The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.

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This report provides a benefit-cost analysis of the impacts on ratepayers of the net metering of solar distributed generation (DG) in the service territory of Entergy Arkansas, Inc. (EAI). The Arkansas Public Service Commission (PSC) has initiated an investigation in Docket No. 16-027-R to review net metering issues in response to recent legislation directing the PSC to evaluate the rates, terms, and conditions of net metering in Arkansas.[1] Key provisions of this legislation state that the rates charged to net metering customers should recover the utility's costs, and must consider both the benefits and the costs of net metering to the electric utility and its ratepayers. Further, the PSC's analysis of net metering should consider all elements of utility service – generating capacity, reliability, and the transmission and distribution (T&D) system to deliver electricity.

This report contributes to the Commission's review by presenting a study of the benefits and costs of solar DG in the service territory of Entergy Arkansas, Inc. (EAI) the state's largest investor-owned utility. Crossborder Energy presented the initial results of this study at a workshop in Little Rock on July 18, 2017.

Our study provides a comprehensive benefit-cost analysis of demand-side solar in EAI's service territory. This analysis has the following key attributes:

1. **Multiple perspectives.** We examine the benefits and costs of solar DG from the perspectives of all of the key stakeholders – DG customers, other ratepayers, and the utility system and society as a whole. Together, these stakeholders constitute the public interest implicated by DG development. To capture all of these perspectives, we examine the benefits and costs of solar DG using the full set of cost-effectiveness tests for demand-side resources that commonly are used in the utility industry.

2. Consider a **comprehensive list of benefits and costs**.

3. Use **a long-term, life-cycle analysis** that covers the useful life of a solar DG system, which is at least 25 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side.

To calculate the benefits of net-metered solar DG, this report begins with the same avoided costs that EAI employs to evaluate the benefits of its other demand-side programs. We have supplemented these avoided costs with data from EAI's FERC Form 1 and with market data from the regional gas and electric markets in which EAI operates. Our approach to valuing solar DG also considers an expanded set of avoided costs and draws upon relevant analyses that have been conducted in other states, including the "public tools" for evaluating net-metered DG that have been developed in Nevada and California.[2]

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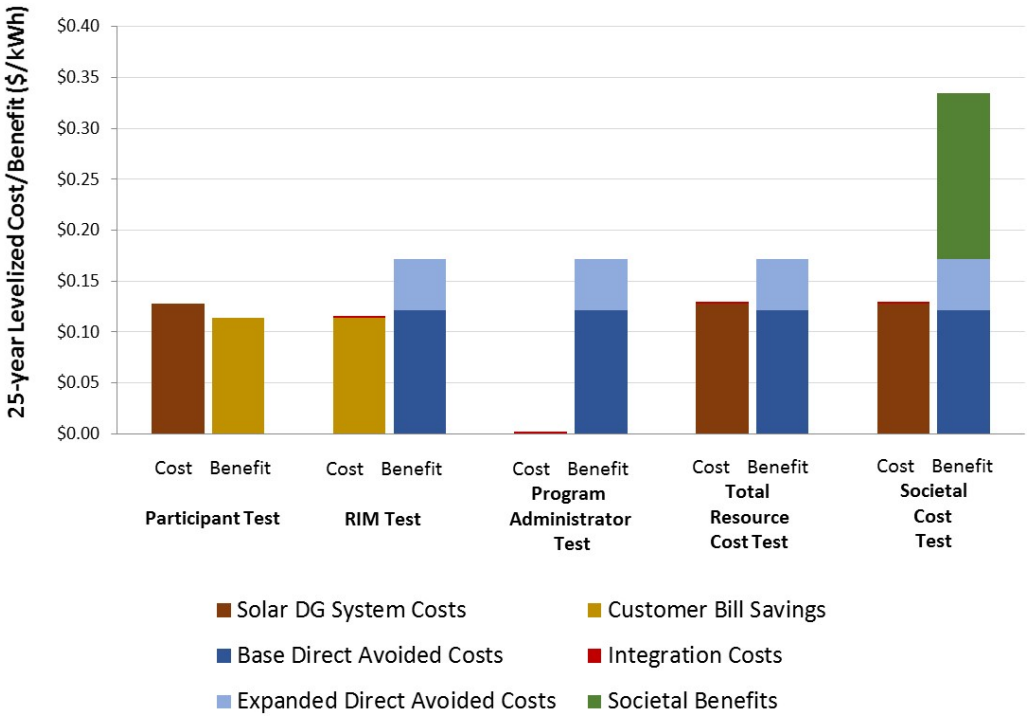
[1] See A.C.A. § 23-18-604.

[2] See the Public Utilities Commission of Nevada's (PUCN) 2014 net metering study at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%2

We also evaluated costs of solar DG, including system costs, lost revenues, and integration costs, as appropriate under each of the standard cost-effectiveness tests. The cost of solar DG as a resource for the utility system and for participating ratepayers is the levelized cost of energy (LCOE) from solar DG installations. We calculate the LCOE for residential solar using a current installed cost of $3 per watt-DC, plus typical operating and financing assumptions for such systems. The costs of solar DG for EAI's non-participating ratepayers are principally the revenues that the utility loses from solar DG customers who use their on-site solar generation to serve their own loads and who export excess output back into the grid, thus running the meter backward using net metering. To determine these costs, we calculate the 25-year levelized lost revenues from residential customers who install solar DG under net metering. In this calculation we assume that EAI's retail rates escalate at 2% per year in the long run. Finally, as the cost of integration, we include an estimate of $2 per MWh as the cost of additional ancillary services that may be needed to integrate solar DG into the grid.

Our work concludes that the benefits of residential DG on the EAI system exceed the costs, such that residential DG customers do not impose a burden on EAI's other ratepayers. The following **Figure ES-1** and **Table ES-1** summarize the results of our application of the primary cost-effectiveness tests to residential solar DG on the EAI system.

Figure ES-1: *Cost-effectiveness Results for Net Metered Solar DG on the EAI System*



0PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study. The California Public Utilities Commission's Public Tool is described and is available at http://www.cpuc.ca.gov/General.aspx?id=3934.

Table ES-1: *Benefits and Costs of Solar DG for EAI (25-yr levelized cents/kWh)*

Benefit-Cost Test	**Participant**		**RIM / PAC**		**TRC**		**Societal**	
Category	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Base Direct Avoided Costs – *EE Assumptions*				12.1		12.1		12.1
Expanded Direct Avoided Costs				17.2		17.2		17.2
Lost Revenues / Bill Savings (RIM / PCT)		11.4	11.4					
Integration (RIM/TRC/SCT)			0.2		0.2		0.2	
Solar DG LCOE	12.8				12.8		12.8	
Societal Benefits								16.4
Totals	12.8	11.4	11.6	12.1 – 17.2	13.0	12.1 – 17.2	13.0	28.5–33.6
Benefit-Cost Ratios	**0.89**		**1.04 -1.48 (RIM) >> 1 (PAC)**		**0.93 – 1.32**		**2.19 – 2.58**	

The principal conclusions of our analysis are as follows:

1. **Solar DG is a cost-effective resource** for EAI, as the benefits equal or exceed the costs in the Total Resource Cost, Program Administrator, and Societal tests. The results of these tests are well above 1.0 when a broad range of benefits are considered. As a result, in the long-run, deployment of solar DG will reduce the utility's cost of service.

2. **Net metering does not cause a cost shift to non-participating ratepayers**, as shown by the result for the Ratepayer Impact Measure test.

3. **Modifications to net metering are not needed** to recover the utility's full cost of service over time from net metering customers. Major rate design changes for residential DG customers, such as increased fixed charges, the use of demand charges, or two-channel billing to set different compensation rates for imported and exported power, are not needed to recover the utility's full cost of service over time from net metering customers.

4. **The economics of solar DG are marginal** for EAI's residential customers, as shown by the Participant test results below 0.9 and the modest amount of solar adoption to date. This means that any reduction in the compensation provided to solar DG customers is likely to be detrimental to the growth of this resource, although these economics may improve as solar costs continue to fall.

5. There are **significant, quantifiable societal benefits from solar DG**, including local economic benefits and public health improvements from reduced air pollution.

6. Solar DG also provides other important benefits that are difficult to quantify. These include the **enhanced reliability and resiliency** of customers' electric service, because solar DG is a foundational element for backup power systems and micro-grids that can provide uninterrupted power when the utility grid is down. Distributed generation also **enhances customers' freedom**, allowing them to choose the source of their electricity, and results in **customers who are more engaged and better informed** about how their electricity is supplied. The choice of using private capital to install solar DG on a customer's private premises **leverages a new source of capital to expand Arkansas's clean energy infrastructure and allows Arkansas to take advantage of federal tax incentives for solar that will begin to phase out in 2020**.

1. Background: Net Metering in Arkansas

Net metering is the billing arrangement used in most states in the U.S. to compensate customers who install renewable distributed generation (DG) on their premises, such as solar photovoltaic (PV) systems.[3] The output of a PV array first serves the DG customer's onsite load, reducing the amount of power which the customer purchases from the serving utility. When the DG output exceeds the onsite load, the excess generation is exported to the utility grid, where the utility uses that generation to serve neighboring loads. Under net metering, the DG customer receives a credit for these exports at the same volumetric rate that the customer pays when it imports power from the utility. Thus, the essence of net metering is the ability of a customer with a solar PV system to "run the meter backwards" when the customer exports power and serves as a generation source for the utility. In the accounting used to calculate the DG customer's bill, the customer can use the credits (when the meter runs backward) to offset the cost of usage from the grid (when the meter runs forward). The customer simply pays the net bill each month. The simplicity of net metering for the DG customer is a major factor in its widespread use and popularity.

Thus, DG located behind the meter both reduces the DG customer's use of power from the utility, and, at times, allows the DG customer to provide a service to the utility, thus becoming a producer (i.e., a generator). Some have applied a new label – "prosumers" – to DG customers in recognition of this dual role as both a customer of the utility and as a supplier providing a service (generation) to the utility.

As generators, renewable DG customers typically have legal status as qualifying facilities (QFs) under the Public Utilities Regulatory Policies Act of 1978 (PURPA). Under this federal law, a utility in whose territory a QF is located is required to do the following:

- interconnect with a customer's renewable DG system,
- allow a DG customer to use the output of his system to offset his on-site load, and
- purchase excess power exported from such systems at a state-regulated price.[4]

These provisions of federal law are independent of whether a state has adopted net metering; thus, the adoption of net metering only impacts the accounting credits which the customer-generator receives for the power exports to the grid.[5]

The Arkansas Public Service Commission (PSC) has initiated a generic investigation in Docket No. 16-027-R to review net metering issues in response to recent legislation directing the PSC to evaluate the rates, terms, and conditions of net metering in Arkansas.[6] Key provisions of this legislation state that the rates charged to net metering customers should recover the utility's

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[3] Today, 47 states offer some type of net metering. See http://programs.dsireusa.org/system/program/maps. This includes Arizona, California, Nevada, New Hampshire, and Hawaii, states which have large numbers of existing DG customers on traditional net metering, but which have adopted new compensation rules for new DG customers that make changes in the compensation for excess generation exported to the grid.

[4] The PURPA requirements can be found in 18 C.F.R. §292.303.

5 Although behind-the-meter DG systems meet the requirements for a qualifying facility, FERC has held that a state requirement that utilities credit customers for exports at the retail rate does not run afoul of PURPA's avoided cost requirement. See MidAmerican Energy Co., 94 FERC ¶ 61,340 (2001).

[6] *See* A.C.A. § 23-18-604.

costs, and must consider both the benefits and the costs of net metering to the electric utility and its ratepayers. The legislation further states that the PSC's analysis of net metering should consider all elements of utility service – generating capacity, reliability, and the delivery (T&D) system.

The statute that established net metering in Arkansas cites the following purposes for a net metering program:

- Promote wise use of Arkansas's natural energy resources,
- Independence from imported fossil fuels,
- Invest in emerging energy technologies,
- Economic development / job creation,
- Reduce environmental stress, and
- Provide greater customer choice.[7]

These represent important societal benefits of the clean, renewable, local distributed generation installed under the net metering program.

2. Methodology

Solar DG is a long-term generation resource for Arkansas. New solar DG systems will provide benefits for the next 25 to 30 years. Thus, our analysis develops 25-year levelized benefits and costs for solar DG on the EAI system, the largest investor-owned utility in Arkansas. This approach is consistent with the statute's focus on assessing the impacts of net metering on the utility's cost of service, because the assessment of benefits and costs measures the impact of net metered DG on the utility's long-term cost of service. As the law recognizes, both the benefits and costs must be estimated, in order to capture factors that either reduce the cost of service (i.e. benefits) or increase them (i.e. costs).

The issues raised by the growth of behind-the-meter DG are not new. Issues of impacts on the utilities, on non-participating ratepayers, and on society as a whole also arose when state regulators and utilities began to manage demand growth through energy efficiency ("EE") and demand response ("DR") programs. To provide a framework to analyze these issues in a comprehensive fashion, the utility industry developed a set of standard cost-effectiveness tests for demand-side programs. These tests examine the cost-effectiveness of demand-side programs from a variety of perspectives, including from the viewpoints of the program participant, other ratepayers, the utility, and society as a whole.

This framework for evaluating demand-side resources is widely accepted, and state regulators have years of experience overseeing this type of cost-effectiveness analysis, with each state customizing how each test is applied and the weight which policymakers place on the various test results. This suite of cost-effectiveness tests is now being adapted to analyses of net metering and behind-the-meter DG, as state commissions recognize that evaluating the costs and benefits of all demand-side resources – EE, DR, and DG – using the same cost-effectiveness framework will help to ensure that all of these resource options are evaluated in a fair and consistent manner.

Accordingly, we have evaluated the long-term benefits and costs of net-metered solar DG

[7] See A.C.A. § 23-18-602.

from multiple perspectives, using each of the major cost-effectiveness tests widely used in the utility industry.[8] Each of the principal demand-side cost-effectiveness tests uses a set of costs and benefits appropriate to the perspective under consideration. These are summarized in **Table 1** below ("+" denotes a benefit; "-" a cost).

