Potential Economic Benefits of Distributed Photovoltaics to the Nevada Power Company

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Executive Summary

The objective of this report is to calculate the potential economic benefits of distributed photovoltaics (PV) to the Nevada Power Company (NPC). The benefits that are presented in this report include T&D savings and energy savings benefits. There are other distributed benefits that are not included in this report.

To determine these benefits, the electric distribution system is divided into four distribution planning areas: Outlying Areas, New Development, the Strip, and Infill. For each of these areas, potential T&D capital deferral benefits on a per kW basis are calculated based upon forecasted load growth, historic capital investment streams, and NPC financial data, and these are combined with O&M cost savings using historic O&M costs allocated to these areas. Avoided energy costs are calculated based on wholesale energy costs at Mead/Marketplace.

As shown in Figure 1, the results indicate that the average potential benefits are $1,550 per kW of PV and that the highest potential benefits are obtained in the Outlying areas at a value of $2,142 per kW of PV. The value of a distributed PV system in the Outlying areas is more than 62 percent greater than the value of a central station plant ($1,322/kW). In addition, the benefits from a 1-axis tracking system are more than one-third greater than the benefits from a 10° tilted south-facing fixed system (see Figure 2).

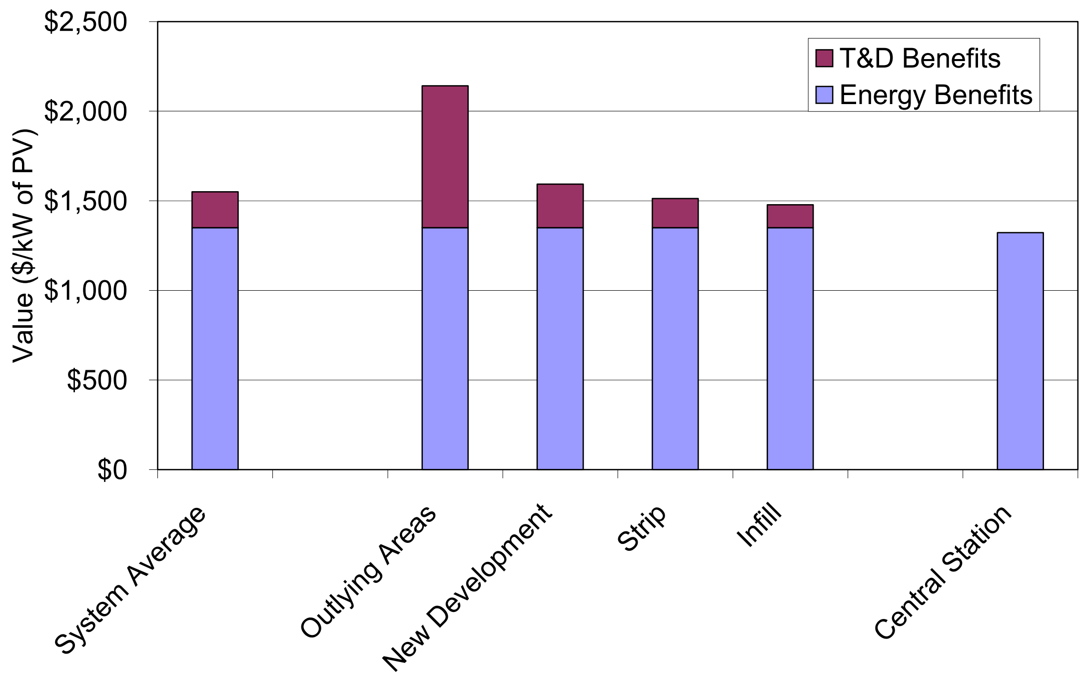

Figure 1. Total benefits (1-axis tracking system).

