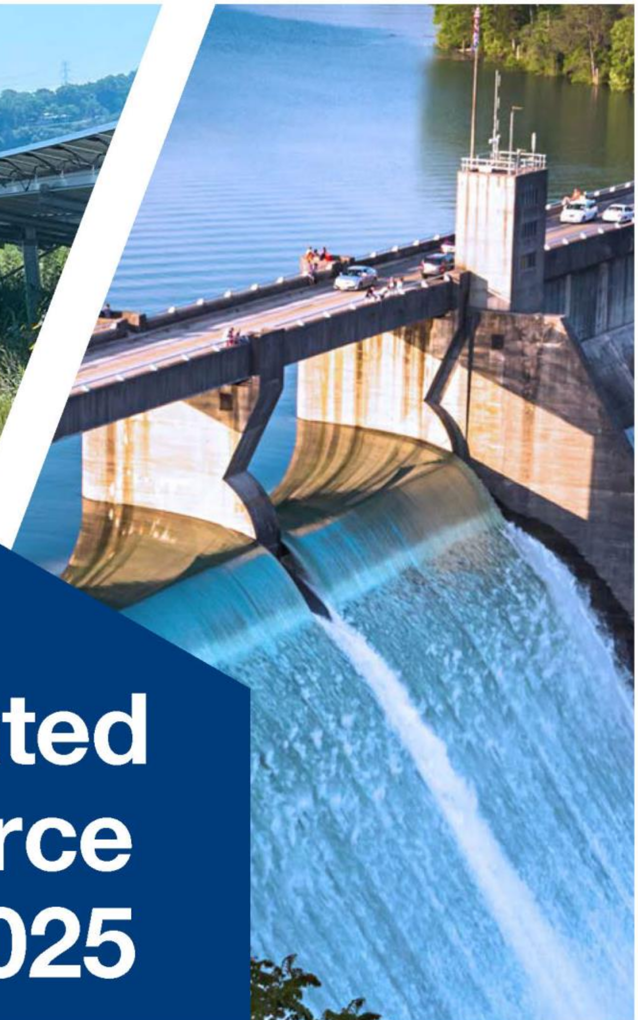


Integrated Resource Plan 2025

VOLUME 1 / DRAFT RESOURCE PLAN

SEPTEMBER 2024

TVA

TENNESSEE VALLEY AUTHORITY

Tennessee Valley Authority, 400 West Summit Hill Drive, Knoxville, Tennessee 37902-1401

September 2024

We're excited to share with you TVA's draft 2025 Integrated Resource Plan (IRP) and programmatic Environmental Impact Statement (EIS). The IRP is a comprehensive, transparent study that evaluates how TVA could meet the energy needs of the Valley region for the coming decades. It considers resource needs and options, as well as physical and operational constraints, risks, and proposed resource choices. The IRP provides strategic direction for how TVA can continue to provide affordable, reliable, resilient, and increasingly cleaner power to the Tennessee Valley region. The accompanying EIS analyzes potential environmental impacts to the Valley that could result from the IRP.

Since our last IRP was completed in 2019, we have been paying close attention to key signposts – or market signals – to inform the timing of our next IRP. Over the past few years, we have experienced residential and industrial growth in the region, policy and regulatory changes, and advancements in emerging technologies, and we expect these to continue as we look forward. These changes indicated it was time to re-evaluate planning assumptions and begin work on the 2025 IRP.

TVA has solicited input from stakeholders around the Valley region to develop these draft documents and has worked closely with the IRP Working Group (IRP-WG) throughout the IRP planning process. The IRP-WG, a diverse stakeholder group, consists of 24 members representing TVA local power companies and direct served customers, research and academia, energy and environment non-governmental organizations, state and federal government, and community and economic development leaders.

The 2025 IRP is an important tool to shape how TVA provides power to the Valley region through 2050. TVA staff and the IRP-WG have designed the framework of the IRP scenarios and strategies, established inputs and assumptions, analyzed outputs, developed evaluation criteria, and evaluated results. The result of that work is the draft 2025 IRP, and the draft EIS evaluates the impacts of the IRP.

The documents are available for review and public comment through November 26. We encourage you to review the documents and share your thoughts and feedback. The documents and feedback form may be found at www.tva.com/irp. In addition, we will be holding virtual public meetings and a number of in-person meetings around the Valley region throughout the public comment period to share the IRP and EIS and answer questions. More information about those meetings, including dates and locations, may be found at www.tva.com/irp.

Thank you in advance for your interest, review, and feedback. Your comments will inform the recommendations that will be outlined in the final reports.

Sincerely,

Brian M. Child	Melanie E. Farrell
Brian M. Child	Melanie E. Farrell
Vice President Enterprise Planning	Vice President Valley Engagement and Strategy

Executive Summary

Introduction

For more than 90 years, the Tennessee Valley Authority (TVA) has executed its mission to serve the Valley region – to provide affordable and reliable power, be a responsible steward of the environment, and support economic development. That mission continues as TVA is planning the future energy system, working to ensure power for the region for the coming decades.

TVA's 2025 Integrated Resource Plan (IRP) and associated programmatic Environmental Impact Statement (EIS) evaluate the long-term demand for power in the TVA region, the resource options available for meeting that demand, and the potential environmental, economic, and operating impacts of these options. Stakeholder input on what they would like to see in the future power system is integral to TVA's IRP process. The IRP will provide strategic direction for meeting the energy needs of TVA's customers and residents of the Valley region between now and 2050, establishing a strong planning foundation and informing TVA's next long-range financial plan.

Why is the IRP Important?

Having the right resources at the right time to power the homes and businesses in the region requires continual and proactive planning, as it takes several years or more to develop and build new power plants to serve the region's energy needs. Periodically, TVA develops an IRP that goes beyond annual updates to take a broader view of potential electricity demand, evolving regulations, and technology advancements, and it incorporates stakeholder input into the planning process.

We live and work in one of the fastest growing regions in the nation, and strides are being made in new clean energy technologies, making the work of this IRP especially important. The IRP recommendations will shape the future power system, ensuring that the region has affordable, reliable, resilient, and increasingly cleaner energy for decades to come.

What some IRP Working Group members had to say about the importance of TVA's 2025 IRP

"It has been enlightening to be part of TVA's IRP process. TVA's efforts to bring diverse viewpoints into the room during IRP Working Group meetings make this IRP stronger."

- Dr. Kendra Abkowitz, Sustainability Chief, City of Nashville

"The Valley faces important decisions as we tackle challenges such as shifting environmental policies and conflicting political priorities to new and expensive generation technologies. The stakes are high, so we need to get this right."

- Wes Kelley, President and CEO, Huntsville Utilities

"TVA is at a critical inflection point, and the steps our nation's largest public power provider takes to decarbonize in the IRP can position the Valley as a leader in the 21st century economy."

- David Rogers, Deputy Director Beyond Coal, Sierra Club

TVA Overview

TVA's Mission

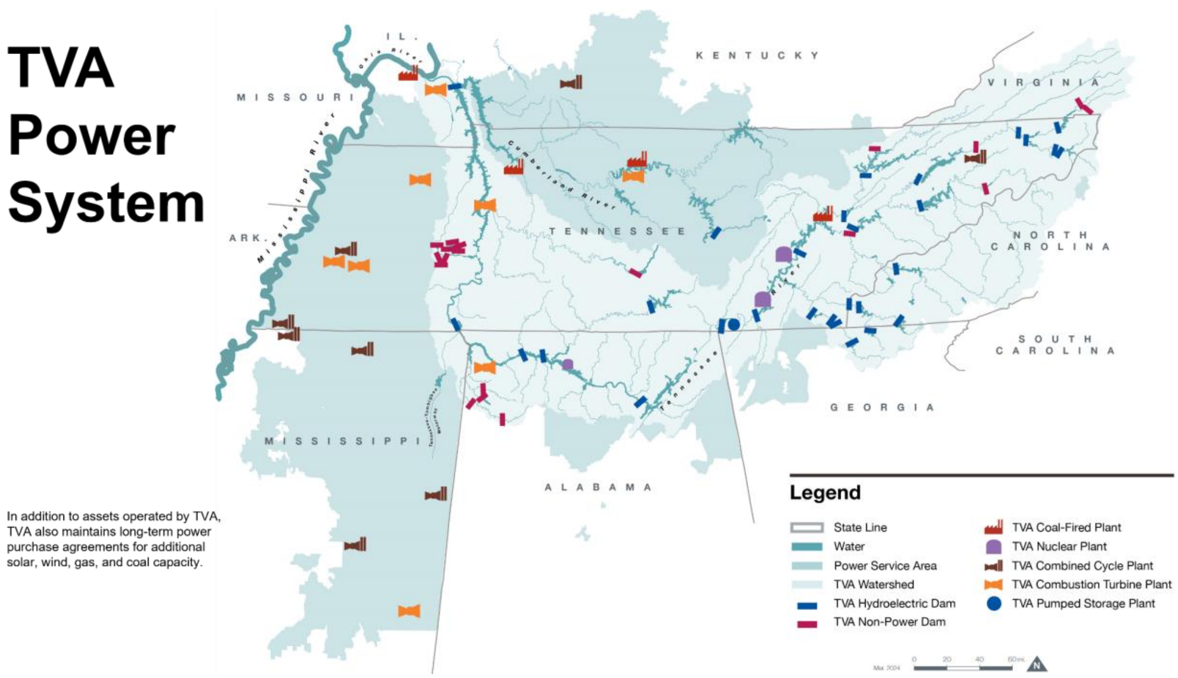
TVA was created by Congress in 1933 and charged with a unique mission – to improve the quality of life in the Valley through the integrated management of the region's resources. For more than 90 years, TVA has carried out this mission to serve the region, providing affordable and reliable energy, being a responsible steward of the environment, and supporting economic development. TVA funds virtually all operations through electricity sales and power system bond financing. TVA sets rates as low as feasible and reinvests net income into power system improvements and economic development initiatives. In addition to operating and investing its revenues in its electric system, TVA provides flood control, navigation, land management and natural resource stewardship for the Tennessee River watershed.

To achieve its mission in today's environment, TVA is focused on five strategic priorities – People Advantage, Powerful Partnerships, Operational Excellence, Igniting Innovation, and Financial Strength. In concert with its mission and priorities, TVA is a leader in reducing carbon emissions and aspires to achieve net-zero by 2050.

Who We Serve

As the nation's largest public power supplier, TVA delivers affordable, reliable, and increasingly cleaner electricity to 153 local power companies and 60 direct served customers. The TVA power system serves approximately 10 million people in a seven-state, 80,000 square-mile region. TVA's portfolio has evolved over the years to a more diverse, reliable, and cleaner mix of generation resources, which today provides 55% carbon-free power. In Fiscal Year (FY) 2023, TVA delivered more than 157 billion kilowatt-hours of electricity to customers from a power supply that was 42% nuclear, 31% natural gas, 14% coal-fired, 9% hydro, and 4% wind and solar. Additionally, TVA programmatic energy efficiency efforts reduced power demand by over 1%.

To meet the region's energy needs in all types of weather, TVA maintains 41,261 megawatts (MW) of generating capability (FY 2023). TVA operates a generating asset portfolio of 32,139 MW, maintains long-term agreements with third-party power producers totaling 7,421 MW, and offers demand response programs that provide 1,701 MW of capacity. To reliably deliver energy to those we serve, TVA operates one of the nation's largest transmission systems.



Objectives of Resource Planning

Integrated resource planning at TVA is grounded in least-cost principles and meets the environmental review requirements of the National Environmental Policy Act (NEPA). Least-cost planning is integral to TVA, and thorough environmental review of the IRP analysis provides valuable insights that are considered as IRP recommendations are developed.

TVA applies the following least-cost principles, aligned with Section 113 of the Energy Policy Act of 1992, to develop plans for providing affordable, reliable, resilient, and increasingly cleaner energy over the long term:

Least-cost planning evaluates cost, operational, environmental, and risk factors in order to provide reliable service at the lowest system cost. A system that is diverse, resilient, and flexible is more reliable, year in and year out, so these aspects are key considerations. Planning also explores opportunities to efficiently reduce environmental impacts. Finally, TVA evaluates variations in electricity demand, resource costs, and environmental regulations to ensure plans are risk informed and flexible to adapt as the future evolves. Metrics being used in the IRP reflect least-cost planning principles, providing insights into tradeoffs across alternative business strategies.

Delivering on Prior IRP Recommendations

Before embarking on the 2025 IRP, it was important to evaluate the progress made on recommendations from the last IRP. The 2019 IRP provided strategic direction for renewables, system flexibility, the existing fleet, energy usage, and distribution planning. Meaningful progress has been made on all fronts:

- Developed planning dates for retiring the aging coal fleet
- Added more solar and battery storage to the resource mix
- Invested in the gas fleet to enable coal retirements and solar expansion and maintain reliability
- Evaluated energy efficiency potential to inform future efforts
- Increased investment in low-income energy efficiency programs
- Collaboratively deployed electric vehicle initiatives
- Initiated collaborative effort for regional grid transformation

Also, TVA is investing in the future transmission grid. This starts with building a state-of-the-art System Operations Center expected to be operational in 2026. The center will employ smart technologies to boost efficiency and enhance integration of distributed resources, along with advanced security systems to protect grid assets.

Key Signposts Informing this IRP

The 2019 IRP identified key signposts – or market signals – to monitor. These signposts were related to changing market conditions, evolving policy and regulations, and technology advancements. Movements in signposts influenced refinements to annual plans and helped identify the timing for initiating the 2025 IRP.

Changing Market Conditions

After a decade of flat electricity demand, the TVA region is now experiencing increasing demand for electricity driven by population, employment, and industrial growth, weather trends, and increasing electric vehicle use. The region is also seeing more volatility in winter temperatures and natural gas prices that affect resource planning. Finally, TVA continues to experience increasing demand for carbon reductions and renewable energy options from residents and businesses in the region and those considering locating here.

Evolving Policy and Regulations

Energy policy and regulations have continued to evolve since the last IRP. The Effluent Limitations Guidelines Rule that establishes stringent wastewater discharge standards at coal plants played a role in determining planned end-of-life dates for TVA's remaining four coal plants. In 2022, the Inflation Reduction Act was signed into law, which funds several priorities, including clean energy production and investment tax credits that incentivize investment in renewable and other clean energy sources. Additionally, the Infrastructure Investment and Jobs Act funds investment in national power and water infrastructure, grid resilience and flexibility, and new clean energy demonstrations.

In May 2024, the Environmental Protection Agency (EPA) finalized a rule under the Clean Air Act that seeks to reduce greenhouse gases (GHG) by establishing carbon dioxide (CO_2) emissions limits for existing coal and new natural gas power plants. EPA's new source performance standards and emission guidelines assume the application of emerging carbon capture and sequestration (CCS) technologies, while also allowing for compliance by co-firing hydrogen. The EPA also finalized a rule establishing more stringent vehicle emissions standards. These recently finalized rules are being litigated and could be stayed, vacated, or amended. The ongoing evolution of energy policy and regulations will continue to influence resource planning.

Technology Advancements

With respect to commercial-ready technologies, TVA has gained experience with increasing amounts of new solar generation and is installing its first owned and operated grid-scale battery storage on the system. Also, progress is accelerating on emerging technologies such as advanced nuclear, carbon capture, and hydrogen production and use. TVA is collaborating with the Department of Energy, Oak Ridge National Laboratory, National Renewable Energy Laboratory, Electric Power Research Institute, universities, startup accelerators, and other industry partners to advance the viability and cost-effectiveness of these emerging technologies.

Ensuring that resources will be online to replace retiring resources, meet expected load growth, and comply with evolving regulations, as well as having confidence in new technology performance, will be essential to meeting the electricity needs of the region between now and 2050.

Stakeholder and Public Involvement

Understanding and balancing the varying needs and priorities of TVA's approximately 10 million stakeholders is an integral part of TVA's IRP. Throughout the process, TVA has been engaging external stakeholders to gather diverse views on the future power system, challenge assumptions, and help shape the analysis and outcomes.

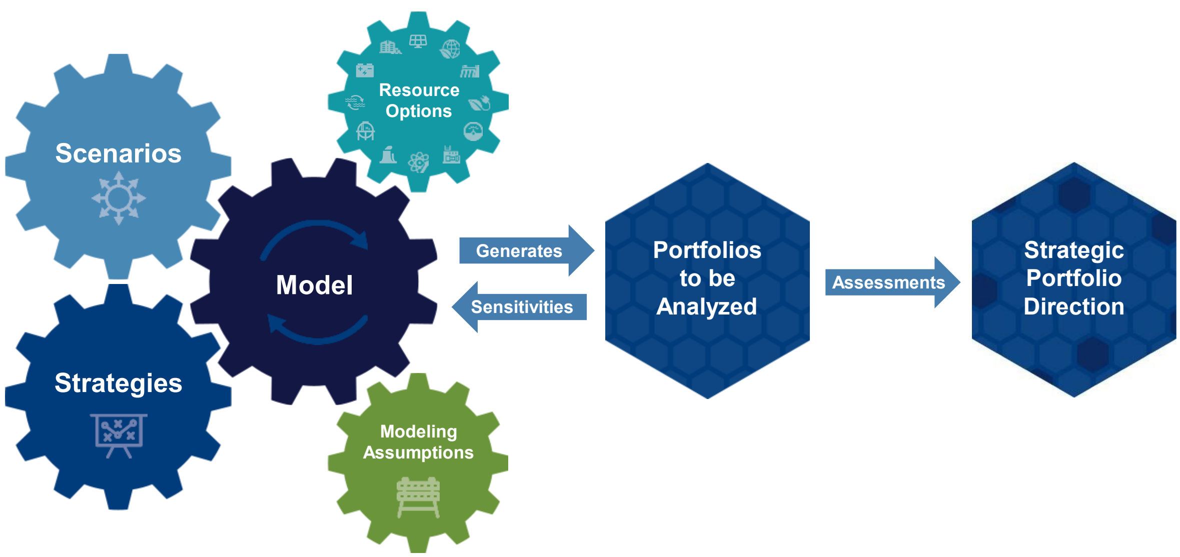
TVA has been involving stakeholders and the public since the IRP process began when a Notice of Intent to conduct an Environmental Impact Statement was published in the Federal Register in May 2023. That initiated a 45-day public scoping comment period when public input was gathered to help frame the IRP effort, along with the input from the Utility of the Future Information Exchange conducted in October 2022 to July 2023. TVA established the IRP Working Group, a diverse group of stakeholders who meet regularly to provide input on all key aspects of the IRP. The Regional Energy Resource Council (RERC), a federal advisory committee that provides formal advice to the TVA Board, also is engaged in the process. Public participation is vital, and TVA has received input during quarterly Board listening sessions and at RERC meetings. TVA also provides information during public webinars and on TVA's IRP website (tva.com/irp). An environmental justice focus is being applied to IRP engagements, with the objective to reach and gain valuable input from all communities.

The process is now entering the next phase with the publication of the draft IRP and EIS. TVA will be holding two webinars and 10 in-person meetings across the region to provide information on the IRP and opportunities for the public to ask questions during the public comment period, which runs through November 26. Insights gained from stakeholders and public input are critical as TVA plans how to meet future power demand.

