. The quality of the operational data from these relatively large renewable energy only projects is especially important to the Arizona LSEs in the context of understanding the impact on individual utilities if a national RPS is enacted. The most common percentage proposed for national RPS legislation is 10 percent, and policy requirements of this magnitude cause concern among utilities. This appendix presents the results of an analysis by TEP based on real photovoltaics project data and measured, wind-site survey data for both photovoltaic and wind energy projects extrapolated to a size sufficient to produce about 10 percent of TEP's 2002 energy needs, based upon actual 2002 hourly retail loads in its service area.

TEP developed three scenarios, as follows:

1. Install 509 MW of **wind generation** in Apache County. Wind data were obtained from monitoring at a 40-meter height, extrapolating the results to 70 meters, and applying the data to a Vestas 660 kW wind machine power curve. Actually installing 772 of these wind machines in 2002 would have cost about $509 million.
2. Install 495 MW (DC) of fixed-angle **PV** generation at the **Springerville** Generation Station. Data on energy output are derived from TEP's 21.6 kW PV unit at Springerville installed in 2000 and extrapolated to the hypothetical 495 MW project. At 2002 prices, such a project would have cost about $2.8 billion.
3. Install 495 MW (DC) of fixed-angle **PV** generation in **Tucson** similar to scenario 2. Energy production is based on the south unit of the two 21.6 kW PV units at TEP's operating headquarters which was installed in 2000.

TEP's major findings from this exercise are discussed below. Figure A2-1 indicates that the AC output of the PV units is slightly less than the DC rating, which is to be expected. Note that the hypothetical Springerville PV project produces slightly more energy and power than the

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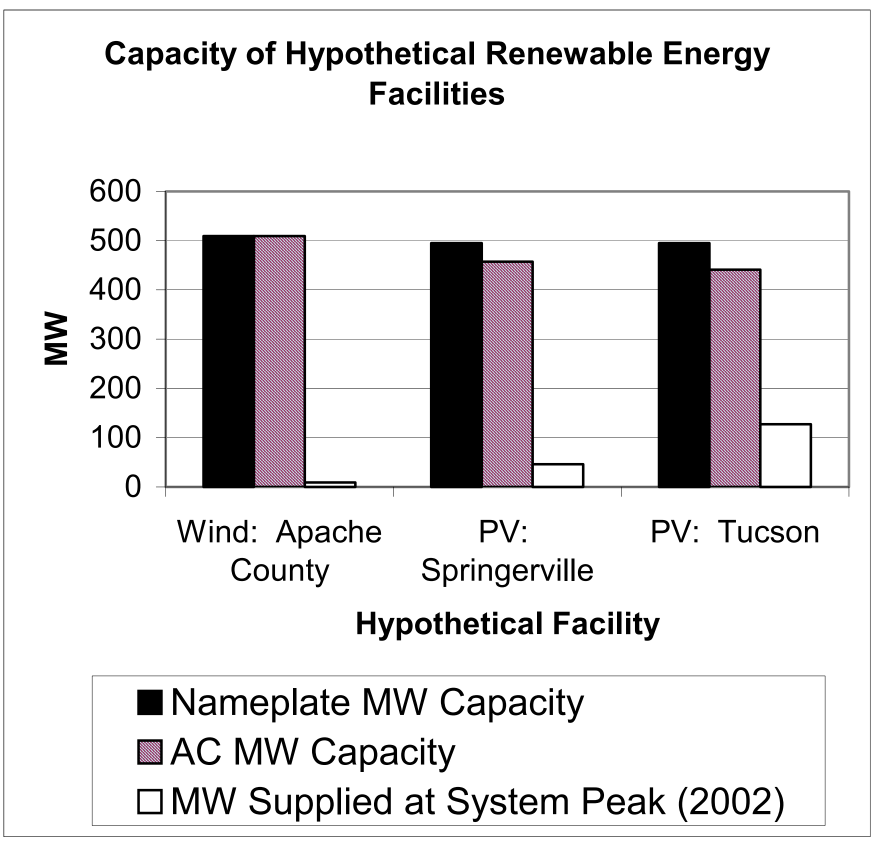
[20] The capacity and reliability impact of intermittent resources would have to be analyzed using a detailed model of each utility's generation and transmission system.