Table 1: *Demand-side Benefit (+) / Cost (-) Tests*

Category	Total Resource Cost (TRC) and Societal	Ratepayer Impact (RIM)	Program Administrator - Utility (PAC)	Participant (PCT)
Capital and O&M Costs of the DG Resource	−			−
Utility Lost Revenues (same as Customer Bill Savings)		−		+
Costs for Incentives (if available)	−	−	−	+
Integration and Program Administration Costs	−	−	−	
Avoided Costs -- Energy -- Generation Capacity -- T&D, including losses -- Risk / Hedging / Market -- Environmental Compliance -- RPS (not applicable in AR) -- Societal (Societal Test only)	+	+	+	
Federal Tax Benefits	+			+

The key goal for regulators is to implement demand-side programs that produce balanced, reasonable results when the programs are tested from each of these perspectives. In this case, full

[8] See the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF. We understand that these tests are used in Arkansas, with the Total Resource Cost test being the primary test for assessing the cost-effectiveness of energy efficiency portfolios.

retail net metering is the program under evaluation. First, the program should provide a resource that is a net benefit to the utility system or to society – thus, the Total Resource Cost (TRC) and Societal Tests compare the costs of solar DG systems to their benefits to the utility system and society as a whole. Second, the DG program will need to pass the Participant test if it is to attract customers to make long-term investments in DG systems. Finally, the Ratepayer Impact Measure (RIM) test gauges the impact on other, non-participating ratepayers. The RIM test sometimes is called the "no regrets" test because, if a program passes the RIM test, then all ratepayers are likely to benefit from the program. However, it is important to keep in mind that the RIM test measures equity among ratepayers, not whether the program provides an overall net benefit as a resource (which is measured by the TRC and Societal tests).

Data. Our starting point for the data needed to perform a full 25-year benefit-cost assessment is the set of publicly-available "key assumptions" for the avoided costs that EAI uses to evaluate its other demand-side programs, as filed most recently on May 1, 2017 in Docket No. 07-085-TF (the "*EE Assumptions*").[9] These avoided cost assumptions are included as **Attachment 1**. We have supplemented these avoided costs with data from EAI's *2015 Integrated Resource Plan* (*2015 IRP*), data on loads and market prices on the Midcontinent Independent System Operator's (MISO) system in Arkansas, FERC Form 1 data for EAI, and with information from analyses of the impacts of solar DG on utilities in other states. Our analysis is based entirely on public data sources without the use of confidential data.

Benefits. In deciding what benefits to include in this analysis, we were guided by A. C.A. § 23-18-604(b)(1)(A), which specifically calls for consideration of energy, generation capacity, transmission, distribution and reliability benefits, by the societal benefits cited by the Legislature in A.C.A. §23-18-602, and by our knowledge of the benefits recognized and quantified in numerous other distributed generation studies.

The largest quantifiable direct benefits of DG are avoided energy, avoided generation capacity, avoided transmission and distribution capacity, and avoided line losses. Our methodologies for quantifying these benefits are discussed in detail below. Several of the most important (and beneficial) characteristics of DG are the shorter lead times and smaller, scalable increments in which DG is deployed, compared to large-scale generation resources. In this respect, DG should be treated like energy efficiency and demand response, which also are small-scale, short-lead-time resources. The small amount of DG included in EAI's *2015 IRP* combines with EE and DR to help to defer the need for larger-scale resources in the long-run. The *2015 IRP* finds that EAI will need new resources as early as 2018, and shows that EAI is depending on the continued growth of demand-side resources to meet its future energy and capacity needs. Our Base set of direct benefits of solar DG use the avoided costs included in the *EE Assumptions,* which EAI also uses to assess the benefits of its other demand-side programs.

We also consider an Expanded set of avoided costs that includes a number of additional direct benefits of DG that also will reduce ratepayer costs, including:

- **Fuel hedging benefits.** Renewable generation, including solar DG, reduces a utility's exposure to volatility in fossil fuel prices.

[9] See *Direct Testimony of Kandice Fielder* for EAI filed May 1, 2017 in Docket No. 07-085-TF

- **Price mitigation benefits.** Solar DG reduces market demand both for electricity and for the natural gas used to produce the marginal kWh of power. These reductions have the broad benefit of lowering prices across the gas and electric markets in which EAI operates.

- **Long-term avoided T&D costs.** Our Expanded set of avoided costs includes a detailed calculation of long-term avoided T&D costs, based on FERC Form 1 data.

In addition, solar DG also provides quantifiable societal benefits to the citizens of Arkansas. These include important environmental benefits, such as reduced emissions of greenhouse gases and criteria air pollutants, and lower use of scarce water resources. We have assembled the data needed to quantify the reduced emissions of these pollutants as well as the water savings, drawing upon recent quantifications of these societal benefits. We also quantify the additional societal benefits of stimulating local economic activity. Finally, we discuss but do not quantify the benefits of enabling customers to enhance the reliability and resiliency of their electric service and of expanding competition and customer choice.

Costs. The relevant costs of solar DG vary across the benefit-cost tests.

The Total Resource Cost, Societal, and Participant Tests use the capital, financing, and operating costs for solar DG systems, as incurred by the participating customers who install solar. These include the installation costs for the systems (offset by the federal investment tax credit), plus the costs for financing, maintenance, and periodic inverter replacement. The cost of DG systems per kilowatt-hour of output can vary based on size, installation costs, financing terms, and output. For those tests in which utility costs are relevant, we add an estimate of the solar integration costs which the utility will incur to incorporate these resources into its system, based on solar integration studies performed by other utilities with larger amounts of solar generation on their systems.

In the RIM Test, the costs of solar DG for non-participating ratepayers are principally the revenues which the utility loses from customers serving their own load with DG. To these lost revenues we add the estimate of solar integration costs.

The following sections discuss each of the benefits and costs of solar DG for EAI. Solar DG is a long-term resource with an expected useful life of at least 25 years. Accordingly, we calculate the benefits and costs of DG over a 25-year period in order to capture the value of these long-term resources, and we express the results as 25-year levelized costs using the same 6.1% per year discount rate that EAI assumes in evaluating its other demand-side programs.[10]

3. Direct Benefits of Solar DG

a. Energy

Solar DG on the EAI system avoids marginal generation, principally gas-fired generation in the MISO South market area. The methodology for calculating the avoided energy costs associated with demand-side resources is well-established. To estimate these avoided costs, we have used recent MISO locational marginal prices (LMPs) for the Arkansas Hub, weighted by a standard output profile for a solar array in Little Rock, and escalated these LMPs using the

[10] This discount rate is EAI's after-tax weighted average cost of capital.

long-term forecast of natural gas prices from the Energy Information Administration's (EIA) *Annual Energy Outlook 2017 (AEO 2017)*.

Specifically, we looked at hourly day-ahead market prices reported by the MISO for the Arkansas Hub over the period June 2016 to May 2017. These prices averaged $27.38 per MWh for a 24x7 baseload profile. Using an hourly solar output profile for Little Rock from the National Renewable Energy Laboratory's (NREL) PVWATTS calculator, the solar-weighted average price for the June 2016 to May 2017 period was 16% higher, or $31.74 per MWh. The higher average price when hours are weighted by typical solar output is due to the fact that MISO prices are higher during the hours when solar DG produces energy, as illustrated in the following two heat maps. **Table 2** shows average solar output by month and daylight hour (in Eastern Standard Time, the format reported by the MISO). **Table 3** indicates the level of June 2016 to May 2017 average MISO prices at the Arkansas Hub in these hours.

Table 2: *PV-Watts Output Profile for Solar PV in Little Rock*

Month	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	0%	0%	3%	17%	31%	42%	49%	48%	46%	37%	24%	11%	1%	0%
2	0%	0%	5%	19%	32%	42%	47%	52%	46%	36%	28%	15%	2%	0%
3	0%	1%	10%	24%	39%	52%	57%	59%	57%	49%	36%	21%	6%	0%
4	0%	7%	21%	33%	45%	54%	63%	69%	60%	54%	40%	24%	9%	0%
5	1%	9%	23%	35%	49%	57%	60%	63%	61%	50%	40%	24%	11%	2%
6	2%	10%	24%	36%	51%	58%	61%	64%	62%	55%	44%	28%	14%	3%
7	1%	8%	23%	39%	52%	62%	65%	68%	63%	54%	42%	29%	14%	3%
8	0%	6%	21%	38%	53%	61%	67%	67%	63%	56%	44%	28%	12%	2%
9	0%	4%	17%	34%	47%	56%	58%	60%	59%	50%	35%	19%	5%	0%
10	0%	2%	16%	32%	47%	56%	61%	63%	55%	45%	29%	13%	1%	0%
11	0%	0%	9%	23%	36%	44%	47%	48%	45%	32%	21%	6%	0%	0%
12	0%	0%	4%	17%	29%	41%	44%	50%	43%	34%	20%	6%	0%	0%

Table 3: *Average June 2016 to May 2017 MISO Arkansas Hub Prices ($/MWh)*

Month	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	22.9	26.5	32.8	30.8	30.2	29.7	28.5	27.6	26.5	25.7	25.0	25.7	30.6	34.2
2	20.4	23.7	26.9	25.6	25.3	24.8	24.4	23.9	23.4	22.9	22.5	22.6	23.7	26.7
3	24.8	31.3	31.5	30.2	29.9	29.1	27.9	27.1	26.4	26.2	26.5	26.8	26.9	29.5
4	27.7	30.5	29.9	30.7	32.4	33.2	33.7	34.8	36.9	38.2	39.2	40.0	37.1	35.1
5	23.1	25.5	26.7	27.8	29.1	30.1	31.4	33.3	35.6	37.5	39.7	40.9	37.6	34.0
6	17.5	18.9	20.3	21.8	23.3	25.1	27.0	29.5	33.5	36.7	37.7	37.5	32.5	28.8
7	19.7	20.3	22.0	23.7	25.3	27.0	29.0	31.9	35.4	39.0	41.7	40.9	35.9	31.3
8	19.4	20.5	21.8	23.4	25.5	28.0	30.7	33.7	37.2	39.7	41.9	39.7	34.8	31.4
9	21.2	22.8	23.2	24.3	25.9	27.1	29.1	32.7	35.8	39.0	39.5	37.2	32.3	30.0
10	25.0	28.0	27.1	27.2	28.6	29.8	31.6	34.4	39.9	47.8	52.1	51.0	40.9	39.2
11	20.4	23.3	25.5	24.5	24.6	24.8	24.6	24.3	24.3	24.5	24.4	24.8	28.1	29.2
12	25.9	30.7	37.2	35.2	33.6	33.2	31.6	30.5	29.4	28.5	28.1	29.1	35.3	37.3

After determining the solar-weighted average price for the Arkansas Hub, we escalate that value, based on the expected growth in natural gas prices at the Henry Hub, Louisiana, relative to historical Henry Hub prices for the base period of June 2016 to May 2017. Our base case natural gas forecast is EIA's *AEO 2017* forecast of prices at the Henry Hub. We also develop low and high scenario forecasts. Our low forecast uses June 1, 2017 Henry Hub forward market prices for 2018, escalated in subsequent years based on EIA's *AEO 2017* forecast. Our high case forecast employs Entergy's *2015 IRP* reference case gas price forecast.[11] The following two figures show the resulting projections of natural gas prices and solar-weighted avoided energy costs.

[11] See *2015 IRP*, at p. 32.

Figure 1: *Natural Gas Price Forecasts*

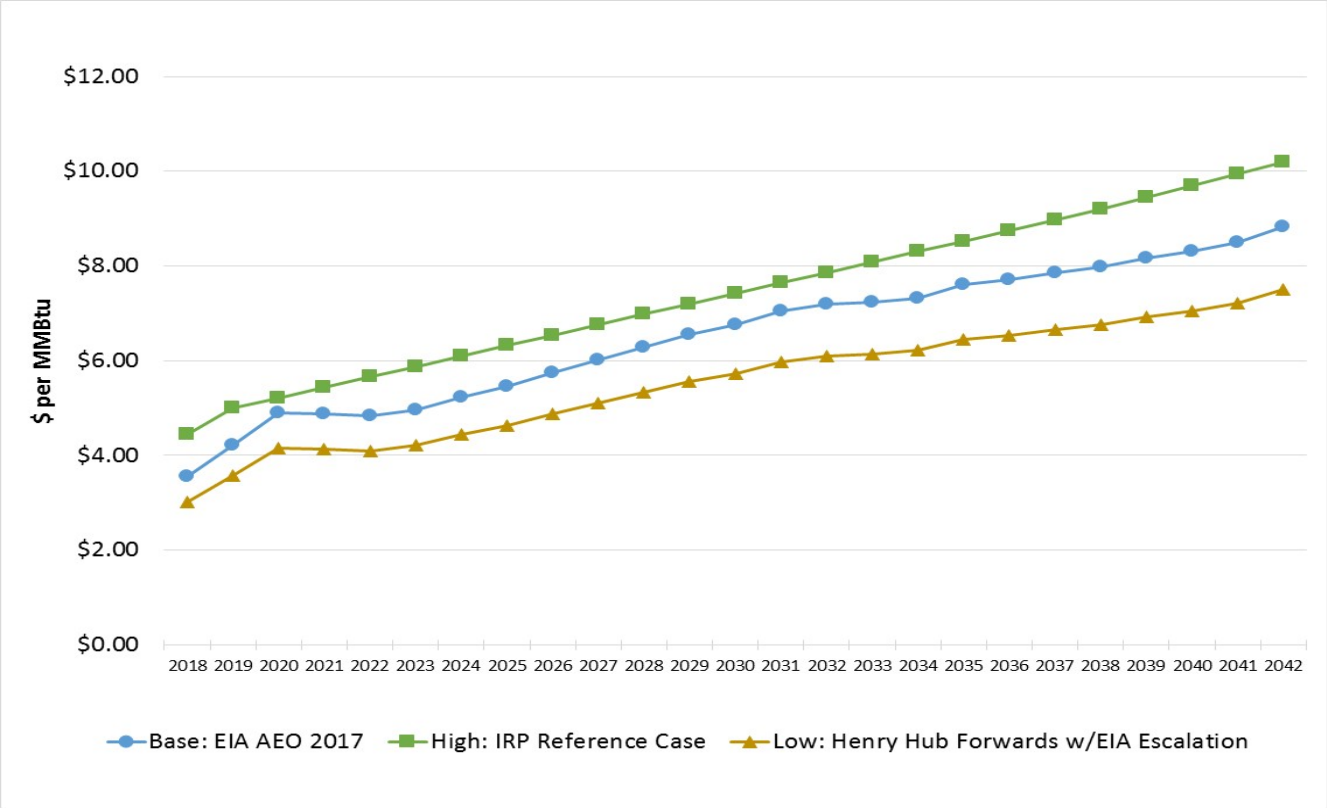
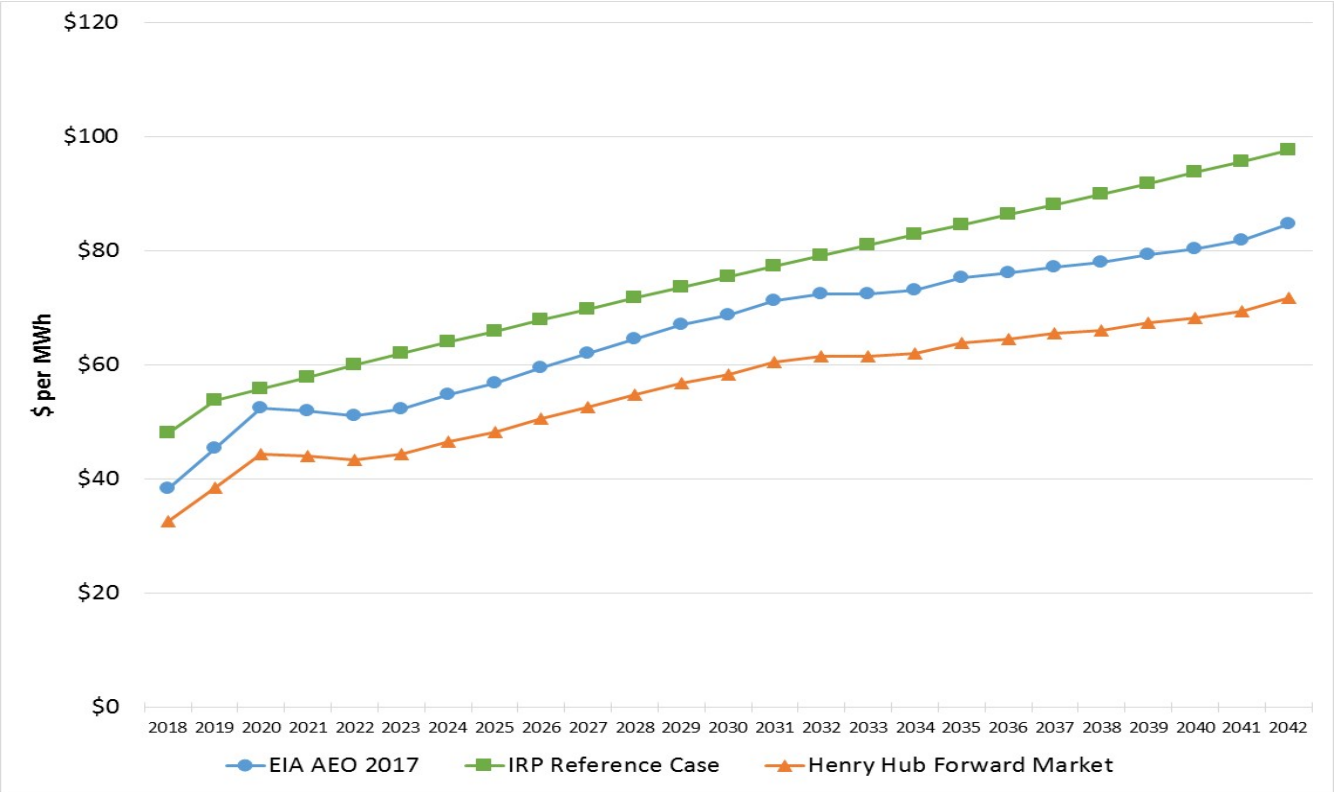