Planning Approach

Key Planning Elements

TVA used a rigorous and comprehensive scenario and strategy approach to evaluate potential paths for providing affordable, reliable, resilient, and increasingly cleaner energy into the future. Stakeholder feedback was a key component in the development of all model inputs.



TVA utilized input from the IRP Working Group and public comments to design scenarios and strategies to be evaluated in the IRP. Scenarios explored possible futures that TVA may find itself operating in that have varying levels of electricity demand, environmental policy and regulations, and technology advancements. Strategies modeled alternative approaches TVA could employ to meet electricity demand by emphasizing certain resource options. TVA also used input from the IRP Working Group to develop the set of resource options to be considered in the IRP analysis.

For each unique scenario and strategy combination, the planning model solved for the lowest-cost portfolio. Combining the various scenarios and strategies generated potential resource portfolios to be analyzed using metrics that reflect TVA's mission and least-cost planning principles. The draft EIS evaluated the environmental impacts of potential changes in the portfolio. Further analysis will be performed to answer questions based on IRP Working Group input and public comments on the draft IRP and EIS. Collectively, these evaluations will inform the IRP recommendations for strategic portfolio direction that will be included in the final IRP report.

Scenarios and Strategies

The six external scenarios and five business strategies evaluated in the IRP are summarized below. Scenario 6 incorporates the EPA's final GHG Rule that was released during the development of the draft IRP analysis. The net-zero regulation scenarios (4 and 5) reflect the draft GHG Rule, which also included regulations that may be adopted in the future related to existing gas plants.

SCENARIOS	STRATEGIES
1 Reference (without Greenhouse Gas Rule) Represents TVA's current forecast that reflects moderate population, employment, and industrial growth, weather-normal trends, growing electric vehicle use, and increasing efficiencies	**A Baseline Utility Planning** Represents TVA's current outlook based on least-cost planning, incorporating existing programs and a planning reserve margin target. This reserve margin target applies in all strategies
2 Higher Growth Economy Reflects a technology-driven increase in U.S. productivity growth that stimulates the national and regional economies, resulting in substantially higher demand for electricity	**B Carbon-free Innovation Focus** Emphasizes and promotes emerging, firm and dispatchable carbon-free technologies through innovation, continued research and development, and strategic partnerships
3 Stagnant Economy Reflects rising debt and inflation that stifle consumer demand and business investment, resulting in weaker than expected economic growth and essentially flat electricity demand	**C Carbon-free Commercial Ready Focus** Emphasizes proven carbon-free technologies like wind, solar, and storage, at both utility-scale and through customer partnerships, along with strategic transmission investment
4 Net-zero Regulation Reflects the impact of the May 2023 draft Greenhouse Gas Rule that targets significant reductions in electric utility CO_2 emissions beginning in 2030 and potential future utility regulations striving for net-zero by 2050	**D Distributed and Demand-side Focus** Emphasizes existing and potentially expanded customer partnerships and programmatic solutions to reduce reliance on central station generation and promote virtual power plants
5 Net-zero Regulation Plus Growth Reflects the impact of the May 2023 draft Greenhouse Gas Rule and potential future utility regulations, along with substantial advancements in clean energy technologies, that spur economic growth and extensive electrification	**E Resiliency Focus** Emphasizes smaller units and the promotion of storage, along with strategic transmission investment, to drive wider geographic resource distribution and additional resiliency across the system
6 Reference (with Greenhouse Gas Rule) Reflects TVA's current forecast and incorporates the impact of the Greenhouse Gas Rule finalized in May 2024 that targets significant reductions in electric utility CO_2 emissions beginning in 2030	

Resource Options

Maintaining diversity in the resource mix is fundamental to TVA's ability to provide affordable, reliable, resilient, and increasingly cleaner energy to the residents, businesses, and industries in the region. The IRP analysis considered the addition of a wide range of supply-side generating resources, distributed generating resources, and demand-side management resources. The major resource types evaluated in the IRP include nuclear, hydro, coal, natural gas, renewables, storage, and energy efficiency and demand response (EE and DR).

Nuclear
- Advanced pressurized water reactor
- Light water small modular reactor
- Gen IV small modular reactor

Hydro
- Hydro uprates

Coal
- Supercritical pulverized coal
- Supercritical pulverized coal w/carbon capture

Gas
- Combined cycle
- Combined cycle w/ carbon capture
- Combustion turbine
- Aeroderivative
- Reciprocating engine
- Hydrogen blending
- Combined heat and power

Renewables
- Utility scale solar
- Distributed solar
- Midwest wind
- Southeast high-hub wind
- High Voltage Direct Current wind

Storage
- Pumped storage
- Lithium-ion battery
- Advanced chemistry battery
- Distributed storage

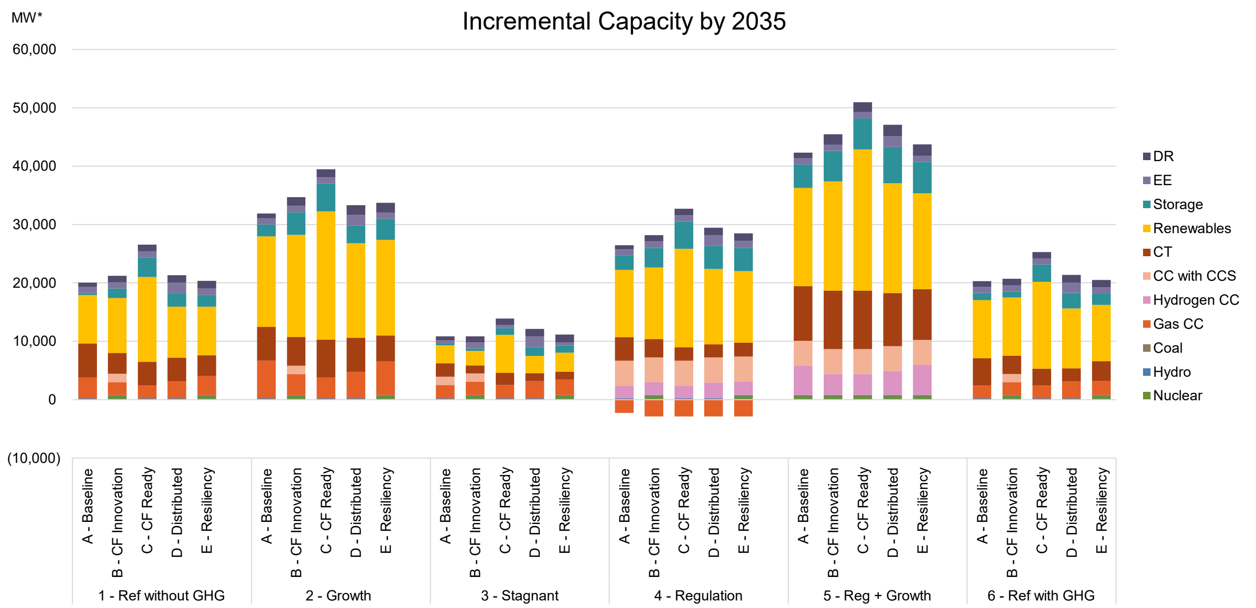
EE and DR
- Energy efficiency
- Demand response

Portfolio Results

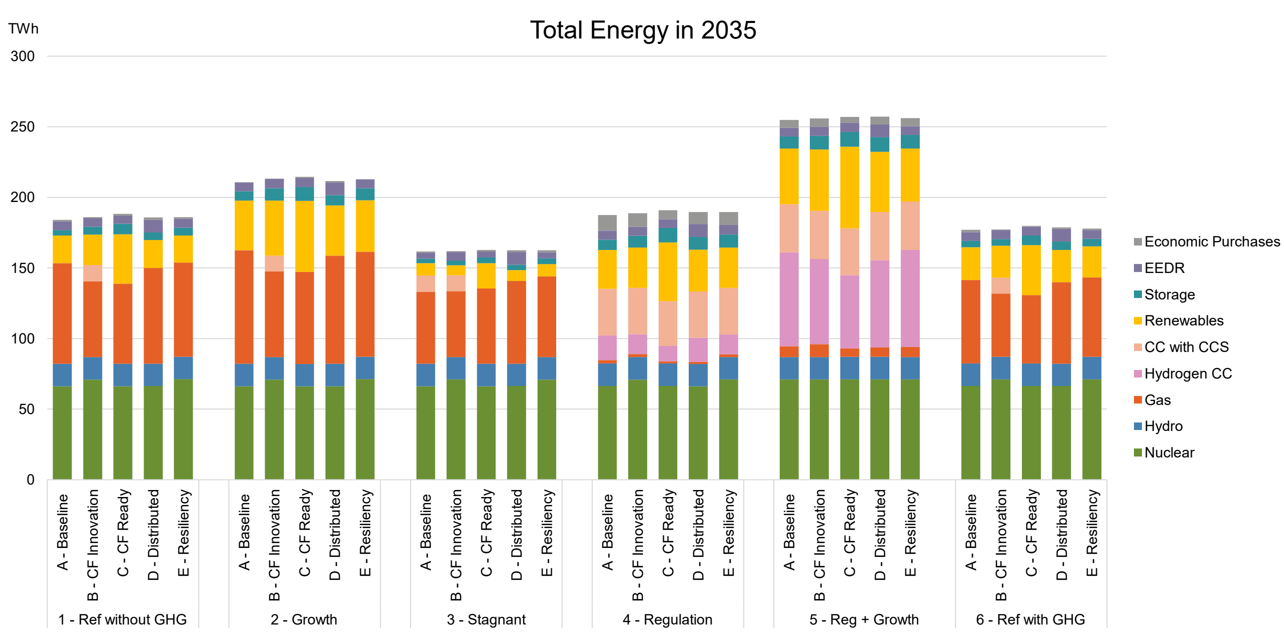
During the IRP process, TVA – with significant input from stakeholders and the public – considered a wide range of future scenarios, various business strategies, and a diverse mix of resource options. Applying the five strategies in the six scenarios generated 30 potential resource portfolios to analyze. The model analyzed how to achieve the lowest-cost portfolio for each unique scenario and strategy combination.

2035 Portfolios

The charts below show the portfolio results for 2035. Results are presented in two ways – incremental capacity changes from now through 2035 and total energy in 2035. Incremental capacity represents the new resources selected to fill capacity needs, including incremental resource additions and retirements. Capacity needs are driven by forecasted growth in energy demand and the retirement or expiration of over 10,000 MW of coal, gas, and renewable capacity. Total energy represents the economic dispatch of resources in the capacity plans for each portfolio. The results for each scenario are grouped together. Within a scenario, strategy results are grouped by resource type, which varies based on strategy focus and the impact on portfolio optimization.

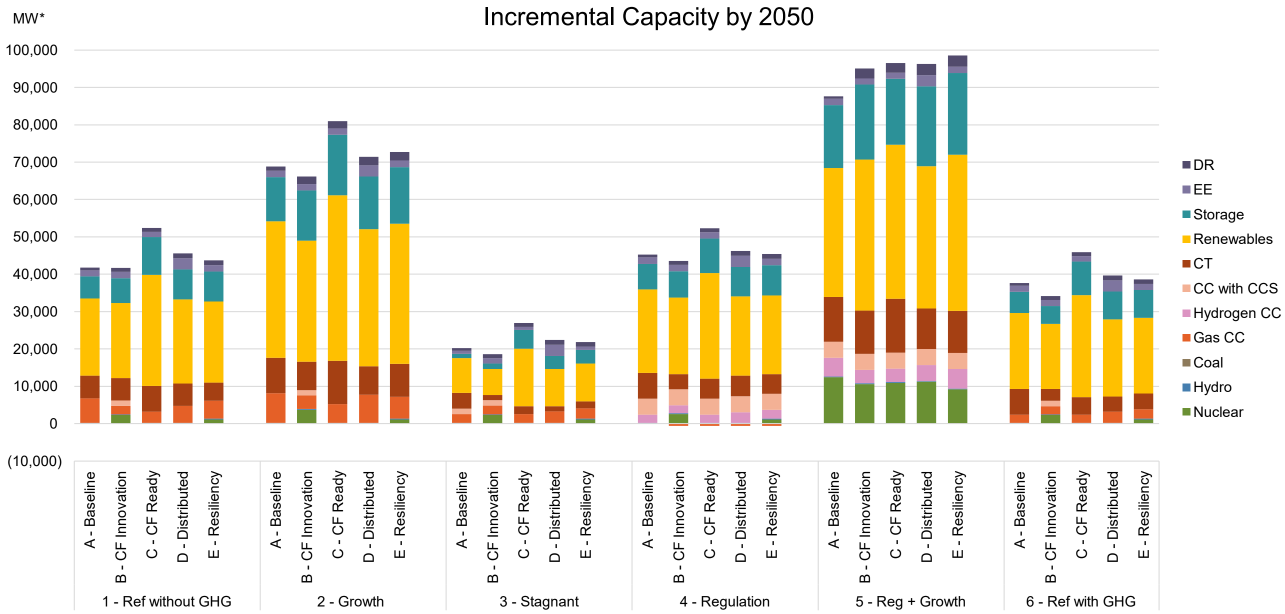


* MW summer net dependable capacity, except for renewables and storage that are shown in nameplate.

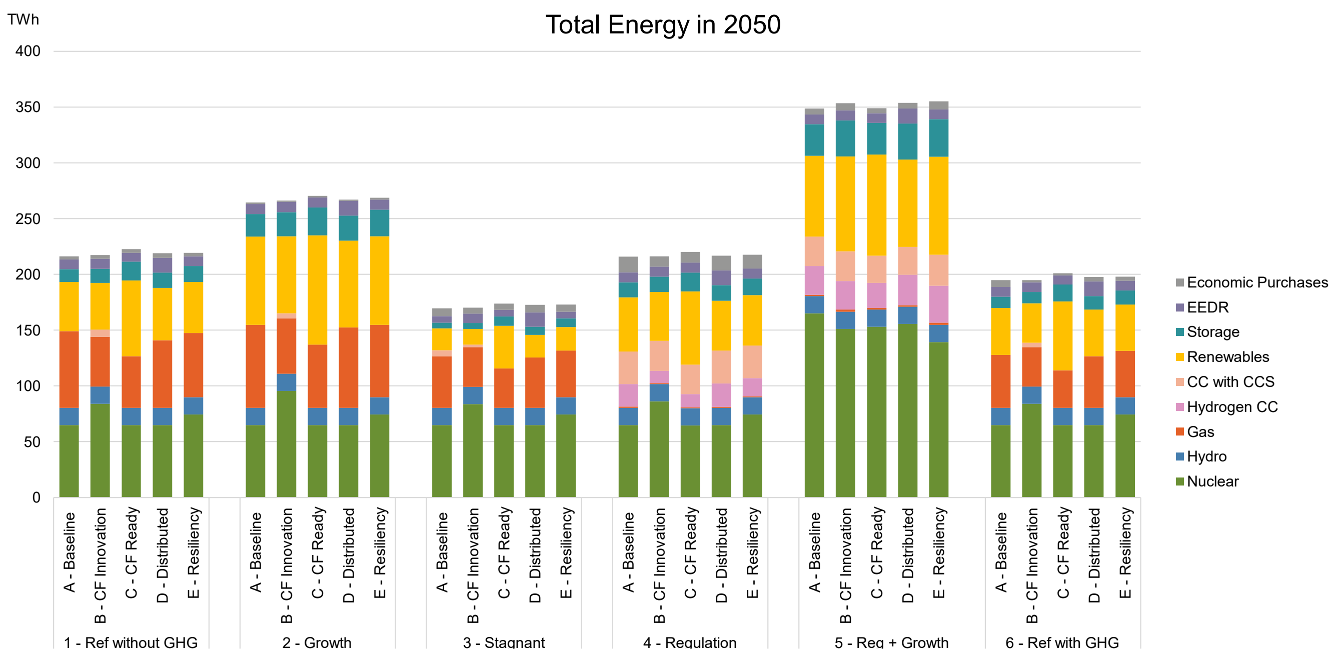


2050 Portfolios

The charts below show the portfolio results for 2050, including incremental capacity changes from now through 2050 and total energy in 2050. Capacity needs are driven by forecasted growth in energy demand and the retirement or expiration of over 13,000 MW of coal, gas, and renewable capacity. Total energy represents the economic dispatch of resources in the capacity plans for each portfolio.



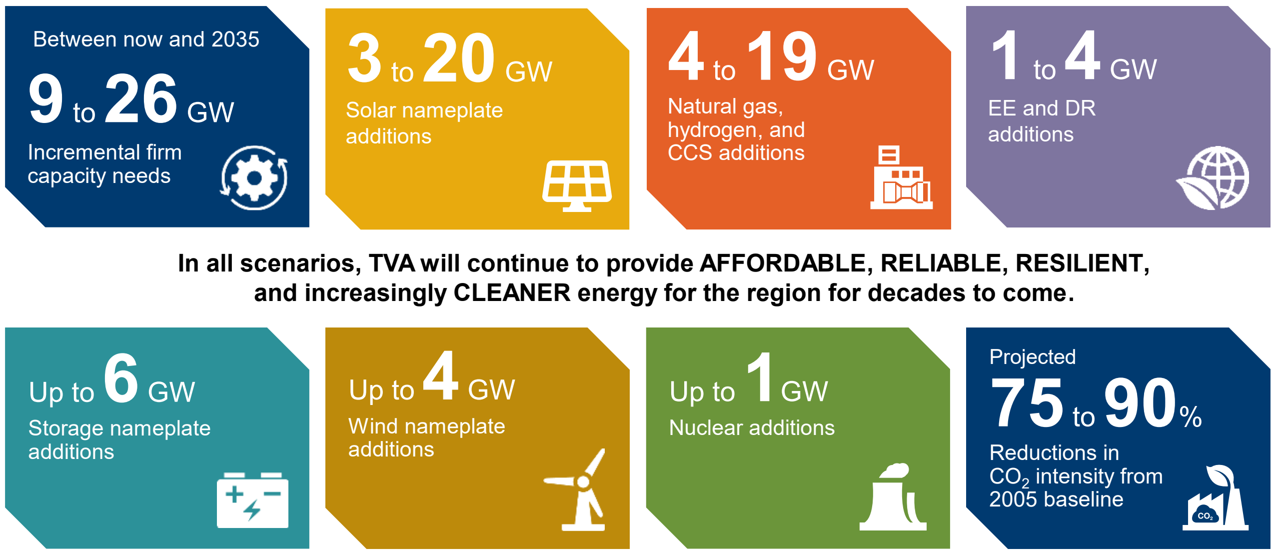
* MW summer net dependable capacity, except for renewables and storage that are shown in nameplate.



Key Themes

Uncertainty in electricity demand, environmental regulations, and available technologies increases with time. The IRP analyzes potential ways the resource portfolio might evolve between now and 2050 to respond to changes in these key drivers, and insights gained from evaluating the entire planning horizon will inform strategic portfolio direction between now and 2035. Key themes are expressed in gigawatts (GW), with one GW providing enough energy to power about 585,000 average homes.