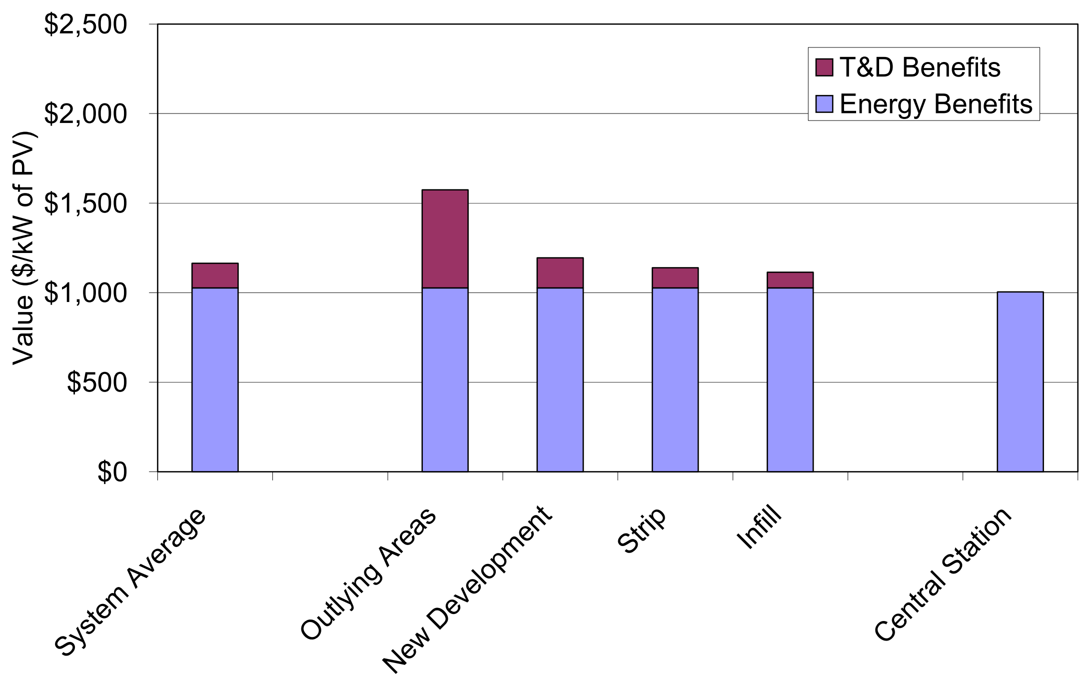

Figure 2. Total benefits (10° tilted south-facing fixed system).

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Introduction

This report evaluates the potential economic benefits to the utility associated with T&D capital investment deferral and energy benefits of distributed PV systems. Excluded from this analysis are potential benefits related to system performance, reliability and security, environmental protection, price risk mitigation, and other benefits. Also excluded are any costs associated with the installed PV systems since the objective of this report was to focus on the potential benefits to the utility.

The methodology used for these calculations were developed by Clean Power Research for similar studies[1] at other electric utilities. The underlying historical and forecasted capital and O&M costs and other technical data were provided by NPC. The results presented in this report are for a 1-axis tracking PV system. The results for a 10° tilted south-facing fixed system are presented in the Appendix.

[1] "Final Results Report with a Determination of Stacked Benefits of Both Utility-Owned and Customer-Owned PV Systems", conducted for Sacramento Municipal Utility District by T. E. Hoff, December 2002.

Transmission & Distribution System Deferral Benefits

Introduction

An appropriately targeted implementation of a sufficient capacity of PV can relieve capacity constraints on the utility's transmission, sub-transmission, and distribution systems. It accomplishes this by providing power to loads directly, effectively reducing loads on these circuits. Since NPV's Long-Term Resource Analysis Department does not consider PV to be a "firm resource", the methodology for quantifying capacity benefits includes an evaluation of PV's effective T&D capacity.

Based upon the effective T&D capacity, planners may be able to defer capital investments and realize cost savings depending on the rate of load growth, the rating of the PV systems, and the temporal match between PV production and peak loading.

Deferring capital investments has three monetary components. First, there are the direct capital cost savings that result from waiting to spend money until a later date. Second, there are indirect financial costs that are incurred when an investment is made and continue as long as the investment exists (e.g., property taxes, insurance, etc.). Third, there are the O&M cost savings associated with the investment.

Methodology

When there is no load growth uncertainty[2] and distributed generation investment life equals the life of the investment being deferred, the cost-savings equal the fully loaded present value cost of the investment plan divided by the load growth times a term involving the interest rate times the match between the distributed generation resource output and the peak load adjusted for loss savings. When the interest rate is real and the deferral period is one year, the finance related savings equals the average investment cost times the time value of money times the load match.

$$\text{Deferred Capital Cost Value (\$/kW)} = \underbrace{[X/L]}_{\text{Avg. Cost}} \; \underbrace{[r/(1+r)]}_{\text{Value of Money}} \; \underbrace{[M]}_{\text{Load Match}} \qquad (1)$$

where X is the fully loaded present value cost of the distribution expansion plan over the study period, L is the annual load growth (MW/yr), r is the real discount rate, and M is a factor corresponding to the effective peak load reduction provided by the PV system.[3]

While this Deferred Capital Cost Value may not represent that actual savings per kW to the utility that can be expected for each kW of PV installed, it can be considered as a

[2] While there is always load growth uncertainty in planning, this analysis assumes that the uncertainty is minimal.