hypothetical Tucson PV project because of insolation and temperature differences between the sites. The graph shows that the capacity available from the hypothetical wind plant at 9 MW was rather small at the hour of TEP's 2002 system peak, but the capacity available from the hypothetical Tucson project would have been significantly higher at 127 MW than the wind project and higher than the Springerville-located solar project capacity available at 46 MW. However, in all cases the capacity benefit of the intermittent resource was much less than the nameplate rating of the project. The conditions at the system peak in 2002 may or may not be typical, and the near absence of wind at the 2002 system peak may or may not be typical. More data gathering will be needed to provide reliable estimates of the capacity values of wind and solar energy. Future analyses should also take into account measures of system reliability (such as loss of load probability, spinning reserve requirements, day ahead unit commitment schedules and/or unserved hours of energy) when assessing the impacts of introducing intermittent resources into the generation system.

By design of the analysis, each of the hypothetical wind and PV projects would have produced about 860,000 MWh in 2002 which is about 10 percent of TEP's 2002 retail load. In 2002, the average spot market price for electricity at Palo Verde was $26.42 per MWh. The average spot market price of energy produced by the hypothetical wind project (if the energy were sold in 2002) would have been $28.41 per MWh. The average spot market price of the energy produced by the hypothetical PV projects (if the energy were sold in 2002) would have been $30.85 per MWh for energy produced at Springerville and $31.27 per MWh for energy produced at Tucson. The PV energy is regularly produced during on-peak hours in the summer and hence would have commanded a higher price than energy produced from wind projects at night during off-peak hours.

Figure A2-1



TEP Balance of System Cost Reduction Detail

The implementation of a multi-year, pay-as-you-build funded EPS allows for development of "cookie cutter" PV system designs. These designs must be of a size to take advantage of partnering opportunities with the manufacturers of the major components of PV systems to optimize BOS costs through both material and installation labor cost reductions.

Electrical costs represent a significant portion of the BOS costs of a utility-size PV system. Development of cookie cutter PV system designs can maximize the amount of connected PV capacity per electrical connection point and reduce electrical costs per DC watt. TEP used the following design approaches to reach the BOS cost goal:

- Components were chosen to take advantage of the National Electrical Code provisions that allow system voltages to be distributed at values that preclude a need for special voltage equipment or wiring.
- High current carrying cable sections were optimized with respect to distance to reduce costs of expensive, large copper cables.
- Because electric equipment is manufactured with a certain class of current capacity, the equipment cost generally increases exponentially with the current carrying capacity. Thus, use of smaller current carrying capacity equipment reduces overall costs, especially when installation labor is included in the cost analysis. The same effect applies for wire and conduit.
- Optimized designs were established to minimize voltage drops on long runs of DC wiring.

The multi-year funding attributed to the EPS policy, allows the utilities to plan for installing numbers of large, utility-scale systems. Such planning can use the design concepts listed above and others in the design phase to reduce the cost of both the DC and AC wiring systems. For instance, with certain types of PV modules, a single DC electrical trunk connection can be made for more than 5 kWp of PV modules. This dramatically reduces the cost of the DC electrical trunk system. Likewise, the AC side of a 480 volt, 200 amp system is nearly perfectly matched to the code requirements of a 150 kVA inverter, and is the lowest cost 480 volt interconnection possible to a high capacity AC grid. Using skilled union labor, proper design of the electrical system and proper construction staging can reduce installed cost to less than $0.30 per DC watt of PV capacity for the electrical portion of a utility-scale PV system.

Likewise, the EPS multi-year approach allows for design optimization of the PV array support structure. Most utility-scale PV systems will likely be installed where there is more land area than is required. In this instance, advantage can be taken of the extra land in optimizing the support structure design. Also, the support structure design can be simple and maximize the PV capacity installed. Support structure design can also be optimized by efficient use of raw material, utilizing coating systems available for the dry Arizona climate, using off-the-shelf construction components, and simplifying designs to allow use of low-cost assembly crews. Supports can also be designed to match a particular PV module to take advantage of the PV module frame rigidity. Again, a multi-year EPS helps LSEs develop long-term commitments with PV module makers to take advantage of partnering opportunities on structure development. This opportunity is not possible with year-to-year EPS programs. Support structure installed costs as low as $0.15 per DC watt of PV capacity have been demonstrated after only one year of experience in developing improved construction designs and methods.