Looking across all portfolios through 2035, draft IRP results suggest:



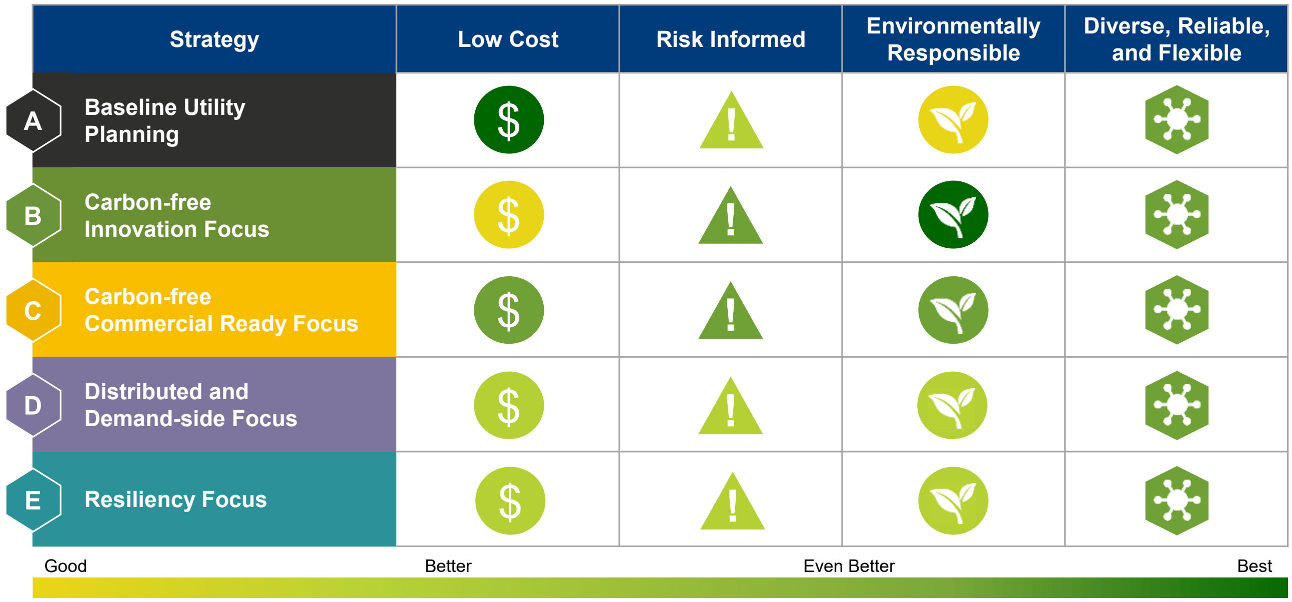
Power supply mix ranges, summarized in gigawatts (GW), vary based on energy demand, market conditions, policy and regulations , and technology advancements.

- New capacity is needed in all scenarios to replace retiring and expiring capacity, support economic growth, and enable further electrification of the economy.
- Firm, dispatchable technologies are needed to ensure system reliability throughout the year.
- Solar expansion plays an increasingly substantial role, providing economic, carbon-free energy.
- Gas expansion serves broad system needs, with the potential for emerging carbon capture and hydrogen options to enable deeper decarbonization.
- Energy efficiency deployment reduces energy needs, particularly between now and 2035, and demand response programs grow with the system and the use of smart technologies.
- Storage expansion accelerates, driven by evolving battery technologies and the potential for additional pumped storage.
- Wind additions have the potential to add more diversity and carbon-free energy to the resource mix.
- New nuclear technologies, with continued advancements, can also support load growth and deeper decarbonization.

As other sectors of the economy electrify, almost all resource types – both supply and demand-side – will be required to meet system needs. In all scenarios, TVA will continue to provide affordable, reliable, resilient, and increasingly cleaner energy for the region for years to come.

Strategy Performance

Reflecting least-cost planning principles and with input from the IRP Working Group, TVA developed a set of metrics to assess the performance of the portfolios. Metrics were grouped into four categories – low cost, risk informed, environmentally responsible, and diverse, reliable, and flexible. Metrics were calculated for the 30 portfolios and were used to evaluate strategy performance for each category, as summarized below.



Looking across the metric categories, there are key tradeoffs to consider. Key takeaways include:

- Strategy A that applies baseline utility planning is the lowest cost strategy overall, but it has less reduction in CO_2 intensity than the alternative strategies.
- While Strategy B is the most expensive strategy, as it requires upfront investments in clean energy technology innovation, it achieves similar levels of decarbonization as Strategy C over the long term and reduces regulatory and financial risk.
- Strategy C that promotes carbon-free commercial ready technologies is second lowest in cost, achieves the fastest near-term reductions in CO_2 intensity, and reduces regulatory and financial risk.
- Strategies D and E generally rank in the middle across the metric categories.
- All strategies include timeline, technological, transmission, and/or market depth uncertainty and execution risks, which are amplified by load growth and regulatory impacts.
- Maintaining sufficient system flexibility to meet dynamic changes in load will require balancing renewable and dispatchable resource additions over time, especially in growth scenarios.

Environmental Impacts

The draft EIS is a programmatic review that broadly assesses the natural, cultural, and socioeconomic impacts associated with the 2025 IRP. The primary study area described in the draft EIS includes the TVA service area. For some resources, such as air quality and climate change, the assessment area extends beyond the TVA region. The five strategies are the basis for the alternatives discussed in the draft EIS. Baseline Utility Planning (Strategy A) is the No Action Alternative, and the remaining four strategies are the Action Alternatives. The draft EIS analyzes and identifies the relative impacts of the five strategies on the natural and human environment.

Highlights of draft EIS observations include:

Environmental Resources	Summary of Impacts
Air Quality	• Results indicate long-term reductions in air emissions of all types, largely driven by the expected retirement of all coal facilities by 2035 in all strategies. • Strategies B and C promote carbon-free resources; Strategy B has the greatest NOx reductions, and Strategy C has the greatest SO_2 and mercury reductions.
Climate and Greenhouse Gases	• All strategies lead to reductions in CO_2 emissions and intensity. • Strategies B and C have the lowest CO_2 emissions, while Strategy A that applies baseline utility planning has the highest CO_2 emissions.
Water Resources	• In most cases, water use decreases between 2025 and 2050 due to expected coal retirements by 2035, except in Scenario 5 where new nuclear generation increases water consumption. • Water use is lowest in Strategy C, which has the highest renewable additions, and is highest in Strategy B that has the highest nuclear additions.
Land Resources	• Land requirements for new power resources increase for all strategies, primarily driven by solar expansion. • Requirements are highest in Strategy C that has the highest solar buildout.
Solid and Hazardous Waste	• Coal combustion residuals decrease and drop to zero by 2035 due to expected coal retirements. • Strategies have similar levels of other solid and hazardous waste with minor variations due to the nuclear, gas, and renewable resource mix.

Environmental impacts do not differ as much between strategies as they do between scenarios, as the scenario that materializes for forecasted load and regulatory impacts is the primary driver of environmental profiles. For most environmental resources, the impacts would be greatest in Scenarios 2 and 5 (Higher Growth Economy and Net-zero Regulation Plus Growth) and would be lowest under Scenario 4 (Net-zero Regulation).

The environmentally preferable alternatives are Strategies B and C that emphasize carbon-free resources and achieve similar CO_2 emissions reductions over the planning horizon. These strategies have tradeoffs across other environmental metrics, with higher water consumption in Strategy B and higher land use in Strategy C.

While the IRP is not site-specific, environmental justice (EJ) considerations help guide TVA's public outreach strategies for the IRP. Also, the draft IRP and EIS provide insights into potential impacts to communities with EJ concerns. For example, the average system cost metric is directionally indicative of overall trends in customer bills (Strategy A is the lowest cost strategy overall), and metrics related to emissions are directionally indicative of air quality trends in the region (Strategies B and C have the lowest emissions overall). Site-specific aspects of actions that are later proposed to implement the IRP will be addressed in tiered environmental reviews.

In the final EIS, TVA will quantitatively and qualitatively evaluate the final IRP recommendations to determine the environmental impacts. Public comments on the draft IRP and EIS will be addressed in the final EIS.

Developing IRP Recommendations

TVA, the IRP Working Group, and the Regional Energy Resource Council (RERC) are continuing to review and discuss key elements of the draft IRP and EIS results. After the public comment period concludes, TVA will review additional input received from the Working Group, the RERC, other key stakeholders, and the public. This input will help refine the list of additional analyses to be performed and considered in developing the IRP recommendations.

The final IRP will contain additional analysis and summarize the process for developing IRP recommendations, which will include:

- Power supply mix ranges by resource type
- Recommended strategic portfolio direction through 2035
- Key signposts and how they will influence portfolio direction from 2035 to 2050

The final IRP will also discuss implementation plans. In Spring/Summer 2025, the final IRP and EIS will be made available to the public for at least 30 days prior to consideration by the TVA Board. Subject to the Board's direction, an official Record of Decision will then be posted. The more site-specific effects of actions that are later proposed to implement the IRP will be addressed in tiered environmental reviews.

Conclusion

TVA encourages stakeholders and the public to review the draft IRP and EIS and provide comments on the analysis and what they would like to see in their future power system. The draft IRP and EIS provide information on planning the future system, stakeholder engagement, process and methodology, and portfolio results and assessments, along with an environmental impacts analysis. TVA looks forward to stakeholder and public feedback on the IRP to help chart the course for the region's future energy system.

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List of Acronyms

Acronym	Description
AC	alternating current
Aero	aeroderivative combustion turbine
APWR	advanced pressurized water reactor
ARL	adoption readiness level
ATB	Annual Technology Baseline
B	billions
Btu	British Thermal Units
C&I	commercial and industrial
CAGR	compound annual growth rate
CARAT	Commercial Adoption Readiness Assessment Tool
CC	combined cycle
CCS	carbon capture and sequestration
CDD	cooling degree days
CEQ	Council on Environmental Quality
CHP	combined heat and power
CO_2	carbon dioxide
CO_2-eq	CO_2 equivalent emissions
CT	combustion turbine
DC	direct current
DG	distributed generation
DPP	Dispersed Power Program
DOE	Department of Energy
DR	demand response
DSM	demand-side management
EE	energy efficiency
EEDR	energy efficiency and demand response
EFOR	equivalent forced outage rate
EIS	Environmental Impact Statement
EJ	environmental justice
ELCC	effective load carrying capability
EO	Executive Order
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EV	electric vehicle
FOM	fixed operating and maintenance
FY	fiscal year
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GHG	greenhouse gases
GW	gigawatt
GWh	gigawatt-hour
H_2	hydrogen
HDD	heating degree days
Hg	mercury
HLE	hydro life extension
HVAC	heating, ventilation, and air conditioning
HVDC	high voltage direct current

IIJA	Infrastructure Investment and Jobs Act
ILB	Illinois basin
IP	interruptible power
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
IRP-WG	IRP Working Group
ITC	investment tax credit
kW	kilowatt
lbs	pounds
LCA	life cycle analysis
LCOE	levelized cost of energy
LOLE	loss of load expectation
LPC	local power company
MISO	Midcontinent Independent System Operator
MMBtu	Metric Million British Thermal Units
MW	megawatt
MWh	megawatt-hour
NDC	net dependable capacity
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
N_2O	nitrous oxide
NOA	Notice of Availability
NOI	Notice of Intent
NOx	nitrogen oxides
NPV	net present value
NREL	National Renewable Energy Laboratory
O&M	operating and maintenance
ORNL	Oak Ridge National Laboratory
PPA	power purchase agreement
PRB	Powder River Basin
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic
PVRR	present value of revenue requirements
PWR	pressurized water reactor
RERC	Regional Energy Resource Council
RICE	reciprocating internal combustion engines
SC-GHG	social cost of greenhouse gases
SEM	Strategic Energy Management
SERVM	Strategic Energy and Risk Valuation Model
SMR	small modular reactor
SND	summer net dependable
SO_2	sulfur dioxide
TN WAP	Tennessee Weatherization Assistance Program
TRL	technology readiness level
TVA	Tennessee Valley Authority
TWh	terawatt hour
UF-IX	Utility of the Future Information Exchange
UTK	University of Tennessee – Knoxville
VOM	variable operating and maintenance
WND	winter net dependable

1 Planning the Energy System of the Future

For 90 years, the Tennessee Valley Authority (TVA) has executed its mission to serve the Valley region – to provide affordable and reliable power, be a responsible steward of the environment, and support economic development. That mission continues as TVA is planning the energy system of the future, working to ensure power for the region for the coming decades.

TVA's 2025 Integrated Resource Plan (IRP) and associated programmatic Environmental Impact Statement (EIS) evaluate the long-term demand for power in the TVA region, the resource options available for meeting that demand, and the potential environmental, economic, and operating impacts of these options. Stakeholder input on what they would like to see in the future power system is integral to TVA's IRP process. The IRP will provide strategic direction for meeting the energy needs of TVA's customers and residents of the Valley region from now through 2050, establishing a strong planning foundation and informing TVA's next long-range financial plan.

The 2025 IRP analyzes how TVA can provide affordable, reliable, resilient, and increasingly cleaner energy over the next 25 years. By 2050, TVA aspires to achieve net-zero carbon emissions, consistent with TVA's least-cost planning mandate. In addition to considering commercially ready resources such as renewables and storage, this IRP includes assumptions for emerging technologies such as advanced nuclear, carbon capture and sequestration, and hydrogen blending that will likely be needed to get there.

In planning the future energy system, it is important to first understand the environment TVA is operating in. For example:

- What role does electricity play in achieving a net-zero economy?
- What actions has TVA recently taken based on prior IRPs?
- What insights can be gleaned from key planning signposts, or market signals?
- What foundational enablers will likely be part of any successful strategy?

Discussions on these questions follow, providing useful insights into the planning environment for the 2025 IRP.

1.1 Achieving a Net-Zero Economy in the Valley

The United Nations defines net-zero as "cutting carbon emissions to a small amount of residual emissions that can be absorbed and durably stored by nature and other carbon dioxide removal measures, leaving zero in the atmosphere." Economy-wide, electricity plays a pivotal role in achieving net-zero carbon emissions nationally and in the Valley region.

TVA and the Baker School of Public Policy and Public Affairs at the University of Tennessee – Knoxville collaborated on a Valley Pathways Study, informed by stakeholder input. This study established a greenhouse gas (GHG) baseline for the region and looked across economic sectors such as transportation, industry, agriculture, and building emissions to evaluate potential paths for achieving a competitive and clean economy by 2050. In 2019, the Valley region generated an estimated 200 million metric tons of carbon dioxide equivalent (CO_2-eq) across all sectors of the economy, or about 3% of U.S. GHG emissions, which aligns to population percentage. Transportation contributed the largest share at 36%, and the electricity sector represented 27% of the total emissions.

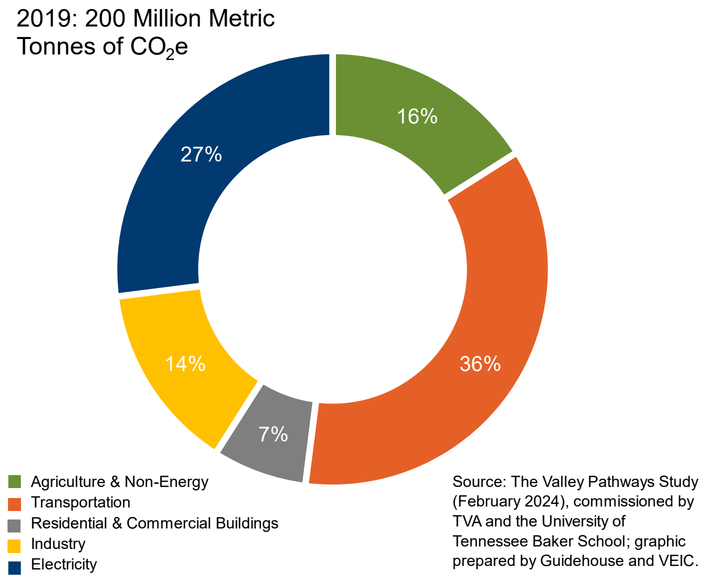


Figure 1-1: 2019 Baseline Greenhouse Gas Emissions for the Valley Region

The study modeled several pathways for reducing GHG emissions. It focused on efficiency, electrification, and low-carbon breakthrough strategies and identified core building blocks for a net-zero economy, including electric vehicles, efficient homes, low-carbon fuels, integrated community planning, and education and innovation. Key findings indicated that accelerated electrification was key to reducing emissions, and a combined strategy across all fronts could drive the lowest emissions. Further information on The Valley Pathways Study can be found on the Baker School's website.

1.2 Delivering on Prior IRP Recommendations

One way TVA has been preparing for the energy transition is by delivering on recommendations made in prior IRPs. TVA's last three IRPs from 2011 to 2019 evaluated the benefits of a diversified portfolio, modeling energy efficiency and renewables as selectable resources, and system flexibility. Specifically, the 2019 IRP provided strategic direction for renewables, system flexibility, the existing fleet, energy usage, and distribution planning to help pave the way for further evolution of the power system. The sections below summarize the progress made on prior IRP recommendations.

Continued Emphasis on a Diversified Portfolio

TVA's recent IRPs have all underscored the importance of a diversified portfolio. TVA's portfolio has evolved to a more diverse, reliable, and cleaner mix of generation resources that today provides 55% carbon-free generation (FY 2023). Diverse portfolios are more resilient to factors such as weather impacts, fuel supply constraints, and unit performance and can more readily adapt to changing conditions impacting forecasts and plans. Keeping an eye on diversity is an integral part of ongoing planning efforts.

Maintaining the Existing Low-Cost, Carbon-free Nuclear and Hydro Fleets

Hydropower has been a vital part of TVA since the beginning, and TVA operates one of the largest nuclear fleets in the nation. Recent IRPs have stressed the importance of the hydro and nuclear fleets, which provide low-cost, carbon-free energy across all hours of the day and seasons of the year. TVA invests in its nuclear and hydro fleets so they can continue to contribute substantial amounts of low-cost and clean energy, which is critical to the future resource mix. Through these investments and leveraging best practices, TVA's nuclear fleet performance currently ranks top quartile in the industry.

Pursued Initial Steps for Nuclear Fleet License Renewal

The second or subsequent license renewal application for all three Browns Ferry units was submitted in January 2024. Once reviewed and if approved by the Nuclear Regulatory Commission, which is expected to take 20 months, the renewal would extend the license an additional 20 years on all three Browns Ferry units – from 2033, 2034, and 2036 to 2053, 2054, and 2056, respectively. Next, work on the first license renewal application for Watts Bar Unit 1 will begin, targeting submission in late 2026 and approval in 2028, followed by work on the second license renewal for Sequoyah Units 1 and 2.

Developed Planning Dates for Retiring the Aging Coal Fleet

Since the 2019 IRP, TVA has developed planning dates for retiring aging coal units as they reach end-of-life, expected by 2035. TVA operated 11 coal plants in 2011 and six coal plants in 2019, and today it operates four coal plants. Retirement of the Cumberland and Kingston coal plants has been evaluated in recent environmental reviews, with units expected to retire as replacement capacity comes online over the next five years. The 2025 IRP includes planning assumptions for retiring all remaining coal plants, with the last plant forecasted to retire by 2035. Retirement of each coal plant is dependent upon replacement capacity being approved and ready for commercial operations and upon the regulatory requirements in place at that time.

