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CHANGES TO GREEN POWER PROVIDERS PROGRAM FINAL ENVIRONMENTAL ASSESSMENT

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Table of Contents

List of Tables

List of Figures

Symbols, Acronyms, and Abbreviations

BTM	Behind-the-meter
BTU	British Thermal Unit
c-Si	Crystalline Silicon
Cd-Te	Cadmium Telluride
CAA	Clean Air Act
CCR	Coal Combustion Residuals
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DC	Direct Current
DER	Distributed Energy Resource
DPP	Dispersed Power Production
EA	Environmental Assessment
EEI	Edison Electric Institute
EIS	Environmental Impact Statement
EU	European Union
EUC	End-use Consumer
FERC	Federal Energy Regulatory Commission
FLIGHT	Facility Level Information on GHGs Tool
FOIA	Freedom of Information Act
GHG	Greenhouse Gases
GP	Generation Partners
GPP	Green Power Providers
GPS	Green Power Switch
GSA	General Services Administration
GWh	Gigawatt-Hour(s)
HAP	Hazardous Air Pollutants
HHW	Household Hazardous Waste
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
kWh	Kilowatt-Hour(s)
LBNL	Lawrence Berkeley National Laboratory
LPC	Local Power Companies
MW	Megawatts
MWh	Megawatt-Hour(s)
MSA	Metropolitan Statistical Area(s)
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NO_2	Nitrogen Dioxide
NO_X	Oxides of Nitrogen
NPDES	National Pollutant Discharge Elimination System
NREL	National Renewable Energy Lab
O&M	Operation and Maintenance
O_3	Ozone
PA	Participation Agreement
Pb	Lead
PM	Particulate Matter
PPA	Power Purchase Agreement
PSA	Power Service Area
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
QCN	Quality Contractor Network
RCRA	Resource Conservation and Recovery Act

REC	Renewable Energy Certificates
SACE	Southern Alliance for Clean Energy
SEIA	Solar Energy Industries Association
SELC	Southern Environmental Law Center
SHE	Safety, Health and Environmental
SO_2	Sulfur Dioxide
Solar DS	Solar Deployment System
TDEC	Tennessee Department of Environment and Conservation
TSCA	Toxic Substances Control Act
TVA	Tennessee Valley Authority
U.S.	United States
USEIA	United States Energy Information Agency
USEPA	United States Environmental Protection Agency

CHAPTER 1 – PURPOSE AND NEED FOR ACTION

The Tennessee Valley Authority (TVA) is proposing to close its Green Power Providers (GPP) Program to new applications on December 31, 2019. TVA is also proposing to establish an alternative solution to assist residential customers interested in solar installations. These proposals would not affect customers that have already entered into participation agreements with TVA or those that apply by the closure date.

TVA is completing an Environmental Assessment (EA) in compliance with the National Environmental Policy Act (NEPA) to consider the environmental impacts of closing the GPP Program and implementing a new private-scale renewable generation offering beginning in 2020.

1.1 Purpose and Need for Action

TVA's GPP Program is an end-use consumer (EUC) generation dual metering program that began in 2003 as the Generation Partners (GP) Pilot Program.[1] It was developed in an effort to provide distributors the opportunity to support environmental stewardship while responding to the growing consumer interest in generating renewable power. It also provided customers with an alternative to net metering that was compatible with the existing power contracts between TVA and local power companies (LPCs). Participation in the program is optional for LPCs. Through the GPP Program, participating LPCs' residential and commercial EUCs with renewable solar, wind, low-impact hydro, or biomass systems sell all of the generation to TVA for the term of their 20-year Participation Agreement (PA) for a fixed kilowatt-hour (kWh) rate.

In 2011, the TVA Board approved replacing the GP Pilot Program with the GPP Program to enable TVA to meet the planning targets of the then-current Integrated Resource Plan (IRP) and achieve the renewable energy goals outlined in TVA's vision. The Board also approved the key features of the program, including the declining generation payment rates that were to start out at retail plus a $0.12 premium in 2012 and incrementally decrease to retail in 2016. Program payments and other key features were to be evaluated annually to align with, among other things, the value of renewable technologies to TVA, customer installation costs, and renewable market conditions. The payment rates were found to be consistent with the reduction in customer installation costs and were therefore implemented as approved by the Board without further modifications.

In 2018 GPP generation payments were modified to reflect the Valley-wide approximate retail rate instead of an LPC-specific retail rate as follows: $0.09/kWh for residential and GSA-1 systems under 10 kW and $0.075/kWh for all other eligible systems. These fixed rates, the same rates that are in effect in 2019, reflect the approximate Valley retail rate for Residential and GSA-2 customers respectively.

TVA has determined that the GPP Program is currently out of balance with the needs of the Valley for three main reasons:

[1] Dual metering refers to a situation where a customer has two meters, one that measures energy flowing from the grid to the household and another that measures energy flowing from the customer's renewable energy system to the grid.

1. Current and forecasted Program participation, supported by qualitative and quantitative market research, suggests that the GPP Program is no longer attractive to consumers;

2. Cost-shifting caused by distributed energy resource (DER) systems, including those enrolled in the GPP Program, results in an unfair burden on non-participants; and

3. Utility-scale solar is a lower-cost solution than the private-scale generation systems enrolled in GPP.

<u>GPP Trends</u>
TVA annually evaluates its renewable offerings and consumer needs in light of evolving technologies, market pace, and fiscal responsibilities. Evaluation of the GPP Program indicates that interest in the program has been steadily declining over recent years. In the past, the program capacity was fully reserved most years. However, in 2018 only 2.5 megawatts (MW) out of the available 10 MW capacity was reserved, leaving 75 percent of the program capacity unutilized. This trend is likely to continue as the GPP value proposition and process become less attractive and less aligned with EUCs' expectations.

When the GPP Program first began, TVA offered generation rates that were well above retail rates for the renewable energy from the participating systems. At that time, the cost of solar photovoltaic (PV) was significantly higher than today and PV penetration was extremely low. High generation rates were aimed at stimulating renewable generation in the Valley by offsetting the high upfront cost of renewable installations. As the cost of solar PV decreased by more than 70% over the last decade (Solar Energy Industries Association 2019) and the DER market has evolved to offer lower cost renewable options, TVA has adjusted its GPP generation rates for private-scale systems accordingly.

Some EUCs, particularly residential EUCs, tend to focus more on the difference between the GPP generation payment and retail rates. When the GPP generation rates were above retail rates, some EUC perceived PV as a good investment. Current GPP generation payment rates – $0.09/kWh for Residential/GSA-1 systems under 10 kW and $0.075/kWh for all other systems eligible for the program – are not attractive to some potential solar participants. In some LPC territories, the GPP rates are slightly below the retail rates EUCs pay for their electricity. Additionally, market research conducted by a third party among Valley residents and solar installers indicated that the GPP process is not sufficiently simple or streamlined. The dual metering configuration required for GPP causes all energy generated by a renewable system to flow to the grid. This approach runs counter to some EUC's preferences to directly consume the electricity their system generates.

Furthermore, installer, LPC, and market signals indicate a growing number of behind-the-meter (BTM) installations.[2] TVA projects that BTM will grow significantly in the coming decades (TVA 2019a), while GPP participation is projected to continue declining (see Section 4.1.1). The current and expected future participation of the program in the marketplace is a strong indication that the GPP Program no longer meets the needs of the maturing market.

Consequently, in February 2019 the TVA Board approved the closure of the GPP Program, contingent on the satisfactory completion of any necessary environmental reviews under

[2] In a BTM installation, the EUC directly consumes the energy that their system generates. The system is "behind-the-meter" in the sense that the amount of energy generated and consumed is not monitored by the LPC.

NEPA and other applicable federal laws. The Board also authorized the CEO to design and implement a program to replace the phased out GPP Program. This EA assesses the impact of closure of the GPP Program and of implementing a new service offering.

Cost-shifting

GPP was successful in stimulating investment in private-scale renewable energy installations by paying participants for the energy generated and delivered to TVA. In addition, when the program began, buying renewable energy from the EUCs was more cost-effective for TVA than constructing renewable generation sites. As a result, TVA originally paid premium rates for the renewable energy purchased through the GPP Program. These premium generation rates reduced the payback period of participants' systems leading to more installations than would have occurred without the premiums. The premium rates also contributed to the overall increase of renewable installations Valley-wide.

However, offering incentives or payments to adequately offset the initial investment for private-scale solar places a cost burden on non-participants, a result known as cost-shifting. In this context, cost-shifting occurs when TVA subsidizes GPP participants for the energy they deliver to the grid by offering a rate that is higher than TVA's cost to generate the same amount of energy through other resources. The imbalance caused by over-compensation for DER energy, including energy produced by GPP participants, means that TVA and LPC costs must be raised for all EUCs, effectively shifting most of the costs of DER onto EUCs that have not installed DER.[3]

Cost-shifting contradicts the principle of equity in energy pricing and creates an undue burden for those in lower income brackets who may not be able to afford solar but are paying to subsidize it (TVA 2018). Additionally, low-income households pay a higher percentage of income toward energy costs, creating a high energy burden (TVA 2018). As a public power entity charged with keeping energy rates as low as feasible, TVA is transitioning away from incentivizing private-scale solar installations to minimize cost-shifting to those who cannot install onsite solar.

Cost-shifting addresses a distributional issue: who pays for private-scale solar? Cost-shifting associated with private-scale solar installations is a separate and distinct issue from the issues of whether such solar installations have social benefits and costs and how DER electricity should be priced. Social benefits and costs are based on benefit-cost analysis and address an economic efficiency question: do the benefits of private-scale solar exceed their costs, without considering who pays? DER pricing considers the question: what is an appropriate payment to DER owners for the electricity they send to the grid? Appendix A provides discussion on these three issues and how they relate to the purpose and need of TVA's proposal.

Utility-Scale Solar is a Lower Cost Solution

Utility-scale solar has become a more cost-effective renewable energy solution to meet the energy needs of the Valley than private-scale solar.[4] The term "cost-effective" in this context means the costs of generating a unit of electricity. This is because utility-scale solar benefits from economies of scale, where the average cost per unit of energy produced

[3] Note that the terms "subsidizes" and "over-compensation" are in the context of costs of service (i.e. TVA's costs of providing electricity to LPCs and TVA's EUCs). See discussion in Appendix A.
[4] Utility-scale solar refers to large solar generation facilities that are operated by utilities and managed in concert with utilities' other generation facilities.

decreases as the size of the generation facility increases. As discussed in the 2019 Integrated Resource Plan (IRP), utility-scale solar is a more viable option for generating renewable energy when compared to building and commissioning other generation assets from any source, and TVA plans to increase its investment in utility-scale solar generation in the coming decades (TVA 2019a). Continued development of private-scale solar reduces the amount of energy TVA would generate at a lower cost, and therefore, effectively increases the system-wide costs of meeting the Valley's electricity needs.

Under the TVA Act of 1933, TVA is mandated to provide power at rates as low as feasible. Therefore when TVA considers cost-effectiveness, it is focusing on the costs per unit of electricity.

1.2 TVA Proposed Action

In February 2019, the TVA Board of Directors approved closure of the existing GPP Program to new applications at the end of 2019. The Board also delegated authority to the CEO to provide for the design and implementation of new renewable offerings consistent with the Board-approved revised metering standard, making these decisions contingent upon the satisfactory completion of any environmental reviews necessary under federal law.

Under the Proposed Action, TVA would close its GPP Program to new applications on December 31, 2019. All current participation agreements (PAs), which outline the terms and rates that will apply to energy generated by GPP systems, will remain in effect for the remainder of their terms. Ending the GPP Program would not preclude individuals from investing in private-scale DER in the future. Several options for implementing DER within the TVA service area remain.

A new private-scale service offering would be implemented in 2020 and would be exclusively for residential EUCs interested in private-scale solar PV installations. TVA would establish a network of qualified solar installers for applicants to choose from when installing solar PV systems, installation standards that include best practices and requirements for installers, inspection requirements, and a more standardized interconnection process. The new offering would be implemented in partnership with LPCs.

The proposed service offering takes into account market research conducted by an independent third party firm in the fall of 2018 with residential homeowners and installers. Quantitative testing was conducted among the homeowners in the Valley who have expressed interest in installing onsite solar and whose household annual incomes were greater than $75,000. The research highlighted that the public sees confidence in the quality of the solar installation as the most important benefit a TVA program can offer. Additionally, residential consumers generally assume they can use the power generated from a renewable system onsite, instead of selling it to a utility as they do under the current GPP technical buy-all/sell all arrangement. The solar installers indicated that marketing support and leads would be important features that a EUC renewables solution could offer.

Another aspect of the proposed service offering would address the disposal of solar arrays and related equipment after their useful life, which usually occurs around 20 to 25 years after installation. Many EUCs are not well informed on the proper disposal of arrays and the potential dangers of improper disposal. Incorporating training and increasing LPC and TVA visibility into private-scale installations may create opportunities to educate the public on proper disposal of solar arrays after they are no longer viable.

The proposed service offering would be available throughout TVA's power service area, shown in Figure 1-1.

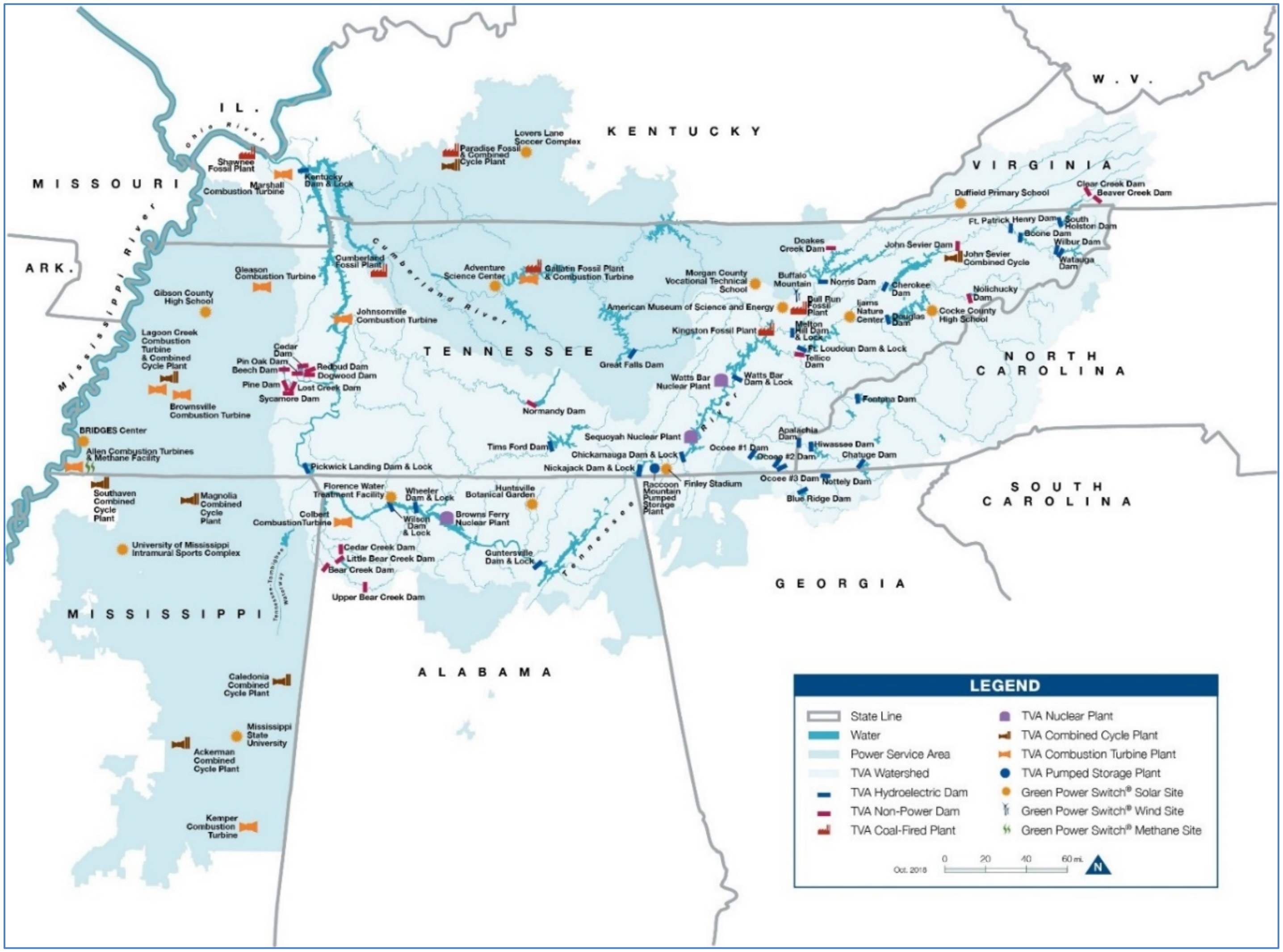

Figure 1-1. Power Service Area and Tennessee River Watershed (herein the TVA region)

1.3 Background

As noted above, the GPP Program has offered Tennessee Valley residential and commercial EUCs an opportunity to receive compensation for renewable energy generated by their private-scale renewable systems. Under the program, participants install a private-scale renewable energy system on their property that is connected to the grid. These systems are considered a type of DER. TVA then purchases all of the energy produced by the system pursuant to a tri-party PA between TVA, the LPC, and the EUC. The energy purchase rate and other financial incentives of GPP have changed over time as private-scale renewable energy systems have become more affordable. The GPP PAs initially included a one-time incentive payment for enrolling in the Program and compensation for each kWh delivered to TVA at a premium above the retail rate to stimulate investment in private-scale renewable energy projects. The enrollment incentive and premium rate have not been offered in recent years.

1.3.1 History of GPP

In 2003, TVA started the GP Pilot Program that would later become GPP. Under the 2003 GP Pilot Program, TVA purchased renewable energy generated by facilities installed by residential, commercial, and industrial EUCs. Initially, only solar photovoltaic (PV) systems and wind turbines were included in the program. Later, eligible renewable system resources were expanded to include low-impact hydropower and systems using several types of biomass fuels. When the program first began, TVA purchased qualifying renewable generation at a fixed rate of \$0.15/kWh via a generation credit on the participant's monthly bill for a 10-year term.

In 2007, the TVA Board approved an official response to the Public Utility Regulatory Policies Act (PURPA), as amended the by Energy Policy Act of 2005. As part of the Board adopted standard, the Board directed TVA to provide customers the option to participate in a dual metering program "modeled after" the GP Pilot Program. The maximum capacity of individual systems installed under GP and GPP has varied from 1 MW_{DC} to the current limit of 50 kW_{DC}.

In 2011, the TVA Board adopted the GPP Program to replace the GP Pilot Program. The GPP Program operated similarly to its predecessor and was consistent with the metering standard TVA adopted in 2007. Qualifying generating systems could not exceed 50 kW direct current (DC) nor generate annually more than the customer's usage at the site's billing meter. The eligible renewable system resources remained the same as in GP. A 20-year PA included a \$1,000 enrollment incentive and an energy generation credit at the retail rate plus a \$0.12/kWh premium.

The \$1,000 incentive was phased out for new non-residential participants in 2015 and for new residential participants in 2016. Additionally, the generation credit paid to participants decreased in concert with the significant decrease in the cost to install solar systems. See Table 1-1 for changes in the GPP payments over time.

Beginning in the 2016 program year, premium payments were eliminated. This change did not affect payment schedules under existing PAs. Generation payments for each kWh generated were set at the retail rate through the 2017 program year. For the 2018 program year, payments were decoupled from the retail rate and modified to the following schedule for the 20-year term: \$0.09/kWh for Residential/GSA-1 systems under 10 kW, and \$0.075/kWh for Residential/GSA-1 systems over 10 kW and non-GSA-1 Commercial. Current (2019) GPP compensation rates are approximately equal to the average retail rate across TVA's service area. As planned, the compensation rates have been highly correlated with the falling costs of solar installations (Figure 1-2). Solar installation costs are based on Matasci (2019). The 2019 value represents the first half of 2019.

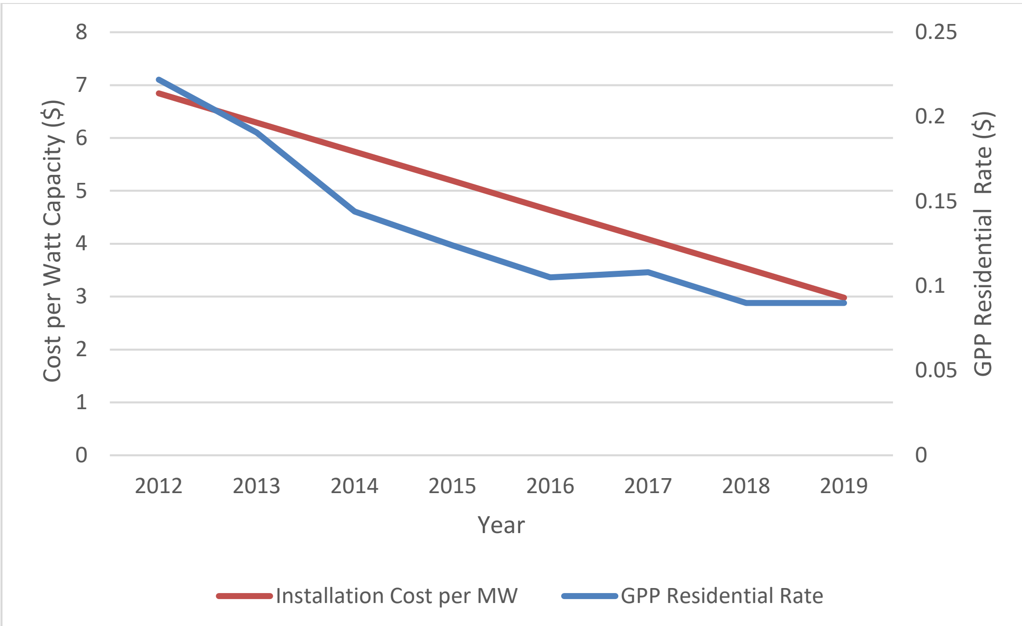

Figure 1-2. Changes in GPP Residential Payback vs. Gross Installation Costs

Currently, 136 of the 154 LPCs offer GPP. Combined, the GP and GPP Programs have over 3,600 generating systems with a total nameplate capacity of about 110 MW_{DC}. Solar PV facilities comprise about 90 percent of this capacity. Biomass (landfill gas, wastewater methane, and wood waste and chips) comprise about 10 percent of capacity. Wind generation provides about 96 kW_{DC}, and small hydroelectric systems provide 9 kW_{DC}.

As noted above, the GP and GPP Programs were both historically offered to residential and commercial EUCs. Residential EUCs account for 60% of the generating systems, while commercial EUCs account for roughly 40%. However, because commercial EUCs tend to install larger systems, they make up almost 75% of the total nameplate capacity. This is important to note because cost-shifting not only occurs across residential households, it occurs from businesses to residential customers, meaning households are subsidizing businesses' for-profit operations.

Enrollments in GPP have been declining in recent years. New GPP systems coming online have decreased from 560 in 2013 to 247 in 2018, a 56 percent decrease (Figure 1-3). New GPP capacity coming online has decreased from about 38.3 MW in 2011 to about 4.1 MW in 2018, an 89 percent decrease (Figure 1-4). This decline may be primarily caused by the reduction in GPP generation credit rates, as these are highly correlated to the number of residential systems coming online (Figure 1-5). In addition, EUCs that are willing and able to enroll in GPP may be participants who are already enrolled in the program.

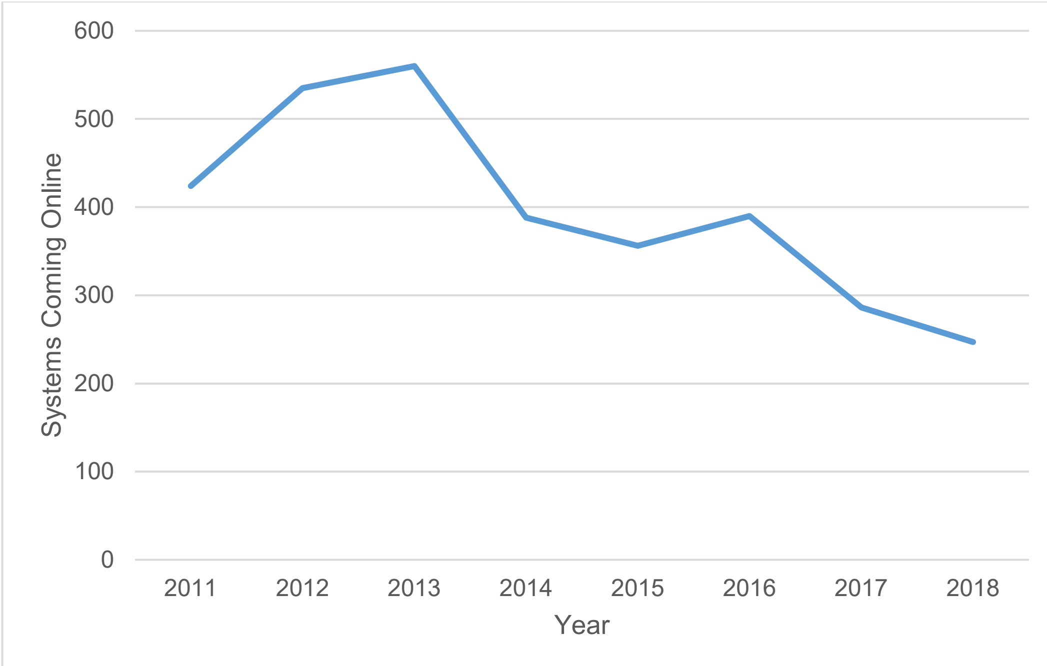

Figure 1-3. Number of New GPP Systems

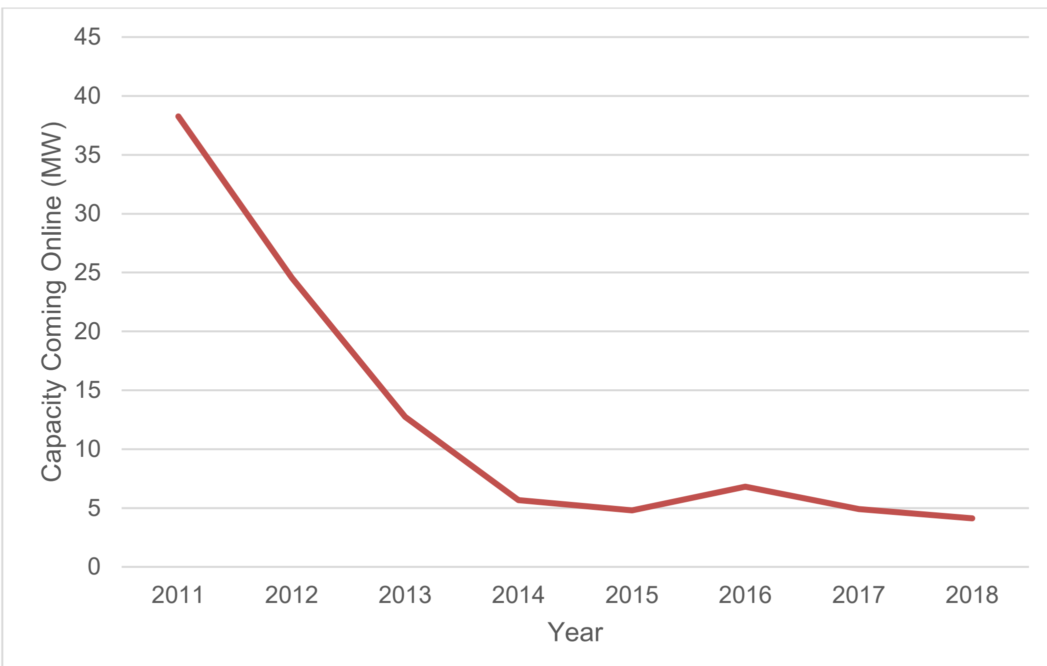

Figure 1-4. New GPP Capacity

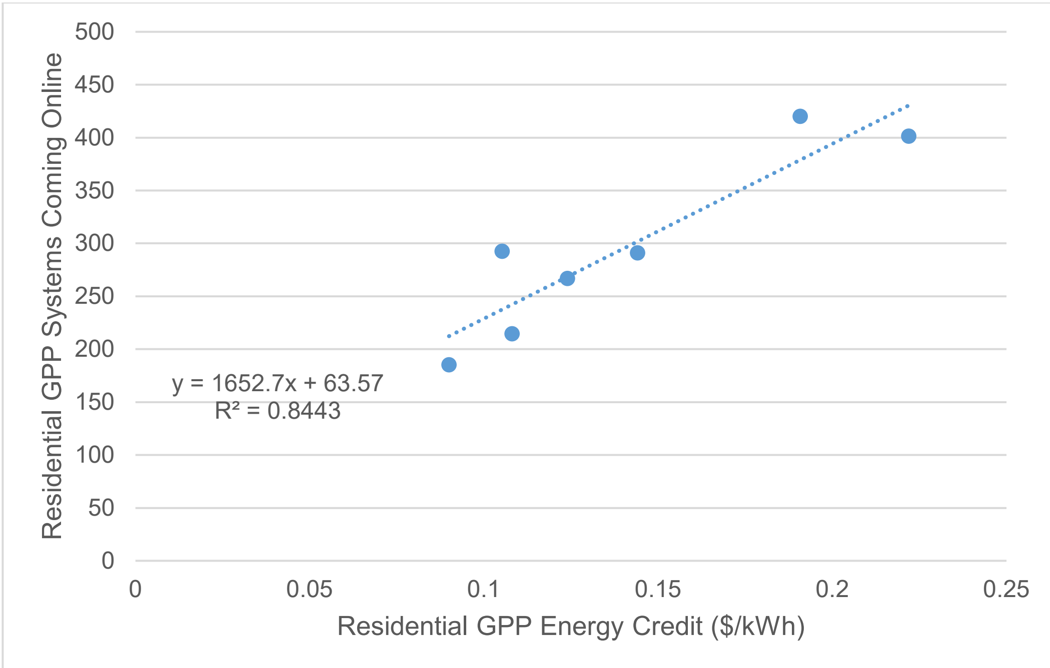

Figure 1-5. Relationship between New Residential Systems and GPP Energy Credit Rate

Table 1-1. GPP Payment Structure

Year	Generation Credit Rate	One-Time Incentive Payment ($)	Premium Rate (Solar) ($/kWh)	Premium Rate (Wind, Biomass, Hydro) ($/kWh)	Capacity Limit (MW)
2012	Retail	1,000	0.12	0 – 0.03 a	N/A
2013	Retail	1,000	0.09	0.03	10
2014	Retail	1,000	0.04	0.03	10
2015	Retail	0	0.02	0.02	10
2016	Retail	0	0	0	10
2017	Retail	0	0	0	10
2018	Residential < 10kW: $0.09/kWh Commercial/Industrial & Residential > 10 kWh: $0.075/kWh	0	0	0	10
2019	Residential < 10kW: $0.09/kWh Commercial/Industrial & Residential > 10 kWh: $0.075/kWh	0	0	0	7.5

1.3.2 Other Private-Scale Renewable Options

The GPP Program is one of several options available for residential and commercial EUCs to support renewable energy in the TVA region. Discontinuation of GPP would not preclude private investment in private-scale DER in the TVA region. TVA offers other renewable energy programs to EUCs, and they also may install BTM renewable energy generation systems. Each of these options is summarized below.

Dispersed Power Production (DPP) Program

Since 1981, TVA has offered the Dispersed Power Production (DPP) Program to commercial and residential EUCs. The DPP Program satisfies the requirements of Title II of PURPA, under which electric utilities, including TVA and LPCs, are required to purchase power from Qualifying Facilities. Qualifying Facilities are defined by the Federal Energy Regulatory Commission (FERC) as power-generating facilities up to 80 MW whose primary energy source is renewable, biomass, waste, or geothermal resources; or cogenerating facilities that sequentially produce electricity and another form of useful thermal energy in a way that is more efficient than the separate production of both forms of energy. TVA complies with this requirement on behalf of its LPCs through the DPP Program. In 2018, capacity of DPP was 157 MW (TVA 2019b). Under the DPP offering, participants have three configuration options:

1. Self-Generation: excess energy flows to grid and is not purchased by TVA;
2. Self-Generation and Dispersed Power Contract: excess energy flows to the grid and is purchased by TVA;
3. Dispersed Power Sell All Contract: all power generated is purchased by TVA.

Under the second and third options, the power is purchased at TVA's monthly avoided cost for the term of a 5-year contract. For reference, the current standard price for September 2019 is set at $0.0176/kWh (TVA 2019c). EUCs may have dual-meter or single bi-directional meter arrangements depending on which option they choose. While the maximum individual system size is 80 MW, there is no program capacity maximum. The system owner retains environmental attributes and Renewable Energy Certificates (RECs).[5]

Green Power Switch (GPS)
Residential and commercial EUCs who cannot install onsite generation or who are not willing or able to participate in the GPP or DPP Programs can support renewables through TVA's Green Power Switch (GPS) Program. GPS, the first renewable program to be founded in the Southeast, launched on Earth Day, April 22, 2000. Through GPS, EUCs can purchase Green-e energy certified RECs, currently sourced from Valley installations, specifically GPP solar and biomass installations and TVA's Buffalo Mountain Wind power purchase agreement (PPA). The GPS product is currently priced at $4 for a 150 kWh energy block. In 2018, participants purchased approximately 63 gigawatt hours (GWh) of renewable energy blocks through the GPS Program (TVA 2019b).

Behind-the-Meter (BTM)
Valley residents also have an option of installing solar systems BTM. A BTM system is a DER system that is located on a customer's property and is designed to supply power to a single building or facility. A BTM system allows the owner to use the energy generated by the solar system first and use the grid as a backup. TVA estimates that in 2018 there was approximately 700 MW of capacity from BTM generation, of which about 90 percent comes from combined heat and power systems (TVA 2018). The capacity of BTM solar in 2018 was estimated as 37 MW. To ensure the safety of BTM installation, EUCs are encouraged to contact their LPC to learn about the terms of the LPC's interconnection agreement. Additional information on these renewable programs is available on TVA's website.

1.4 Related Environmental Reviews and Consultation Requirements

TVA's consideration of the PURPA-promulgated net metering standard was addressed in TVA's *Public Utility Regulatory Policies Act Standards Final EA*, completed in 2007. In the EA, TVA considered a Smart Metering standard that led to a rate change process to assess the feasibility of implementing season and/or time-of-use pricing in combination with the advancement of technological capabilities for certain customers. In addition, as noted above, TVA decided to adopt a dual metering alternative to Net Metering implemented through its then-current GP Pilot Program.

Another pertinent environmental review completed by TVA includes the *2019 IRP Final Environmental Impact Statement* (EIS; TVA 2019b), which describes the TVA power

[5] A Renewable Energy Certificate (REC) is the accepted U.S. legal instrument representing property rights to the non-power attributes of renewable energy generation. RECs are used to substantiate claims of renewable electricity generation.

system and the anticipated impacts of its future operation. The information utilized for the assessment of effects from the proposed GPP Program changes reflects and encompasses the most current data and information available to TVA. Other environmental reviews of relevance include the *Alternative Electric Power Rate Structures Final EIS* (TVA 1980) and *Policies Relating to Electric Power Rates Final EIS, Volumes 1 and 2* (TVA 1976).

In 2015 and 2018, TVA also completed environmental reviews relating to rate changes. The *2018 Wholesale Rate Change EA* addressed the establishment of a wholesale grid access charge and the application of an equivalent reduction in rates. This change in the wholesale electric power rate structure was needed to better align wholesale rates with the underlying costs to serve wholesale customers.

