Comments in response to Tennessee Valley Authority's November 16, 2010 release of its Draft Integrated Resource Plan and accompanying Environmental Impact Statement (No. 20100379) for public review and comment

Submitted by the Southern Alliance for Clean Energy

November 15, 2010

The Southern Alliance for Clean Energy (SACE) respectfully submits these comments in response to TVA's request for review and comment on its Draft Integrated Resource Plan (IRP) and accompanying Draft Environmental Impact Statement (EIS).

The IRP process is necessary to ensure TVA's ability to meet the Tennessee Valley's future energy demand while fulfilling its statutory mandates to steward the environment, support economic development and be a leader in technological innovation. The current planning process, including the formation of the Stakeholder Review Group, is a significant step forward not only for TVA's planning processes, but also for TVA's relationship with the nine million people it serves.

SACE strongly encourages TVA to establish a policy of updating its resource plan on a biannual basis, with major updates (including a programmatic EIS) occurring every four years. Prevailing practice among major utilities is to update resource plans every 1-3 years, which provides transparency and consistency in responding to changing economic and policy circumstances. Furthermore, regular review and amendment of TVA's IRP will ensure continued dialogue between TVA and its constituents. In short, an iterative planning process ensures TVA the best plan for meeting future energy demand.

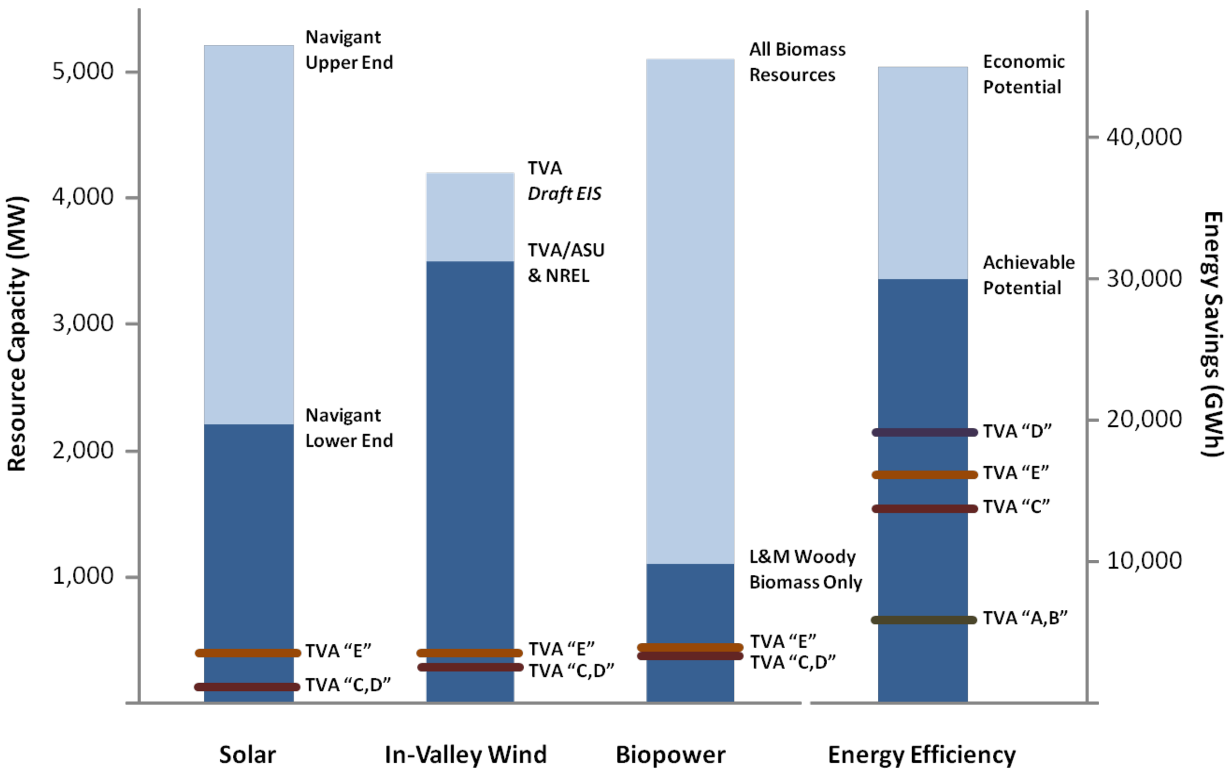
TVA's general framework for analysis is consistent with national best practices and provides a structured format to stress-test various resource portfolios. We also acknowledge that TVA leadership and staff have been candid and responsive to stakeholder input and requests for additional information (after occasional delays and disagreement), making our involvement with TVA's Stakeholder Review Group (SRG) worthwhile. We commend TVA for these accomplishments.

However, SACE has identified several shortcomings of the Draft IRP and EIS, most of which can be addressed within TVA's existing planning framework. Several of these shortcomings, however, are symptoms of broader concerns that we have regarding TVA operations. These issues may limit the effectiveness of the IRP process.

TVA maintains a general lack of interest in renewable energy resources, and has not committed to relying on energy-efficiency as a long-term resource.

TVA has yet to make any meaningful commitment to developing the Valley's renewable energy resources at a utility scale. TVA's failure to conduct the necessary analysis to fully define the Valley's renewable energy resources, discussed in detail below, is a symptom of TVA's overall lack of commitment to developing these resources. While TVA's various strategies were designed with the intent of studying a wide range of resource options, renewable energy potential is barely varied among the strategies, and the full range of energy efficiency potential is not explored (Figure 1).

Figure 1: TVA Strategies Do Not Fully Explore Potential Renewable and Energy Efficiency Resource Opportunities



Renewable energy resources in strategies "A" and "B" rely primarily on out-of-Valley wind resources and a small amount of capacity from TVA's Generation Partners program. Resource capacity details are described below (Figures 3, 4, 5, 21 and 23).

Unlike TVA's recent progress in developing energy efficiency programs, TVA has yet to commit any significant budget or staff to developing the Valley's renewable energy resources. Further, TVA's August 20th announcement of its new vision made no mention of renewable energy resources, leaving many stakeholders wondering when, if ever, TVA will recognize the potential of these resources to meet a significant portion of the Valley's future electrical demand. Irrespective of whether TVA develops utility scale renewable generation internally or via power purchase agreements (PPAs), it will require dedicated staff and budget to assess renewable resource costs and benefits and to manage TVA's resource development efforts. Without these commitments, the role of in-Valley renewables in meeting TVA's future energy demand will continue to be undervalued regardless of the IRP process.

TVA is over-enthusiastic about increasing its nuclear generating capacity.

TVA has accelerated its nuclear program prematurely, relying on analysis that is unsound for reasons that are similar to many of the detailed concerns described in our comments on the Draft IRP and EIS. At the August 20th TVA Board meeting, TVA stated the goal of being the national leader in nuclear power production and committed nearly $250 million towards completing Bellefonte Unit One. TVA's rationale for these commitments, in spite of the ongoing IRP process, was that preliminary IRP results indicate a strong likelihood that Bellefonte Unit One would be necessary to meet demand in 2018[1] and would facilitate higher levels of coal plant retirements.[2] However, with proper levels of efficiency and renewable energy[3], TVA could achieve aggressive levels of coal-plant retirements and meet energy demand beyond 2018 while delaying, or possibly avoiding altogether, the need to construct additional nuclear reactors. .

The Draft IRP lays out several portfolios that include large-scale coal-plant retirements without additional nuclear reactors before 2022 if ever. Figure 2 compares the timing of Bellefonte Unit One under the Draft IRP's Strategy B, TVA's Baseline, and Strategy C, the diversity-focused strategy.

Figure 2: Timing of Bellefonte Unite One Under Strategies B and C

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Draft IRP Baseline
Strategy B	2018	2020	N/A	2018	2018	N/A	N/A
Strategy C	2018	2022	N/A	2018	2022	N/A	2018

TVA, *Stakeholder Review Group Working Session*, presented to the Stakeholder Review Group, July 20, 2010.
Note: Constraints on the Draft IRP's other strategies, i.e. Strategy A's prohibition on new supply-side generation and Strategy E's prohibition on nuclear units before 2022, did not allow for a proper comparison.

Strategy C only adds Bellefonte Unit One in 2018 under the Baseline Scenario and Scenarios 1 and 4, the three highest load growth strategies.[4] Under the moderate (and more realistic)

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[1] TVA, *Draft IRP,* p. 110 – 111.
[2] See, for example: TVA, *Draft Supplemental Environmental Impact Statement: Single Nuclear Unit at the Bellefonte Plant Site,* November, 2009, p. 12 – 14.
[3] The Draft IRP's flawed treatment of efficiency and renewables is discussed at length later in these comments.
[4] TVA, *Scenarios for IRP Project*, slide 8. Presented to the Stakeholder Review Group, December 9, 2010.

load growth conditions of Scenarios 2 and 5, Bellefonte Unit One is delayed until 2022. Strategy C includes 1,000 MW *more* coal plant retirements and nearly twice as much energy efficiency, demand response and renewable energy than Strategy B.[5]

It is also worth noting that Strategy E: EE/DR and Renewables Focused Strategy, while not directly comparable due to its set prohibition on new nuclear units before 2022, is almost identical in generation additions to Strategy B other than Bellefonte Unit One.[6] However, Strategy E includes 3,000 MW more coal plant retirements and almost three times as much efficiency, demand response and renewables as Strategy B.

These results indicate that reduced load growth due to energy efficiency and demand response, coupled with modest levels of renewable energy resources, can allow for significant levels of coal plant retirement without additional nuclear units.[7] The Draft IRP simply does not adequately consider whether an even higher, yet feasible, level of energy efficiency and renewable energy would be a better path forward than nuclear energy (even from TVA's current perspective). While there are several additional factors at play in this analysis, we question TVA's decision to continue pursuing this high cost, high risk resource in spite of several indications that it is not necessary.

TVA's Board of Directors is not compelled to act in accordance with the IRP.

While SACE supports this IRP process, we continue to be concerned because the TVA Act does not require the TVA Board of Directors to act in accordance with IRP results. Unlike the Bonneville Power Administration where the Administrator is statutorily compelled to act in accordance with the Northwest Power Council's IRP, the TVA Board of Directors has sole discretion in its decision-making, potentially impacting the current IRP's effectiveness.

This is not meant to be a criticism of current TVA Board members. However, Board members change over time, and inconsistent strategic direction has hampered TVA's past ability to meet electricity demand while fulfilling its statutory environmental and economic directives. Given the significant investments of time and effort by TVA staff, the Stakeholder Review Group and others who have engaged in this process to draft a sound strategy, the TVA Board of Directors should be compelled to act in accordance with the final IRP in the absence of compelling justification for diverting from the IRP's recommendations.

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[5] TVA, *Draft IRP,* p. 103.
[6] TVA, *Draft IRP*, p. 145 – 148.
[7] The additional sensitivity runs that TVA plan to conduct between now and the release of the final IRP may shed further light on how efficiency and renewables can delay, or even obviate the need for additional nuclear generation.

The Draft IRP has a number of shortcomings, particularly with respect to renewable energy, energy efficiency, and load forecasts that should be addressed.

In support of the general concerns described above, SACE has identified several shortcomings in the Draft IRP and EIS that should be addressed. In the interest of brevity, SACE is not commenting on areas of the IRP where we are in general agreement with TVA. Furthermore, in cases where we have a different interpretation of data or methods, but we have not identified any path in which these differences would likely affect the IRP's results in a meaningful manner, we are also refraining from comment. However, these differences may be important in the context of specific programmatic or policy decisions.

The shortcomings SACE has identified are discussed below. In most cases, this discussion reflects a refinement of comments and input provided by SACE during the Stakeholder Review Process. To some extent, our comments also reflect new reactions that were only possible after receiving the results of the analysis and consulting with outside experts to validate assumptions or methods used by TVA.[8] SACE urges TVA to revise its Draft IRP and EIS in response to our concerns to ensure a sound strategy for meeting the Valley's future electricity needs.

1. TVA has not accurately assessed the Valley's potential for renewable energy resources. As a result, these resources are undervalued in the Draft IRP and EIS.

Even though TVA's "Strategy E" is characterized as "EE/DR and Renewables Focused," TVA has not evaluated any resource strategy that includes truly aggressive level of renewable energy resources. For some resources, TVA does not appear to have completed the appropriate analysis to fully quantify these resources. For other resources, TVA has inexplicitly restricted use of the identified resources. SACE estimates of feasible potential, confirmed by independent analyses, demonstrate how TVA could develop significantly higher levels of renewable energy resources over the course of the planning period.

[8] SACE gratefully acknowledges the input of experts from Crossborder Energy, Larson & McGowin, Navigant Consulting, and Optimal Energy who provided analysis or advised us on aspects of our participation in the Stakeholder Review Group process and the review of the Draft IRP and EIS.

a. The Draft IRP's assessment of in-Valley renewable energy resources is incomplete and inaccurate.

TVA's Draft IRP and EIS lack the necessary analysis to reasonably assess the potential for developing the Valley's renewable energy resources. One reason TVA offers for its weak analysis of in-Valley renewables is that it does not have the in-house expertise to develop these resources.[9] TVA's analysis of in-Valley renewable energy resources is incomplete because:

- A comprehensive resource potential study was not completed to determine the feasible potential of the Valley's wind, solar and biomass resources;
- No integration study was completed to determine how the Valley's renewable resources could be integrated into TVA's transmission and distribution system;
- TVA has not completed an analysis of the potential ancillary benefits or costs of integrating significant levels of in-Valley renewable energy resources, including:
    - The potential benefits regarding grid stability;
    - The potential efficiency gains in transmission and distribution associated with higher levels of distributed generation;
    - The economic benefits of higher levels of in-Valley investments; and
    - The reduced costs associated with greenhouse gas and air pollutant mitigation.

We recommend that TVA re-consider its limitations on renewable energy resources, including a full assessment and characterization of the cost-effectiveness of renewable energy resources in the context of its IRP.

Without comprehensive resource potential and implementation assessments encompassing the entire 20-year planning period, TVA has arbitrarily limited in-Valley renewable resources to model inputs that reflect only a small fraction of their potential. These defined incorrectly imply a very limited potential for in-Valley renewable energy resources.