[3] A detailed derivation of this equation is presented in T. E. Hoff, Identifying Distributed Generation and Demand Side Management Investment Opportunities, The Energy Journal: 17(4) (September 1996).

typical benefit value and as a measure of the comparative potential value of installed PV between different utility systems or planning areas.

Performing an area-specific T&D analysis requires segmenting the distribution system into meaningful planning areas. These areas are typically defined as separate load areas where it would be difficult to solve capacity constraints by simply transferring load to other portions of the system.

NPC determined that such a segmentation was beyond the scope of this project since cost data are not readily available according to the above scheme. As an alternative, it was decided that the data would be collected based on developmental areas, where the developmental areas may not be located in the same geographic location. The total developmental area would then be treated as a planning area.[4] These areas are:

1. *The Strip*
2. *Outlying Areas* (Primm, Laughlin, Indian Springs, Mt. Charleston, etc.)
3. *New Development* (rapidly growing areas in the Northwest, Henderson, Southwest, Spring Valley, etc.)
4. *Infill* (mostly developed areas with spot areas of development)

Results

Table 1 presents the data, assumptions, and deferral value calculations. It should be noted that since PV is to be considered as a firm resource based upon its Effective Load Carrying Capability (discussed later), no cost for the utility to install backup capacity has been considered.

The following sections present the capital cost calculations, O&M cost calculations, and deferral value calculations. The discount rate of 8.37 percent is the approved rate for NPC. Results indicate that the deferral value ranges from a low of $127/kW of PV to a system average of $200/kW of PV to a high of $791/kW of PV. The remainder of this section discusses the data, assumptions, and calculations.

[4] Distribution planning areas are defined as isolated regions between which loads cannot be directly transferred by distribution operators. When peak loading within such a planning area approaches capacity limits, additional capital investment is required. Current NPC practice is to conduct planning for the system as a whole, so the “planning areas” used in this study are not electrically isolated, but rather reflect developmentally distinct regions.

Table 1. Transmission and distribution deferral value (1-axis tracking system)

		Strip	Outlying Areas	New Development	Infill	Total
	I. CAPITAL COST CALCULATIONS					
(1)	Direct Expansion Cost - 2003 ($M)	$6.86	$11.22	$53.53	$29.40	$101.01
(2)	Direct Expansion Cost - 2004 ($M)	$5.77	$9.44	$45.05	$24.74	$85.00
(3)	Direct Expansion Cost - 2005 ($M)	$7.40	$12.11	$57.77	$31.73	$109.01
(4)	Direct Expansion Cost - 2006 ($M)	$3.73	$6.11	$29.15	$16.01	$55.00
(5)	4-yr Present Value Direct Expansion Cost ($M)	$19.76	$32.34	$154.28	$84.73	$291.12
(6)	Equivalent Direct Expansion Cost ($M per year)	$6.02	$9.84	$46.97	$25.79	$88.62
	II. O&M COST CALCULATIONS					
(7)	Annually Recurring O&M Cost ($/kW per year)	$0.45	$1.14	$0.25	$1.63	$1.33
(8)	O&M Cost ($/kW - present value)	$4.89	$12.40	$2.72	$17.73	$14.46
(9)	Load Growth (MW per year)	21	7	109	123	258
(10)	O&M Cost ($M per year) = (8) (9) / 1000	$0.10	$0.09	$0.30	$2.18	$3.73
	III. DEFERRAL VALUE CALCULATIONS					
(11)	Capital + O&M ($M per year) = (6) + (10)	$6.12	$9.93	$47.26	$27.97	$92.35
(12)	Capital + O&M ($M - 30-year pres. value)	$66.55	$108.00	$514.01	$304.25	$1,004.40
(13)	Load Growth (MW per year)	21	7	109	123	258
(14)	Financial Term r/(1+r)	0.077	0.077	0.077	0.077	0.077
(15)	Load Match (kW reduction per kW of PV)	65%	65%	65%	65%	65%
(16)	System Losses	2.1%	2.1%	2.1%	2.1%	2.1%
(17)	Capacity Gain = (16)/[1-(16)]	2.1%	2.1%	2.1%	2.1%	2.1%
(18)	Adjusted Load Match (kW per kW of PV) = (15)[1+(17)]	66%	66%	66%	66%	66%
(19)	Deferred Value ($/kW) = 1000 [(12) / (13)] (14) (17)	***$162***	***$791***	***$242***	***$127***	***$200***

Capital Costs

Table 1, Section I presents the fully loaded expansion costs for NPC's planning areas. NPC provided Clean Power Research with capacity expansion plan cost data that included:

- Direct capital costs
- Indirect capital costs
- Net present value of the property taxes and insurance costs over the life of the investment

The costs include both transmission and distribution capital costs, so the analysis includes both, recognizing the full 30-year impact of PV capacity on both transmission and distribution. Thus, the deferral benefit is not limited to avoidance of only near-term planned projects (such as considering only individual distribution substation upgrades), but also long-term plans that would include transmission upgrades.