Each review discussed aspects of TVA's fundamental rate structure and customer classes and its historical relationship with the electricity sellers (the distributors) and consumers in the Tennessee Valley region. Both the 1976 and 1980 EISs and the 2015 and 2018 EAs concluded that the timing and magnitude of resulting impacts on the physical environment (air, water, land, and other primary natural resources) were somewhat speculative, primarily because rate change (and rate adjustment) effects on the physical environment depend on numerous decisions to be made by persons and entities outside TVA's control. Despite these uncertainties, the EISs and the EAs concluded that in all likelihood any resulting physical environmental impacts would be insignificant.

1.5 Public Involvement

TVA has worked with LPCs and other stakeholders to inform the new service offering in Alternative C. This collaboration includes market research on households' preferences across potential service offerings. Additional detail is provided in Chapter 1 and Section 2.1.3.

On October 9, 2019, TVA issued a draft EA for public review and comment. TVA provided notice to the public of the review period via a media advisory, notices in key regional newspapers, and outreach to key stakeholders. TVA posted the draft EA on its webpage (www.tva.gov/nepa) with information about how to submit comments. During the comment period, TVA received almost 290 submissions from the public and other stakeholders. Most submissions (181) originated from a form letter initiated by the Southern Alliance for Clean Energy (SACE). Comments were submitted by the states of Tennessee and North Carolina, the Commonwealth of Kentucky, the Metropolitan Government of Nashville and Davidson County, and the City of Knoxville. TVA received one letter submitted on behalf of nine environmental organizations and individual submissions from three other environmental groups. Several solar industry organizations also submitted input.

TVA considered these comments when completing the final EA and has responded to substantive comments in Appendix B. As noted in the respective responses, TVA revised the EA as a result of several comments to improve clarity and provide additional discussion and analysis about relevant issues.

1.6 Necessary Permits or Licenses

Because there are no state or federal permits or licenses required for TVA to undertake this action, TVA has not consulted with other agencies relating to the proposal.

CHAPTER 2 - ALTERNATIVES

This chapter describes the three alternatives analyzed in this EA, summarizes the environmental impacts associated with each alternative, identifies potential mitigation measures, and presents the preferred alternative.

2.1 Description of Alternatives

2.1.1 Alternative A – No Action Alternative (GPP Program Continues)

Under Alternative A, TVA would continue offering the GPP Program, and there would be no changes to the services or offerings currently available to customers with private-scale renewable generation. The 2019 electricity purchase rates ($0.075 or $0.09 per kWh, depending on system capacity) would remain the same and the annual total GPP capacity limit for new enrollments would revert to the 10 MW capacity limit set each year between 2013 and 2018, up from the 2019 limit of 7.5 MW.

TVA would continue offering DPP and REC purchasing programs to residential and commercial EUCs interested in renewable energy. EUCs would also have the option of installing BTM generation.

2.1.2 Alternative B – Discontinue GPP Program without Replacement Program

Under Alternative B, TVA would close GPP to new applications effective 5:00 PM CST on December 31, 2019, and offer no replacement solution for private-scale renewable generators. Existing GP/GPP PAs and applications submitted prior to the closure date would continue for the duration of the agreement terms.

TVA would continue offering DPP and REC purchasing programs to residential and commercial EUCs interested in renewable energy. EUCs would also have the option of installing BTM generation.

2.1.3 Alternative C – Discontinue GPP Program and Present New Offering

Under Alternative C, TVA would (1) close GPP to new applications effective 5:00 PM CST on December 31, 2019, and (2) implement a new private-scale service offering shortly after GPP closure. Existing GP/GPP PAs and applications submitted prior to the closure date would continue for the duration of the agreement terms.

The new private-scale solar offering would not include contracts for sale of renewable energy or payments for energy generated by the EUC systems. Rather, the offering would be structured to include features and benefits identified as important by Valley residents and installers during market research conducted for TVA by a third party vendor. The surveyed EUCs identified “confidence in the quality of the installation” as the most important benefit a TVA program could offer and installers pointed to marketing and support as important features. The service offering would be exclusively for residential rate-class EUCs interested in installing private-scale solar PV systems. LPCs would have to elect to participate in the offering for it to be available in their service territory, just as they elect to participate in GPP today.

TVA proposes to establish (1) a Quality Contractor Network (QCN) of vetted solar installers for applicants to choose from when installing their solar systems, (2) installation standards that include best practices and requirements for PV systems and batteries, (3) inspection requirements, and (4) a more standardized interconnection process. The solar installers participating in the QCN would be licensed and insured, have completed special training on TVA installation standards and best practices, and maintain high customer satisfaction. In return TVA would publicly showcase the solar QCN installers on the private-scale offering website. QCN members could also potentially benefit from more productive leads originating from this website since interested EUCs would have access to educational materials, which could be used to decide whether a solar system is the right investment for their property. The educational materials would include modules on the ideal placement and size of a solar system, insight into the technical set-up and functions of a solar system, and a link to the TVA solar calculator; the EUCs would have access to these resources prior to, during, and post installation. Further, the program website would offer a scheduling feature for the installation and inspection process. With the new structure, TVA and LPCs would have visibility into private-scale installations, which is crucial for safety of LPC and/or TVA personnel and equipment.

Another aspect of the proposed service offering would address the disposal of solar arrays and related equipment after their useful life, which usually occurs around 20 to 25 years after installation. Incorporating training and increasing LPC and TVA visibility into private-scale installations may create opportunities to educate the public on proper disposal of solar arrays after they are no longer viable.

TVA would continue offering DPP and REC purchasing programs to residential and commercial EUCs interested in renewable energy. EUCs who participate in the private-scale offering could also participate in DPP and REC purchase programs pursuant to the terms of those programs.

2.2 Comparison of Alternatives

This section summarizes TVA's findings in Chapter 4 of the EA. Consistent with past environmental reviews completed by TVA that relate to this proposal, TVA has initially identified the following resources and issues as potentially affected by the proposal:

- Energy production and use,
- Socioeconomics,
- Air resources,
- Water resources,
- Land use, and
- Production of solid and hazardous waste.

Because changes to GPP would occur throughout the TVA Power Service Area (PSA), potential impacts are evaluated in the context of the TVA PSA. As discussed in Section 4.1, future electricity generation through the GPP Program is a small fraction of the total and renewable electricity generation in the TVA PSA. The best projection is that future GPP electricity generation represents at most 0.1 percent of total electricity generation in the TVA PSA, while the upper bound scenario is 0.2 percent (Table 4-6). Of the renewable generation in the TVA PSA, the projected GPP generation would be between 0.5 percent and 1.5 percent (Table 4-6). Because the projected generation is so small in relation to total and renewable generation, any changes in TVA electricity generation operations under the three alternatives would not be discernable in the context of the TVA PSA.

Potential impacts to socioeconomics consist of three main factors. First, future potential GPP participants are directly affected by the alternatives, which either allow future GPP enrollment (in Alternative A) or disallow enrollment after 2019 (Alternatives B and C). Second, changes in DER adoption have the potential to affect the amount of cost-shifting in the TVA PSA. Third, the replacement service offering in Alternative C could directly impact future potential DER adopters and current adopters.

Compared to current conditions, future potential GPP participants would have a minor financial benefit under Alterative A associated with current GPP energy credits. Alternatives B and C would eliminate this financial opportunity. Additional DER in Alternative A could result in $67 million to $146 million of cost-shifting over the 20-year planning period, based on the best estimate and upper bound scenarios, respectively (Section 4.2.1). Cost-shifting represents an increase in costs to all EUCs resulting from installation of private-scale DER. The amount of cost-shifting in Alternative A is considered minor. Alternatives B and C would minimize cost-shifting caused by TVA's subsidies to DER adopters that would occur through the GPP Program in Alternative A. However, some EUCs would likely install BTM if GPP were not available, which would still result in cost-shifting but less than that in Alternative A.

The replacement service offering in Alternative C would focus on system quality and safety. This program would benefit future potential private-scale solar adopters. Alternative C would also provide safety benefits to both EUCs and TVA and LPC workers. The information provided by TVA on the proper disposal of solar systems could also benefit current and future DER adopters.

Under all alternatives, potential adverse impacts, such as increases in energy bills due to cost-shifting, would generally be spread across all EUCs in the TVA PSA. No disproportionately high adverse impacts on low-income or minority populations have been identified in any of the alternatives.

The potential for the alternatives to result in an impact on air, water quality, and the production of solid and hazardous waste are highly dependent on whether the alternatives would require TVA to modify its electricity generation operations. Because there would be no discernable changes to TVA's energy generation operations under any of the three alternatives, any impacts to these resources would not be discernable under the alternatives. Even under a conservative, worst-case scenario, impacts would range from not discernable to minor. TVA quantified the effects of the alternatives on GHG emissions and concluded that changes would not be discernable in the best estimate scenario and would be minor in the worst-case scenario.

Land conversion, clearing, or modification is generally not associated with private-scale solar systems typical for those enrolled in the GPP Program. When ground mounting is proposed, the 500 square feet of land required for the typical 5 kW residential system represents a small fraction of the approximately 25,000 acres currently used to support energy production in the TVA PSA (see Section 3.5). Under all three alternatives, the potential for land conversion is assumed to be a small fraction of the overall area currently used to support energy production in the TVA PSA. Therefore, any potential land use impacts are minor for each alternative.

Solid and hazardous wastes are associated with changes in total energy use, the renewable to non-renewable energy mix, and/or wastes generated as part of system installation and disposal. Under Alternative A, there would be minor increases in the production of solid and hazardous waste compared to current conditions as a result of new users installing systems, and thus, minor negative environmental impact would occur. Alternative B would result in a minor increase equal to or lower than that of Alterative A based on EUCs adoption of BTM systems. Alternative B, therefore, also represents a minor negative environmental impact. Alternative C eliminates waste resulting from future potential GPP participation and provides guidance on the proposer disposal of solar panels to all DER adopters, which is likely to result in a minor positive environmental impact.

Table 2-1. Summary and Comparison of Alternatives by Resource Area[a]

Resource Area	Impacts by Alternative		
	A	B	C
Energy Production and Use	Minor changes in energy production and use; no discernable impacts on TVA operations	Minor changes in energy production and use; no discernable impacts on TVA operations	Minor changes in energy production and use; no discernable impacts on TVA operations
Socioeconomics and Environmental Justice	Minor positive financial impacts to future GPP participants; minor negative impacts to non-participants due to cost-shifting	Minor negative financial impacts to future GPP participants; minor positive impacts to non-participants	Substantively similar as for Alternative B; quality and safety benefits for future DER adopters
Air Resources	Not discernable	Not discernable to Minor Negative	Not discernable to Minor Negative
Water Resources	Not discernable	Not discernable to Minor Negative	Not discernable to Minor Negative
Land Use	Minor Negative	Minor Positive	Minor Positive
Production of Solid and Hazardous Waste	Minor Negative	Minor Negative	Minor Positive

[a] Note: The impacts for Alternative A are compared to current conditions, and the impacts for Alternatives B and C are compared to Alternative A.

2.3 Identification of Mitigation Measures

TVA has not identified any mitigation measures necessary to offset or reduce the level of impacts of the alternatives.

2.4 The Preferred Alternative

Alternative C, ending new GPP enrollment at the end of 2019 and offering a new private-scale renewable service offering, represents the proposed action and is preferred by TVA.

CHAPTER 3 – AFFECTED ENVIRONMENT

This chapter describes the natural and socioeconomic resources that could be affected under the three alternatives. Because the alternatives would apply to the entire TVA PSA, the resources are described at a regional scale. The primary study area, hereinafter called the TVA region, is the combined PSA and the Tennessee River watershed (Figure 1-1), including all counties in Tennessee and portions of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia. The TVA PSA is comprised of 202 counties and approximately 59 million acres.

3.1 Energy Production and Use

The 2019 IRP and associated EIS, incorporated herein by reference, describe TVA's current and projected future energy generation system in detail (TVA 2019a and 2019b). This section provides a brief overview of key information.

3.1.1 Overview

TVA is the largest public power supplier in the United States. Dependable generating capacity on the TVA system is approximately 38,000 MW. TVA generates most of this electricity with 3 nuclear plants, 6 coal-fired plants, 9 simple-cycle combustion turbine plants, 8 combined cycle plants, 29 hydroelectric dams, and 14 small PV facilities. A portion of delivered power is also provided through long-term PPAs. TVA transmits electricity from these facilities over 16,000 circuit miles of transmission lines. Like other utility systems, TVA has power interchange agreements with utilities surrounding its region and purchases and sells power on an economic basis almost daily.

Consumers of TVA-generated electricity consist of a mix of residential, commercial, and industrial EUCs in the PSA. Recent (2009–2018) energy sales totaled between 133,000 and 163,000 GWh annually, with sales in fiscal year 2018 of 162,933 GWh. This included sales to 154 distributors serving residential, commercial, and industrial EUCs and 58 directly served large industrial customers and federal installations. In 2018, 21 percent of TVA's power supply was from coal; 39 percent from nuclear; 27 percent from natural gas; 10 percent from hydroelectric; 3 percent from wind; and less than one percent each from solar and biomass (see Figure 3-1). Overall, 13 percent of 2018 generation was from renewable sources.

The 2019 IRP found that in the current outlook scenario, future capacity requirements were similar to current requirements until the end of the 20-year planning horizon; at that time, required capacity was projected to increase slightly. However, the IRP reports that new generation resources will be needed to replace facilities that will be retired during the planning horizon. Further, the IRP reports that expansion of solar resources, including a combination of utility-scale and private-scale solar, is a key component of meeting future energy needs. The recommended power supply mix in the IRP envisions adding between 1,500 and 8,000 MW of solar by 2028 and up to 14,000 MW by 2038 if a high level of load growth materializes. This is a large potential increase compared to the current solar capacity of approximately 148.4 MW, which consists of about 110 MW_{DC} of DER enrolled in GPP, 37 MW of BTM solar DER, and 1.4 MW generated by TVA-owned small PV installations.

Importantly, TVA's 2019 IRP modeling found that future utility-scale solar capacity is expected to be much higher than future private-scale solar capacity in the TVA PSA across all scenarios and strategies considered. The IRP's base case strategy, in which the least-cost generation mix that meets projected energy needs is selected, preferred utility-scale generation over private-scale solar due to its lower cost per unit.

The SACE produces an annual solar energy report covering states in the southeast United States. The 2018 report provides a forecast for distributed solar capacity until 2022 (SACE 2019). The geographic areas of analysis in the SACE report are states and therefore cannot be fully aligned with the geographic boundaries of the TVA PSA. However, the increase in distributed solar capacity is generally in the same range as developed in this analysis. For example, the state of Tennessee is forecast to experience an 83 percent increase in non-utility distributed solar capacity between 2018 and 2022 (SACE 2019). This analysis projects an increase of 118 percent over the same time frame in TVA's higher set of projections.[6]

3.1.2 Renewable Energy in the TVA Region

TVA's 2019 IRP and associated EIS discuss TVA's current energy generation mix in detail (TVA 2019a and 2019b).Total generation in FY2018 was 162,933 GWh, including both TVA generation and purchased power. TVA's 2018 generation mix was approximately 39 percent nuclear, 48 percent fossil fuels (27 percent natural gas and 21 percent coal), and 13 percent renewables (Figure 3-1).[7] The vast majority of the 21,232 GWh of renewable energy generation was hydroelectric and wind (a combined 96 percent), with solar and biomass each comprising between one and three percent of renewable energy generation (Figure 3-2).

In 2018, TVA generated less energy from fossil fuels (48 percent) than the national average of 64 percent.[8] As discussed in the 2019 IRP, TVA expects to increase the future generation of renewable energy, specifically utility-scale solar, while decreasing generation from fossil fuels.

[6] This is based on Projection 2. Projection 1 focused only on GPP capacity and therefore is not comparable.
[7] Renewables includes hydroelectric, wind, solar, and biomass.
[8] National number from EIA (2019).

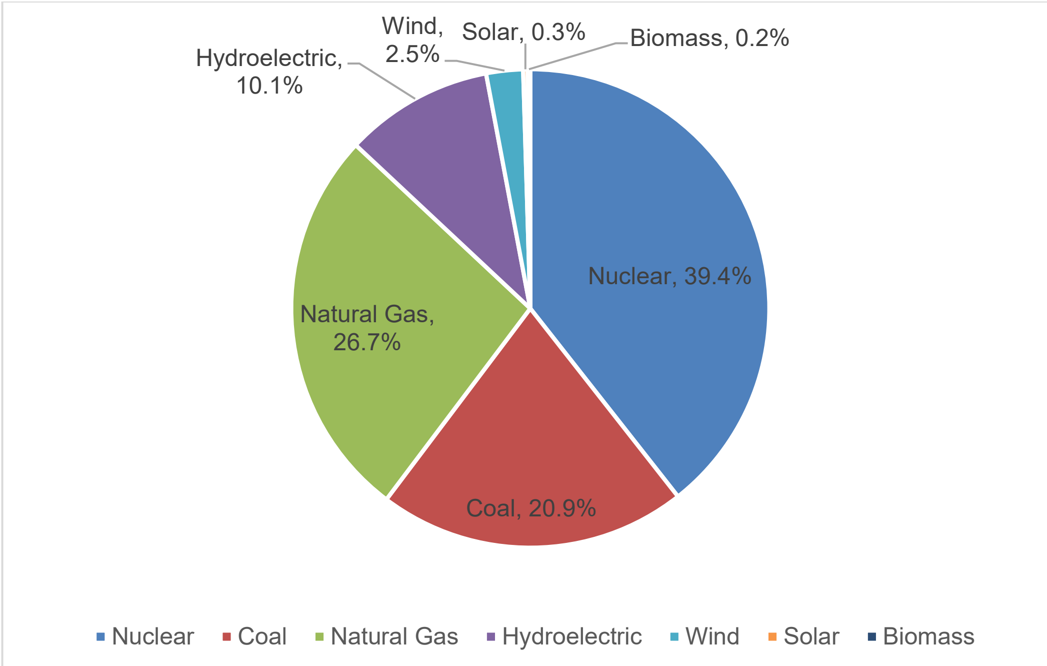

Figure 3-1. TVA 2018 Energy Generation

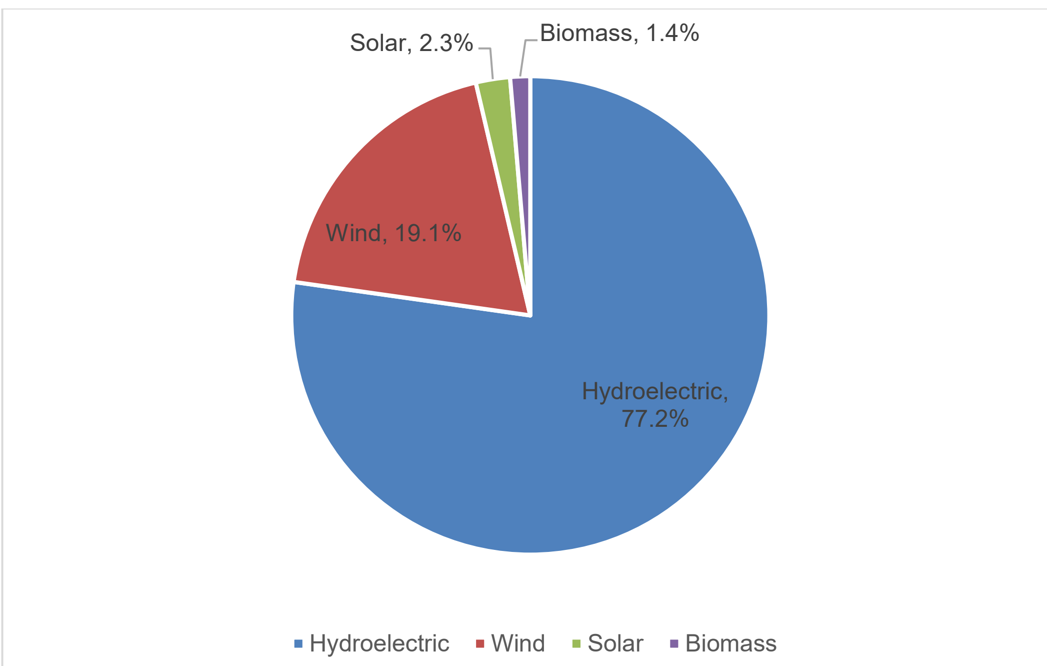

Figure 3-2. TVA 2018 Renewable Energy Generation

The DER options discussed in Section 1.3.2 have a combined capacity of 967 MW, of which the GPP Program makes up 11 percent (Table 3-1). In its IRP study, TVA estimated that GPP systems generated approximately 200 GWh of power in 2018, which is less than 1 percent of the total renewable generation and about 0.1 percent of total energy generation in the TVA region.

Table 3-1. Capacity of Distributed Generation Systems in 2018 [a]

Distributed Generation Option	Capacity (MW_{DC})	Proportion
Green Power Providers (GPP)	110	11.4%
Distributed Power Production (DPP)	157	16.2%
Behind-the-Meter (BTM)	700	72.4%
Total	**967**	**100.0%**

[a] Green Power Switch (GPS) is not included here because energy is not generated by the EUCs and would overlap with GPP energy generation.

3.2 Socioeconomics and Environmental Justice

This section summarizes the social and economic conditions in the TVA service area. This EA incorporates by reference the socioeconomic conditions and trends of the TVA region that are discussed in detail in the *2019 IRP EIS* (TVA 2019b) and *2018 Wholesale Rate Change EA* (TVA 2018).

3.2.1 Overview

The population of the TVA region was 10.3 million in July 2017, a 4.4 percent increase from July 2010. TVA projects that the rate of population increase in the TVA region will slow in the coming decades. Population density varies substantially among counties in the region, which contains a mix of rural and metropolitan areas. More populated areas are generally located along larger river corridors. About two-thirds of the population lives in defined metropolitan statistical areas (MSAs). As of July 2017, there are four MSAs with populations over 500,000, all located in Tennessee: Nashville (population of 1.9 million), Memphis (1.3 million), Knoxville (0.9 million), and Chattanooga (0.6 million). The largest metropolitan area in the TVA region located outside of Tennessee is Huntsville, AL, with a population of 0.45 million as of July 2017.

Selected social, demographic, and economic characteristics for the TVA region and the United States are presented in Table 3-2 (data from TVA 2019b). Primary observations include:

- The population of the TVA region is slightly older and includes a higher proportion of persons self-identifying as “white alone” than in the United States as a whole;

- The economy of the TVA region has a slightly higher percentage of workers employed in “blue collar” occupations such as natural resources, construction, production, and transportation than the nation as a whole and the proportion of persons with at least a high school degree was 84.7 percent, slightly lower than the national average; and

- The unemployment rate in the TVA region and the proportion of persons below the poverty level is higher than the national average, and per capita income is lower than the national average.

Table 3-2. Selected Social, Demographic, and Economic Characteristics

Characteristic	TVA Region	United States
Median Age	40.8	37.7
% Age 65 or Older	15.3	14.5
% High School or Higher	84.7	87.0
% Minority	26.3	38.7
Unemployment Rate (%)	7.7	5.8
Per capita income ($)	42,578	51,640
% Below Poverty Level	19.7	12.7
% Employment in Management, Business, Science, and Arts Occupations	32.9	37.0
% Employment in Service Occupations	16.8	18.1
% Employment in Sales and Office Occupations	24.1	23.8
% Employment in Natural Resources, Construction, and Maintenance	9.4	8.9
% Employment in Production, Transportation, and Material Moving	16.8	12.2

Source: *2019 IRP EIS* (TVA 2019b).

3.2.2 Minority and Low-Income Populations

Potential environmental justice impacts are analyzed in accordance with Executive Order 12898, which instructs Federal agencies to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of federal programs, policies, and activities on minority populations and low-income populations. While TVA is not subject to this Executive Order, it routinely considers environmental justice impacts in its NEPA review processes.

The *2019 IRP EIS* presents recent information about the geographical distribution of low-income and minority populations within the TVA PSA. Because the Alternatives considered herein would apply throughout the TVA PSA, this EA summarizes system totals. Refer to TVA (2019b) for more detailed information.

This EA also incorporates by reference TVA's *2018 Wholesale Rate Change EA*, which discusses energy use and the proportion of income spent on energy in the context of low-income and minority populations. The *2018 Wholesale Rate Change EA* discusses that, in general, low-income households tend to use less energy than higher-income households but spend a higher proportion of their incomes on energy bills. Also within the TVA region, minority households are more likely to be low-income households than non-minority households.

3.2.3 Households with Distributed Energy Resources

The primary direct impact of the alternatives considered in this EA would be the discontinuation of the GPP Program including payments to prospective new enrollees. As such, the socioeconomic characteristics of households that invest in DER or participate in renewable energy programs are of particular interest.

A recent study found that households that adopt rooftop solar systems tend to have higher monthly electricity bills and higher incomes, have residents with higher education levels, and be over 50 years old, compared to non-adopters (Moezzi et al. 2017). As that study notes, these findings match the results of other research. The study also found that saving money was the primary factor driving households' decisions regarding rooftop solar. Environmental considerations were often cited as important but secondary considerations.

3.3 Air Resources

Ambient air quality is protected by federal and state regulations. With authority granted by the Clean Air Act (CAA) 42 U.S.C. 7401 et seq. as amended in 1977 and 1990, the United States Environmental Protection Agency (USEPA) established National Ambient Air Quality Standards (NAAQS) to protect human health (primary standards) and public welfare (secondary standards).[9] The USEPA codified NAAQS in 40 CFR Part 50 for the following "criteria pollutants": nitrogen dioxide (NO_2), carbon monoxide (CO), ozone (O_3), sulfur dioxide (SO_2), lead (Pb), particulate matter (PM) with an aerodynamic diameter equal to or less than 10 microns (PM10), and PM with an aerodynamic diameter equal to or less than 2.5 microns (PM2.5).[10] These NAAQS reflect the relationship between pollutant concentrations and health and welfare effects. Areas not meeting the standards are called "nonattainment" areas. There are no nonattainment areas designated within the TVA PSA.

TVA coal-fired and natural gas fired electric generating facilities either directly emit these pollutants or contribute to their formation (O_3 and PM2.5) in certain atmospheric conditions. Generally, TVA's hydro, nuclear, and renewable energy facilities do not directly contribute to air emissions. TVA has also installed air emission controls at its fossil fueled facilities to reduce air emissions. For instance, TVA has installed selective catalytic reduction systems on 21 of its coal units and on all of its natural gas fired combined cycle plants to reduce nitrogen oxide emissions. TVA has also equipped 60 percent of its coal-fired capacity with scrubbers to address sulfur dioxide emissions. These emissions are expected to go down even further when coal-fired units at Allen Fossil Plant are replaced with a combined cycle gas plant.

Hazardous air pollutants (HAPs) are those that are listed under Section 112(b) of the CAA because they present a threat of adverse human health effects or adverse environmental effects. The CAA requires the USEPA to regulate HAPs from listed categories of industrial facilities. HAPs are toxic air pollutants, which are known or suspected to cause cancer or other serious health effects or adverse environmental conditions. The CAA identifies 187

9 Additional air pollutants such as VOCs and HAPs are regulated through other components of the CAA.
10 The current NAAQS are listed on USEPA's website at https://www.epa.gov/criteria-air-pollutants/naaqs-table.

pollutants as HAPs. Most HAPs are emitted by human activity, including motor vehicles, factories, refineries and power plants. Mercury is the HAP compound most associated with the burning of coal and power plant emissions. Other important issues concerning power plant emissions include acid deposition related to SO_2 and NO_x emissions, and visibility impairment, which, in the TVA region, is related mostly to ammonium sulfate particles formed from SO_2 emissions from coal-fired power plants. The most sensitive areas in the region are high elevation, forested areas such as the Great Smoky Mountains National Park. The nature of these pollutants, their effects, and their relationships to power production and industry are discussed more fully in TVA's 2019 IRP EIS.

Greenhouse gases (GHGs) occur in the atmosphere both naturally and as a result of human activities, such as the burning of fossil fuels. GHG emissions due to human activity are the primary cause of increased atmospheric concentration of GHGs since the industrial age and are the primary contributor to climate change. The primary GHGs are carbon dioxide (CO_2), methane, and nitrous oxide. GHGs are non-toxic and non-hazardous at normal ambient concentrations, and there are no applicable ambient air quality standards or emission limits for GHGs under the CAA. The primary greenhouse gas emitted by electric utilities is CO_2, produced by the combustion of coal, natural gas, and other fossil fuels. Under the 2019 IRP, TVA CO_2 emissions (measured by tons and by the emissions rate) resulting from the power generated by TVA and from non-TVA facilities marketed by TVA are anticipated to decline.

3.4 Water Resources

The quality of the region's water (surface water and groundwater) is critical to the protection of human health and aquatic life. Major watersheds in the TVA region include the entire Tennessee River basin, most of the Cumberland River basin, and portions of the lower Ohio, lower Mississippi, Green, Pearl, Tombigbee, and Coosa River basins. As described in detail in TVA's 2019 IRP EIS, these water resources provide habitat for aquatic life, recreational opportunities, domestic and industrial water supplies, navigation and other benefits. Wastewater discharges from cities or industries and runoff from nonpoint source activities such as construction, agriculture, mining, and air deposition can potentially degrade water quality.

Pollution involves the presence or introduction of a substance or object into water resources that may harm the water resource and impact its beneficial uses, such as swimming or aquatic life. Every two years, states are required to submit a report to the USEPA under Section 303(d) of the Clean Water Act. This report identifies the "impaired" lakes and streams that are not complying with water quality criteria and, consequently, are not suitable for their designated use(s). Thus, each state's 303(d) report provides an updated overview of assessed water quality in each state.

Sources of degraded water quality may include:

- Wastewater discharges from municipal sewage treatment systems, industrial facilities, concentrated animal feeding operations, and other sources;

- Runoff discharges from agriculture, forest management activities, urban uses, and mine lands, which transport sediment and other pollutants into streams and reservoirs. Runoff from commercial and industrial facilities and some construction sites is regulated through state National Pollutant Discharge Elimination System

(NPDES) storm water permitting programs. Sources not regulated through the NPDES program are referred to as "nonpoint source" runoff;

- Cooling systems, such as those used by electrical generating plants and other industrial facilities to withdraw water from streams or reservoirs, use it to cool facility operations, and then discharge the above ambient water into streams and reservoirs. Impacts can result from temperature changes, the trapping of organisms against intake screens, or sucking organisms through the facility cooling system. These water intakes and discharges are controlled through state-issued NPDES permits; and

- Air pollution in the form of airborne pollutants such as SO2, mercury and NOx being spread through rainfall and deposition.

- Man made impoundments such as dams, can cause low dissolved oxygen and other water quality issues in head and tail waters.

- Contamination of the bottom sediments of a stream from point or non-point source pollution can cause bioaccumulation of contaminant in fish tissue, which could lead to fish consumption advisories and compromise of species health, especially of bottom feeding/dwelling species.

Additional regulatory protections for water quality and the mechanisms of how power generation can affect water quality and aquatic life are discussed in detail in the TVA (2011) and TVA (2019b) EISs.

Groundwater refers to water located beneath the surface in rock formations known as aquifers. Eight major aquifers occur in the TVA region. Approximately half of the region has limited groundwater availability because of natural geo-hydrological conditions. More than 64 percent of the region's residents rely totally, or in part, on groundwater for drinking water. More than 1.7 million residents (22 percent) in the region maintain individual household groundwater systems, usually a well. All areas in the Tennessee Valley region can generally supply enough water for at least domestic needs. For the most part, the groundwater quality is adequate to support existing water supply uses even though some minimal treatment, such as filtration and chlorination, is sometimes required. Generating facilities involving combined cycle combustion turbines often make use of groundwater for either cooling or reinjection of heated water.

3.5 Land Use

TVA provides wholesale and retail power to portions of a seven state region comprising 80,000 square miles. Major land uses in the TVA region include forestry, agriculture, and urban/suburban/industrial development. Regional land use is described in detail in the *2019 IRP EIS* (2019b). Of the non-federal land in the TVA region, about 12 percent is considered developed and 88 percent is considered rural.

TVA's existing power plant reservations, excluding the hydroelectric plants associated with multi-purpose reservoirs, occupy about 25,000 acres. The actual disturbed acreage of these non-hydroelectric facilities is about 17,400 acres. Existing non-TVA generation facilities from which TVA purchases power under PPAs utilize an area of approximately 2,400 acres.

3.6 Production of Solid and Hazardous Waste

Residential, Commercial and Industrial Wastes

Residential and commercial wastes are usually generated in many diffusely located areas and handled at municipal solid waste landfills. Most municipalities and counties currently engage in long-range planning processes to ensure that adequate capacity is provided for solid wastes generated within their jurisdictions. Solid waste reduction and recycling is an important emphasis in most of these plans. For example, in the state of Tennessee, in 2017, Tennessee businesses, industries, citizens and others disposed of 17,045,462 tons of solid waste. Of this amount, 7,373,749 tons went to Class 1 landfills and 161,897 tons were recycled, reused, or diverted to other facilities. (TDEC 2019).

Tennessee, along with other states in the Valley, has also implemented a program for the collection and safe storage and disposal of household hazardous waste (HHW). The program collects and properly disposes of paint, flammable liquids, corrosives, oxidizers, batteries, and pesticides. Ninety-four counties in Tennessee have participated in the mobile collection service since it began in 1993, and an average event yielded 4,592 pounds of HHW (with a 0.6 percent participation rate). (TDEC 2015)

Industrial solid and hazardous waste generation and handling is similar. Current legislative and regulatory programs encourage and/or mandate the reduction, recycling, and proper disposal of industrial solid and hazardous wastes. The states within the TVA PSA have state-administered Resource Conservation and Recovery Act (RCRA) equivalent programs, which emphasize waste reduction, recycling, and proper handling and disposal of solid and hazardous wastes. Industries benefit both financially and from a public relations standpoint by engaging in waste reduction and recycling opportunities in the same way that TVA benefits from its marketing and utilization of coal combustion residuals (CCR) that are a by-product of coal-based generation. It is, therefore, likely that industrial solid and hazardous waste generation and disposal will continue to decline in the future.

Disposal of solar equipment at the end of its useful life could also result in solid and hazardous waste. Solar panels can be recycled, but recycling is currently not widely available in the U.S. (Marsh 2018). However, options for recycling solar panels are expected to increase as the overall market expands and currently deployed panels near the end of their expected lives. If recycling is not available, solar panels often end up in landfills. According to Tao and Yu (2015), recycling of typical PV solar panels lacked strong economic rationale during the first half of the present decade.

The impacts of solar equipment disposal, especially improper disposal, have been widely noted in various literature (Aman et al., 2015; Paiano, 2015). In a detailed report on global waste from solar systems, Weckend et al. (2016) estimate that the U.S. will generate a cumulative 7.5 million to 10 million tons of solar equipment waste by 2050, making the U.S. the second greatest producer of solar waste after China. Weckend et al. (2016) also estimate that by 2050, global annual waste from solar panels alone could exceed 10% of the total global electronic waste produced in recent years.

According to Weckend et al. (2016), only the European Union (EU) has enacted waste regulations specific to solar panels. In other countries, like the U.S., solar panels are typically treated as general waste or industrial waste. According to this same report, the most common type of solar panels produced globally are based on crystalline silicon (c-Si) technology. These panels are composed primarily of glass, aluminum, silicon, polymer, and copper.

An alternative solar panel technology that is currently less common is termed thin-film Cadmium Telluride (Cd-Te), which is composed primarily of glass and polymer (Weckend et al. 2016). In addition, these panels contain small amounts of cadmium compounds, which are potentially harmful to human health if leached from landfills. Cyrs et al. (2014) assessed the potential human health burden from these panels in landfills and determined that they did not likely present a material risk given current levels of solar adoption.