Figure 2: *Solar-weighted Avoided Energy Costs*



We have levelized these prices over the 25-year period from 2018 to 2042 using Entergy's 6.1% discount rate. The levelized avoided cost also assumes that solar output declines by 0.5% per year, based on the industry-standard assumption for the degradation over time in solar panel output.

With these inputs, our base forecast of EAI's avoided energy costs for solar DG is a 25-year levelized value of 6.35 cents per kWh, in 2018 dollars, as shown in **Table 4**.

Table 4: *EAI Avoided Energy Costs (25-year levelized 2018 $/MWh)*

Scenario	Base Case	Sensitivities	
		Low Gas	High Case
Gas Price Forecast	EIA *AEO 2017*	Henry Hub Forwards	*2015 IRP*
Avoided Energy ($/MWh)	**63.50**	**53.90**	**72.40**

b. Generation capacity

The *2015 IRP* finds that EAI has a need for new generating capacity as early as 2017.[12] Combustion turbines ("CTs") are the least-cost source of new utility-scale capacity. The avoided capacity cost of $77.98 per kW-year (in 2016 $) stated in the *EE Assumptions* is the annualized cost for CT capacity.

The capacity value of solar resources is only a fraction of its nameplate capacity, because solar will not be producing at full nameplate during the afternoon hours when demand peaks. MISO has adopted rules to determine the accredited capacity value of solar resources, as a percentage of nameplate capacity. MISO solar capacity value for resource adequacy is the capacity factor of solar facilities from hour ending (HE) 3 p.m. to 5 p.m. Eastern Standard Time in June, July, and August, with a default of 50% of nameplate until actual output is available.[13] Based on PVWATTS simulated solar output for Little Rock for a south-facing fixed array, the capacity value of solar according to the MISO accreditation formula is 54% of nameplate, with total annual solar production of 1,530 kWh per kW-AC of solar capacity.[14]

The capacity value of distributed solar PV is based on its ability to reduce the peak demand for power on the grid. This reduced peak demand also lowers the reserve capacity that the utility must maintain to serve that peak. EAI's current reserve margin is 12%. Accordingly, we increase avoided capacity costs by 12% to reflect the benefit of the lower required reserves.

Table 5 presents the complete calculation of avoided generation capacity costs.

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[12] See *2015 IRP*, at p. 16.

[13] See MISO Business Practice Manual BPM-011-r16, Section 4.2.3.4.1.

[14] The MISO capacity criteria is based on solar output during a defined set of hours. To estimate average solar output during these hours, we use hourly output from PVWATTS because it calculates solar output using solar insolation data from a typical meteorological year (TMY).

Table 5: *Avoided Generation Capacity Costs ($ per MWh in 2018$)*

line	Parameter	Value	Notes
1	Avoided Capacity Cost (2016 $)	77.98 / kW-year	from *EE Assumptions*
2	Avoided Capacity Cost (2018 $)	81.13 / kW-year	2% per year inflation
3	MISO Solar RA Capacity Value	54%	MISO BPM-011
4	Solar Output	1,530 kWh / kW	NREL PVWATTS
5	EAI Avoided Reserves	12%	EAI reserve margin
6	**Solar Avoided Capacity Cost**	**0.0321 / kWh**	[(2 x 3) / 4] x 1.12
		32.10 per MWh	

c. Line losses

The avoided energy and capacity costs calculated above are at the generation level, and need to be increased to reflect the marginal line losses on both the transmission and distribution systems that are avoided by customer-sited solar DG, which is located behind the customer's meter at the point of end use. We understand that the line loses included in the *EE Assumptions* are average losses.[15] We have increased these losses by 50% to capture the higher marginal losses avoided by new DG resources, based on a study from the Regulatory Assistance Project on the relationship between average and marginal line losses.[16] The resulting loss factors are still conservative, in that they may not reflect the higher losses experienced during the peak demand hours in summer afternoons when solar output is high. Finally, we assume that the 2.0% transmission losses included in the *EE Assumptions* already are included in the MISO LMP prices used to determine avoided energy costs. **Table 6** shows our calculations of avoided line losses for both energy and capacity.

Table 6: *Avoided Line Losses ($ per MWh in 2018$)*

Avoided Cost	Value *($ per MWh)*	Loss Factor	Convert to Marginal Losses	Avoided Losses *($ per MWh)*
Energy	63.50	7.44%	1.5	7.10
Capacity	32.10	9.44%	1.5	4.50
Total				11.60

d. Transmission and distribution capacity

A significant share of the output of solar DG serves on-site loads. This share typically ranges from 40% to 60%, and depends on the size of the solar system and the load profile of the customer. The DG output used onsite never touches the grid, and thus clearly reduces loads on the utility's T&D system. Even for the remaining power that a solar DG unit exports to the grid, these exports are likely to be entirely consumed on the distribution system by the solar customer's neighbors, unloading the upstream portions of the distribution system and the transmission system. Thus, much like energy-efficiency and demand response resources, solar DG displaces traditional

[15] This is notwithstanding our understanding that EAI is required to use marginal losses in its EE cost effectiveness calculations. See Order No. 7 in Docket 13-002-U, at page 39 of 91: "The Commission adopts the use of marginal, rather than average line losses, which is unopposed by any party, to quantify EE's incremental effects."

[16] Regulatory Assistance Project, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* (August 2011), at p. 5. See http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

generation sources which must use the utility T&D system to be delivered to customers.

Solar DG avoids transmission and distribution capacity costs to the extent that solar production occurs at times of peak demand on the T&D system. Solar DG helps the utility to manage and to reduce current loads and load growth, thus avoiding and deferring the need for load-related T&D investments. Solar DG also can defer the need for new transmission to access utility-scale renewables, if DG provides an alternative to larger-scale renewable projects to supply needed capacity or to meet renewable energy goals. These T&D benefits can be quantified by calculating the utility's marginal cost of load-related transmission and distribution capacity.

As DG penetration grows, and a deeper understanding is gained of the impacts of DG on the delivery circuits, utility T&D planners will integrate existing and expected DG capacity into their planning. A comparable evolution has occurred over the last several decades, as the long-term impacts of EE and DR programs are now incorporated into utilities' capacity expansion plans for generation, transmission, and distribution, and it is generally recognized that these demand-side programs can help to manage demand growth and to avoid capacity-related costs for T&D as well as generation.

In this study, we have developed two separate estimates of avoided T&D costs for EAI. The first is the avoided T&D capacity costs included in the *EE Assumptions*, which we use in the Base avoided costs. The second is an alternative calculation of long-term avoided T&D capacity costs which we use with the Expanded set of avoided costs.

i. Avoided T&D in the *EE Assumptions*

We first use the avoided T&D capacity costs of $23.86 per kW-year in 2016 that are included in EAI's *EE Assumptions*. Escalating that value by 2% per year over a 25-year period results in a levelized price of $29.80 per kW-year for 2018-2042, including standard degradation of 0.5% per year in solar output.

The next step is to convert a portion of this marginal T&D capacity value into an equivalent price per kilowatt-hour that considers the extent to which solar DG avoids investments in marginal T&D capacity. Distributed generation can avoid transmission investments by reducing peak loads on the EAI transmission system. We determined that the capacity contribution of solar PV to reducing peak transmission loads is 52.2% of the solar nameplate. This is based on a Peak Capacity Allocation Factor (PCAF) analysis of solar output at the time of Entergy's peak loads over the five-year period 2009-2013. The peak load data for these years is from FERC Form 714. In each of these years, we calculated an hourly set of peak capacity allocation factors for those hours in which Entergy's loads were within 10% of the maximum hourly load for the year. In this allocation, the hours with loads in the range of 90% to 100% of the maximum hourly load for the year are weighted according to the amount by which they exceed the threshold of 90% of maximum load. The following heat map, **Table 7**, shows the resulting PCAF distribution for 2009-2013 of the hours with loads within 10% of the annual peak hour loads. As the heat map shows, this allocation focuses on the mid-afternoon hours in the months of June to August.

Table 7: *PCAF Heat Map – 2009 to 2013 Loads*

Month\Hour	10	11	12	13	14	15	16	17	18	19	20	21
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.1%	1.1%	3.4%	5.8%	7.3%	7.0%	4.7%	2.3%	0.5%	0.1%	0.0%
7	0.0%	0.0%	0.2%	2.0%	3.9%	5.2%	5.1%	3.1%	1.1%	0.2%	0.1%	0.0%
8	0.0%	0.1%	1.4%	4.3%	7.8%	10.0%	9.7%	6.6%	3.1%	1.0%	0.5%	0.0%
9	0.0%	0.0%	0.0%	0.1%	0.5%	0.8%	0.8%	0.2%	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

This PCAF allocation then was applied to solar output based on actual solar insolation in Little Rock in 2009-2013 from Clean Power Research's *Solar Anywhere* tool, with the NREL Solar Advisor Model used to convert the actual insolation to solar PV generation. We used actual solar insolation data in order to capture the correlation between solar output and the hot summer weather that drives periods of high demand. In other words, when it is hot and electric demand is high, it also tends to be sunny.[17] This correlation would be lost if solar output were based on typical meteorological year ("TMY") data, as it is in the PVWATTS tool. The result is that solar DG will reduce EAI's peak loads by an average of 52.2% of the solar nameplate capacity. This is the solar contribution to reducing the system peak loads that drive load-related transmission investments.

The product of the levelized cost of T&D capacity and the 52.2% solar capacity contribution measures the transmission capacity cost avoided by a solar PV resource. We divide this product by the expected solar generation per kW of AC capacity to produce a volumetric ($/MWh) rate, as shown in the following table:

Table 8: *25-year Levelized Avoided T&D Marginal Capacity Cost for Solar DG*

Parameter	Value	Notes
Avoided T&D Capacity Cost	$23.86 per kW-year	EE value, in 2016 $
Annual Escalation Rate	2.0%	
25-year Levelized Cost (2018 $)	$29.80 per kW-year	6.1% discount rate
Solar Contribution to MISO South Peak Load	52.2%	PCAF calculation
Solar Output – Annual kWh per kW-AC	1,530 kWh	NREL PVWATTS
Solar Avoided T&D Capacity Cost	**$10.20 per MWh**	$29.80 x 0.522 / 1.53 MWh

ii. Long-term avoided T&D

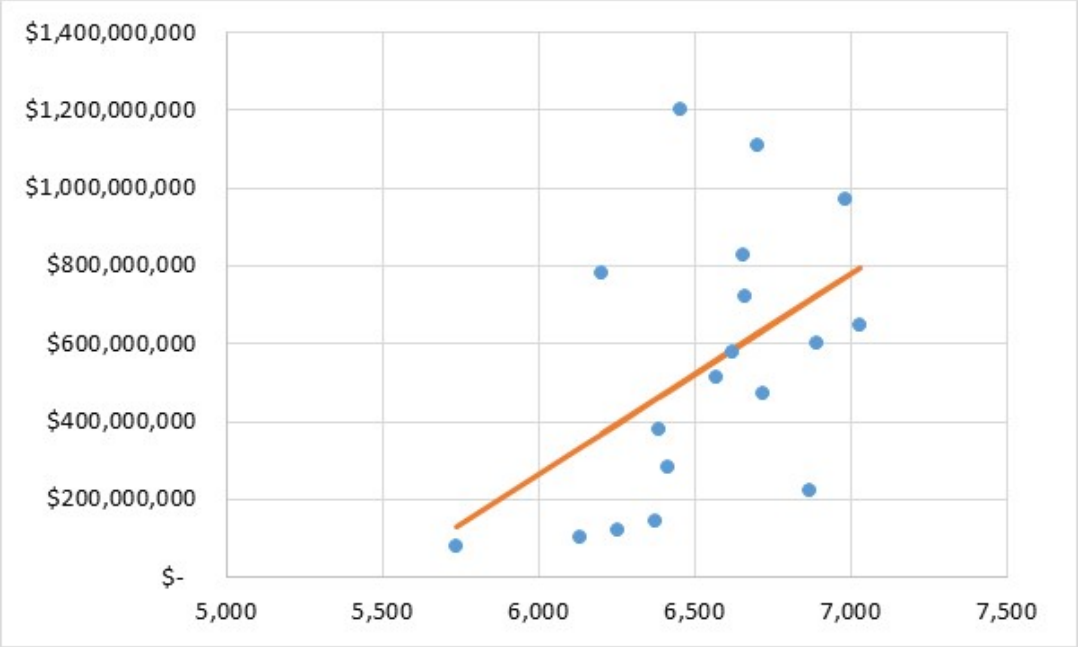
As an alternative calculation of long-term avoided T&D investment costs for use in the Expanded set of avoided costs, we have used the well-accepted National Economic Research

[17] EAI's 2015 testimony in support of its Stuttgart solar power purchase agreement recognizes this correlation. EAI witness Mr. Castleberry observed that solar output and peak electric demand are correlated, because it is the same resource (the sun) that produces both. See *Direct Testimony of Kurtis W. Castleberry, Director, Resource Planning and Market Operations on Behalf of EAI*, Docket No. 15-014-U, dated April 15, 2015, at pp. 19-20, hereafter "EAI's Stuttgart Testimony."