As shown in the table, areas of new development have relatively high annual costs, while planning areas with available system capacity (such as the Strip), without need for significant new capital investment, have low annual costs. The projected capacity expansion costs (lines 1 through 4) are present valued (over the four-year period, line 5) and converted to an equivalent annual value (line 6). It is assumed that the capacity expansion plan will continue at the current rate.[5]

O&M Costs

Deferring capital investments also results in avoidance of substation and line O&M on those deferred investments. The analysis treats the benefits by allocating savings according to average O&M costs. O&M cost savings are a small component of the overall benefits, but are included here for completeness.

The O&M cost is calculated as shown in Table 2 based upon the estimated costs for 2003. It is assumed that these costs will be the same for future years. This analysis calculates O&M costs per unit of capacity ($/kW-yr), however an alternative method which may provide greater accuracy would be to base the calculation on miles of line, number of transformers, or some other basis. This calculation would require additional cost breakdowns from NPC and could be considered in the future.

Table 2. Avoided O&M Costs

	2003 O&M Cost ($)	2003 Capacity (MVA)	O&M Cost ($/kW-yr)
Strip	250,150	555	0.45
Outlying	500,300	440	1.14
New Devel	250,150	1,006	0.25
Infill	9,005,400	5,538	1.63
Total/Average	10,006,000	7,539	1.33

The results indicate that the Infill planning area has the highest O&M costs per unit of installed capacity, and the New Development planning area has the lowest.

The O&M cost in $/kW-year is entered from Table 2 into line 10 in Table 1. O&M costs are annually recurring. As a result, they need to be 30-year present valued (line 11) and multiplied by the annual load growth (line 12) to determine the total O&M cost associated with the new capital investments (line 13). Load growth is used as an approximation of capacity growth over time.

Calculations

The capital and O&M costs are shown line 14 of Table 1. The total expansion plan cost equals the present value of this annually recurring cost (line 15).

Peak loads as estimated by NPC's planning engineers for 2003 and 2007 are shown in Table 3. These are used to estimate the annual load growth (L) for each of the planning areas (line 16).

[5] This approach could not be used if the future expansion costs were not expected to be similar to the current expansion costs and load growth rates.

Table 3. Load Growth

	2003 Peak Load (MVA)	2007 Peak Load (MVA)	Load Growth (L) (MVA/yr)	Load Growth (%/yr)
Strip	342	424	21	5.99
Outlying	141	167	7	4.61
New Devel	537	972	109	20.25
Infill	4030	4520	123	3.04
Total	5050	6083	258	5.11

Two factors are required to determine the matching factor (*M*). First, the effective load match between PV generation and the local peak must be estimated. A ratio of 100 percent represents a perfect load match in which each kW of installed PV capacity results in a corresponding reduction of peak T&D loading by 1 kW. The actual value depends upon a variety of factors, such as local meteorology, the type (tracking, fixed, etc.) and orientation of the PV system, the makeup of customer classes in the planning area (affecting the load profile), and T&D losses.

For the present analysis, the Effective Load Carrying Capability (ELCC) calculated for NPC by Richard Perez is used.[6] The ELCC at 10 percent penetration is 65 percent for 1-axis tracking installations, 50 percent for fixed low-tilt South-West facing arrays and 45 percent for horizontal systems. Nevada Power had a weather-normalized peak of 4,524 MW in 2002, which is expected to increase to approximately 6,700MW by 2020.[7]
For this analysis, the matching factor is 65 percent for the 1-axis tracking system (line 18) and 45 percent for the fixed 10° tilt south-facing system (see Appendix).

Second, by placing PV directly at the customer load, some losses that would have been incurred in serving the customer through the T&D system are avoided. Losses in the secondary distribution system, the primary distribution system, the sub-transmission system, and the transmission system are all avoided.

Suppose the consumer consumes E units of electricity. How much electricity does the utility save (call this F)? If the utility generates F units of electricity at the wholesale level, it loses F x Losses. Thus, F x (1- Losses) = E. Solving for F, this means that F = E / (1 – Losses). NPC provided data for the year 2000 data that estimates peak T&D energy losses to be 2.1 percent.[8] Consequently, each 1 kW of firm generating capacity at

[6] Perez, Dr. Richard, *"Determination Of Photovoltaic Effective Capacity For Nevada Power"*, Clean Power Research, September, 2003.
[7] Nevada Power Company Integrated Resource Plan 2003, available at http://www.sierrapacificresources.com/resources/npc/images/2003ResourcePlanVolIII_Redacted.pdf.
[8] NPC's peak system losses are substantially lower than estimates provided by other utilities. For example, another utility in California estimated that its peak marginal T&D losses were about 18 percent (Final

the load effectively provides 1/(1-0.021) = 1.021 kW of capacity relief to the T&D system (line 20).