Added More Solar and Battery Storage to the Resource Mix

A key 2019 IRP finding was that solar expansion would play a substantial role. Adding solar based on economics and to meet customer demand was recommended, along with gaining battery storage experience. As of FY 2018, TVA had contracted for about 140 megawatts (MW) of utility-scale solar nameplate capacity through power purchase agreements. By the end of FY 2019, that amount grew to about 800 MW. Each year since, TVA has contracted for additional solar capacity. As of the last procurement cycle concluded in early 2024, the total solar amount contracted through these agreements has increased more than four-fold to approximately 3,600 MW. About 700 MW of these solar installations were online as of FY 2023, and the balance of the projects are forecasted to come online over the next several years. To complement solar additions, approximately 400 MW of contracted battery storage has been added to the resource mix.

Additionally, TVA is pursuing solar projects at two sites – 200 MW at a greenfield site and about 100 MW at the Shawnee Fossil Plant site using a solar cap system on the closed coal combustion residuals facility. TVA also has constructed a 20 MW battery facility in Vonore, Tennessee, expected to begin commercial operations in fall 2024, to gain direct operational experience with battery storage.

Invested in the Gas Fleet to Reliably Enable Coal Retirements and Solar Expansion

TVA has invested in the existing natural gas fleet and in additional gas capacity. Maintaining and modernizing the existing gas fleet ensures TVA has sufficient capacity and enhances system flexibility. Additional gas capacity is required to enable needed retirements of aging coal units, provide sufficient flexible resources to ramp up and down with increasing solar generation, and maintain system reliability as other clean technologies develop. Since the 2019 IRP, TVA has approved plans to build about 4,900 MW of new gas capacity, with 1,400 MW currently operating and 3,500 MW expected to come online over the next several years. This incremental capacity will replace about 2,500 MW of retiring coal and 1,100 MW of retiring gas capacity, and the balance will support load growth. Currently, TVA is conducting environmental reviews for additional gas capacity to replace retiring coal capacity, maintain reliability as load grows, and increase system flexibility to support solar expansion.

Evaluated Energy Efficiency Potential to Inform Future Efforts

In 2022, DNV (a global leader in energy program consulting) conducted a study for the TVA region to evaluate the achievable potential for energy efficiency programs that incentivize investment in making homes and businesses more energy efficient. The study indicated a 10-year potential for regional energy efficiency gains ranging from 2-7% of base sales and 2-9% and 4-16% of summer and winter peak demand, respectively. The residential sector accounts for most of the potential, particularly homes utilizing electric heating. Potential in the less weather-sensitive commercial and industrial sectors is driven by linear fluorescent and high-intensity discharge lighting applications. TVA is using insights from the study to inform current program development and energy program resource options in the IRP.

Increased Investment in Low-Income Energy Efficiency Programs

TVA introduced its Home Uplift program in 2018, in partnership with local power companies and communities. By FY 2019, about 1,300 Valley residences were retrofitted with more energy efficient technology for heating and cooling, water heating, and insulation. This number grew to 5,400 retrofitted residences by FY 2023, reducing system energy needs by nearly 19,000 megawatt hours, benefitting those with high energy burdens. To date, TVA, local power companies, and communities have collectively contributed $56 million in total toward this program, with roughly half coming from local sources and half from TVA matching funds, making this program more sustainable across the Valley region. Similar programs have recently been developed to help schools and small businesses, particularly in underserved communities, make smart energy choices.

Collaboratively Deployed Electric Vehicle Initiatives

Since 2018, TVA has been collaborating with a coalition of partners to prepare for and enable adoption of electric vehicles (EVs) in the region. Tennessee is emerging as a national leader in EV manufacturing with four major EV manufacturers active or planned as well as numerous EV parts and battery suppliers. Increasing EVs will lead to significant fuel and maintenance savings for drivers, growth in local jobs and investment, and significant reductions in carbon emissions. The shared goal of the coalition is to pave the way for more than 200,000 EVs on Valley roads by 2028. To encourage EV adoption, TVA is working with partners to install approximately 80 new fast charging sites across the region. As of August 2024, 35 new fast charging sites have been installed.

Initiated Collaborative Effort for Regional Grid Transformation

In 2020, TVA and local power companies began a multi-year collaborative effort to transform the region's existing power grids into a more flexible, resilient, and integrated system to meet customer expectations and changing market conditions. This initiative is addressing foundational capabilities for grid transformation, regional guidelines, enhanced operational coordination and end-user experience, and integrated planning. With respect to planning, the focus is on advancing distribution planning and operational capabilities to improve load and distributed energy resource forecasts that could be integrated into future TVA IRPs.

1.3 Implications of Planning Signposts

Since completion of the last IRP in 2019, TVA has monitored key planning signposts – or market signals – related to changing market conditions, evolving regulations, and technological advancements. In the 2019 IRP, the forecast for electricity demand was essentially flat, while current forecasts indicate moderate load growth with a potential for more rapid increases if electrification accelerates. The following table summarizes recent developments in key signposts and the resulting implications for resource planning.

Table 1-1: Key Signposts and Implications to Planning

Signpost	Developments	Planning Implications
Increasing Demand for Electricity	• Population, employment, and industrial growth • Increasing electric vehicle adoption • Energy demand increasing 9% by 2035 in Reference without GHG Rule scenario (nearly 50% in highest case)	More resources currently needed beyond replacing retiring/expiring resources to meet load growth
Fuel Prices and Risk	• Growing connection to global markets • National coal retirements increasing gas price exposure • More variable generation resources increasing market power and natural gas price volatility	Analyze wide range of gas prices in IRP cases and test impact of increasing natural gas price volatility
Evolving Customer Expectations	• Large customers' environmental goals • Growing sustainability focus in local government • Increasing consumer interest in clean energy	Reflect current trends in IRP forecasts and proactively update in annual plans
Policy and Regulatory Requirements	• Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA) incentives • Effluent Limitations Guidelines Rule • Greenhouse Gas (GHG) Rule • Infrastructure siting and permitting timelines	Reflect policy incentives, model reference cases with and without GHG Rule, and evaluate potential future regulations in IRP analysis
Operating Costs for Existing Fleet	• Increasing operating costs for aging coal fleet • Gas unit cycling impacts as renewables increase • Older gas units reaching end-of-life before 2050	Use latest assumptions for unit operating costs and projected end-of-life dates
Solar and Wind Costs	• Cost pressure from solar supply chain challenges • Interconnection timelines for multiple solar sites • Improvements in high-hub wind technologies	Use latest assumptions for solar and wind costs and interconnection timelines
Progress on Emerging Technologies	• Clinch River environmental assessment completed, and SMR detailed design underway • Industry partnerships focused on advancing new clean energy technologies such as carbon capture and hydrogen blending	Use latest cost and timing estimates for emerging technologies from Clinch River and industry partnership efforts
Maintaining Reliability as System Evolves	• Recent experience coordinating coal plant retirements and new resources coming online • Increasing winter reliability risk as electricity demand and the power supply evolve	Plan to replace capacity before retiring aging fossil units and test impact of increasing winter risk

Collectively, movement in signposts and input from the IRP Working Group and public comments informed the scenarios, strategies, modeling assumptions, and resource options evaluated in the 2025 IRP. Scenarios were heavily influenced by increasing electricity demand and evolving policy and regulations, while strategies reflected evolving customer expectations and emerging technology opportunities. Modeling assumptions will be varied to test the potential impact of increasing winter risk. Finally, assumptions for resource options incorporated the latest information from the 2023 National Renewable Energy Laboratory's Annual Technology Baseline, TVA's recent experience, and industry partnership efforts to advance new clean energy technologies.

1.4 Key Enablers of the Future Energy System

Considering all aspects of the planning environment, some key enablers became evident that would play a role in any successful strategy. These enablers, described below, are foundational to providing affordable, reliable, resilient, and increasingly cleaner energy and will support the strategic recommendations from this IRP.

Nuclear License Renewals

Carbon-free generation from TVA's three nuclear plants contributes 42% of the total power supply today. Nuclear generation provides substantial, long-term system benefits and will play a significant role in a net-zero energy future. The first step to ensuring this is continuing to invest in and extend the licenses of TVA's existing nuclear plants. This was a recommended action from the 2019 IRP, and it will continue to be foundational in future plans. TVA has submitted the application to extend the operating license of the Browns Ferry nuclear plant, with Watts Bar Unit 1 and Sequoyah nuclear plant extension requests to follow.

Firm, Dispatchable Resources to Maintain Reliability and Integrate Renewables

Recent IRPs have emphasized that adding renewable generation – especially solar – to the system can be both cost-effective and further diversify the power supply mix. Successfully integrating increasing amounts of renewables requires firm, dispatchable resources to maintain reliability and provide the operational flexibility needed to manage changes in net load across all hours of the day and year. Natural gas units provide energy when renewable sources are not generating, and they can ramp up and down as solar and wind generation varies. TVA's Raccoon Mountain Pumped Storage plant provides significant longer-duration system benefits in this regard, and battery storage additions will contribute shorter-duration system benefits, providing further diversity and a fuel hedge that complements the dispatchability of gas generation. Collectively, renewables, storage, and gas resources work together to maintain reliability, provide diversity benefits, and reduce emissions as the system evolves and new clean energy technologies develop.

Collaboration with Customers on Innovative Programs and Tools

Collaboration with customers is an integral part of TVA's public power model, and it will be increasingly important as we collectively navigate the energy transition and leverage the advantages of distributed and demand-side resources in the resource mix. TVA has provided local power company partners the flexibility to generate up to 5% of their own energy to meet consumer demand for new renewables and address other local needs. TVA and local power companies in the region can work together to design new, innovative programs to influence load and distributed generation for overall benefit, as well as develop the tools needed to better forecast local electricity demand and distributed resources that can be factored into planning. Also, TVA and industrial customers can collaborate to design new programs and tools tailored to the industrial sector that help meet future energy needs and align with other customer goals.

Strategic Industry Partnerships

To support the pace of the energy transition and spread the cost and risk of developing new clean energy technologies, strategic industry partnerships are essential. TVA's partnerships to advance the future of new nuclear is a recent example of this. TVA is working with the University of Tennessee – Knoxville to engage with students and prepare the nuclear workforce of the future. TVA is collaborating with Oak Ridge National Laboratory (ORNL) to combine ORNL's world-leading research capabilities and TVA's operating expertise to accelerate the next generation of cost-effective nuclear power. Additionally, TVA is participating in industry partnerships to advance the practical viability of carbon capture and hydrogen production and use through programs led by the Electric Power Research Institute (EPRI) and the National Carbon Capture Center.

Also, TVA sponsors promising startup companies in ORNL's Innovation Crossroads program and EPRI's Incubatenergy Labs to take world-changing ideas from research and development to the marketplace. These new technologies range from direct air capture and advanced battery chemistries to the use of submersible robotics for safety inspections. TVA team members serve as mentors and subject matter experts for leading startups in the University of Tennessee's Spark Clean Tech Accelerator program and in Vanderbilt University's Climate Innovation Accelerator to support minority businesses in their journey toward a climate positive future.

Preparing for Emerging Technology Opportunities

As TVA executes near to mid-term plans, ways to prepare for emerging technology opportunities are being considered and incorporated wherever possible. TVA is studying the potential for the current natural gas fleet to accommodate hydrogen as a fuel and/or be retrofitted with carbon capture and sequestration equipment. New gas units can be "hydrogen capable" to facilitate future hydrogen blending or ultimately run on hydrogen. The potential for future carbon capture and sequestration, along with the associated logistics, will also factor into site decisions using the best information available at the time. Site requirements for potential new nuclear plants also are a consideration. Following the IRP, when evaluating potential sites for new generating assets, TVA must look ahead and consider the locational needs of existing and emerging technologies to best enable the energy system of the future.

Integrated Transmission Planning

Integrated transmission planning is critical to accommodating load growth, expected asset retirements, and new generation resources in a safe, reliable, compliant, and cost-effective way. Preparing for local and regional load growth, as well as understanding when and where retirements will likely occur and new generation will be needed, are key inputs into transmission planning. As demand and supply change, TVA is incorporating enhancements to manage more complex two-way flows to support the grid of the future. Timing is key – and TVA will develop an integrated transmission plan, incorporating stakeholder input. The integrated transmission plan will consider the strategic direction from the IRP, along with the locational aspects of connecting load and generation, to enable the timely and reliable evolution of the power system.

1.5 Conclusion

TVA's 2025 IRP approach considered the planning environment, along with and the progress made to date in the energy transition. Based on movement in key signposts, TVA initiated the 2025 IRP to evaluate a broad set of potential futures for electricity demand, environmental regulations, and technology advancements and to inform a strategic path forward for the power system.

2 Stakeholder Engagement

The IRP will help shape TVA's future energy system, ensuring that the residents and businesses in the seven-state region have affordable, reliable, resilient, and increasingly cleaner energy for decades to come. To effectively balance these objectives, TVA needs the diverse opinions of key stakeholders and the public at large to understand what is important to them and to broaden thinking and challenge assumptions.

2.1 Objectives of Stakeholder Engagement

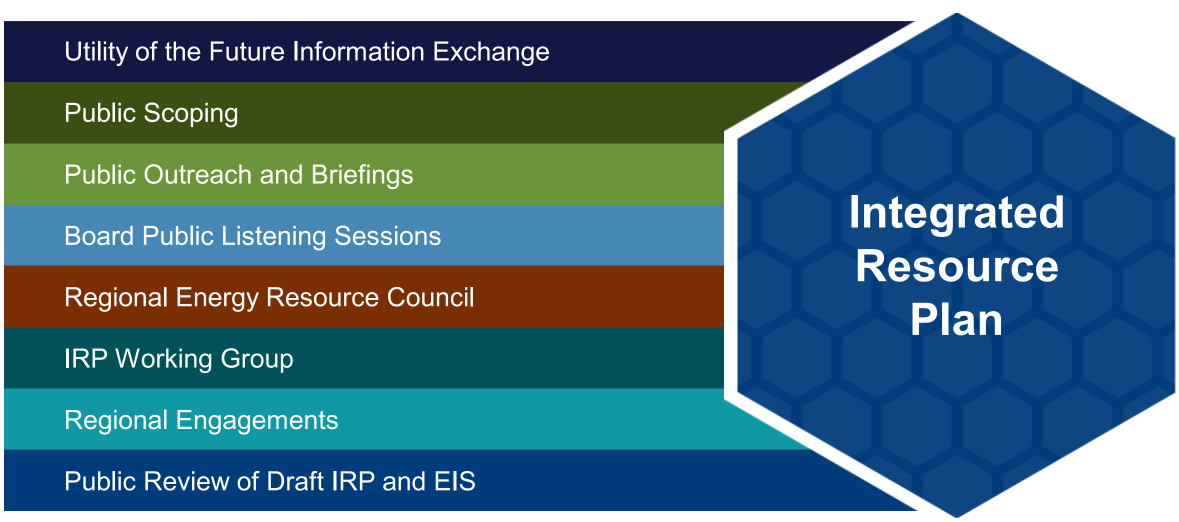
Throughout the IRP, TVA has sought to increase familiarity with TVA and the IRP across the Valley region and to increase participation in the IRP process. The approximately 10 million people TVA serves are all stakeholders, including everyone who lives and works in the region. Local power companies, direct served customers, industry partners, and other interested parties are stakeholders as well. Stakeholder input has strengthened the analysis, helping to ensure that the IRP meets the needs of the region. TVA's engagement goals are to:

- Engage numerous stakeholders with differing viewpoints and broad perspectives during the process;
- Educate stakeholders on what an IRP is, why it's important, and how it supports TVA's effort to build the energy system of the future; and
- Provide information and opportunities for key stakeholders and the public to provide input during the scoping period and during development and review of the 2025 IRP and EIS.

The draft IRP includes and benefits from diverse stakeholder input. The final IRP will incorporate additional input received through public comments on the draft IRP and EIS, and the final EIS will include responses to all stakeholder comments received.

2.2 Engagement Opportunities

Active public involvement and engagement with a diverse group of stakeholders has been an integral part of the IRP process. Since before the IRP process began, TVA looked for ways to expand and enhance public participation opportunities in the 2025 IRP to gain additional insights from across the region. In addition to IRP specific events, TVA has leveraged other existing forums to reach more stakeholders and facilitate participation in the IRP process. The primary avenues for stakeholder engagement in the IRP process include:



Utility of the Future Information Exchange

From October 2022 to July 2023, TVA led a Utility of the Future Information Exchange (UF-IX) to provide a forum for a diverse set of stakeholders to discuss the IRP process and broad issues they believe should be considered in the upcoming IRP. The group was facilitated by Future 500, a non-profit third party, and included 20 members representing a diverse mix of stakeholder interests from across the region. They discussed opportunities to enhance TVA's IRP process and explored several topics in depth, including distributed energy resources and distribution, generation and transmission considerations in an evolving system, community impacts, and IRP modeling approach. The group also weighed in on several strategic topics beyond the IRP. To summarize the effort, TVA published a Utility of the Future Information Exchange Report, compiling recommended considerations developed by the UF-IX group for use in the development of the 2025 IRP and by TVA leadership.

Public Scoping

Engagement in TVA's 2025 IRP officially began with a Notice of Intent (NOI) that initiated a 45-day public scoping period from May 19 to July 3, 2023. The objective of this initial step was to gather input from the public and key stakeholders to help frame the IRP study and identify future conditions, strategies, and resource options to be evaluated. The NOI also initiated the environmental review process for the IRP, consistent with the requirements of the National Environmental Policy Act (NEPA). The NOI included five scoping questions for consideration:

- How do you think the demand for energy will change between now and 2050 in the TVA region?
- Should the diversity of the current power generation mix (e.g., nuclear, coal, natural gas, hydroelectric, renewable resources) change? If so, how?
- How should distributed energy resources be considered in TVA planning?
- How should energy efficiency and demand response be considered in planning for future energy needs, and how can TVA directly affect energy usage by consumers?
- How will the resource decisions discussed above affect the reliability, dispatchability (ability to turn on or off energy resources), and cost of electricity? Are there other factors of risk to be considered?

During the scoping period, TVA received 43 official comments through the online portal, email, and mail-in options. Comments were primarily received from states in the TVA region, with the balance from four other states and Washington, D.C. Of the 43 submissions, 22 comments were received from individuals, nine from businesses, 10 from civic or non-governmental organizations, and two from government agencies. In addition to comments formally submitted by the public, TVA reviewed several hundred statements posted by the public on several social media pages.

Public comments covered a broad spectrum of issues. Common themes were:

- Support and opposition for various types of power generation sources
- Increasing decarbonization efforts
- Promoting distributed energy resources
- Interest in energy efficiency and energy storage alternatives
- Feedback on the IRP process and need for transparency
- Importance of reliability and resilience in the face of increasing demand
- More attention to environmental justice communities
- Concern about climate change and environmental impacts

Commenters also provided advice on scenarios and strategies to explore and suggestions to improve public outreach and stakeholder involvement. Additional information on the scoping effort and comments received can be found in the Integrated Resource Plan 2025 Scoping Report on TVA's IRP website and in the EIS.