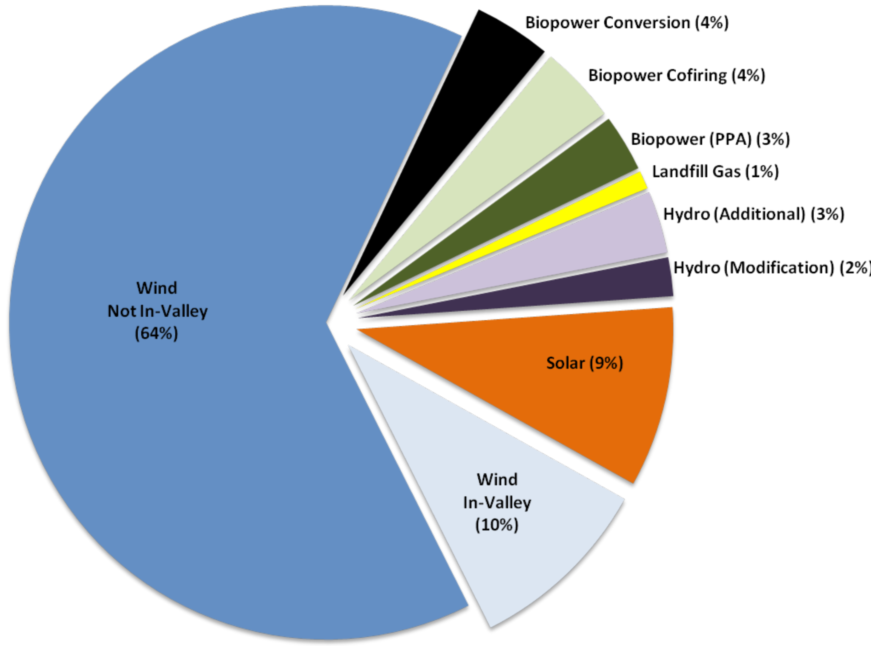
The Draft IRP considers a maximum of about 1,120 MW by 2029 of in-Valley renewable energy from solar, wind and biomass resources.[10] This maximum development path is "Strategy E" in the Draft IRP, the EE/DR and Renewables Focused Strategy (Figure 3), including:

- In-Valley solar: approximately 350 MW
- In-Valley wind: approximately 360 MW
- In-Valley biomass (including co-firing, conversions and power-purchase agreements): approximately 410 MW

In contrast, this strategy anticipates approximately 2,450 MW of out-of-Valley wind.

[9] *Draft IRP*, p. 70 and 71.
[10] The entire maximum renewable energy package, including out-of-Valley resources, consists of approximately 3,800 MW.

Figure 3: TVA's IRP Strategy E Renewable Energy Portfolio (by 2029)



TVA, *IRP Renewable Energy Additions*; provided to IRP Stakeholder Review Group, June 2010.
Note: Total capacity of this renewable energy package is approximately 3,800 MW by 2029. All values are approximate as estimated from charts provided by TVA.

It is clearly appropriate for TVA to aggressively develop out-of-Valley wind resources (providing that appropriate transmission development is feasible). Nevertheless, available independent analysis, summarized in Figure 4 below, confirms that the realistic achievable potential for in-Valley wind, solar and bioenergy resources is significantly higher than what is represented by the Draft IRP's most aggressive proposed portfolio.

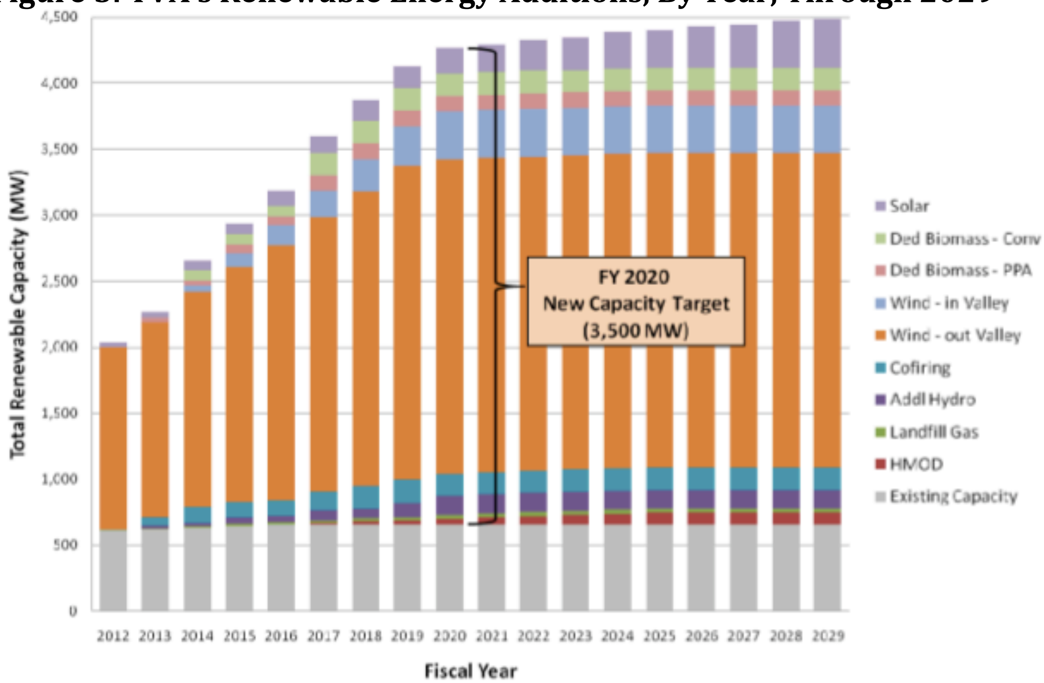
Figure 4: The Draft IRP's Maximum Development of in-Valley Renewable Energy Compared with SACE Estimates of Feasible Potential by 2029

Resource	**TVA Maximum Capacity** (MW)	**SACE Feasible Potential** (MW)
Solar Photovoltaic	350	2,200 – 5,200
In-Valley Wind	360	3,500 +
Biopower	410	1,100 – 4,000
Total	**1,120**	**6,800 – 12,700**

TVA considered hydroelectric, out-of-Valley wind, and other renewable energy resources in its Draft IRP. This table highlights areas where SACE feels TVA should improve its analysis. The details of SACE's feasible potential estimates are discussed below.

Furthermore, TVA effectively limits renewable energy development to the first half of the planning period. None of TVA's strategies consider substantial renewable energy development after 2020. For example, TVA's most aggressive renewable energy portfolio adds 3,500 MW of renewable energy by 2020, but only about 300 MW between 2020 and 2029 (Figure 5). As a result, TVA's resource options are unreasonably constrained in the 2020-2029 timeframe. These constraints potentially leave significant amounts of cost-effective renewable energy undeveloped and artificially skew the model towards other resource options such as natural gas and nuclear.

Figure 5: TVA's Renewable Energy Additions, By Year, Through 2029



TVA, *IRP Renewable Energy Additions*, provided to IRP Stakeholder Review Group, June 2010.

In all, TVA has failed to conduct a proper analysis of in-Valley renewable energy resources, leading to improper assumptions about the potential for these resources to contribute to meeting TVA's energy demand over the planning period. As a result, the Draft IRP and EIS are skewed against in-Valley renewable energy resources and in favor of more traditional and potentially more costly generation resources. Independent analysis of the Valley's potential for solar, wind and biomass resources clearly indicates significantly higher potential than what is represented in the Draft IRP.

b. Solar Photovoltaic Resources

The Draft IRP's defined model inputs for in-Valley solar PV represent only a fraction of this resource's potential over the course of the planning period.

Independent analysis clearly indicates a much larger in-Valley solar PV resource than what is represented in TVA's Draft IRP and EIS. TVA could reasonably achieve 10 to 15 times more solar PV than the levels identified by the Draft IRP and EIS.

The Draft IRP and EIS provide only a superficial analysis of TVA's available solar PV resource. The Draft IRP provides only a brief description of this technology, with no discussion of solar PV's achievable potential over the course of the planning period. The Draft EIS provides a bit more substantive analysis, but still fails to address the key questions necessary for a proper evaluation, namely how much solar PV could be developed within the planning period and what are the costs and benefits of developing this resource.

Even the Draft EIS's limited discussion, however, suggests that TVA is significantly undervaluing this resource. Using 2009 data collected by the National Renewable Energy Laboratory (NREL), the Draft EIS briefly explores the land area requirements necessary to meet TVA's entire 2005 electrical load with solar PV and reviews the available rooftop area in the TVA region to develop solar PV resources. The conclusions drawn by this brief analysis are that:

- The solar resource in the TVA region is plentiful[11], and
- The TVA power service area PV rooftop potential in 2010 is approximately 23,000 MW, expected to grow to approximately 30,000 MW of capacity in 2015.[12]

This "technical potential" analysis reaches findings similar to a 2009 report published by SACE (see Attachment 1). Utilizing the best available data from independent and governmental sources, SACE estimated 45,851 MW of solar capacity in Tennessee, considering rooftop and ground-mounted resource opportunities.[13]

In order to address the lack of current solar energy data in the draft IRP and EIS, SACE commissioned a study by Navigant Energy Consulting to analyze the solar PV resource in TVA's service territory (see Attachment 2).[14] Navigant's study estimates the level of penetration that TVA could reasonably achieve by 2030, considering:

- A 2008 Navigant study completed for NREL,
- TVA data provided in the Draft IRP and EIS,
- TVA's baseline forecast for 1.1% load growth and 1.4% peak demand growth,

[11] *Draft EIS*, p. 128 – 129.

[12] *Draft EIS*, p. 129.

[13] Southern Alliance for Clean Energy, *Yes We Can: Southern Solutions for a National Renewable Energy Standard*, February 2009, p. 12

[14] Navigant Consulting, *Independent Solar Assessment*, completed for the Southern Alliance for Clean Energy, November 2010.

- Available public research, particularly regarding the uncertainties surrounding the upper limit on PV penetration that could impact grid operation and the location of PV interconnection,
- Navigant's own in-house expertise.

Navigant analyzed nine different combinations of maximum penetration levels and allocations of investment between rooftop-mounted and ground-mounted technologies. Based on this analysis, Navigant Consulting estimated that TVA could add as much as 5,200 MW of solar energy resources to its system by 2030 without impacting grid operations (see Figure 6).[15]

Figure 6: Solar Energy Installation Scenarios for 2030, Navigant Consulting

Penetration Levels	**Capacity Scenario**		**Estimated Energy Output***	
	MW	% of Baseline Forecast	GWh	% of Baseline Forecast
Lower End	2,200 – 3,200	5 – 8 %	3,900 – 5,600	2 – 3 %
Mid Range	3,200 – 4,200	8 – 10 %	5,600 – 7,400	3 – 4 %
Upper End	4,200 – 5,200	10 – 13 %	7,400 – 9,100	4 – 5 %

* Energy output specific to the TVA service area was beyond the scope of the project conducted by Navigant Consulting. SACE estimated energy output based on a 20% capacity factor for illustration purposes only. The actual output would depend on characteristics such as technology, site and interconnection opportunities.

In comparison, TVA's most aggressive renewable energy package includes only about 350 MW of solar PV capacity by 2030. This represents only 7 to 16% of the reasonable solar PV potential identified by Navigant.

TVA's cost estimates for solar PV are excessively high.

The Draft IRP also uses excessively high cost estimates for solar PV resources in the TVA service territory. The Draft IRP assumes a levelized cost of energy (LCOE) of approximately $296 per MWh for solar PV resources.[16] This is clearly too high, and as a result solar PV resources are artificially disadvantaged compared with other resource options.

A primary resource in determining the levelized costs of solar PV is the June 2010 presentation from Black & Veatch (B&V), a consultant to the California Public Utilities

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[15] Note that Navigant Consulting recommends that TVA conduct load flow and solar integration studies to better understand the impacts of aggressive levels of solar energy development on the TVA system. Navigant consulting found that the levels of solar PV installation it considered in this study "will not likely significantly impact TVA's grid operation." (Navigant, p. 7)

[16] TVA, *Stakeholder Review Group Working Session*, presentation to the Stakeholder Review Group, February 17, 2010, slide 28.

Commission (CPUC), in its docket on planning the state's Renewables Portfolio Standard.[17] B&V has extensive experience both with large-scale PV projects and with public databases on PV costs. We adjusted for the difference between the cost and performance of the California-based systems studied by B&V (Figure 7).

Figure 7: Tennessee vs. California Solar PV Index

PV Characteristic	TN/CA
PV output	0.86
Local Construction Costs	0.76
Local cost %	50%
System cost	0.88
LCOE	1.020

Our adjustment for PV output is based on the National Renewable Energy Lab's industry-standard PVWATTS calculator, comparing the outputs of reference PV arrays in Fresno, San Francisco, Knoxville and Nashville.[18] Using this calculator, we estimate that the output of the California arrays is, on average, 14% higher than solar PV arrays in Tennessee.

Discrepancies in construction costs can be accounted for using the U.S. Army Corps of Engineers' Civil Works Construction Index System.[19] In 2009, such costs were 24% less expensive in Tennessee than in California. We assume that the costs of PV panels and inverters is the same in both states, and that the cost difference applies only to the balance of the plant that consists of standard structural materials, typical construction techniques, or involves straightforward utility equipment (approximately 50% of the total project costs altogether). Considering these factors, the levelized cost of energy for a solar PV project in Tennessee should be approximately 2% higher than one in California on a per MWh basis, taking into account the greater output of solar PV projects in California.

Because cost advantages almost exactly balance out performance disadvantages, a $296 per MWh cost in Tennessee is equivalent to a $290 per MWh cost in California. This is equivalent to the highest cost for the least cost-effective technology identified by B&V (Figure 8). A far more reasonable comparison for use in the Draft IRP would be to the larger and utility-scale systems identified by B&V, which is less than 60% of the cost estimate used by TVA.

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[17] Ryan Pletka, *LTPP Solar PV Performance and Cost Estimates*, Black & Veatch presentation to the California Public Utilities Commission, June 18, 2010.
[18] NREL's PVWATTS calculator is available at: http://www.nrel.gov/rredc/pvwatts/version1.html
[19] USACE Civil Works Construction Index System in available at: http://140.194.76.129/publications/eng-manuals/em1110-2-1304/entire.pdf

Figure 8: Black and Veatch Cost Estimates for Solar PV ($ per MWh)

Cost	Rooftop	Ground			Utility-Scale	
	0.5 – 2 MW Fixed	0.5 – 2 MW Tracking	2 – 5 MW Fixed	5 – 20 MW Fixed	150 MW Tracking	150 MW Fixed
Low	$248	$185	$175	$168	$148	$137
High	$290	$229	$213	$205	$161	$155

Ryan Pletka, *LTPP Solar PV Performance and Cost Estimates*, Black & Veatch presentation to the California Public Utilities Commission, June 18, 2010.

Recent utility experience with procuring solar PV resources in the U.S. also indicates that the actual costs of solar PV resources are lower than the Draft IRP's estimate of $296/MWh. Some recent examples of solar PV development include:

- The CPUC has established a cap of $260 per MWh for Southern California Edison (SCE) 0.5 to 10 MW rooftop and ground-mounted PV projects in its service territory. SCE recently announced that it had awarded over 50 MW of 20-year contracts under this cap.[20]
- Sacramento Municipal Utility District (SMUD) contracted for 100 MW of solar PV capacity, consisting of 3-to-5 MW projects, under a feed-in tariff with a levelized, 20-year price of $148 per MWh[21] for projects commencing operations in 2012.[22]
- Pacific Gas and Electric (PG&E) has 13.5 MW, consisting of nine small (1.5 MW) solar PV projects, under contract at a 20-year price of approximately $140-$150 per MWh.[23]

Taken together, the B&V cost estimates, these contracts, and the evidence that levelized costs in California are coincidentally similar to those in the TVA region clearly indicate that TVA has overestimated solar PV costs. TVA should revisit its cost estimate for solar PV resources based on a reasonable expectation of significantly lower average price per MWh for solar PV projects in the TVA service territory than the $296/MWh estimated in the Draft IRP.

The Draft IRP and EIS unreasonably assume that the installed cost of solar PV will remain constant throughout the planning period.