The load match, adjusted for T&D loss savings, is presented in line 21.

Discussion

Section IV of Table 1 presents the deferral value calculations. First, the present value of the annual cost over 30 years (the typical life of PV equipment) is calculated (*X* - line 15). Inserting *X*, *L*, *M*, and the financial term $r/(1+r)$ into Equation 1, the deferred value is determined, as shown in line 22.

The results indicate that the highest capital deferral value is found in the Outlying planning area. While the New Development area is by far the most capital intensive, the potential benefits are offset by high growth rates. The best locations have a combination of high capital cost and low growth rate, and this ratio is highest for the Outlying area. For comparison purposes, it was determined that the highest value T&D deferral value for a fixed system for one municipal utility was $136/kW of PV, thus suggesting that NPC has the potential for high T&D benefits.[1]

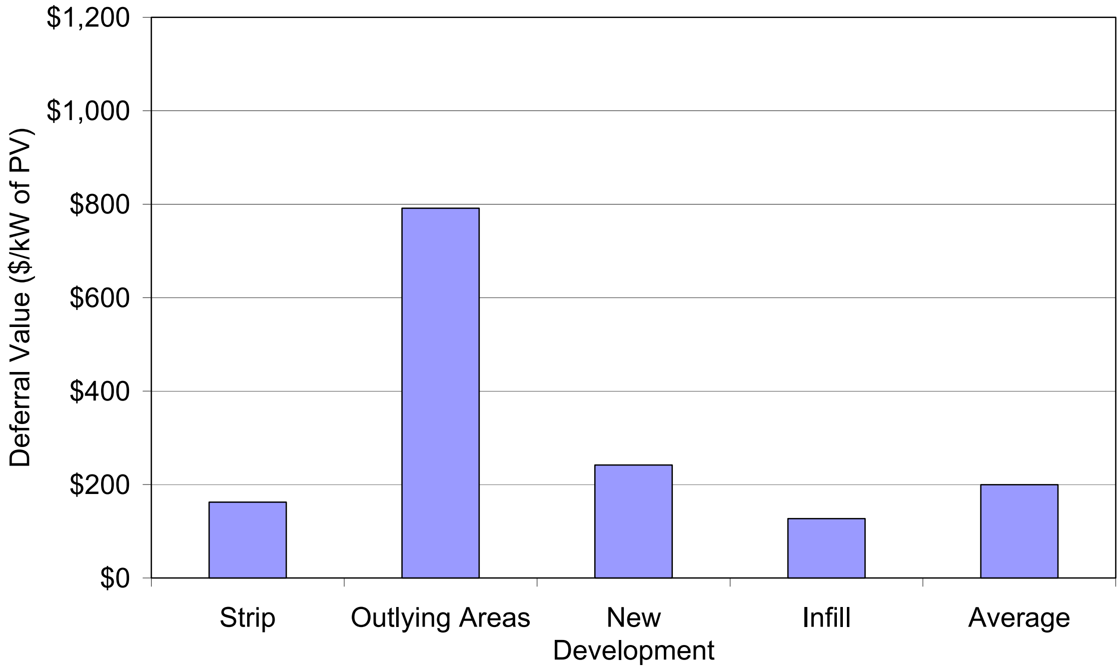

Figure 3. T&D deferral value (1-axis tracking system).

Results Report with a Determination of Stacked Benefits of Both Utility-Owned and Customer-Owned PV Systems, available at http://www.smud.org/pier/reports/S-034,%201.3.5.2,%2012-02,%20DEL(rev).pdf, page 18). This means that NPC's peak losses are estimated to be almost an order of magnitude less than that utility's losses. Furthermore NPC's Integrated Resource Plan 2003, Volume III, page 8, forecasts that system losses are 7.5% for June, July and August and 6.2% the rest of the year.

Energy Value

Introduction

PV generation delivers energy to the customer load. Thus, it reduces the quantity of wholesale energy purchased by the utility adjusted for a reduction in T&D system losses.

Methodology

The ideal way to calculate the energy savings benefit is to determine the time-specific PV system output, adjust this for the time-specific T&D system losses, multiply this by the time-specific wholesale energy value, and discount the results.