Associates (NERA) regression method. This approach is used by many utilities to determine their marginal transmission and distribution capacity costs that vary with changes in load. The NERA regression model fits incremental T&D investment costs to peak load growth. The slope of the resulting regression line provides an estimate of the marginal cost of T&D investments associated with changes in peak demand. The NERA methodology typically uses 10-15 years of historical expenditures on T&D investments and peak transmission system loads, as reported in FERC Form 1, and, if available, a five-year forecast of future expenditures and expected load growth.

Transmission. We have utilized a NERA regression based on Entergy's historical peak load growth and transmission expenditures, over an 18-year period from 1996 to 2013. Our analysis of marginal transmission costs uses Entergy's FERC Form 1 data for this period. **Figure 3** shows the regression fit of cumulative transmission capital additions as a function of incremental demand growth on the Entergy system.

Figure 3: *Regression of Cumulative Entergy Transmission Costs vs. Peak Demand*



The regression slope resulting from this analysis is $517 per kW. We add 2.6% to this amount as a general plant loader, convert the total to an annualized marginal transmission cost using a real economic carrying charge (RECC) of 6.5%,[18] and include $4.29 per kW-year for transmission O&M costs. Our estimate of general plant and transmission O&M costs are also based on EAI's FERC Form 1 data. The resulting avoided cost for transmission capacity for Entergy is $38.76 per kW-year.

We use the same capacity contribution of 52.2% discussed above, using the PCAF method based on Entergy loads and actual solar insolation from 2008-2013. We convert the marginal transmission cost in $ per kW-year into a $ per MWh value using an annual solar output of 1,530 kWh per kW-AC. **Tables 9 and 10** show our calculations of this alternative avoided cost of transmission capacity for EAI. The result is that solar DG avoids transmission capacity costs of $13.20 per MWh.

[18] Based on EAI's currently-authorized capital structure and cost of capital.

Table 9: *EAI Marginal Transmission Cost*

Parameter	Value
Slope ($/kW)	517
General Plant Loader (%)	2.6%
General Plant Loader ($/kW)	13
Total Marginal Transmission ($/kW)	530
RECC Factor	6.50%
Annualized Transmission ($/kW-yr)	34.5
Transmission O&M ($/kW-yr)	4.29
Total Annual Marginal Cost ($/kW-yr)	**38.80**

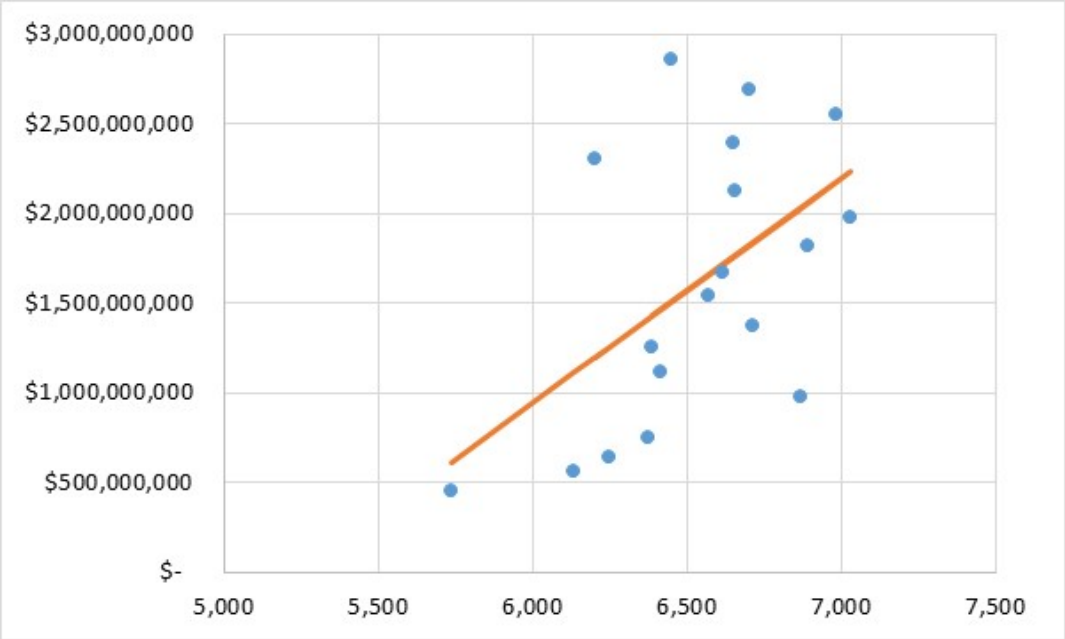
Table 10: *25-year Levelized Avoided Transmission Costs for EAI*

Parameter	Value	Notes
Avoided Transmission Capacity Cost	$38.80 per kW-year	From Table 9
Solar Contribution to MISO South Peak Load	52.2%	PCAF calculation
Solar Output – Annual kWh per kW	1,530 kWh	NREL PVWATTS
Solar Avoided Transmission Capacity Cost	**$13.20 per MWh**	$38.80 x 0.522 / 1.53 MWh

Distribution. The extent to which solar generation avoids distribution capacity costs is a more complex question than for transmission, for various reasons. Distribution substations and circuits can peak at different times than the system as a whole, which complicates the calculation of the avoided distribution costs that result from solar DG reducing distribution system loads. It is clear, however, that the significant share of solar DG output which serves on-site loads will reduce demand on the distribution system, because that power is consumed behind the mater, never touches the grid, and will reduce the loads that must be served from the grid. Further, the remaining DG output that is exported to the distribution system will serve nearby loads, and thus will unload upstream portions of the local distribution system. As a result, solar DG will reduce distribution system loads, avoiding the cost of distribution system expansions or upgrades, and extending the life of existing equipment.

To calculate EAI's marginal distribution costs, we use the same NERA regression method discussed above, using historical peak load growth and distribution expenditures, from FERC Form 1, over the 18 years 1996 to 2013. **Figure 4** shows the regression fit of cumulative distribution capital additions as a function of incremental demand growth on the Entergy system.

Figure 4: *Linear Regression of Cumulative Distribution Costs vs. Peak Demand*



Converting the regression slope of $1,249 per kW to an annual cost using a RECC of 6.5%, plus loaders for general plant and O&M from FERC Form 1 data, results in an annualized marginal distribution cost of $93.98 per kW-year.

Table 11: *EAI Marginal Distribution Cost*

Parameter	Value
Slope ($/kW)	1,249
General Plant Loader (%)	2.6%
General Plant Loader ($/kW)	32
Total Marginal Distribution Cost ($/kW)	1,281
RECC Factor	6.50%
Annualized Transmission ($/kW-yr)	83.30
Transmission O&M ($/kW-yr)	10.71
Total Annual Marginal Cost ($/kW-yr)	**94.00**

For the solar capacity contribution to reducing distribution costs, we used the hourly profile of EAI's residential loads to determine a PCAF allocation of residential demand. We then applied this PCAF allocation to the typical meteorological year profile of hourly solar output in Little Rock. The result is a capacity contribution of 13.5% of solar nameplate to reducing the highest residential class loads. We note that this is a conservative calculation given that we do not have data on actual residential class loads, so this contribution does not reflect the correlation between high loads and high solar output. If we had data on actual residential class loads, we would use a PCAF analysis of these loads applied to actual solar output data from the same period. **Table 12** shows the resulting calculation of avoided distribution costs on a $ per MWh basis.

Table 12: *25-year Levelized Avoided Distribution Costs for EAI*

Parameter	Value	Notes
Avoided Distribution Capacity Cost	$94.00 per kW-year	From Table 11
Solar Contribution to MISO South Peak Load	13.5%	Solar contribution to reducing residential class peaks
Solar Output – Annual kW per kW	1,530 kWh	NREL PVWATTS
Solar Avoided Distribution Capacity Cost	**$8.30 per MWh**	$94.00 x 0.135 / 1.53 MWh

We note that this regression analysis considers only the historical relationship between distribution capital additions and load growth. Moving forward, with the advent of smart inverters and other technologies, PV systems will be able to provide additional services and avoid new categories of costs in addition to those attributable to capacity expansion alone. Such services include voltage regulation, power quality, and conservation voltage reduction. For these reasons, this estimate of avoided distribution costs should be considered conservative.

This alternative **long-term calculation of marginal transmission and distribution capacity costs yields a combined avoided T&D value of $21.50 per MWh.**

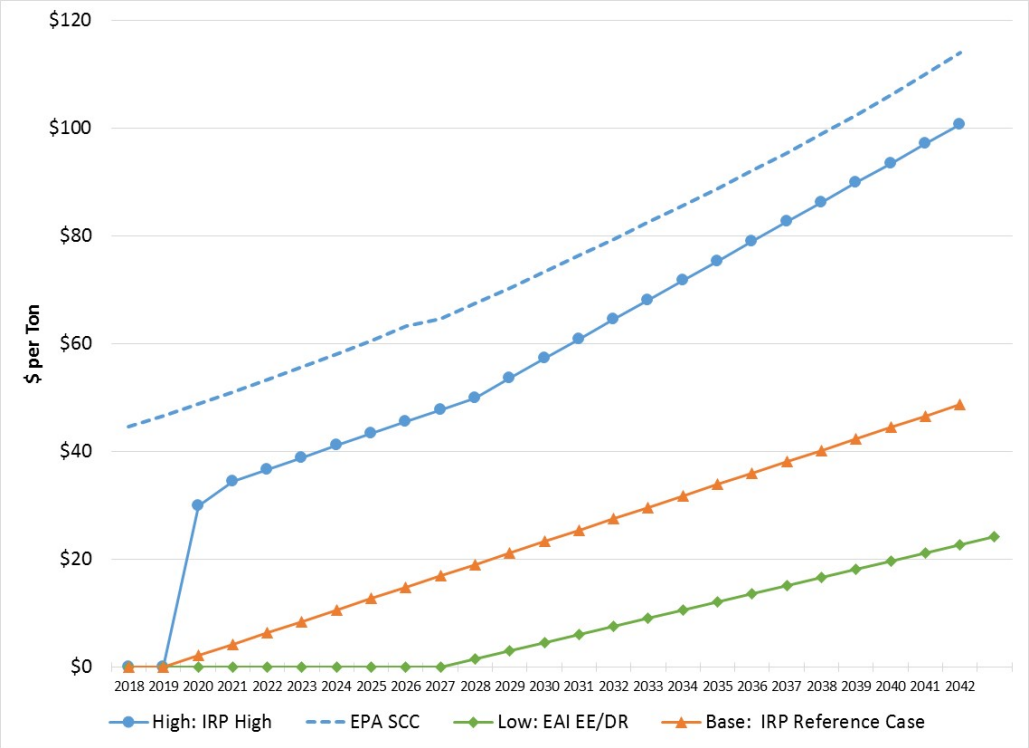
e. Avoided carbon emission compliance costs

Solar PV will avoid carbon emissions from traditional fossil-fueled power plants, and thus avoid the anticipated compliance costs associated with those emissions. Our analysis uses the Environmental Protection Agency's ("EPA") "AVoided Emissions and geneRation Tool" (AVERT) to calculate the avoided carbon emissions due to solar DG installations in Arkansas. AVERT calculates hourly avoided emissions based on a given hourly profile for energy efficiency savings or renewable energy production. Our model assumes 3 MW of DG solar in the state, uses a PV profile for Little Rock, and the Southeast AVERT regional data file to calculate the avoided carbon emissions in Arkansas. The avoided carbon emissions are 1.44 lbs per kWh of DG output, which is similar to the utility's assumed carbon emission reductions from its energy efficiency programs.[19]

Figure 5 shows the range of carbon emission compliance costs (in $ per short ton) that we have used to evaluate this benefit for EAI. For a base case forecast of carbon compliance costs, we make use of EAI's reference case forecast from the *2015 IRP*. For a high case we use EAI's *2015 IRP* high case. As a low case, we include the carbon prices assumed in EAI's *EE Assumptions*, which start at $1.51 per ton in 2027, and which we assume to escalate with the same trajectory as EAI's *2015 IRP* reference case. The figure also shows the U.S. Environmental Protection Agency's (EPA) social cost of carbon (SCC), which is a measure of carbon costs based on the societal damages from unmitigated climate change. We use the SCC later in this report to value the societal benefits from reduced carbon emissions.

[19] See EAI's *Energy Efficiency Program Portfolio Annual Report for the 2015 Program Year*, filed May 2, 2016 in Docket No. 07-085-TF, at page 44, reporting 887 metric tons of reduced carbon dioxide emissions from 1,312,305 kWh net energy savings, or 1.49 lbs per kWh saved.

Figure 5: *Carbon Cost Forecasts*



Based on the carbon compliance costs in Figure 5 and assumed avoided carbon emissions of 1.44 lbs per kWh, we calculate 25-year levelized avoided costs for carbon compliance, assuming a 6.1% discount rate and 0.5% annual solar output degradation. This calculation results in the following avoided costs.