A multi-year EPS allows for developing relations with inverter manufacturers to standardize large utility-scale inverters and their support software and infrastructure. The result is that cost of inverters and inverter installation support components and tooling is reduced. Utility-scale PV inverters with 99+ percent reliability, 96+ percent conversion performance and sophisticated service features can now be purchased for less than half the cost/DC watt of smaller PV inverters. Installed costs of utility-scale inverters and support software and infrastructure are now less than $0.40 per DC watt of PV capacity.

In addition, ground preparation and grid connection work for a utility-scale PV system can be done in sections, allowing for modular construction planning and associated efficiencies of construction. Preparation for the initial phase of the SGS Solar System included blocks for the interconnection of 24 systems, each of 150 kVA size, for a total of 3,600 kVA AC rated capacity. The ground prep and grid connection work was completed at a cost of less than $450,000. If it is assumed that each block will have a DC capacity of 135 KW, the installed cost is $0.14 per DC watt. This includes all surface preparation, underground conduit, concrete foundations, high voltage wiring, high voltage disconnects, soil stabilizer, transformers and grounding to a power plant specification. Based on this experience, the second SGS installation phase includes blocks for 20 more 150 kVA units and is expected to cost less than $270,000, at a cost of $0.10 per DC watt.

The TEP SGS solar electric installations have determined that data collection systems, metering, and connection to the Internet, again optimized for utility scale systems have an installed cost less than $1,000 for a 150 kVA system which results in a cost of less than $0.01 per DC watt.

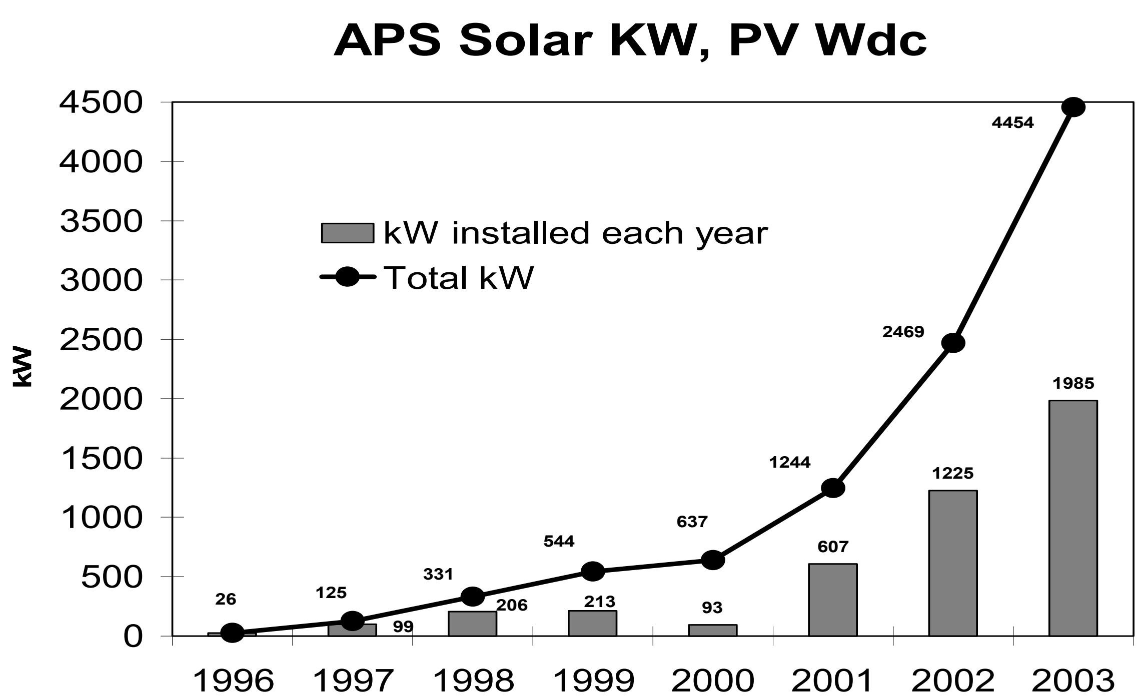
Arizona Public Service Company
Benefits of the Environmental Portfolio Standard