Such time-specific loss and economic data were not available for use in this study. As a result, average values are used. The energy value equals the average non-firm[9] peak power prices from Mead/Marketplace Electricity Price Index for July & August 2003 ($48.6/MWh) and the loss savings value is the average system losses (2.1 percent).[10] It is assumed that the energy prices do not escalate over time relative to the real discount rate of 8.37 percent.

The energy output estimate was provided by PowerLight.[11] A 1 kW_{AC} 1-axis tracking system is estimated to produce 2,501 kWh per year. A 1 kW_{AC} 10° tilt south-facing PV system PV system is estimated to produce 1,901 kWh per year.[12]

[9] The matching factor is used to provide an equivalent capacity for T&D benefits. In evaluating energy benefits, the resource is assumed to be a "non-firm" peaking resource.

[10] NPC's estimates of its average system losses are substantially lower than estimates provided by other utilities. For example, another utility in California estimated that its T&D losses were more than 5 times that of NPC's (Final Results Report with a Determination of Stacked Benefits of Both Utility-Owned and Customer-Owned PV Systems, available at http://www.smud.org/pier/reports/S-034,%201.3.5.2,%2012-02,%20DEL(rev).pdf). Furthermore NPC's Integrated Resource Plan 2003, Volume III, page 8, forecasts that system losses are 7.5% for June, July and August and 6.2% the rest of the year.

[11] The Clean Power Estimator is another tool that can be used to estimate PV system electricity production. Documentation is available at www.clean-power.com/research.asp.

[12] These numbers are based on Sharp 185 modules for single-axis tracking in Las Vegas using NREL TMY2 data.

Results

The results are presented in Table 4. As shown in the table, the energy value equals $1,350/$kW_{AC}$ of PV.

Table 4. Energy value (1-axis tracking system).

(1)	Discount Rate	8.37%
(2)	System Losses	2.1%
(3)	Loss Savings = (2) / [1-(2)]	2.1%
(4)	Energy Production (kWh/yr)	2,501
(5)	Adjusted Energy Produciton (kWh/yr) = (4) [1+(3)]	2,555
(6)	Energy Value	$0.0486
(7)	Avoided Energy Costs ($/yr) = (5) (6)	$124
(8)	Present Value Factor	10.88
(9)	30-yr Avoided Energy Costs ($/kW) = (7) (8)	$1,350

Summary

The objective of this report was to calculate of potential economic benefits of distributed PV to NPC. This investigation focuses on the T&D capital investment deferral and energy benefits, with the understanding that further study is required to determine if the capital investment deferral benefits can be realistically achieved in the practical application of PV on the NPC system. The results for a 1-axis tracking system are summarized in Table 5 and Figure 4. The T&D benefits include direct and indirect capital cost savings and O&M cost savings based on cost data provided by NPC. The energy benefit is based on wholesale energy prices and is adjusted to include 2 percent loss savings.

To determine these benefits, the electric distribution system is divided into four distribution planning areas: the Strip, Outlying Areas, New Development, and Infill. For each of these areas, potential capital deferral benefits are calculated based upon forecasted load growth, historic capital investment streams, and NPC financial data, and these are combined with O&M cost savings using historic O&M costs allocated to these areas. Avoided energy costs are calculated using modeled PV production for the Las Vegas area and wholesale energy costs at Mead/Marketplace.

As shown in Table 5, the results indicate that the average benefits are $1,550 per kW of PV and that the highest benefits are obtained in the Outlying areas at a value of $2,142 per kW of PV. The value of a distributed PV system in the Outlying areas is more than 60 percent greater than the value of a centrally located system ($1,322/kW). As shown in the Appendix, the benefits from a 1-axis tracking are more than one-third greater than the benefits from a 10° tilted south-facing fixed system.

Table 5. Summary of benefits for 1-axis tracking ($/kW)

	Energy Benefits	T&D Benefits	Total
System Average	$1,350	$200	$1,550
Outlying Areas	$1,350	$791	$2,142
New Development	$1,350	$242	$1,592
Strip	$1,350	$162	$1,513
Infill	$1,350	$127	$1,477
Central Station	$1,322	$0	$1,322