Additional sources of waste related to private-scale solar systems include panel mounting and racking systems, which are typically composed of aluminum and steel. A smaller total quantity of waste may also be produced from end-of-life electrical inverters and stationary batteries.

TVA-Generated Wastes

Types of wastes typically produced by construction activities, whether by TVA or others, include vegetation, demolition debris, oily debris, packing materials, scrap lumber, and domestic wastes or garbage. Non-hazardous wastes (excluding CCR) typically produced by common operation of TVA facilities include sludge and demineralizers from water treatment plant operations, personal protective equipment, oils and lubricants, spent resins, desiccants, batteries, and domestic waste. In 2016, TVA facilities produced approximately 23,000 tons of non-hazardous solid waste per year; this quantity decreased to approximately 18,750 tons in 2017 (TVA 2019b).

TVA facilities include large, small, and very small quantity generators (previously conditionally exempt generators) of hazardous waste. Hazardous non-radiological wastes typically produced by common TVA facility operations include paint and paint solvents, paint thinners, discarded out-of-date chemicals, parts washer liquids, sand blast grit, chemical waste from cleaning operations, and broken fluorescent bulbs. Routine operations between 2015 and 2017created an average of 9.49 tons of hazardous waste. In 2017, approximately 27.4 tons of universal waste was generated and recycled by TVA (TVA 2019b). TVA's hazardous wastes and those requiring special handling (TSCA and universal waste) are generally shipped to Waste Management's Emelle, Alabama facility for disposal. TVA programs for reducing hazardous waste, based upon source reduction, have been in place for some time.

Coal combustion solid wastes or residues (i.e. CCRs) include fly ash, bottom ash, boiler slag, char spent bed material, and sludge from operation of wet flue gas desulfurization systems. In the past, the USEPA determined that CCRs are not hazardous, and in April 2015 the USEPA decided to continue to regulate them as non-hazardous, solid waste. In 2015, TVA produced approximately 3.9 million tons of CCRs, of which 33.6 percent was utilized or marketed (TVA 2016). Annually, CCR production at TVA's coal-fired plants fluctuates due to a variety of factors including: plant planned and forced maintenance outages, load swings, plant dispatch (the process by which plants are directed to increase or decrease power generation based on the cost of production at each plant—generally the larger, more efficient units run more and the smaller, less efficient units run less), and variation in fuel supplies (BTU, sulfur, and ash content of the fuels burned). Additionally, recent decisions to retire coal-fired generation further reduce the amount of CCRs generated by TVA at its plants. The amount of CCRs that are disposed of is also reduced through marketing and utilization of these by-products in a number of commercial applications including the use of fly ash in concrete products, bottom ash as aggregate in cement block manufacturing, boiler slag for roofing granules and industrial abrasives, and scrubber gypsum in gypsum wallboard and cement manufacturing.

CHAPTER 4 – ENVIRONMENTAL CONSEQUENCES

This section includes the analysis of the potential environmental and socioeconomic effects of the three alternatives. An analysis of taking no action (Alternative A) is also provided to establish a baseline for comparison among alternatives.

4.1 Energy Production and Use

4.1.1 Alternative A – No Action Alternative (GPP Program Continues)

Under Alternative A, the GPP Program would generally continue as it was implemented in 2019. The price at which TVA purchases energy from EUCs would continue to be $0.09/kWh for Residential/GSA-1 systems under 10 kW, and $0.075/kWh for Residential/GSA-1 systems over 10 kW and non GSA-1 Commercial Customers. The purchase agreements would continue to be for a 20-year term. The annual capacity of new enrollments would be capped at 10 MW, a slight increase from 2019. In 2018, the annual enrollment cap was 10 MW and only 2.5 was reserved; the remaining 7.5 MW was carried over into 2019. An annual enrollment cap of 10 MW is assumed starting in 2020.

The potential future enrollment in GPP under Alternative A is projected using several methods to account for potential uncertainty. First, an upper bound scenario is developed based on the maximum potential enrollment. Second, a simple forecast based on extending recent trends is calculated. Third, an economic forecast is based on the potential financial decisions that households and businesses could face in future years when considering among the three alternatives of installing a system with GPP enrollment, installing BTM, or neither.

4.1.1.1 Upper Bound Scenario

Because of the annual capacity limit, the maximum amount of capacity from GPP projects that could be added from 2019 through 2038 is 197.5 MW (Figure 4-1).[11] For comparison, the total firm summer capacity in 2038 in the TVA PSA is projected to be over 39,900 MW (TVA 2019a, Figure G-1.) Thus, the maximum GPP participation in 2038 would comprise less than 0.5 percent of the total TVA capacity.[12] Renewable energy is projected to account for about 8,400 MW of the 2038 capacity, approximately 21 percent of the total. The maximum GPP capacity in 2038 would be approximately 2.4 percent of the capacity from renewable sources in 2038. These comparisons are based on the highest amount of new GPP capacity during the planning period, which would runs through 2038.[13] The percentages in 2019 would be near zero and would increase through 2038 as additional capacity is added each year.

[11] The annual capacity limit would be 7.5 MW in 2019 and 10 MW thereafter. 19 years x 10 MW per year + 1 year x 7.5 MW per year = 197.5 MW.
[12] 197.5 MW ÷ 39,900 MW x 100 = 0.49%.
[13] This comparison is also conservative (likely to overstate potential impacts) because the GPP Program's non-firm capacity is compared to system-wide firm capacity, and firm capacity is higher than non-firm capacity.

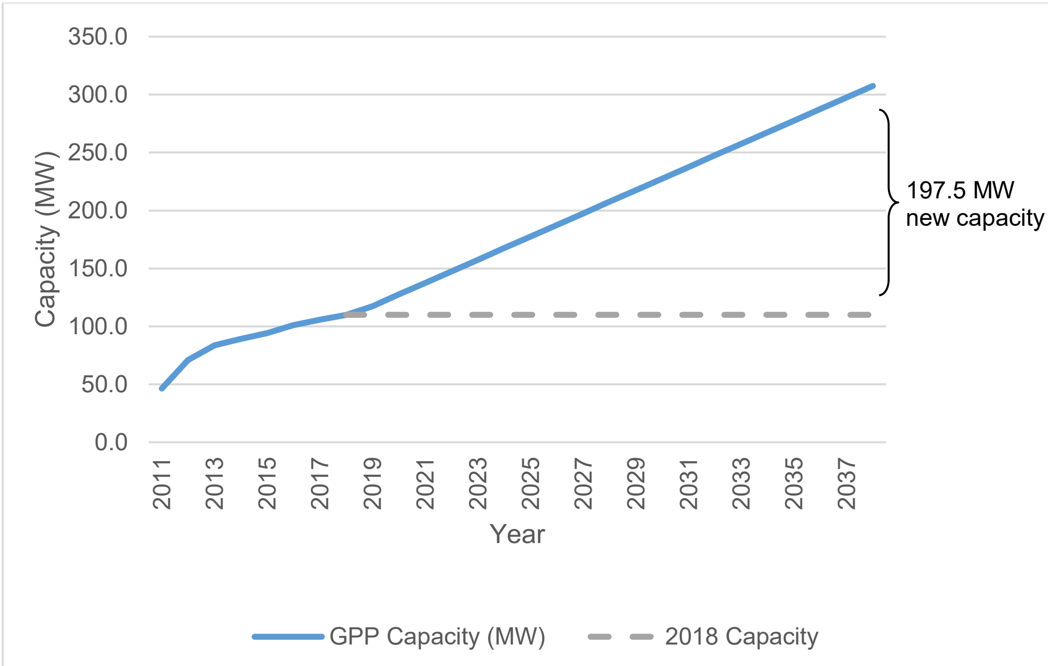

Figure 4-1. GPP Capacity in the Upper Bound Scenario

Because energy generation systems operate below full capacity, considering energy generation serves as a better basis than capacity for analyzing the potential environmental impacts that may result from growth. Most GPP installations in the last few years have been solar. Because of this and the fact that the cost of solar systems is expected to decrease in the upcoming years (see TVA 2019a), TVA assumes for the purposes of this analysis that all future GPP enrollment would be private-scale solar systems. Over an entire year, solar systems generate electricity at a much lower average rate than the maximum capacity, largely because the panels operate at maximum capacity only during optimal atmospheric conditions.[14]

Consistent with assumptions in the 2019 IRP, this analysis assumes that private-scale residential solar systems operate at an average of 15.5 percent of maximum capacity over the course of a year and private-scale commercial systems operate at an average of 19.0 percent of maximum capacity over the course of a year. There are 8,766 hours in an average year.[15] Each 1 MW of private-scale residential solar capacity will generate about 1,400 MWh of energy in one year,[16] and each 1 MW of private-scale commercial solar capacity will generate about 1,700 MWh of energy in one year.[17] About 75 percent of the current GPP capacity is commercial. Assuming that this percentage applies in the future, the weighted-average energy produced per 1 MW of future GPP solar capacity is about

[14] Optimal conditions generally occur during direct sunlight in the late spring. During other times of year and during cloudy conditions, the panels will produce far less electricity than rated capacity.
[15] 365.25 days per year x 24 hours per day.
[16] 1 MW capacity x 15.5% capacity factor x 8,766 hours = 1,358.73 MWh.
[17] 1 MW capacity x 19.0% capacity factor x 8,766 hours = 1,665.54 MWh.

1,600 MWh.[18] Applying this to maximum future GPP capacity of 197.5 MW, the maximum energy generated in 2038 would be about 314,000 MWh.[19]

For context, the TVA system delivered 163 million MWh of electricity in FY2018 (TVA 2019a), of which about 13 percent was from renewable sources (hydro, wind, solar, and biomass). Thus, the upper bound projection equates to 0.2 percent of TVA's total generation and 1.5 percent of the renewable generation in FY2018.

The percentages based on energy generation are lower than those for capacity because solar generates less electricity per unit of capacity over the course of a year than other generation technologies (Table 4-1). This concept is often referred to as capacity factor, which is the percent of electricity generated over a time increment (typically one year) divided by the maximum electricity generation possible over that same time increment based on rated power capacity. The differences in capacity factors across types of generation reflect both the physical systems and the way that they are utilized.

Because nuclear has the highest capacity factor, nuclear facilities are used as the "base load", meaning that it is typically run when not undergoing maintenance. Coal and natural gas are both turned on and off as needed, adjusting to varying generation of renewables as well as varying load based on customer demand. Renewables are generally used as much as possible; however, the availability varies over time depending on factors such as precipitation and river flows, wind speed, and solar intensity. While hydroelectric and wind have capacity factors comparable to coal and natural gas, solar has the lowest capacity factor of all the technologies.

Table 4-1. Comparison of Capacity Factors for Generation Sources in the TVA PSA

Type of Generation	FY2018 Capacity (MW)[a]	Max Generation at 100% Capacity (GWh)[b]	FY2018 Energy Generation (GWh)[c]	FY2018 Capacity Factor[d]
Nuclear	7,700	67,498	64,194	95.1%
Coal	7,900	69,251	34,026	49.1%
Natural Gas	12,500	109,575	43,481	39.7%
Hydroelectric	4,200	36,817	16,399	44.5%
Wind	1,227	10,756	4,055	37.7%
Solar	371[e]	3,252	491	15.1%
Total	**33,898**	**297,150**	**162,646**	**54.7%**

[a] From TVA 2019(a), Section 5.2.1
[b] Capacity (MW) x 365.25 days per year x 24 hours per day.
[c] From TVA 2019(a), Integrated Resource Plan Volume I – Final Resource Plan
[d] FY2018 Energy Generation ÷ Max Generation at 100% Capacity.

[18] 0.75 x 1,665.54 MWh + 0.25 x 1,358.73 MWh = 1,588.84.
[19] 1,588.84 MWh/MW x 197.5 MW = 314,000 MWh.

[e] Includes 1 MW of TVA-owned capacity and 370 MW of programs and long-term purchased power contracts, including the GPP.

4.1.1.2 Projection 1: Extension of Current Trends

The maximum capacity and energy generation discussed above is unlikely, as new GPP enrollments have decreased in recent years and have been well below the maximum capacity limits. Another method of projecting future GPP enrollment is to extend recent trends.

Trend lines were fitted to recent GPP enrollment data and used to forecast future GPP participation (Figure 4-2 and Figure 4-3). This method suggests that both new GPP systems and new GPP capacity coming online would decline to zero around 2025 if recent trends continued. Note that this method is simplistic in that it does not account for changing financial values faced by EUCs or variables that affect GPP participation over time; it simply assumes that recent trends would continue. This method implicitly assumes that GPP payments would continue to decline, although they would likely be held constant at the 2019 levels. Therefore, the trend lines may understate future new enrollment.

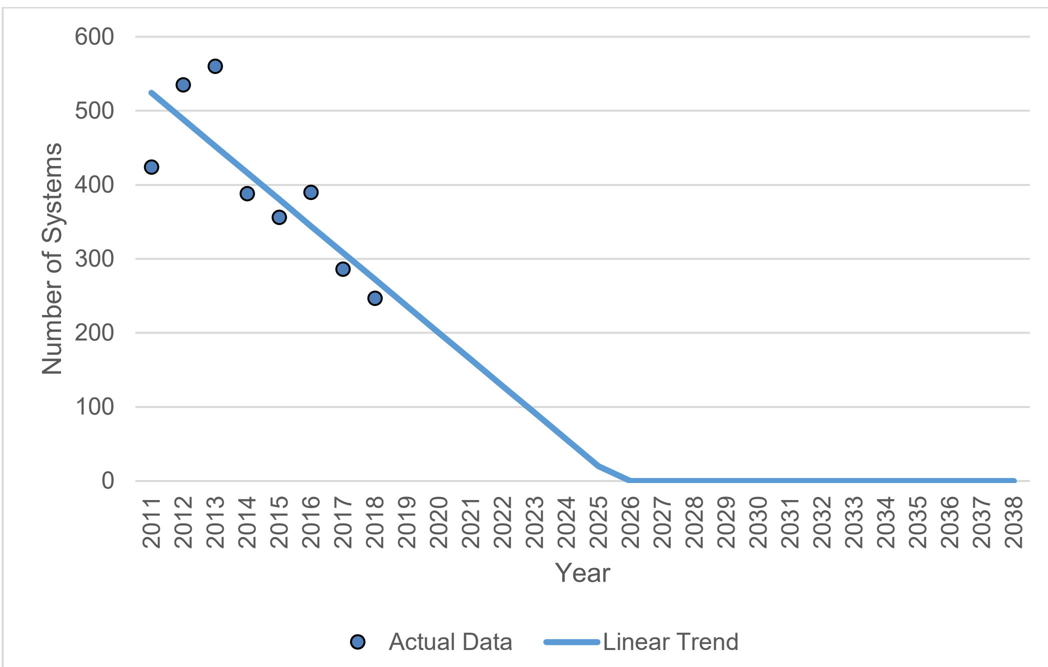

Figure 4-2. Forecast of New GPP Systems Coming Online

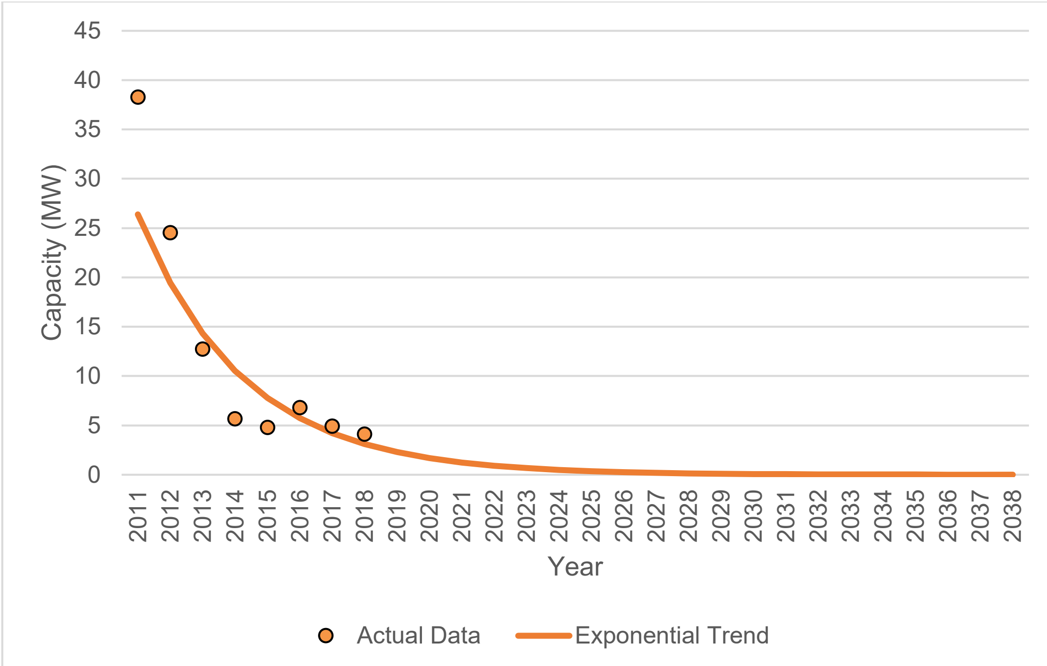

Figure 4-3. Forecast of New GPP Capacity Coming Online

4.1.1.3 Projection 2: Behavioral Modeling

Another method to project the potential maximum GPP growth over time, under Alternative A, is based on behavioral modeling of residential and commercial EUCs' financial decisions. These projections also incorporate expected future changes in the main variables that inform these decisions, such as the future energy prices and costs of private-scale system installation. The financial decision considers three mutually exclusive options: a) install a private-scale solar system and enroll in GPP; b) install a private-scale solar system as BTM; or c) do not install a private-scale solar system.

The projections occur in three main steps:

1. An adoption rate curve, which forecasts increasing adoption in private-scale solar from 2018 levels, is forecast for each year from 2019-2038. The adoption rate curve assumes that all other factors, such as solar installation costs, are constant over time. The remaining steps adjust the adoption curve to account for the expected changes in important financial factors over time.

2. The "simple payback period", a common metric for evaluating the length of time in years it takes for a solar project investment to pay for itself with future financial savings, and is calculated based on projected values over time of variables that affect the payback period, such as solar installation costs and the GPP energy credit.

3. The maximum market share, which is the maximum percentage of residential and commercial buildings that are suitable for adopting private-scale solar, is calculated based on the payback period. The maximum market share equation is based on a published relationship between solar adoption and the payback period. The

maximum market share is used to adjust the result of (1) over time to account for variables that affect the financial outlook of GPP and BTM investment.

The adoption rate curve and maximum market share come from a National Renewable Energy Laboratory publication (Denholm, Drury, and Margolis 2009) and were used in the TVA 2019 IRP modeling. Each step in the projections is summarized in the following sections.

Adoption Rate Curve

The adoption rate curve models the adoption rate of new technologies as an S-shaped curve. This reflects that fact that technology adoption rates are typically relatively slow soon after a technology is available, increase relatively rapidly over time as the technology becomes more familiar, and then slow as the market becomes saturated, meaning that most people who will adopt the technology have done so.

The NREL report uses 2001 as the year that private-scale solar was widely available at the national level. TVA uses 2003, the beginning of the GP/GPP Program, as this date.[20] The resulting curve (Figure 4-4) predicts that private-scale solar adoption would increase fairly rapidly from 2019 through 2029 and would slow thereafter, reaching close to the maximum adoption by 2038. Note that the percentage in the maximum adoption rate is calculated out of the number of EUCs that would install solar, not the total number of households that could install solar. Thus, the curve does not imply that 100% of EUCs would have installed solar by 2038.

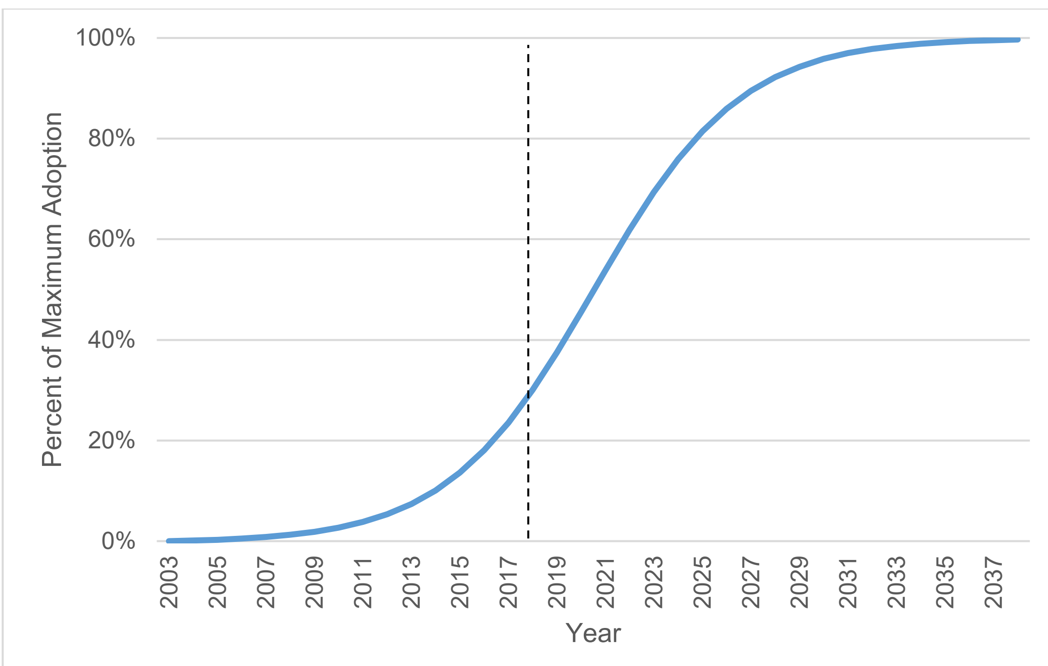

Figure 4-4. Adoption Rate Curve used in Projections

[20] The adoption rate curve requires two other parameters, p and q. Consistent with the 2019 IRP modeling, we use p=0.001 and q=0.33.

<u>Payback Period</u>

The payback period is used in two ways in the projections. First, it is used as a proxy for whether or not a private-scale solar system is a viable investment. Second, it is used as an input into the maximum market share equation.

From an economic standpoint, a private-scale solar system is considered a viable investment if the total financial benefits of the system are less than its total cost. The simple payback period, or the number of years that is required for a system to “break even” (i.e., when the benefits equal or exceed the costs) is often used as a way to simplify the economic calculation.[21] If the simple payback period is less than the useful life of the system, then the system is considered a viable financial investment.

For GPP-enrolled systems, financial benefits are accrued for 20 to 30 years, depending on decisions EUCs make after the 20-year PA with TVA expires.[22] The payback period is then the number of years required for the total energy credit payments to equal or exceed the initial installation costs plus any expected operation and maintenance (O&M) costs that may occur. If the payback period is less than 20 years, GPP enrollment is a viable financial investment. If the payback period is between 20 and 30 years, GPP may be a viable investment depending on the EUC’s decision at the end of the PA.

A BTM system will accrue financial benefits over its useful life in the form of reduced energy consumption and bills from an LPC. The useful life is assumed to be 30 years based on 2019 IRP modeling. If the payback period is less than 30 years, then the system is a viable financial investment. The simple payback period indicates that residential EUCs who install a typical solar system at recent prices will experience monetary savings (compared to not having a solar system) during the second half of the useful life of the system. Figure 4-5 illustrates the amount of savings for a solar system for a typical BTM residential system at current costs.[23]

The average initial expenditure for a private-scale solar system is about $13,000, meaning that the EUC has negative savings of $13,000 in the year the system is installed. Each year after installation, the EUC spends money on O&M and saves money on electric bills (they use energy produced by the system, which reduces the amount of energy they purchase from their LPC). Net savings of about $740 per year accumulate over time. The payback period, when the total net savings equals $0, is almost 18 years. For the remaining 12 years of the system’s useful life, savings are positive each year and accumulate over time. At the end of the system’s useful life, the cumulative savings over the entire 30-year life of the system are approximately $9,000. Thus, the initial expenditure of $13,000 results in a net savings of $9,000 over 30 years.

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[21] The “simple payback period” ignores some valid economic considerations, such as a discount rate, and is commonly used because of its simplicity. For example, many online solar investment calculators use the simple payback period. See Drury et al. 2011 for discussion of different metrics used to evaluate the financial viability of solar investments.

[22] EUCs have three main choices after the PA expires: 1) let the system continue to operate and send energy to the grid and receive no energy credit from TVA; 2) uninstall the system after 20 years; or 3) convert the system to BTM for the remainder of its useful life.

[23] This assumes a 6 kW capacity system with a cost of about $3,000/kW and an ITC of 30%.

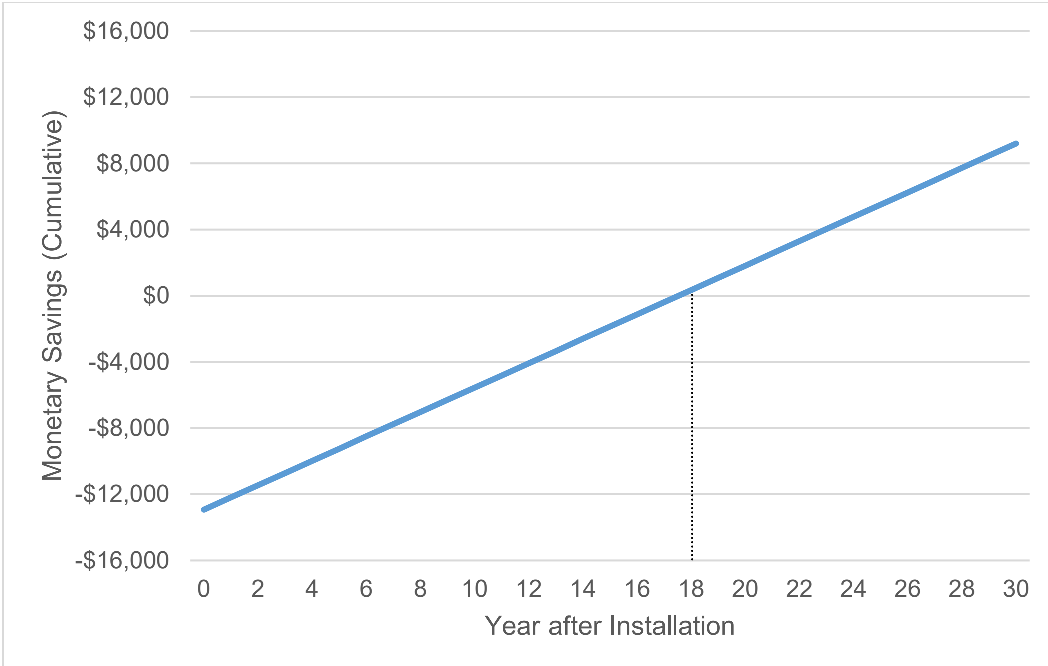

Figure 4-5. Monetary Savings over the Useful Life of a Typical Private-scale BTM Solar System

This example illustrates the importance of the payback period. Lower payback periods result in earlier systems break even times and more years of monetary savings. All else equal, more EUCs are expected to adopt private-scale solar systems when the payback period is lower.

The payback period for a private-scale solar BTM installation depends on several variables:

- The initial cost of the system (higher increases the payback period);
- The Federal Investment Tax Credit (ITC) (higher decreases the payback period);
- A capacity factor, which is the average amount of energy that can actually be generated measured as a proportion of the system's maximum capacity (higher decreases the payback period);
- A utilization factor, which is the proportion of energy possibly generated that an EUC actually self-consumes coincident with generation (higher decreases the payback period);
- The per unit rate the EUC is charged for electricity (higher decreases the payback period); and
- Annual O&M (higher increases the payback period).

The decision to install a GPP-enrolled system versus a BTM system is influenced by two main factors. First, a GPP system sends energy to the grid any time it is generating energy, which does not depend on simultaneous energy demand by the EUC as BTM does. Therefore, the utilization factor is not included in determining the payback period for GPP systems.[24] Second, GPP does not reduce the amount of energy the EUC purchases from the grid as does a BTM system. Instead, a GPP system receives a monetary payment for the energy sent to the grid, called an energy credit.

The current modeling calculates the payback periods for four EUC and system combinations: GPP and BTM systems and residential and commercial EUCs. These four groups are modeled separately because they have different costs, energy rates, and differing ITC levels over time.

Table 4-2 through Table 4-4 contain the main assumptions of the modeling. Importantly:

- Commercial systems have higher capacity and utilization factors, lower costs (per kw), and higher a ITC than residential systems after 2021 (all tend to decrease payback period relative to residential systems);
- Commercial systems have a lower GPP energy credit and a lower retail energy rate than residential systems (both tend to increase payback periods relative to residential systems);
- The installation costs for both commercial and residential systems are projected to decrease over time (tends to decrease future payback periods);
- The ITC for both commercial and residential systems are projected to decrease over time (tends to increase future payback periods); and
- Retail energy rates are projected to increase (tends to decrease payback periods for BTM installations).

Table 4-2. Assumptions for Variables that do not Change over Time

Variable	Value
Residential Capacity Factor	0.155
Commercial Capacity Factor	0.190
Residential Utilization Factor (BTM only)	0.6
Commercial Utilization Factor (BTM only)	0.8
Residential GPP Energy Credit (GPP only)	$0.09 / kWh
Commercial GPP Energy Credit (GPP only)	$0.075 / kWh
Residential Annual O&M	$21 / kW
Commercial O&M	$15 / kW

GPP energy credits are discussed in Section 2.1.1.
The utilization factor is an estimate based upon the TVA's Solar Calculator FAQs (TVA 2019d) and from McKenna et al. (2018).
All other variables are taken from the 2019 IRP solar modeling.

[24] As all of the energy generated goes to the grid, the utilization factor essentially is equal to 1.

Table 4-3. Assumptions for Variables that Change over Time (Residential EUCs, applies to GPP and BTM systems)

Year	Solar Install Costs ($/kW$_{DC}$)	ITC (Percentage)	Retail Energy Rate ($/kWh)
2019	3,079	30	0.106
2020	2,985	26	0.106
2021	2,896	22	0.106
2022	2,811	0	0.107
2023	2,729	0	0.107
2024	2,671	0	0.109
2025	2,620	0	0.109
2026	2,573	0	0.110
2027	2,529	0	0.111
2028	2,489	0	0.112
2029	2,450	0	0.113
2030	2,412	0	0.114
2031	2,376	0	0.114
2032	2,341	0	0.114
2033	2,308	0	0.115
2034	2,278	0	0.116
2035	2,249	0	0.116
2036	2,221	0	0.116
2037	2,195	0	0.116
2038	2,170	0	0.117

All variables are from the 2019 IRP solar modeling.

Table 4-4. Assumptions for Variables that Change over Time (Commercial EUCs, applies to GPP and BTM systems)

Year	Solar Install Costs ($/kW$_{DC}$)	ITC (Percentage)	Retail Energy Rate ($/kWh)
2019	2,004	30	0.104
2020	1,939	26	0.104
2021	1,876	22	0.104
2022	1,816	10	0.105
2023	1,758	10	0.106
2024	1,714	10	0.107
2025	1,674	10	0.107
2026	1,638	10	0.108
2027	1,605	10	0.109
2028	1,573	10	0.110
2029	1,542	10	0.111
2030	1,513	10	0.112
2031	1,485	10	0.112
2032	1,457	10	0.112
2033	1,430	10	0.113
2034	1,406	10	0.114
2035	1,382	10	0.114
2036	1,359	10	0.114
2037	1,337	10	0.114
2038	1,316	10	0.115

All variables are from the 2019 IRP solar modeling. All dollars are inflation-adjusted.

The projected payback periods for GPP and BTM are shown in Figure 4-6 below. While GPP systems had lower payback periods in the past due to higher GPP energy credits, GPP systems have higher payback periods in all future years. Residential systems generally have higher payback periods than commercial systems in the future.

Based solely on these payback periods, little investment in residential private-scale solar is expected, as payback periods for both GPP and BTM systems are generally above their respective useful life periods (20 years for GPP and 30 years for BTM). This is consistent with the findings of Projection 1, Extension of Current Trends, for GPP systems. It is also consistent with the 2019 IRP modeling, which finds that most future private-scale solar capacity would be commercial rather than residential. However, some residential EUCs likely install solar systems for reasons other than pure financial return, such as environmental concerns and the ability to rely on self-generated energy. Therefore, some residential EUCs may adopt private-scale solar even if the payback period suggests the financial costs may not be fully recovered. Another factor to consider is that these payback periods are calculated assuming typical input variables; however, some EUCs may have different input variables and therefore have a different financial outlook. The economic projections do not limit future projections under the assumption that EUCs consider only financial benefits. Therefore, future residential investment is projected. As shown in

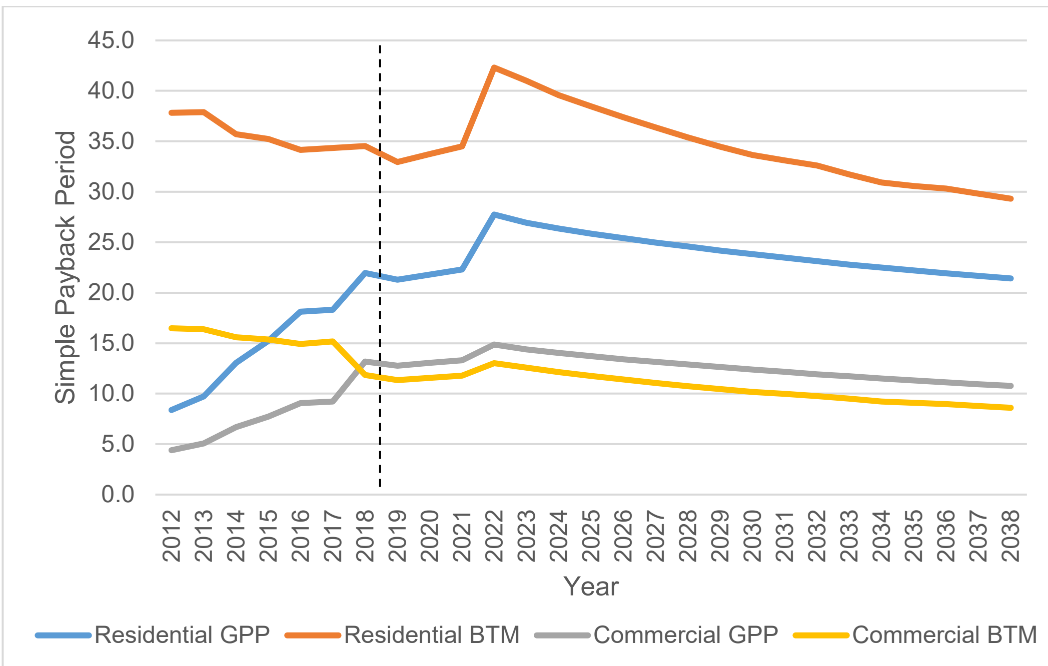

Figure 4-6. Projected Private-Scale Solar System Payback Periods

Section 4.1.1.4, this provides an intermediate projection between the Upper Bound Scenario (Projection 1) and the extension of recent trends (Projection 2).

Future commercial GPP and BTM systems are both viable investments in terms of the simple payback period occurring prior to the end of expected system useful life. Based on the payback periods, BTM is a slightly better investment in all future years. EUCs likely have multiple considerations when deciding whether to install solar, including the potential financial return compared to other investments, public relations value of self-generation, etc. In addition, commercial EUCs may undertake more detailed financial calculations than the simple payback period. Therefore, these projections should be considered a useful simplification for the purposes of this analysis.