Public Outreach and Briefings

To encourage interest and participation in the 2025 IRP, TVA is conducting public outreach and briefings throughout the process. Outreach began during the public scoping period. In addition to publishing the NOI in the Federal Register on May 19, 2023, TVA:

- Provided notification and information about the next IRP on the TVA website;
- Issued a news release to more than 300 outlets, including local, state, national, and trade sources and requested public comments through social media channels;
- Directly notified state and local government entities and federal agencies as well as numerous individuals and organizations that have expressed interest in TVA and the IRP; and
- Hosted two live public webinars (May 23 and June 7, 2023) to provide information on the IRP process and an opportunity for the public to ask clarifying questions during the scoping comment period.

During the process of framing and completing the analysis, TVA held three live public webinars (September 21 and December 14, 2023, and July 25, 2024) to provide progress updates on the IRP project and an opportunity for stakeholders and the public to ask questions along the way.

TVA utilizes its existing corporate website as a platform for outreach, with the IRP project website (tva.com/irp) serving as a hub for distributing information to the public. TVA encourages public participation on the website and provides registration links and avenues for submitting comments. Also, TVA sends out communications to a mailing list of individual stakeholders who have provided contact information for future IRP updates, webinars, and public meetings. The IRP website is regularly updated with the latest project information and links to webinar recordings and documents.

Upon release of the draft IRP and EIS, TVA will conduct two live public webinars and 10 open houses across the region. The goal of these sessions is to provide information on the IRP analysis and key themes, answer questions, and encourage stakeholders and the public to provide comments on the draft IRP and EIS.

Board Public Listening Sessions

Another opportunity for public participation in the IRP is through TVA Board public listening sessions. These quarterly sessions provide an open forum for stakeholders and the public to convey their perspectives directly to the Board on any topic related to TVA that is important to them. Over the past year, a number of stakeholders took advantage of the opportunity to share their thoughts with the Board on the IRP process and what they would like to see considered in the analysis and recommendations. The Board reflects on what they hear in public listening sessions as they deliberate and make decisions on all topics, including the IRP.

Regional Energy Resource Council

The Regional Energy Resource Council (RERC), established under the guidelines of the Federal Advisory Committee Act, is comprised of a diverse group of external stakeholders representing regional government, customers, academia, and advocacy groups. The RERC provides guidance on how TVA plans and manages its energy resources against competing objectives and values. During the IRP process, the RERC is receiving progress updates on the project and is providing advice to TVA to be incorporated into the IRP. The meetings of the RERC are open to the public, meeting agendas are posted to the Federal Register, and the minutes from the meetings are published on the TVA website. The public is invited to provide comments on related topics, including the IRP, at listening sessions at RERC meetings.

IRP Working Group

To ensure stakeholder views and needs are considered throughout the process, TVA established the IRP Working Group, a diverse group of stakeholders that reviews and challenges IRP inputs and assumptions, analyzes outputs, designs evaluation criteria, and evaluates results and recommendations. The 24 members represent local power companies, customer associations, academia and research, state governments, environmental non-government organizations, community stakeholders, and other special interest groups. In addition to representing their individual views to TVA, they also represent and keep their constituencies informed during the IRP process. 2025 IRP Working Group members are:

Dr. Kendra Abkowitz (TN) City of Nashville	Wes Kelley (AL) Huntsville Utilities	Cortney Piper (TN) Tennessee Advanced Energy Business Council
Mike Butler (TN) Tennessee Wildlife Federation	Mike Knotts (TN) Tennessee Electric Cooperative Association	Jim Powell (National) White House Climate Policy Office
Dr. Don Colliver (KY) University of Kentucky	Dr. Teja Kuruganti (TN) Oak Ridge National Laboratory	David Rogers (NC) Sierra Club
Odell Frye (Valley) Associated Valley Industries	Melissa Lapsa (TN) Department of Energy – Energy Efficiency	Tim Smith (MS) Tippah Electric Power Association
Lindsay Hanna (TN) Nature Conservancy	Kim Lewis (AL) PROJECTXYZ, Inc.	Brian Solsbee (TN) Tennessee Municipal Electric Power Association
Shane Homan (MS) Community Development Foundation	Pete Mattheis (Valley) Tennessee Valley Industrial Committee	Landon Stevens (National) Clear Path
Gil Hough (TN) Tennessee Solar Energy Industries Association	Susan Hadley Maynor (TN) Greater Memphis Chamber	Kenya Stump (KY) State of Kentucky
Mark Iverson (KY) Bowling Green Municipal Utilities	Doug Peters (Valley) Tennessee Valley Public Power Association	Dr. Jennifer Tribble (TN) Tennessee Dept. of Environment and Conservation

Figure 2-1: IRP Working Group

Since July 2023, TVA has met approximately monthly with the IRP Working Group to gather input on the planning approach, inputs, and analyses prior to the release of the draft IRP and EIS. To enhance communication of Working Group activities, meeting summaries have been posted to the IRP website. Additional meetings are scheduled through the release of the final IRP and EIS in Spring/Summer 2025.

Regional Engagements

New to the 2025 IRP, TVA is leveraging ongoing regional engagements to heighten awareness of the IRP and solicit public input on considerations for how to best meet future electricity demand. The TVA region is diverse, and regional engagements provide the opportunity to personalize interactions and utilize local forums already in place to convey information about the IRP to the public. With the support of its regional representatives, TVA is carrying the IRP message to a broader audience, answering questions of local interest, and receiving additional feedback on the IRP.

Public Review of Draft IRP and EIS

The draft IRP and EIS, which incorporate stakeholder input received to date, were posted on TVA's website on September 23, 2024, with a Notice of Availability published in the Federal Register on September 27, 2024. The draft IRP includes an executive summary and discussions of the planning environment, stakeholder engagement, process and methodology, and portfolio results and assessments, followed by supporting appendices. The associated EIS provides information on the environmental impacts of potential future resource portfolios evaluated in the IRP. To complement the reports, an IRP overview and short fact sheets discussing aspects of the IRP process can be found on TVA's IRP website. TVA encourages stakeholders and the public to review the materials and provide their comments on the draft IRP and EIS during the 60-day comment period that concludes on November 26, 2024.

Summary of Stakeholder and Public Involvement to Date

Through the various avenues for stakeholder and public involvement, summarized below, TVA has received valuable input on the scope of the IRP effort and the development of the analysis.

Figure 2-2: Stakeholder and Public Involvement to Date

2.3 Environmental Justice Approach

TVA is incorporating environmental justice considerations – which address disproportionate health, environmental, economic, and climate impacts on disadvantaged communities – into IRP and EIS processes. During the development of the IRP, TVA is focused on engaging disadvantaged communities in new ways.

Environmental Justice Principles

Environmental justice (EJ) guidance is provided through several Executive Orders (EO). EO 12898 (1994), Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, directs federal agencies to identify and address “disproportionately high and adverse human health or environmental effects” of their actions on minority and low-income populations (i.e., EJ communities). EO 14096 (2023), Revitalizing our Nation’s Commitment to Environmental Justice for All, reinforces addressing “disproportionate and adverse” impacts and builds upon the federal government’s commitment to deliver EJ to all communities across the nation. EJ includes the just treatment and meaningful involvement of all people regardless of income, race, color, national origin, Tribal affiliation, or disability in agency decision-making and other federal activities that affect human health and the environment.

These executive orders contemplate that federal agencies will:

- Seek out and facilitate the involvement of those potentially affected by agency actions;
- Provide opportunities for people to meaningfully participate in decisions about activities that may affect their environment and/or health; and
- Consider the concerns of all communities in the decision-making process.

In TVA's NEPA review processes, EJ principles are important considerations, consistent with EOs and guidance from the EPA and the Council on Environmental Quality. To inform decision-making, TVA reviews its proposed actions to determine whether actions have the potential to adversely affect EJ communities and provides those communities opportunities to provide input. For instance, future TVA power generation proposals initiated based on strategic guidance in the 2025 IRP would be subject to a site-specific analysis that considers effects on EJ communities.

TVA also engages and supports communities in the region, including EJ communities, through programs that directly support the public. TVA's Uplift suite of programs that addresses energy challenges in homes, schools, and small businesses is a prime example of this. Home Uplift provides weatherization free-of-charge to qualifying households to reduce energy costs and improve living conditions. School Uplift offers energy efficiency training and grants that reduce energy costs and improve the quality of the learning environment. Small Business Uplift helps local businesses in underserved communities make smart energy choices that decrease energy use and save money while improving facilities and reducing carbon emissions. Additionally, TVA workforce development efforts create learning opportunities for skilled green jobs and increase minority participation in TVA's Quality Contractor Network.

EJ Approach for the IRP

The IRP evaluates potential ways to meet future electricity demand for the entire Valley region through 2050, providing strategic but not site-specific direction for TVA's future power system. Leveraging strategic direction from the IRP, future recommendations will be made over the coming years for site-specific asset additions and/or retirements. As EJ has locational aspects, EJ considerations factor most into site-specific asset decisions.

While the IRP is not site-specific, EJ considerations help guide TVA's public outreach strategies for the IRP, as described further below. Additionally, the draft IRP and EIS provide directional insight into potential impacts to communities with EJ concerns. For example, the average system cost metric is directionally indicative of overall trends in customer bills, and metrics related to emissions are directionally indicative of air and water quality trends in the region. Site-specific aspects of actions that are later proposed to implement the IRP will be addressed in tiered environmental reviews.

Engaging EJ Communities

EJ in the IRP starts with encouraging and facilitating the involvement of disadvantaged communities so their opinions on the future power system can be considered. To accomplish this, an EJ focus is being applied to IRP engagements, with the objective to reach and gain valuable input from EJ communities.

The first step in reaching out to disadvantaged communities has been understanding where they are located. TVA utilized screening methodology and mapping tools from the Department of Energy (DOE) and the Council on Environmental Quality (CEQ) to identify EJ populations in the region (recent snapshot below).

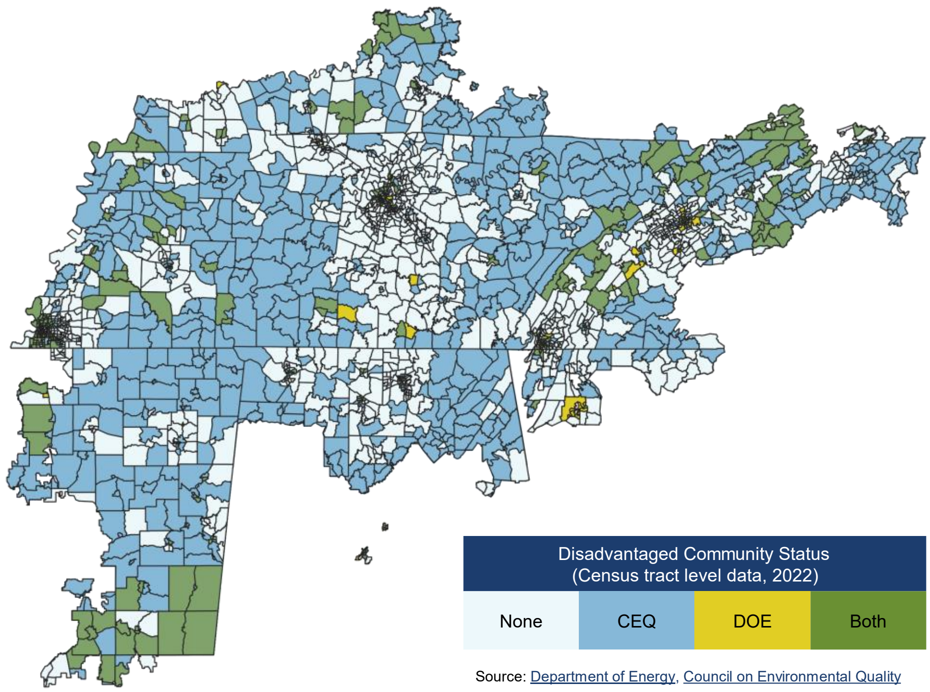


Figure 2-3: Environmental Justice Communities Screening Map for the TVA Region

Then, TVA developed strategies for reaching and engaging EJ communities throughout the IRP and EIS process and after the 2025 IRP is adopted. These strategies include:

Table 2-1: Environmental Justice Engagement Strategies

Scoping to Draft IRP/EIS	Draft to Final IRP/EIS	Post-IRP Adoption
• Utilize diverse channels to communicate the IRP and EIS process • Provide IRP summary and fact sheets in English and Spanish • Leverage local power company communications channels to promote IRP open houses and public comment period • Leverage TVA regional teams to work with local community and business leaders to identify EJ engagement opportunities	• Continue to utilize diverse channels of communication • Provide electronic and hard copies of the draft IRP and EIS in locations accessible to EJ communities • Hold public informational open houses in locations accessible to EJ communities • Use communication style that is digestible by all stakeholders	• Employ EJ tools and outreach strategies as site-specific asset recommendations are evaluated • Leverage TVA regional teams and community leaders to develop site-specific outreach and engagement plans • Build relationships and provide timely opportunities for EJ communities to share concerns and provide input

2.4 Conclusion

Promoting effective public and stakeholder engagement to obtain diverse perspectives is crucial to a successful IRP and environmental review process. Examples of how stakeholder input has been incorporated to date in the IRP are discussed further in Section 3.2. With input from stakeholders including EJ communities, TVA is creating an IRP aimed at achieving TVA's mission of making life better for everyone in the region.

3 Process and Methodology

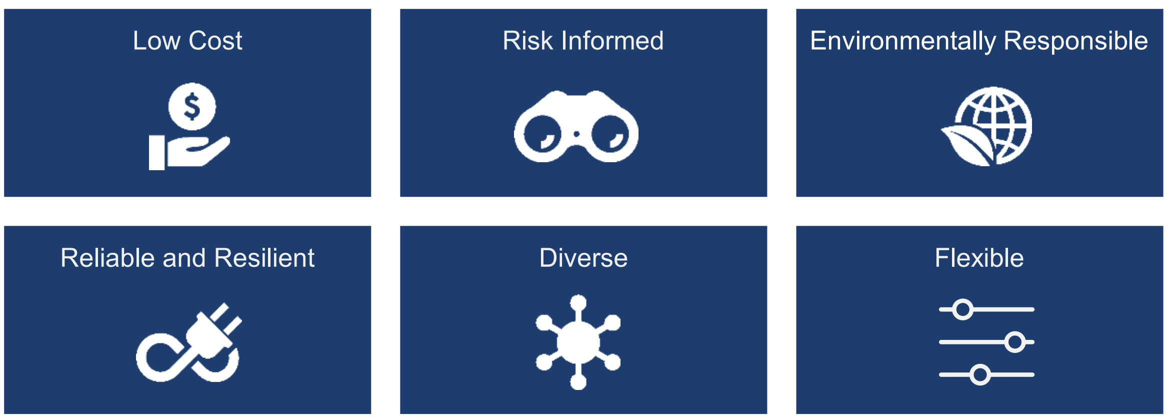
Having the right resources at the right times to power the homes and businesses in the region requires continual planning. Periodically, TVA develops an IRP that goes beyond annual updates to take a broader view of potential electricity demand, evolving policy and regulations, and technology advancements, and it incorporates stakeholder input into the planning process. This chapter explains planning objectives, how the IRP process works, and the methodology used in the 2025 IRP for the key steps in the process.

3.1 Objectives of Resource Planning

Integrated resource planning at TVA is grounded in least-cost principles and meets the environmental review requirements of the National Environmental Policy Act (NEPA). Least-cost planning principles are integral to TVA, and TVA's plans are strengthened by thorough environmental review.

Least-Cost Planning Principles and the Energy Policy Act of 1992

TVA applies the following least-cost principles, in alignment with Section 113 of the Energy Policy Act of 1992, to develop plans for providing affordable, reliable, resilient, and increasingly cleaner energy over the long term:



Least-cost planning evaluates cost, operational, environmental, and risk factors in order to provide reliable service at the lowest system cost. A system that is diverse, resilient, and flexible is more reliable, year in and year out, so these aspects are key considerations. Planning also explores opportunities to efficiently reduce environmental impacts. Finally, TVA evaluates variations in electricity demand, resource costs, and environmental regulations to ensure plans are risk informed and flexible to adapt as the future evolves. Metrics being used in the IRP reflect least-cost planning principles, providing insights into tradeoffs across alternative business strategies.

As TVA puts the nuts and bolts of its plans together, planners also consider that load varies across all hours of the day and seasons of the year, with weather a large driver, and that highest peak loads are typically of short duration. Resources have various operational, economic, and environmental characteristics and constraints, requiring a mix of resources to achieve the best portfolio fit overall.

In conducting least-cost planning, TVA must comply with the following requirements in Section 113 of the Energy Policy Act of 1992:

- The least-cost planning program "evaluates the full range of existing and incremental resources (including new power supplies, energy conservation and efficiency, and renewable energy resources) in order to provide adequate and reliable service…at the lowest system cost";

- System cost encompasses only those costs that are "direct and quantifiable net costs for an energy resource over its available life, including production, transportation, utilization, waste management, and environmental compliance"; and
- In addition to cost, the planning process will also consider "necessary features for system operation," including diversity of resources, reliability, dispatchability, and other factors of risk.

When making specific asset decisions, TVA stays within the planning direction and resource ranges that were studied and approved in the most recent IRP.

Environmental Review

In accordance with NEPA, TVA considers the potential environmental effects of its proposed actions during its decision-making processes. These environmental studies improve TVA resource planning and provide opportunities for public and stakeholder engagement. Comments received from the public and stakeholders during public scoping helped define the analysis presented in the draft IRP and EIS, which describes potential resource portfolios and associated environmental impacts. Public and stakeholder input received during the draft IRP and EIS comment period will be considered and evaluated in the final analysis.

Continuous Improvement and Innovation

With each IRP, TVA strives for continuous improvement and innovation. TVA is utilizing insights from new initiatives such as the Valley Pathways Study and the Utility of the Future Information Exchange to inform the IRP. The IRP includes refined assumptions for emerging technologies such as advanced nuclear, carbon capture and sequestration, and hydrogen blending that will likely play a part in a low-carbon future. Also, TVA engaged the National Renewable Energy Laboratory (NREL) to develop a best-in-class approach for greenhouse gas life cycle analysis. This analysis established parameters for generation resources that were applied to IRP analysis outcomes and discussed in the EIS. NREL representatives are also attending IRP Working Group meetings and providing input for consideration.