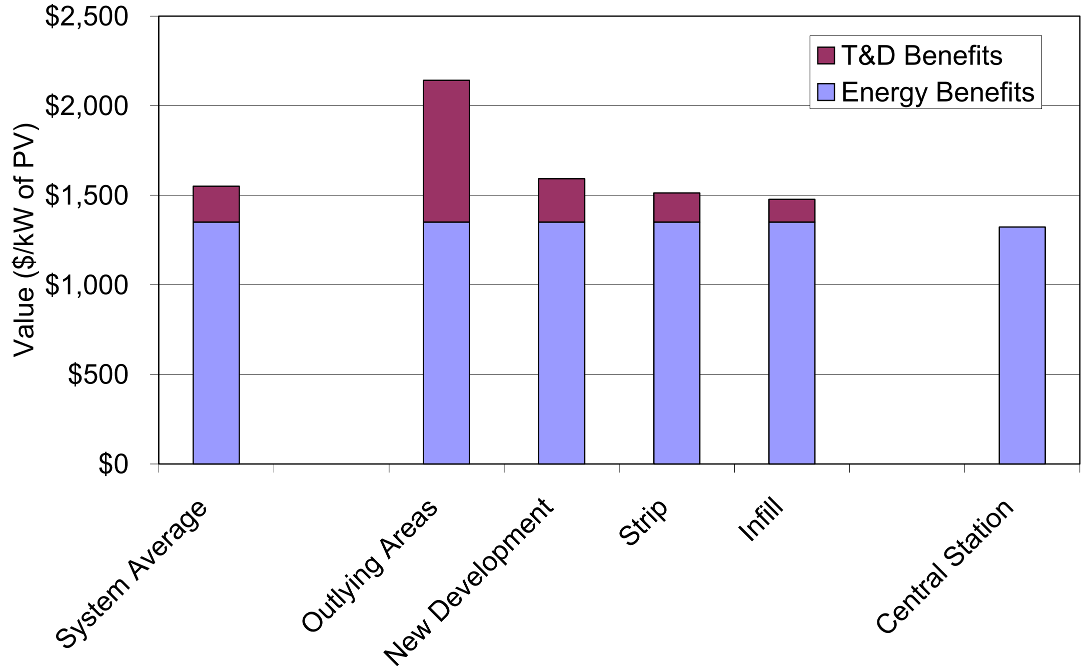

Figure 4. Total benefits (1-axis tracking system)

Future Work

The objective of this project was to perform an area- and time- specific analysis of NPC's transmission and distribution system and compute marginal distribution capacity cost for its planning areas. NPC could perform a more detailed analysis should it wish to investigate this further. Two options that NPC may wish to consider for future work are presented below.

T&D Load/PV Output Match

This project used the system-wide equivalent load carrying capability (ELCC) to determine the load match necessary to calculate the T&D benefits. However, a more detailed assessment would assess the temporal match between distribution substation/feeder loads and PV output. Distribution substation and/or feeder load data would be obtained for a select number of locations, and a more accurate T&D deferral value would be obtained.

Reductions in Operating Reserve Requirements

A unique aspect of distributed PV systems is that they tend to have a large number of independent units with very low outage rates. As a hypothetical example, compare a non-modular 50 MW PV plant to a modular plant with 50 1-MW PV systems with each unit having an outage probability of 4 hours per year. The availability of the modular plant is more certain than the non-modular plant if equipment failures are independently distributed. This is because a failure in a modular plant only affects a portion of the plant while a failure in a non-modular plant affects the entire plant.

According to probability's Central Limit Theorem, the variance for a plant with independent identical segments equals (outage probability) x (1 - outage probability)/(number of segments). While the expected outage rate is the same for both plants, the variance is high for the non-modular plant and very low for the modular plant. As a result, a higher operating reserve should be required for the non-modular plant to maintain reliability than for the modular plant. The value of this benefit could be investigated by NPC.[13]

[13] T.E. Hoff, Integrating Renewable Energy Technologies in the Electric Supply Industry: A Risk Management Approach, NREL report NREL/SR-520-23089 (July 97).

Appendix: Fixed System Results

This appendix presents results for a fixed PV system facing south at a 10° degree tilt.

Table 6. Transmission and distribution deferral value (fixed system)