Introduction

Under the EPS, APS has significantly increased its pace of solar installations to well over a megawatt per year. The unit costs of solar have been substantially reduced to under \$6000/kWac, and innovation and use of new solar technologies with lower cost potential has expanded. Solar dish engine work is continuing, and APS is in final contract discussions for a 1 MW solar trough, which would be the first commercial solar trough project used for electricity production since 1989.

In addition, several megawatt-scale biomass and geothermal generation projects are now under development by APS. These "other" renewable projects can play a valuable role to add some lower cost renewable energy into the EPS mix to increase progress toward the EPS goal and to utilize available resources, while solar installations, improvements and cost reductions still continue for greater long-term deployment.

Figure A2-2



Grid-Tied Solar Installations

From 1997 through 2002, APS completed several PV projects on the order of 100 kW around the state in locations visible in the community. These sites included APS STAR at the Ocotillo Power Plant in Tempe, APS Service Center in Flagstaff, Glendale Airport, Gilbert Nature Center, Embry Riddle Aeronautical University in Prescott, APS Yucca Power plant in Yuma, and the Water Campus in Scottsdale. Also, 22 rooftop systems were installed on customer premises ranging from 2 kW under the educational Project Sol, to larger systems under special commercial relationships with the City of Scottsdale, ST Micro, and the new Arizona Department of Environmental Quality (ADEQ) building owners.

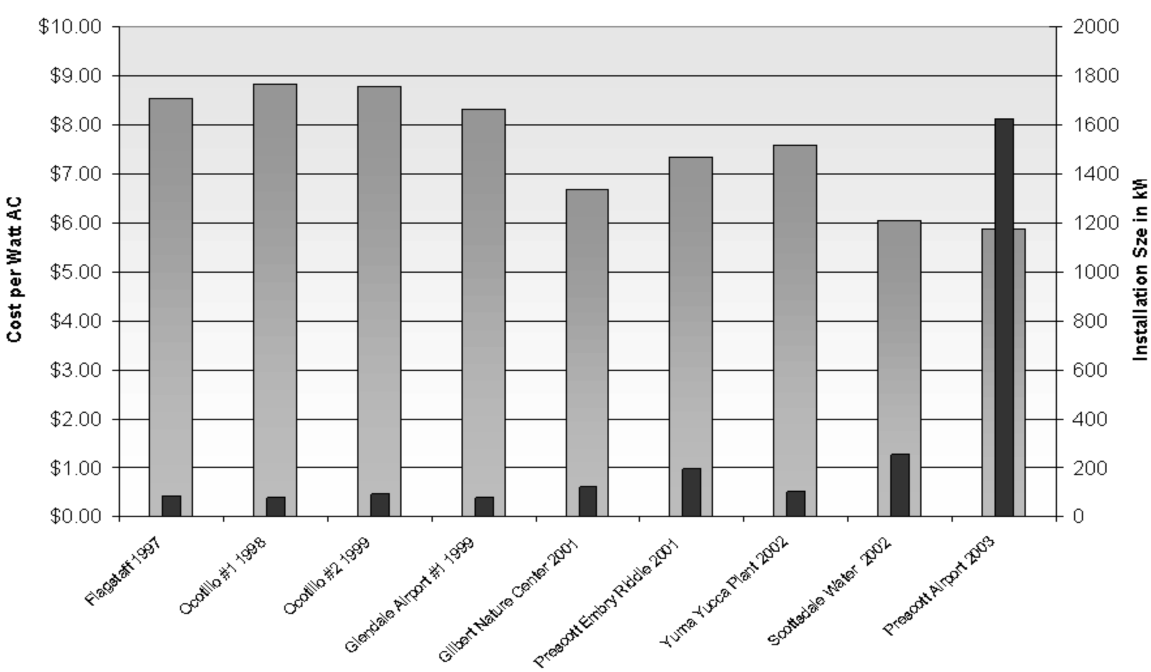
In 2003, to prepare for a more rapid pace of installations for solar, a new large project site was developed adjacent to the northeast corner of the Prescott Airport. This site will allow over 5 MW of solar power to be installed. The solar plant operations will benefit from the clearer skies and cooler temperatures of this area compared to sites in the Phoenix valley. Over 1,500 kW have been installed in the first six months at this site, and the entire build-out to 5 MW is expected to be completed in the next three to five years.