Table 13: *EAI Marginal Carbon Costs*

Scenario:	Base	High Cases		Low Case
Carbon cost forecast	*2015 IRP* Reference Case	*2015 IRP* High Case	EPA SCC*	*EE Assumptions*
Avoided Carbon ($/MWh)	**12.00**	**33.20**	**47.90***	**3.50**

* The EPA SCC forecast is <u>not</u> used to calculate carbon compliance costs. It is only used to calculate societal benefits.

f. Reducing fuel price uncertainty

Renewable generation, including solar DG, reduces a utility's use of natural gas, and thus decreases the exposure of ratepayers to the volatility in natural gas prices, as exemplified by the periodic spikes in natural gas prices. Such spikes have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 6** below.[20]

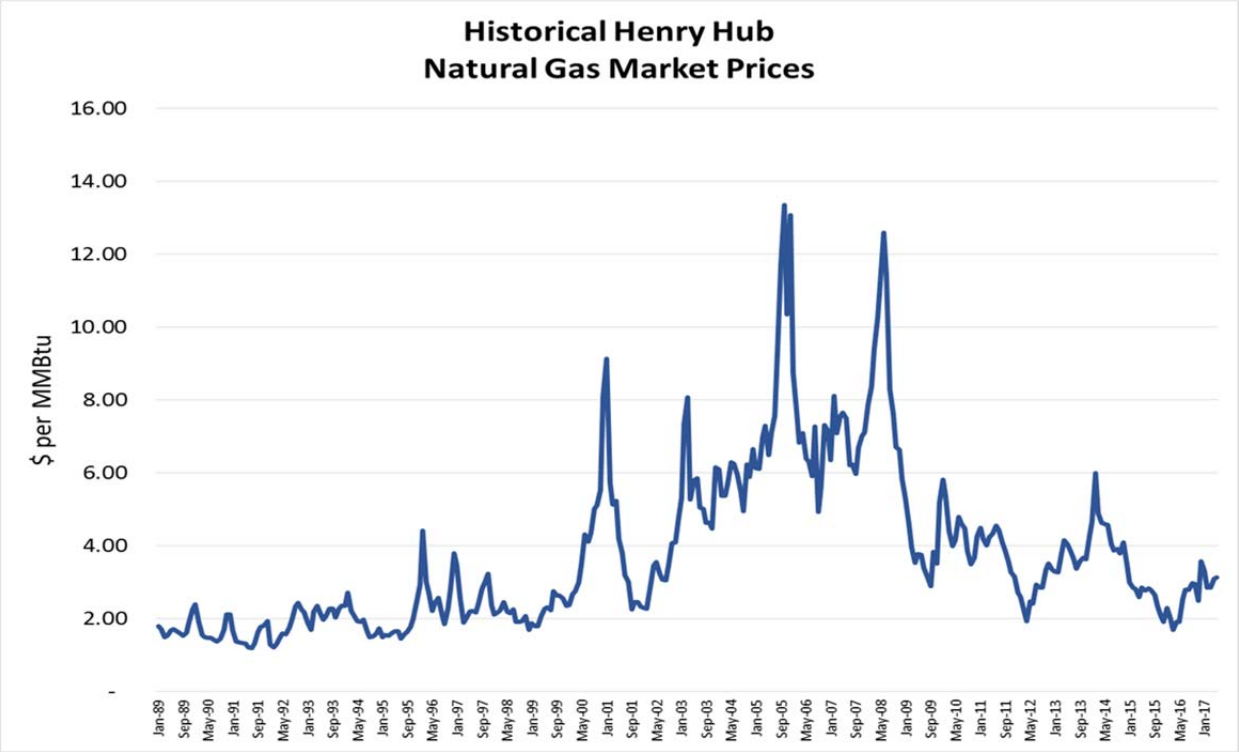
Renewable generation also hedges against market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as has occurred periodically during drought conditions in the U.S. that reduce hydroelectric output and curtail generation due to the lack of water for cooling. For example, in 2014, the rapidly

[20] Source for Figure 3: Chicago Mercantile Exchange data.

increasing output of solar projects in California made up for 83% of the reduction in hydroelectric output due to the multi-year drought in that state.[21]

EAI recognized this fuel hedging benefit in its testimony requesting Commission approval of cost recovery for the power purchase agreement for the Stuttgart solar project. The company argued that the project would diversify its resource portfolio and that "a diverse generation portfolio mitigates risk by helping protect customers from fluctuations in the cost and availability of the fuel needed to produce electricity."[22]

Figure 6:



To calculate this benefit, we follow the methodology used in the *Maine Distributed Solar Valuation Study (Maine Study)*, a 2015 study commissioned by the Maine Public Utilities Commission and authored by Clean Power Research.[23] This approach recognizes that one could contract for future natural gas supplies today, and then set aside in risk-free investments the money needed to buy that gas in the future. This would eliminate the uncertainty in future gas costs. The additional cost of this approach compared to purchasing gas on an "as you go" basis (and using the money saved for alternative investments) is the benefit of reducing the uncertainty in the costs for the fuel that solar DG displaces.

We have performed this calculation for EAI, assuming our base gas cost forecast (the EIA

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[21] Based on Energy Information Administration data for 2014, as reported in Stephen Lacey, *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-fifths of California's lost hydro production in 2014* (Greentech Media, March 31, 2015). Available at http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california.

[22] See EAI's Stuttgart Testimony, at p. 15.

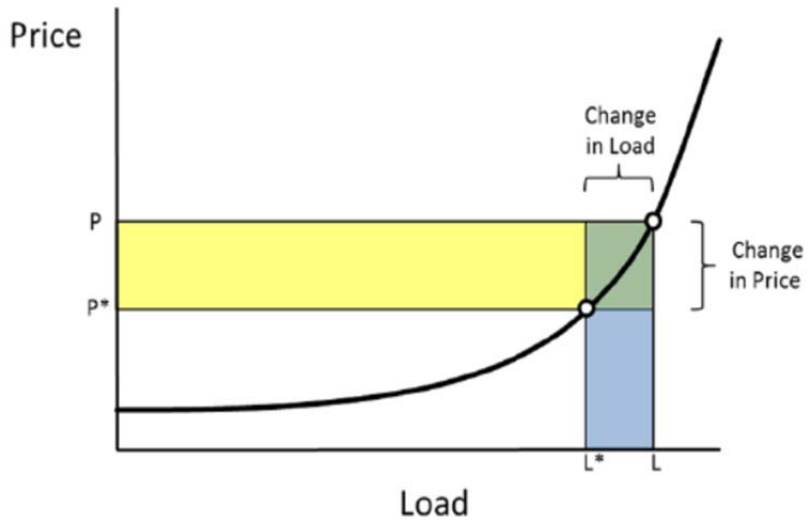
[23] See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015). Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

AEO 2017 forecast), U.S. Treasuries (at current yields) as the risk-free investments, and a marginal heat rate of 7,500 Btu per kWh. The result is **a value of $28.60 per MWh** as the 25-year levelized benefit of reducing fuel price uncertainty.

g. Market price mitigation

The increasing penetration of new renewable generation in Arkansas will place downward pressure on the region's energy market prices. New renewable generation, including solar DG, will reduce demand in the MISO South market. Because this generation is must-take (and has zero variable costs), it will displace the most expensive power that utilities such as EAI would otherwise have generated or purchased, which typically is natural gas-fired generation.[24] Thus, the addition of this local generation in EAI's service territory will reduce the demand which EAI places on the regional markets for both electricity and natural gas. With this reduction in demand, there is a corresponding reduction in the prices in these markets, which benefits EAI across the full volumes of its purchases in these markets. This "market price mitigation" benefit of renewable generation is widely acknowledged, and has become highly visible in markets that now have high penetrations of wind and solar resources.[25] The benefit is illustrated schematically in the yellow-shaded section of **Figure 7**.

Figure 7: *Reduced Demand in the Energy Market Lowers the Price*



The magnitude of this benefit will depend on the overall amount of renewables on the grid. From 2010-2014, the National Renewable Energy Laboratory (NREL) and GE Consulting released the multi-phase Western Wind and Solar Integration Study (WWSIS), a major modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S.[26] This work focused on the West Connect area (basically, Arizona, Colorado, New Mexico, Nevada, and Wyoming), but also modeled the entire WECC grid in the U.S. This modeling included analysis

[24] MISO reports the hourly marginal source of generation on its system. For our base period of June 2016 to May 2017, the MISO South marginal resource has been natural gas in 73% of hours and coal in 27% of hours.

[25] The market price mitigation benefit is not the same as the fuel hedging benefit discussed above. Both benefits involve energy market prices for electricity and natural gas. However, the fuel hedging benefit for consumers results from a reduction in the volatility of these market prices – in other words, in a reduced risk of periodic price spikes in these commodity markets, whereas the market price mitigation benefit is from an overall reduction in the levels of these market prices. Thus, these benefits are related but do not overlap and are not duplicative.

[26] All reports from the WWSIS, are available on the NREL website at http://www.nrel.gov/electricity/transmission/western_wind.html.

of the impact of increasing solar penetration on market prices in the West; the results for spot prices in Arizona are shown in the figure below.[27] Generally, the high penetration solar cases (15% to 25% penetration) result in 10% to 20% reductions in spot market prices. Note that the largest reductions in market prices occur from the initial 5% penetration of solar, which Arkansas is still well within.

Figure 8:

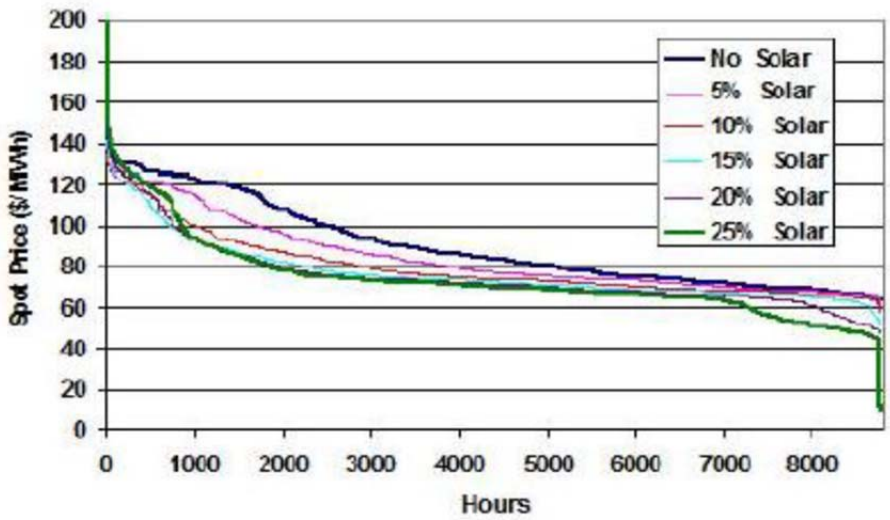


Figure 19 – Arizona Spot Price Duration Curves.

The same market mitigation benefit exists on the natural gas side. Renewable generation reduces marginal gas-fired generation, thus lowering the demand for natural gas. A study by Lawrence Berkeley National Lab (LBNL) has estimated that the gas-related market mitigation benefits of renewable energy range from $7.50 to $20 per MWh of renewable output.[28]

The New England states have done the most extensive work to calculate this market benefit, which they have labelled the Demand Reduction Induced Price Effect (DRIPE). DRIPE is included in the region's biennial forecast of avoided costs used for demand-side programs, *Avoided Energy Supply Costs in New England (AESC)*.[29] We have reviewed the DRIPE calculations in the *2013 and 2015 AESC* reports. There is a significant difference in the DRIPE impacts between the *2013* and *2015 AESC* reports, as a result of changes in the methodology for the DRIPE calculations in the *2015 AESC*.[30] For example, the *2015 AESC* assumes (1) a much shorter duration for energy DRIPE impacts (three years) and (2) zero capacity DRIPE as a result of an assumed near-term need for new capacity in New England. We have not attempted to resolve these differences, but for the purposes of this study have used the average of the energy DRIPE impacts between the two studies – a 4% reduction in avoided energy costs. We do not assume any capacity DRIPE, given the near-term need for new capacity in Arkansas. **Thus, the energy**

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[27] The results from the WWSIS for high penetrations of solar are reported in *Impact of High Solar Penetration in the Western Interconnection* (NREL and GE Consulting, December 2010), with the impact on spot market prices in Arizona reported at p. 8 and Figure 19.

[28] See Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (LBNL, January 2005), at p. ix, available at http://eetd.lbl.gov/EA/EMP.

[29] See *2015 AESC*, at Appendix B., Tables One and Two. This report is available at https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf.

[30] See *2015 AESC*, at pages 1-5 and 1-16 to 1-17.

market price mitigation benefit is 4% of our avoided energy costs, plus associated losses, or $2.80 per MWh.

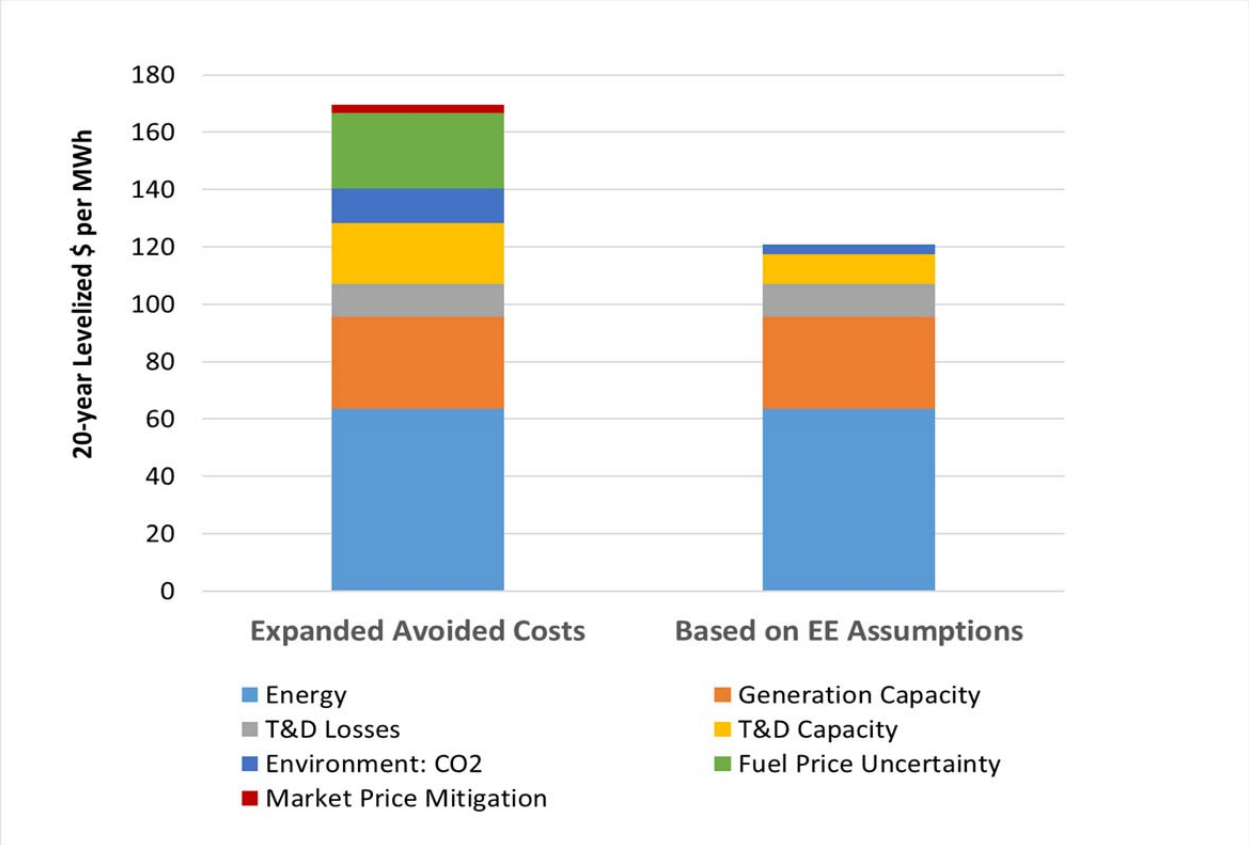
h. Total Direct Benefits

The following **Table 14** and **Figure 9** summarize the direct benefits of solar DG for EAI's ratepayers, for two sets of avoided costs – first, avoided costs limited to the *EE Assumptions*, and second, a broader set of avoided costs that includes the full set of long-term direct benefits discussed above. **The direct benefits range from 12.1 to 17.2 cents per kWh.**