3.2 Overview of the IRP and EIS Timeline

The process for the development of the IRP consists of seven distinct steps, complemented by public outreach efforts and the incorporation of stakeholder input along the way:

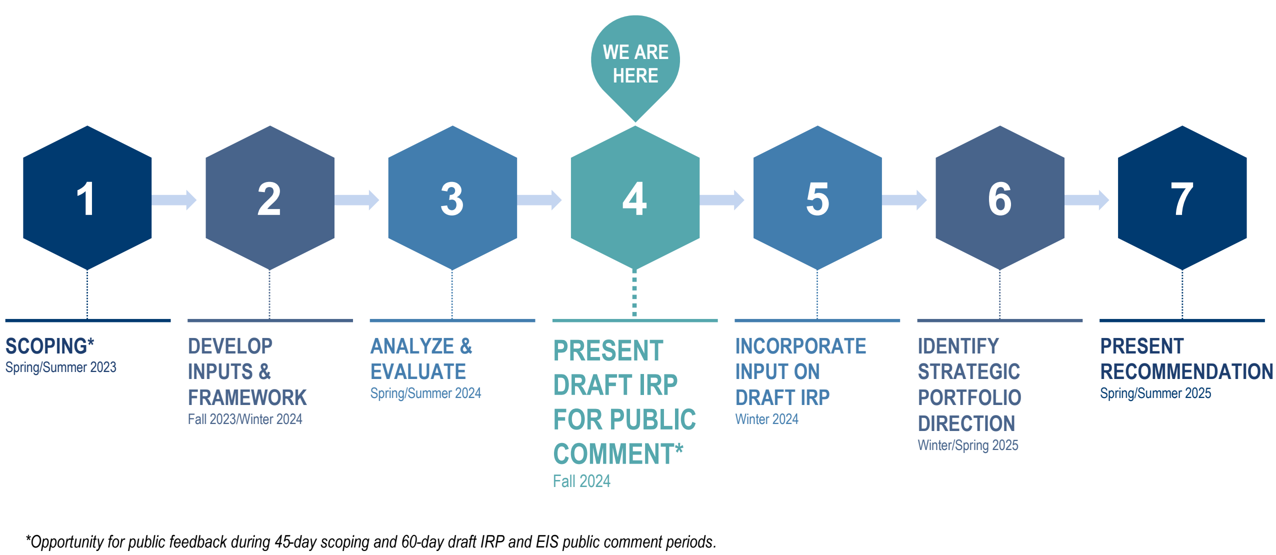


Figure 3-1: IRP Timeline

The process began with the publication of a Notice of Intent (NOI) filed under NEPA in the Federal Register in May 2023 that initiated a 45-day public scoping comment period. TVA published a Public Scoping Report in October 2023 that summarized public input received and considered in framing the scope of the IRP effort. Over the ensuing months, TVA worked closely with the IRP Working Group, a diverse group of stakeholders, to establish the inputs for the analysis, evaluate case results, and summarize findings of the IRP. In September 2024, TVA provided the draft IRP and EIS for public review during a 60-day comment period. After the comment period ends, TVA will consider additional input from the IRP Working Group, the Regional Energy Resource Council (RERC), and public comments to refine the analysis. All IRP findings, including insights from additional analysis performed based on input received during the comment period, will be considered in developing strategic portfolio direction. In Spring/Summer 2025, the final IRP and EIS will be made available to the public for at least 30 days prior to consideration by the TVA Board. Subject to the Board's direction, an official Record of Decision will then be posted to conclude the NEPA process for the IRP.

Engaging Stakeholders

In developing the IRP analysis and recommendations for the region's future energy system, TVA considers and balances the varying needs and priorities of TVA's approximately 10 million stakeholders. Throughout the development of the IRP, TVA has engaged external stakeholders to gather diverse opinions on the future power system, challenge assumptions, and help shape the analysis and outcomes. In the 2025 IRP, TVA has looked for ways to expand and enhance public participation opportunities to gain additional insights from across the region. TVA applied environmental justice principles to the overall approach for the study, with the objective to reach and gain valuable input from all communities.

Incorporating Stakeholder Input

Outreach efforts have prompted significant stakeholder and public engagement. Comments received during scoping helped frame the IRP effort, in addition to planning considerations from the Utility of the Future Information Exchange. The IRP Working Group (IRP-WG) provided input that influenced the scenarios and strategies, challenged assumptions, refined the resource options, and strengthened the analysis. The graphic below highlights the key themes of stakeholder input and how it has influenced the draft IRP analysis.

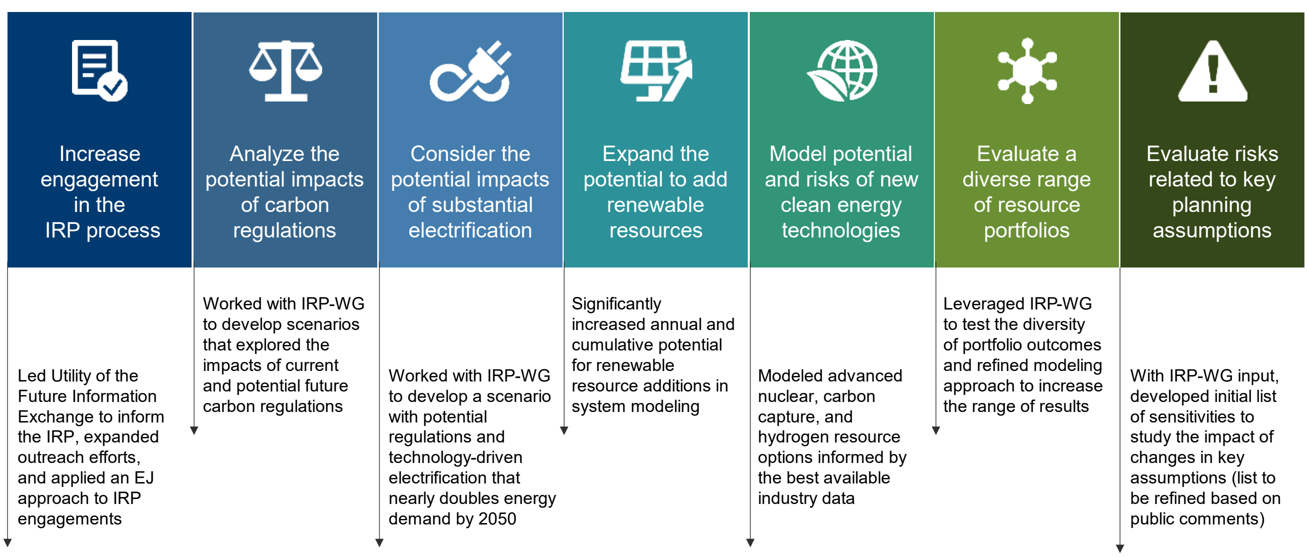


Figure 3-2: Incorporating Stakeholder Input

Comments received on the draft IRP and EIS will prompt additional analysis that will be considered for the recommendations that will be included in the final IRP and EIS.

3.3 How Integrated Resource Planning Works

TVA used a rigorous and comprehensive scenario and strategy approach to evaluate potential paths for providing affordable, reliable, resilient, and increasingly cleaner energy into the future. Stakeholder feedback was a key component in the development of all model inputs during the process.

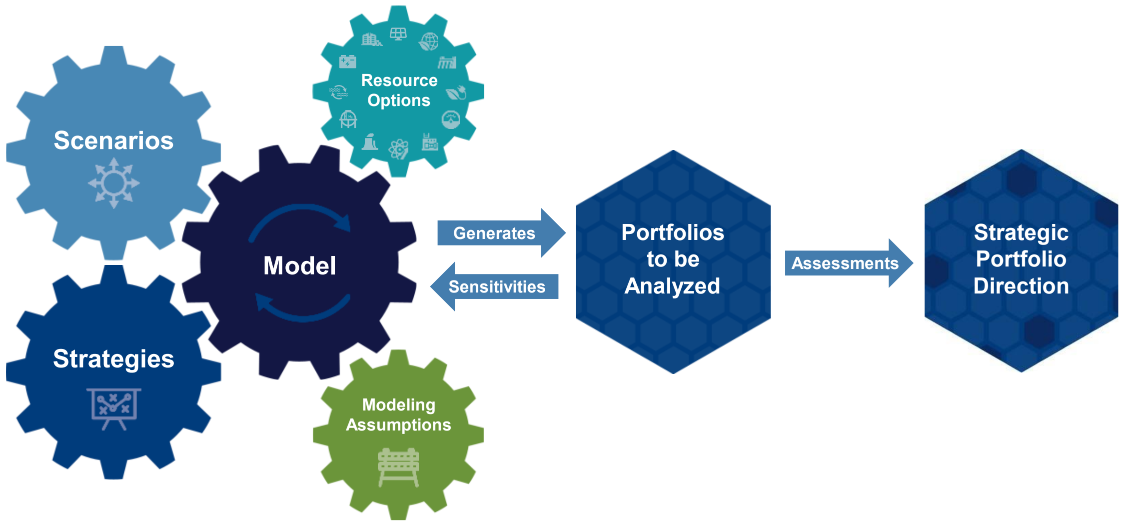


Figure 3-3: TVA's Integrated Resource Planning Process

TVA utilized input from the IRP Working Group and public comments to design scenarios and strategies to be evaluated in the IRP. Scenarios explored possible futures that TVA may find itself operating in that have varying levels of electricity demand, environmental policy and regulations, and technology advancements. Strategies modeled alternative approaches TVA could employ to meet electricity demand by emphasizing certain resource options. TVA also used input from the IRP Working Group to develop the set of resource options to be considered in the IRP analysis.

Combining the various scenarios and strategies generated potential resource portfolios to be analyzed using metrics that reflect TVA's least-cost planning principles. The draft EIS evaluated the environmental impacts of potential changes in the portfolio. Further analysis will be performed to answer additional questions based on IRP Working Group input and public comments on the draft IRP report. Collectively, these evaluations will inform the IRP recommendations for strategic portfolio direction that will be included in the final IRP report.

Benchmarking Peer IRPs

Early in the IRP process, TVA engaged Deloitte to review TVA's 2019 IRP and conduct benchmarking of utility peer IRPs. Key findings from reviewing TVA's 2019 IRP were an organized structure, strong stakeholder participation, thorough scenario and strategy analysis, and a variety of data sources and third-party involvement. Additionally, Deloitte reviewed the IRPs of 10 peer utilities primarily located in adjoining regions. Benchmarking analyzed load and other trends, scenarios and methodologies, and resource options with a focus on emerging technologies. Based on its analysis, Deloitte identified several key themes and evolving trends to be considered in future IRPs:

- Increased deployment of renewables and energy storage technology
- Goal to provide reliable, affordable, and cleaner power to customers
- Investment in cost-effective renewable energy solutions
- Continuous evolution of policy and external regulatory pressure

- Electrification of transportation and other sectors

Deloitte reviewed a summary of its findings with the IRP Working Group for consideration in providing input on TVA's 2025 IRP.

3.4 Creating Possible Scenarios

Often forecasts rely primarily on continuations of historical trends to suggest the possible future. In its IRP, TVA used scenarios as the mechanism to explore a more robust range of ways the future could unfold. Generally defined, scenarios are the future worlds which TVA may find itself operating in. They are driven by factors outside of TVA's control but to which TVA must be prepared to respond. The IRP scenarios were designed assuming that key uncertainties would deviate from historical trends in the future. Key uncertainties identified relate to electricity demand, environmental policy and regulations, technology advancements, and other factors. As possible scenarios were considered and developed, TVA and the IRP Working Group collectively strove for a set of possible futures that was relevant, informative, and diverse.

3.4.1 Scenario Development

TVA collaborated with the IRP Working Group to develop scenarios for the IRP analysis. The TVA team did some initial brainstorming, and then TVA and the Working Group refined scenario design, focusing on how the future might be shaped by changes in key uncertainties such as economic trends, electricity demand, consumer preferences, regulation, and technology. Themes emerged, leading to potential scenarios that combined key uncertainties and correlated impacts. The Working Group met several times to refine the scenarios and associated narratives to ensure that each one:

- Reflected a possible future in which TVA might be operating between now and 2050
- Was unique from the other scenarios being studied
- Provided a robust foundation for analyzing a range of resource selections
- Encompassed the relevant interests of key stakeholders

The Working Group aligned on six unique scenarios for study in the IRP analysis, with results and metrics from all scenarios reflected in a balanced manner. The six scenarios evaluated were:

1 **Reference (without Greenhouse Gas Rule)**
Represents TVA's current forecast that reflects moderate population, employment, and industrial growth, weather-normal trends, growing electric vehicle use, and increasing efficiencies

2 **Higher Growth Economy**
Reflects a technology-driven increase in U.S. productivity growth that stimulates the national and regional economies, resulting in substantially higher demand for electricity

3 **Stagnant Economy**
Reflects rising debt and inflation that stifle consumer demand and business investment, resulting in weaker than expected economic growth and essentially flat electricity demand

4 **Net-zero Regulation**
Reflects the impact of the May 2023 draft Greenhouse Gas Rule that targets significant reductions in electric utility CO_2 emissions beginning in 2030 and potential future utility regulations striving for net-zero by 2050

5 **Net-zero Regulation Plus Growth**
Reflects the impact of the May 2023 draft Greenhouse Gas Rule and potential future utility regulations, along with substantial advancements in clean energy technologies, that spur economic growth and extensive electrification

6 **Reference (with Greenhouse Gas Rule)**
Reflects TVA's current forecast and incorporates the impact of the Greenhouse Gas Rule finalized in May 2024 that targets significant reductions in electric utility CO_2 emissions beginning in 2030

Figure 3-4: IRP Scenarios

The first three scenarios generally relate to each other. The Reference without Greenhouse Gas Rule scenario represents TVA's current forecast for moderate levels of economic growth and increasing adoption of electric vehicles (EV) without the Greenhouse Gas (GHG) Rule finalized by the EPA in May 2024. The Higher Growth Economy and Stagnant Economy scenarios represent bounding cases around the Reference without Greenhouse Gas Rule scenario driven by significantly varying economic conditions. Taken together, these three scenarios realistically depict the range of futures TVA could operate in without carbon regulation.

Similarly, the last three scenarios are related, as they consider futures where carbon dioxide (CO_2) emissions from power generators are regulated. The Reference with Greenhouse Gas Rule scenario represents TVA's current forecast incorporating the recently finalized GHG Rule (May 2024). The two net-zero regulation scenarios consider additional potential regulations and technology advancements. The Net-zero Regulation scenario reflects the draft rule for regulating GHG emissions proposed by the EPA in May 2023, which also included regulations that may be adopted in the future related to existing gas plants, and considers potential future regulations designed to achieve net-zero carbon emissions by 2050. In addition to these regulatory influences, the Net-zero Regulation Plus Growth scenario also assumes a faster pace of technology advancement that lowers resource costs and drives strong electrification growth across all major sectors – residential, commercial, industrial, and transportation.

The GHG Rule recently finalized by the EPA is being litigated and could be stayed, vacated, or amended. Because of this litigation status, the IRP includes reference scenarios with and without this recently finalized rule. This allows TVA to evaluate the range of potential system impacts that could be driven by where these regulations ultimately land.

The following subsections provide highlights on the key elements underpinning the scenarios. Additional details can be found in Appendix B – Scenario Design and Forecasts.

3.4.2 Electric Load Forecast

Based on the scenario narratives, forecasts were then developed for key uncertainties, beginning with drivers of the load forecast. The load forecast represents the future energy needs for the region under normal weather conditions for each of the modeled scenarios. Variations from normal weather conditions are addressed in the Need for Power Analysis section that follows. The figure below shows energy and peak demand forecasts for each scenario, along with their associated compound annual growth rates (CAGR) over the study window.

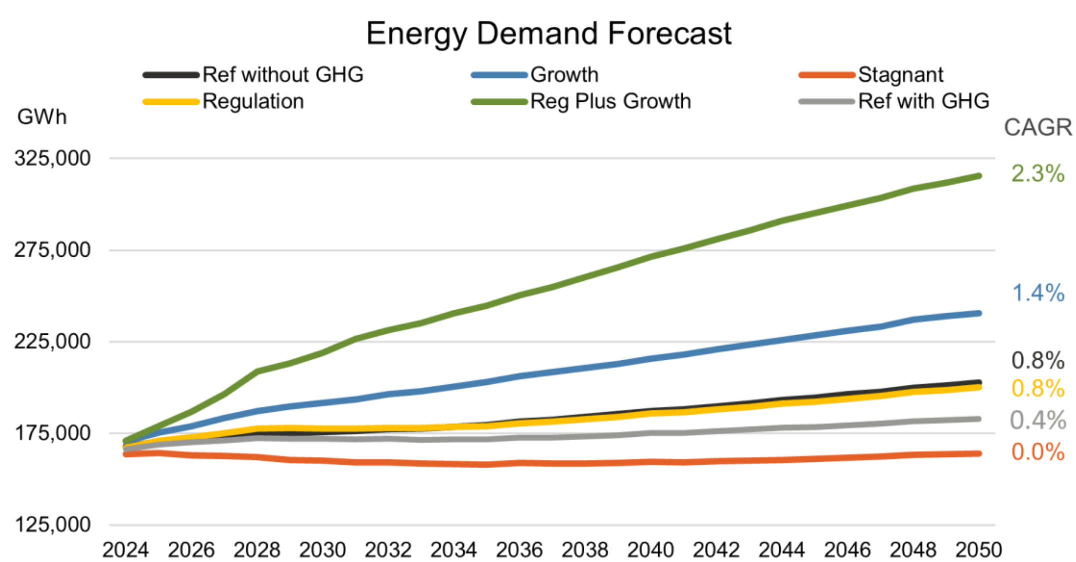


Figure 3-5: Energy Demand Forecast

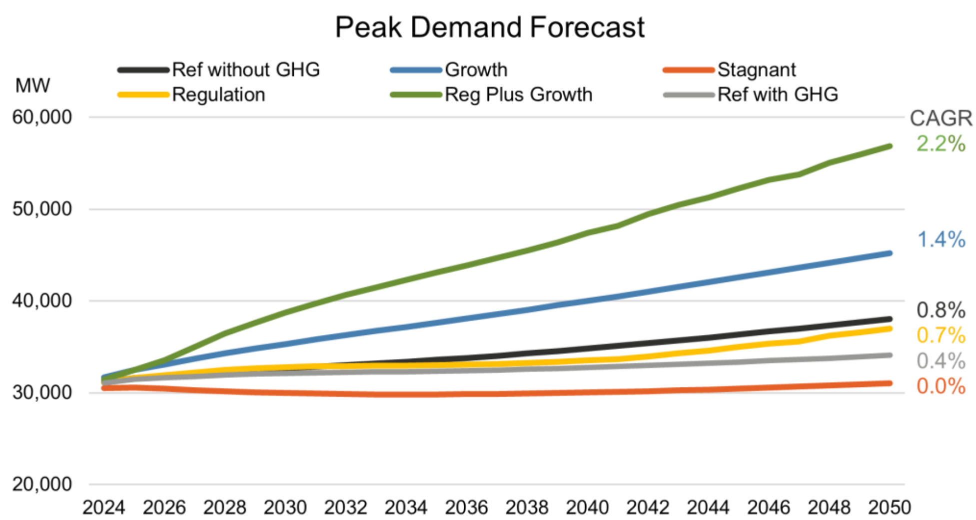


Figure 3-6: Peak Demand Forecast

- **Reference (without GHG Rule)**: Reflects moderate economic growth and adoption of EVs that drives steady load growth.
- **Higher Growth Economy**: Projects more robust technology and productivity driven economic growth, resulting in a higher load forecast.
- **Stagnant Economy**: Projects inflationary pressures that dampen economic growth, causing load to remain essentially flat over the study period.
- **Net-zero Regulation**: Foresees future carbon regulations that drive higher energy prices than Scenario 1, causing slightly lower energy demand in the long run.
- **Net-zero Regulation Plus Growth**: Envisions carbon regulations, rapid technology advancement, and electrification of transportation and industry, driving the highest load forecast across the scenarios.
- **Reference (with GHG Rule)**: Reflects the GHG Rule which drives increased energy prices that dampen growth in electricity demand relative to Scenario 1.