Projected future cost trends should also be incorporated into the Draft IRP's analysis of solar PV resources to reflect the rapid development of the region's solar markets and supply chains. TVA provided its assumed cost of installed solar energy to its Stakeholder Review Group on a confidential basis. For this reason, we cannot directly discuss it in these

[20] SCE advice Letters 2513-E and 2514-E, available at: www/sce/com/AboutSCE/Regulatory/adviceletters/pending.htm
[21] This price includes a $20/kW development security cost that developers must pay to SMUD.
[22] SCE Advice Letters 2513-E and 2514-E, available at www.sce.com/AboutSCE/Regulatory/adviceletters/pending.htm.
[23] PG&E's under 1.5 MW solar PV contracts are summarized at: www.pge.com/b2b/energysupply/wholesaleelectricsupplierssolicitation/standardconstractsforpurchase/.

public comments. However, based on our review of this information, the Draft IRP and EIS assume that the costs associated with solar energy installation remain constant throughout the planning period, which is inconsistent with its forecast methods for other resources.[24]

The industry standard for assessing future cost trends in solar PV is to look at the cost of installed solar on a $/kW basis. Navigant Energy Consulting analyzed current and future installed cost trends for solar PV technologies on a $/installed kW basis in the TVA service territory (Attachment 2). Based on this analysis, supported by industry and DOE projections, it would be more reasonable for TVA to assume a declining cost trend for solar PV technologies over the course of the planning horizon.

Navigant's analysis "is based upon Navigant's internal cost models that account for regional variations in system costs, publicly available data on system costs in TVA's territory, and interviews with installers active in TVA's territory." [25] Notably, Navigant *did not assume* "technological breakthroughs or significant business changes" that have led the US Department of Energy to set even lower installed cost goals. Therefore, Navigant's cost estimates are likely conservative.

Navigant estimates various solar PV technologies to have an installed cost of $4,800 – $7,100 per kW, and projects the costs of solar PV technologies to decline between 17 and 22% by 2020 and between 35 and 45% by 2030.

In contrast, TVA's Draft IRP and EIS provide no discussion of forecasted cost trends of solar PV. Given the rapid growth of solar supply chains in the TVA service territory in recent years, TVA's Draft IRP and EIS should include an analysis of solar PV's potential to become a more cost-effective resource option over the course of the planning horizon.

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[24] TVA, *Solar Wind and Biomass Co-firing*, provided to the Stakeholder Review Group, September 24, 2009.
[25] Navigant, p. 18.

Figure 9: Projected Installed Cost Trends of Solar PV Technologies

Technology	Installed Cost Estimate ($/kW$_{DC}$)		
	2010 (Current)	2020	2030
Ground-mounted Polycrystalline PV: with tracking (10 – 50 MW)	5,900	4,900	3,750
Ground-mounted Polycrystalline PV: w/o Tracking (10 – 50 MW)	5,500	4,300	3,100
Ground-mounted polycrystalline PV: w/o tracking (100 – 300 MW)	4,800	3,800	3,100
Ground-mounted Thin-film PV: w/o tracking (10 – 50 MW)	4,800	3,800	3,100
Ground-mounted Thin-film PV: w/o tracking (100 – 300 MW)	4,700	3,700	3,000
Roof-mounted Polycrystalline PV: commercial (10 kW – 2 MW)	5,600	4,350	3,100
Roof-mounted Polycrystalline PV: residential (1 kW – 10 kW)	7,100	5,700	4,400

Navigant, p. 21 to 25.
Note: Costs include permitting and interest during construction, but do not include any necessary interconnection, transmission or substation upgrade costs. Costs are given in $2010.

TVA could achieve Navigant's "Lower End" penetration level at a cost that would be approximately 3% of its forecast revenue requirement.

In order to place the costs of investing in solar PV resources in context, we compared the cost forecast developed by Navigant to the Draft IRP's revenue requirement forecast. TVA forecasts a revenue requirement of about $14.8 billion for 2018 (Figure 10). In Navigant's Lower End, Minimal Central Station scenario, Navigant projects a revenue requirement of about $520 million for 2018 (Figure 11).[26] Therefore, solar energy investment in this scenario would represent about 3% of total system costs in 2018.

Figure 10: TVA Revenue Requirement Estimate, 2018

Energy forecast	185,000 GWh	Draft IRP, p. 52
Rate	$ 80 per MWh	Draft IRP, p. 118
Revenue Requirement	$ 14.8 billion	

[26] These costs are based on a scenario with a "lower end" penetration, a linear adoption rate, and a minimal level of central station located systems. Specific costs for 2018 were confirmed by Navigant staff.

Figure 11: Solar Capital Costs, Operating Costs, and Fuel Savings, 2018

Capital expenditures	$ 475 million	Navigant, p. 35
Operating expenditures	$ 45 million	Navigant, p. 35
Solar revenue requirement	$ 520 million	

The point of this analysis is not to specifically define how TVA should develop the solar PV resources of the Tennessee Valley, but rather to highlight that an aggressive pursuit of the Valley's solar PV resource would not require an outlandish investment by TVA. In contrast, an orderly, sustained approach to developing the solar PV resource would result in economic and environmental benefits to Tennessee Valley residents while supplying a significant portion of TVA's future electricity demand.

c. Wind Resources

Even the Draft IRP's most aggressive renewable energy strategy represents less than one-tenth of the potential wind resource that could be developed by TVA within the Valley.

The Draft IRP and EIS limit the development of in-Valley wind resources to a fraction of the Valley's potential to develop this resource. The problem is not with TVA's assessment of the resource, as our potential estimate is similar to TVA's potential estimate. Rather, the Draft IRP's strategic options for resource development limit the contribution of in-Valley wind resources to a maximum of approximately 360 MW by 2030 (Figures 3 and 4 above).[27] Similar to TVA's treatment of solar PV resources, these defined model inputs seem both arbitrary and unreasonably low.

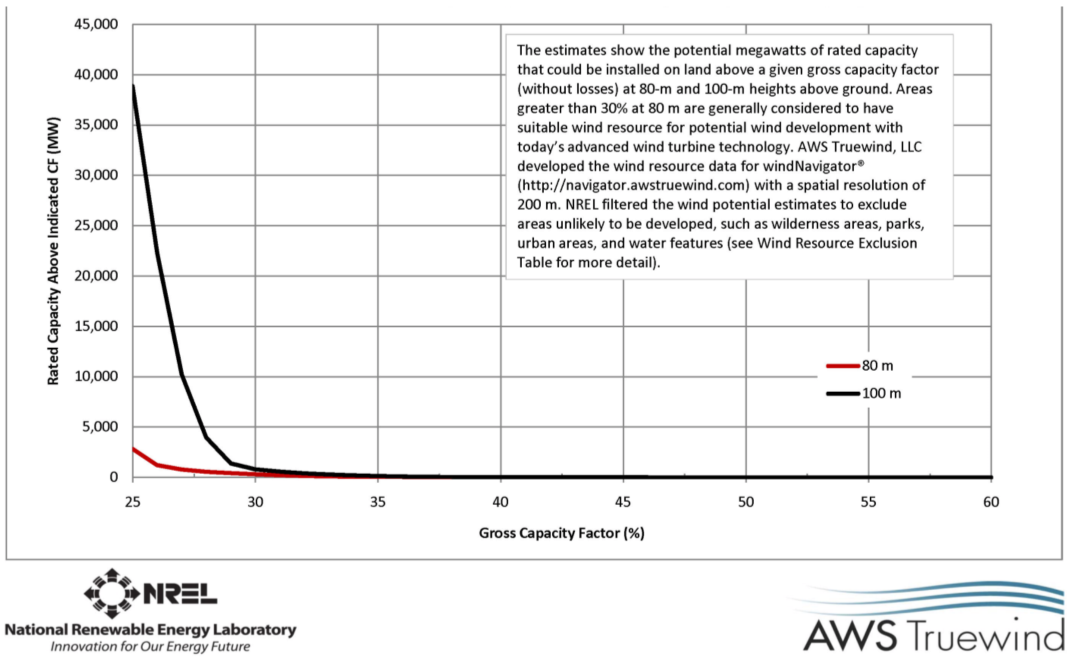
Unfortunately, the Draft IRP and EIS do not provide an explanation for why wind resource development is limited to less than one-tenth of the in-Valley resource opportunity. TVA does discuss the relatively greater "potential and economics" for wind energy development outside the TVA region, but considering TVA's mission to support economic development in the Valley, more attention to the feasibility of in-Valley wind energy development is warranted.

Specific concerns regarding TVA's opportunity to pursue in-Valley wind development are discussed in the Draft IRP, but these are not clearly substantiated. For example, TVA claims a net capacity factor for the TVA service area of 20-22%, and that "taller turbine hub heights do not increase the net capacity factor significantly."[28] Yet both of these claims are contradicted by the NREL resource cited in TVA's previous paragraph.[29]

[27] *Draft EIS,* p. 144.
[28] *Draft IRP,* p. 71.
[29] National Renewable Energy Laboratory, *Tennessee Wind Map and Resource Potential*, Wind and Water Power Program website, content dated October 6, 2010.

As illustrated in Figure 12, NREL suggests that development of more than 2,000 MW in Tennessee could occur at a gross capacity factor of greater than 25% for 80 m turbines. For the same 2,000 MW level of development at 100 m, the gross capacity factor increases to about 29%. NREL does not provide a net-to-gross calculation estimate; if TVA has alternative data resources, these have not been disclosed.

Figure 12: Tennessee Wind Resource Potential, Cumulative Rated Capacity vs. Gross Capacity Factor (CF)



National Renewable Energy Laboratory, *Tennessee Wind Map and Resource Potential*, Wind and Water Power Program website, content dated October 6, 2010.

Other concerns, such as the brief description of possible siting resistance and competition for "choice" sites are also inadequately developed to explain why TVA considered extremely limited wind resource potential in the Draft IRP.[30] The Draft IRP does not explain why siting is more difficult or costly than similar challenges associated with the IRP's non-constrained fossil fuel and nuclear resource options. The Draft IRP also fails to reconcile concerns about competition for "choice" sites with the TVA's negative characterization of in-Valley wind potential.

While the Draft IRP and EIS clearly acknowledge the presence of significant in-Valley wind resources, the ability of the planning model to choose these resources is constrained by defining the in-Valley wind resource as a set model input. Because little substantive explanation is given in either the Draft IRP or Draft EIS as to why this resource should be

[30] *Draft IRP,* p. 71.

limited, it is difficult to comment on TVA's rationale. However, we feel strongly that TVA should reevaluate the potential for this resource and re-define the wind resource on more equal footing with TVA's other, more traditional resources options.

TVA's wind potential estimate is somewhat higher than the estimate developed by SACE.

The Draft IRP, relying on a Tennessee Wind Map and Resource Potential estimates from the DOE's Office of Energy Efficiency and Renewable Energy, acknowledges the availability of approximately 4,200 MW of wind power at an 80-meter turbine hub height.[31] The Draft EIS also notes the estimated 1,247 MW of wind resources discussed in the NREL Eastern Wind Integration and Transmission Study.[32]

In comparison, SACE estimates that about 3,500 MW of wind power is available in the TVA region. We developed our estimate using two resources, a 2005 study by Carson and Raichle (Figure 13) and a 2010 resource assessment by NREL (Figure 14).[33]

Figure 13: Carson and Raichle Study of Appalachian Wind Potential in the TVA Region

Site	State	Feasible Wind Development				
		Wind Class	Size (Mi)	Capacity (MW)	Energy (GWh)	report source
Bryson Mountain	KY	3	8.1	122	266	Table 5.2-3
	TN		12.2	183	402	
Black Mountain	KY	3	38.8	582	1,275	Table 5.1-3
Cross Mountain	TN	3	103.6	1,554	3,404	Tables 5.3-3, 4
English Mountain	TN	3	1.1	17	37	Page 5-21
Forge Mountain	TN	4	10.8	162	426	Table 5.5-3
Subtotal	KY		46.9	704	1,541	
	TN		127.8	1,917	4,268	
Total			**174.7**	**2,620**	**5,809**	

Note: These data were developed by SACE based on the discussion and data provided in TVA's wind prospecting report by Carson and Raichle[34] and a memo describing wind potential estimating methods.[35]

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[31] *Draft IRP*, p. 70 – 71. The Draft IRP also discusses an estimate of 57,000 MW available at 100 m at a 25% capacity factor. It is unclear why the 57,000 MW estimate is discussed, since NREL's discussion of industry practice indicates a minimum 30% capacity factor at 100 m.

[32] *Draft EIS,* p. 127. Note that an expected annual energy generation of 3,500 – 4,000 GWh from 1,247 MW suggests a net capacity factor of 32-37%, which is significantly higher than the 20-22% claimed by TVA (*Draft IRP,* p. 71).

[33] Carson, R. and B. Raichle, *Wind Monitoring Around the Tennessee Valley Region*, Tennessee Valley Authority - Appalachian State University Wind Assessment Collaboration, December 2005.

[34] Carson, R. and B. Raichle, *Wind Monitoring Around the Tennessee Valley Region*, Tennessee Valley Authority - Appalachian State University Wind Assessment Collaboration, December 2005.

[35] Raichle, B., *Method for Estimating Potential Wind Generation in the Appalachians*, Appalachian State University, 2007.

Figure 14: NREL Wind Potential Data for TVA States (100 meter height, >30% capacity factor)

State	Feasible Wind Development 80 meter height, >30% capacity factor			Feasible Wind Development 100 meter height, >30% capacity factor		
	Area (km^2)	**Capacity** (MW)	**Energy** (GWh)	**Area** (km^2)	**Capacity** (MW)	**Energy** (GWh)
Alabama	23.6	118	333	113.6	568	1,588
Georgia	26.0	130	380	58.7	294	863
Kentucky	12.1	61	173	139.7	699	1,899
Tennessee	61.9	309	900	163.3	817	2,355
Total	**123.6**	**618**	**1,786**	**475.3**	**2,378**	**6,705**

National Renewable Energy Laboratory (NREL) and AWS Truewind, *Estimates of Windy Land Area and Wind Energy Potential by State*, spreadsheet dated February 4, 2010.

Although it is authoritative for most developable wind resource areas, we do not recommend the more recent NREL resource assessment for ridgetop wind in the TVA service territory. As TVA notes, "Due to the spatial resolution of this data, the ridgetop potential in the TVA region appears to have been devalued from previous National Renewable Energy Laboratory (NREL) estimates."[36] While spatial resolution is an issue, we have reviewed this issue, discussed it with NREL staff, and identified three additional problems that suggest the most recent NREL assessment is not ideally suited to estimating ridgetop potential.

- When ridge crests are aligned perpendicular to prevailing winds, wind strength is substantially increased along the ridge crest. For example, Carson and Raichle concluded that, "Wind maps developed by computer modeling should only be used as an indication of the wind resource. Many of the sites where monitoring data was available were estimated incorrectly by one wind class."[37] This issue is a refinement of the "spatial resolution" issue, as NREL's national models lack the spatial resolution to model this effect and thus tend to underestimate the capacity factor in the ridge crest locations where wind turbines are most ideally located.
- The NREL resource assessment may have improperly applied forest-related exclusions in non-protected areas on ridge crests in the Appalachians.
- The NREL studies relied on a 5 MW per km^2 turbine area density estimate, which is appropriate for most sites other than ridgetops. A 15 MW per mile linear density estimate is appropriate for development along the crests of ridgetops.[38]

Until NREL addresses these issues, we recommend the use of other data sources where available.

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[36] *Draft EIS,* p. 127.