Table 14: *Summary of Direct Benefits (25-year levelized $ per MWh)*

Benefit	**Base Case:** Avoided Costs from *EE Assumptions* ($ per MWh)	**Expanded Case:** Broader Set of Benefits ($ per MWh)
Energy	63.50	63.50
Generation Capacity	32.10	32.10
T&D Losses	11.60	11.60
T&D Capacity	10.20	21.50
Environment: CO_2	3.50	12.00
Fuel Price Uncertainty		28.60
Market Price Mitigation		2.80
Total Benefits	120.90	172.10
	12.1 cents per kWh	**17.2 cents per kWh**

Figure 9: *Summary of Direct Benefits*



4. Societal Benefits of Solar DG

Renewable DG has benefits to society that do not directly impact utility rates, many of which were expressly recognized by the Arkansas legislature when it enacted the Arkansas Renewable Energy Development Act of 2001 (AREDA).[31] When renewable generation takes the place of conventional fossil fuel generation, all members of society benefit from reductions in air pollutants that harm human health and exacerbate climate change. Demands on existing water supplies are reduced, avoiding the potential need to acquire new sources of supply. Distributed generation uses already-built sites, preserving land for other uses or as natural habitat. Distributed generation makes the power system more reliable and resilient, and stimulates the local economy. Many of these benefits can be quantified, as discussed below. We use a lower, societal discount rate of 5% (3% real) in calculating these benefits, rather than the 6.1% EAI discount rate used for the direct benefits.

a. Carbon

The **social cost of carbon** (SCC) is "a measure of the seriousness of climate change."[32] It is a way of quantifying the value of actions to reduce greenhouse gas emissions, by estimating the potential damages if carbon emissions are not reduced. The carbon costs which we have included in the direct benefits of solar DG above are limited to the anticipated costs to comply with future regulation of carbon emissions. These compliance costs are assumed to be lower than the true costs that carbon pollution imposes on society, which are the damages estimated by the SCC. As a result, the additional costs in the SCC, above the compliance costs of mitigating carbon emissions, represent the societal benefits of avoided carbon emissions.

The most prominent and well-developed source for estimates of the social cost of carbon is the federal government's Interagency Working Group on the Social Cost of Carbon.[33] These values have been vetted by numerous government agencies, research institutes, and other stakeholders. The cost values were derived by combining results from the three most prominent integrated assessment models, each run under five different reference scenarios.[34] The group gave equal weight to each model and averaged the results across each scenario to obtain a range of values depending on the discount rate, given in the table below.

Table 15: *Social Cost of Carbon*[35] *(2007 $ per metric tonne of CO_2)*

	Discount Rate		
	5%	**3%**	**2.5%**
Social Cost of Carbon	11	36	56

[31] A.C.A. § 23-18-601.

[32] Anthoff, D. and Toll, R.S.J. 2013. The uncertainty about the social cost of carbon: a decomposition analysis using FUND. *Climactic Change* 117: 515-530.

[33] Interagency Working Group on Social Cost of Carbon, *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (May 2013, Revised July 2015). Available at: https://www3.epa.gov/climatechange/Downloads/EPAactivities/social-cost-carbon.pdf.

[34] *Id.* The three models are the Dynamic Integrated Climate-Economy (DICE) model, the Climate Framework for Uncertainty, Negotiation and Distribution (FUND) model, and the Policy Analysis of the Greenhouse Effect (PAGE) model.

[35] *Id.*, p. 13.

We recommend a base case SCC using the mid-range value of $36 per tonne based on a 3% discount rate. We escalate these benefits by 5% per year, recognizing that "future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change."[36]

While estimating the social cost of carbon contains many inherent uncertainties, we believe these values are appropriate. The mid-range real discount rate of 3% is a typical societal discount rate often used in long-term benefit/cost analyses. It is also a conservative assumption, when considering the diminished prosperity future generations will face in a world heavily impacted by climate disruption. Because "the choices we make today greatly influence the climate our children and grandchildren inherit," future benefits should not be significantly discounted relative to current costs.[37] As Pope Francis wrote in his encyclical calling for "all people of goodwill" to take action on climate change: "The climate is a common good, belonging to all and meant for all."[38]

We calculate the societal benefits for the years 2018 – 2042 of reducing carbon emissions as (1) the mid-range value of the SCC less (2) the base case for the compliance carbon costs used in our direct benefits, discussed above. The 25-year levelized difference is $35.90 per MWh.

Reduced methane leakage. In addition, we also determine the total greenhouse gas emissions that will result from methane leakage in the natural gas infrastructure that serves marginal gas-fired power plants. We attach to this report as **Attachment 2** a recent white paper calculating the additional greenhouse gas emissions associated with methane leaked in providing the fuel to gas-fired power plants. This issue has received significant attention recently as a result of the major methane leak from the Aliso Canyon gas storage field in southern California. The bottom line is that the CO_2 emission factors of gas-fired power plants should be increased by 50% to account for these directly-related methane emissions from the production and pipeline infrastructure that serves gas-fired electric generation. This additional societal benefit amounts to $8.00 per MWh.

b. Health benefits of reducing criteria air pollutants

Reductions in criteria pollutant emissions improve human health. Exposure to particulate matter (PM) causes asthma and other respiratory illnesses, cancer, and premature death.[39] Nitrous oxides (NO_X) react with volatile organic compounds in the atmosphere to form ozone, which causes similar health problems.[40]

We use AVERT to calculate the avoided emissions of SO_2 and NO_x assuming 20 MW of solar DG development. To calculate the avoided fine particulate matter ($PM_{2.5}$) emissions, we assume an emissions factor of 0.0077 lbs/MMBtu for $PM_{2.5}$ emissions from the combustion of

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[36] *Id*, pp. 13-14. 5% annual escalation in carbon costs has been used in both California and Arizona. See the CPUC Final Public Tool referenced in Footnote 2, at tab "Key Driver Inputs," at Cell D33. 5% is also midway between the two escalation rates (2.5% and 7.5% per year) used in the carbon cost scenarios in Arizona Public Service's *2014 Integrated Resource Plan*.

[37] California Climate Change Center, Our Changing Climate: Assessing the Risks to California (2006) at p. 2. http://www.energy.ca.gov/2006publications/CEC-500-2006-077/CEC-500-2006-077.pdf.

[38] Encyclical Letter *Laudato Si'* of the Holy Father Francis on Care for Our Common Home. June 18, 2015.

[39] EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014), p. 4-17 ("CPP Technical Analysis"). Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

[40] *Ibid.*

natural gas. This factor is from "AP 42," the EPA's compilation of air pollutant emissions factors.[41]

For quantifying the health benefits, we recommend using the health co-benefits from reductions in criteria pollutants that EPA developed in conjunction with the Clean Power Plan. These benefit estimates were developed in 2014 as part of the technical analysis for the proposed rule.

Table 16: *Avoided Emissions of Criteria Pollutants*

Pollutant	Avoided Emissions lbs/MWh
SO_2	1.68
NOx	1.01
$PM_{2.5}$	0.067

The value of these avoided emissions is calculated as follows:

1. Determine the amount of avoided emissions using AVERT as described above.
2. Calculate the social cost of the avoided emissions and subtract the compliance cost or emissions market value of those emissions.

SO_2. The analysis for SO_2 follows the same steps as the analysis for carbon. The total social cost of SO_2 is taken from the EPA's *Regulatory Impact Analysis for the Final Clean Power Plan (CPP Impact Analysis)*.[42] The EPA calculated social cost values for 2020, 2025, and 2030. This analysis uses the values given for these three years assuming a 3% discount rate. Values for intermediate years are interpolated between the five-year values. The market value of SO_2 is taken from the EPA's 2016 SO_2 allowance auctions. However, the final clearing price of the latest spot auction was just $0.06 per ton.[43] This is low enough compared to the social cost that it is negligible for our calculations. The societal benefit of avoided SO_2 emissions is $71.90 per MWh.

NOx. Heath damages from exposure to nitrous oxides come from the compound's role in creating secondary pollutants: nitrous oxides react with volatile organic compounds to form ozone, and are also precursors to the formation of particulate matter.[44] The social cost of NOx is taken from the EPA's CPP Impact Analysis.[45] We use a recent 2017 NO_x market price of $750 per ton for compliance with the Cross State Pollution Rule as the compliance cost for NOx.[46] The benefit of avoiding NOx emissions is $8.80 per MWh.

Fine Particulates ($PM_{2.5}$). We use the emissions factor and damage costs for $PM_{2.5}$, because $PM_{2.5}$ are the small particulates with the most adverse impacts on health. The EPA health co-benefit figures distinguish between types of PM, and calculate two separate benefit-per-ton

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[41] U.S. EPA, "Emissions Factors & AP 42, *Compilation of Air Pollutant Emission Factors*," http://www.epa.gov/ttn/chief/ap42/index.html. See also Section 1.4 (*Natural Gas Combustion*), Table 1.4-2, "PM emission factors presented here may be used to estimate PM10, PM2.5 or PM1 emissions."

[42] *Regulatory Impact Analysis for the Final Clean Power Plan*. Found at: https://www.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule-ria.pdf.

[43] EPA 2016 SO2 Allowance Auction. Found at: https://www.epa.gov/airmarkets/2016-so2-allowance-auction.

[44] CPP Technical Analysis, p. 4-14.

[45] *CPP Impact Analysis*, at Table 4-7.

[46] See the EPA Cross State Air Pollution Rule. Found at: https://www.epa.gov/csapr. Recent NOx emission allowance prices can be found at http://www.evomarkets.com/content/news/reports_23_report_file.pdf.

estimates for PM: for PM emitted as elemental and organic carbon, and for PM emitted as crustal particulate matter.[47] The EPA estimates that approximately 70% of primary $PM_{2.5}$ emitted in Arkansas is crustal material, with the bulk of the remainder being elemental or organic carbon.[48] The emissions factor of 0.0077 lbs per MMBtu for total primary $PM_{2.5}$ does not differentiate among particle types.[49] As a result, we weigh the mid-point of each of the two benefit-per-ton estimates according to EPA's assumptions for Arkansas emissions. The health benefits of reducing $PM_{2.5}$ emissions are $3.70 per MWh on a 25-year levelized basis.

c. Water

Thermal generation consumes water, principally for cooling. Reducing water use in the electric sector through the use of renewable generation lowers the vulnerability of the electricity supply to the availability of water, and reduces the possibility that new water supplies will have to be developed to meet growing demand. However, water consumption by efficient gas-fired generation is relatively low, and the cost of incremental water supplies varies widely depending on the local abundance of water resources. As a result, the value of avoided water use is relatively modest. We have used $1.20 per MWh for the value of avoided water use, based on several sources.[50]

d. Local economic benefits

AREDA specifically notes the economic development benefits associated with distributed renewable energy.[51] Indeed, while distributed generation has higher costs per kW than central station renewable or gas-fired generation, a portion of the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – are spent in the local economy, and thus provide a local economic benefit in close proximity to where the DG is located. These local costs are an appreciable portion of the "soft" costs of DG. Central station power plants have significantly lower soft costs, per kW installed, and often are not located in the local area where the power is consumed.

There have been a number of recent studies of the soft costs of solar DG, as the industry has focused on reducing these costs, which are significantly higher in the U.S. than in other major international markets for solar PV. The following **Table 17** presents data on the soft costs for residential PV systems that are likely to be spent in the local area where the DG customer resides, from detailed surveys of solar installers that were conducted by two national labs (LBNL and NREL) in 2013.

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47 CPP Technical Analysis, p. 4-26, Table 4-7.

48 *Ibid*., p. 4A-8, Figure 4A-5.

49 AP 42, Table 1.4-2, Footnote (c).

50 This figure is based on the American Wind Energy Association's estimate that, in 2016, operating wind projects produced 226 million MWh and avoided the consumption of 87 billion gallons of water, with a cost of new water resources of about $1,000 per acre-foot. This is similar to the mid-point of cost estimates for the cost of water savings at gas-fired power plants by implementing dry cooling technologies. See Maulbetsch, J.S.; DiFilippo, M.N. *Cost and Value of Water Use at Combined-Cycle Power Plants*. CEC-500-2006-034. Sacramento: California Energy Commission, PIER Energy-Related Environmental Research, 2006, available at http://www.energy.ca.gov/2006publications/CEC-500-2006-034/.

51 A.C.A. § 23-18-602(a) ("Increasing the consumption of renewable energy . . . fosters investments in emerging renewable technologies to stimulate economic development and job creation in the state.").