As APS installations grow, customers are also provided an opportunity to install their own solar system and receive a $2000/kW rebate from APS. Although the cost of solar is still high enough to prevent most customers from purchasing their own system, this provides a significant savings for those who chose to install solar. As of the end of 2002, 121 homeowners and institutions have taken advantage of this program. To date, this program totals 235 kW of PV installations. In addition, more than 60 installations were supported for Native American homeowners on the Hopi Reservation totaling 17.3 kW.

Solar Cost Reductions and Projections

To improve kWh output, APS has helped develop a very efficient 1-axis PV tracker design. At very low added cost, the tracker produces 10-20 percent more energy from the PV modules, lowering the cost per kWh. During the summer months when the power is most needed, the output is 50 percent more than a fixed system. A new APS Tilted Tracker$_{tm}$ design with even higher energy output is now being fielded initially for off-grid use. Its cost/benefit for grid-tied use will be evaluated.

Figure A2-3
APS Installation Costs for PV Tracking Systems
(System kW size is indicated by black bar.)



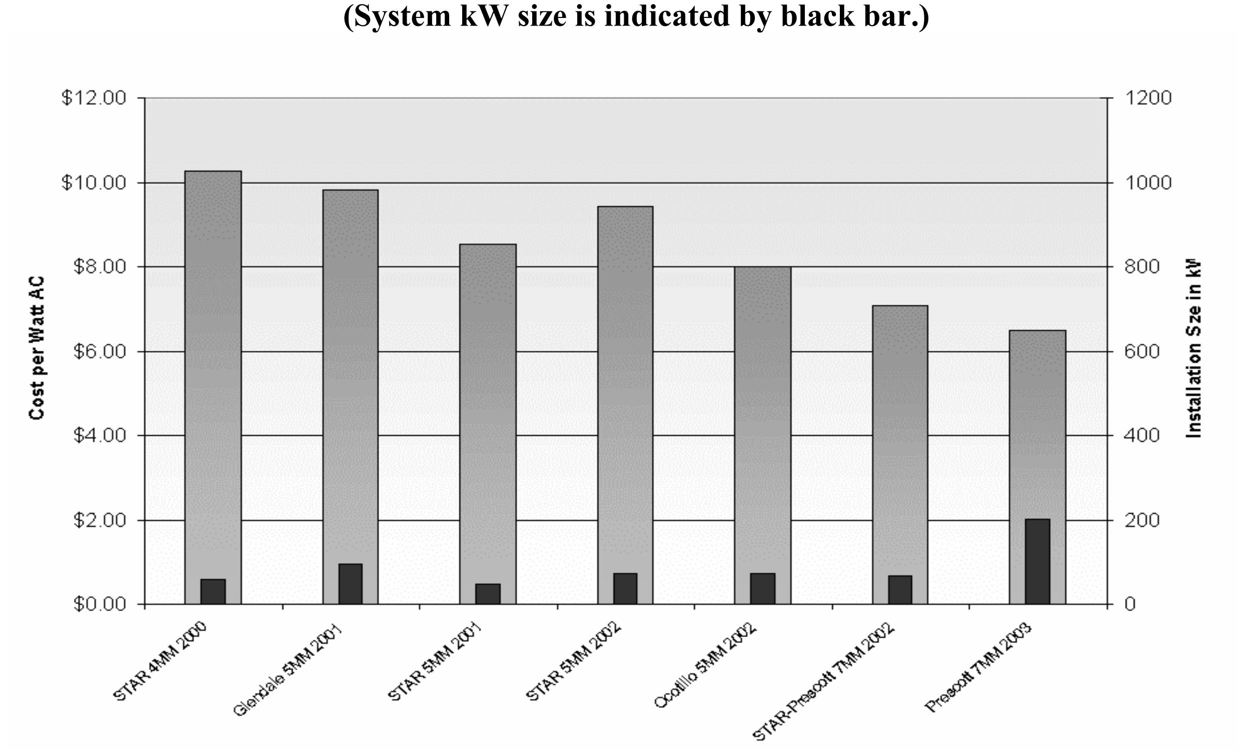
Other large PV system installers such as Salt River Project have followed APS' lead in the use of trackers, and now Powerlight of California has adopted the tracker design that APS helped develop, and is promoting it for its large utility sales.