3.4.3 Need for Power Analysis

The next step in creating scenarios was to develop capacity requirements for winter and summer for each scenario. Capacity requirements represent the megawatts (MW) needed to serve projected demand plus required planning reserves in each season. Planning reserves provide sufficient resources above forecasted load to respond to variations from normal weather, consumer behavior, and generating unit availability. Calculating capacity needs requires understanding the forecast for baseline firm supply from existing resources, which declines over time due to planned retirements and contract expirations. Then, firm capacity requirements are compared to projected baseline firm supply from existing resources and power purchases to identify the capacity gap – or the need for incremental power resources. The capacity gap reflects the minimum amount of new capacity that would be required to meet energy demand in each scenario.

To illustrate this concept, the figure below shows winter firm capacity requirements for each scenario compared to baseline firm supply. The difference between a scenario's firm requirements and the forecast for baseline firm supply over time represents the capacity gap.

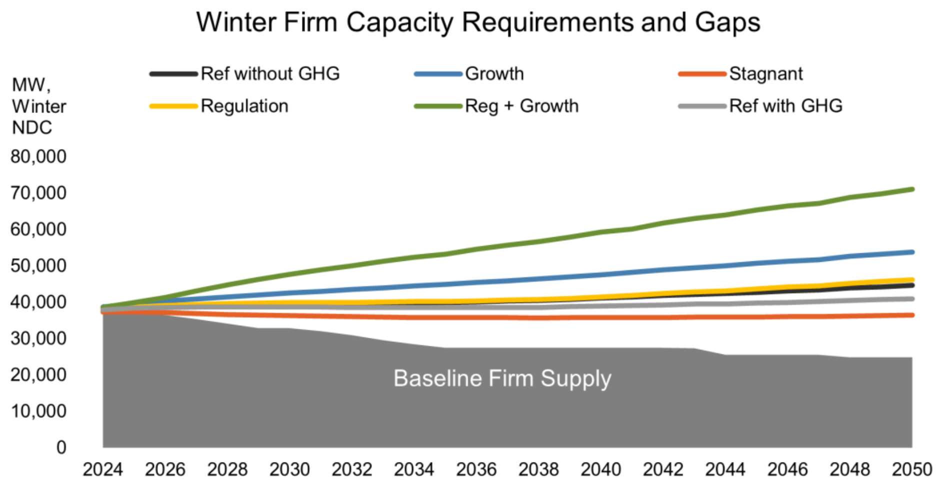


Figure 3-7: Winter Firm Capacity Requirements and Capacity Gaps

3.4.4 Current and Potential Future Regulations

The changing regulatory landscape represented another key uncertainty in scenario design. Key elements in policy and regulatory space were the Inflation Reduction Act, Infrastructure Investment and Jobs Act, and Greenhouse Gas Rule.

Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA)

All IRP scenarios reflect the impacts of the IRA and IIJA on resource costs and national and regional energy prices. The figure below shows the level of IRA Investment Tax Credit (ITC) assumed in the IRP modeling of scenarios and resource cost assumptions. TVA generally assumed a 40% ITC for nuclear, renewable, and storage resources through the full study window. The IRA allows up to a 50% ITC if wage and apprenticeship standards, domestic content guidelines, and siting criteria (in an energy or low-income community) are met. To account for potential cost increases to meet requirements, siting challenges, and other risk factors, the IRP analysis applies a 40% ITC. In the Net-zero Regulation scenario, the national model projects that U.S. power sector emissions would drop below 25% of 2022 levels by 2034. In that scenario, ITC phase-out is triggered for projects initiating construction after 2034, with the final year of ITC availability based on the typical length of construction for each resource type. The Net-zero Regulation Plus Growth scenario assumes the maximum amount of ITC (50%) for all eligible resources through the full study window.

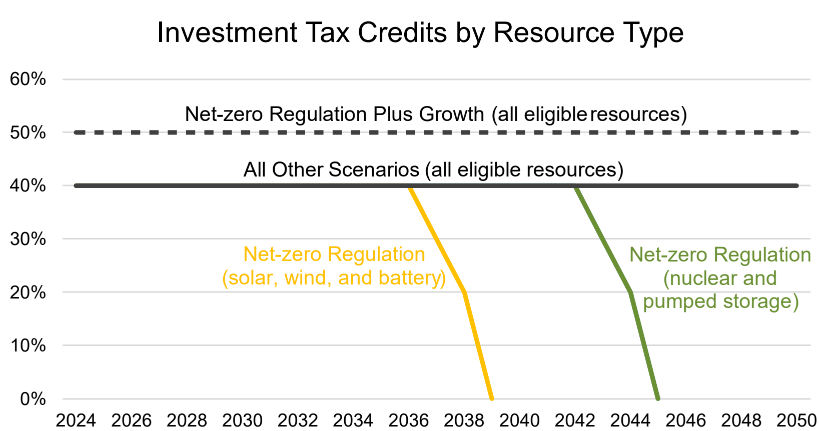


Figure 3-8: Investment Tax Credits by Resource Type

Also, the IRP analysis reflects the impact of the Section 45Q tax credit for carbon capture projects under construction before 2033. Credits are available for the first 12 years of commercial operation.

Greenhouse Gas Rule

The last three scenarios reflect the impacts of recently finalized and potential future regulations. The Reference with GHG Rule scenario evaluates the impact of EPA's GHG Rule finalized in May 2024. The GHG Rule under the Clean Air Act seeks to reduce greenhouse gases by establishing CO_2 emissions limits for fossil fuel-fired power plants. The final GHG Rule would require TVA to:

- Operate its existing coal fleet with increasing emissions limits and capacity factor restrictions over time
- Build and operate new gas generation resources with carbon capture and sequestration (CCS) systems or operate with low-emitting alternative fuels or capacity factor restrictions

While Scenario 6 incorporates the EPA's final GHG Rule, the net-zero regulation scenarios (4 and 5) reflect the draft GHG Rule, which included regulations that may be adopted in the future related to existing gas plants. Specifically, the May 2023 draft version of this rule required operating existing natural gas fleets with increasing hydrogen blending over time or installing CCS equipment. In addition to reflecting the draft rule, these two scenarios also assume future regulatory actions intended to drive CO_2 emissions to net-zero by 2050. As a proxy for potential future regulations, these scenarios include an escalating tax on CO_2 emissions beginning in 2034. The Net-zero Regulation scenario uses the 2023 EPA social cost of carbon at a 2.5% discount rate as the basis for its carbon tax (begins at about $220/ton in 2034). The Net-zero Regulation Plus Growth scenario uses the 2021 White House interim social cost of carbon at a 3% discount rate (begins at about $125/ton in 2034), as the advancements in new clean energy technologies in this case would likely reduce the carbon tax needed to achieve net-zero by 2050.

3.4.5 Natural Gas Commodity Prices

The price of natural gas over the study period was another key uncertainty that varied across the scenarios, and it also plays a role in resource selection. Informed by their narratives, each of the six scenarios utilized a unique forecast for natural gas prices, as shown below.

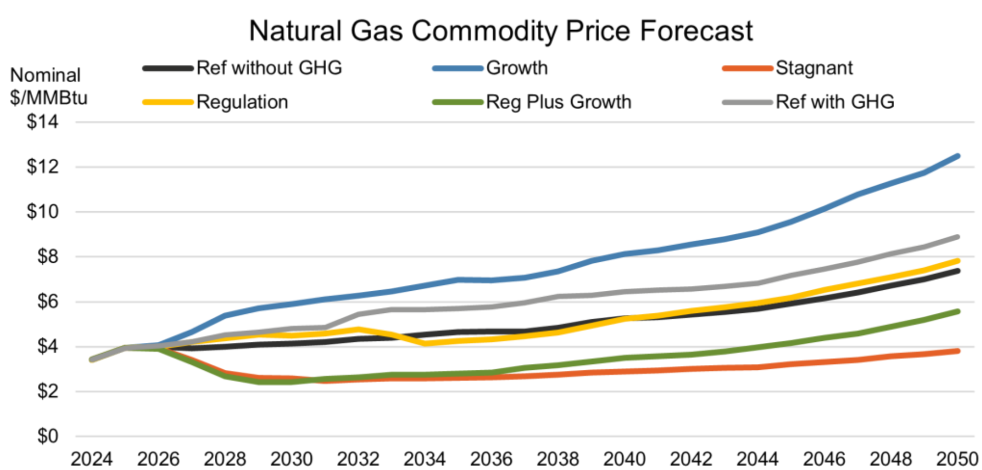


Figure 3-9: Natural Gas Price Forecast

- **Reference (without GHG Rule)**: Industrial demand and growing export volumes are the primary drivers of nominal natural gas price increases in this scenario, while prices adjusted for inflation remain relatively stable.
- **Higher Growth Economy** and **Stagnant Economy**: All things being equal, changes in economic activity will lead to increases or decreases in demand for energy of all types. These two scenarios highlight the significant price uncertainty due to changes in energy demand, representing the upper and lower bounds that TVA expects for natural gas prices.
- **Net-zero Regulation**: Reduction in natural gas demand from the power sector that tends to drive lower prices is largely offset by higher inflation in this scenario, resulting in a gas price forecast similar to the Reference without Greenhouse Gas Rule scenario.
- **Net-zero Regulation Plus Growth**: Natural gas prices in this scenario are lower than in the Reference cases, as the power sector sees significant reductions in natural gas demand and advances in technologies keep inflation low.
- **Reference (with GHG Rule)**: The GHG Rule drives increased retirement of national coal capacity, increased demand for natural gas (in part for the existing gas fleet), and generally higher inflation that result in higher natural gas prices than Scenario 1.

3.4.6 Resource Technology Costs

Scenario development generally assumes the same resource technology cost baseline for all scenarios. An exception in this IRP was the Net-zero Regulation Plus Growth scenario. This scenario assumes future carbon regulations combined with strong electrification economy-wide and must consider market power prices that impact usage. Market power prices represent the average cost of electricity in the U.S. A primary driver of change in market power prices is the cost of incremental resource additions, so substantial investment in clean energy resource technologies was identified as a necessary key driver in this scenario. To reflect this, Scenario 5 uses the advanced rather than the moderate levels of resource technology costs published by NREL as a baseline for determining market power prices that contribute to driving the highest energy demand in this possible future.

3.5 Identifying Potential Strategies

After scenario forecasts were developed, the next task was to identify planning strategies. Where scenarios describe the potential futures TVA may find itself operating in, strategies depict business approaches TVA could employ to meet energy demand in these future worlds. The IRP analysis compares baseline utility planning with alternative strategies that promote certain resource types to evaluate tradeoffs.

3.5.1 Strategy Development

To develop IRP strategies, TVA again leveraged the IRP Working Group to brainstorm ideas and ultimately identify a set of strategies to analyze. Baseline Utility Planning represents fundamental least-cost planning, and all strategies apply a planning reserve margin to provide sufficient resources to account for variations in load and generating unit availability. The alternative strategies emphasize specific themes – from promotion of carbon-free resources with an innovation or commercial-ready focus to promotion of distributed and demand-side resources or smaller, more dispersed resources that enhance local resiliency. Narratives for the alternative strategies were developed to identify resource types for promotion based on how their attributes contributed to each strategy's theme.

TVA collaborated with the IRP Working Group and landed on five distinct strategies to explore in the IRP analysis, supported by the following narratives:

A **Baseline Utility Planning**
Represents TVA's current outlook based on least-cost planning, incorporating existing programs and a planning reserve margin target. This reserve margin target applies in all strategies

B **Carbon-free Innovation Focus**
Emphasizes and promotes emerging, firm and dispatchable carbon-free technologies through innovation, continued research and development, and strategic partnerships

C **Carbon-free Commercial Ready Focus**
Emphasizes proven carbon-free technologies like wind, solar, and storage, at both utility-scale and through customer partnerships, along with strategic transmission investment

D **Distributed and Demand-side Focus**
Emphasizes existing and potentially expanded customer partnerships and programmatic solutions to reduce reliance on central station generation and promote virtual power plants

E **Resiliency Focus**
Emphasizes smaller units and the promotion of storage, along with strategic transmission investment, to drive wider geographic resource distribution and additional resiliency across the system

Figure 3-10: IRP Strategies

Promotion of a resource can be accomplished in a number of ways, such as sending an artificially lower cost signal or defining minimum amounts to be selected. All resource options are available to be selected in each strategy, including those with no promotion, allowing the model to select and optimize the resource portfolio from the full suite of available resources.

3.5.2 Strategy Design and Evaluation

The IRP analysis compared Baseline Utility Planning with the alternative strategies to evaluate tradeoffs based on least-cost planning principles. At a high level, the steps in the strategy design and evaluation process were:

- Develop Baseline Utility Planning cases for all scenarios (no resources promoted)
- Identify promotion of resource types to achieve objectives in each strategy
- Run cases with resource promotions for alternative strategies in all scenarios
- Evaluate tradeoffs across all scenarios and strategies using metrics based on planning principles

The details of strategy design involved identifying the level and mechanism for promoting resources. TVA and the Working Group opted for base, moderate, and high levels of promotion to help drive differentiation across the strategies. Base reflects no level of promotion, while moderate and high apply increasingly greater levels of promotion. The mechanism applied to promote resources was a combination of artificially lower costs and required minimum additions, as each method has modeling advantages to drive efficient and diverse portfolio outcomes. Where a cost signal was used for resource promotion, the artificial cost reduction was later removed to accurately calculate cost metrics.

The Strategy Design Matrix below provided the roadmap for how resource promotions were applied in the strategies. Resource types not listed, such as frame combustion turbines for example, were available for selection in all strategies but were not promoted in any strategy.

STRATEGY		UTILITY SCALE RESOURCES						DISTRIBUTED AND DEMAND-SIDE RESOURCES				
		Solar and Wind	Battery Storage	Long-duration Storage	Aero CTs and Recip Engines	Nuclear	CCS*	Distributed Solar	Distributed Storage	Combined Heat and Power	Energy Efficiency	Demand Response
A	Baseline Utility Planning	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
B	Carbon-free Innovation Focus	Moderate	Moderate	Moderate	Base	High	High	Moderate	Moderate	Base	Moderate	Moderate
C	Carbon-free Commercial Ready Focus	High	High	High	Base	Base	Base	Moderate	Moderate	Base	Base	Moderate
D	Distributed and Demand-side Focus	Base	High	Base	High	Base	Base	High	High	High	High	High
E	Resiliency Focus	Base	High	Moderate	High	Moderate	Base	Moderate	Moderate	Moderate	Base	High

*Carbon capture and sequestration

Figure 3-11: Strategy Design Matrix and Levels of Promotion

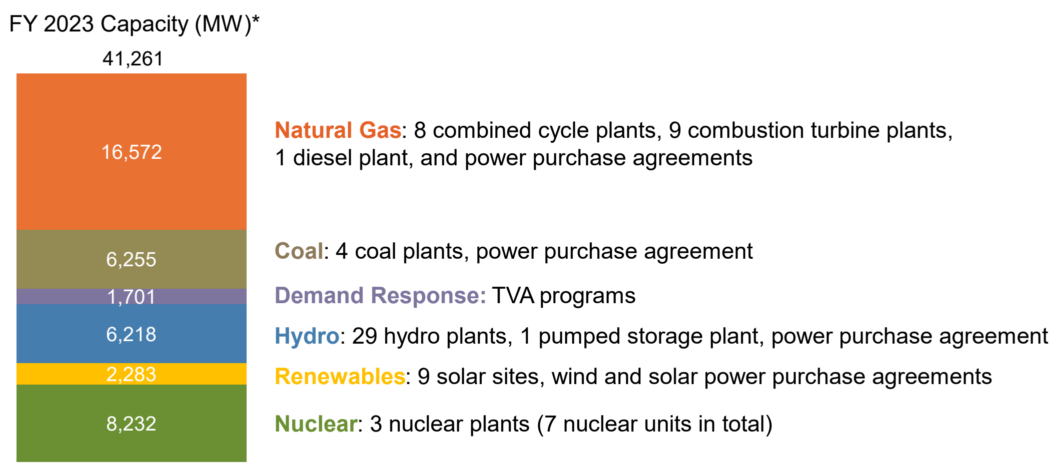
Each of the five strategies was modeled in each of the six scenarios, resulting in 30 portfolios. Additional details can be found in Appendix C – Strategy Design and Application.

3.6 Defining Resource Options

The next step in the IRP process was to define resource options. This entailed understanding the current set of existing resources, identifying new resource options, and defining the key assumptions for each resource option to accurately model operational characteristics and costs.

3.6.1 Existing Resources

TVA employs a diverse resource mix to meet the region's energy demand. Power generation resources serve different needs – from those that run continually to meet constant energy needs, to those that help meet fluctuating needs, to those that are used for a few hours when energy demand is at its highest. Today, the TVA power system is comprised of generating resources and power purchase agreements that provided 41,261 megawatts (MW) of capacity in FY 2023. A new simple-cycle combustion turbine plant in Paradise, Kentucky, entered commercial operations in December 2023, adding 681 MW to the power system.



* Capacity aligns to FY 2023 10-K summer net capability and power purchase agreement tables, adjusted to include demand response programs and exclude delivered energy. Planning capacity is lower, as it accounts for hydro and renewable expected generation at peak, fuel blend derates and other factors.

Figure 3-12: TVA's Existing Resource Portfolio

The resource planning model uses net dependable capacity, or the expected output of a given resource at the forecasted time of peak demand. Net dependable capacity is lower than summer net capability published in TVA's annual 10-K report, as it accounts for hydro and renewable expected generation at peak, fuel blend derates, and other factors. Renewable resources are typically referred to in nameplate capacity, or maximum hourly generating capability, while the planning model uses expected output at peak demand times.

The forecasted capacity available from existing resources changes over the study window as generating units are projected to reach the end of their useful life and purchased power contracts expire, as shown below.

Table 3-1: Significant Baseline Firm Supply Reductions (MW Summer NDC)

Year	Coal	Gas CC	Gas CT	Diesel	Hydro	Solar	Wind	Landfill Gas	Total MW SNDC
Baseline Firm Supply 2023									36,429
2024									0
2025		750	1,295		271		4		2,320
2026									0
2027	1,075								1,075
2028	1,171			62					1,233
2029	1,075								1,075
2030				23					23
2031		735					47	2	784
2032	1,404			20		3	55		1,482
2033		833					63	8	904
2034	1,071	762							1,833
2035				10					10
2024-35	5,796	3,080	1,295	115	271	3	169	10	10,739
Baseline Firm Supply 2035									25,690
2036								12	12
2037						51			51
2038						104			104
2039						151			151
2040						25			25
2041						71			71
2042						259			259
2043									0
2044		1,659							1,659
2045									0
2046									0
2047									0
2048		636							636
2049									0
2050									0
2024-50	5,796	5,375	1,295	115	271	664	169	22	13,707
Baseline Firm Supply 2050									22,722

As resource options were identified for the IRP, the potential to retire existing gas combined cycle assets before the end of their useful life was also considered. Also, expected dates for coal plant retirements reflect the assumed regulatory requirements in each scenario, which slightly accelerates the last coal plant retirement in the Scenario 6 portfolios.