Table 17: *Residential Local Soft Costs*

Local Costs	LBNL – J. Seel *et al.*[52]		NREL – B. Friedman *et al.*[53]	
	$/watt	%	$/watt	%
Total System Cost	6.19	100%	5.22	100%
Local Soft Costs				
Customer acquisition	0.58	9%	0.48	9%
Installation labor	0.59	10%	0.55	11%
Permitting & interconnection	0.15	2%	0.10	2%
Permit fees	0.09	1%	0.09	2%
Total local soft costs	**1.41**	**22%**	**1.22**	**23%**

Based on these studies, we assume that 22% of residential solar PV costs are spent in the local economy where the systems are located. These economic benefits occur in the year when the DG capacity is initially built, which for the purpose of this study is 2018. We have converted these benefits into a $ per kWh benefit over the expected DG lifetime that has the same net present value in 2018 dollars. We also use more current DG capital costs than the system costs used in the LBNL and NREL studies. The result is a societal benefit of $33.60 per MWh of DG output for residential systems.

e. Land use

Distributed generation makes use of the built environment in the load center – typically roofs and parking lots – without disturbing the existing use for the property. In contrast, central station fossil or renewable plants require large single parcels of land, and tend to be more remotely located where the land has agricultural or habitat uses. Unless the site is already being used for power generation, the land must be removed from its prior use when it becomes a solar farm or a fossil power plant. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-AC, or 3.3 to 4.4 acres per GWh per year. The lost value of the land can vary over a wide range, depending on the alternative use to which it could be put. Based on the 2017 U.S. Department of Agricultural rental value for irrigated croplands in Arkansas ($132 per acre),[54] and 4 acres per GWh, the land use value avoided by DG is about $0.5 per MWh. This value will be lower if the land has an alternative use of lower value than irrigated land for farming.

f. Reliability and resiliency

AREDA specifically calls for the Commission to consider impacts to reliability as part of the "cost of providing service" to net metering customers and the benefits associated with distributed generation.[55] Renewable distributed generation resources are installed as thousands of small, widely distributed systems and thus are highly unlikely to experience outages at the same time. Furthermore, the impact of any individual outage at a DG unit will be far less consequential

[52] J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (Lawrenece Berkeley National Lab, February 2013), at pp. 26 and 37.

[53] B. Friedman et al., *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition* (National Renewable Energy Lab, October 13, 2013), at Table 2.

[54] See USDA, National Agricultural Statistics Service, Survey of 2017 Cash Rents, available at https://quickstats.nass.usda.gov/results/58B27A06-F574-315B-A854-9BF568F17652#7878272B-A9F3-3BC2-960D-5F03B7DF4826.

[55] See A.C.A. § 604(b)(1)(A)(ii).

than an outage at a major central station power plant. In addition, the DG customer, not the ratepayers, will pay for the repairs. DG is located at the point of end use, and thus also reduces the risk of outages due to transmission or distribution system failures.

One study of the benefits of solar DG has estimated the reliability benefits of DG from a national perspective.[56] The study assumed that a solar DG penetration of 15% would reduce loadings on the grid during peak periods, mitigating the 5% of outages that result from such high-stress conditions. Based on a study which calculated that power outages cost the U.S. economy about $100 billion per year in lost economic output, the levelized, long-term benefits of this risk reduction were calculated to be $20 per MWh ($0.02 per kWh) of DG output. This calculation does not necessarily assume that the DG is located behind the customer's meter, so this reliability benefit also might result from widely distributed DG at the wholesale level.

However, most electric system interruptions do not result from high demand on the system, but from weather-related transmission and distribution system outages. In these more frequent events, renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain government, institutional, and economic functions related to safety and human welfare during grid outages.

Both DG and storage are essential in order to provide the reliability enhancements that are needed to eliminate or substantially reduce weather-related interruptions in electric service. The DG unit ensures that the storage is full or can be re-filled promptly in the absence of grid power, and the storage provides the alternative source of power when the grid goes down. DG also can supply some or all of the on-site generation necessary to develop a micro-grid that can operate independently of the broader electric system. It is challenging to quantify this benefit, which will be realized over time as storage technology is added to renewable DG systems.[57] Nonetheless, solar DG is a foundational element necessary to realize this benefit – in much the same way that smart meters are necessary infrastructure to realize the benefits of time-of-use rates, dynamic pricing, and demand response programs that will be developed in the future – and thus the reliability and resiliency benefits of wider solar DG deployment should be recognized as a broad societal benefit.

g. Customer choice

AREDA also cites "greater consumer choices" as a benefit of renewable generation that justifies the adoption of net metering.[58] There are important public policy reasons to ensure that the customers who invest in DG are treated equitably in assessments of the merits of net metering and renewable DG, so that consumers continue to have the freedom to exercise a competitive choice, to become more engaged and self-reliant in providing for their energy needs, and to encourage others to invest private capital in Arkansas's clean energy infrsatructure.

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[56] Hoff, Norris and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2 and pages 18-19.

[57] It is also important to recognize that adding storage may be cost-effective even without considering its reliability benefits when paired with DG. Distributed storage can reduce demand charges, allow TOU rate arbitrage, and provide power quality and capacity-related benefits to the utility or grid operator. Indeed, distributed storage may be economic as a result of the benefits in these other use cases, without considering the reliability benefits for the customer.

58 See A.C.A. § 23-18-602(a).

There are many dimensions to the customer choice benefits of DG technologies, including:

- **New Capital.** Customer-owned or customer-sited generation brings new sources of capital for clean energy infrastructure. Given the magnitude and urgency of the task of moving to clean sources of energy, expanding the pool of capital devoted to this task is essential.

- **New Competition.** Rooftop solar provides a competitive alternative to the utility's delivered retail power. This competition can spur the utility to cut costs and to innovate in its product offerings. With the widespread availability of rooftop solar, energy efficient appliances, and load management technologies, plus – in the near future – customer-sited storage, this competition will only intensify. In the now-foreseeable future, the combination of solar, storage, and load management may offer an electric supply whose quality and reliability is comparable to utility service.

- **High-tech Synergies.** Rooftop solar appeals to those who embrace the latest in technology. Solar has been described as the "gateway drug" to a host of other energy-saving and clean energy technologies. Studies have shown that solar customers adopt more energy efficiency measures than other utility customers, which is logical given that it makes the most economic sense to add solar only after making other lower-cost energy efficiency improvements to your premises.[59] Further, with net metering, customers retain the same incentives to save energy that they had before installing solar. These synergies will only grow as the need to make deep cuts in carbon pollution drives the increasing electrification of other sectors of the economy, such as transportation.

- **Customer Engagement.** Customers who have gone through the process to make the long-term investment to install solar learn much about their energy use, about utility rate structures, and about producing their own energy. Given their long-term investment, they will remain engaged going forward. There is a long-term benefit to the utility and to society from a more informed and engaged customer base, but only if these customers remain connected to the grid. As we have seen recently in Nevada, this positive customer engagement can turn to customer "enragement" if the utility and regulators do not accord the same respect and equitable treatment to customers' long-term investments in clean energy infrastructure that is provided to the utility's investments and contracts. Emerging storage and energy management technologies may allow customers in the future to "cut the cord" with their electric utility in the same way that consumers have moved away from the use of traditional

[59] See the *2009 Impact Evaluation Final Report on the California Solar Initiative*, prepared by Itron and KEMA and submitted in June 2010 to Southern California Edison and the Energy Division of the California Public Utilities Commission. See pages ES-22 to ES-32 and Chapter 10. Also available at the following link: http://www.cpuc.ca.gov/workarea/downloadasset.aspx?id=7677. Also see Center for Sustainable Energy, *Energy Efficiency Motivations and Actions of California Solar Homeowners* (August 2014), at p. 6, finding that more than 87% of solar customers responding to a survey had installed or upgraded one or more energy efficiency technologies in their homes. Available at https://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/Energy%20Efficiency%20Motivations%20and%20Actions%20of%20California%20Solar%20Homeowners.pdf.

infrastructure for landline telephones and cable TV. Given the important long-term benefits that renewable DG can provide to the grid if customer-generators remain connected and engaged, it is critical for regulators and utilities to avoid alienating their most engaged and concerned customers.

- **Self-reliance.** The idea of becoming independent and self-reliant in the production of an essential commodity such as electricity, on your own property using your own capital, has deep appeal to Americans, with roots in the Jeffersonian ideal of the citizen (solar) farmer.

These benefits of customer choice are difficult to express in dollar terms; however, all are strong policy reasons for ensuring that the development of clean energy infrastructure includes policies which sustain a robust market for rooftop solar, as the Arkansas legislature has acknowledged.

h. Summary of societal benefits

Table 18 below summarizes the societal benefits of solar DG that we have quantified and discussed. **The societal benefits total 16.3 cents per kWh.**

AREDA cites many of the societal benefits discussed above as the reasons why the state should implement net metering, reflecting the Legislature's clear judgment that these benefits have significant value for the residents of the state.[60] As discussed above, many of these benefits can be quantified, and indeed they do have significant value. Accordingly, these benefits cannot and should not be ignored by policymakers, because ignoring them implicitly values them at zero.

[60] See A.C.A. § 23-18-602.

Table 18: *Societal Benefits*

Benefit	Value ($ per MWh)	Method Used
Carbon: avoid societal damages from climate change	35.90	Use the difference between *the 2015 IRP* carbon cost and the EPA's social cost of carbon value measuring societal damages from climate change.
Carbon: reduce methane leaks from natural gas infrastructure	8.50	Assumes 2% leakage, per 2015 National Academy of Sciences paper.
Reduce SO_2 emissions	71.90	EPA AVERT model for avoided SO2 emissions. EPA estimates of health benefits.
Reduce NO_x emissions	8.80	EPA AVERT model for avoided NOx emissions. EPA estimates of health benefits.
Reduce $PM_{2.5}$ emissions	3.70	EPA Clean Power Plan technical appendices and EPA AP 42 for emissions factors.
Avoid consumptive water use	1.20	Several estimates of avoided water use from renewable generation.
Local economic benefit	33.60	22% of residential system cost is incremental expenses in the local economy, compared to a central station plant.
Land use	Small and positive, but varies	Highly variable based on alternative uses of land at which large power plants are sited.
Reliability	Significant and positive	Significant reliability and resiliency benefits from the pairing of solar DG and on-site storage.
Customer choice	Significant and positive	
Total	**163.60**	Use in the Societal Test

5. Costs of Solar DG for Participants

We use a pro forma cash flow analysis to project the lifecycle levelized cost of energy (LCOE) from a solar DG system based on 2015 solar system costs surveyed and reported by Lawrence Berkeley National Laboratory (LBNL) in their annual *Tracking the Sun* report. Due to the small penetration of solar in Arkansas, we adopt the solar costs that LBNL reported for Texas. The other major assumptions we use are summarized in **Table 19**.

Table 19: *Key Assumptions for the Residential Participant Cost of Solar*

Assumption	Value
Median Cost	$3.00 per watt DC
Range of Costs	$2.70 - $3.50 per watt DC
Federal ITC	30%
Financing Cost	5%
Participant discount rate	5%
Financing Term	15 years
Inverter Replacement	$500/kW in Year 15
Maintenance Cost	$10 per kW-year

The resulting **levelized cost of solar for residential customers is 12.8 cents per kWh.** This cost drops to 11.7 cents per kWh at the low end of the range of costs ($2.70 per watt DC).

6. Costs of Solar DG for the Utility and Non-Participating Ratepayers

We evaluated two additional costs from the perspective of the utility and non-participating ratepayers or the utility system as a whole: solar customer bill savings (lost revenues) and solar integration costs. The primary costs of solar DG for non-participating ratepayers are the retail bill savings provided to solar customers through net metering, i.e., the revenues that the utility loses as a result of DG customers serving their own load and that may be recovered from other ratepayers after rates are readjusted in a subsequent rate case.

We calculate this amount assuming that a residential customer using 15,000 kWh per year installs a solar PV system with annual generation equal to 80% of the customer's annual load prior to any degradation. Thus, the customer's solar PV system produces 12,000 kWh per year, and this output degrades by 0.5% per year thereafter.

We model hourly customer load based on NREL data for a typical load profile for a residential customer in Little Rock.[61] An hourly solar PV generation profile for a rooftop PV system in Little Rock is taken from the NREL PVWATTS model. We scale the customer load to 15,000 kWh per year, and scale the PV output to 12,000 kWh per year (the estimated output for a 7.8 kW-AC system). The hourly differences between these series are, when positive, the customer's net demand for delivered power from the utility, and, when negative, the customer's net exports to the utility grid. We then add up the hourly amounts in order to compute the monthly net usage which determines the customer's bill under net metering.

Bill calculations assume EAI's General Purpose Residential Service (RS) rates, as approved in Docket No. 15-015-U. We estimate that the modeled customer's bill would decrease from $127 per month without solar to $33 per month with solar PV. The $95 per month bill savings associated with our modeled 7.8 kW-AC solar PV system indicate that the customer is able to save 9.5 cents per kWh of solar PV generation in the first year (i.e. $95/1000 kWh = $0.095 per kWh). Assuming 2% annual rate escalation and 0.5% solar PV degradation, **the 25-year levelized value of the customer's bill savings (the utility's lost revenues) are 11.4 cents per kWh**.

Next, we add an estimate of solar integration costs derived from solar integration studies of other utilities with much higher solar penetrations.[62] These integration costs are the cost of the additional ancillary services needed to accommodate the increased variability that intermittent solar output adds to the utility system. Xcel Energy in Colorado calculated solar integration costs as $1.80 per MWh on a 20-year levelized basis.[63] A March 2014 study by Duke Energy estimated

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[61] See the data file at https://openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states for Little Rock.

[62] It is also possible that the utility may incur costs to administer the net metering program. It is speculative to estimate these costs without specific information from the utility. However, we expect that such costs are minimal at the current penetration of net metered systems in Arkansas.

[63] Xcel Energy Services for Public Service Company of Colorado, "Cost and Benefit Study of Distributed Solar Generation on the Public Service Company of Colorado System" (May 23, 2013), at Table 1, pages v and 41-42. Available at http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Costs%20and%20Benefits%20of%20Distri

solar integration costs on its system in North Carolina ranging from $1.43 to $9.82 per MWh, depending on the level of PV penetration.[64] Based on the penetration level in Arkansas, the lower end of the range in the Duke study would apply. Arizona Public Service did a 2012 integration study that estimated integration costs on its system of $2 per MWh in 2020.[65] Based on this body of work, we assume that **$2 per MWh represents a reasonable assumption for a 25-year levelized solar integration cost in Arkansas**.

Thus, the utility costs associated with **reduced customer bills and solar integration combine to equal 11.6 cents per kWh** (i.e. 11.4 cents per kWh in lost retail revenues plus 0.2 cents per kWh in solar integration costs).

7. Results and Key Conclusions of this Benefit / Cost Analysis

The following **Table 20** and **Figure 10** incorporate the results of the above analyses into each of the primary cost-effectiveness tests for residential solar DG on the EAI system. These tests of the cost-effectiveness of solar DG consider benefits and costs from multiple perspectives. Other demand-side programs typically are evaluated from these multiple perspectives, and policymakers should take a similarly broad view in assessing solar DG.