APS installed costs for solar photovoltaic (PV) systems have declined from $8,800/kWac to $5,900/kWac, a decrease of over 33 percent over a five-year period. These cost reductions have been achieved at the same time as kWh output performance of the PV modules has been increased by 10-20 percent through the use of single-axis tracking systems that APS has helped develop. However, the EPS goal of over 1 percent energy to be derived from solar and other renewables by 2007 still cannot be met without increasing the surcharge, or further dramatic cost reductions in solar, or the increased use of non-solar renewables, or some combination of these.

To help drive its costs down, APS has assembled an engineering and technical team that works with local and national industry specialists to design projects. APS then often acts as the general contractor to procure and construct using local contractors whenever feasible. Although APS has created its own systems design and installation management capability, it has not chosen to create a separate "PV systems company" in order to avoid creating external competition with existing companies. APS also tests and debugs new solar products at the APS Solar Test And Research facility (STAR) prior to its use at a larger scale or in service to customers.

Cost reductions in PV have come from a combination of increased project sizes, decrease in PV module market prices, and improvements in "balance of system" design which includes the electrical, structural, and installation costs. With this process, most of the "balance of system" cost reduction opportunities now have been achieved, and so the largest remaining area for cost improvements lie in the PV modules.

Figure A2-4
APS Installation Costs for Concentrating PV Systems
(System kW size is indicated by black bar.)



APS has installed and operates the largest Concentrating PV (CPV) system in the world, which will total over 500 kWac by end of 2003. Although still in development and produced at a very small volume, CPV has already achieved costs comparable to conventional PV. New multijunction PV cells from the spacecraft industry have efficiencies of 30-40 percent, and are now being designed into utility CPV systems. At volumes of 5-10 MW/year, installed costs of CPV are projected to be in the $3,000-$4,000/kWac range.

Dish-engine development and testing also continues and the technology is improving, with new systems now being planned that should resolve the operating problems of the past. Also there is resurgence in the solar thermal trough industry, with APS planning a 1 MW "modular" project that will help the solar trough product fit into more markets.

The solar dish and solar trough technologies are thermal-mechanical systems that offer additional benefits of energy storage and fuel-supplement operation. These features are essential to provide the load-following "dispatchability" that will become critical for utility use as renewables grow to hundreds or perhaps thousands of megawatts in size.

To help leverage federal resources toward the goal of lower costs concentrating solar systems for use in Arizona, APS is entering into collaboration agreements with the National Renewable Energy Lab (NREL) and Sandia National Labs. Cost reductions and field validations still need to be completed for these technologies to meet EPS goals as well; however, the potential for solar thermal systems to subsequently be used at larger scales appears very good.

<u>Non-Solar Renewables</u>

Non-solar renewables, such as biomass and wind, are indirect forms of solar energy that are available but do not offer the potentially huge and consistent resource for Arizona that is offered by the direct use of the sun's energy. However, geothermal, biomass and wind are more mature technologies that presently have costs substantially lower than solar.

Recently, the dramatic and disastrous loss of Arizona's forest trees to drought and infestation has created an immediate imperative toward consideration of wood wastes as renewable fuel. In the near term, the use of wood wastes for energy can help resolve the critical need to thin the forests and dispose of the very large amounts of wood fuel in an environmentally sound manner.

APS is investigating the need to expand its typical right-of-way (ROW) clearing programs in light of the bark beetle infestations. An extensive thinning program on both sides of APS' ROW is being investigated. The standard annual thinning effort has typically removed 10,000 tons of material. The proposed expansion of forest thinning along the APS transmission ROW will more than double the millions of dollars already being spent and is expected to add a total of 53,000 tons of biomass over the next three to five years. Currently, this material is being chipped and blown back onto the forest floor or collected for controlled burns in clearings.