[37] Carson, R. and B. Raichle, *Wind Monitoring Around the Tennessee Valley Region*, Tennessee Valley Authority - Appalachian State University Wind Assessment Collaboration, December 2005.

[38] Raichle, B., *Method for Estimating Potential Wind Generation in the Appalachians*, Appalachian State University, 2007.

For Alabama and Georgia, however, we do recommend use of the 100 meter NREL data as the best representation of wind resource potential (Figure 14). We recommend this data set due to a lack of alternative data sources and because many or most of the mapped locations with substantial wind potential appear to be appropriately analyzed using the NREL data (i.e., while they are elevated areas, they may not be ridge crests). Better studies would be worthwhile but the NREL data are likely to provide a reasonable "order of magnitude" estimate.

For Tennessee and Kentucky, the 2005 Carson and Raichle study is the best available resource (Figure 13). This study provides site-specific data for several promising wind resource development sites in the TVA region. We analyzed these data in 2008 and estimated the wind development potential for sites in Tennessee and Kentucky. While this data resource is highly credible and likely to provide a useful foundation estimate, a number of sites mapped by NREL with additional capacity up to 2,00 MW are not included in the Carson and Raichle study.

Based on these resources, we estimate that TVA could feasibly develop about 3,500 MW of wind resource within the TVA service territory, resulting in about 8,300 GWh of annual generation, which is equivalent to an average 27% capacity factor (Figure 15).

An alternative (in our opinion, highly conservative) estimate of wind development potential would be NREL's estimate of 618 MW for 80 meter turbine heights at greater than 30% capacity factor (Figure 14). This would offer nearly twice the capacity and nearly three times the annual energy generation as the largest resource considered among the Draft IRP's strategic options.

Figure 15: TVA Wind Potential

<table>
<tr><th rowspan="2">State</th><th colspan="3">Feasible Wind Development</th></tr>
<tr><th>Capacity (MW)</th><th>Energy (GWh)</th><th>Notes</th></tr>
<tr><td>Alabama</td><td>568</td><td>1,588</td><td rowspan="2">- NREL 100 m data used
- NREL maps indicate wind potential is in or near TVA service area</td></tr>
<tr><td>Georgia</td><td>294</td><td>863</td></tr>
<tr><td>Kentucky</td><td>704</td><td>1,541</td><td rowspan="2">- TVA/ASU study data used
- NREL maps indicate additional areas with wind potential, but the data were insufficiently detailed to assess those areas</td></tr>
<tr><td>Tennessee</td><td>1,917</td><td>4,268</td></tr>
<tr><td>Total</td><td>3,483</td><td>8,260</td><td></td></tr>
</table>

SACE synthesis of data in Figures 13 and 14, as discussed.

TVA should also consider forthcoming findings from NREL in establishing near-term wind resource potential. TVA partnered with Tennessee's Energy Office and the Southern Alliance for Clean Energy in the summer of 2010 to apply to the US Department of Energy Technical Assistance Program. In response to this request, NREL will identify specific locations, especially non-ridgetop, which may be suitable for a utility-scale wind development in the TVA service territory. The report from NREL will be completed by the end of 2010 and should be integrated into the IRP process before the final IRP is produced.

TVA should consider between two and ten times more in-Valley wind capacity in its Draft IRP.

Given the wealth of data indicating a significant in-Valley wind resource, TVA should reevaluate the Draft IRP's treatment of in-Valley wind and consider analyzing the development of between 720 and 3,500 MW of this resource. Because the Draft IRP and EIS treat in-Valley wind as a fixed model input, the model's ability to choose in-Valley wind to fill TVA's potential future capacity gaps in improperly constrained. However, even as a fixed model input, the evaluation of significantly higher levels of in-Valley wind resources would be more appropriate.

d. Biopower Resources

The Draft IRP and EIS also significantly undervalue the potential biopower resources available in the Valley. Even the most aggressive strategy (Strategy E: EE/DR and Renewables Focused Strategy) represents less than one-tenth of the potential biopower that could be developed by TVA using in-Valley biomass resources as fuel.

The Draft IRP's shortcoming is not with TVA's assessment of the resource, as our potential estimate is similar to TVA's estimate of potential biomass resources of 36 million potential tons per year. Rather, TVA unreasonably concludes that its own potential assessment may be "too optimistic" and therefore restricts the biopower potential in its plan to 456 MW (Figure 16).[39] Notably, TVA estimates that it could increase biopower generation by only about 3,400 GWh,[40] in contrast to the resource potential estimate cited by TVA of 47,000 GWh of annual generation using in-Valley biomass resources.[41]

Figure 16: TVA Biomass-fueled Generation Options in Draft EIS

Biomass co-firing	169 MW	Draft EIS, p. 147
Conversion (coal to biomass)	170 MW	Draft EIS, p. 147
New biomass-fueled facilities (via PPAs)	117 MW	Draft EIS, p. 147
Total Capacity	**456 MW**	
Total Annual Generation	**3,400 GWh**	Assumes 85% capacity factor.

TVA has not provided a clear rationale as to why the Draft EIS indicates a biopower potential that is restricted to 7% of the total resource potential. TVA describes some operating requirements that suggest a methodical development strategy is required. We agree, but a methodical development strategy could be much more aggressive than the one considered by TVA. TVA also provides one statement that suggests that its concern relates to "current ownership and competing markets." However, TVA has not made a persuasive case that "current ownership and competing markets" constrain TVA to such a limited use of biopower resources.[42]

Furthermore, the most aggressive strategy considered in the Draft IRP further limits biopower utilization to 410 MW (Figure 4). This additional 10% reduction below the amount identified in the Draft EIS is unexplained.

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[39] *Draft EIS*, p. 147.

[40] Information on assumed capacity factors and anticipated generation from TVA's proposed renewable energy portfolios was provided to the Stakeholder Review Group in June 2010.

[41] *Draft EIS,* p. 130.

[42] We are unaware of any analysis by TVA that explores this issue.

Independent analysis confirms that TVA could develop much higher levels of bioenergy resource using existing resources in the TVA service territory.

In order to explore the issue of resource competition, SACE commissioned a study of the woody biomass inventory and supply in the TVA region (included as Attachment 3).[43] The consultant that conducted the study for SACE, Larson & McGowin, is a forestry firm that provides a full range of land management and on-demand decision support and consulting services, with a focus on forests in the South. Among its services, Larson & McGowin provides financial analysis for timberland appraisals and acquisitions, in addition to its core business of owning and managing timberland. In short, we consulted experts in the very markets that TVA suggests are a constraint on biopower development opportunities.

The Larson & McGowin analysis includes both US Forest Service estimates of forest resources and urban wood waste resources. In addition to an assessment for the TVA region, the assessment provides estimates for the vicinity of TVA's existing coal plants. The assessment of forest resources includes the full range of forest resources, as follows:

- Inventory of woody biomass based on USFS Forest Inventory and Analysis data which reflects an average age of 2005;
- Annual growth and removal projections (supply and demand) for pulpwood and sawtimber are based on the 2010 Southern Forest Resource Assessment Consortium (SOFAC) Subregional Timber Supply Model Southwide V23 Demand Run;
- Annual supply is based on the difference between growth and removal projections representing historical timber removals and growth including land use changes;
- Resource stocks and supply are reported in dry tons, based on individual tree components using the component ratio method as described in the FIA database description and users manual;
- Urban wood waste assessment is restricted to large diameter wood generated by tree services companies;
- Resources are sorted into "supply buckets" based on current timber market specifications;
- Excludes mill residues because markets generally exist for these resources;
- Excludes public lands and stands over 80 years in age;
- Restricted for utilization constraints and possible environmental considerations;
- No consideration of management options for increasing future supply; and
- No consideration of cost feasibility.

Even though Larson & McGowin did not consider cost feasibility, SACE took cost considerations into account by evaluating only the three lowest value supply buckets included in the analysis. Since the assessment makes several conservative assumptions (e.g., no consideration of options for increasing supply), the overall assessment represents a reasonable effort to assess available supply.

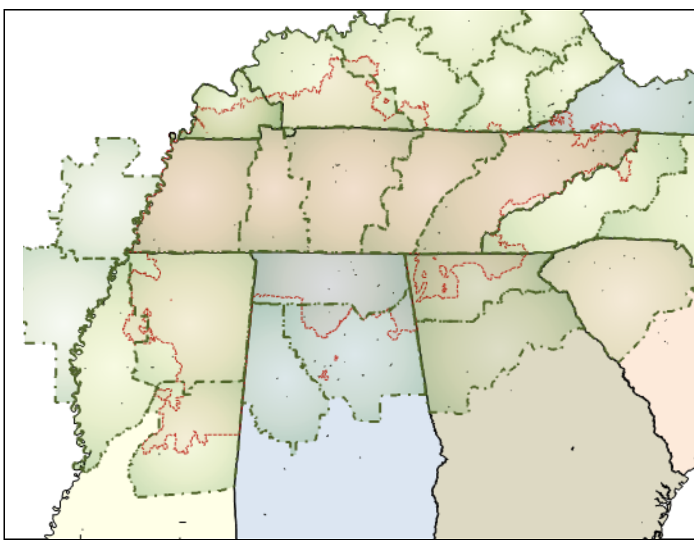
[43] Seawell, R. C., *Woody Biomass Supply and Forest Resource Issues*, Larson & McGowin, Inc., prepared for Southern Alliance for Clean Energy, November 1, 2010.

According to Larson & McGowin's analysis (see Attachment 3), an annual supply of about 14 million dry tons of woody biomass is available in the TVA region. This matches the estimate of 14 million dry tons discussed by TVA in the Draft EIS.[44] Of these 14 million dry tons, over 7 million dry tons are included in low value "supply buckets."

Figure 17: TVA Woody Biomass Resource Potential, based on Larson & McGowin analysis

Woody Biomass Resource "Supply Buckets"	**Resource Total** (Dry Tons)
Urban Wood Waste	646,720
Salvage from Damaged Stands	510,776
Slash & Brush	856,572
Logging Residuals (merchantable)	5,312,049
Subtotal – Low Value "Supply Buckets"	**7,326,117**
Logging Residuals (pre-merchantable)	288,202
Pulpwood from Pre-merchantable Stands	233,099
Pulpwood Inventory from Merchantable Stands	2,983,376
Small Sawtimber Inventory	3,315,406
Total – Annual Woody Biomass Resource Supply	**14,146,200**

Figure 18: Larson & McGowin Analysis is Based on GIS Interpretation of FIA Unit-Level Data



Larson & McGowin used FIA unit-level data to develop area-specific resource supply estimates. Thirty-five FIA units were included in the analysis for the TVA region. Only 5% of the potential biomass supply region for TVA coal plants was outside the FIA units used for the analysis.

FIA units outlined in green.
TVA service area outlined in red.

[44] *Draft EIS, p. 132.*

TVA could reasonably develop about twice as much biopower capacity as it considers in its Draft IRP with woody biomass fuels for which there is little or no competing market.

We developed a scenario in which TVA develops 1,100 MW of biomass-fueled power generation using “low value” woody biomass resources (Figure 19). This scenario has the following constraints:

- Woody biomass is restricted to four “low value” biomass “supply buckets”:
    - Salvage from damaged stands
    - Slash and brush
    - Logging residuals (merchantable)
    - Urban wood waste
- Co-fire modifications (20 MW) or biopower conversions (50 MW) are applied to each of TVA’s existing coal plant sites to take advantage of existing infrastructure. (In the event that the suggested technology is infeasible, a similar capacity new unit could be sited nearby.) A maximum scale of 100 MW is assumed at any single site.
- The required annual fuel supply for the plants sited at existing TVA facilities is determined based on typical operating data.
- It is assumed that independent developers build remaining capacity, utilizing most of the remaining “low value” biomass resources as fuel.

A total of approximately 25-40 biopower plants, co-fire modifications, or conversions would be built in this scenario.

Figure 19: TVA Woody Biomass-fueled Generation Options, based on Larson & McGowin analysis

Potential Biomass Plants	**Capacity** (MW)	**Annual Fuel Required** (thousand tons)	**Woody Biomass** 50 mile supply region (Fig 19a) (thousand tons)		**Notes**
			Low Value	Total	
Allen	20	112	245	1,019	1 co-fire unit
Bull Run	20	112	141	487	1 co-fire unit
Colbert	20	112	172	996	1 co-fire unit
Cumberland	50	280	378	1,469	1 conversion unit
Gallatin	100	561	1,446	4,904	2 conversion units
John Seveir	50	280	379	1,826	1 conversion unit
Johnsonville	40	224	290	1,458	2 co-fire units
Kingston	20	112	150	523	1 co-fire unit
Paradise	100	561	821	2,720	2 conversion units
Shawnee	50	280	307	1,258	1 conversion unit
Widows Creek	50	280	362	1,350	1 conversion unit
Total Coal Plant Sites	**520**	**2,914**			
Independent Plants (PPAs)	580	3,253			11-26 units
Total TVA	**1,100**	**6,167**	**7,326**	**14,146**	**25 – 40 units**

Figure 20: Biomass Supply Areas for Existing TVA Coal Plants (50 mile region)

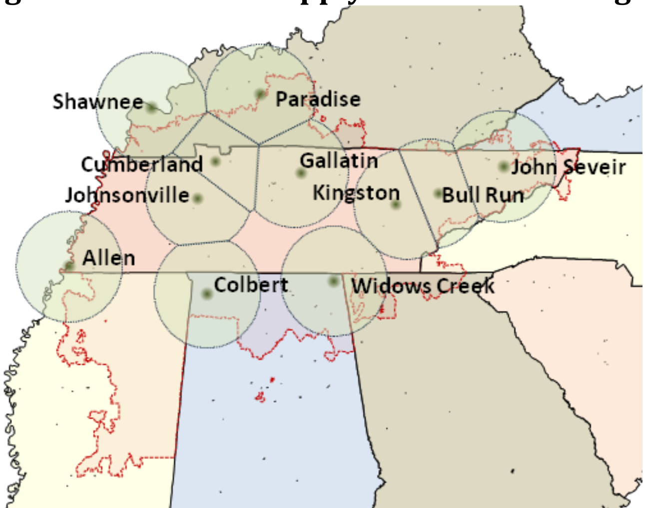


Figure 20a: Non-overlapping supply regions are used for data presented in Figure 19. This supply scenario assumes eventual development of biopower generation at all coal plants, if feasible.

TVA service area outlined in red.

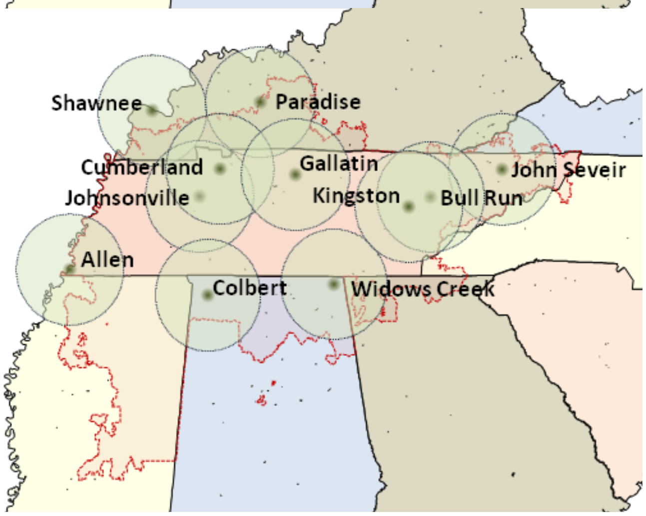


Figure 20b: Larson & McGowin also calculated available supplies at each coal plant within a 50-mile radius. These data will be useful in assessing the feasibility of individual biomass-fueled power plants at these locations. In the aggregate, however, these data would over-represent total biomass potential within these regions due to (intentional) double-counting.