Maximum Market Share

The PV technical potential refers to the maximum proportion of EUCs with suitable buildings or land that adopt GPP or BTM systems. The maximum market share is the proportion of the PV technical potential, which is economically viable based on the payback period. The maximum market share is estimated using the equation described in the 2019 IRP (see illustration in TVA 2019a, Figure C-6):

$$Maximum\ Market\ Share = e^{-0.3 \times Payback\ Period}.$$

This equation predicts a maximum market share of about 75 percent for a 1-year payback period and a maximum market share of about 0.25 percent for a 20-year payback period.

Using the Maximum Market Share to Adjust the Adoption Rate Curve

The final step is to combine the adoption rate curve and the maximum market share. Changes in the maximum market share each year were used to adjust the adoption rate curve accordingly. In other words, if the maximum market share decreased by 5 percent from one year to the next, the adoption rate in the second year would be adjusted downward by 5 percent. Starting with the 2018 known amounts of private-scale solar capacity, the adjusted adoption rate curve was used to project capacity from 2019 through 2038 (Figure 4-7).

The overall shape of future private-scale solar deployment is driven by the adjusted adoption rate curve. The allocation across the four categories depends on both the starting amounts in 2018 and the maximum market shares, which depend on the different payback periods over time. As of 2018, GPP capacity was about 110 MW, and about 75 percent of that was commercial. TVA found that known BTM solar in 2018 was about 37 MW (TVA 2018).[25] The total private-scale solar capacity is projected to be 365 MW by 2038, of which 240 MW is enrolled in GPP. This is a total increase over current capacity of 130 MW.

The annual additions to GPP capacity are projected to be at the capacity limit of 10 MW for almost 10 years and then decrease. This is largely a function of the increasing adoption rate curve, which outweighs the effect of the increasing payback period.

[25] TVA does not have complete information on BTM systems. Therefore, the actual amount in 2018 could be higher.

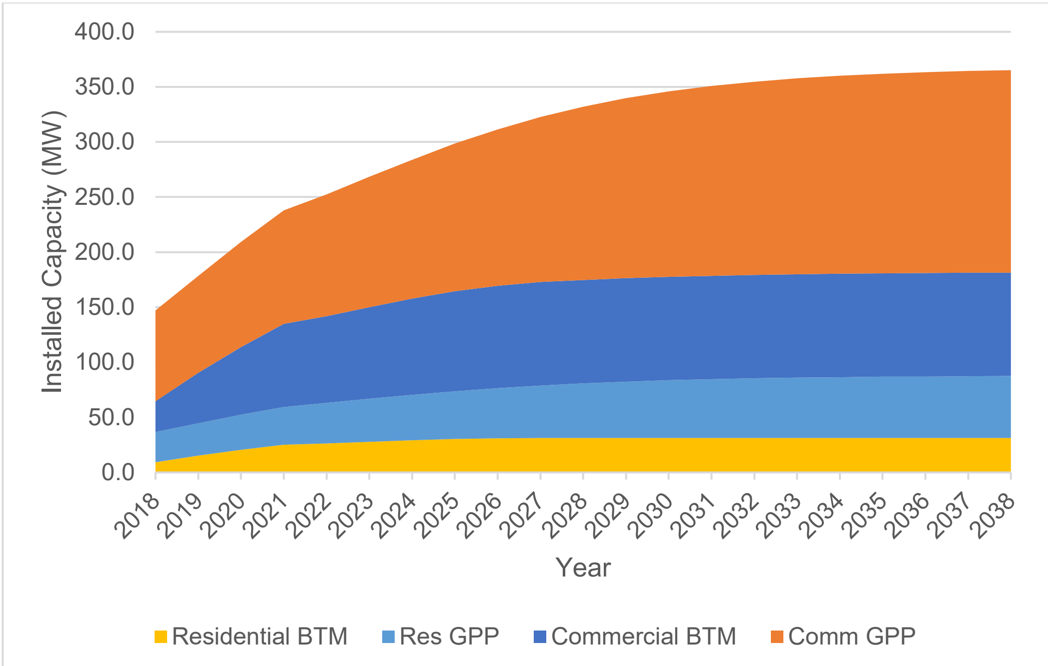

Figure 4-7. Projected Private-Scale Solar Capacity

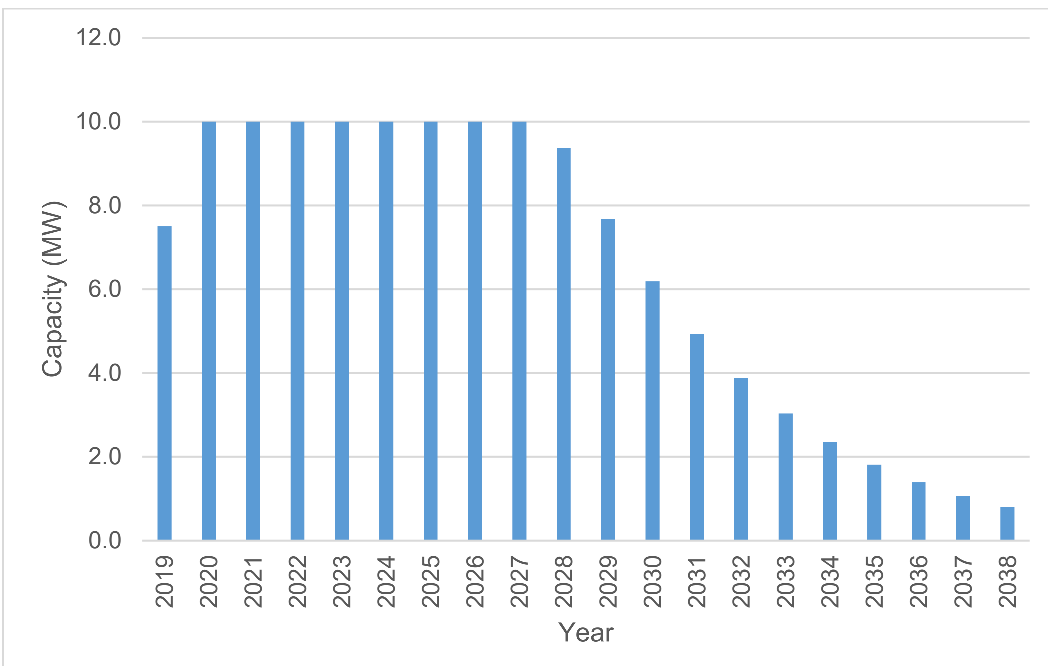

Figure 4-8. Projected New GPP Capacity Coming Online

4.1.1.4 Summary of Private-Scale Solar Projections under Alternative A

The preceding sections summarize three methods used to project future GPP capacity under Alternative A, the No Action Alternative. First, the upper bound scenario calculates the maximum possible amount of GPP participation from 2019 through 2038. Projection 1 extended recent GPP enrollment trends and found that new GPP enrollment would continue to decline to zero within 10 years. Projection 2 modeled a behavioral decision based on financial considerations (summarized as the simple payback period) and changing adoption rates over time. Projection 2 suggests that new GPP enrollment would increase over the first 10 years of the forecast and would decline in the second 10 years. Based solely on the payback period estimated in Projection 2, and ignoring the adoption rate curve, there would be little or no future GPP enrollment, which is similar to the result of Projection 1.

Considering all of the available information, our best estimate is the average of Projections 1 and 2. The best estimate projects that new GPP enrollment will be similar to recent levels for about 10 years and then will decrease over the next 10 years. The results of the projections for Alternative A are presented in Figure 4-9 (new annual capacity) and Figure 4-10 (new cumulative capacity).

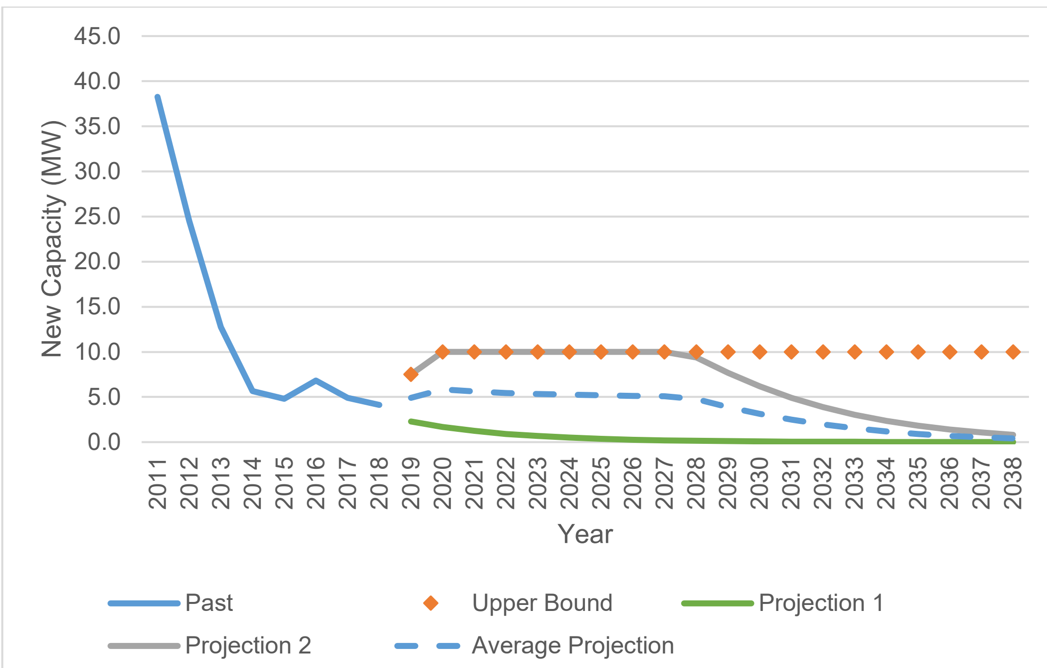

Figure 4-9. Forecast Annual New GPP Capacity

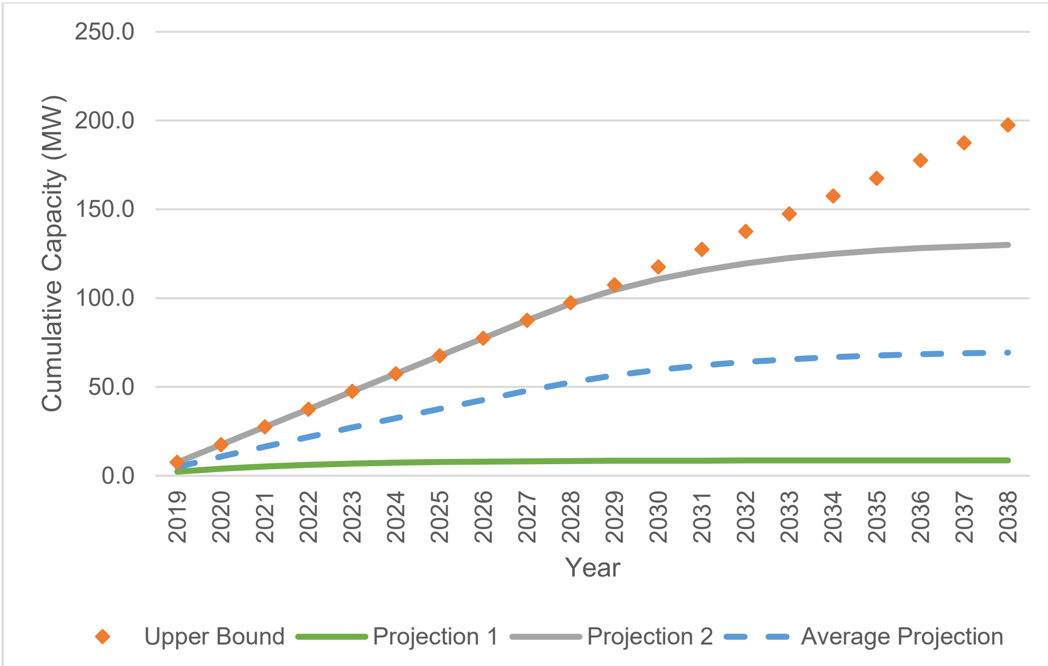

Figure 4-10. Forecast Cumulative New GPP Capacity, starting in 2019

It is important to place these GPP projections into context. As the GPP Program is offered throughout the entire TVA PSA, the TVA PSA is the most relevant context for considering the potential magnitudes of these projections. Table 4-5 and 4-6 compare the results of the projections to the 2018 renewable and total energy capacity and energy generation in the TVA PSA. The proportions are small compared to the TVA PSA system totals. Continuation of the GPP Program is considered to have minor changes on the total energy generation and renewable to non-renewable mix in the TVA PSA. However, there would be no discernable changes in TVA operations.

Table 4-5. Comparison of Projected Future GPP Capacity to TVA PSA Capacity

Projection Scenario	Cumulative New GPP Capacity, 2019 through 2038 (MW)	Proportion of Renewable Capacity[b]	Proportion of Total Capacity[c]
Upper Bound	197.5	2.35%	0.49%
Projection 1	8.7	0.10%	0.02%
Projection 2	130.0	1.55%	0.33%
Average Projection (Best Estimate)[d]	**69.3**	**0.83%**	**0.17%**

[a] Capacity for the entire TVA PSA in 2018.
[b] Renewable capacity in 2018 was approximately 8,400 MW.
[c] Total capacity in 2018 was approximately 39,900 MW.
[d] Average calculated over Projections 1 and 2. Does not include the upper bound scenario.

Table 4-6. Comparison of Projected Future GPP Energy Generation to TVA PSA Generation

Projection Scenario	Energy Generation in 2038 (GWh)	Proportion of Renewable Energy Generation[b]	Proportion of Total Energy Generation[c]
Upper Bound	313.8	1.48%	0.19%
Projection 1	13.8	0.07%	0.01%
Projection 2	206.6	0.98%	0.13%
Average Projection (Best Estimate)[d]	**110.2**	**0.52%**	**0.07%**

[a] Generation for the entire TVA PSA in 2018.
[b] Renewable generation in 2018 was approximately 21,144 GWh.
[c] Total generation in 2018 was approximately 162,646 GWh.
[d] Average calculated over Projections 1 and 2. Does not include the upper bound scenario.

4.1.2 Alternative B – Discontinue GPP without Replacement Program

In Alternative B, the GPP Program would be discontinued at the end of 2019. This would not affect existing GPP customers, and the current GPP capacity of 110 MW would decrease to 0 MW by the end of 2039 as all 20-year purchase agreements that began through the end of 2019 would expire. The current capacity, except for 2019, was known and included in the 2019 IRP. Therefore, there would be no future changes to TVA's energy generation plans because of current GPP customers.

It is likely that many of the potential EUCs who would enroll in GPP under Alternative A would install a BTM system if the GPP Program was not available. Both involve installing a private-scale solar system and getting some reduction in energy bills.[26] BTM and GPP typically involve similar systems (other than the metering connection), and the two systems would be similarly attractive to customers who are interested in installing solar for environmental and/or self-sufficiency reasons.

In this document, the behavioral modeling projections (Projection 2) included BTM.[27] These projections estimated that BTM capacity would be 125 MW in 2038. However, these projections depended on the 2018 levels of BTM, which are only partially known (TVA 2018). TVA does not have complete information on current levels of BTM in the TVA PSA, and the 2018 estimate of known BTM solar (37 MW) may be significantly understated. The 2019 IRP projection uses a different method to project future BTM, which is based on the total potential solar capacity technically suitable for BTM and is independent of the current amount of BTM capacity. The IRP projects there to be about 1,500 MW of BTM solar capacity in 2038, about 90 percent of which would be commercial and 10 percent would be residential. This suggests that the potential BTM capacity could accommodate an extra 69.3 MW, if all GPP enrollees under Alternative A chose to install BTM under Alternative B.

[26] This occurs directly in BTM because energy use from LPCs is reduced. It occurs indirectly in GPP because the customer receives an energy credit for the energy they generate.
[27] Projection 1, extension of GPP trends, did not consider BTM.

All else equal, if not all GPP capacity under Alternative A shifts to BTM under Alternative B, then TVA would have to increase its energy generation to cover the shortfall. As discussed in Section 4.1.1, the amounts of energy associated with future GPP enrollment under Alternative A are very small compared to energy generation in the TVA PSA. Absorbing any energy generation lost from GPP Program discontinuation would result in no discernable changes to TVA operations and would require a minor change in the renewable to non-renewable energy mix in the TVA PSA. This change is well within the range of expected uncertainty (see TVA 2019a for discussion of uncertainty in future energy supply and demand).

4.1.3 Alternative C – Discontinue GPP Program and Present New Offering

Alternative C would discontinue new GPP enrollments at the end of 2019 and would offer a new private-scale service program designed to better reflects customers' needs (see Section 2.1.3). For the purpose of this assessment, TVA assumes that all LPCs that currently participate in GPP will elect to make this offering available to their EUCs. All of the discussion for Alternative B compared to Alternative A (Section 4.1.2) would apply for Alternative C, as both Alternative B and C involve a discontinuation of the GPP Program.

The new service offering included in Alternative C is primarily intended to help ensure that future private-scale solar systems would be installed properly and safely. By establishing a QCN of vetted solar installers, installation standards, inspection requirements, and a more standardized interconnection process, TVA would help its EUCs obtain high-quality private-scale solar installations. The potential benefits of this service offering to EUCs is discussed in Section 4.2.3.

While the primary purpose and direct impact of the service offering is ensuring installation quality and safety, the program would likely have an indirect impact on energy production and use by stimulating an increase in private-scale solar systems compared to Alternative B. Quality and safety concerns are second only to financial concerns among issues cited by potential adopters (Moezzi et al. 2017). The service offering would help to alleviate EUCs' quality and safety concerns. In addition, the service offering would provide non-biased information to help EUCs better understand the decision to install solar. Therefore, some potential EUCs may adopt BTM who would otherwise not have, as discussed below.

A review of strategies employed by solar PV incentive programs across the U.S., which was prepared by the Lawrence Berkeley National Laboratory, includes a list of 10 recommendations for best practices to promote well-performing solar PV systems (Barbose et al. 2008). These recommendations include building customer knowledge and capabilities, ensuring applicable codes are followed and enforced, and more thorough certification and testing protocols. Alternative C addresses several of these recommendations.

A survey conducted by the National Renewable Energy Laboratory (NREL) between 2014 and 2015 across 3,600 respondents and 4 states found that, of those individuals who were considering installing solar panels at their residence but did not ultimately install a system, 28% claimed they had low levels of trust in available information sources, 15% were concerned with damage to their roof, and 31% perceive solar as 'risky' (Moezzi et al. 2017). Furthermore, when those who had seriously considered solar installations (but opted against) were asked why they did not install solar, 44% said they stopped consideration based partially on concerns over "equipment quality and reliability over time," while 40% stopped consideration because it "risked damage to their roof" (Moezzi et al. 2017). This research aligns with market research commissioned by TVA, which found that about 90 percent of study participants rated qualified contractors as important and over 60 percent rated qualified contractors as extremely important, the highest of any factor tested. The service offering in Alternative C should alleviate these types of concerns for some customers.

In addition, other research has shown that non-financial factors can impact private-scale solar adoption. For example, Bollinger and Gillingham (2012) have shown that social effects (i.e. interacting with one's peers) significantly impacts solar adoption in California. Controlling for other important factors, the authors found that one additional solar installation in a zip code increases the adoption of solar elsewhere in the same zip code.

Peer-reviewed research suggests that public certifications of installers, similar to the QCN of vetted installers in the Alternative C service offering, increased the potential for solar adoption. We did not find published papers from the United States on this topic and thus rely on published literature from other countries. For example, Simpson and Clifton (2015) found that there is a general lack of trust toward solar industry members in Western Australia, and that these concerns could be alleviated by certification schemes. The authors conclude that independent information (like that from governmental agencies) can be critical in increasing solar demand by distributed consumers. Similarly, Verma et al. (2016), found that for the Indian residential solar market, "a trusted certification scheme could turn a vicious cycle of consumer skepticism into a virtuous cycle".

In summary, Alternative C would have many of the same minor impacts on energy production and use as Alternative B, resulting from the discontinuation of the GPP Program and the likely increase in BTM installations as EUCs that would have adopted GPP in Alternative A choose BTM in Alternatives B and C. Compared to Alternative B, Alternative C would likely result in more BTM installations because some EUC's concerns over system quality and safety would be alleviated. Increasing BTM installations is not a goal of the service offering, and TVA expects any increase in BTM to be minor compared to Alternative B.

4.2 Socioeconomics and Environmental Justice

4.2.1 Alternative A – No Action Alternative (GPP Program Continues)

In Alternative A, the GPP Program would continue as implemented in 2019.[28] Projections indicate that residential and commercial EUCs would likely enroll at similar rates to recent years from 2019 through 2028, and then new enrollment is projected to decline to zero over between 2029 and 2038 (Section 4.1.1).

Current GPP participants would not be directly affected by continuation of the GPP Program in Alternative A, as the terms of their 20-year agreements would continue. However, they may seek to enroll in GPP again once their current 20-year agreement expires. In this case, impacts among current enrollees would be similar to impacts among those who would have been future GPP participants as discussed in the following paragraph.

Alternative A would directly impact EUCs that would enroll in GPP in the future. Future GPP participants would benefit by being able to sell electricity to TVA at a fixed rate for a 20-year

[28] The only exception is that the annual limit for new capacity would revert to 10 MW rather than the 7.5 MW offered in 2019 (See Section 2.1.1).

contract. Although not all GPP participants would fully recover the costs of their solar systems, many EUCs would not participate if they did not expect a positive financial return.[29] The financial return depends on individual-specific factors, including the discount rate.[30] Based on the inputs underlying the simple payback periods in Section 4.1.1.3, a typical business owner with a solar installation of 10 kW could save approximately $7,600 over the 20-year contract period.[31] At a 7 percent discount rate, this would represent a $2,700 loss in present-valued dollars. A typical residential solar installation of 6 kW would result in a loss of approximately $1,100 over the 20-year contract period at a 0 percent discount rate and a $6,800 loss at a 7 percent discount rate.[32] A loss projected for a typical residential EUC at a zero discount rate is consistent with the projected simple payback periods in Section 4.1.1.3. Any gains or losses would be spread over 20 years. Given that most participants in GPP would be commercial EUCs or residential EUCs with above-average incomes, these values are considered minor.

Alternative A could indirectly impact non-participating EUCs if GPP enrollment was significant enough to induce cost-shifting. Projected GPP enrollment represents a small proportion of TVA's total capacity and energy generation and the continuation of the GPP Program would have minor impacts on energy production and use (see Section 4.1). Any changes in TVA's costs of operating its facilities would not be discernable. The energy credits paid to GPP participants are a cost paid by TVA, and this cost ends up being spread across all EUCs in the TVA PSA.

In the upper bound scenario, future GPP enrollment included 197.5 MW of capacity and about 314 GWh of energy generation in 2038 (Section 4.1.1.1). The best projection is about one-third of the upper bound scenario (Section 4.1.1.4). TVA previously estimated that DER results in cost-shifting of about $71,000 per MW capacity (TVA 2018).[33] Assuming that a similar ratio applies to future GPP participation, cost-shifting in 2038 would be about $14 million annually in the upper bound scenario and $5 million annually in the best projection scenario. Over the entire 20-year period, total cost-shifting would be about $146 million in the upper bound scenario and $67 million in the best projection scenario, respectively.[34]

TVA serves about 4.8 million residential and commercial EUCs. Assuming the cost-shifting was spread evenly across all EUCs, electricity bills would increase by $2.92 per year in the upper bound scenario and $1.02 per year in the best projection scenario. These values are minor to most EUCs in the TVA PSA, although for some low-income households, any increase in energy costs may be a burden. Cost-shifting is considered minor for most EUCs at the individual level, and the total cost-shifting of $67 to $146 million over a 20-year

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[29] Moezzi et al. (2017) found that financial return was the most important factor considered by potential private-scale solar adopters.

[30] The discount rate indicates a consumer's time preference of money. At a discount rate of zero, a consumer is indifferent between some amount of money today and any time in the future. At a discount rate of 7 percent, a consumer is indifferent between a payment of $1.07 in one year and a payment of $1.00 today.

[31] Savings means the total GPP energy credit payments minus the total costs of the system, including installation and O&M.

[32] Individual-specific factors could result in a positive return for some customers.

[33] The 2018 study estimated $50 million in cost-shifting from 700 MW of installed capacity.

[34] All values in this paragraph assume constant real dollars and no discount rate. The cumulative values are calculated by tracking the cumulative incremental GPP capacity starting in each year. For example, 7.5 MW capacity added in the first year (2019) results in 7.5MW x $71,000/MW x 20 years = $10.65 million over the entire 20-year period. A similar calculation is performed for each start year between 2019 and 2038.

period is considered a minor negative impact compared to current conditions. The vast majority of the shifted costs would accrue to non-GPP participants.

In summary, Alternative A would result in minor positive direct financial impacts to EUCs that would enroll in GPP and shift costs toward non-enrollees. The cost-shifting that would occur in Alternative A tends to benefit commercial EUCs and residential EUCs with above-average incomes at the expense of all other EUCs, including low-income residential EUCs.[35] In absolute terms, cost-shifting is spread evenly over EUCs in the TVA PSA. From this perspective, there is no disproportionate impact on low-income or minority residents. However, any financial impact may represent a greater burden on low-income residents, simply because it is a higher proportion of their incomes. While low-income residents have the potential to have a higher burden in this relative sense, the absolute amounts are low ($1 to $3 per year) and the adverse impact of cost-shifting is considered minor. TVA therefore concludes that there are no disproportionately high adverse impacts to low-income or minority populations in the TVA PSA as a result of Alternative A.

On balance, Alternative A results in negative socioeconomic impacts on residential and commercial EUCs in the TVA PSA. Alternatives B and C, which both discontinue the GPP Program, reduce these negative impacts.

4.2.2 Alternative B – Discontinue GPP Program without Replacement Program

In Alternative B, new GPP Program enrollment would be discontinued at the end of 2019. Existing customers' enrollments and PAs based on applications received by December 31, 2019 would not be affected. There would be no direct impacts to existing GPP participants or those that apply by December 31, 2019. At the end of the term of their PA agreements, impacts among these would be similar to impacts among those discussed below.

Potential future participants would be directly affected compared to Alternative A. They would no longer have the option to enroll in GPP, eliminating a future opportunity to achieve financial benefits. This is a minor negative impact among future enrollees compared to Alternative A, in which the GPP Program would continue. However, it is important to note that these EUCs would be made no worse off than they are today.

Many of the public comments in response to the Draft EA indicated support to continue the GPP Program or a similar program that provides compensation for energy produced by private-scale DER and focused on potential benefits to households that might install DER as well as environmental benefits of reducing air emissions and GHGs. However, no comments specifically expressed support for TVA to provide payments for DER generation to private commercial entities. This distinction is important because the majority of current and expected future private-scale DER in the Valley, measured as installed capacity and generation, is commercial rather than residential. By discontinuing the GPP Program in Alternatives B and C, TVA would help to reduce overall cost-shifting from businesses with private-scale DER to households, as well as cost-shifting across other customer classes. This aspect of cost-shifting is important from a socioeconomics perspective because it involves residential households subsidizing businesses' profits, which TVA believes most residents in the Valley would view as unfair.[36] However, the distinction between commercial and residential customers is often overlooked in discussions about the

[35] See TVA 2018 for additional discussion of how cost-shifting can affect low-income and minority EUCs.
[36] TVA has received public input for past NEPA analyses that commercial EUCs should not benefit at the expense of residential EUCs.

distributional effects of private-scale DER and was not addressed in public comments supporting continuation of the GPP Program or a similar program.

Alternative B would eliminate future cost-shifting resulting from the GPP Program by ending the subsidy to GPP participants. Cost-shifting resulting from existing PAs and applications received by December 31, 2019, would continue for the term of those PAs. In addition, future cost-shifting could still occur if EUCs that would have enrolled in GPP in Alternative A choose to install BTM if the GPP Program is discontinued. If these EUCs install the same amount of BTM capacity instead, cost-shifting would be lower than in Alternative A.[37] However, the cost-shifting would be wholly attributable to private actions and decisions, rather than being influenced by TVA subsidies through the GPP Program. Cost-shifting would be negligibly smaller under Alternative B because TVA would no longer pay GPP energy credits (to potential future participants), which are very small on an annual basis.[38]

Therefore, Alternative B would have fewer adverse socioeconomic impacts than Alternative A.

4.2.3 Alternative C – Discontinue GPP Program and Present New Offering

In Alternative C, TVA would discontinue the GPP Program at the end of 2019 and would implement a new service offering. Existing customers' enrollments and PAs based on applications received by December 31, 2019 would not be affected. There would be no direct negative impacts to existing GPP participants or those that apply by December 31, 2019. At the end of the term of their PA agreements, impacts among these participants would be similar to impacts among those discussed below.

The direct negative impacts on future GPP participation and the potential positive impacts on EUCs resulting from reducing cost-shifting would be minor as described for Alternative B. As with Alternative B, there would be no disproportionately high adverse impacts on low-income or minority populations within the TVA PSA.

The replacement service offering is expected to result in additional positive impacts compared to Alternative B. The offering would focus on the quality and safety of private-scale solar installations by establishing a network of vetted installers and installation standards, requiring inspections, and providing information on installation and disposal to EUCs. Increasing safety is the main benefit of Alternative C. Safety benefits would mainly accrue to future EUCs who install private-scale solar systems and to TVA and LPC linemen.

Another benefit of Alternative C would be providing additional information to EUCs who are considering installing private-scale solar systems. Alternative C is expected to increase the number of private-scale solar installations compared to Alternative B (see section 4.1.3). Assuming these customers would only install solar if they expect the benefits to outweigh the costs, these customers would benefit from Alternative C compared to Alternative B and are expected to have minor positive financial impacts related to savings on electricity bills.[39]

[37] This is because GPP systems send all electricity generated to the grid, while BTM systems do not use all of the electricity produced. Therefore, a similar amount of BTM capacity would result in a smaller reduction in energy generated by TVA, which would result in less cost-shifting.

[38] Under the upper bound scenario, GPP credits would be about $28,000 in 2038 (313.8 MWh x 1000 kWh/MWh x $0.09/kWh = $28,242. This would be less than $0.01 per year across the 4.8 million EUCs in the TVA PSA.

[39] This statement assumes BTM solar installations, in which EUCs directly use energy from their systems, thereby reducing the amount of electricity they purchase from LPCs.

The information on proper disposal of solar systems provided in Alternative C could benefit all existing EUCs with private-scale solar systems, including those enrolled in GPP, DPP, or who have BTM installations.

Finally, Alternative C would provide benefits to TVA and LPCs in terms of better information for planning purposes regarding the number and capacity of BTM solar installations. Alternative C is therefore preferred to both Alternatives A and B.

4.3 Air Resources

4.3.1 Alternative A – No Action Alternative (GPP Program Continues)

Continuation of the GPP Program has the potential to impact air resources primarily through changes in total energy generation or the renewable to non-renewable energy mix ratio. In general, increased GPP enrollment would add renewable solar generation capacity to the TVA PSA, which has potential to reduce the utilization of non-renewable generation and result in a positive impact on air resources by reducing emissions.

However, as discussed in Section 4.1.1, projections of future GPP enrollment represent a small fraction of both the total and renewable energy generation in the TVA PSA. Such a small increase in total generation is unlikely to change how TVA conducts its energy generation operations or require TVA to alter its generation systems. In addition, if any alterations were to be necessary, it is highly unlikely that TVA operations could attribute those changes to GPP enrollment specifically, given the number of other factors that influence TVA power generation operations. As such, there would be no discernable changes to TVA's energy generation operations. Continuation of the GPP Program under Alternative A would therefore not have a discernable impact on air resources in the TVA PSA compared to current conditions. Current trends in air quality would continue.

4.3.2 Alternative B – Discontinue GPP Program without Replacement Program

Discontinuation of the GPP Program in Alternative B could result in a loss of future renewable energy generation compared to Alternative A, but would have no impact on current conditions. As discussed in Section 4.1.1, projections of future GPP enrollment represent a small fraction of both the total and renewable energy generation in the TVA PSA. As such, there would be no discernable changes to TVA's energy generation operations that could be attributed to the discontinuation of the GPP Program. Discontinuation of the GPP Program under Alternative B would therefore not have a discernable impact on air resources in the TVA PSA compared to Alternative A or current conditions. Current trends in air quality would continue. As discussed in Section 4.1.2, some future GPP participants under Alternative A may choose to install BTM solar under Alternative B. BTM solar installations have potential to reduce the utilization of non-renewable generation, reducing the potential for adverse impacts on air resources.

Although TVA planners do not forecast that changes in GPP enrollment would be discernable in the context of TVA energy generation operations, TVA received comments on the draft EA suggesting that air emissions from potential replacement sources would be significant. Thus, for additional context and analysis, conservative estimates (i.e., likely to overstate impacts) of potential air emissions were calculated under the worst-case assumption that TVA would have to increase its energy generation to offset 100 percent of the upper-bound future GPP generation of 313.8 GWh in 2038 (see Section 4.1.1.1 for discussion of the upper-bound scenario). Additional air emissions under the assumption that future GPP generation would be replaced by TVA using either coal and/or natural gas is presented in Table 4-7. Estimates are provided under three assumptions: 100% of GPP generation is replaced with coal, 100% is replaced with natural gas, and an equal mix of coal and gas. The additional air emissions would be less than 1 percent of the annual total emissions for the electric utility industry in Tennessee (Table 4-8). These estimates are conservative (overstate potential impacts) for several reasons:

- These estimates assume that no future GPP enrollees would install BTM if GPP is discontinued;
- These estimates are based on the maximum new GPP generation in the planning horizon (in 2038);
- These estimates assume that either coal or natural gas units would make up the GPP generation. However, TVA plans to add additional solar generation, and if this were used to make up the GPP generation, there would be no change in emissions;
- The comparisons to total emissions include just Tennessee, which would overstate percent impacts compared to the entire TVA Service Area. This comparison becomes even more overstated for GHG emissions that have the potential for global impacts.

Table 4-7. Annual Air Emissions if TVA Replaced Upper Bound GPP Generation with Coal and/or Natural Gas Generation

Compound	100% Coal	100% Natural Gas	Coal & Natural Gas (Even Split)
Sulfur dioxide (SO_2, short tons) [a]	399.92	0.82	200.37
Nitrogen oxide (NO_x, short tons) [a]	185.39	72.48	128.94
Carbon dioxide (CO_2, thousand metric tons) [a]	353.09	169.75	261.42
Other GHGs (thousand metric tons CO_2e) [b]	2.28	1.09	1.69
Total GHGs (thousand metric tons CO_2e) [c]	**355.37**	**170.85**	**263.11**

[a] Based on 2017 data for Tennessee (USEIA 2019a). Data contain SO_2, NO_x, and CO_2 emissions and electricity generation amounts for coal and natural gas generation. The data were used to calculate the amount of emissions per GWh of electricity generation, which was applied to the upper bound 2038 GPP generation estimate of 313.8 GWh.
[b] Other GHG emissions includes methane (CH_4), nitrous oxide (N_2O), and fluorinated GHGs. 2018 GHG emissions data were obtained for 11 power generation facilities located in Tennessee from USEPA (2019a). Across these 11 facilities, CO_2 comprised 99.36% of the total GHG CO_2e emissions. In the table, other GHGs were calculated as: Other GHG = CO_2 x (1-0.9936).
[c] Total GHG emissions are calculated as: Total GHGs = CO_2 + Other GHGs.