The amount of biomass material that will have to be collected and disposed of for the foreseeable future is more than can be processed. APS is one of several organizations investigating multiple alternative technologies to help mitigate the forest biomass problem. Alternatives include biomass to energy power plants; lumbering of small-diameter logs with a MicroMill; and converting the biomass into a liquid with multiple co-products being refined for commercial sale.

The energy costs from wood-waste projects and the large quantity of wood available would help meet EPS goals in the near term if a higher contribution of kWh to the EPS is accepted.

Public Involvement and Economic Development

APS provided the first solar energy purchase program to customers in the state, the APS Solar Partners Program. This program, important for its involvement of customers more so than its revenue, continues to grow. Other utilities in Arizona soon followed and created their own "green pricing" programs.

APS placed all of its early projects in a variety of visible community locations. These range from Flagstaff to the Mexican border, from rooftops to 100 kW fields, including tracking-PV systems and fixed-PV rooftops. This took more effort by APS but it has enhanced critical public awareness and understanding of solar, involved the communities, addressed siting issues, and facilitated the process of innovation. Though the new APS Prescott Airport Site as a single large, cooler high elevation site with clear skies has known production and cost advantages, APS siting diversity has clearly enhanced involvement of customers, industry, and researchers.

In conjunction with each installation, APS has held dedications to which the public is invited. As many as 300 people have attended these events including key state and community leaders such as the Governor of Arizona. These events also include education information about the project as well as general information about solar and other renewable energy along with electric and hydrogen fueled vehicles. APS also regularly opens its Solar Test and Research Facility to the public so they can learn about and see solar and other renewable technologies in operation.

On the education front, APS also maintains an educational web site called Project SOL. At this site students can learn about how photovoltaics works and see graphical presentation of the actual performance of similar PV systems installed throughout the state. These PV systems were donated by APS to educational facilities such as the Challenger Learning Center and Lowell Observatory and included educational information for visitors. APS also participates in numerous outreach efforts such as the Southwest Renewable Energy Fair to educate the public about renewable energy.

APS also has supported Arizona companies. First, APS uses in-state engineering and manufacturing whenever practical, in combination with experts from around the world. This has yielded new designs and manufacturing in solar structures, trackers and controls, with new inverter designs now in development.

In addition, APS has helped attract an internationally established inverter/systems company to open an office and hire technical staff in Arizona. This company is filling inverter needs not met by other suppliers, and has created a U.S. company in order to serve the United States and other markets.

Appendix 3
APS SOLAR PARTNERSHIPS

Type of Partnership	Partner	Type of Installation	Size	Description
Private	ST Microelectronics	Building integrated rooftop PV	25.7 kW	ST Micro is APS' largest commercial solar partner. The site was provided at no charge to APS by ST Micro.
City	Scottsdale	Rooftop PV	3.6 kW	APS installed 2 PV systems on the roof of Scottsdale's libraries.
City	Scottsdale	PV Covered Parking	93.3 kW	Scottsdale provided the parking structures so APS could install these integrated PV modules. A first for Arizona.
City	Scottsdale Water Campus	Tracking PV on water storage tanks	300.6 kW	The Scottsdale Water Campus had allowed APS to use this space on top of its water storage tanks to install PV systems. A first of its kind.
City	Glendale Airport	Tracking and high concentrati on PV systems	204.1 kW	Using land on which other structures can't be built, Glendale partnered in this project to help reduce the installation cost.
City	Gilbert	Tracking PV	144 kW	PV system was installed using land near the migratory waterfowl nature center.
City	Prescott Airport	Concentrati ng and single axis tracking	Currently 746 kW Up to 5 MW	Developing what could potentially be the largest PV installation in Arizona.
City	Tempe Recycle Center	PV shade canopy	2.4 kW	Tempe recycling center provided the site for this PV Shade Canopy.
State	Arizona DEQ	PV Covered Parking	127 kW	Provided shade structures for the installation if this system at the new LEED-certified state office building.
Federal	Yuma Proving Grounds	Remote Hybrid PV system	107.1 kW	Assisted Yuma Proving Grounds in the design, building and operation of this system to provide power at the Smart Weapons Testing Range.
Educational	Embry Riddle Aeronautical University	Tracking PV system	228.5 kW	ERAU provided land for our first Prescott large-scale PV installation.
Educational	Project SOL educational facilities	Rooftop PV systems	12 kW	Five rooftop systems installed on customer sites with performance collected electronically and displayed though the APS website.