TVA service area outlined in red.

Based on our analysis, it is apparent that TVA has the available resources to develop as much as 1,100 MW of bioenergy utilizing in-Valley resources of limited current markets. Therefore, doubling the in-Valley bioenergy resources considered by the Draft IRP would be reasonable given the apparent resource potential.

In addition to woody biomass resources, TVA also recognizes a potential annual supply of about 22 million tons of energy crops, crop residues and methane sources.[45] If such potential were fully accessed, about 4,000 MW of additional biopower capacity could be fueled.

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[45] *Draft EIS*, p. 132.

TVA has a strong interest in successful biopower development.

In-Valley biopower development has the potential to support every aspect of TVA's mission by providing power, supporting economic development and enhancing the environment. Yet by understating the resource opportunity, TVA is failing to make a clear commitment to developing biopower resources. Rather, TVA is signaling that it won't commit to the resource's development until the markets are developed. The result of this catch-22 is a failure to reasonably consider how biopower resources should be a meaningful part of TVA's future generation portfolio.

While it should be obvious that biopower can provide power and support economic development,[46] the case for environmental enhancement is less well established. A wide variety of stakeholders feel that environmental safeguards are insufficient to provide for the economic and environmental sustainability of forests that will come under additional pressure from bioenergy development. Nevertheless, these same stakeholders also see a potential "connection" between "biomass harvesting" and "ecosystem restoration."[47]

In sum, the Draft IRP and EIS, while recognizing the abundance of biopower resources, do not properly value these resources as potentially significant contributors to TVA's future generation requirements. Based on TVA's own estimates of this resource, and reinforced by the analysis conducted by Larson and McGowin, TVA should substantially increase both TVA-owned and independently developed biomass generation resource options in the Draft IRP and EIS.

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[46] A 40 MW plant supports $21 million in annual economic impact and 370 jobs. Hodges, A. W. and M. Rahmani, *Economic Impacts of Generating Electricity*, University of Florida, Institute of Food and Agricultural Sciences, Publication FOR-136, September 2007.
[47] The Heinz Center and the Pinchot Institute for Conservation, *Forest Sustainability in the Development of Wood Bioenergy in the U.S.*, June 2010.

2. TVA does not properly value the energy efficiency resource, leaving significant amounts of cost-effective efficiency undeveloped over the planning horizon.

TVA's increased emphasis on energy efficiency is a welcome development and appears likely to position TVA as one of the leading energy efficiency utilities in the Southeast. Nevertheless, the Draft IRP uses methods and makes assumptions that constrain the opportunity for energy efficiency to meet future energy demand. As a result, the final preferred strategy will likely include higher costs and risks than would be the case if efficiency were treated as a resource on equal footing with other resource options.

a. TVA's choice to analyze energy efficiency as an adjustment to the load forecast does not allow the model to optimize cost-effective energy efficiency in portfolio outputs.

TVA should not be judging efficiency as a limited, defined resource input when the preferred treatment of energy efficiency, evidenced by national trends, is to treat it as equal or even preferred to supply-side resources for planning purposes.

TVA's Draft IRP and EIS integrate energy efficiency as a fixed model input, best characterized as a load adjustment.[48] As a result, the IRP's model basically "works around" the efficiency input, selecting resources to meet TVA's "adjusted load."

In contrast to TVA's method, utilities that seek to identify the "best" level of energy efficiency investment generally model energy efficiency and other DSM on an equivalent basis to supply-side resources. In the California Public Utilities Commission's "Best Practices" report, eight of thirteen non-California utilities were identified as using this approach.[49] Only three[50] of the thirteen utilities surveyed used an approach similar to that of TVA.

If TVA uses its resource planning process to establish the level of energy efficiency investment, it should use an approach that models energy efficiency and other DSM on an equivalent basis to supply-side resources. Ideally, it would adopt the advanced approach used in the Pacific Northwest, where the Northwest Power and Conservation Council has pioneered the use of *two* supply curves for energy efficiency in the model that develops least-cost portfolios.[51]

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[48] See *Draft IRP*, discussion of EE resource, p. 75 to 82, and Figure 5-4: Attributes of Planning Strategies, p. 89.
[49] Aspen Environmental Group and Energy and Environmental Economics, Inc. (Aspen/E3), *Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California: Final Report and Appendices*, prepared for California Public Utilities Commission, April 2009. Utilities identified as modeling energy efficiency on an equivalent basis to supply-side resources include Avista Energy, British Columbia Hydro, Georgia Power Company, Idaho Power, PacifiCorp, Puget Sound Energy, Northwest Planning and Conservation Council, and Seattle City Light (p. 71-73).
[50] Public Service Colorado, Arizona Public Service, and Public Service New Mexico are the three utilities that follow a similar approach to TVA (Aspen/E3, p. 69).
[51] Apsen/E3, p. 71.

The use of two supply curves allows for different treatment of discretionary and lost-opportunity energy efficiency resources.

- Discretionary energy efficiency resources are investments that can be advanced or deferred based on near-term market decisions. An example of a discretionary energy efficiency resource would be a CFL market promotion.
- Lost-opportunity energy efficiency resources are programs that take advantage of opportunities due to market or customer circumstances. New construction and replace-on-burnout programs are the major categories of lost-opportunity programs.

Just as utilities use short-term market power purchases for different purposes than investments in new power plants, the most sophisticated energy efficiency planning process includes appropriate distinction between discretionary and lost-opportunity resources. TVA's load-adjustment approach does not allow for this distinction to be incorporated into its IRP process.

We would recommend that TVA adopt a similar, two-supply-curve approach to evaluate the energy efficiency resource in its IRP process. At a minimum, TVA should model energy efficiency and other DSM on an equivalent basis to supply-side resources within the IRP planning process. This would be preferable to TVA's "adjusted load" method that does not account for all cost-effective energy efficiency and therefore leads to resource portfolios with unnecessarily high levels of both cost and risk.

b. The failure to allow incremental increases in energy efficiency beyond 2020 skews the Draft IRP towards unnecessary additions of supply-side resources.

In four of the Draft IRP's five strategies,[52] energy efficiency program impacts grow during the first decade, but level off to a nearly flat trend in the second decade of the planning horizon. As a result, while aggressive levels of energy efficiency may be sufficient to eliminate load growth through about 2020, the Draft IRP is skewed towards unnecessary supply-side additions in the second decade of the planning period.

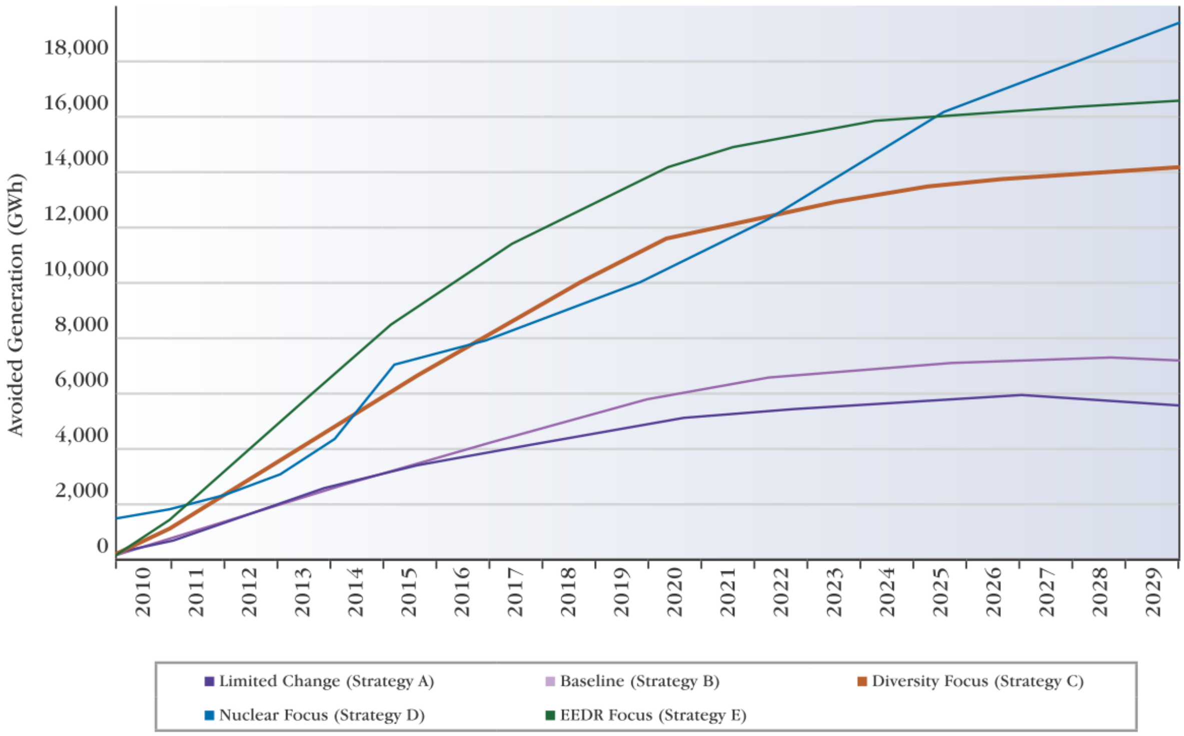
Because of the Draft IRP's failure to include incremental increases in energy efficiency beyond 2020, the capacity gap from 2020 to 2029 is artificially increased. As a result, the Draft IRP recommends excessive levels of supply-side generation that carry increased cost and risk compared with the efficiency resource. Given the long lead-time required to construct supply-side resources, the artificially increased capacity gap leads to unnecessary near-term investments in supply-side resources.

This phenomenon has already begun to occur as TVA committed nearly $250 million in FY 2011 towards completing a proposed nuclear unit at the Bellefonte Nuclear Site in anticipation of needing this resource in 2018. This is approximately the time that the

[52] The only exception is Strategy D, which is not being recommended by staff for further evaluation. For reasons that were never clearly explained, the energy efficiency resource inputs in that strategy were developed in a unique manner.

efficiency resource begins to level off in the Draft IRP. A more realistic representation of the potential for efficiency to continue contributing to TVA's resource portfolio beyond 2020 would likely allow deferral of this expense, if not obviate it altogether.

Figure 21: Avoided Generation of Energy Efficiency Options



TVA, *Draft IRP*, p. 79.

The Draft IRP and EIS provide no explanation for the leveling off illustrated in Figure 21. However, in conversations with TVA staff, it was indicated to us that TVA did not feel confident relying on potential, but as yet uncertain, investment opportunities for energy efficiency beyond 2020. We do not find this explanation adequate to explain the leveling off of EE/DR portfolios after 2020.

In our review of numerous energy efficiency and IRP documents, we are unaware of any utility with a serious commitment to energy efficiency[53] that assumes energy efficiency opportunities will effectively cease to exist after a decade. One perspective on TVA's "confidence" is that the Northwest Power and Conversation Council concluded in a retrospective review that at least 85% of the projected 20 year energy savings in its first regional plan were realized.[54]

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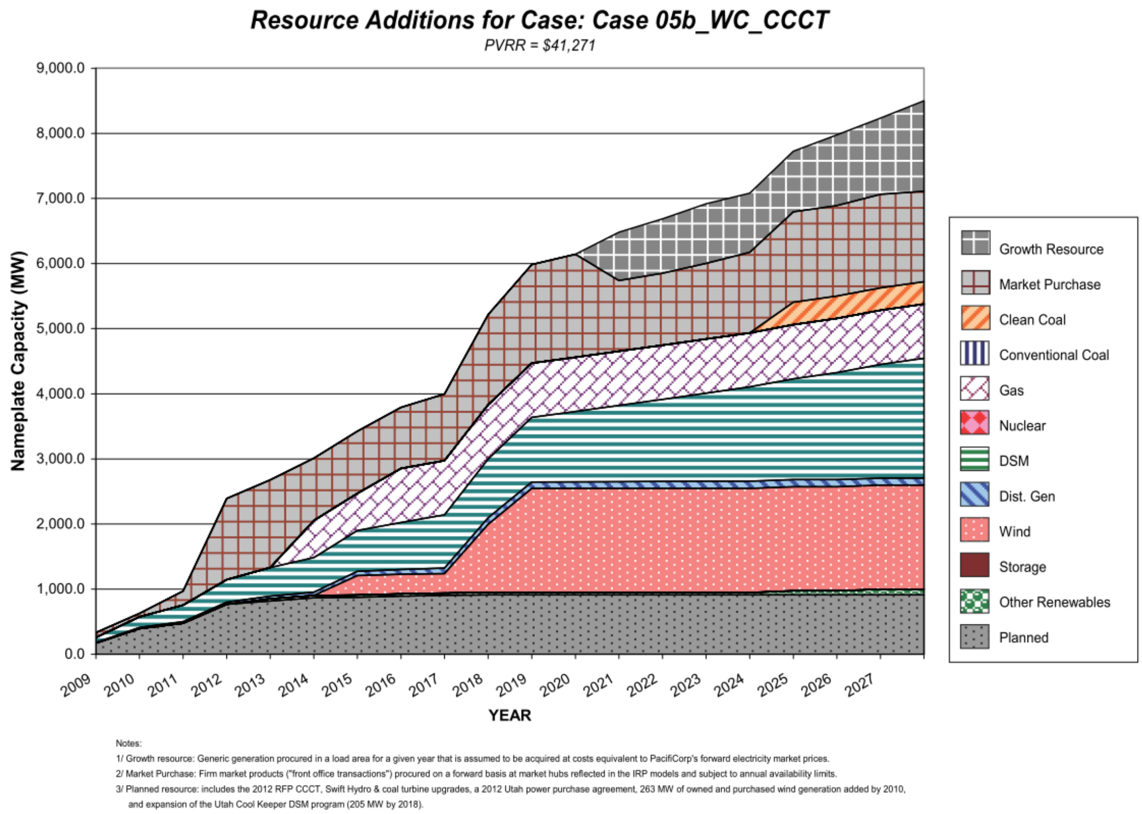
[53] By "serious commitment," we mean a plan to achieve more than 3% energy savings over 10 years – a relatively low threshold.

[54] Northwest Power and Conservation Council, *Achievable Savings: A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions*, Council document 2007-13, August 2007.

Another example is illustrated in PacifiCorp's 2008 preferred resource portfolio (Figure 22), where the contribution of DSM resources continued to grow throughout the second decade of the plan.

Figure 22: PacifiCorp Preferred Resource Portfolio, 2008 IRP



PacifiCorp, *2008 Integrated Resource* Plan, May 2009, Volume I, p. 239 and Appendix A, p. 31.