Table 4-8. Air Emissions if Upper Bound Annual GPP Generation was Replaced by TVA, compared to Total Air Emissions from Tennessee Electric Utility Industry

Compound	Total Emissions (TN Electric Generation) [a]	100% Coal [b]	100% Natural Gas [b]	Coal & Natural Gas (Even Split) [b]
Sulfur dioxide (short tons)	44,231	0.90%	0.00%	0.45%
Nitrogen oxide (short tons)	19,905	0.93%	0.36%	0.65%
Carbon dioxide (thousand metric tons)	35,792	0.99%	0.47%	0.73%
Other GHGs (thousand metric tons CO_2e)	231	0.99%	0.47%	0.73%
Total GHGs (thousand metric tons CO_2e)	**36,023**	**0.99%**	**0.47%**	**0.73%**

[a] See notes for Table 4-7 for data sources and definitions.
[b] Calculated as the corresponding column in Table 4-7 divided by Total Emissions.

Calculations for the best estimate GPP projections in 2038 (110.2 GWh) are provided below. Air emissions would increase by less than 0.5 percent of the total for the Tennessee electric utility industry (Table 4-10)

Table 4-9. Annual Air Emissions if TVA Replaced Best Estimate of GPP Generation with Coal and/or Natural Gas Generation

Compound	100% Coal	100% Natural Gas	Coal & Natural Gas (Even Split)
Sulfur dioxide (SO_2, short tons) [a]	140.44	0.29	70.37
Nitrogen oxide (NO_x, short tons) [a]	65.11	25.46	45.28
Carbon dioxide (CO_2, thousand metric tons) [a]	124.00	59.61	91.81
Other GHGs (thousand metric tons CO_2e) [b]	0.80	0.38	0.59
Total GHGs (thousand metric tons CO_2e) [c]	**124.80**	**60.00**	**92.40**

[a] Based on 2017 data for Tennessee (USEIA 2019). Data contain SO_2, NO_x, and CO_2 emissions and electricity generation amounts for coal and natural gas generation. The data were used to calculate the amount of emissions per MWh of electricity generation, which was applied to the best estimate of the 2038 GPP generation of 110.2 GWh.
[b] Other GHG emissions includes methane (CH_4), nitrous oxide (NO_2), and fluorinated GHGs. 2018 GHG emissions data were obtained for 11 large power generation facilities located in Tennessee using U.S. EPA's Facility Level Information on GHGs Tool (FLIGHT) (USEPA 2019). Across these 11 facilities, CO_2 comprised 99.36% of the total GHG CO_2e emissions. In the table, other GHGs were calculated as:
Other GHG = CO_2 x (1-0.9936).
[c] Total GHG emissions are calculated as: Total GHGs = CO_2 + Other GHGs.

Table 4-10. Air Emissions if Best Estimate of Annual GPP Generation was Replaced by TVA, compared to Total Air Emissions from Tennessee Electric Utility Industry

Compound	Total Emissions (TN Electric Generation) [a]	100% Coal [b]	100% Natural Gas [b]	Coal & Natural Gas (Even Split) [b]
Sulfur dioxide (short tons)	44,231	0.32%	0.00%	0.16%
Nitrogen oxide (short tons)	19,905	0.33%	0.13%	0.23%
Carbon dioxide (thousand metric tons)	35,792	0.35%	0.17%	0.26%
Other GHGs (thousand metric tons CO2e)	231	0.35%	0.17%	0.26%
Total GHGs (thousand metric tons CO2e)	**36,023**	**0.35%**	**0.17%**	**0.26%**

[a] See notes for Table 4-7 for data sources and definitions.
[b] Calculated as the corresponding column in Table 4-9 divided by Total Emissions.

Total GHG emissions are presented in the tables above. For context, total U.S. GHG emissions in 2017 was 6.5 billion MT CO_2e (USEPA 2019b, Figure ES-1), of which 5.3 billion MT CO_2e (82% of the total) was CO_2 (USEPA 2019b). In the states overlapping the TVA service area, the total 2017 CO_2 emissions was 755.1 million MT (USEIA 2019b). The worst-case increase in air emissions for Alternative B (353.1 thousand MT for 100% coal replacement and the upper bound scenario) represents less than 0.01 percent of the national CO_2 emissions and less than 0.05 percent of the CO_2 emissions in states overlapping the TVA service area.

These worst-case estimates are small in intensity within appropriate contexts, and are minor negative impacts. These findings support the conclusion that under the more realistic best estimate scenario, there would be no discernable impacts to air resources emissions in Alternative B.

4.3.3 Alternative C – Discontinue GPP Program and Present New Offering

As discussed in Section 4.1.1, projections of future GPP enrollment represent a small fraction of both the total and renewable energy generation in the TVA PSA. As such, there would be no discernable changes to TVA's energy generation operations that could be attributed to the discontinuation of the GPP Program. Discontinuation of the GPP Program under Alternative C would therefore have no discernable impacts to minor impacts on air resources in the TVA PSA compared to current conditions and Alternatives A, and similar impacts as Alternative B. Current trends in air quality would continue.

As discussed in Section 4.1.3, Alternative C is expected to result in more private-scale solar than Alternative B. Therefore, Alternative C could have a positive impact on air resources compared to Alternative B because more installations may reduce the utilization of non-renewable generation. Thus, the conservative analysis of potential upper-bound air emissions including GHGs for Alternative B (Section 4.3.2), which found no significant impact, would overstate potential impacts for Alternative C because there may be additional BTM solar compared to Alternative B. Therefore, there would be no significant air impacts or change in air emissions including GHGs in Alternative C.

4.4 Water Resources

4.4.1 Alternative A – No Action Alternative (GPP Program Continues)

Increased GPP enrollment would add renewable solar generation capacity to the TVA PSA, which could reduce the utilization of non-renewable generation and result in a positive impact on water resources by offsetting other power generation that may have greater water impacts due to water use, particularly natural gas and nuclear (TVA 2019b). As discussed in Section 4.1.1, projections of future GPP enrollment represent a small fraction of both the total and renewable energy generation in the TVA PSA. As such, there would be no discernable changes to TVA's energy generation operations. Continuation of the GPP Program under Alternative A would therefore not have a discernable impact on water resources in the TVA PSA compared to current conditions. Current trends in water quality would continue.

4.4.2 Alternative B – Discontinue GPP Program without Replacement Program

Discontinuation of the GPP in Alternative B could result in a loss of future renewable energy generation compared to Alternative A, and no impact compared to current conditions. As discussed in Section 4.1.2, some future GPP participants under Alternative A may choose to install BTM solar under Alternative B, which would reduce any potential negative impacts on water resources of Alternative B compared to Alternative A. As discussed in Section 4.1.1, projections of future GPP enrollment represent such a small fraction of both the total and renewable energy generation in the TVA PSA that there would be no discernable changes to TVA's energy generation operations. Discontinuation of the GPP Program under Alternative B would therefore not have a discernable impact on water resources in the TVA PSA compared to current conditions or Alterative A. Current trends in water quality would continue.

Although TVA planners do not forecast that changes in GPP enrollment would be discernable in the context of TVA energy generation operations, TVA received comments on the draft EA suggesting that environmental impacts from potential replacement sources could be significant. Thus, for additional context, conservative estimates (i.e., likely to overstate impacts) of potential water use (withdrawals and consumption) were calculated under the worst-case assumption that TVA would have to increase its energy generation to offset 100 percent of the upper-bound future GPP generation of 313.8 GWh in 2038 (see Section 4.1.1.1 for discussion of the upper-bound scenario). Additional water use under the assumption that future GPP generation would be replaced by TVA using either coal and/or natural gas is presented in Table 4-11. Estimates are provided under three assumptions: 100% of GPP generation is replaced with coal, 100% is replaced with natural gas, and an equal mix of coal and gas. The additional water use would be less than 0.5 percent of the annual totals for TVA facilities (Table 4-11). These estimates are conservative (overstate potential impacts) for several reasons:

- These estimates assume that no future GPP enrollees would install BTM if GPP is discontinued;

- These estimates are based on the maximum new GPP generation in the planning horizon (in 2038);
- These estimates assume that either coal or natural gas units would make up the GPP generation. However, TVA plans to add additional solar generation, and if this were used to make up the GPP generation, there would be no change in water withdrawals.

Table 4-11. Annual Water Withdrawals if TVA Replaced Upper Bound GPP Generation with Coal and/or Natural Gas Generation

Energy Source[a]	Withdrawals (MG/Yr)[b]		Consumption (MG/Yr)[b]	
	Alternative B compared to A[c]	Proportion of Total[d]	Alternative B compared to A[c]	Proportion of Total[d]
100% Coal	17,309.3	0.4%	169.6	0.4%
100% Natural Gas	99.6	0.002%	63.2	0.2%
50% Coal & 50% Natural Gas	8,704.5	0.2%	116.4	0.3%

[a] Fuel mix used to replace GPP electricity generation.
[b] Water withdrawal and consumption data from TVA 2019(b), Tables 4-8 and 4-9. These tables contain 2015 data.
[c] The increase in water use for Alternative B compared to Alternative A is calculated by multiplying an average water use factor (MG/MWh) and the additional 313,800 MWh of generation under the assumption that TVA would have to make up this generation. The water withdrawal factor is 54,778 for coal and 315.3 for natural gas. The water consumption factors are 17.3 and 2.2, respectively.
[d] Calculates the additional water use as a proportion of the total annual water use for TVA thermal generating facilities in Tennessee in 2015.

The additional water use under the assumption that TVA would have to generate additional electricity using coal or natural gas to make up for the reduction in GPP generation in Alternative B compared to Alternative A is less than 0.5 percent of TVA's annual water use, which is a minor negative impact.

4.4.3 Alternative C – Discontinue GPP Program and Present New Offering

Impacts to water resources in Alternative C would be indiscernable to minor compared to Alternative A and similar to Alternative B. As discussed in Section 4.1.3, Alternative C is expected to result in more private-scale solar than Alternative B. The new service offering is expected to add renewable solar generation capacity to the TVA PSA, which, like Alternative A, could reduce the utilization of non-renewable generation and result in a positive impact on water resources by offsetting other power generation that may have greater water impacts due to water use. Again, enrollment in the program represents such a small fraction of both the total and renewable energy generation in the TVA PSA that there would be no discernable changes to TVA's energy generation operations. Current trends in water quality would continue.

As discussed in Section 4.1.3, Alternative C is expected to result in more private-scale solar than Alternative B. Therefore, Alternative C could have a positive impact on water resources compared to Alternative B because more installations may reduce the utilization of non-renewable generation. Thus, the conservative analysis of potential upper-bound water use impacts for Alternative B (Section 4.4.2), which found no significant impact, would overstate potential impacts for Alternative C because there may be additional BTM solar compared to Alternative B. Therefore, there would be no significant water use impacts in Alternative C.

4.5 Land Use

4.5.1 Alternative A – No Action Alternative (GPP Program Continues)

The private-scale solar systems that would typically enroll in GPP Program in the future are expected to be mostly "rooftop" systems, although some systems could be ground-mounted. In general, land conversion, clearing, or modification would not be required for rooftop systems. Ground-mounted systems, when installed on a lawn or other cleared land, would not result in significant land use conversion, clearing, or modification. Generally, each kW of solar panels requires approximately 100 square feet of land (Narasimhan 2019). Therefore, a typical 5 kW residential system would require 500 square feet of land. If 50 percent of the upper bound GPP capacity were ground-mounted, this would require approximately 227 acres.[40] This is less than one percent of the more than 25,000 acres currently used to support energy production in the TVA PSA (see Section 3.5). This is considered a minor change in land use compared to current conditions because of GPP continuation.

4.5.2 Alternative B – Discontinue GPP Program without Replacement Program

Alternative B would discontinue new enrollment in the GPP Program, which would eliminate the potential land conversion or alteration for GPP systems in Alternative A. As discussed in Section 4.1.2, some EUCs may choose to install BTM installations if GPP is discontinued. If all EUCs switch to BTM systems, then land use impacts for Alternative B would be similar to those in Alternative A. However, it is more likely that only some future GPP participants would switch to BTM, in which case the land use impacts of Alternative B would be lower than those in Alternative A. In either case, potential land use impacts in Alternative B are minor.

4.5.3 Alternative C – Discontinue GPP Program and Present New Offering

Alternative C would discontinue new enrollment in the GPP Program that would reduce potential land use for solar installations compared to Alternative A. Alternative C is, however, expected to increase the number of private-scale solar installations compared to Alternative B. As with Alternative B, EUCs may switch to BTM installations. Overall, impacts in Alternative C are expected to be similar to or higher than those in Alternative B, but still represent a small fraction of the area used to support energy production in the TVA PSA. The potential land use changes in Alternative C are also considered minor.

4.6 Production of Solid and Hazardous Waste

4.6.1 Alternative A – No Action Alternative (GPP Program Continues)

Impacts potentially occurring from continuation of the GPP Program would be associated with changes in total energy use, the renewable to non-renewable energy mix, and/or wastes generated as part of system installation or disposal.

[40] 0.5 x 197.5 MW x 1000 kW/MW x 100 sqft/kW ÷ 43560 sqft/acre.

As of 2018, GPP capacity was about 110 MW and as discussed in section 4.1.1, the highest amount of future GPP Program enrollment would represent a small fraction of the total and renewable energy generation in the TVA PSA. Therefore, there would be minor changes on the production of solid and hazardous waste within the TVA PSA. System installation is comparable to other household building and maintenance and is not expected to generate significant solid or hazardous wastes.

Overall, Alternative A would result in a minor increase in the production of solid and hazardous waste compared to current conditions, a minor negative environmental impact.

4.6.2 Alternative B – Discontinue GPP Program without Replacement Program

Alternative B would eliminate future GPP enrollment. Therefore, any solid and hazardous waste resulting from future GPP participation would be eliminated compared to Alternative A, resulting in a minor positive impact. Assuming all EUCs switch to BTM systems, then solid and hazardous waste impacts for Alternative B would be similar to those in Alternative A, a minor increase and minor negative environmental impact. However, it is more likely that only some future GPP participants would switch to BTM, in which case solid and hazardous waste impacts of Alternative B would be lower than those in Alternative A. This results in a lower minor increase in comparison to Alternative A, but still represents a minor negative environmental impact.

Although TVA planners do not forecast that changes in GPP enrollment would be discernable in the context of TVA energy generation operations, TVA received comments on the draft EA suggesting that environmental impacts from potential replacement sources could be significant. Thus, for additional context, conservative estimates (i.e., likely to overstate impacts) of potential production of solid and hazardous waste were calculated under the worst-case assumption that TVA would have to increase its energy generation to offset 100 percent of the upper-bound future GPP generation of 313.8 GWh in 2038 (see Section 4.1.1.1 for discussion of the upper-bound scenario). Additional production of solid and hazardous waste under the assumption that future GPP generation would be replaced by TVA using either coal and/or natural gas is presented in Table 4-12. Estimates are provided under three assumptions: 100% of GPP generation is replaced with coal, 100% is replaced with natural gas, and an equal mix of coal and gas. The additional production of solid and hazardous waste would be less than 0.5 percent of the annual totals for the TVA PSA (Table 4-12). These estimates are conservative (overstate potential impacts) for several reasons:

- These estimates assume that no future GPP enrollees would install BTM if GPP is discontinued;
- These estimates are based on the maximum new GPP generation in the planning horizon (in 2038);
- These estimates assume that either coal or natural gas units would make up the GPP generation. However, TVA plans to add additional solar generation, and if this were used to make up the GPP generation, there would be no change in production of solid and hazardous waste.

Table 4-12. Annual Production of Solid and Hazardous Waste if TVA Replaced Upper Bound GPP Generation with Coal and/or Natural Gas Generation

Energy Source[a]	Average Waste Factor (tons/million GWh)[b]	Additional Annual Waste, Alternative B to Alternative A (tons)[c]	Total Annual Waste (tons)[d]	Percent of Total[e]
100% Coal	175.7	0.06	19.0	0.3%
100% Natural Gas	0.9	0.0003	19.0	0.001 %
50% Coal & 50% Natural Gas	47.6	0.01	19.0	0.1%

[a] Fuel mix used to replace GPP electricity generation.
[b] Calculated by total tons of waste produced at TVA facilities by the total GWh generated at those facilities, years 2015-2017. Tons of waste is from TVA (2019b) Table 4-12. GWh generated from TVA (2019b), Table 2-1.
[c] The increase in production of solid and hazardous waste for Alternative B compared to Alternative A is calculated by multiplying an average waste factor (tons/ million GWh), the additional 313.8 GWh of generation under the assumption that TVA would have to make up this generation, and a unit conversion of $1e^{-6}$.
[d] The total annual waste across TVA facilities from TVA (2019b), Table 4-12.
[e] The additional annual waste divided by the total annual waste.

The additional production of solid and hazardous waste under the assumption that TVA would have to generate additional electricity using coal or natural gas to make up for the reduction in GPP generation in Alternative B compared to Alternative A is less than 0.5 percent of production of solid and hazardous waste within the TVA PSA, which is a minor negative impact.

4.6.3 Alternative C – Discontinue GPP Program and Present New Offering

Like Alternative B, Alternative C would eliminate future GPP Program enrollment. Therefore, any solid and hazardous waste resulting from future GPP participation would be eliminated compared to Alternative A, a minor positive impact. Production of solid and hazardous waste by TVA facilities under Alternative C would be similar to that under Alternative B. As discussed in Section 4.6.2, these impacts would not be discernable in the best estimate scenario and would result in minor negative impacts in the conservative upper bound scenario.

Alternative C is expected to result in more private-scale solar than Alternative B. The new service offered by Alternative C would include guidance on the proper disposal of solar panels. This guidance would be available to all DER adopters, including those enrolled in the GPP Program. Vellini et al. (2017) performed a life cycle assessment of the two most common types of PV panels. In both cases, they found that recycling panels at end-of-life, rather than landfilling them, materially reduces overall environmental impacts as well as life cycle energy usage. Similarly, Xu et al. (2018) discussed the status and benefits of recycling solar equipment, suggesting that effective recycling of end-of-life panels could improve the cost efficiency of new panel production.

Depending on the availability of recycling resources, providing better information to consumers about proper disposal could result in a minor reduction in solid and hazardous waste generation, compared to Alternatives A and B, which is a positive environmental impact.

4.7 Cumulative Impacts

As discussed in Section 4.1.1, the GPP Program represents a small portion of the renewable and total energy generation within the TVA PSA. As discussed in Sections 4.1 through 4.6, because there would be no discernable changes to TVA's energy generation operations under Alternatives B or C, the environmental impacts associated with Alternatives B and C would not be discernible compared to taking no action. Generally, when a proposed action does not result in direct or indirect effects on an environmental resource, there would be no cumulative impacts to that resource. In its analysis, TVA found that there would be no direct environmental impacts and there would no or indiscernible indirect environmental effects. Therefore, no cumulative impacts or only marginal cumulative impacts associated with these alternatives are predicted.

The main negative impacts of Alternatives B and C (compared to Alternative A) are the loss of the opportunity for EUCs to enroll in GPP after the end of 2019, which affects a minor proportion of EUCs in the TVA PSA. However, it is important to note that these EUCs would be made no worse off financially than they are today. In contrast, the positive impacts from a reduction in cost-shifting compared to Alternative A, would accrue to all EUCs (as discussed in Section 4.2). On balance, the positive impacts to the residents of the TVA PSA in Alternative C outweigh the negative impacts.

Given that TVA's proposal addresses energy production in the Valley as well as the market for renewable energy resources, there are past, present and foreseeable actions relevant to the consideration of cumulative impacts associated with TVA's proposal. TVA utilizes its Integrated Resource Planning process to consider the many cumulative market and social forces that programs addressing renewable energy resources, expansion of DER, energy efficiency, as well as other relevant inputs, have on TVA's energy generation. TVA also utilizes its IRP process to provide direction on how to best meet future electricity demand. The 2019 IRP provides an important discussion regarding past, present, and foreseeable activities that influence energy use, and the EIS that accompanied it describes cumulative impacts from combining different scenarios and strategies (TVA 2019a; TVA 2019b).

As noted above, TVA found that under the best projections scenario, it is unlikely that the proposal to end the GPP program or the replacement offering would have a discernable effect on TVA power generation operations. Any change to operations would not be substantial enough to discern any impacts, including incremental impacts, to air quality, water quality, or waste generation. Therefore, the discussion of cumulative impacts addressed in the 2019 IRP EIS would essentially apply to Alternatives B and C. See Section 5.5 of the 2019 IRP EIS (Base Case strategy, Current Outlook scenario).

Climate change resulting from GHG emissions is a cumulative impact. TVA assessed GHG emissions, under the worst-case scenario, in the air resources section (Section 4.3) as a proxy for potential climate change impacts. The analysis of the direct and indirect effects for GHG emissions adequately addresses the cumulative impacts for climate change because the potential effects of GHG emissions are inherently a global cumulative effect.

Other related actions conducted by TVA that may cumulatively affect consumer behavior and investment in DER include TVA economic development efforts, rate changes, and TVA energy efficiency programs for residences, businesses, and industries (e.g., EnergyRight

Solutions). As noted in section 1.3.1 above, TVA had previously taken actions that changed the incentives and energy credit rates in the GPP program; how these changes affected GPP participation is summarized in this EA. TVA has partnered with LPCs for decades to support renewable energy growth and informed customer choice in the Tennessee Valley. Advances in the renewables market and technologies—especially solar—have driven the costs of solar materials and installation down by more than 70% in the last decade. As previously discussed, TVA initially subsidized private-scale renewable energy installations to help establish a solar market when the technology was new and the costs were relatively high; as the costs have declined, technology has improved and solar adoption has dramatically increased. Incentives once offered to promote private-scale solar and offset initial investments are no longer needed.

TVA has a legacy of evolving programs that support solar. The Green Power Switch program, which is nearly 20 years old, allows those interested in supporting renewable energy to do so via a REC solution and the Green Power Switch program is easily accessible with a monthly commitment, available to all LPCs and their customers, and will become more accessible in 2020 as the block size is increased and price is decreased. The Dispersed Power Production (DPP) program is another TVA program that has supported private-scale solar since its inception in 1981 and DPP remains available for customers who want to install onsite generation. Under DPP, TVA buys either all or just the excess generation from qualifying facilities, which gives EUCs the flexibility to meet their onsite needs first. As discussed above, many of those who are unable to participate in GPP in the future are expected to install new BTM installations or enroll in DPP, such that any cumulative effect associated with DER adoption is further minimized. As the market evolves, TVA will continue to evolve its renewable offerings, and there is potential for additional offerings to be provided in the future.

In 2018, TVA implemented a rate change that included establishing a grid access charge. In reviewing the rate change proposal, TVA found that the grid access charge may marginally affect the incentive to invest in alternative energy sources; TVA estimated, for instance, that the payback period of a typical rooftop solar investment would increase from approximately 15 to 16 years. Other than minor socioeconomic impacts, TVA found that the 2018 rate change may result in negligible changes in energy sales that are not substantial enough to discern impacts to environmental resources.

In August 2019, the TVA Board approved the Long-Term Partnership Proposal to lengthen and strengthen the contractual relationships between LPCs and TVA. In return for agreeing to a 20-year termination notice under the WPC, LPCs will receive a monthly bill credit. TVA also committed to explore additional power supply flexibility options for a portion of LPCs' load through enabling rate structures to be established by October 2021. TVA is currently considering allowing LPCs the flexibility to generate up to 5 percent of their average hourly retail sales to provide to their retail customers (LPCs currently do not have approval to generate any power to serve their customers). This flexibility proposal could result in numerous community-scale renewable energy projects. LPCs may opt to implement programs that are intended to support and expand private-scale renewable energy investments with LPC customers. Although there is substantial uncertainty regarding whether such programs would be implemented by LPCs, it is possible that the LPC efforts may reduce any minimal social and economic effects relating to ending TVA's GPP program.

In the near future, TVA is likely to build and operate the first TVA-owned solar facility to assist TVA in meeting immediate needs for additional renewable generating capacity in response to customer demands and fulfill the renewable energy goals established in the 2019 IRP. As discussed in the EA, this type of project would help address cost-shifting among TVA consumers and help ensure that TVA provides the lowest cost power. Such a facility may have a generating capacity that exceeds that of the current GPP program.

The actions of other Federal agencies may influence energy use in the Tennessee Valley, as well as the rate of investment in DER by private consumers. These include tax credits or deductions for renewable energy initiatives, trade tariffs applied to DER components, and programs instituted by other Federal agencies (e.g., Department of Energy) addressing DER (the fate of these programs and policies remain uncertain). These Federal programs and policies have influence on the rate of adoption of DER, with actions that provide financial incentives (e.g., tax credits) increasing the rate of adoption of DER and those that increase costs (e.g., tariffs on certain solar products) adversely affecting adoption. In addition, many of TVA's 154 LPCs may conduct related activities that influence customer behavior, including programs to promote investments in DER and energy efficiency. Programs that provide financial incentives would generally decrease the potential adverse impacts to future EUCs that may result from implementing Alternatives B or C. When considering other Federal or LPC actions that increase costs or lengthen the period of return on investments, Alternatives B or C may have an incremental negative effect on future investments in DER. However, potential future EUCs would be no worse off financially than they are today.

In general, there is a potential for Alternative B or C to contribute to the cumulative impacts of any actions, technological changes, or market forces that affect energy generation costs or use in the TVA PSA. Alternative B or C could contribute to cumulative impacts on environmental and socioeconomic resources in the TVA PSA. In general, the minor negative and positive impacts expected to result from Alternative B or C are not anticipated to result in significant cumulative environmental or socioeconomic impacts.

4.8 Unavoidable Adverse Environmental Impacts

No specific unavoidable adverse environmental impacts were identified. Environmental impacts from the alternatives are generally tied to the total energy production and mix of renewable and non-renewable energy sources. Because the changes in total energy use and the renewable to non-renewable mix under all three alternatives would be minor in the context of the TVA PSA, any unavoidable environmental impacts are expected to be minor.

4.9 Irreversible and Irretrievable Commitments of Resources

No irreversible or irretrievable commitments of resources have been identified.

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CHAPTER 6 – LITERATURE CITED

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APPENDIX A: ADDITIONAL INFORMATION ON COST-SHIFTING

Introduction

Cost-shifting is one of the three elements of the underlying purpose and need of the changes proposed by TVA to the Green Power Providers (GPP) program. As used by TVA in this environmental assessment (EA), *cost-shifting* refers to what happens when customers with distributed energy resources (DER) underpay for their access and connection to the electric grid and/or are overcompensated for the energy they generate, thereby shifting costs onto customers without DER. The term *overcompensated* refers to compensation that is higher than TVA's *avoided costs*, that is the reduction in TVA's costs of providing the same electricity. After making the draft EA available for public review, TVA received many public comments suggesting that TVA's analysis of cost-shifting is incorrect for various reasons. Some comments argued that cost-shifting is not a valid theory, some argued that cost-shifting is not occurring at meaningful levels in the Valley, and others argued that TVA left out important categories of benefits that DER provides to the Valley. The purpose of this Appendix is to clarify what TVA means by cost-shifting, provide additional detail of how cost-shifting occurs and contributes to the purpose and need, and to provide TVA's responses to public comments regarding cost-shifting.

It should be noted upfront that there are three separate types of analyses at issue: 1) cost-shifting; 2) net social benefits; and 3) fair pricing of payments to DER owners. Cost-shifting focuses on how DER affects the distribution of cost recovery across different groups of customers. In other words, cost-shifting looks at how DER can increase the electricity bills of customers that do not have DER. Net social benefits is related to benefit-cost analysis and measures the benefits of DER compared to its costs, without consideration of distributional effects. In other words, it seeks to answer the question: do the total social benefits of DER outweigh the costs, and if so, by how much? However, net social benefits does not address the question of whether or how DER should be paid for by society (by individuals only or should the public subsidize DER installations?). Finally, pricing of compensation to DER participants looks at how the value of DER compares to potential payments, such as the retail rate of electricity.

Some of the public comments appear to be mixing ideas from these three separate analyses, leading to some confusion. To address this, this Appendix highlights these differences in order to clarify TVA's responses to those comments.

What is Cost-Shifting?

Cost-shifting is a shifting of the cost recovery burden from one group of EUCs to another, in this case from EUCs who have installed private-scale DER systems to those who have not.[41] Cost-shifting occurs because of a mismatch between the costs of service across customer groups and the costs recovered from those groups. *Cost of service* means the actual cost of supplying electricity and access to the grid to a customer or group of customers. *Cost recovery* means the recovery of costs by charging fees for delivered electricity and access to the grid.[42] Cost recovery must be sufficient to pay for the total cost of service across all EUCs.

In order to understand why and how cost-shifting occurs, it is necessary to understand: 1) the balance between fixed and variable components of cost of service and cost recovery; 2) how this balance changes when some customers install DER; and 3) how compensation to DER

[41] Note that cost-shifting also occurs in other contexts, such as health care. Costs can be shifted between different groups of customers, such as insured and uninsured.
[42] All customers make use of access to the grid, meaning a connection between the grid and the customer's property that allows the customer to receive electricity from the grid. As explained further below, customers with DER may use additional "grid services" such as receiving excess electricity produced by the DER system, which is somewhat like the customer using the grid as a battery.

owners for electricity they generate affects cost-shifting. After providing an overview of these topics, we look at some benefits that DER might have for the grid, for other customers, and the environment.

Understanding Fixed and Variable Costs

Cost-shifting fundamentally occurs because there is an intentional mismatch between the structure of TVA's costs (the costs of service) and the fee structure that it charges to LPCs and TVA's direct EUCs (cost recovery). TVA's costs, like utilities in general, include both fixed and variable costs. Fixed costs are costs that do not vary with the amount of electricity generated and delivered, such as the costs of maintaining existing power generation stations and transmission lines. In contrast, variable costs do vary with the amount of electricity generated. An example of a variable cost is fuel costs, the cost of fuel used at a specific power generation unit to produce a given amount of electricity. Producing more or less electricity at a particular natural gas fired unit will require burning more or less natural gas, and so the fuel costs vary with the amount of electricity generated. The following equation shows how fixed and variable costs contribute to an electric utility's total cost of operation:

Total Costs = Fixed Costs + Variable Costs (MWh).

In this equation, the total costs equals the sum of the fixed costs and the variable costs. The MWh in parenthesis after variable costs indicates that the variable costs are a function of (i.e., vary with) the amount of electricity produced. Something that this equation makes clear is that, even if no electricity was produced, the electric utility would still have to make expenditures in order to cover its fixed costs and would therefore need to charge fees to its EUCs. [43]

Cost recovery can include both fixed and variable charges to EUCs. Fixed charges, such as a monthly fee, do not vary based on the amount of electricity delivered. Variable charges apply an energy rate to the amount of electricity delivered, and thus vary depending on how much electricity is delivered.

There is a significant mismatch between the proportions of fixed and variable costs in TVA's actual cost structure (the costs of service) and in cost recovery. Specifically, the costs of service have a much higher percentage of fixed costs than does the cost recovery structure. Approximately two-thirds of TVA's costs are fixed, but a relatively small percentage of TVAs cost recovery charges to EUCs are fixed. Prior to the 2018 Wholesale Rate Change, all of TVA's cost recovery was variable, based on the volume of sales rather than fixed charges. After the 2018 Wholesale Rate Change, approximately 8 percent of TVA's cost recovery is fixed. Although not completely within TVA's control, it is likely that similar changes may occur at the retail rate level, with a relatively small fixed fee being charged by some LPCs while most of costs will continue to be recovered by variable energy charges.

There are several reasons why TVA and other electric utilities do not directly align the mix of fixed and variable cost recovery to the cost of service. Although a detailed discussion is beyond the scope of this Appendix, important reasons include maintaining energy charges to provide

[43] This is generally true in the short-term. For example, if no electricity is demanded for one week, TVA would still incur interest and depreciation expenses and would still have to maintain resources and infrastructure to provide electricity for the rest of the year. Even if no electricity were needed for one year, TVA would have to expend costs to provide electricity the following year. In economics, the short term (or "short run") is defined as a period within which there are some fixed costs, which can be decades for an electric utility like TVA that has substantial holdings of land and facilities. In the economic "long run", all of a firm's costs are variable, meaning everything that the firm chooses can be varied given demand and other external factors, such as costs of inputs.

incentives for EUCs not to waste electricity and so that EUCs can reduce their bills by reducing their use of electricity.

Understanding How DER Changes the Cost of Service and Cost Recovery Balance
This discussion focuses on private-scale solar systems, but the principles apply to other types of DER as well. Solar DER can be disconnected or connected to the grid.

When DER is not connected to the grid, some owners will have a battery system to store energy generated during times when the system is generating more than is being used, such as when the family is away during the day at work and school. Because these systems do not directly affect the grid, one might assume that it wouldn't affect an electric utility's cost of service and cost recovery. However, this is not true. As long as the customer remains connected to the grid (for the household, not for DER) and uses any electricity from the electric utility, the electric utility will incur both fixed and variable costs for serving that customer. As the customer will be purchasing less electricity from the electric utility, electric utility's cost of serving that customer will decline. However, the cost recovery by the electric utility will decline by more than the electric utility's cost to serve the customer because the customer is not paying an appropriate level of fixed monthly fees to cover the fixed costs. Therefore, the electric utility is no longer recovering the full cost of serving this customer and will face a revenue shortfall.[44]

Residential Example
Consider a residential household that uses an average of 1,000 kWh of electricity per month. Their monthly bill is based on a $15 fixed monthly fee and an energy charge of $0.10 per kWh. Therefore, their average monthly bill is 15 + 0.1 x 1000 = $115. Assume that the cost of service for this individual is exactly $115, which is two-thirds fixed costs ($77) and one-third variable costs ($38). Assume that they install a DER system that is not connected to the grid, and this system provides 50% of their electricity needs.

Figure A-1 shows what happens after the customer installs DER. Without DER, the cost of service and cost recovery are equal, even though the percentages of fixed are variable costs are not equal. The installation of DER changes the amount of electricity provided by the electric utility and results in a larger reduction in cost recovery than the reduction in the cost of service. Therefore, a revenue shortfall occurs.

[44] Note that this example is simplified in that it assumes there are no cost savings associated with using the grid less because of delivering less energy. This additional complexity is addressed below.