Appendix 4
ARIZONA'S ENVIRONMENTAL PORTFOLIO STANDARD RESULTS
(in kWh)

	2001	2002
Arizona Public Service		
Solar Electricity	17,237,202	9,126,664
Solar Hot Water*	6,241,328	2,208,334
Solar Air Conditioning	--	--
Landfill Gas*	11,307,931	44,938,574
Biomass	--	--
Wind	--	--
Total	34,786,461	56,273,572
	(99.1% of requirement)	(59.68% of requirement)
Tucson Electric Power		
Solar Electricity	2,990,538	9,006,169
Solar Hot Water	--	--
Solar Air Conditioning	--	--
Landfill Gas	6,884,068	16,024,836
Biomass	--	--
Wind*	--	388,070
Total	9,874,606	25,419,075
	(71.7% of requirement)	(79.31% of requirement)
Citizens Communications		
Solar Electricity	152,000	39,000
	(6% of requirement)	(1% of requirement)
Navopache Electric		
Landfill Gas*	150,000	644,377
	(50% of requirement)	(50% of requirement)

* Indicates purchase of tradable credits from another party.

Appendix 5
COST EVALUATION WORKING GROUP MEMBERS

ORGANIZATION	REPRESENTATIVE	ALTERNATE
AZ Community Action Association	Mary-Ellen Kane	
Arizona Clean Energy Industries Alliance	Robert "Bud" Annan	
Arizona Electric Power Cooperative, Inc.	Romi Carrell Wittman	John Wallace
Arizonans for Electric Choice & Competition	Mike McElrath	
Arizona Public Service Company	Cassius McChesney	Bentley Erdwurm
Arizona Solar Energy Industries Association	Michael Neary	Sean Seitz
Citizens Communications	Raymond Mason	Rebecca Weber
Grand Canyon Trust	Rick Moore	John Gaglioti
Kyocera Solar, Inc.	Cecilia Aguillon	
Land and Water Fund of the Rockies	David Berry	
Navopache Electric Co-op., Inc.	John Wallace	Dennis Hughes
City of Phoenix	Bill Murphy	
Renewable Energy Leadership Group	Phil Key	
Residential Utility Consumer Office	Tim Coley	Marylee Diaz Cortez
City of Scottsdale	Chuck Skidmore	
Sierra Club, Grand Canyon Chapter	Sandy Bahr	
Southwest Windpower	Andy Kruse	David Calley
Tucson Electric Power	Tom Hansen	David Couture
City of Tucson	Vinnie Hunt	
Arizona Corporation Commission Staff	Ray T. Williamson	Barbara Keene

Visitors participating in various Working Group or Committee meetings:

NAME	ORGANIZATION
Al Bellac	Sempra Energy Resources
Mike Boyd	Western Wind
Steve Chalmers	PowerMark
Bob Durham	Solar Focus
Robert Franciosi	Goldwater Institute
Lane Garrett	ETA Engineering Inc.
Lori Glover	Stirling Energy Systems Inc.
Bob Hammond	ASU/APS
Herb Hayden	APS
Peter Johnston	APS
Barb Klemstine	APS
Ray Kosanke	Global Solar
Paul Li	Office of Bob Lynch, Attorney
Tim McDonald	Pinnacle West
Paul Michaud	Navopache Electric Co-op Inc.
Daniel Musgrove	Universal Entech
Tod O’Conner	O’Conner Consulting Services
Mike Pasqualetti	ASU
Patrick Rowe	Squire, Sanders
David Rowley	Solar Farms
Paul Symanski	
Lee Tanner	ElectriSol
Jana Van Ness	APS
Jim Wontor	APS