The durability of energy efficiency programs is also suggested by a study for Rhode Island, a state that has been aggressively pursuing the efficiency resource for several years. According to KEMA, Rhode Island could continue to achieve increasing levels of efficiency, saving as much as 29% of projected energy demand over the next decade at a savings of $1.85 billion for ratepayers.[55] As a result, the latest energy efficiency plan filed with the state's Public Utilities Commission aims to double annual energy savings over the next three years, from approximately 1.2% currently to 2.5% by 2014.[56]

Apparent from these cases is that TVA can and should rely on new technologies to be brought to market and additional cost-effective opportunities for efficiency in the outer years of the IRP planning horizon. This should be reflected in the Draft IRP and EIS by the inclusion of incremental energy efficiency gains beyond 2020.

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[55] KEMA, Inc., *The Opportunity for Energy Efficiency that is Chepare than Supply in Rhode Island*, prepared for Rhode Island Energy Efficiency and Resource Management Council, August 26, 2010.
[56] Association of Energy Services Professionals newsletter October, 2010; available at: http://aesp.org/

c. TVA's reliance on the EPRI study to estimate TVA's achievable efficiency potential is misguided, resulting in undervaluation of this resource.

TVA has unreasonably adopted a 7% cumulative energy reduction as its maximum energy efficiency potential. While the Draft IRP and EIS do not discuss it, TVA has indicated to the SRG that it relies on the conclusions of a March, 2010 report by the Electric Power Research Institute (EPRI) to constrain its inputs of energy efficiency into the IRP model.[57] This report claims a realistic achievable potential of 5% of baseload demand by 2020 and 7% by 2030.

The EPRI report's claim of an achievable potential of 5% by 2020 and 7% by 2030 cumulative energy reduction over TVA's draft baseline demand forecast is simply not credible. The credibility of this figure is challenged by actual impacts in many states across the country, by energy efficiency potential studies in the Southeast, and by identified flaws in EPRI's methods.

Current efforts by dozens of utilities across the country are likely to exceed 7% energy savings within one decade, suggesting EPRI's potential estimate is excessively conservative. According to ACEEE, 2008 energy efficiency programs reduced energy use by more than 1% in five states.[58] Further, the Consortium for Energy Efficiency reports that dozens of utilities are investing in energy efficiency at a pace that will easily exceed 7% within a decade or less.[59] Given the fact that the TVA service territory currently ranks as one of the least energy efficient regions in the nation, it is difficult to find the EPRI study's estimates of achievable efficiency reliable.

Recent analysis of the South's energy efficiency potential confirms that this resource is larger than the EPRI estimate for the TVA region.[60] A meta-analysis of energy efficiency potential studies conducted by Georgia Tech indicated that the South has the economic potential to reduce its energy consumption by 1.5% per year and the achievable potential, with vigorous policies, to reduce energy consumption by one percent per year.[61] While the meta-analysis targeted the next decade, the state level studies that accompanied Georgia Tech's 2010 report, *Energy Efficiency in the South*[62] examined energy efficiency potential over a 15-20 year time horizon suggested an economic potential of 20-35%, consistent with the study's 1.5 percent per year finding, and a maximum achievable potential of 15-30% in all but one study, well in excess of the study's 1% per year finding.

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[57] Electric Power Research Institute, *Assessment of Achievable Potential for Energy Efficiency and Demand Response Programs for the Tennessee Valley Authority*, March 2010.
[58] American Council for an Energy-Efficient Economy, *The 2010 State Energy Efficiency Scorecard*, Report E107, October 2010.
[59] Consortium for Energy Efficiency, *The State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts 2009*, March 2010.
[60] Discussed estimates of achievable efficiency potential include the development of recycled energy opportunities such as combined heat and power and waste-heat recovery projects.
[61] Chandler, S. and M. Brown, *Meta-Review of Efficiency Potential Studies and Their Implications for the South*, Georgia Tech, Working Paper #51, August 2009.
[62] Brown, M. et al, *Energy Efficiency in the South,* Georgia Tech, April 13, 2010; See specifically *Appendix G: State Profiles of Energy Efficiency Opportunities in the South.*

The various energy efficiency potential studies reviewed by Georgia Tech researchers strongly suggest that TVA can achieve significantly more energy efficiency than 7% by 2030 and the Draft IRP should reflect this greater potential. Based on this analysis, we suggest that TVA could achieve energy savings of 30 - 45,000 GWh by 2030 (Figure 23).

Figure 23: Energy Efficiency Potential in TVA Region, Based on Conclusions in Georgia Tech Meta-Analysis

	2030 Energy Savings (GWh)
Economic Potential	45,000
Maximum Achievable Potential	30,000
Maximum in Draft IRP, Scenario D	19,500
Maximum in Draft IRP, Scenario E	16,500

Based on Chandler, S. and M. Brown, *Meta-Review of Efficiency Potential Studies and Their Implications for the South*, Georgia Tech, Working Paper #51, August 2009; assuming 200,000 GWh in 2030.

Several issues with the EPRI study have also been identified that call into questions its accuracy. EPRI's analysis of efficiency potential in the TVA service territory involved applying the methodology and technology data developed for the EPRI National Study on the same subject.[63] Both McKinsey and Company and ACEEE challenged this methodology as over conservative. The fundamental problem with EPRI's analysis is, as explained by McKinsey & Company, "EPRI focuses on understanding existing programs and best practices to capture energy efficiency and analyzing likely achievability based on current experience."[64] Similarly, ACEEE notes:

> The EPRI/EEI estimates include only existing efficiency technologies and nothing that is not already commercialized and cost-effective. This is illustrated by the fact that the EPRI/EEI savings estimates are virtually the same in 2020 and 2030. Essentially, EPRI/EEI estimated 2020 potential and not 2030 potential, and did not take into account technology change or innovation that would create new efficiency opportunities in the 2020-2030 period.[65]

Both the McKinsey and ACEEE critiques of EPRI's approach are critical of the fact that EPRI does not take into account additional cost-effective efficiency opportunities for energy efficiency arising in the future. As a result of the EPRI study's failure to account for technological advances and innovation, McKinsey and ACEEE both conclude that EPRI's estimate is overly conservative.

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[63] Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: (2010- 2030). EPRI, Palo Alto, CA: 2009. 1016987

[64] McKinsey & Company, *EPRI and McKinsey Reports on Energy Efficiency: A Comparison*, October 2009.

[65] American Council for an Energy-Efficient Economy, *ACEEE Review of the Preliminary EPRI/EEI Estimates of Energy Efficiency Potential*, April 2008.

Further, the EPRI study conducted for TVA does not make effective use of advanced energy efficiency program methods to foster adoption of efficiency products and opportunities. For example, under EPRI's models, three incentive scenarios are considered: no incentives, 10% of incremental costs and 20% of incremental costs, amounting to 1.5 and 3.0 cents/kWh respectively. In contrast, national best practices consider incentives ranging as high as 100% of incremental costs because even these incentives levels are often less costly than developing supply-side resources. The EPRI study provides no discussion of a similar analysis for the TVA service territory.

Larger incentive levels are not the only program strategy overlooked by EPRI. A relatively new concept in residential energy auditing and education is the home energy comparison report. Based on the experience of utilities elsewhere in the country, deployment of this program across TVA's distribution utilities could save about 0.7% of annual energy use, or *one-tenth* of the total potential that EPRI claims is available in the TVA region over two decades. Recent measurement and verification studies of similar programs indicate an opportunity for almost immediate 2% residential energy savings.[66] Furthermore, Arizona Public Service (APS) notes that, "It is anticipated that in addition to achieving conservation related savings of approximately 2% usage reductions per household, this program can help increase participation in other efficiency programs by up to 25%."

In all, TVA's reliance on the EPRI study of achievable efficiency potential is misguided. We have raised these same issues with TVA staff through our position on the Stakeholder Review Group and, to TVA's credit, TVA staff have responded to our concerns by adding additional sensitivity runs that will be conducted before the IRP is finalized. The pending sensitivity runs[67] should help to reduce some of the impacts of the shortcoming identified in these comments. However, we would strongly recommend that TVA include energy efficiency contributions of at least 1% after a brief ramp-up period in the IRP model, and, in the longer term, undertake renewed analysis of the potential for energy efficiency to contribute significantly to meeting future electricity demand.

[66] Allcott, H., *Social Norms and Energy Conservation*, MIT Center for Energy and Environmental Policy Research Report 09-014, October 2009; and Summit Blue Consulting, LLC, *Impact Evaluation of OPOWER SMUD Pilot Study*, September 24, 2009.
[67] *Draft IRP, p. 125.*

3. **TVA's "high" scenario demand forecast is implausible. Portfolios developed with this scenario result in levels of resources that TVA is unlikely to utilize as scheduled.**

The Draft IRP's scenarios represent a range of potential demand growth, the high end of which is not realistic and should, therefore, not be included in the IRP model. While considering a range of growth scenarios is certainly reasonable, consideration of a 2% average annual growth rate across the entire 20-year planning period, as is represented in TVA's Scenario 1: Economy Recovers Dramatically, is implausible (Figures 24 and 25). TVA should either remove Scenario 1 from the analysis or substantially reduce the annual growth rate in that scenario.

Portfolios based on the inflated demand growth projections of Scenario 1 include excessive resource additions that influence the Draft IRP's conclusions. For example, TVA highlights that "Nuclear capacity is selected in 19 out of 28 possible portfolios."[68] However, based on Appendix C data, if Scenario 1 were removed, then nuclear capacity would be selected in only 15 of 24 possible portfolios. More dramatically, if Scenario 1 were removed, *the TVA plan would not contain a single portfolio with new coal generation*.

Figure 24: TVA Projected Generation Growth (GWh per year)

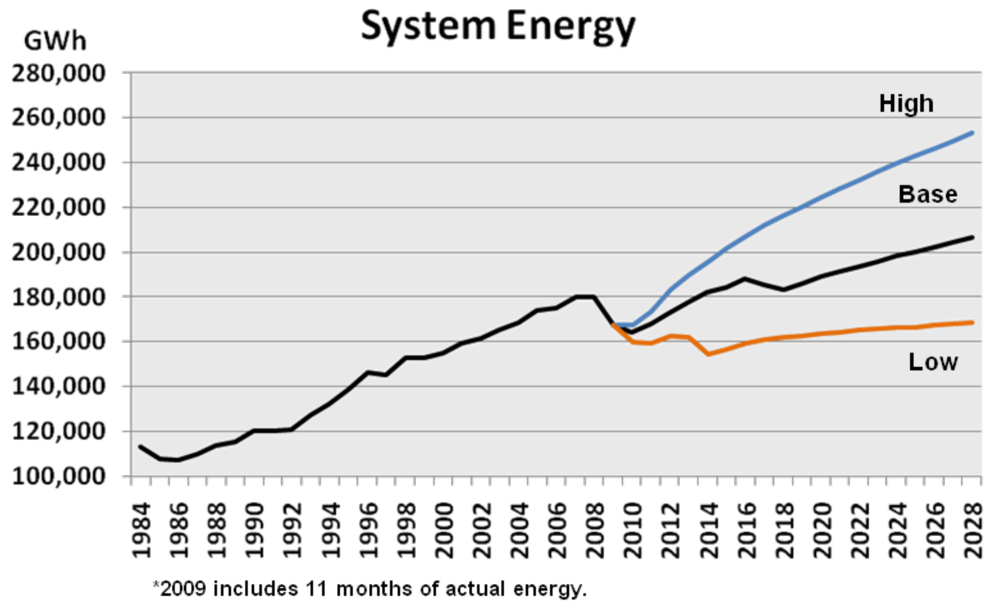
Scenario	2010	2028	Annual Growth
High (#1)	175,000	250,000	2.0%
Low (#3)	155,000	155,000	0.0%
Medium (#7)	165,000	200,000	1.1%

Scenario 1 does not represent either long-term historical trends or the historical link between population growth and growth in electrical demand.

Figure 25, shows TVA's load forecasts compared with historical trends. While TVA sales did increase rapidly in the early 1990s (i.e. by over 4% per year from 1992 to 1996), the trend in sales from 1998 through 2009 increased at an average of just 0.7% per year. In fact, when analyzed over the past 12 years, even the 1.1% annual load growth in the medium forecast (Scenario #7) is higher than the trend in historical load growth from the prior twelve years (0.7% per year). While growth is certainly likely to exceed 2% per year over a short period sometime in the future, current conditions do not indicate that 2% per year growth per year for 20 years is plausible absent some dramatic technology shift (e.g., widespread adoption of electric vehicles).

[68] *Draft IRP,* p. 111.

Figure 25: TVA Load Forecasts and Historical Trends

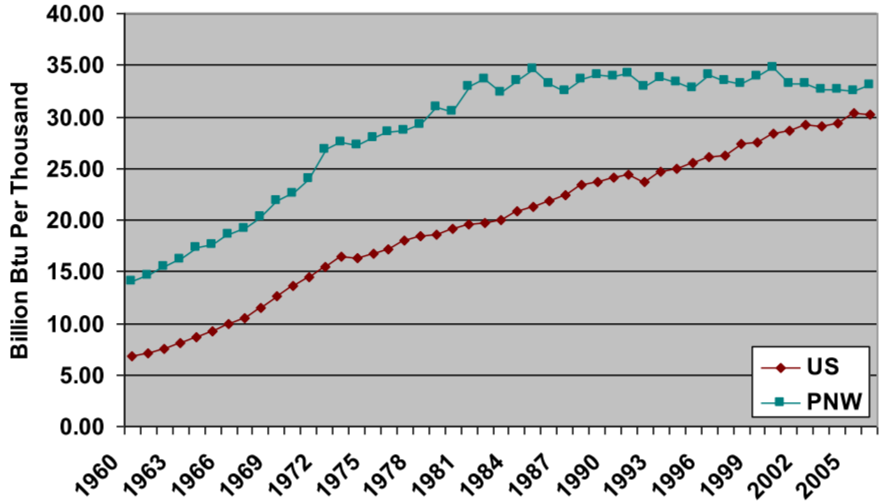


TVA, *Planning Inputs*, External Stakeholder Review Presentation, October 23, 2009.

We also challenge TVA's underlying assumption, apparent from the Draft IRP's scenarios, that growth in electricity demand is directly related to economic growth. California provides the classic long-term example that calls this link into question. Since the mid-1970s, per capita electric demand in California has been constant, at about 7,000 kWh per year per capita. At the same time, electric demand in the rest of the U.S. has grown by about 50%, to 12,000 kWh per capita in 2005. Even though California has experienced a wide variety of economic conditions over the past thirty years, none has had a major impact on the state's per capita electricity use.

Similarly, the Pacific Northwest region has held per capita residential and commercial electricity use essentially flat for three decades (Figure 26).

Figure 26: Residential and Commercial Electricity Use Per Capita, US Compared to the Pacific Northwest Region



Northwest Power and Conservation Council, Sixth Northwest Conservation and Electric Power Plan, Council Document 2010-09, February 2010, p. 1-9.

California and the Pacific Northwest have distinguished themselves by keeping per capita electric use constant over such a long period due in large part to energy efficiency programs. These regions have used comprehensive, consistently applied, continuously improved programs over several decades. Their success provides authoritative evidence that electricity demand is not necessarily linked to economic growth.

With the artificial link between economic growth and growth in electricity demand removed, it is more appropriate for the Draft IRP to model possible load growth based on potential population growth. According to US Census data, Tennessee's population grew by 0.9% per year from 2000 to 2010. Similarly, TVA's electric sales increased at a rate of 0.8% per year over the decade from 1998 to 2009. It would therefore seem that an assumption that load growth should be consistent with constant per capita electric use is more reasonable than the assumption that load growth is directly related to economic growth.