	Discount Rate	8.37%

		Strip	Outlying Areas	New Development	Infill	Total
	I. CAPITAL COST CALCULATIONS					
(1)	Direct Expansion Cost - 2003 ($M)	$6.86	$11.22	$53.53	$29.40	$101.01
(2)	Direct Expansion Cost - 2004 ($M)	$5.77	$9.44	$45.05	$24.74	$85.00
(3)	Direct Expansion Cost - 2005 ($M)	$7.40	$12.11	$57.77	$31.73	$109.01
(4)	Direct Expansion Cost - 2006 ($M)	$3.73	$6.11	$29.15	$16.01	$55.00
(5)	4-yr Present Value Direct Expansion Cost ($M)	$19.76	$32.34	$154.28	$84.73	$291.12
(6)	Equivalent Direct Expansion Cost ($M per year)	$6.02	$9.84	$46.97	$25.79	$88.62
	II. O&M COST CALCULATIONS					
(7)	Annually Recurring O&M Cost ($/kW per year)	$0.45	$1.14	$0.25	$1.63	$1.33
(8)	O&M Cost ($/kW - present value)	$4.89	$12.40	$2.72	$17.73	$14.46
(9)	Load Growth (MW per year)	21	7	109	123	258
(10)	O&M Cost ($M per year) = (8) (9) / 1000	$0.10	$0.09	$0.30	$2.18	$3.73
	III. DEFERRAL VALUE CALCULATIONS					
(11)	Capital + O&M ($M per year) = (6) + (10)	$6.12	$9.93	$47.26	$27.97	$92.35
(12)	Capital + O&M ($M - 30-year pres. value)	$66.55	$108.00	$514.01	$304.25	$1,004.40
(13)	Load Growth (MW per year)	21	7	109	123	258
(14)	Financial Term r/(1+r)	0.077	0.077	0.077	0.077	0.077
(15)	Load Match (kW reduction per kW of PV)	45%	45%	45%	45%	45%
(16)	System Losses	2.1%	2.1%	2.1%	2.1%	2.1%
(17)	Capacity Gain = (16)/[1-(16)]	2.1%	2.1%	2.1%	2.1%	2.1%
(18)	Adjusted Load Match (kW per kW of PV) = (15)[1+(17)]	46%	46%	46%	46%	46%
(19)	Deferred Value ($/kW) = 1000 [(12) / (13)] (14) (17)	***$112***	***$548***	***$167***	***$88***	***$138***

Table 7. Energy value (fixed system).

(1)	Discount Rate	8.37%
(2)	System Losses	2.1%
(3)	Loss Savings = (2) / [1-(2)]	2.1%
(4)	Energy Production (kWh/yr)	1,901
(5)	Adjusted Energy Produciton (kWh/yr) = (4) [1+(3)]	1,942
(6)	Energy Value	$0.0486
(7)	Avoided Energy Costs ($/yr) = (5) (6)	$94
(8)	Present Value Factor	10.88
(9)	30-yr Avoided Energy Costs ($/kW) = (7) (8)	$1,026

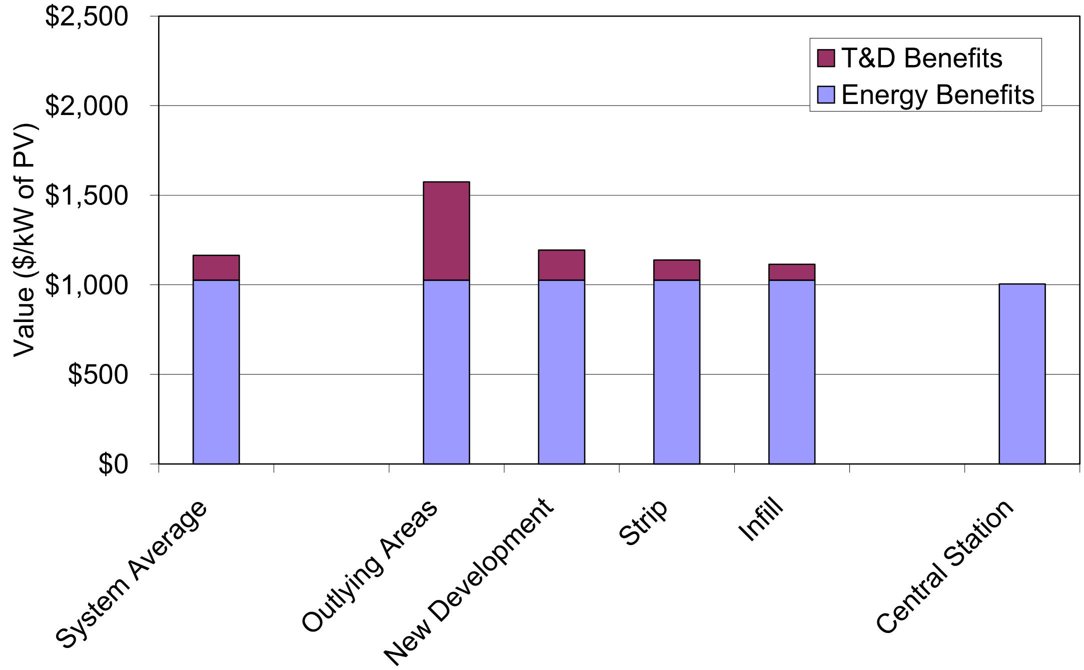

Figure 5. Total benefits (fixed system).