Table 20: *Benefits and Costs of Solar DG for EAI (25-yr levelized cents/kWh)*

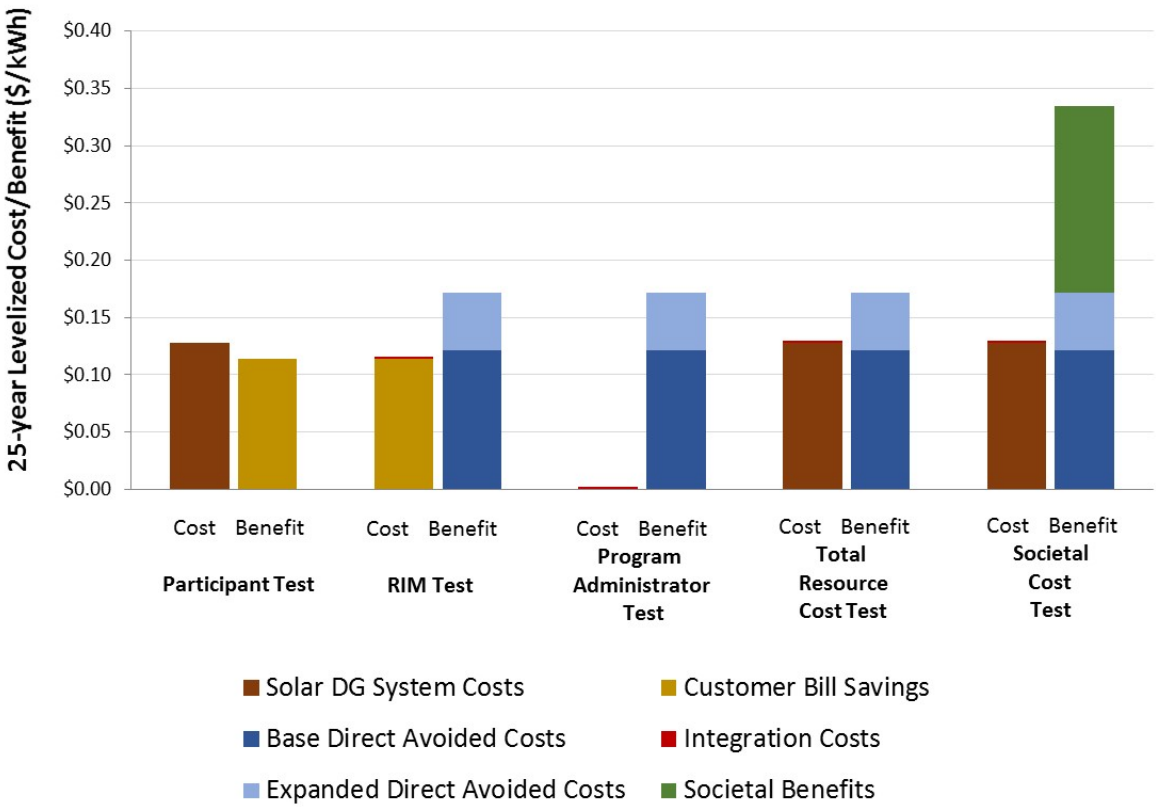
Benefit-Cost Test	**Participant**		**RIM / PAC**		**TRC**		**Societal**	
Category	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Base Direct Avoided Costs – *EE Assumptions*				12.1		12.1		12.1
Expanded Direct Avoided Costs				17.2		17.2		17.2
Lost Revenues / Bill Savings (RIM / PCT)		11.4	11.4					
Integration (RIM / TRC)			0.2		0.2		0.2	
Solar DG LCOE	12.8				12.8		12.8	
Societal Benefits								16.4
Totals	12.8	11.4	11.6	12.1 – 17.2	13.0	12.1 – 17.2	13.0	28.5 – 33.6
Benefit / Cost Ratios	**0.89**		**1.04 -1.48 (RIM) >> 1 (PAC)**		**0.93 – 1.32**		**2.19 – 2.58**	

buted%20Solar%20Generation%20on%20the%20Public%20Service%20Company%20of%20Colorado%20System%20Xcel%20Energy.pdf

[64] See http://www.pnucc.org/sites/default/files/Duke%20Energy%20PV%20Integration%20Study%20201404.pdf

[65] See Arizona Public Service, *2014 Integrated Resource Plan*, at p. 43, citing Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

Figure 10: *Cost-effectiveness Results for Net Metered Solar DG on the EAI System*



The principal conclusions of our analysis are as follows:

1. **Solar DG is a cost-effective resource** for EAI, as the benefits equal or exceed the costs in the Total Resource Cost, Program Administrator, and Societal Tests. The results of these tests are well above 1.0 when a broad range of benefits are considered. As a result, in the long-run, deployment of solar DG will reduce the utility's cost of service.

2. **Net metering does not cause a cost shift to non-participating ratepayers**, as shown by the result for the Ratepayer Impact Measure test.

3. **Modifications to net metering are not needed** to recover the utility's full cost of service over time from net metering customers. Major rate design changes for residential DG customers, such as increased fixed charges, the use of demand charges, or two-channel billing to set different compensation rates for imported and exported power, are not needed.

4. **The economics of solar DG are marginal** for EAI's residential customers, as shown by the Participant Test results below 0.9 and the modest amount of solar adoption in Arkansas to date. This means that any reduction to the compensation provided to solar DG customers is likely to be detrimental to the growth of this resource, although these economics may improve as solar costs continue to fall.

5. There are **significant, quantifiable societal benefits from solar DG**, including local economic benefits and public health improvements from reduced air pollution.

6. Solar DG also provides other important benefits that are difficult to quantify. This includes **enhanced reliability and resiliency** of customers' electric service, because solar DG is a foundational element for backup power systems and micro-grids that can provide uninterrupted power when the utility grid is down. Distributed generation also **enhances customers' freedom**, allowing them to choose the source of their electricity, and results in **customers who are more engaged and better informed** about how their electricity is supplied. The choice of using private capital to install solar DG on a customer's private premises **leverages a new source of capital to expand Arkansas's clean energy infrastructure and allows Arkansas to take advantage of federal tax incentives for solar that will begin to phase out in 2020 .**

Attachment 1

EAI's *Key Assumptions* for Demand-side Resources

Back

Key Assumptions

Discount Rate 6.10%

Methodology for calculating the TRC Benefit Cost Results

The California Manual was followed in computing the benefit cost results.

Avoided Cost

1. Natural Gas price starting R $2.96 per MMBtu in 2010
2. Price on Carbon Dioxide (CO2) starting at $1.51/ton in 2027
3. Avoided Capacity Costs based on the following inputs

(a) Baseline Capital Cost (2016$ of $744 per kW)

(b) Levelized Fixed Charge Rate of $77.98

(c) Line Losses

Customer Class Inputs	T Line Loss (2016)	D Line Loss (2016)	Total Line Loss
Residential Service	2.17%	7.27%	9.44%
Small General Service	2.16%	7.03%	9.19%
Large General Service	3.30%	4.33%	7.63%
Large Industrial Power Service	3.30%	4.33%	7.63%
Agricultural Pumping	2.17%	7.27%	9.44%

(d) 12.0% in 2016 and in forward years

(e) Avoided Transmission & Distribution cost of $23.86 per kW-yr in 2016

The avoided costs for natural gas is based on Energy Information Administration of the Department of Energy.

Attachment 2

Methane Leaks from Natural Gas Infrastructure Serving Gas-fired Power Plants

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February 19, 2016

1. Summary

Natural gas has been commonly depicted as a “bridge” fuel between coal and renewable energy for the generation of electricity. Natural gas is considered more environmentally friendly because burning natural gas produces less CO_2 than coal on a per unit of energy basis. Most analyses of the greenhouse gas (GHG) emissions associated with burning natural gas to produce electricity use an emission factor of 117 lbs of CO_2 per MMBtu of natural gas burned. However, this number does not include methane leaked to the atmosphere during the production, processing, and transmission of natural gas from the wellhead to the power plant. Methane is both the primary constituent of natural gas and a potent greenhouse gas (GHG), so quantifying the methane leakage is important in assessing the impact of natural gas systems on global warming.

Methane is emitted to the atmosphere from natural gas systems in both normal operating conditions and in low frequency, high emitting incidents. The Environmental Protection Agency’s (EPA) “Inventory of U.S. Greenhouse Gas Emissions and Sinks” attempts to calculate methane emissions from natural gas systems using a “Bottom Up” accounting method, which essentially adds up methane emissions from production, processing, transmission, storage, and distribution. This method sets a reasonable baseline for methane emissions during normal operating conditions, but does not account for low frequency high emitting situations.

Low frequency high emitting situations happen when some part of the production, processing, or transmission systems fail, leaking large amounts of methane into the atmosphere. The recent Aliso Canyon leak from a major Southern California Gas storage field in Parker Ranch, California is probably the best-known example of a low frequency high emitting event. The Aliso Canyon leak has emitted 2.4 MMT CO2-eq., or roughly 1.5% of total yearly methane emissions from all U.S. natural gas Infrastructure, in a single event. Several studies have shown that low frequency high emitting events like Aliso Canyon contribute significantly to methane emissions from natural gas systems.

The following analysis and discussion lays out an argument for increasing the carbon emission factor for burning natural gas in power plants to include the carbon equivalent of the methane emitted in the production, processing, transmission, and storage of natural gas, leaving out the losses in local distribution that are downstream from power plants on the gas system. A conservative starting point for the leakage from wellhead to power plant is that 2% of natural gas produced is lost to leakage in the form of methane. This estimate is based the IPCC Fifth Assessment Report, the EPA’s “Inventory of U.S. Greenhouse Gas Emissions and Sinks,”

adjusted based on several studies quantifying how the EPA's method underestimates actual emissions.

Using the conservative estimates of 2% of total production emitted, and a global warming potential (GWP) of 25 (the low end of methane's GWP) increases the CO_2 emitted by burning methane to 175.5 lbs of CO_2-eq. per MMBtu of natural gas burned (a factor of 1.5). Using a GWP of 34 (high end) yields 196.6 lbs of CO_2 per MMBtu of natural gas burned (a factor of 1.68).

2. Measuring Natural Gas Leakage (Methods)

Determining methane leaks from natural gas systems is relatively new field of study. Until 2011 methane leaks were calculated almost exclusively using a Bottom Up accounting method based on data published in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks". Several issues with this method, including outdated Emission Factors and low frequency high emitting events, have led researchers to use "Top Down" aerial measurements of methane leakage.

Bottom Up. Bottom Up (BU) methods attempt to identify all sources of methane emissions in a typical production chain and assign an Emission Factor (EF) to each source. The total emissions are determined by adding up all of the EFs through the life cycle of natural gas. BU measurements are useful because they avoid measuring methane from biogenic sources (landfills, swamps, etc), anthropogenic sources in geographic proximity to natural gas systems (coal plants, oil wells, etc), and only require an engineering inventory of equipment and activity. However, BU measurements often rely on decades-old EFs. The EFs used in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks" are based on a report published in 1996, which in turn is based on data collected in 1992. The EPA has developed a series of correction factors based on technological improvements and new regulations.

BU studies have been shown to underestimate methane emissions from natural gas systems.[1]–[5] While outdated EFs can cause both under and overestimation of emissions, low frequency high emission events are responsible for consistent underestimation of emissions by BU calculations.[1], [5]–[7] A recent study in the Barnett Shale region of Texas found that 2% of facilities were responsible for 50% of the emissions and 10% were responsible for 90% of the emissions.[5] BU measurements do not accurately take into account these low frequency high emitters. First, most BU measurements either sample only a few facilities or rely on facility and equipment inventories rather than local measurements. Secondly, most BU data is self-reported. Finally, several studies have found that the low frequency high emitters were both spatially and temporally dynamic, with the high emission rates resulting from equipment breakdowns and failures, and not from design flaws in a few facilities.

Top Down. Top Down (TD) methane measurements have used aerial flyovers to measure the atmospheric methane content, then use mass balance and atmospheric transport models to determine methane emissions from a geographical region. A signature compound such as ethane is used to distinguish fossil methane from biogenic methane. Unlike BU

measurements, TD measurements account for low frequency high emitter situations. TD studies consistently measure higher levels of methane emissions than do BU studies. Only recently have measurements TB and BU studies converged, and this convergence was only after additional low frequency high emission situations were characterized in BU studies.[5]

3. Methane Leak Calculations

The EPA divides methane emissions from natural gas systems into four categories: Field Production, Processing, Transmission and Storage, and Distribution. This analysis focuses on only the first three categories, leaving out local distribution networks. Detailed descriptions of these categories can be found in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."

US Natural Gas Production 2005 - 2013

Expressed as BCF Natural Gas

Source	2005	2009	2010	2011	2012	2013
Withdrawals from Gas Wells	16,247	14,414	13,247	12,291	12,504	10,760
from Shale Shale Wells	0	3,958	5,817	8,501	10,533	11,933
Total Withdrawals from Natural Gas Systems	16,247	18,373	19,065	20,792	23,037	22,692

Emissions from US Natural Gas Systems 2005 - 2013

Expressed as % of Total Production

Stage	2005	2009	2010	2011	2012	2013
Field Production	0.91	0.66	0.58	0.48	0.42	0.41
Processing	0.20	0.20	0.18	0.20	0.19	0.20
Transmission and Storage	0.59	0.56	0.53	0.51	0.44	0.47
Total	1.70	1.43	1.30	1.19	1.05	1.07

Using the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," methane emissions from natural gas infrastructure from the wellhead to a gas-fired power plant (excluding local distribution) are currently estimated to be 1.1% of production.[8] Given that EPA uses a BU method for calculating emissions, it is reasonable to assume that 1.1% is an underestimation. A 2015 study that combined seven different datasets from both TD and BU and included the most aerial measurements to date concluded that methane emissions were 1.9 (1.5 – 2.4) times the number reported in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."[5] If the EPA's estimate is multiplied by 1.9 the result is 2.09%.

The IPCC Fifth Annual Report agrees, stating that: "Central emission estimates of recent analyses are 2% - 3% (+/– 1%) of the gas produced, where the emissions from conventional and unconventional gas are comparable." [9]

4. Global Warming Potential of Natural Gas

Global warming potentials (GWP) provide a method of comparing different GHGs. A GWP is: "a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide." The Intergovernmental Panel on Climate Change (IPCC) regularly publishes updated GWPs based on the most current scientific knowledge. The most current value for methane (based on the 2013 IPCC AR5) is 34.[9] The previous value (based on the 2007 IPCC AR4) is 25. Policy makers continue to tend to use the values closer to 25.[9] For example, the EPA uses 25 in its "Inventory of U.S. Greenhouse Gas Emissions and Sinks," but 34 is more commonly used in the scientific literature.[10]

5. Conclusion

This report recommends the use of a 2% emissions rate for methane leakage from natural gas systems when calculating the GHG emissions associated with natural gas-fired electric generation. Current analyses use 117 lbs of CO2 per MMBtu as the emissions factor from burning natural gas, which essentially assumes zero leakage. Adopting a 2% emission rate would increase this number to 175.5 lbs of CO2 per MMBtu of natural gas burned, assuming a conservative GWP of 25.

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