The implausibility of the high load growth numbers are suggested by a comparison to California forecasts. Coincidentally, California and Tennessee are forecast by the US Census Bureau to have similar population growth rates through 2030.[69] Nevertheless, TVA and the California Energy Commission have very different ideas regarding maximum growth rates for electricity use.

- TVA's stochastic analysis takes load growth well beyond the 2% per year assumed in Scenario 1. While the exact values used by TVA are considered confidential, for illustrative purposes we can assume that TVA analyzed a range of ± 1/3, or 1.3% to 2.7%, for Scenario 1.
- The highest recent load growth scenario by the California Energy Commission is 1.2% per year, which did not take into consideration many of the state's energy

[69] U.S. Census Bureau, Population Division, *Interim State Population Projections*, 2005.

efficiency programs and goals.[70] Using the same ± 1/3 range of analysis, we could consider an upper bound of 1.6% per year.

Applying these population and load forecasts to each state through 2030 would suggest that California's per capita electricity use would be about 7,600 kWh per year and Tennessee's per capita electricity use would be about 21,000 kWh per year. It is clearly absurd to anticipate that TVA's customers will be using nearly three times as much electricity as California energy users within two decades. While we understand the purpose of the scenario, TVA notes several times that scenarios are meant to be "plausible."

We recommend that TVA revise the range of demand growth in its scenarios to reflect a range of 0% (low) to 1.2% (high), with a medium case at 0.7% per year based on the recent historical trend in TVA loads from 1998 to 2009.[71] In particular, the high Scenario 1 forecast, which assumes rapid economic recovery, should assume median (50th percentile) load growth that is not above 1.2% per year over 2008 loads, which is the rate of load growth over the last 18 years, including the high-growth years of the 1990s.

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[70] California Energy Commission, *California Energy Demand 2010-2020, Adopted Forecast*, CEC-200-2009-012-CMF, December 2009.

[71] We are aware that TVA is either considering, or has decided to, revise its baseline forecast to indicate lower long-term growth rates for the Valley. If TVA makes this revision, it provides further support for substantially decreasing projected growth in the high growth scenario.

4. TVA has not properly estimated natural gas and nuclear resource costs such that it may impair the Draft IRP's ability to choose the best resource portfolio.

The Draft IRP's cost estimates for natural gas and nuclear generation appear flawed. As a result, the Draft IRP's selection of future generation resources may be skewed.

While the draft documents do not provide a discussion of the resource cost estimates used in the Draft IRP, TVA shared its cost estimates for various resource options in presentations to the Stakeholder Review Group.[72] TVA also provided the Stakeholder Review Group with confidential material providing further details on its resource cost estimates.[73] Based on an analysis of these estimates, we recommend TVA review and revise its projections of natural gas prices, nuclear resource costs, and solar PV costs (discussed earlier in these comments).

a. Natural gas fuel cost projections

The Draft IRP relies on projections of natural gas prices that appear too high when compared with reference market forecasts. According to TVA, it considers five "key drivers" when developing its long-range price forecasts for natural gas.[74]

- Production cost
- Domestic and global supply
- Storage conditions and accessibility
- Regulatory developments (e.g., emission limits)
- Competing fuel sources

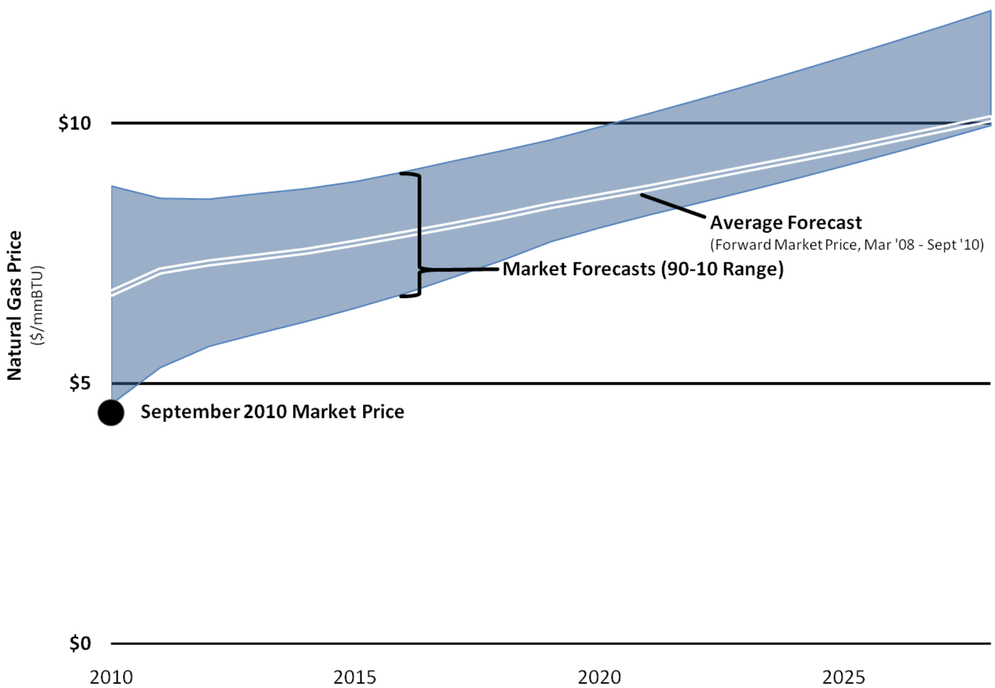
TVA uses the NYMEX Henry Hub natural gas market price forecast for its commodity forecasts. To a large extent, this market price forecast will take into account these same "key drivers" to the extent that market traders are able to form an opinion regarding potential impacts on market prices.

For comparison, SACE obtained the assistance of Crossborder Energy in analyzing forward market prices at the Henry Hub. Crossborder Energy used an approach that is similar to the method that the California Public Utilities Commission uses to forecast long-term gas market prices for its benchmark "market price referent."[75] Rather than using a single day's forward market prices, the CPUC reduces volatility by sampling Henry Hub forward market prices over a 22-day period.

[72] TVA, *Supply Resource Options,* presentation to the Stakeholder Review Group, October 22, 2009; and TVA, *Stakeholder Review Group Working Session*, presentation to the Stakeholder Review Group, February 17, 2010.
[73] TVA, *Range of Stochastic Variables*, September 20, 2010 informational report to the Stakeholder Review Group.
[74] TVA, *Planning Inputs*, presentation to the Stakeholder Review Group, October 23, 2009.
[75] The MPR is the key pricing benchmark in the California renewable energy program, and is similar to an avoided cost estimate in some respects.

Crossborder Energy sampled over a longer period of time to consider a broad range of gas market conditions,[76]selecting one set of forward market prices for each of the past 31 months, generally sampling on the first day of the month. The three highest and lowest values were excluded, providing a "90-10" range of values. The period sampled includes periods with very high and very low prices, reflecting a wide range of price environments, as illustrated in Figure 27.

Figure 27: Natural Gas Price Projections, Henry Hub Forward Market Prices



Crossborder Energy, analysis provided to Southern Alliance for Clean Energy, October 2010.

In general, the natural gas price projections used by TVA for many of the scenarios in the Draft IRP are significantly higher than market forecasts for the second decade of the planning period. This is surprising, since we understood that TVA based its natural gas price forecasts on the same data that Crossborder Energy analyzed for SACE. The divergence is particularly large for the "Economic Recovery" scenario which appears to consider a range of natural gas prices in the 2025-2030 time period that are inconsistent with market price projections.

Natural gas price forecasts are a particularly important component of the models used to develop the Draft IRP because natural gas fuel prices often serve as the marginal cost, or basis for the marginal price, against which other energy resources are measured.

[76] Crossborder Energy noted that current forward gas prices are at the lowest level over the past several years, so its analysis provided us with references from periods with higher forward market prices as well as current, lower forward market prices.

Therefore an artificially high natural gas price forecast would likely result in model results skewed in favor of decreased coal retirements and the quicker build out of nuclear capacity. This is even more pronounced under the current IRP because TVA's model does not allow renewable energy or energy efficiency capacity to be increased in portfolio outputs. If TVA were to adopt a lower natural gas price forecast that is more in line with market forecasts, the IRP model would likely correct itself in favor of increased coal retirements and delays in adding nuclear capacity.

It is reasonable for TVA to consider a wide range of natural gas price projections in the development of its plan. Nevertheless, TVA's projections should be grounded in market fundamentals, and be adjusted in a manner that is systematic. Since we lack full information regarding TVA's methods for developing its natural gas price scenarios, we cannot reach a clear conclusion regarding these projections. However, we recommend that TVA re-evaluate its natural gas price scenarios for the Final IRP.

b. Nuclear resource cost estimates

TVA appears to have estimated inappropriately low costs for its AP1000 nuclear reactor cost estimate. While TVA provided members of the Stakeholder Review Group with information regarding its capital cost estimate for nuclear units, the only data provided regarding other nuclear costs was in the form of a levelized cost component comparison, with the levelized cost indicated as $71 per MWh.[77] We compared the figures presented by TVA with the output of the *California Energy Commission's Cost of Generation Model*.[78]

SACE operated the model using default assumptions with input selections that appeared to most closely match TVA circumstances.[79] Using the CEC model, we found significant discrepancies between the levelized cost components used by TVA and those suggested by the CEC model (Figure 28).

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[77] TVA, *Stakeholder Review Group Working Session*, presentation to the Stakeholder Review Group, February 17, 2010, slide 29.
[78] California Energy Commission, *Cost of Generation Model User's Guide: Version 2*, Publication CEC-200-2010-002, April 2010. Model version 2.02 was applied.
[79] For example, the "Default POU" ownership type was selected.

Figure 28: Comparison of AP1000 Nuclear Unit Levelized Cost Components From TVA With CEC Model Outputs ($/MWh – 2009 dollars)

Components	**CEC Model Outputs**	**TVA Data**
Capital & Financing Costs, Taxes, and Insurance	54	42
Fixed O&M	28	15
Nuclear Decommissioning	0	0
Fuel	11	13
Variable O&M	7	1
Total Levelized Cost ($ / MWh)	**$ 100**	**$ 71**

CEC Cost of Generation Model, version 2.02; and TVA, *Stakeholder Review Group Working Session*, presentation to the Stakeholder Review Group, February 17, 2010, slide 29.

TVA's estimates are substantially lower than the CEC model with respect to capital costs, fixed O&M and variable O&M costs.

- With respect to capital costs, we verified that the "instant" cost estimated in the CEC model ($3,900 per kW) is comparable with the TVA estimate ($3,700 to $4,300 per kW[80]). We also varied certain financial parameters (e.g., interest rates, financing periods, and inflation rates); these adjustments affected the CEC model output by no more than $5, which fails to reconcile the results. We also considered whether TVA may be assuming use of existing land and other infrastructure, but presumably this would be reflected in the "instant" cost estimate and would not be a factor in the levelized cost discrepancy.
- With respect to Fixed O&M and Variable O&M, we were unable to identify any assumptions that might explain the discrepancies. While labor costs and other factors affecting O&M costs may be lower in the TVA region compared to California, this is unlikely to explain the substantial differences.

The CEC model's review of nuclear resource development costs is highly transparent and conducted by credible consulting firms.[81] While SACE provided this review to TVA during the SRG process, there is no indication that TVA considered these data in its analysis.

Our review of TVA model results left us somewhat uncertain what the impact of higher nuclear costs might be on model results. It appears that the primary alternatives to nuclear power would be natural gas capacity and delays in coal retirements because TVA's model does not allow renewable energy or energy efficiency capacity to be increased in portfolio outputs. However, based on our analysis, we recommend that TVA re-evaluate its nuclear power costs for the Final IRP for both the AP1000 and the BLN BW2005[82] nuclear technologies.

[80] TVA, *Stakeholder Review Group Working Session*, presentation to the Stakeholder Review Group, February 17, 2010, slide 29.

[81] KEMA, Inc., *Renewable Energy Cost of Generation Update*, prepared for California Energy Commission, PIER Interim Project Report CEC-500-2009-084, August 2009.

[82] Because no other utilities are planning BLN BW2005 technology, there are no external benchmarks to compare with TVA data.

5. **TVA's inclusion of a $0 cost estimate for GHG requirements artificially skews the model towards higher levels of fossil-fuel generation.**

Even excluding the possibility of federal regulation of greenhouse gas (GHG) emissions, the inclusion of a zero-cost estimate for greenhouse gas requirements is not reasonable. U.S. utilities, including TVA, will continue to face mounting public, regulatory and international pressure to reduce GHG emissions. Because of this mounting pressure, U.S. utilities will almost certainly face future costs to reduce GHG emissions. Therefore, it would seem more reasonable for the Draft IRP to place the lower bound of potential GHG reduction costs at a level higher than $0, the figure utilized in Scenario 3 of the Draft IRP.[83]

To calculate a minimum bound of the GHG cost uncertainty, it would be more reasonable for TVA to look to the European Union (EU) market – the most comprehensive carbon emission allowance market in the world. The EU carbon market for 2010 allowances is currently trading at about $19 per short ton (as reported by Evolution Markets). While TVA does not interact with this market, current prices on the EU carbon market give a good indication of the current costs of reducing greenhouse gas emissions.

In the longer-run, TVA should look at "meta-studies" that have sought to synthesize available projections of the costs of mitigating GHG emissions. In 2007, Synapse Energy Economics prepared a meta-study of the available models of long-term GHG mitigation costs, including models run by EIA, EPA, MIT, and the Tellus Institute.[84] Synapse used this work to prepare low, medium, and high projections for GHG mitigation costs in 2020 and 2030 (Figure 29).

Figure 29: Synapse GHG Mitigation Cost Forecasts (nominal $ per ton CO_2)

Year / Case	Low	Medium	High
2015	$7	$21	$26
2020	$14	$36	$58
2025	$26	$51	$75
2030	$37	$65	$93

Adjusted to 2010 dollars, assuming a 2.5% annual inflation rate.
Synapse Energy Economics, *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning*, p. 50-55.

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[83] See *Draft EIS,* p. 28.
[84] Synapse Energy Economics, *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning*, p. 50-55.

While the IRP's Medium and High GHG prices are similar to the Low-to-High range of the Synapse projections, TVA's low price of $0.00 for the long-term essentially assumes that there will be no future need to reduce GHG emissions. This assumption is not reasonable in light of EPA's recent Endangerment Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act.[85] This finding, in response to a Supreme Court order[86], formally declared carbon dioxide and five other heat-trapping gases to be pollutants that endanger public health and welfare. The finding is also the first step towards the implementation of regulations that will govern the emissions of greenhouse gases. Given these regulatory happenings, it would be more appropriate for TVA to assume that some level of greenhouse gas regulation will be implemented over the course of the planning period.

The impact of TVA's $0 GHG price assumption is that the potential cost and risk of either developing additional carbon-intensive resources or declining to reduce TVA's carbon footprint is artificially reduced. TVA should revise IRP Scenario 3 to include a non-zero, lower end, albeit modest, price on carbon.

[85] Environmental Protection Agency, *Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act.* December 7, 2009.
[86] *Massachusetts v. EPA*, 549 U.S. 497 (2007).

6. The Draft IRP's economic impact indicator may not provide meaningful distinctions among the different resource portfolios.