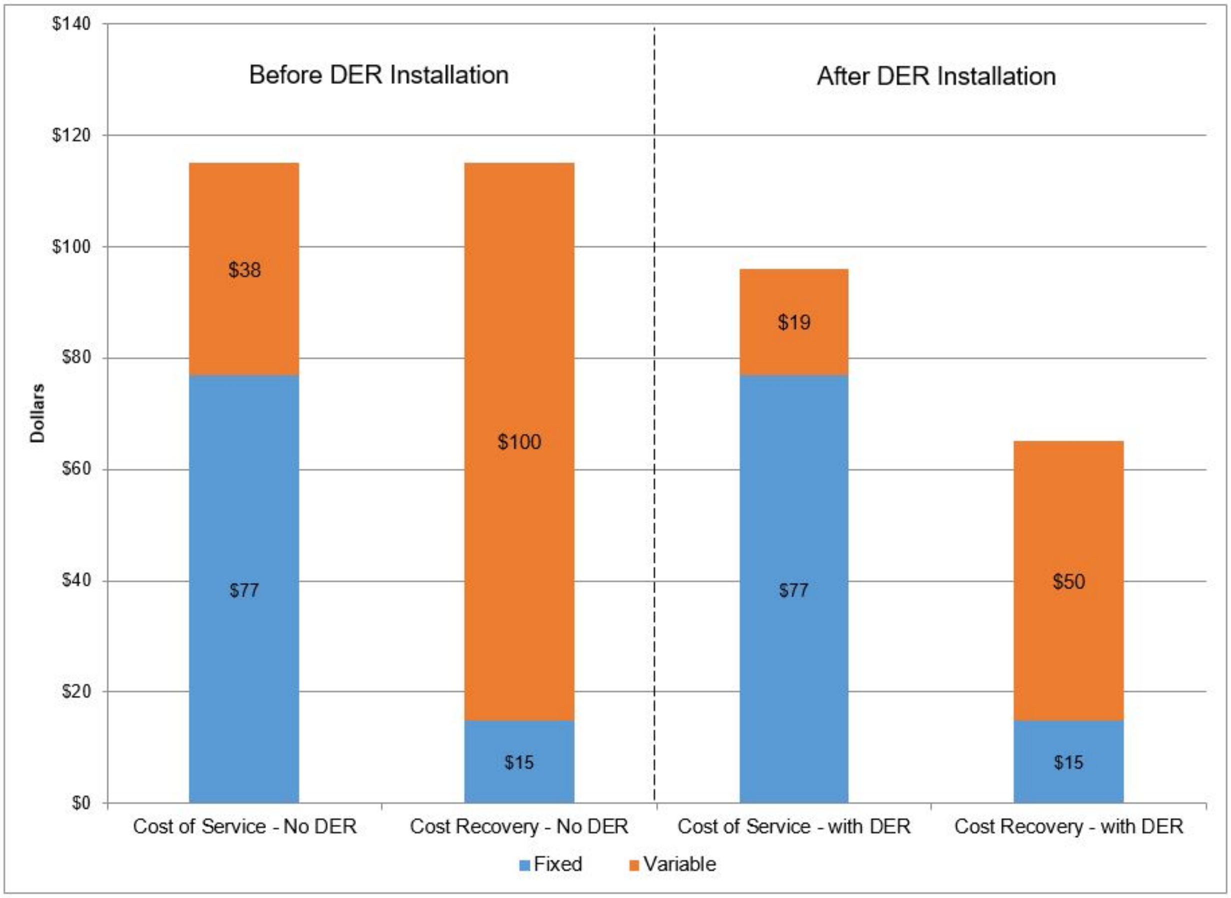

Figure A-1. Illustration of how DER Causes an Imbalance between Costs of Service and Cost Recovery

If the electric utility could raise fees just for this customer, then it could recover costs without increasing fees for anyone else. However, this is impractical for a variety of reasons and tends to be strongly opposed by the DER system owner (as it would eliminate much of the financial incentive to install DER). What happens then is that the electric utility raises its fees for all customers in order to make up the revenue shortfall. As a result, some of the fixed costs of serving this particular customer get spread across other customers. This is cost-shifting. It is also called a "cross-subsidy" because, in effect, customers without DER subsidize the fixed cost recovery of those who have DER.

One of the main principles of utility rate design is that cost of service should be fair, meaning that cost recovery should generally align with different customer classes' costs of service (Bonbright 1961). Cost-shifting that results in misalignment of cost recovery and costs of service is inconsistent with a fundamental rate design principle.

Even if the customer generates 100% of their electricity from their DER system and goes completely "off the grid", no longer having any connection to the grid, the DER would still result in a change in the electric utility's costs of service and cost recovery. The electric utility would still face a revenue shortfall because its sales would decline and its cost recovery would decline by more than the reduction in its costs of service, as illustrated in Figure A-1. As a result, the electric utility would have to increase fees to its remaining customers to make up the revenue shortfall. Note that even though one customer's choice raises costs for all other customers, most people would consider this situation to be "fair" because the DER owner is no longer using *any* electricity or grid services from the electric utility and therefore should not be expected to pay for maintaining the system.[45] In the language of economists, the DER owner's actions impose a "negative externality" on others.[46]

When DER is connected to the grid, there are more pieces to the puzzle but the end result is similar. When DER is connected to the grid, electricity is flowing from the grid to the customer and from the customers' DER system to the grid. The grid absorbs any excess energy produced by the DER system. From the perspective of the DER owner, the grid functions somewhat like the battery does for a system that is not connected to the grid. In addition, the grid supplies electricity if the DER system does not meet the customers' total demand.

Just as with a system that is not connected to the grid, the electric utility now sells less electricity, meaning that it faces a revenue shortfall because some of the fixed costs are not being recovered. This in itself can lead to cost-shifting. In addition, the connected DER is using the grid (but now with electricity flowing in two directions) and is therefore resulting in fixed costs to the electric utility that must be recovered from others.

Understanding how Compensation to DER Owners affects Cost-Shifting

The previous section shows how DER results in cost-shifting even if the DER owner is not compensated for any energy that it produces. In the discussion above, DER leads to cost-shifting simply because the customer purchases less electricity from the electric utility. Compensating the DER owner for electricity they produce can lead to additional cost-shifting.

First, we should note the two main forms of measuring electricity flowing back-and-forth from the customers system and the grid. In net metering, there is a single bi-directional meter that measures the net flow of energy to and from the grid. In dual metering, there are two separate meters, one that measures energy flowing from the grid (just like it would for a household with no DER) and one that measures the flow of energy to the grid. Dual metering allows the most options for compensation.

With dual metering, owners of DER systems can receive compensation for the energy they send to the grid, while continuing to pay full retail rate (and any monthly fees) for energy they receive from the grid. Compensation is typically either:

- *Avoided costs*, the reduction in costs of service for that electricity, which may include just fuel costs or can include some apportionment of fixed costs as well; or
- *Retail costs*, where TVA pays the customer based on the same rates that the LPC charges EUCs for electricity.

Depending on several factors, compensation at avoided costs may or may not increase cost-shifting. Compensation at retail rates will generally increase cost-shifting, as TVA pays the customer more to generate electricity than it would have cost TVA to generate it. This drives up the average cost of generating electricity, resulting in additional cost-shifting.

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[45] Note that in the long-term, TVA could adjust the size of the system to match the demand of current customers, but there will generally be disturbances in the short-term, during which large-scale adjustments to the system cannot be made.

[46] DER may also have positive externalities such as reduced emissions. These are discussed further below.

Some commenters have suggested that DER owners should get compensated at rates above the retail level, typically justifying this view with the claim that DER provides social benefits that are not fully captured in the retail rate level. This is discussed further below.

How is DER Viewed in terms of Social Benefits and Costs?
Another way to look at DER is in terms of social benefits and costs, as in benefit-cost analysis. This approach seeks to quantify and compare the social benefits and social costs of DER, where social benefits and costs are aggregated across individual members of society. Some commenters suggested that the "full value" or "full benefits" of DER should be considered. Some commenters claimed that including the full benefits would lead to a different conclusion about cost-shifting.

Regarding the former, net social benefits can be considered when evaluating whether and how much to incentivize private-scale DER. However, this does not change cost-shifting. DER contributes to cost-shifting no matter how high the social benefits might be. In economics language, social benefits and costs considers economic efficiency, while cost-shifting concerns equity and fairness. TVA is mandated to provide the lowest-cost electricity to the Valley, and it is committed to promoting rate fairness by aligning its cost recovery with costs of service across customer classes. For the reasons explained in the EA, this Appendix, and in other NEPA documents, incentivizing DER does not meet either of these objectives. Therefore, TVA need not consider the full set of social benefits resulting from subsidizing DER if that subsidy runs counter to TVA's mandate and the purpose and need of TVA's proposed action to close the GPP program.

Pricing of DER Electricity

The third type of analysis involves answering the question: what is an appropriate or fair price for utilities to pay DER owners for the electricity they generate? These studies often look at the value of DER, measured as total monetized social benefits, compared to potential prices such as the retail price of electricity charged by a utility. While the incentive structure chosen affects the amount of cost-shifting that may occur, this type of analysis has nothing to do with measuring cost-shifting for a given incentive structure. In other words, this type of analysis is not germane to the issue of whether or not the GPP Program, as currently structured, results in cost-shifting, nor how much that cost-shifting is. Since continuation of the GPP Program does not meet the purpose and need of TVA's proposed action, the analysis need not consider what an appropriate pricing would be if the GPP Program were continued.

Addressing Specific Public Comments regarding Cost-Shifting and Net Social Benefits

This section discusses public comments submitted to TVA during the review of the draft EA and addresses the papers cited by commenters with respect to cost-shifting. These commenters generally argue against TVA's conclusions regarding cost-shifting. The following section ("Additional Studies on Cost-Shifting") cites papers that support TVA's conclusion on cost-shifting.

Many of the papers cited by commenters discuss "net metering" or "retail net metering". Net metering is the use of a single bi-directional meter that measures the *net* flow of electricity between a household or business and the electric grid. If the net flow of energy is to the customer (they use more energy than they generate), the customer pays the utility the retail rate for the net amount. If the customer generates more electricity than they consume (there is a net flow to the grid), different utilities have different compensation schemes. For example, some will allow the customer to build up an electricity credit that can be used to offset future periods when the net electricity flow is to the customer. In contrast, TVA's GPP Program has utilized a dual-metering system, in which there are two meters: one that measures flow from the grid to the customer and one that measures flow from the customer's DER system to the grid. The GPP Program has always provided compensation at rates comparable to or above retail rates. Therefore, the GPP Program and dual metering operate similarly enough to net metering in practice (in terms of customer's bills) so that the discussion regarding net metering is generally applicable to TVA's GPP Program, particularly discussions regarding cost-shifting.

Center for Biological Diversity (CBD)
In their comments to TVA on the draft EA, CBD states that "[t]he 'cost-shift' argument is based in the premise that compensation paid to solar customers for excess generation unfairly transfers costs both to non-solar customers and electric utilities by reducing the number of grid customers who are contributing to grid maintenance" (Pg. 11). We agree. CBD continues "However, numerous studies have shown that the benefits of distributed solar equal or exceed costs to the utility and non-solar customers where, as in the Valley, distributed solar penetration levels remain relatively low" and references several studies.

This argument mistakenly conflates cost-shifting and net social benefits. The studies do not contradict TVA's conclusion regarding cost-shifting; they simply consider a different sort of analysis altogether. TVA's analysis, which focuses on cost-shifting, is consistent with TVA's rate design principle of fairness based on cost of service and its mandate to provide the lowest-cost electricity to the Valley. As noted above, TVA has no mandate under NEPA or the TVA Act to consider or promote net social benefits for actions that are contrary to these considerations.

The Brookings Institute report cited by CBD (Muro and Saha 2016) concludes that benefit-cost studies often find that there is a net social benefit of DER (i.e. that total benefits outweigh total costs) while noting: "Of course, there are legitimate cost-recovery issues associated with net metering, and they vary from market to market…utilities could have trouble recovering costs when distributed energy sources reach higher levels of penetration (Pg. 9)." This conclusion supports TVA's position, which is that continuing to subsidize DER can lead to future increases in cost-shifting.

The Frontier Group and Environment America Research and Policy Center report (Hallock and Sargent 2015) also focuses on the "value of solar" and net benefits of solar, which clearly refer to social benefit-cost analyses rather than cost-shifting. In fact, this report does not even address cost-shifting.

CBD cites a study performed by Maine Public Utilities Commission (Norris et al 2015) that found that the total benefits of DER exceed the retail energy rate. However, the study states that it "does not identify who the benefits and costs accrue to" (Executive Summary Pg. 5), meaning that cost-shifting is not considered. Second, we note that the report only estimates the social benefits of private-scale solar, but it does not consider the social costs, meaning that it is incomplete from the standpoint of a net social benefit analysis. As noted above, TVA's focus on cost-shifting is consistent with its mandate and principles.

CBD claims that "DOE's Lawrence Berkeley National Laboratory (LBNL) has directly debunked the "cost-shift" argument upon which TVA relies". However, this study (Barbose 2017) actually supports TVA's conclusions and does not address TVA's argument. TVA's two main concerns regarding cost-shifting are: 1) that any amount of future cost-shifting encouraged by TVA is not appropriate because it does not align cost recovery with costs of service; and 2) cost-shifting, even though it is at low levels now, would increase if GPP were continued or (as some commenters suggest) expanded.

The first sentence in the Barbose report states, “The rapid growth of distributed solar in a number of states has raised questions about its potential effects on retail electricity prices, prompting concerns by some utilities and stakeholders about cost-shifting between solar and non-solar customers.” (Pg. 1). This statement supports TVA’s general concern regarding cost-shifting.

The study presents a simplified formula for estimating the change in the overall retail rate resulting from DER. Applying this formula to TVA’s current levels of DER suggests that the resulting change in the retail rate of electricity would be modest. This supports TVA’s findings that future GPP participation at current incentive levels would result in cost-shifting, albeit likely causing only a minor change in non-participants’ bills.

The study above includes an illustrative scenario in which 1 percent penetration of DER could raise retail electricity costs by 1 percent. As noted in Section 3.1.1 of the EA, TVA delivered approximately 163,000 GWh of electricity (2018), and the average retail rate was close to $0.10 per kWh (value is rounded for simplicity). The 99 percent of customers who do not have DER would collectively have to pay more than $150 million each year as a result of the 1 percent of customers who install DER. While these numbers are illustrative, they are in the range of the cost-shifting estimated in TVA’s 2018 Wholesale Rate Change EA, which estimated annual cost-shifting of around $100 million from all types of DER.

While TVA has concluded in this EA that cost-shifting associated with continuation of GPP at current incentives is expected to be minor, cost-shifting as a whole (including solar and other technologies) is expected to increase significantly in the coming years and decades. TVA has concluded that contributing to additional future cost-shifting is not warranted given its rate design principle of fairness and its mandate to provide the lowest-cost electricity to the Valley.

Southern Alliance for Clean Energy (SACE)

In their comments on the draft EA, SACE states that TVA’s claim about cost-shifting has been disproven in several studies (Pg. 8). It cites the Brookings Institution (Muro and Saha 2016) and Environment America Research & Policy Center (2015) studies (Hallock and Sargent 2015) discussed above. As already noted, these studies address net social benefits and/or a fair price of solar. They do not address cost-shifting. SACE’s argument is therefore not supported by the studies that they cite.

Southern Environmental Law Center (SELC)

In their comments on the draft EA, SELC argues that “As explained above and throughout this letter, distributed solar provides significant value in addition to marginal avoided energy” (Pg. 10). First, as illustrated above, avoided energy by itself can lead to cost-shifting due to the mismatch between fixed and variable costs of service and cost recovery. Second “significant value” refers to the social benefits of DER, but does not address cost-shifting. SELC cites the same study performed for Maine cited by CBD and discussed above.

SELC later states that “cost-shifting is based on a flawed assumption that fails to acknowledge the value that solar provides to the grid. The argument’s premise is that compensation paid to customers generating electricity with DER unfairly transfers costs to those customers without DER by reducing the number of participants paying for maintenance of the grid.” (Pg. 30). We agree that this is generally what cost-shifting means and is how TVA is considering cost-shifting. Numerous studies cited in this Appendix support TVA's conclusion that cost-shifting is a valid concern for utilities.

SELC then switches to net social benefits and fair pricing language rather than discussing cost-shifting: "Meta-analyses have shown that electricity generated by solar panels is worth more than the rates at which that generation is compensated. Similarly, Maine calculated the value of solar using a robust cost-benefit analysis and found that the value of solar was more than twice the retail rate for electricity" (Pg. 30). The meta-analyses and the Maine study are the same studies (Muro and Saha 2016, Hallock and Sargent 2015, and Norris et al 2015) discussed above.

SELC also cites the same DOE study discussed above (Barbose 2017) in support of cost-shifting being minor, which as noted above supports TVA's conclusion that future cost-shifting caused by the GPP Program at current levels would likely be minor. However, this does not contradict TVA's conclusion that the GPP Program is contrary to TVA's rate design principles of fairness with respect to aligning cost of service and providing the lowest-cost electricity to the residents of the Valley.

SELC's final conclusion is, "The evidence before TVA shows that cost-shifting is not occurring" (Pg. 30). This conclusion does not follow from the studies they cite or their discussion, which focus on other analyses altogether. Numerous studies cited in this Appendix support TVA's finding that private-scale DER results in cost-shifting.

Tennessee Solar Energy Industries Association (SEIA)

In their comments on the draft EA, SEIA has a similar line of argument against cost-shifting as noted above, stating "there are a number of studies that show a benefit to the system with distributed solar, especially in comparison to how TVA calculates avoided rate". Although no actual studies are cited, this statement is likely referring to types of studies similar to those discussed above. The same problem likely applies – these studies are discussing social benefits and/or fair pricing, but are not relevant to cost-shifting.

Additional Studies on Cost-Shifting

TVA notes that the commenters above referenced a common group of studies in support of their arguments against cost-shifting, yet few of the studies actually focused on cost-shifting. Cost-shifting is an issue that utilities and regulators are considering across the country. In this section, TVA highlights several studies that support TVA's concern over cost-shifting.

Homer and Orrell (2019)

This paper provides a good overview of issues. The authors note that cost-shifting can go either way (costs can be shifted to or from non-participants), depending on a number of case-specific factors. They note that in Nevada, a 2016 study found that "there was a $36 million per year cost -shift from [net energy metering] NEM participants to non-participants" (Pg. 6). Citing seven other studies conducted between 2013 and 2015, five of the studies concluded that there was cost-shifting between participants and non-participants (Pg. 8). These studies support TVA's view that cost-shifting is a valid concern.

Edison Electric Institute (EEI 2016)

Discussion in an EEI paper supports TVA's definition of cost-shifting, stating that "when rooftop solar or other [distributed generation] DG customers generate electricity, they avoid paying for the utility's power, which is fair because they did not use it. But, they also avoid paying for all of the fixed costs of the grid that delivers power when they need it and/or takes the excess power they sell back to the utility. As a result, these grid costs are shifted to those customers without rooftop solar or other DG systems through higher utility bills" (Pg. 2-3).

In addition, EEI notes: "Electric utilities must invest in their distribution systems to avoid overloading circuits, causing voltage regulation or power quality problems, or jeopardizing the safety of the public or utility employees. However, if net-metered customers do not contribute to the fixed costs of maintaining the grid and keeping it operating reliably, a utility's remaining customers will face higher rates to pay for these costs" (Pg. 3).

Institute for Energy Research (Arduin, Laffer, and Moore Econometrics 2016)
This study concludes that subsidies for DER are generally inefficient from an economic standpoint, which is contrary to the conclusions on net benefits cited by many commenters and discussed above. Specific conclusions related to cost-shifting include (Pg. 3-4):

- Net metering structures threaten today's electrical grid system by allowing solar customers to bypass grid maintenance costs, as well as by imposing additional operating stresses…

- The retail price under many states' net metering schemes is often much higher than the rate that grids could reasonably obtain in the wholesale power market, creating immense distortions in the energy market that incentivize inefficient forms of solar energy production technology, often at the expense of taxpayers and non-solar electricity users.

- As net metering schemes continue to pay out elevated rates to solar customers, the amount paid back by net metering customers is often below utilities' costs for servicing those customers, resulting in higher amounts charged to non-net metered customers—the result is doubly regressive, as non-solar customers, who are often less well-off, must cross subsidize solar customers, who are generally wealthier.

The authors also note that subsidizing DER is being reconsidered, stating "many U.S. states have called upon their respective public utility commissions in order to determine whether current net metering programs should continue to provide subsidies in their current forms, with many studies confirming not only that non-solar consumers are cross-subsidizing solar consumers, but that often solar consumers are more well-off than non-solar consumers, thereby contributing to additional cost burdens on the poor" (Pg. 4).

They also summarize a number of findings for specific states and international examples.

MIT (2015)
This study has similar conclusions to those above. Some relevant passages include:

- "When this rate structure [having fixed costs partially or fully recovered through variable energy rates] is combined with net metering, which compensates residential PV generators at the retail rate for the electricity they generate, the result is a subsidy to residential and other distributed solar generators that is paid by other customers on the network. This cost -shifting has already produced political conflicts in some cities and states — conflicts that can be expected to intensify as residential solar penetration increases" (Pg. xviii).

- "when distributed PV grows to account for a significant share of overall generation, its net effect is to increase distribution costs (and thus local rates). This is because new investments are required to maintain power quality when power also flows from customers back to the network, which current networks were not designed to handle." (Pg. xviii).

- "If solar generation is valued for its contribution at the system or wholesale level, and assuming that solar penetration causes no net increase in distribution costs (see below), PV generation by residential systems is, on average, about 70% more costly than from utility-scale PV plants." (Pg. xvii).

Wood (2016)
This op-ed for the Brookings Institution provides useful summary information. Wood discusses the general cause of cost-shifting, disputes the conclusions of one of the studies relied on by several commenters above (Muro and Saha 2016), notes that the Muro and Saha review omits a key study that quantified significant cost-shifting for utilities in Nevada, and notes a number of states are changing their policies to reduce or avoid cost-shifting.

Conclusion

The purpose of this appendix was to provide additional information to support TVA's conclusions regarding cost-shifting and to address public comments related to this issue. In addition to providing an overview of how cost-shifting can happen, several studies that support TVA's conclusions were cited. Analysis of the public comments received on the Draft EA show that these commenters did not actually address cost-shifting, but rather discussed different analyses related to social benefits and pricing of solar systems.

Considering all of the relevant information, it is clear that cost-shifting is a valid concern and, like other utilities and regulators across the country, TVA is justified in addressing the negative consequences of cost-shifting on fairness and electricity costs.

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APPENDIX B: PUBLIC COMMENTS ON THE DRAFT EA AND TVA RESPONSES

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
I. General Comments			
1	S. Abel, B. Adcock, V. Alexiades, D. Barger , N. Beavers, N. Bell, B. Bennett, A. Bosela, B. Brunson, K. Bryant, D. Carrier, C. Cohen, J. Denton, P. Dudley, J. F., S. Feathers, R. Fledermaus, M. Glass, T. Haehn, R. Hall, H. Harvey, A. Hoffmann, H. Hoyt, T. Igou, C. Jones, K. Kline, B. Knisley, S. Kuhlenschmidt, M. Lipton, T. Lovino, P. Lowery , E. Martin, L. Martin, G. McConnell, J. Morgan, T. Morris, J. Newton, G. Niessen, J. Noel, E. Nuell, D. O'Dell, C. O'Kelley, W. Pannell, E. Pitt, J. Plumlee, D. Radzieta, J. Rasnic, C. Reid, N. Robertson, L. Romero, J. Rossow, K. Sisco, G. Snodgrass, L. Stalnaker, J. Steitz, J. Taylor, D. Vollrath, R. Whitmore, J. Williamson, R. Wynn, D. Zandstra, E. Zebko,	Commenters expressed a general support for solar energy within the Valley, mostly as a way to address climate change. Many of these commenters also expressed general support for private-scale DER.	Comment noted. As discussed in the EA, there will be no discernible change in TVA's power generation operations due to the proposed closure of the GPP program. As discussed in Section 3.1.2 of the EA, the GPP Program represents only a small portion (less than 1 percent) of renewable energy generation in the TVA service area. Several other options for private investment in private-scale DER currently exist such as the Dispersed Power Production (DPP) program and Behind-the-Meter (BTM) generation. In addition, as discussed in the 2019 Integrated Resource Plan and Environmental Impact Statement, TVA plans to invest in utility-scale solar to meet future generation needs. TVA added text in Section 3.1.2 of the EA discussing that TVA generates less of its energy from fossil fuel sources than the national average.
2	Form Letter 1: S. Alexander, J. Allen, B. Allen, B. Altman, M. Angell, J. Applegate, J. Atkins, C. Bahlinger, L. Baker, S. Banbury, B. Bates, T. Berney, J. Berry, T. Boughan, G. Bowers, N. Brannon, J. Brooks, C. Brooks, G. Bulmer, H. Burrows, D. Bursch, D. Campbell, L. Cannito, J. Carico, D. Carlson, D. Carrier, J. Cavalieri, J. Chase, N. Christison, M. Christophersen, K. Clark, M. Clarke, M. Clarridge, L. Cook, V. Crawford, N. Crockett, D. Cross, A. Curtis, D. Davidson, L. Delaney, D. Denis, R. Dennison, D. Dickinson, M. Dillman, J. Dixon, G. Dooley, S. Dornan, C. Dowell, C. Duke, J. Duvall, L. Edgerton, A. Ercelawn, R. Finch, E. Fitzgerald, N. Fitzgerald, M. Forbes, K. Ford, B. Fowler, G. Fox, J. Franklin, B. Gamache, D. Gilley, J. Gonzalez, J. Gore, C. Graham, W. Griffith, T. Grose, T. Haehn, J. Hage, C. Halliday, J. Haney, S. Harootyan, B. Harris, H. Harvey, A. Hathaway, S. Hathcock, D. Haverland, M. Hawk, R. Held, R. Heller, T. Henderson, C. Henry, E. Herrmann, J.	To aid in quickly stabilizing the global climate, both large-scale and distributed, customer-owned solar are needed to decarbonize TVA's electric grid as fast as possible.	Comment noted. TVA agrees that renewable energy has benefits for the environment, and TVA continues to reduce its carbon footprint. Under the TVA Act, TVA is mandated to conduct least-cost planning for its power generation resources, with consideration given to the environmental stewardship and economic development aspects of its mission. Today, nearly 60% of the energy supplied by TVA comes from carbon-free sources, including nuclear, hydro, solar and other renewables. After reviewing future strategies and options in the 2019 IRP study, TVA found that utility scale renewable energy is a more cost-effective renewable energy solution to meet the energy needs of the Valley than private-scale solar installations. Under the IRP, TVA anticipates additional reductions in its carbon footprint over the next twenty years. In addition, options for private investment in private-scale DER currently exist such as the Dispersed Power Production (DPP) program and Behind-the-Meter (BTM) generation.

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	Higgs, J. Hobbs, A. Hoffmann, J. Holland, H. Hoyt, D. Hunter, L. Innis, J. Irvin, L. Jamison, R. Jennings, M. Johnson, L. Kaplan, J. Kendall, C. Kimble, D. Kinard, D. King, J. Knoxville, K. Koontz, E. Langston, A. Lauber, S. Lemons, A. LeQuire, E. Levine, T. Livingston, M. Longmire, R. Loor, S. MacLaren, J. Mandes, J. Marlin, B. McCabe, L. McCall, G. McConnell, C. McDonald, L. McDonald, R. Mcilmoil, K. McIntyre, B. Miller, M. Miller, K. Minault, C. Montgomery, K. Moore, S. Moses, J. Moynihan, L. Mulford, H. Murphy, John Noel, J. Needham, S. Noethen, D. O'Dell, C. Orr, D. Page, D. Phelps, C. Poston, D. Potter, B. Powers, L. Prestridge, B. Prewitt, A. Quo, E. Ray, M. Reagan, J. Renfro, T. Rhodes, P. Riblett, J. Ridenour, L. Romero, T. Sahlin, A. Salzmann, C. Sands, M. Saums, L. Sharp, R. Shaw, K. Shepherd, E. Simon, P. Slentz, R. Smith, G. Snodgrass, P. Speltz, P. Steele, J. Steitz, J. Stephenson, C. Sullivan, T. Surface, C. Synnatzschke, T. Thomas, N. Thomas, M. Toohey, J. VanDyke, K. Watkins, P. Watkins, J. Watkins, B. Watson, B. Wheeler, C. Wheeler, B. Williams, L. Wood, M. Woods, R. Wynn, M. Zeitlin		
3	S. Abel , H. Acosta, V. Alexiades, D. Barger , J. Barrick, N. Beavers, B. Bennett, C. Boyd, B. Brunson, C. Cohen, P. Dudley, P. Elledge, M. Feathers, J. Flanagan, R. Hall, S. Hamilton, T. Igou, S. Kuhlenschmidt, D. Lewis, M. Lipton, L. Martin, J. Morgan, T. Morris, M. Morris, M. Neal, J. Newton, E. Nuell, E. Pitt, J. Plumlee, J. Rasnic, C. Reid, K. Sisco, R. Smith, H. Tashian, W. Thomas, A. Trusich, D. Vollrath, J. Waller, R. Whitmore, D. Williams, J. Williamson, D. Zandstra	Commenters expressed support for continuing the GPP Program.	Comment noted. For reasons described in Section 1.1 of the EA, TVA has determined that the GPP program is no longer meeting the needs of the Valley.

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
4	K. Herzig, C. Landis, J. McIntosh	Commenters expressed support for continuing the GPP Program temporarily while additional options are considered.	Comment noted. As discussed in Section 1.1 of the EA, the program is currently not meeting the needs of the Valley. A temporary extension of the program would fail to address the declining utilization of the program as well as cost-shifting resulting in an unfair burden on non-participants. Any such continuation of the GPP program, albeit temporary, would continue to ignore the availability of utility scale solar as a lower cost solution than the solar systems enrolled in GPP.
5	B. Adcock, V. Alexiades, J. Atkins, D. Barger , N. Beavers, M. Brindle, B. Brunson, K. Bryant, C. Cohen, R. Finch, M. Glass, T. Grose, D. Hrivnak, A. Jackson, M. Kelley, K. Kline, B. Knisley, T. Livingston, M. Morris, J. Plumlee, D. Radzieta, J. Scott, L. Stalnaker, P. Steele, J. Stephenson, D. Vollrath, R. Whitmore, J. Williams, J. Williamson	Commenters expressed support for TVA to provide additional incentives for private-scale solar.	Comment noted. While TVA recognizes that many in the Valley would like additional incentives for private-scale solar, TVA must also weigh the costs of continuing existing programs or establishing new programs that include financial incentives. As discussed in the EA (Section 1.1), based on TVA analysis, utility-scale solar has become a more cost-effective renewable energy solution to meet the energy needs of the Valley than private-scale solar installations. This is because utility-scale solar benefits from economies of scale, where the average cost per unit of energy produced decreases as the size of generation facility increases. Continued development of small or private -scale solar by providing additional incentives reduces the amount of energy TVA would generate at a lower cost, and, therefore, effectively increases the system-wide costs of meeting the Valley's electricity needs.
6	C. Boyd, B. Brunson, M. Feathers, B. Knisely, S. Kuhlenschmidt, P. Patel, K. Sisco, J. Wallace, R. Whitmore, J. Williamson	Commenters suggested expanding or improving the GPP Program, often suggesting providing additional financial incentives within the program.	Comment noted. As discussed in Section 1.1 and Appendix A of the EA, the financial incentive of the GPP Program causes cost-shifting and raises costs of electricity in the Valley. Expanding or improving the Program would only serve to accelerate the cost-shifting and deter from the mandate to provide electric service at rates as low as feasible.
7	N. Bell, M. Bixler, K. Bryant, J. Eastman, G. Jernigan, C. Jones, C. O'Kelley, D. Radzieta, W. Rice, J. Rossow, L. Stalnaker, J. Taylor, E. Zebko	Commenters were in support of fair compensation for energy generated by private-scale DER.	Comment noted. As discussed in Section 1.1 and Appendix A of the EA, financial incentives of the GPP Program or other compensation programs causes cost-shifting and raises costs of electricity in the Valley. Expanding or improving the Program would not meet the purpose and need of ending the GPP Program. It results in unfair compensation for the energy generated from private-scale solar.
8	J. Eastman, R. Williams, E. Zebko	Commenters suggested that the observed decline in GPP Program participation is the result of changes to program incentives or other design characteristics.	Comment noted. TVA added text in Section 1.1 that provides additional detail on the changes in incentives, which were planned when the GPP Program was first approved. The design of the Program was based on

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
			a periodic review of premium payments and key program attributes such that they reflect the value of renewable technologies to TVA, customer installation costs, and renewable market conditions.
9	J. McIntosh	Commenters expressed concern that Alternative C is not adequately defined.	Comment noted. The description of Alternative C in Section 2.1.3 of the EA provides a summary of the services that would be provided under a replacement program. TVA proposes to establish (1) a Quality Contractor Network (QCN) of vetted solar installers for applicants to choose from when installing their solar systems, (2) installation standards that include best practices and requirements for PV systems and batteries, (3) inspection requirements, and (4) a more standardized interconnection process. Alternative C is adequately defined for purposes of the EA to allow an assessment of the impacts of that alternative.
10	D. Clark	Commenter suggested that interconnections between private-scale DER and the grid should be standardized across the TVA service area.	Comment noted. While the broader issue of establishing interconnections between private-scale DER and the grid is beyond the scope of this EA, TVA would establish a more standardized interconnection process under Alternative C.
11	D. Corbitt, H. Eich	Commenter supports closing GPP because of effects on non-participants.	Comment noted. Impacts to non-participants as a result of cost-shifting and lower cost of utility-scale solar as compared to private-scale DER systems are discussed in the EA as components of TVA's purpose and need for ending the GPP program.
12	J. Steitz	Commenter suggested that cost should not be considered and/or prioritized lower than environmental concerns.	As a public power entity charged with keeping energy rates as low as feasible, TVA must consider costs when determining how to meet the electricity needs of the region. TVA is mandated under the TVA Act of 1933 to provide power at rates as low as are feasible.
13	D. Corbitt	Commenter expressed support for BTM.	Comment noted. Alternative C is designed to help improve the safety and reliability of BTM. It is expected that these improvements will help bolster participation in other DER programs such as DPP and BTM.
14	E. Zebko	Commenter expressed concern that Alternative C was limited to residential customers only.	Comment noted. TVA continues to engage with LPCs to develop a viable solution for Commercial & Industrial Customers. In the meantime, DPP is available to those who are interested in on-site solar, and several REC products are available for those who want to support renewable energy but are unable or unwilling to install on-site generation.

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15	J. Plumlee	Commenter expressed concern that discontinuation of the GPP Program would cause solar installers to go out of business and result in a regional loss of jobs.	TVA recognizes that there could be some negative effect on solar installation companies. However, we note that BTM is projected to grow significantly, which would partially or fully offset some of these losses. In addition, development of utility-scale solar rather than private-scale solar would also create jobs.
16	M. Allison, C. Bahlinger, M. Briggs, J. Cheelyh, W. Coombs, N. DiBiasi, N. Fitzgerald, G. Fox, M. Friddell, R. Heller, C. Henry, A. James, T. Marshall , M. Meadows, D. Page, M. Saums, R. Westbrooks	Commenter expressed general disagreement with TVA's decision, general displeasure with TVA, or had other comments that are not within the scope of the EA.	Comments noted.
17	Bullwinkel, G.	Commenter notes that environmental impacts were not quantified and had several comments related to TVA's overall policy toward solar resources.	Chapter 4 of the EA has been updated with quantitative analyses of potential environmental impacts. The more general policy comments are outside the scope of this EA. The IRP (2019a) discusses TVA's analysis of solar resources in the context of future energy production planning.
18	States of North Carolina, State of Kentucky	Commenters provided information on state requirements and procedures.	Comments noted.
II. TVA Purpose and Need -- Attractiveness of GPP Program			

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
19	CBD, SACE, TN SEIA, SELC	TVA's claim that the principal reason it is eliminating the GPP Program is that it is being underutilized, 2019 GPP EA at 1, is entirely spurious. Despite its many limitations, the program was working until last year, when TVA, for the first time, began offering sub-retail rates, which are obviously unattractive to customers considering installing distributed solar. TVA has thus created a self-fulfilling prophecy by making the program financially unattractive, and then eliminating it on the illogical ground that it must no longer be appropriate since it is no longer attractive… TVA has made it completely financially unattractive by, for the first time, offering consumers a sub-retail rate for the electricity generated from solar systems...TVA has thus deliberately killed interest in the GPP program, and now seeks to use that as an excuse to eliminate the program altogether.	As discussed in Section 1.1, the reasons for program closure are threefold and not based exclusively on program utilization. TVA added text in Section 1.1 of the EA that provides additional detail on the reasoning for changes in GPP Program incentives over time. TVA offered high incentives to GPP participants when PV installation costs were high and penetration in the Valley was extremely low. These high rates were aimed at stimulating the market for renewable generation by offsetting the high upfront costs of renewable installations. The incentives offered through the duration of the program (since its inception in 2011) are closely correlated to the price of solar installations (see Figure 1-2) and were not intended to reduce program participation. It is however obvious that interest in the program has continuously declined over time (Figures 1-3 and 1-4). The decrease in program participation did not start with the 2018 generation rate change but rather was a continuation of the trend observed for a number of years. As the cost of solar installations has continued to decrease and the DER market has evolved to offer lower cost renewable options, TVA has adjusted its generation rates accordingly. As envisioned in the design of the GPP program approved by the Board in 2011, the premium rates were phased out for new participants in 2016. The new fixed rates that went in effect starting with the 2018 GPP program year ($0.09 for residential and GSA-1 systems under 10 kW and $0.075 for all other eligible systems) were set at approximate Valley retail rates for the Residential and GSA-2 customers respectively. For some EUCs those rates were slightly above their actual retail rate and for others slightly below.

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
20	SACE	Commenter challenges TVA's conclusion that participation in the GPP Program has been declining. Commenter notes that program participation in 2019 has increased over last year, based on TVA's dashboard, which shows the amount of GPP enrollment at comparable times in 2019 and 2018.	The commenter has stated that the GPP program design and more specifically the current generation rates that went into effect in 2018 have resulted in program underutilization but likewise noted the increase in participation with exactly the same program design in 2019. It is therefore unclear to TVA if the commenter finds the current program design to be aligned with the market demand. The generation rates offered through the program closely correlate to the price of solar installations as demonstrated in Figure 1-2 and were not intended to reduce program participation. As the cost of solar installations has continued to decrease and the DER market has evolved to offer lower cost renewable options, interest in the GPP program has reduced over time, as can be observed in Figures 1-3 and 1-4. TVA does not believe that the increase in participation seen in 2019 is indicative of an increased interest in the program. Two factors could be contributing to an increase in 2019 compared to 2018. First, announcement of potential GPP discontinuation, subject to NEPA review, could have stimulated some customers to enroll in 2019. This is especially true when combined with the upcoming ramp down and expiration of the Federal ITC. Given these confounding factors, it makes more sense to look at the trend over several years, not just 2019 compared to 2018. This long-term trend (from 2012 to 2019) is unmistakably in the direction of lesser participation in the GPP program. It is also worth mentioning that even with an increased participation in 2019, the GPP program enrollment remains underutilized, as less than 50% of program capacity has been reserved at the date of publication of the final EA (less than a month left to go in the 2019 program year).

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21	Sierra Club	The decline in participation of homeowners and small businesses in small scale solar photovoltaic installations was caused by TVA's foolish decision to set the reimburse rate per kilowatt hour of generation at the fuel cost avoidance amount rather than a straight offset of the retail rate charged the end user by the Local Power Company. TVA admits that there is no economic incentive and in some cases net losses for homeowners and small business participants, as GPP is now structured.	TVA disagrees. The GPP rates have never been set at the TVA avoided cost. Rather, the rates have always been at or above the retail rate. When GPP was implemented in 2011, the TVA Board also approved the key features of the program, including the premium payment rates (i.e. the increment above the retail rate) that were to start out at $0.12 in 2012 and gradually be phased out in 2016 as the value of solar installations decreased and the market evolved to offer lower cost installations. The fixed GPP rate since 2018 ($0.09 for residential and GSA-1 customers; and $0.075 for all other customers) reflect the average retail rates for these customers. Additional information on the program's design has been added in Section 1.1 in the EA including information on the generation rate changes overtime.
22	SELC	In the face of this overwhelming evidence of customer interest, TVA instead looks to the recent poor performance of the GPP program to justify its actions. However, TVA fails to acknowledge that the recent low participation rates in the GPP program are due more to its faulty design than customer choice.	Customers who can afford small-scale solar systems and are interested in installing them generally support programs that provide them financial incentives. Consistent with its mission and statutory mandate, TVA must consider how payments for generation affect overall costs of electricity in the Valley and the distribution of costs across all customer groups. Additional information on the program's design has been added in Section 1-1 in the EA. As noted therein, incentives were always intended to decline as the cost of installing private-scale solar decreased over time. TVA does not rely exclusively on the recent program performance in its analysis of program utilization, but rather on the trend observed over the years. This trend unmistakably confirms the declining utilization of the GPP program. Please see Figures 1-3 and 1-4 of the EA for more information.

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
23	TDEC	TVA made modifications to its incentive structure, such as the addition of a cap and increasing GPP purchase rates. Has TVA considered how changes in incentive structure, specifically cap and purchase rate, can affect EUC participation and how past program performance has informed the proposed action?	Comment noted. As discussed in Section 1.1 of the EA, TVA evaluates the performance of the program on an annual basis when it decides to renew or change the Program. Caps are common in similar programs (see http://www.ncsl.org/research/energy/net-metering-policy-overview-and-state-legislative-updates.aspx). For example, a cap helps to prevent commercial entities from developing large solar projects for profit by producing electricity at a lower cost than the compensation provided to them by TVA. While the incentive structure affects participation in GPP, any such effect was more pronounced in the early stages of the GPP program when PV costs were high. Additional information on the program's design has been added in Section 1-1 in the EA. As noted therein, incentives were always intended to decline as the cost of installing private-scale solar decreased over time and the DER market evolved to offer lower cost options.
24	Warmath	The decline in GPP participation is a direct, empirical result of the rate change to a flat and fixed rate, which discouraged small scale solar investment during the peak of solar growth in the United States.	Comment noted. The flat rate payments referenced by commenters that were established in 2018 reflect the approximate retail rates across TVA's service area. As the decline in GPP participation began before the 2018 Wholesale Rate Change was implemented, TVA does not find any basis to conclude that this change caused the decline. As noted in the EA, the GPP program approved by the Board in 2011 envisioned a reduction in the incentives over time as solar installation costs decreased and the renewables market evolved to offer lower-cost renewable options.

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25	SACE	The market study from October 2018 that TVA released on October 28, 2019 to support the Draft 2019 GPP EA found that when they surveyed 200 households that could be targets to become solar customers, 58% had never heard of GPP and another 25% had heard of it but knew little about it. The Topline Results Summary of the market study (page 35) includes a conclusion that “We are likely to have fewer participants with ‘Concept C - Confidence’ concept versus ‘Control – Concept G’.” Concept C is the qualified contractor network (i.e., Alternative C in the Draft 2019 GPP EA). Concept G is the existing GPP program (i.e., Alternative A in the Draft 2019 GPP EA). If the basis for replacing GPP is that the current program is underutilized, it would seem counterproductive to advance alternatives that are likely to engage even fewer participants.	Declining program utilization is only one of three reasons for discontinuing the GPP Program. Continuing the GPP program would not be consistent with the purpose of TVA’s proposal. Further, continuing to incentivize DER under the GPP program creates cost-shifting and ignores the fact that utility scale solar systems are more cost-effective than private-scale solar systems. It is not surprising that potential participants rate a program that would provide them financial benefits higher than a program that does not. However, as discussed in Section 1-1 and Appendix A of the EA, such a program results in cost-shifting, which is counter to TVA's rate design principle of fairness by cost of service and TVA's mandate to provide electricity in the Valley at the lowest rates feasible, and is therefore not consistent with TVA's purpose and need.
26	SELC	TVA ignores the third party market research that shows customers in the Valley want solar options and want a program that fully compensates their exported solar generation.	It is not surprising that potential participants rate a program that provides them financial benefits higher than a program that does not. However, as discussed in Section 1-1 and Appendix A of the EA, such a program results in cost-shifting, which is counter to TVA's rate design principle of fairness by cost of service and TVA's mandate to provide electricity in the Valley at the lowest feasible rates, and is therefore not consistent with TVA's purpose and need.
27	SELC	Looking at the expansive scope of participation in the GPP program across a diverse group of LPCs throughout the Tennessee Valley, it is apparent that customers are interested in solar generation. (Map 1).	We disagree. This map shows that customers throughout the TVA service area signed up for the GPP program during the 2010-2018 period. The map, however, does not depict any trends in utilization of the GPP program over this period. This trend is reflected in Figures 1-2 and 1-3 of the EA. TVA conducted several sets of projections of future GPP participation, which indicate that new enrollment would decline to zero by the end of the planning period (see Figure 4-9 of the EA).

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
28	SELC	The study recognizes that TVA is “likely to have fewer participants with ‘Concept C—Confidence’ versus ‘Control—Concept G.’” Therefore, the Homeowners study contradicts TVA’s purported reason for terminating the GPP program and adopting the No Compensation Alternative: customers are more interested in the GPP program than they are in TVA’s preferred replacement.	TVA's purpose and need includes three components: 1) decline in utilization of the GPP program; 2) avoid subsidizing DER to prevent TVA from encouraging cost-shifting; and 3) investing in utility-scale solar which is a more cost-effective form of electricity generation than private-scale DER systems. The marketing study used a sampling frame of households that were interested in solar and is therefore not representative of the entire population of the Valley. Continuing the GPP is not consistent with TVA's purpose and need.
29	Form Letter 1, SELC	TVA’s own survey found the GPP program to be more popular than the proposed replacement option, therefore TVA should be expanding and improving the GPP program instead of eliminating it. Improvements should include: expand access to low-income households, renters, and people living in multi-family homes; add the program features discussed in the GPP Replacement EA like a quality contractor network; and make the process to sign up more streamlined and consistent across the Tennessee Valley.	Comment noted. Continuing and/or expanding the GPP program would not meet the underlying purpose and need for this proposal. As described in the EA, the purpose and need of taking this action has three components: 1) participation in GPP has declined; 2) TVA is reducing incentives to reduce cost-shifting; and 3) investing in utility-scale solar is a most cost-effective form of electricity generation. The marketing study targeted households that were interested in solar and is therefore not representative of the entire population of the Valley. That residents in the Valley who are interested in installing DER support financial incentives for them to do so is not surprising. However, this is not a sufficient reason for TVA to continue or expand GPP. Continuing GPP Program is contrary to all 3 elements of the purpose of and need, and expanding the GPP Program would be contrary to 2 of those 3 elements.
III. TVA Purpose and Need -- Cost-Shifting and Utility-Scale Solar			
30	CBD, SELC	DOE’s Lawrence Berkeley National Laboratory (LBNL) has directly debunked or rebutted the “cost-shift” argument upon which TVA relies. According to the LBNL report, for the “vast majority of states and utilities, the effects of distributed solar on retail electricity prices will likely remain negligible for the foreseeable future.”	TVA disagrees that this study contradicts TVA’s analysis in the Draft EA. In fact, the study supports TVA’s conclusions that cost-shifting is an important concern and cost-shifting will increase as DER penetration increases. In addition, as discussed in the EA, TVA’s concern is not just with the amount of cost-shifting, but also the fact that TVA would encourage additional cost-shifting if it continues to provide financial incentives for private-scale DER. TVA has included additional discussion of cost-shifting in Appendix A, including literature that support’s TVA’s concern over cost-shifting.

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31	CBD	NEPA requires that agencies make decisions based on “high quality” data, and thus forbids agencies from relying on unsupported speculations regarding the bases for, or impacts of, its actions...By basing the elimination of the GPP program on unsupportable assumptions about the relative cost of DER to the grid and purported “cross-subsidies,” TVA is violating these mandates.	Cost-shifting is a well-known issue that utilities are grappling with across the country, and therefore is very well supported. TVA has added additional discussion and citations supporting its concerns regarding cost-shifting in Appendix A.
32	SELC	Low distributed solar penetration means that any purported cost -shifting TVA uses to justify its action is not occurring… TVA concludes that cost -shifting serves as a satisfactory reason for terminating the GPP program and replacing it with the No Compensation Alternative, despite the contrary evidence before TVA. TVA failed to show that cost-shifting is occurring, nor is it likely that it would even at high levels of participation. In fact, TVA acknowledges in its alternatives analysis, flawed as it is, there would be only “minor” cost-shifting effects.	TVA disagrees. Cost-shifting occurs even at low levels of penetration. In Section 4.2.1, TVA estimates that the potential cost-shifting from continuation of the GPP Program that may occur over a 20-year period could reach $67 to $146 million. While this is characterized as a minor socioeconomic impact, reducing cost-shifting is aligned with TVA’s mission to provide low-cost electricity to the Valley at rates that are fair across customer groups. Moreover, attempting to address cost-shifting at this stage when the penetration rates are low makes sense compared to waiting until the problem is more significant. TVA added additional discussion of cost-shifting in Appendix A.
33	SELC	TVA’s conclusion that the termination of the GPP program and adoption of the No Compensation Alternative would not affect DER adoption, but merely shift it from the GPP program to BTM installations, undermines the entire purpose and need of the draft EA...The same, or roughly the same, amount of distributed solar would be installed. The same purported cost shifts would occur.188 The only difference is that without a program that compensates customers for the value of solar, middle- and low-income homeowners would have little to no opportunity to create their own BTM solar. Therefore, both the No Replacement and No Compensation Alternatives fail to satisfy the purported needs and purposes expressed in the draft EA.	This is not what TVA concluded in the EA. As stated in Section 4.1.2 of the EA, TVA expects that some, but not necessarily all of GPP participants would switch to BTM. It is therefore likely that there would be some reduction in cost-shifting in Alternatives B and C compared to Alternative A (the No Action Alternative). In addition, cost-shifting per unit of electricity is not equal for GPP participants (that receive payments) and BTM participants who receive no payments, because the payment itself results in cost-shifting. Furthermore, as discussed in Section 4.2.2 of the EA, even if cost-shifting is unchanged, TVA itself would no longer be incentivizing cost-shifting, i.e. any cost-shifting would be the result of purely private decisions. This meets TVA's purpose and need of reducing any cost-shifting resulting from TVA actions. In addition to cost-shifting, two other factors form the purpose and need of TVA’s proposed action: (1) declining utilization of the GPP program; and (2) investment in utility-scale solar is more cost-effective than private DER solar-based systems. Both Alternatives B and C satisfy the three-fold purpose and need. TVA notes that discontinuation of the GPP Program does not affect

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			anyone's ability to install BTM solar. As discussed in Section 1.3.2 of the EA, there are several options other than GPP for customers who wish to invest in renewable electricity.
34	CBD, SACE, SELC, TN SEIA, Form Letter 1	There were many comments on cost-shifting, the benefits and value of solar, and the price of solar. In general, these comments stated that TVA's analysis of cost-shifting should have taken the benefits/value of solar into account. Some comments stated or cited studies that solar provides a net benefit to customers.	Due to many public comments regarding cost-shifting, the benefits/value of private-scale solar, and the pricing of private-scale solar, TVA has included an expanded discussion of these topics in Appendix A in the EA. As discussed therein, these are three separate issues. Cost-shifting occurs even when private-scale solar provides benefits to non-participants.
35	TN SEIA	Recent data strongly suggests that adding solar to the system, with its coincident summer peak and overall distributed energy delivery, can actually reduce system-wide costs–even for nonparticipants.	Due to many public comments regarding cost-shifting and the value of solar, TVA has included an expanded discussion of these topics in Appendix A in the EA. No citation is provided for the recent data provided by the commenters. Appendix A contains references for studies that support TVA's conclusion that continuation of the GPP Program will increase electricity bills and result in cost-shifting.
36	CBD, SACE, Sierra Club, SELC	TVA asserts that utility scale solar has efficiencies of scale. While true on the surface, utility-scale solar also concentrates solar in distinct locations and does not take advantage of the distributed benefits including the creation of micro grids which improve grid reliability, and the value of privately owned storage to a homeowner, landlord, or business for time shifting resiliency, customer choice, etc.	TVA has added clarifying text in the EA. TVA agrees that utility-scale and private-scale are not perfect substitutes. As TVA's mandate is to provide electricity to the Valley at the lowest rates feasible, "cost-effective" in the context of this EA means the cost of providing a unit of electricity. Other factors such as potential differences in benefits are a separate issue. As discussed in Appendix A for cost-shifting, considering social benefits and minimizing system costs are distinct analyses with different goals. TVA continues to monitor the capabilities of battery storage and inverters and engage in related conversations with LPCs. Residential customers who are interested in microgrids can enter into an interconnection agreement with their local power company and participate in DPP.
IV. Consistency with TVA Act, TVA's Mission, and PURPA			

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
37	SACE	Alternatives in Draft EA no longer respect intent of the 2005 Energy Policy Act...Because the GPP rate no longer has any correlation to retail rates nor are participants being compensated for the RECs they are relinquishing, SACE contends that TVA is no longer conforms to the PURPA net metering standard. If TVA eliminates the GPP program as proposed in the Draft EA, it will be even further from compliance with the PURPA net metering standard.	Under PURPA, TVA was required to consider the net metering standard promulgated by PURPA. The TVA Board was specifically charged with considering and making a determination on whether or not it was appropriate to implement the PURPA net metering standard. In 2007, the TVA Board considered the net metering standard in accordance with PURPA and the objectives and requirements of the TVA Act. Instead of adopting PURPA's net metering standard, TVA's Board of Directors adopted a revised dual metering standard. In 2019, the TVA Board approved a revised net metering standard to replace the standard adopted by the Board in 2007. Because TVA considered the net metering standard before adopting its revised standard, TVA complied with the requirements of PURPA.
38	Sierra Club	TVA promised net metering would be available to all in its 2007 decision under the PURPA. Net metering as now practiced by TVA does not allow a full and equal credit for each kilowatt hour generated by a small solar system...Nothing in the standard as actually adopted supports TVA's current underpayment and avoidance of true net metering	In 2007, the TVA Board considered the net metering standard in accordance with PURPA and the objectives and requirements of the TVA Act. Instead of adopting PURPA's net metering standard, TVA's Board of Directors adopted a modified dual metering standard. In 2019, the TVA Board approved a revised net metering standard to replace the standard adopted by the Board in 2007. TVA's current net metering standard is as follows: *Any compensation for electricity produced by an electric consumer from an eligible onsite generation source that is delivered to the local distribution facilities, or otherwise to TVA, may only be made under, and in accordance with, rates, metering, and billing arrangements approved by TVA and determined by TVA to be consistent with its regulatory and wholesale power contract requirements.* TVA's current programs and proposed replacement service offering are consistent with this standard.

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39	SELC	These same customer classes—and the LPCs who serve them—can benefit from DER by reducing bills and deferring the need for investment in the distribution system. DER can also enhance reliability and resilience for these customers. Yet contrary to its obligations under § 10, the No Replacement and No Compensation Alternatives would make it harder and less economical for these same LPCs and customers to invest in DER. Therefore, the alternatives considered in the draft EA are inconsistent with the TVA Act.	We disagree. As documented in the EA, TVA has concluded that the GPP Program causes cost-shifting and that private private-scale DER systems are not as cost-effective as utility-scale solar. Continuing the GPP Program does not meet TVA's rate design principle of fairness based on cost of service and does not meet its mandate to electricity in the Valley at the lowest rate feasible. Therefore, the alternatives that include ending the GPP program (Alternatives B and C) are consistent with the TVA Act.
40	TN SEIA	As noted in Section 1.3.1 and again referenced in Section 1.4 of the EA, TVA's consideration of the PURPA-promulgated net metering standard was addressed by the GPP program, as required by the PURPA. Although it is stated that the GPP meets PURPA requirements, the EA fails to detail the standards/requirements that the GPP meets and how the various alternative options in the EA will meet those standards as required by Federal law. TVA should include a review of how the various alternatives will impact PURPA requirements and standards. It should be noted that TVA, at the time of the PURPA review, felt constrained by the GPP and its dual-meter approach because of "all-requirement" contracts having buy-all sell-all provisions with the LPC. This has changed in 2019 with new 20-year contracts (allowing contract flexibility) that the majority of LPCs have signed that allow LPC's to purchase excess power from customers in a net metering program.	PURPA only required TVA to consider a net metering standard; it did not require TVA to implement a net metering program. After considering the PURPA net metering standard, TVA adopted a dual metering standard. TVA later implemented GPP, a program that was consistent with TVA's dual metering standard. By considering the PURPA-promulgated net metering standard before adopting its revised standard, TVA complied with the requirements of PURPA Title I. TVA has a separate obligation under PURPA Title II to purchase generation from QFs. TVA complies with this requirement through its DPP program. DPP will still be available for QFs under each alternative considered in the EA. The "all requirements" contracts were only one of several reasons the TVA Board rejected the proposed net metering standard in favor of the modified dual metering standard. Additionally, the new 20-year power contracts do not allow LPCs to purchase excess power from customers in a net metering program.
41	SACE	TVA is failing to embrace renewable energy as a key strategy...TVA has become increasingly hostile to solar in the Tennessee Valley	Comment noted. TVA disagrees that its actions are hostile to distributed solar development and has recently approved an Integrated Resource Plan that is expected to result in expansion of solar power generation across the Valley.

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42	Sierra Club	Private, distributed small scale generation will be valuable as coal plants are closed. To abandon rather than improve the GPP means ignoring the value of widespread private investment in small scale renewable energy.	As explained in the EA, TVA would continue to support the currently enrolled GPP participants after the proposed end of the GPP program through their existing agreements. In proposing to close the GPP program to new participants, TVA is considering renewable energy solutions to meet the energy needs of the Valley that are more cost-effective than private-scale solar installations (Section 1.1). Utility-scale solar benefits from economies of scale, where the average cost per unit of energy produced decreases as the size of the generation facility increases. As discussed in the 2019 Integrated Resource Plan (IRP), TVA considers utility-scale solar to be a more viable option for generating renewable energy when compared to building and commissioning other generation assets from any source, and TVA plans to increase its investment in utility-scale solar generation in the coming decades (TVA 2019a). Private investment in renewable energy can still occur through one of TVA's other programs or outside of a TVA program.
43	Sierra Club	Time has run out for a maximum response to climate disruption. Every effort to end all fossil fuel use and to power us with renewable energy is vital. Revision of the GPP program is a relatively simple and straight forward action which TVA should and must take. Do not punish all of us who live in Valley by failing to offer a financially compensatory and simple program for distributed small scale solar.	Comment noted. As explained in the EA, TVA is considering renewable energy solutions to meet the energy needs of the Valley that are more cost-effective than private-scale solar installations (Section 1.1). Utility-scale solar benefits from economies of scale, where the average cost per unit of energy produced decreases as the size of the generation facility increases. As discussed in the 2019 Integrated Resource Plan (IRP), TVA considers utility-scale solar to be a more viable option for generating renewable energy when compared to building and commissioning other generation assets from any source, and TVA plans to increase its investment in utility-scale solar generation in the coming decades (TVA 2019a).
44	SELC	The draft EA represents another link in a long chain of TVA actions aimed at limiting consumer choice and energy options in the Valley...In short, TVA is focused on how best to maintain its existing monopoly business model, rather than adapting and changing to the benefit of ratepayers and communities. Perhaps as a result, TVA now seeks to terminate the GPP program and "replace" it with a "program" that would not compensate customers for the value they provide to the grid and to the Valley.	Comment noted. TVA disagrees that the purpose of this proposal is to limit consumer choice and energy options in the Valley. Rather, the three-fold purpose is spelled out clearly in Section 1.1. Multiple options remain available to households and businesses in the Valley to invest in solar or other renewable generation sources. As explained in the EA, TVA considers utility-scale solar to be a more cost-effective option to meet the energy needs of the Valley than private-scale solar installations.

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45	SELC	TVA has made policy choices to undermine distributed generation's growth in the Valley, to the detriment of both its bottom line and the citizens of the Valley.	Comment noted. TVA disagrees that the purpose of this proposal is to discourage distributed solar development. Rather, the three-fold purpose is spelled out clearly in Section 1.1. Multiple options remain available to households and businesses in the Valley to invest in solar or other renewable generation sources.
46	TDEC	TDEC is supportive of a decentralized, diversified power supply in the state. In the event of an energy emergency, solar PV systems may provide an emergency source of electricity that could serve critical infrastructure and facilities (e.g., hospitals, shelters, food banks) in the region. Additionally, TDEC is supportive of resiliency efforts, including island-able power sources and micro grids throughout the state. In order to supply power in the event of a prolonged grid outage or energy emergency, TDEC encourages projects establishing micro grids in continuity zones to maintain critical infrastructure. Distributed power generation as contemplated in the program may provide an emergency source of electricity for critical infrastructure.	Comment noted. TVA continues to review diversified and decentralized power options such as Automatic Transfer Switches, battery storage and inverters and continues to engage in related conversations with LPCs so that these technologies can be appropriately utilized as they reach maturity. Currently, the EUCs who are interested in microgrids can do so by entering into an interconnection agreement with their local power company and, if they choose to sell power, participate in DPP. As noted in the EA, the GPP Program is a relatively small portion of renewable energy generation in the Valley. Please see IRP (TVA 2019a) for more information on TVA's policies on renewable energy and solar generation within the Valley.
47	City of Knoxville, Metropolitan Government of Nashville and Davidson County	We have a desire to invest in renewable energy in ways that accelerate the decarbonization of our municipal electricity footprint while providing an eventual return on investment and long-term economic benefit. The existing GPS program, which never provides any direct economic benefit to participants, is not a viable solution for these objectives. Fully behind-the-meter solar is a potential option, but is not as economically attractive when compared to solutions that benefit from net metering and/or economies of scale.	Comment noted. TVA's current renewable program portfolio includes some offerings that provide the prospect of an eventual return on investment to enrolled participants. For example, there are multiple LPCs in the TVA service area that offer Community Solar programs, which include the prospect of an economic benefit. Should such a program be of interest to a customer, we respectfully ask that the customer express said interest to their LPC. Additionally, TVA offers the DPP program with three configurations (See Section 1.3.2 of EA). Further, Valley residents also have the option of installing BTM solar systems that may become more economically attractive as battery storage technology reaches maturity.
V. Range of Alternatives			

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
48	CBD	The EA fails to consider a reasonable range of alternatives to eliminating the GPP program. Indeed, TVA only offers a binary choice: to continue the program (no action), or eliminate it. As a threshold matter, the EA’s Alternative C – which involves eliminating the program and beginning a “new private-scale service offering,” 2019 GPO EA at 13 – is not a NEPA alternative. It is precisely the same as Alternative B – elimination of the GPP program; to suggest otherwise turns NEPA on its head.	Alternative C represents TVA's proposed action, which is to close the GPP program and to replace it with a new private-scale offering. TVA has provided a discussion and analysis of the economic and environmental effects of the new service offering (Alternative C) and how those effects may differ from the current GPP program (Alternative A). TVA also reasoned that it would be illustrative to its analysis, particularly of Alternative C, to also analyze the alternative of ending the GPP program with no replacement offerings (Alternative B). This analysis provides perspective on the extent to which the service offerings associated with Alternative C would differ from ending the program without new offerings (Alternative B). In the analysis, TVA found that the proposed service offerings have the potential to benefit future potential private-scale solar adopters as compared to Alternative B that would close the GPP program with no replacement. Alternative C would also provide some safety benefits to both EUCs and TVA/LPC workers. The information provided by TVA under Alternative C on the proper disposal of solar systems could also benefit current and future DER adopters. Thus, Alternative B and C are distinct in several respects, including their potential to benefit future solar adopters.
49	CBD	Reasonable alternatives include: paying the retail rate for solar electricity; move away from dual metering to net metering system; expanding the GPP offering.	Continuing to pay the retail rate to private-scale DER owners and expanding the GPP Program are not considered reasonable because they are contrary to the purpose and need; both cause cost-shifting and would be less cost-effective than utility-scale solar. The TVA Board previously considered the net metering standard proposed by PURPA in accordance with PURPA and the objectives and requirements of the TVA Act. Instead of adopting PURPA’s net metering standard, TVA’s Board of Directors adopted a revised dual metering standard. In 2019, the TVA Board adopted a revised standard (see response to Comment #38) that enables TVA to meet its obligation to keep rates as low as feasible and avoids conflict with the all-requirements wholesale power contract.

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50	Sierra Club	TVA should modernize the GPP program or its successor to financially reward all systems which can safely contribute to the grid power supply.	As discussed in Section 4.2 and Appendix A of the EA, providing financial incentives to customers to invest in private-scale solar results in cost-shifting, which is contrary to TVA's rate design principle of fairness based on cost of service and TVA's mandate to provide electricity to the Valley at the lowest rates feasible. Continuation of the GPP program is not consistent with TVA's purpose and need.
51	SELC	TVA failed to consider any alternatives that would adequately compensate solar exports for the value they contribute to the grid and the Valley. TVA must also at a minimum consider the following alternatives: (1) retail net metering; and (2) the “Promote DER” strategy developed by TVA in its 2019 IRP. TVA must consider the Promote DER strategy that TVA developed as part of the 2019 IRP...Because TVA created the Promote DER strategy and found it reasonable in the context of the 2019 IRP, and because the Promote DER strategy satisfies the purported needs and purposes of the draft EA, TVA must consider it as a reasonable alternative to the GPP program.	Alternatives that provide or increase compensation are not considered because they are contrary to the purpose and need of TVA’s proposed action. Among other things, these alternatives would result in cost-shifting and would not promote TVA's mandate to provide the lowest-cost electricity to its customers. Under the "Promote DER" strategy considered by TVA in the 2019 IRP, TVA analyzed incenting DER in its modeling to achieve higher end of long-term penetration levels. The strategy included TVA activities to promote distributed generation. While it is true that the strategy was reasonable and helped TVA identify potential future power generation needs, it is inappropriate to assume that applying any strategy to incentivize DER would be reasonable under any future circumstance. The IRP compared five strategies in the context of six future scenarios in which TVA may find itself operating. The 2019 IRP analysis was developed based on least-cost planning, as mandated by the TVA Act, with consideration of environmental stewardship and economic development. The fact that TVA considered the promotion of DER as a strategy does not mean that the promotion of all DER is reasonable or meets TVA's generation needs in this case or that it would provide the power at the lowest system cost. As explained in the EA, the costs associated with the continuation of the GPP program are greater than other forms of DER that are available, and the costs result in unfair cost-shifting to other consumers. Comments relating to the adequacy of IRP metrics have been addressed by TVA in Appendix F of the 2019 IRP, EIS-Volume II

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52	SELC	Retail net metering would satisfy the purported purpose and needs of the draft EA, to the extent they are valid. It must be considered as a reasonable alternative.	TVA disagrees. Retail net metering does not meet the stated purpose and need. It would result in cost-shifting and would not promote TVA's mandate to provide the lowest-cost electricity to its customers. The TVA Board previously considered the net metering standard proposed by PURPA in accordance with PURPA and the objectives and requirements of the TVA Act. Instead of adopting PURPA's net metering standard, TVA's Board of Directors adopted a revised dual metering standard. In 2019, the TVA Board adopted a revised standard (see response to Comment #38) that enables TVA to meet its obligation to keep rates as low as feasible and avoids conflict with the all-requirements wholesale power contract.
53	City of Knoxville, Metropolitan Government of Nashville and Davidson County	We respectfully request that TVA select Alternative A) and continue the GPP program unchanged for a limited amount of time. We request that the program continue until a more comparable alternative can be offered that would allow Valley ratepayers to invest in renewable energy while maintaining utility connections and achieving economic net benefits. Such solutions might include: a single-meter option implemented in partnership with LPCs that compensates homeowners at retail value for any excess power returned to the grid; standardized framework that enables community solar projects in partnership with LPCs wherein customers may invest in off-site renewable energy and achieve an eventual financial return on that investment; and standardized Valley-wide Green Tariff product implemented in partnership with LPCs to allow aggregation of customer demand for renewables and offering customers long-term pricing options that return financial gains over the long-term.	Comment noted. Continuation of the GPP program is not reasonable as it does not meet the purpose and need of TVA's proposed action. TVA will continue to work with LPCs and TVPPA to identify opportunities that expand DERs and develop new renewable solutions. Paying the retail rate to private-scale DER owners is not considered a reasonable future option because it would cause cost-shifting and would be less cost-effective than utility-scale solar and goes against TVA's obligation of keeping rates as low as feasible. Community Solar has been made available in multiple LPC service areas across the Valley. Green Tariff or similar products are currently being researched.

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
54	City of Knoxville, Metropolitan Government of Nashville and Davidson County	By discontinuing the GPP program and driving the majority of distributed systems to go Behind-the-Meter, TVA risks eliminating any incentive for systems to properly adhere to the proposed quality and interconnection standards. We encourage TVA to launch the QCN and associated standards, while continuing to leverage the GPP program to entice customers to participate in this offering.	Comment noted. TVA disagrees because homeowners and businesses would still have incentives to install safe and reliable systems to protect themselves and their property. The interconnection agreements for BTM developed by LPCs generally have standards and have to meet local codes. One benefit of the QCN and associated standards would be to make it easier for customers to be sure that installations are compliant with LPC and other standards.
55	TN SEIA, Lightwave	TenneSEIA and Lightwave recommended a combination of Alternatives A and C. As an association, TenneSEIA feels that continuing the existing GPP program while implementing the QCN presents the best option moving forward	Comment noted. Combining Alternatives A and C would continue the GPP Program, which does not meet the three-fold purpose and need described in Section 1.1 of the EA.
56	CBD	The fact that TVA claims it will design a new program at some later date is irrelevant to this analysis, since TVA has not revealed what the elements of that program might be. Rather, for purposes of NEPA, TVA must analyze the impacts of the specific action taken by TVA now: eliminating the GPP program. TVA cannot assume that some new, undefined substitute program will provide the clean energy that the GPP program could have achieved.	Section 2.1.3 of the EA describes the new private-scale service offering that TVA proposes to initiate. This description of Alternative C is adequately defined to to allow a comparison of its potential impacts to those of the other alternatives.

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57	TDEC	Under Alternatives B and C, no economic incentive is provided to potential participants. Instead these alternatives rely on a QCN that depends on the rigor of installation standards and TVA's inspection requirements. Purchasers of residential solar PV may choose contractors outside the solar QCN, which could lead to reduced visibility for TVA and LPCs and may potentially push the market further into private, BTM installations. Outside installations could increase the use of poor quality contractors and increase the risk of safety hazards for both homeowners and linemen. If TVA considered a nominal rate, such as a "Value of Solar" rate determined by a third party for excess generation, then TVA may incentivize applicants to participate, increasing TVA's and LPCs' visibility into private-scale, and thus reducing safety risks associated with poor quality contractors. TDEC encourages TVA to include additional discussion relating to the comparative benefits and impacts to program uptake of both rate incentives as well as the QCN in the Final EA.	Participation in the TVA program described in Alternative C is not expected to result in increased installation cost to the end use consumer, as there would still be competition among approved installers. It is, therefore, unclear why a consumer would choose to go with an installer outside of the QCN network and take on additional risk of working with an installer whose work is not guaranteed. Additionally, participation in the service offering described in Alternative C does not prevent a consumer from also entering into a PPA with TVA through the DPP program if the consumer wishes to sell power to TVA.
58	TDEC	For residential customers interested in installing solar, Alternative C (the Proposed Action) has the potential to result in the addition of batteries as a backup or consumption of all of the energy produced on-site, adding additional cost as well as potentially deterring private-scale solar for EUCs. Has TVA explored options to assist EUCs with this added cost? If not, has TVA considered that this could negatively impact the potential for any new installations of private-scale solar? TDEC encourages TVA to include these considerations in the Final EA.	Comment noted. In Alternative C, TVA would not offer any financial assistance to the EUCs to address additional costs associated with batteries for EUC customers. Financing battery installations does not meet the purpose and need nor does it meet TVA's mission for providing electricity in the Valley at rates that are as low as feasible.