While TVA reasonably selected the REMI Policy Insight model to conduct its economic impact indicator analysis, it is not clear that the analysis was conducted in a manner to provide meaningful distinctions between the various resource options. The analysis was rushed, did not clearly adopt best practices from similar projects that also used the REMI Policy Insight model, and was incomplete in several ways that may have adversely affected TVA's observations about the model results.

The Stakeholder Review Group did not have an adequate opportunity to provide feedback and impact the development of the economic impact indicator.

TVA did not develop the economic impact indicator until late in the process; the evaluation method was presented to the Stakeholder Review Group on July 21, 2010. The presentation offered a general overview of the REMI Policy Insight model.

During the presentation, a number of questions were raised relating to aspects of the model application that TVA staff had not considered due to resource constraints that affected the schedule. Some of the questions and topics of discussion were noted in the minutes:[87]

- Does the model you are running account for investment inside or outside the valley [for renewables]? – the model spits out jobs, economic development and investment
- Can the model reflect the reality of the Tennessee valley region being in position to be a clean energy producer?
- Make sure the economic development indicators are appropriate assessments
- Look into using the JEDI model
- Can the model assess the impact of Energy Efficiency consumer savings in economic development?

As participants in this meeting, we were not confident that TVA had developed this metric in a manner that is well adapted to its purpose.

[87] TVA Integrated Resource Plan Stakeholder Review Group, Working Session Meeting Minutes, July 20-21, 2010.

SRG members continued to express concerns at the August 26, 2010 meeting. The meeting notes reflect concern about the economic and technology innovation metrics as lacking a "level of rigor" equal to the financial indicators. Relevant comments or questions noted in the minutes include:[88]

- Still have concerns on the economic development strategic metric in terms of the rigor and inputs – hard to sort through how conclusions were reached. Can lead to skewed interpretation of results
    - (It was stated that the IRP is not supposed to predict an economic development strategy for TVA but is meant to set a pathway for TVA. From the analysis, it is evident that the impact is pretty small).
- May be more appropriate to change economic development to economic impact because economic development implies that the economy is "developing" as a result of what TVA is doing; but, if it is a result of what happens in a strategy, might be considered economic development.

To date, we have not been presented with additional information that addresses the concerns raised at the SRG meeting and have not had an opportunity to fully understand, much less evaluate and provide feedback on, the Draft IRP's economic indicator metric.

REMI Policy Insight is a highly regarded tool for analysis of economic impacts and has been successfully applied to provide useful information for similar projects.

There are a number of tools that may be used to assess the economic benefits of energy plans or projects. According to a US Environmental Protection Agency report, the REMI Policy Insight model is the "most sophisticated" approach for conducting economic analysis of energy policy or projects.[89]

However, the EPA report's praise for the REMI Policy Insight model is accompanied by some cautions.

- The REMI model can "require a fair amount of massaging inputs, especially with energy sector inputs." EPA notes that, "Many states have found that detailed energy-related analyses require energy modeling to be done separately and used as inputs to a hybrid model."
- It is "important to examine how [the] energy sector is treated."
- Default data provided in the REMI model may need to be updated "to account for most recent energy assumptions."

Other applications of the REMI model to energy policy issues illustrate how these cautions may be addressed.

The need for customized inputs is illustrated in a 2004 study of energy efficiency activities for Massachusetts.[90] In order to model expenditures on energy efficiency products and services, a firm developed "Bill of Goods" data which desegregated energy efficiency

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[88] TVA Integrated Resource Plan Stakeholder Review Group, Working Session Meeting Minutes, August 26, 2010.

[89] US Environmental Protection Agency, *Assessing the Multiple Benefits of Clean Energy: A Resource for States*, Climate Protection Partnerships Division,

[90] Massachusetts Division of Energy Resources, *2002 Energy Efficiency Activities*, Office of Consumer Affairs and Business Regulation, Summer 2004.

expenditures across specific industry sectors. Examples of sectors with energy efficiency related demand are manufacturing, including spending on windows, insulation, HVAC controls, and motors; plastics and rubber industry products; and professional and business services. Changes in these and other industries' demand were input as policy variables to the REMI model.

A similar approach was used by NYSERDA to analyze the economic impact of its programs. Product sales data were obtained directly from NYSERDA financial records generated as a result of "recoupment agreements" with funding recipients. These data were mapped to economic sectors for entry into the REMI policy insight model.[91]

A particularly detailed discussion of the process of analyzing economic impacts of energy programs is provided in an Economic Development Research Group report on Wisconsin's energy efficiency and renewable energy programs.[92] Some of the key steps considered necessary to use of the REMI model in the Wisconsin study include:

- Use program evaluation report data to estimate program spending, program participant spending, induced spending by non-participants, direct financial benefits (particularly energy cost savings), and shifts in retail energy sales and development business.
- Reduction in power plant emissions, resulting in reduced energy generation costs.

These data were then mapped to the relevant industries; program evaluators assisted with determining to what extent these products and services are provided by in-state firms.

Effective use of the REMI model should provide a clear understanding of four types of economic development impacts, as described in the Wisconsin study:

- "Increased efficiency, conservation, and lower emission compliance costs" can decrease energy costs, which in turn enhances "business competitiveness."
- These decreased energy costs also lower the cost of living for current residents and make the state a more attractive place to live and work.
- The programs "stimulate sales" for in-state manufacturers and other firms involved in developing in-state "solar, wind and biomass energy production." This "import substitution" effect stimulates job creation, increases personal income, and makes the economy more competitive.
- Spending changes induced by energy programs are "both positive and negative." Some businesses see "less growth (or actual reductions) in business sales and jobs," while other firms can "realize increased orders."

The Wisconsin study provides a good example of how the REMI Policy Insight model can be used to cover "all aspects of changes in the economy," including changes in business sales, gross regional product, real after-tax income, and jobs (Figure 30).

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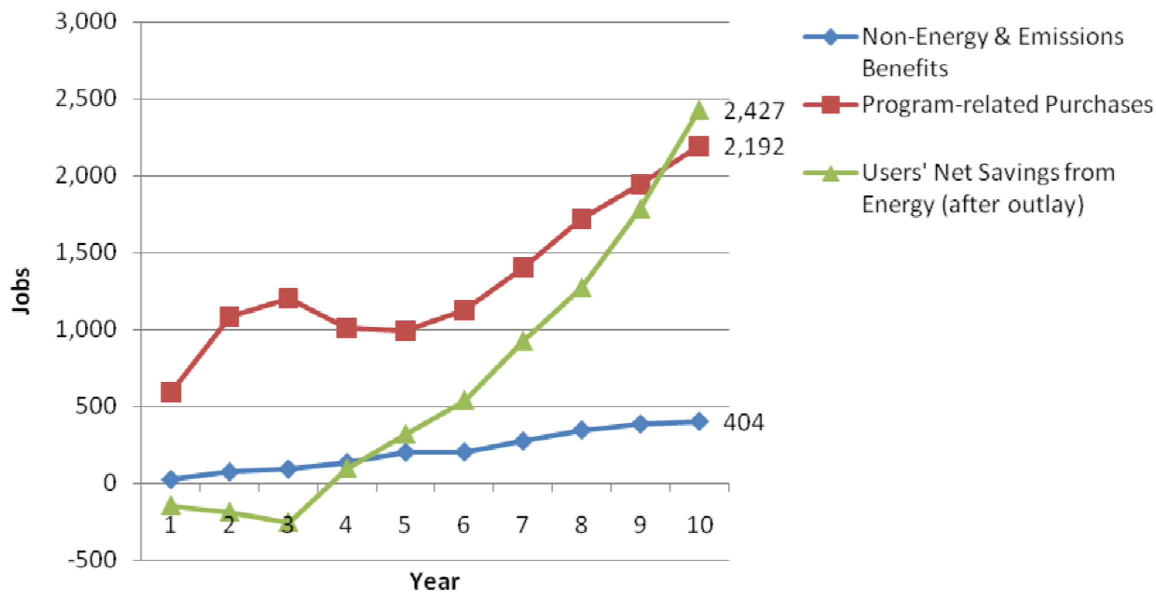
[91] New York State Energy Research and Development Authority (NYSERDA), *New York Energy $mart^SM Program Evaluation and Status Report, Year Ending December 31, 2008,* report to the Public Service Commission, March 2009.
[92] Economic Development Research Group (EDRG), *Focus on Energy Evaluation, Economic Development Benefits: CY09 Economic Impacts*, report to Public Service Commission of Washington, March 2, 2010.

Figure 30: REMI Model Estimates of Employment Impacts for Focus on Wisconsin Programs



Economic Development Research Group (EDRG), *Focus on Energy Evaluation, Economic Development Benefits: CY09 Economic Impacts*, report to Public Service Commission of Washington, March 2, 2010.

In sum, the REMI model has been used in a variety of ways to analyze the economic impacts of resource development strategies. However, the experiences of the stakeholder Review Group, coupled with modest discussion of this tool's use in the Draft IRP and EIS, does not give us confidence that this tool was used successfully by TVA in its assessment of the Draft IRP's model outputs.

The Draft IRP does not indicate that the types of data necessary to assess energy efficiency and renewable energy were developed and used in the REMI model. If this step was not completed, the model results may be misleading.

While TVA has used the REMI Policy Insight model in the past to assess its energy projects, these projects have likely been "conventional" energy projects such as natural gas, coal and nuclear development projects. TVA's investment in energy efficiency and renewable energy has increased recently, but it is not clear that TVA has yet invested in developing the necessary model inputs to ensure that these new clean energy resources are adequately modeled.

The Draft IRP discusses the methodology used to run TVA's regional economic model, and specifically mentions the entry of "annual construction expenses" and "annual operations expense data." Some detail is offered, such as an explanation of the application of fuel purchase expenses to areas outside the Valley, and methods for estimating customer energy costs and savings attributable to the various portfolio resource mixes.

However, the Draft IRP gives no indication that resource expenditures associated with energy efficiency and renewable energy programs were estimated and mapped to specific industries. Nor is there any discussion given to how any such expenditure was allocated geographically. In contrast to the accurate allocation of fuel purchase expenses outside the Valley, there is no indication that TVA has allocated energy efficiency or renewable energy product and service expenditures appropriately.

Limiting the data to the most extreme cases may bias TVA's calculation of the economic impact indicator.

TVA limited its analysis of economic impacts for each strategy to Scenario 1 and Scenario 6, due to time or resource constraints. TVA considered this reasonable because the two Scenarios would define the "upper and lower range of the impacts of the strategies within the scenario range."[93]

Even though TVA states that its use of scenarios does not "assign probabilities or likelihoods to certain futures arising," by selecting only two scenarios for analysis in this measure, there is a certain implication that each of these two scenarios represents a plausible boundary on impacts. This implication is not clearly supported because:

- TVA did not develop the scenarios to explore a linear relationship with two boundaries,
- Scenario 1 is problematic due to an unreasonably high average annual load growth rate and unreasonably high natural gas price projections, and
- The REMI Policy Insight model was not clearly configured in a manner that estimated benefits in an accurate and consistent manner.

We are not certain that providing model output for all six scenarios will result in a credible economic impact indicator, but it should not be assumed that output for two scenarios provides adequate information without conducting further analysis across at least one strategy.

Ideally, TVA would revisit the economic impact indicator prior to finalizing the IRP. Due to time constraints, however, this may not be practical. At a minimum, TVA should address these shortcomings in the final IRP and EIS and acknowledge the need to expand its analysis to include the proper valuation of efficiency and renewable energy resources. Considering the importance of economic development to the mission of the TVA and to the people who live and work in the Valley, this aspect of the resource plan should be better developed.

[93] TVA, *Draft IRP*, p. 141. The Stakeholder Review Group had limited opportunity to comment on this decision; it was only mentioned once, during open discussion late in the August 26, 2010 SRG meeting.

7. The Draft IRP and EIS do not include certain pieces of information that would inform a more comprehensive review of TVA's options:

In addition to the issues identified above, the Draft IRP and IES are silent on certain key pieces of information that would allow for more meaningful input by the public in this commenting process.

a. A discussion of purchased power as an energy resource option

In order to fully evaluate all of TVA's resource options for meeting future energy demand, the Draft IRP and accompanying EIS should include a discussion of purchased power, including recycled energy installations, as an energy resource option.

It is clear from the draft documents that TVA considers purchase power to be a viable resource option for meeting future energy demand. The discussion regarding renewable energy options, particularly wind and solar, indicate that TVA considers power purchase agreements to be the primary method for adding these resources to TVA's generation portfolio. Also, nearly all of the model's portfolio outputs contain some level of power purchases to meet future energy demand. However, the draft documents provide almost no discussion of purchase power as a resource option to meet future energy demand.

While a brief discussion of current power purchase agreements is provided in the Draft EIS[94], the Draft IRP and Draft EIS are silent on purchased power as a potential future resource. Cost estimates, a discussion of the resource's potential contributions, or a discussion of the relative costs and benefits of pursuing this as a resource option are not provided in the draft documents. At a minimum, the Draft IRP and EIS should provide a description of how this resource was modeled and how it was modeled as a proxy for a number of technologies that were not modeled. Once this information is provided, a more informed review of TVA's resource options for meeting future energy demand is possible.

Of particular interest would be a discussion of the potential for recycled energy technologies to contribute to TVA power needs through the use of PPAs. SACE has engaged in discussions with leading developers of recycled energy technologies that indicate hundreds, possibly thousands of MW of potential are available for development across the TVA service territory[95], yet the Draft IRP and EIS provide no discussion of these technologies.[96]

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[94] *Draft EIS,* p. 44

[95] For example, a high-level potential study conducted by a developer of recycled energy technologies estimates as much as 4,300 MW of potential for recycled energy in Tennessee alone.

[96] In conversations with TVA staff, it is apparent that TVA has no current initiative in place to identify and develop recycled energy technologies. However, this does not obviate the need to analyze this resource in the context of this IRP process.

b. **Model outputs in terms of energy use per resource type:**

While the Draft IRP and EIS provide a generally complete description of the model outputs in terms of capacity, they do not provide an adequate description of the model outputs in terms of energy generated or saved by resource type.

Providing levels of generation by resource type for the models portfolio outputs is critical to a thorough review of the Draft IRP's results. Levels of generation are directly correlated to several of the Draft IRP's uncertainties, including GHG and environmental compliance costs, and the Draft IRP's evaluation metrics, including cost, risk and environmental performance.

In order to truly evaluate the various resource portfolio options and provide meaningful comment on their potential impact on the Valley's environmental and economic future, it is critical that Valley stakeholders be able to understand how the various resource portfolios differ in terms of generation output by resource type. Without this level of understanding, it is difficult to truly evaluate the various options and determine whether the Draft IRP is, in fact, presenting the best path forward towards meeting the Valley's future energy demand.

SACE respectfully submits these comments in response to TVA's Draft Integrated Resource plan and Programmatic Environmental Impact Statement. We look forward to working with TVA to address these concerns.

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Attachments

1. Southern Alliance for Clean Energy, *Yes We Can: Southern Solutions for a National Renewable Energy Standard*, February 2009.

2. Navigant Consulting, *Independent Solar Assessment*, completed for the Southern Alliance for Clean Energy, November 2010.

3. Seawell, R. C., *Woody Biomass Supply and Forest Resource Issues*, Larson & McGowin, Inc., prepared for Southern Alliance for Clean Energy, November 1, 2010.