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
59	TDEC	In the Draft EA, TVA assumes all current LPCs participating in GPP will elect to make the new offering proposed by Alternative C available to their EUC. Has TVA been in communication with LPCs to ensure their continued interest in offering this to their EUCs? Additionally, has TVA contemplated engaging with LPCs that are not currently participating in GPP to gauge interest in participation? TDEC recommends TVA include these considerations in the Final EA.	As noted in Section 4.1.3, TVA assumed for the purposes of the analysis that the LPCs offering GPP will elect to make the Alternative C offering to their EUCs. TVA has been working with various stakeholders, including LPCs, to develop the new offering. Based on current information, TVA believes that this is a reasonable assumption for purposes of the analysis.
60	TDEC	TDEC encourages TVA to create a simple, streamlined, low-cost process for interconnection of solar from residential homes to the LPCs. This standardization will help maximize participation and ease reporting of distributed solar efforts throughout the Valley. For example, TVA could simplify the BTM if the requirement for a second meter was replaced with using a single, bi-directional meter.	Comment noted. TVA will continue to work with LPCs and TVPPA to identify opportunities that expand DERs. There is no dual metering requirement for BTM. BTM systems today only require a single bi-directional meter.
61	TN SEIA	By pushing systems to go BTM with no economic driver for homeowners to participate with their LPC or a TVA program, there is no clear incentive for systems to be professionally installed or to work with the LPC to ensure quality and interconnection standards are met	We disagree. As indicated by the findings of the marketing study and discussed in the EA, there are incentives for homeowners to seek out quality installations to avoid potential dangers. Alternative C, by providing additional resources for customers to find quality installers, is expected to lead to more quality installations. We agree that providing financial incentives could further stimulate this, but subsidizing DER is counter to the purpose and need of TVA's proposed action.

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62	TN SEIA	TenneSEIA Believes that Alternative C Could be Successful by Including: A simple one-meter electrical design that allows homeowners to get full retail value for all power used on site; A higher than the avoided rate for export power, modeled on the TVA Value of Solar study; A TVA contract or other mechanism to allow projects to achieve financing, allowing lower income ratepayers to take advantage of solar and related technologies	These suggestions are not considered because they are contrary to the purpose and need of TVA's proposed action. They would result in cost-shifting and would be less cost-effective than utility-scale solar.
63	Lightwave	By not including a reimbursement for the true value of solar, there is little incentive for ratepayers to use the QCN program driving lower overall participation in solar, and possibly more systems without the proper installation standards to ensure safe, long -term value to the ratepayer.	We disagree. As indicated by the findings of the marketing study and discussed in the EA, homeowners have an incentive to seek out quality installations that are safe and reliable to avoid potential dangers. Alternative C, by providing additional resources for customers to find quality installers, is expected to lead to more quality installations. We agree that providing financial incentive could further stimulate this, but subsidizing DER is counter to the purpose and need of TVA's proposed action.
64	SACE	The market study itself represents a very selective subset of utilities for a key part of the analysis: benchmarking pricing of other utility programs...This small dataset is not sufficiently representative of the larger utility market as a whole.	Comment noted. That particular aspect of the marketing study (*i.e.* benchmarking other utility programs) is not relevant for this EA. As discussed in Section 4.2 and Appendix A of the EA, providing incentives to customers to install private-scale solar results in cost-shifting, which is contrary to TVA's rate design principle of fairness based on cost of service and TVA's mandate to provide electricity to the Valley at rates as low as feasible. The benchmarking of DER programs does not affect the current analysis.
65	TN SEIA	There are a number of key discrepancies and issues with the marketing study that impact its applicability to the EA	Comment noted. The commenter generally focuses on options within the marketing study that allow financial incentives for private-scale DER. However, as discussed in Section 4.2 and Appendix A of the EA, this would result in cost shifting, which is contrary to the stated purpose and need of TVA's proposed action.

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
66	SACE	Distributed solar should be administered by the LPCs rather than TVA...there is no apparent reason that TVA should necessarily be involved in the transactions...LPCs should be empowered to design single-meter (bi-directional meter) programs that meet the needs of their local business and residential customers.	Comment noted.
67	TN SEIA	The LPCs could administer a solar value program more efficiently than TVA since the majority of benefits are realized on the distribution system. The challenge to this approach would be the administration for small LPCs that might not have the staff and administration bandwidth and need support from TVA. It is not clear why this option is not addressed in the EA.	Comment noted. This alternative is not considered because it is out of the scope of the current EA. TVA will perform a NEPA review, as appropriate, of any future LPC programs that have TVA involvement.
68	SELC	Retail net metering would also prevent any possible cost-shifting because it allows customers with solar panels to provide a net benefit to all customers	We disagree. Cost-shifting as the term is typically used refers to changes in end-use customers' electricity bills. Retail net metering has been shown to result in cost-shifting in numerous locations throughout the United States. See Appendix A for more discussion on cost - shifting and references that support TVA's conclusion.
69	TN SEIA	TVA supports energy efficiency. When homeowners make energy efficient home improvements, they are offsetting consumption at a rate that is equivalent to the retail rate of power they are being charged. The homeowner expects to be able to do the same with solar, and from the overall system perspective, a kW-hr saved is the same as kW-hr generated.	We disagree with this comment for several reasons. First, we note that the current GPP prices are similar to the average retail rates across TVA's service area. Second, the effects of DER are different on the system than energy efficiency, as they have different effects on peak load, timing of load, and the use of "grid services". Therefore, DER and energy efficiency can have disparate effects on costs for the same reduction in electricity used.
VI. Energy Use and Production Analysis			
70	SACE, SELC, TenneSEIA	Commenters noted potential problems with TVA's October 2015 Distributed Generation – Integrated Value (DG-IV) study, and noted that an updated study is warranted to properly quantify the value of DER solar	The stated purpose of the DG-IV study is to develop a methodology for considering the value of solar. It presents example calculations for illustrative purposes only. It does not inform the compensation under the GPP or DPP programs. Conclusions in this EA are based on

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			relevant literature and previous analysis, such as the IRP. A new value of solar study is therefore not necessary to complete this analysis.
71	TN SEIA	The 60 percent utilization factor stated on page 34 cites a McKenna study "Solar photovoltaic self-consumption in the UK residential sector" when the actual paper references 45 percent as the internal consumption rate. This is further flawed since the insolation in central TN (reference global solar atlas @http://globalsolaratlas.info) being more than 40 percent greater than that in the UK. This further exacerbates the midday export and lack of self-consumption, driving the utilization factor down significantly. This will have a significant negative impact on the private -scale BTM payback analysis (EA figure 4-5 page 34) and the corresponding analysis on GPP vs. BTM at the private -scale. At the end of the day, residential BTM solar only works for households with large loads during the day and is not generally an option without also implementing storage.	TVA's Solar Calculator FAQs describe self-consumption for residential solar as being between 60% and 100%. The assumed value in the presented analysis is consistent with the most conservative value proposed by TVA's suggested range, and is specific for this particular geography and demographic. With respect to the Mckenna study's 45% number, it is not necessarily the case that higher solar insolation leads to lower self-consumption. Rather, system sizing would be optimized for a particular use case and geography. Therefore, higher rates of solar insolation in TN would result in an optimally sized solar PV system that is likely smaller (lower peak kW capacity) than that in the UK, all else equal. However, there is one important factor that will increase self-consumption rates in TN relative to the UK: demand for home cooling. Very few homes in the UK have air conditioning, whereas the majority of homes in the TVA area do have air conditioning. This is reflected in the seasonal electricity demand of the UK electrical grid, which is lowest in the warmest months and highest in the coldest months. PV solar is fairly well matched to AC demand, which is a common and substantial household load present in the TVA area but nearly totally absent from UK household load. This difference alone is expected to increase the rate of self-consumption relative to UK numbers. This variable does not affect the projections of the future GPP Program, which is more important for the purposes of the current EA.

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72	CBD	Indeed, by significantly altering the value proposition of distributed solar, TVA is demonstrably altering whether TVA customers will make the necessary investments in these systems, and thereby add new renewable electric generation capacity.	TVA disagrees. TVA adjusted the compensation rates for GPP (since its inception in 2011) as the cost of solar installations has continued to decrease and the DER market has evolved to offer lower cost renewable options. This was envisioned in the design of the GPP program approved by the TVA Board in 2011. TVA's 2019 IRP considered this question in the context of future energy mix and found that incentivizing DER was not a preferred strategy. TVA has partnered with LPCs for decades to support renewable energy growth and informed customer choice in the Tennessee Valley. As discussed in the 2019 IRP, TVA plans to continue increasing its share of generation from renewable sources and decrease its air emissions.
VII. Socioeconomics Analysis			
73	TN SEIA	Another positive impact of the GPP is providing long-term contracts to purchase power backed by TVA, allowing people to finance systems through the savings. By eliminating the GPP program, TVA is preventing lower-income households eligible for financing from participating through the savings shown in the TVA contract. This impact presents a socioeconomic shift counter to what the EA suggests	See Appendix A for discussion of cost-shifting on lower-income households. TVA cites several studies that support TVA's conclusion that cost-shifting negatively affects lower-income households. One of the purposes behind TVA's proposed action to close the GPP program is to prevent future cost-shifting, which negatively affects lower-income households. In addition, installation of private-scale solar requires a large initial investment, which is paid off over decades. It is unlikely that many lower-income households would be able to reap benefits of the investment over 20 years. It is vital that TVA maintains low rates for the people we serve.
74	Warmath	Solar developers desire to build solar projects within the Tennessee Valley. By disincentivizing these projects, TVA is instead diverting valuable jobs, resources, and economic development to other states.	TVA recognizes that there could be some negative effect on solar installation companies. However, we note that BTM is projected to grow significantly, which would partially or fully offset some of these losses. In addition, development of utility-scale solar rather than private-scale solar would also create jobs. TVA does not believe that jobs would be diverted to other states, as we expect that local market forces would determine the number of jobs in different regional and local economies.

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75	Lightwave	The EA suggests that the QCN would continue to support and drive demand in lieu of the reimbursements offered by the GPP program. The data presented in the EA and the supplemental materials does not support this hypothesis and instead suggests that consumers would expect to get reimbursed for energy sent to the grid at, or near, their retail rate of electricity just like they would if they did an energy efficiency or energy conservation project.	In Section 4.1.3 of the EA, TVA cites several studies that suggest programs such as the QCN would increase BTM installations in Alternative C relative to Alternative B. TVA finds that these studies provide sufficient support for the conclusions in this EA.
76	SELC	A recent study conducted by Greenlink on behalf of the Southern Environmental Law Center shows that the avoided energy-only price TVA offers as compensation for distributed solar exports is significantly less than the cost of generating power from TVA's most expensive unit operating (i.e. the marginal unit) on an hour-by-hour basis...Thus, distributed solar exports could be used to offset TVA's use of more expensive marginal resources. Greenlink's analysis shows that TVA has been undervaluing and undercompensating distributed solar.	This study was not provided to TVA and was not readily available on the Greenlink or SELC website. Although TVA does not have the information necessary to fully review and address this comment, the information that was provided appears to support TVA's analysis of the GPP Program. The commenter notes that compensation for solar energy under the DPP Program is cheaper than using TVA's facilities on the margin. However, the proposed action concerns the GPP Program; the DPP Program would not be affected. The current GPP rates would be similar to or higher than TVA facility costs, as calculated by the commenter. This supports TVA's conclusions that continuation of the GPP Program would raise overall costs of electricity in the Valley and would cause cost-shifting, and supports TVA's decision to discontinue the GPP Program (while leaving the DPP Program unaltered).
77	Form Letter 1	TVA should compensate customers that generate solar fairly based on the benefits that distributed solar provides to all customers.	As discussed in the EA (Section 1.1), TVA is concerned that payments or incentives to participants in the GPP program places a cost burden on non-participants. TVA has provided compensation to participants since the program's initiation in order to stimulate investment in private-scale renewable energy. However, given the maturity of the market, TVA proposes to end this compensation to minimize cost-shifting to non-participants. Cost-shifting contradicts the principle of equity in energy pricing and creates an undue burden for non-participants. As a public power entity charged with keeping energy rates as low as feasible, TVA is transitioning away from incentivizing private-scale solar installations to minimize cost-shifting to those who cannot install onsite solar.
VIII. Environmental Impact Analysis			

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
78	CBD	While the 2019 GPP EA acknowledges that TVA power generates air pollution, including greenhouse gases, 2019 GPP EA at 22-23, the EA is deficient because it ignores the impacts that eliminating this program will have on the quantity of this pollution over the long-term.	TVA has revised Section 4.3 of the EA to address the potential impacts on greenhouse gas emissions relating to the proposal. The analysis now includes estimated emissions associated with changes in power generation.
79	CBD	NEPA requires that TVA consider the reasonably foreseeable environmental impacts of its decisions, and the fact that the GPP program may be providing a relatively small amount of power to TVA's territory is not license to ignore those impacts altogether.	TVA must consider the degree to which consumers would likely respond to each of the three action alternatives. The potential for environmental impacts to air quality, water quality, waste, or land use depends on subsequent decisions made by consumers in the region and how TVA provides energy and meets demand in response to those decisions. Predicting consumer response to the TVA proposal is complicated by numerous other factors that may influence consumer behavior. Consequently, the assessment of potential indirect and cumulative impacts on the physical environment involves some degree of speculation because the effects on the physical environment depend on decisions made by intervening consumers and are outside of TVA direct control. In the draft EA, TVA presented a discussion of the potential impacts to the environment in the context of whether consumers' decisions would impact the amount of power generated by TVA. In the draft EA, TVA discussed whether it would have to alter its power operations if the portion of electricity that is generated under the GPP program would disappear. TVA power system operators reviewed the proposal and found that the amount of GPP power on the system at any given time and the amount of power that would be generated in the future to make up for the closure of the GPP program, is not substantial enough to affect TVA's operation of its power system in a discernible way. Other factors affecting TVA power supply requirements are much more likely to influence TVA energy production (e.g., weather conditions). TVA believes that this conclusion, namely that the GPP program closure would not affect the operation of the TVA system in a discernible way, provides critical perspective to its review of potential environmental impacts. If the amount of power is so small that TVA operations would not be affected, it is reasonable to conclude that the proposal would have minimal impacts.

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			After considering public comments, TVA revised the environmental analysis to provide additional perspective. The revised analysis addresses the impacts associated with the amount of electricity that TVA generates from the GPP program. Relying on general assumptions that reflect a worst-case scenario, the new analysis addresses what impacts can be attributed to this small amount of electricity if it were generated using other generation sources (e.g., coal, natural gas facilities).
80	CBD	It violates NEPA for TVA to have made absolutely no attempt to quantify the amount of pollution that could have been avoided had TVA allowed this generation to come online, rather than stifling it by eliminating the GPP program. In short, this decision will have concrete environmental impacts that must be addressed.	TVA has revised Chapter 4 of the EA to address the potential impacts relating to the proposal. As noted above, although TVA power system operators do not foresee that the proposal would alter generating plant operations in any discernible way (thereby rendering the assessment of potential impacts difficult), TVA has provided additional analysis in the EA that estimates impacts associated with the amount of power that would be generated under the GPP program in this worst-case scenario.
81	SELC	To comply with NEPA, TVA should use the social cost of carbon to monetize the environmental effects of CO2 emissions.	TVA considers the GHG emissions analysis provided in the EA to be a reasonable proxy of the proposed actions' contribution to climate change. TVA believes that the analysis serves as a more appropriate measure of climate change impacts and their significance under NEPA than the use of the Social Cost of Carbon metric. The SCC metric is not appropriate or informative because (1) the lack of consensus on the appropriate discount rate leads to significant variation in outputs, rendering those outputs unreliable and meaningless; (2) the SCC tool does not measure the actual incremental impacts of a project on the environment; and (3) there are no established criteria identifying the monetized values considered significant for NEPA purposes. In comparison, the GHG emissions analysis provided is a far more reliable/relevant proxy.

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82	CBD	NEPA requires that TVA consider the reasonably foreseeable environmental impacts of its decisions, and the fact that the GPP program may be providing a relatively small amount of power to TVA's territory is not license to ignore those impacts altogether.	The fact that the GPP program provides a relatively small amount of power to TVA's territory is an important consideration in determining the potential impacts of the proposal. In its analysis, TVA concluded that there would essentially be no discernible change in its power generation operations at any given time due to the reduction in GPP generation. TVA's conclusions were based on internal review by TVA power system operators, considering the relatively small levels of power generated by GPP and other more influential factors influencing how TVA operates it power operations (e.g., weather or economic trends).
IX. Cumulative Impacts			
83	SELC	TVA failed even to take a hard look at the cumulative impacts of the alternatives it did consider, particularly the effect that stifling the distributed solar industry would have on greenhouse gas emissions and climate change.	TVA has revised Section 4.3 of the EA to address the potential impacts on GHG emissions relating to the proposed action in the worst-case scenario. TVA has also updated the discussion of cumulative impacts in Section 4.7. TVA has provided the greenhouse gas emissions analysis in the air quality section of the EA by estimating the amount of GHG emissions. Because the proxy analysis of effects of GHG emissions is essentially a cumulative effects analysis, the analysis in Section 4.3 adequately addresses the cumulative impacts for climate change (consistent with previous NEPA guidance from CEQ on addressing climate change).
84	SELC	TVA's cumulative impacts analysis is incomplete, conclusory, and perfunctory.	TVA has revised the cumulative impacts analysis section in Section 4.7 in response to public comments on the draft EA.
85	SELC	TVA's analysis of past programs is inadequate because it fails to assess the impacts of the actions it identified…TVA provides no justification for why it could not analyze the effects of the federal programs.	TVA has revised the cumulative impacts analysis section in Section 4.7 in response to public comments on the draft EA. TVA provides additional analysis relating to actions identified in the section as well as to the incremental impacts of the TVA proposal when considering other federal programs.

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86	SELC	TVA fails to identify recent TVA-led actions that would also affect the adoption of DERs in the Valley, except for a vague reference to TVA's economic development efforts, rate changes, and TVA energy efficiency programs	TVA has revised the cumulative impact analysis discussion in the EA (Section 4.7). TVA provides additional discussion of past, present, and foreseeable TVA actions that may affect DER adoption.
87	SELC	The cumulative impacts of the No Action, No Replacement, and No Compensation Alternatives must include analysis of the increased environmental impacts above baseline conditions because it would encourage TVA to run existing coal or gas generation at higher rates or to purchase or build additional generation instead of relying on DER	As stated in the EA, the potential amount of future GPP generation is a small portion of TVA's overall generation and would result in no discernable changes to TVA operations. Furthermore, TVA expects at least some of future GPP participants to install BTM solar instead if the GPP Program is closed, which would offset potential environmental impacts. Finally, future GPP participation may also be offset by utility-scale solar. Therefore, we disagree that TVA would have to run existing coal or natural gas at higher rates. Nonetheless, for additional context, TVA added discussion in Sections 4.3, 4.4. and 4.6 of the EA that quantify environmental impacts under the worst-case assumption that TVA would run existing coal or natural gas facilities more to offset the DER generation potentially lost from closure of the GPP program.
88	SELC	Where TVA addresses the cumulative impacts of the proposed alternatives, it is in general terms that are conclusory and free of analysis...Generic, specious analysis of cumulative impacts does not satisfy the agency's obligation to take a hard look.	TVA has revised the cumulative impacts analysis in Section 4.7 of the EA in response to public input on the draft EA. Additional discussion and analysis is provided relating to actions identified in the section. As noted therein, given that TVA's proposal addresses energy production in the Valley as well as the market for renewable energy resources, there are other past, present, and reasonably foreseeable future actions relevant to the consideration of cumulative impacts associated with TVA's proposal. TVA utilizes its Integrated Resource Planning process to consider cumulative market and social forces that programs addressing renewable energy resources, expansion of DER, energy efficiency, as well as other relevant inputs, have on TVA's energy generation and to provide direction on how to best meet future electricity demand. The 2019 IRP provides an important discussion regarding past, present, and foreseeable future activities that influence energy use, and the EIS that accompanied it describes cumulative impacts from combining different scenarios and strategies (TVA 2019a; TVA 2019b).

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89	SELC	Greenhouse gas emissions and climate change are absent from the cumulative effects analysis. The impact of greenhouse gas emissions on climate change is precisely the kind of cumulative impacts analysis that NEPA requires agencies to conduct." Because we are so close to the tipping point where we will no longer be able to slow or stop the effects of climate change, consideration of greenhouse gas emissions is vital.	As noted in Section 4.3 of the EA, TVA engineers do not believe that discontinuation of the GPP Program will have any discernable impacts on the operation of TVA's power system, meaning that there would be no discernable change in air emissions. Nonetheless, TVA has revised the air resources analysis in Section 4.3 of the EA and includes estimates of GHG emissions associated with TVA's proposal. Given the cumulative nature of climate change effects and the proxy emission analysis conducted by TVA, a separate discussion of the cumulative impacts associated with GHG emissions is not necessary if the direct and indirect effects are addressed, as TVA has done in air resources section of the EA (Section 4.3).
90	SELC	Courts have made it clear that a federal entity must address an action's potential effects on greenhouse gas emissions, particularly in a situation where it is a given that the No Action, No Replacement, or No Compensation Alternative in conjunction with related past and future programs "will affect the level of the nation's greenhouse gas emissions and impact global warming." Courts have found this analysis inadequate if an agency's analysis fails to grapple with the "incremental impact that those emissions will have on climate change or the environment more generally in light of other past, present, and reasonably foreseeable actions." As shown in the EIA analysis laid out above, the effect of the No Compensation and No Replacement Alternatives in addition to other federal actions could be significant....Because the Draft EA is devoid of any analysis of greenhouse gas emissions and climate change, TVA has failed to comply with NEPA.	As noted in Section 4.3 of the EA, TVA engineers do not believe that discontinuation of the GPP will have any discernable impacts on the operation of TVA power system, meaning that there would be no discernable change in air emissions. Nonetheless, TVA has revised the air resources analysis in Section 4.3 of the EA and includes estimates of GHG emissions associated with TVA's proposal. Given the cumulative nature of climate change effects and the proxy emissions analysis conducted by TVA, a separate discussion of the cumulative impacts associated with GHG emissions is not necessary if the direct and indirect effects are addressed, as TVA has done in air resources section of the EA (Section 4.3).
X. NEPA Process			

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91	Sierra Club	The EA refers to "market research" but failed to attach any such documents to the EA	After the draft EA was released for public review and comment, TVA received a request under the Freedom of Information Act requesting this information. On October 28, 2019, TVA responded to these requests for the market research referenced in the draft EA by posting the supporting information on the TVA project webpage. While the information serves as background information relevant to TVA's proposal, the information is not critical to the economic or environmental analysis included in Chapter 4 of the EA. The information will remain posted on the TVA webpage.
92	SELC	To the extent TVA attempts to tier to its 2019 IRP's assessment of cumulative impacts to supplement this paltry analysis, that attempt is unfounded. Tiering is only permissible for an issue that was considered in prior NEPA review. Tiering to the 2019 IRP is not permitted because the 2019 IRP assumed only that the GPP program would be terminated at the end of December 2019 and did not analyze impacts associated with the No Action or No Compensation Alternatives.	TVA references the cumulative impact analysis in the 2019 IRP EIS in section 4.7 (Cumulative Impacts) of the GPP EA because the discussion is relevant to the GPP proposal. The GPP Program is addressed in the IRP cumulative impact analysis, along with discussion of rate structure changes, pricing changes, and other policies that may affect DERs. Incorporating relevant information by reference in such a manner is encouraged in order to reduce the bulk of analysis (40 CFR 1502.21). TVA has revised the cumulative impact analysis section of the EA; included in the revision is deletion of the sentence in the cumulative impact analysis section that suggests that the analysis is "tiered" from the IRP EIS.
93	TN SEIA	Did there need to be an EA before prior changes were made to the GPP program?	Prior to implementing changes to pricing in 2018, TVA considered whether additional environmental review was necessary. TVA determined that the pricing adjustments fell within the ambit of the existing GPP program and that there was no potential for an incremental impact on the human environment. The GPP program was modeled after and replaced the GP Pilot Program. As envisioned in the design of the GPP program approved by the Board in 2011, the premium rates were phased out for new participants in 2016. As the cost of solar installations has continued to decrease and the DER market has evolved to offer lower cost renewable options, TVA has adjusted the project rates accordingly.

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94	Sierra Club, SACE, SELC, TenneSEIA	The NEPA requires TVA to carefully assess impacts on the human environment which would result from an action. Here TVA made a decision and then prepared an EA to offer an (insufficient) rationale for its action. TVA has issued the draft EA eight months after the Board of Directors decided to terminate the GPP program. Rather than improving its decision-making process through an objective analysis, the draft EA represents a post-hoc rationalization for a decision TVA's Board of Directors has already made and TVA has already implemented. TVA's actions have thereby limited the range of reasonable alternatives and the "no action alternative" has been rendered meaningless TVA has limited the choice of reasonable alternatives because the Board has already made its decision to terminate the GPP program, and TVA has essentially implemented that decision TVA has limited the choice of reasonable alternatives because the Board has already made its decision to terminate the GPP program, and TVA has essentially implemented that decision.	At its February 2019 meeting, the TVA Board of Directors voted to close the GPP Program to new applications effective January 1, 2020, and to delegate authority to TVA's CEO to design and implement one or more replacement programs that are consistent with the terms of the revised TVA metering standard. These decisions were made contingent upon the satisfactory completion of appropriate environmental reviews. Since the Board decision, TVA leadership directed staff to explore GPP replacement options, consistent with Board direction. TVA has developed a replacement proposal and has prepared an EA that analyzes the potential impacts of the proposal. The EA also includes an alternative for the continuation of the GPP program as well as implementing no replacement program(s). Consistent with 40 CFR 1506.1(a), TVA has taken no action since the February meeting relating to the GPP program's future that would have an adverse environment impact or limit the choice of reasonable alternatives. Because the Board decision was contingent upon completion of the appropriate environmental review, TVA is not precluded from selecting and implementing any of the alternatives analyzed in the EA.
95	City of Knoxville, Metropolitan Government of Nashville and Davidson County	We respectfully request that TVA select Alternative A) and continue the GPP program unchanged for a limited amount of time.	Comment noted. As discussed in the EA, TVA has evaluated the GPP since it began in 2011. Continuing the GPP program, even for a limited period of time, would be counter to the three-fold purpose and need that forms the basis of TVA's proposed action.
96	TN SEIA	It is clear that the GPP should be continued through 2020 at a minimum. This allows time for an updated EA which includes details on how it will meet the needs and safety/legal requirements presently being met by the GPP program.	Comment noted. TVA, however, disagrees that additional time is needed for TVA to implement any of the alternatives reviewed in the EA.

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97	CBD	TVA must consider all of its efforts to stifle distributed solar development (e.g., rate changes, pricing, integrated resource planning) in a single Environmental Impact Statement (EIS).	TVA disagrees that the purpose of this proposal is to discourage distributed solar development, nor does it agree that past actions taken by TVA that are identified by the commenter (e.g., rate changes, pricing adjustments, integrated resource planning) are part of a single initiative to stifle distributed solar development. The GPP proposal is independent of those activities. All of the actions identified by the commenter, except the current GPP proposal, are past actions that in most cases have been implemented or partially implemented already. These decisions precede TVA's consideration of the GPP proposal. NEPA requires consideration of past actions when addressing cumulative impacts but does not require agencies to return to past actions to reconsider them based on future proposals. TVA's 2019 Integrated Resource Plan (2019 IRP), which guides how TVA can best meet future demand for power, identifies the potential for significant solar expansion over the next 20 years. The 2019 IRP was developed with an associated EIS that addressed the potential environmental impacts associated with such development. The IRP's cumulative impact discussion (section 3.10 of Volume II, IRP EIS) addresses past actions such as rate changes, rate adjustments, and the GPP Program. TVA did not find that the associated cumulative impacts would result in significant impacts. Notably, the analysis indicates that past and ongoing GPP activities are "unlikely to influence the rate of adoption of DER across the Tennessee Valley." (2019 IRP, Volume II, page 65).
98	SACE	TVA’s recent 2019 IRP is substantially misleading with respect to TVA’s planning and intent regarding solar development.	TVA disagrees that the purpose of this proposal is to discourage distributed solar development, nor does it agree that actions taken by TVA are hostile to distributed solar development. TVA addressed the comments by SACE regarding the IRP models and analysis in Appendix F of the 2019 IRP, Volume II Final EIS.

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99	SACE	The limited, 30-day comment period was wholly inadequate for informed public scrutiny of the Draft 2019 GPP EA as required by both the TVA Act and the National Environmental Policy Act (NEPA)2 -- particularly when key supporting documentation, TVA's market study dated October 2018, was only made available late in the day on October 28, 2019, leaving 9 business days for review and incorporation into comments.	For environmental assessments, TVA normally provides a 30-day period for review and comment by the public. Based on TVA's experience, this period of time is sufficient for the public to review and provide comments on a draft EA. TVA is encouraged with the high number of public comments received from the public, organizations, and stakeholders. The duration of the comment period has helped facilitate timely and meaningful public input. During the review period, TVA received requests for additional information under the Freedom of Information Act (FOIA). TVA responded to the request by providing the information on the TVA project webpage as soon as possible, and well in advance of the time period applied under FOIA. TVA notes that the commenter has provided in a timely manner substantive comments relating to the additional information.
100	SELC	Termination and replacement of the GPP program would have a significant effect on the human environment and would have a significant effect on public health and safety.	TVA acknowledges that the Promote DER strategy analyzed in its 2019 IRP would result in reduction in air pollutants and be environmentally beneficial. It is not reasonable, however, to suggest that the end of the GPP program would equate to the loss of all beneficial impacts associated with fully implementing the IRP's strategy to Promote DER. The Promote DER strategy, as stated in the IRP, represents a much broader strategy than simply this program. TVA addresses comments regarding the commenters' net metering alternative elsewhere in this Appendix. The EA discloses that the GPP program represents a very small portion of potential DER. The analysis does not identify significant public health or safety impacts associated with ending the program and providing a new service offering, nor significant environmental impacts. Given the global scope of climate impacts associated with GHG emissions, TVA is unable to link changes in emissions associated with any of its actions with any particular climate impact. TVA addresses comments regarding the need for an EIS based on GHG emissions elsewhere in this Appendix.

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101	SELC	Without that analysis, TVA cannot justify its decision to prepare an EA rather than an EIS. Moreover, as Citizen Groups outlined above, the cumulative effects of an appropriate range of reasonable alternatives would have significant cumulative effects.237 Therefore, this action would have significant cumulative effects and should be analyzed in an EIS. Without that analysis, TVA cannot justify its decision to prepare an EA rather than an EIS. Moreover, as Citizen Groups outlined above, the cumulative effects of an appropriate range of reasonable alternatives would have significant cumulative effects.237 Therefore, this action would have significant cumulative effects and should be analyzed in an EIS.	TVA has revised section 4.3 of the EA to provide additional analysis relating to potential impacts associated the GHG emissions. The analysis incorporates the use of project GHG emissions as a proxy for assessing the potential effects on climate change. TVA agrees that rising global atmospheric GHG emission concentrations are significantly affecting the climate. However, all GHG emissions contribute to cumulative climate impacts, and given the global scope of these impacts, TVA is unable to link emissions increases or decreases resulting from any of its actions to any particular climate impact in a specific location or region. Instead, the proxy analysis conducted by TVA is a practical and effective way of assessing the cumulative potential effects on climate change. Further, as noted in Section 4.7 of the EA, TVA utilizes its Integrated Resource Planning process to consider cumulative market and social forces that its programs, as well as other relevant inputs, have on TVA's energy generation and to provide direction on how to best meet future electricity demand. The 2019 IRP provides an important discussion regarding past, present, and foreseeable activities that influence energy use, and the EIS that accompanied it describes impacts from combining different scenarios and strategies. Analysis in the 2019 IRP EIS shows that quantified estimations of GHGs (CO2 averages and rates) resulting from implementation of the 2019 IRP would result in "continued, significant, long-term reductions in CO2 emissions from the generation of power marketed by TVA." (2019 IRP EIS, section 5.5.2.2). These findings are relevant to the proposal because the IRP analysis incorporates minor changes within DER programs such as the GPP.

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
102	SELC	Because TVA failed to adequately analyze the potential cumulative effects of the termination and replacement of the GPP program, it is impossible for TVA to know whether a change in greenhouse gas emissions would "be a significant step toward averting the 'tipping point' and irreversible adverse climate change.	TVA has revised section 4.3 of the EA to provide additional analysis relating to potential impacts associated the GHG emissions. The analysis incorporates the use of project GHG emissions as a proxy for assessing the potential effects on climate change.

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
103	SELC	Because Citizen Groups present a substantial dispute about the size and effect of the analyzed alternatives and those alternatives TVA failed to consider, this action is controversial and should be analyzed in an EIS.	TVA has revised the discussion on the potential impacts of the proposal and has provided additional information relating to the climate change concerns raised by the commenter. Comments raised concerning the alternatives considered by TVA and TVA's purpose and need for the proposal are addressed elsewhere. TVA considers both context and intensity relating to its proposal when determining whether an environmental impacts statement is required. There is no substantial dispute regarding the EA’s consideration of reasonable alternatives. TVA has explained in the record why certain alternatives suggested by commenters are not reasonable alternatives. Nor is there a substantial dispute about the effect of the alternatives analyzed in the EA. TVA does not dispute the importance of the rising global atmospheric GHG emission concentrations that are significantly affecting the climate. However, all GHG emissions contribute to cumulative climate impacts. Given the global scope of these impacts, TVA is unable to link emissions increases or decreases resulting from any of its actions to any particular climate impact in a specific location or region. As noted in Section 4.7 of the EA, TVA utilizes its Integrated Resource Planning process to consider cumulative market and social forces that its programs, as well as other relevant inputs, have on TVA's energy generation and to provide direction on how to best meet future electricity demand. The 2019 IRP provides an important discussion regarding past, present, and foreseeable activities that influence energy use, and the EIS that accompanied it describes impacts from combining different scenarios and strategies. Analysis in the 2019 IRP EIS shows that quantified estimations of GHGs (CO2 averages and rates) resulting from implementation of the 2019 IRP would result in "continued, significant, long-term reductions in CO2 emissions from the generation of power marketed by TVA." (2019 IRP EIS, section 5.5.2.2). These findings are relevant to the proposal because the IRP analysis incorporates minor changes within DER programs such as the GPP.

#	COMMENTER(s)	COMMENT STATEMENT OR SUMMARY OF STATEMENTS	TVA RESPONSE
104	SELC	TVA has significantly undervalued distributed solar and has taken steps to reduce customer interest in investing in it. The true purpose of TVA's proposal is to continue to undermine DER in the Valley. Accordingly, a substantial dispute exists regarding the nature of TVA's action and an EIS is necessary	The comment expresses disagreement with TVA's discussion in the EA of the underlying purpose and need for the TVA proposal. While commenters dispute this discussion of TVA's purpose, the information provided does not represent a substantial dispute regarding the "nature" of TVA's proposal. TVA has explained (see Appendix A) why the GPP program in its current form results in cost-shifting. The studies cited by the commenters do not contradict this conclusion. And TVA has provided a litany of other studies that support cost-shifting. Moreover, cost-shifting is only one of three factors that form the purpose and need for TVA's proposed action. TVA is not working to undermine DER adoption in its service area. TVA is considering renewable energy solutions to meet the energy needs of the Valley that are more cost-effective than private-scale solar installations (EA, Section 1.1). After extensive study by TVA planners, TVA considers utility-scale solar to be a more viable option for generating renewable energy when compared to building and commissioning other generation assets from any source, and TVA plans to increase its investment in utility-scale solar generation in the coming decades (TVA 2019a). Utility-scale solar benefits from economies of scale, where the average cost per unit of energy produced decreases as the size of the generation facility increases.
105	SELC	Terminating the GPP program has uncertain, or unique or unknown risks…TVA is attempting to predict customer behavior in a way that it acknowledged it is unable to do accurately…Because of the uncertain and unknown risks associated with TVA's action, TVA must complete an EIS	TVA acknowledges in the EA's analysis that projections include some uncertainty and has provided reasonable analyses to provide meaningful projections. Predicting future consumer behavior is difficult and TVA's economic analysis and methodology is generally accepted within the economic community to determine foreseeable impacts of the proposal. In its analysis, TVA does not identify substantial uncertainties or unique or unknown risks to the human environment under any of the alternatives considered.