3.6.2 Resource Options

Maintaining diversity in the resource mix is fundamental to TVA's ability to provide affordable, reliable, resilient, and increasingly cleaner energy to the residents, businesses, and industries in the region. To help accomplish this, the IRP analysis considered the addition of a wide range of supply-side generating resources, distributed generating resources, and demand-side management resources.

To be considered in the IRP, a given resource option must utilize a proven technology, or one that has reasonable prospects of becoming commercially available in the planning horizon. It must also be available to TVA within the region or be available to be imported through a power purchase agreement. As the 2025 IRP looks out to 2050, several emerging technologies were included as options using best available industry data.

The major resource types evaluated in the IRP include nuclear, hydro, coal, natural gas, renewables, storage, and energy efficiency and demand response (EE and DR), and they were available for selection in all cases. The figure below shows the major resource types, technologies, and relative advantages and considerations.

Major Resource Types	Nuclear	Hydro	Coal	Gas	Renewables	Storage	EE and DR
Resource Technologies	• Advanced pressurized water reactor • Light water small modular reactor • Gen IV small modular reactor	• Hydro uprates	• Supercritical pulverized coal • Supercritical pulverized coal w/ carbon capture	• Combined cycle (CC) • CC w/ carbon capture • Combustion turbine • Aeroderivative • Reciprocating engine • Hydrogen blending • Combined heat/power	• Utility scale solar • Distributed solar • Midwest wind • Southeast high-hub wind • High Voltage Direct Current wind	• Pumped storage • Lithium-ion battery • Advanced chemistry battery • Distributed storage	• Energy efficiency • Demand response
Advantages	• Dispatchable • Carbon-free • Large energy output • Low operating cost	• Dispatchable • Carbon-free • No fuel cost • Low variable cost	• Dispatchable • Large energy potential	• Dispatchable • Large energy potential • Operational flexibility	• Carbon-free • No fuel cost • Low variable cost	• System efficiency benefits • Operational flexibility	• Carbon-free • Reduced need to construct new resources
Considerations	• High build and fixed cost • Cost and timeline risk for new builds • Spent fuel disposal	• Energy limited based on water availability and other missions • Relatively high build cost	• Carbon-emitting • Waste disposal • Environmental risk • CO_2 storage and transportation	• Carbon-emitting • Air permit timelines • Pipeline challenges • CO_2 and H_2 storage and transportation	• Weather dependent • Solar supply chain • Solar land use • Local wind speeds • Wind importation cost and risk	• Energy limited based on hours of duration • Efficiency losses	• Program protocols and limitations • Free ridership • Evolving codes and standards

Figure 3-13: Summary of Resource Options

In addition to the option to add resources, the capacity expansion model also had the option to retire existing combined cycle units earlier than their end-of-life planning dates, if cost effective to do so.

3.6.3 Technology and Adoption Readiness

The ability to successfully deploy a technology is dependent upon the maturity of that technology from a fundamental perspective, as well as the readiness to adopt that technology throughout its entire value chain. To better assess adoption readiness, the Department of Energy (DOE) has developed a Commercial Adoption Readiness Assessment Tool (CARAT) that establishes an Adoption Readiness Level (ARL) framework to complement the existing Technology Readiness Level (TRL) framework. Taken together, they provide a more complete view of the readiness to deploy various resource technologies in the energy sector.

Technological readiness is assessed with a 1 to 9 TRL score that ranges from research to development and demonstration to commissioning and operations. The ARL framework establishes a rubric for evaluating the commercial factors related to a technology's value proposition, market acceptance, resource maturity, and license to operate, resulting in an overall 1 to 9 ARL score that reflects level of readiness across the adoption value chain. A high-level summary of TRL and ARL scoring levels is shown below.

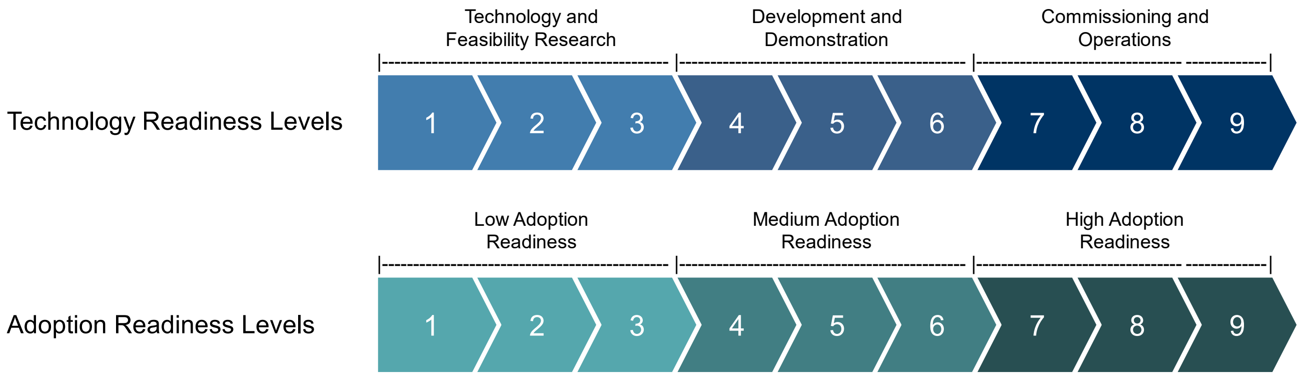


Figure 3-14: DOE's TRL and ARL Frameworks

Using DOE rubrics, TVA scored the technology and adoption readiness levels for the various resource options included in the IRP analysis. TVA referenced industry-led risk registers to help identify technology-specific risk types and levels. For the ARL assessment, TVA considered production, transportation, and distribution infrastructure in a 3-to-5-year commercialization window and assumed the current policy environment including the recently finalized GHG Rule. The figure below summarizes the scoring results.

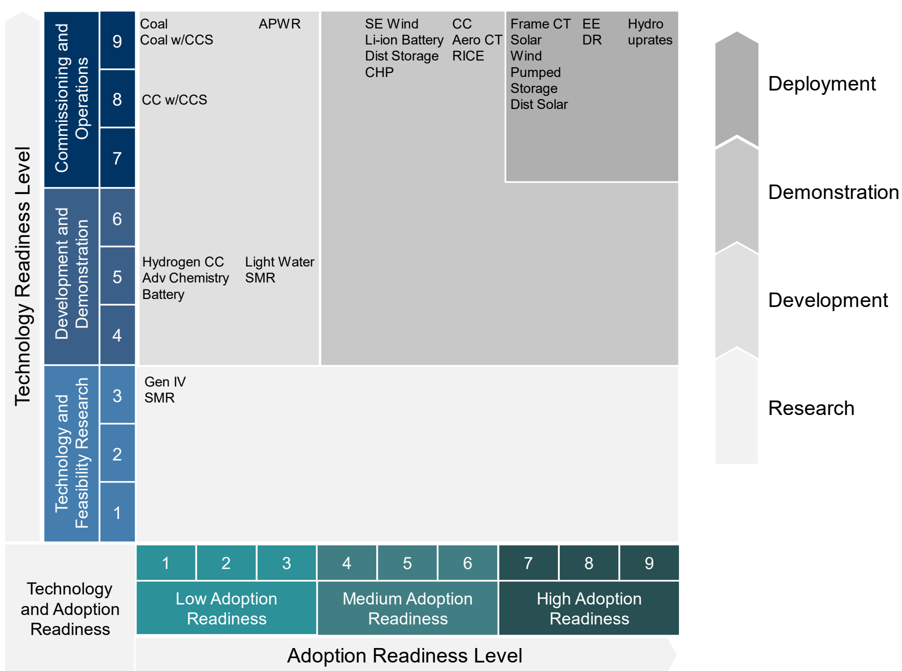


Figure 3-15: TRL and ARL Assessment Summary

TVA and the Working Group considered relative technology maturity in strategy design and in determining earliest deployment, as well as in risk assessments. Also, the strategic portfolio direction from the IRP will help shape TVA's future innovation and research efforts. More information on DOE's TRL and ARL assessment tools and details of the scoring results for the resource options included in the IRP analysis can be found in Appendix E – Utility Scale Resource Methodology.

3.6.4 Key Assumptions by Resource Type

After determining the resource types to include in the IRP, TVA then developed detailed assumptions for each resource option and reviewed a summary with the IRP Working Group. To effectively model a resource option, certain questions need to be answered, including:

- How soon can a specific resource option be designed, reviewed, constructed, and brought online?
- How many units of a given resource type can be added annually and over the planning horizon?
- What are the operational characteristics and constraints for each resource option?
- What contribution to peak load will renewable and storage resources have as penetration increases?
- How much does each resource cost, and how do costs change over time?

The following table highlights the key modeling assumptions by resource type.

Table 3-2: Key Assumptions by Resource Type

Resource Type	Key Assumptions
Nuclear	• First-of-a-kind light water small modular reactor available beginning 2033 and nth-of-a-kind available afterward; annual limit of one build • Advanced pressurized water reactor available beginning 2038; annual limit of one build • Gen IV small modular reactor available beginning 2041; annual limit of one build
Hydro	• Hydro uprates available beginning 2026 as part of established Hydro Life Extension program • Assumptions are specific to opportunities across the TVA power system which total 200 MW
Coal	• Supercritical pulverized coal available beginning 2029; annual limit of two builds • Supercritical pulverized coal with carbon capture and sequestration available beginning 2033; annual limit of one build, total limit of 11 builds
Gas	• Conventional natural gas available beginning 2029; annual limit of two builds of each type • Combined cycle with carbon capture and sequestration available beginning 2033; annual limit of one build, total limit of 11 builds • New gas units assumed to be hydrogen-capable (Scenarios 4 and 5 incorporate required blending according to the May 2023 draft GHG Rule)
Solar	• Single-axis tracking (storage modeled separately) • Solar available beginning 2027 (currently contracting for solar coming online in 2028); annual limit of 1,000 MW in reference cases and up to 1,850 MW in highest promotion cases • Incremental solar contribution to peak of 68% in summer and 15% in winter, declining over time • Average capacity factor of 25%
Wind	• Midwest and Southeast high-hub wind available beginning 2029; annual limit of 1,000 MW • HVDC-enabled wind available beginning 2029; annual and cumulative limit of 3,000 MW • Incremental wind contribution to peak of 19% in summer and 33% in winter, declining over time • Average capacity factor of 55% (HVDC), 40% (Midwest), and 30% (Southeast high-hub)

Resource Type	Key Assumptions
Storage	• Pumped storage available beginning 2033; cumulative limit of 1 build • Lithium-ion battery (4-hour) available beginning 2029; annual limit of 500 MW in reference cases and up to 650 MW in highest promotion cases • Advanced chemistry battery (10-hour) available beginning 2029; annual limit of 500 MW in reference cases and up to 650 MW in highest promotion cases
EE and DR	• Current program cycle extends through 2026 • Expansion EE and DR programs available beginning 2027 • Program tier design informed by recent Energy Programs Potential Study and TVA experience • Demand response capability is assumed to grow with the size of the system
Distributed Generation	• Baseline forecast for distributed generation adoption modeled based on consumer payback • For strategies where distributed generation was promoted, accelerated adoption was modeled based on level of promotion and impact on consumer payback

Best practice in utility planning is to use annual limits as the modeling vehicle for simulating the practical ability to construct or procure new resources, so the analysis will generate executable portfolios. The IRP analysis includes annual limits for all resource types based on recent experience designing, permitting, and constructing new generating assets and procuring new resources through Request for Proposal processes. For example, the market capability for solar has increased, and this is reflected with solar limits that are more than double the limits used in the previous IRP. In promotion cases, certain annual limits were increased to reflect additional build or procurement potential resulting from strategic transmission investment. Cumulative limits for the entire study period also apply to model physical limitations for certain resources, such as uprate potential at existing hydro plants and regional carbon sequestration potential for coal and gas plants equipped with CCS systems.

3.6.5 Resource Technology Costs

Developing the costs for the various resource options considered in the IRP was the next step in the process. The sub-sections below summarize the general methodology used to develop resource costs, how recent policy changes were incorporated, and the overnight capital cost for each resource technology.

General Methodology

For utility scale options, TVA utilized the moderate case from NREL's 2023 Annual Technology Baseline as the primary source for resource costs, with a few exceptions. Informed by direct experience exploring designs for potential small modular reactors (SMRs) at the Clinch River Nuclear Site, TVA used refined forecasts for new nuclear resources that are higher than NREL estimates. The refined nuclear forecasts reflect all-in cost assumptions using information from preliminary estimate determination efforts. Hydro expansion costs were based on internal estimates specific to opportunities across the TVA power system, and gas expansion estimates were based on recent experience with gas build projects. In the Net-zero Regulation Plus Growth scenario, TVA assumed the lower cost estimates from NREL's advanced case to represent the potential for more rapid technology advancements in that future world, except for nuclear estimates which were lowered from internal estimates to NREL's moderate case.

Adoption of distributed generation resources (solar, storage, and combined heat and power) was modeled based on consumer payback, with accelerated adoption in promotion cases. The modeling of demand-side resource options, including EE and DR program tiers, was designed based on TVA program experience and information included in the Energy Programs Potential Study. Further information on the methodology and costs for distributed generation and demand-side resource options is included in Appendix F – Distributed Generation Resource Methodology and Appendix G – Demand-side Resource Methodology, respectively.

Inflation Reduction Act and Infrastructure Investment and Jobs Act

The Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA) promote investment in clean energy technologies and resilient grid infrastructure. TVA has established a dedicated team to identify, prioritize, and facilitate pursuing related investment opportunities.

As mentioned previously, estimated impacts from the IRA and IIJA were applied in all IRP scenarios, and they were also applied to resource cost estimates. The primary impact to resource costs was in the form of clean energy production and investment tax credits that incentivize investment in renewable and other clean energy sources. In IRP modeling, TVA generally assumed a 40% investment tax credit (ITC) for nuclear, renewable, and storage resources through the full study window. This assumption reflects the potential for up to a 50% ITC adjusted for risk factors related to meeting all requirements to achieve the maximum ITC (see section 3.4.4 for additional explanation). In the Net-zero Regulation scenario, the ITC phase-out is assumed to be triggered for projects initiating construction after 2034. For the Net-zero Regulation Plus Growth scenario, TVA maximized the potential credits to align with assumptions about the regulatory environment and rapid technology advancement in that possible future.

Overnight Costs by Technology

A key assumption contributing to resource selection is the cost to construct a particular resource. Overnight capital costs represent the total estimated cost to build a given resource in the first year available, restated in 2024 dollars and divided by its capacity in kilowatts ($/kW). Cost assumptions were derived from the sources explained in the general methodology section, incorporating the impacts of recent policy changes. The table below summarizes overnight capital costs for the utility scale resource options considered in the IRP. Capacity is expressed as Summer Net Dependable Capacity (NDC) for thermal resources and as nameplate for renewable and storage resources. Further information on utility scale resource characteristics and costs can be found in Appendix E – Utility Scale Resource Methodology.

Table 3-3: Overnight Capital Costs

Resource Type	Resource Technology	Summer NDC or Nameplate (MW)	Overnight Capital Cost (2024 $/kW)
Nuclear	Advanced Pressurized Water Reactor (APWR)	1,150	12,928
	Small Modular Reactor – Light Water (first-of-a-kind)	285	17,949
	Small Modular Reactor – Light Water (nth-of-a-kind)	285	12,471
	Small Modular Reactor – Gen IV with Integrated Storage (500 MW w/storage)	345	9,175
Hydro	Hydro Uprates	200	942
Coal	Coal Supercritical Pulverized	650	3,176
	Coal Supercritical Pulverized with Carbon Capture and Sequestration	650	4,762
Natural Gas	Combined Cycle – 2x1x1	1,430	1,372
	Combined Cycle with Carbon Capture and Sequestration – 2x1x1	1,430	3,017
	Frame Combustion Turbine – 4x*	884	744
	Aeroderivative Combustion Turbine – 20x*	1,060	1,642
	Reciprocating Internal Combustion Engine – 24x*	426	1,287
Solar (nameplate)	Solar Single-Axis Tracking	50	1,300

Resource Type	Resource Technology	Summer NDC or Nameplate (MW)	Overnight Capital Cost (2024 $/kW)
Wind (nameplate)	Wind – Midcontinent Independent System Operator (MISO)	200	1,625
	Wind – Southeast High-Hub	200	2,358
	Wind – High Voltage Direct Current (HVDC)	200	3,171
Storage (nameplate)	Pumped Storage	1,600	2,088
	Battery – Lithium-ion 4-Hour	50	1,445
	Battery – Advanced Chemistry	50	3,106
EE and DR	Energy Efficiency and Demand Response Programs	Varies by program – refer to Appendix G for modeling details	
Distributed Generation	Distributed Solar, Storage, and Combined Heat and Power	Varies by resource – refer to Appendix F for modeling details	

* Smaller configurations of these resources were also offered as available options.

Depending on how an asset's dispatch costs compare to others in the fleet, the amount of energy generated from a specific asset may vary significantly over time. For example, when gas prices are low, assets powered by natural gas serve customers with more energy than when gas prices are high. A concept that is sometimes utilized to compare asset costs is Levelized Cost of Energy (LCOE). LCOE divides the total cost of an asset (i.e., construction and capital, ongoing operating and maintenance, and dispatch costs which are primarily fuel) by expected output or generation. Because dispatch costs and expected output vary widely across the IRP scenarios, LCOE is not a useful metric to benchmark resource costs. A better comparison is overnight capital cost, a key assumption used in the model that is benchmarked by independent third-party review.

Transmission Costs

In addition to the costs to build or procure resources, costs are incurred to connect each resource to the transmission system. Transmission costs are based on a review of recent projects constructing new generating assets of various types across the TVA system. Phased increases in the cost of transmission projects per MW by asset type are calculated based on planning assumptions regarding the expected increase in project complexity, outage constraints, material costs, and labor requirements.

Large resource additions like natural gas and nuclear plants typically require more robust transmission buildouts, including items like new substations and longer transmission lines for interconnection, along with significant upgrades to existing transmission assets in the local area. Inverter-based resources such as solar and battery storage often require relatively fewer traditional transmission upgrades. However, the size and dispersed nature of these resources makes the scale of new and upgraded transmission projects more complex on a per MW basis compared to larger generating plants. Also, inverter-based resources typically require supplemental reactive resource transmission projects to ensure system stability and reliability that are not required for spinning generation. As the deployment of inverter-based solar and battery storage increases on the TVA system, the likelihood of more extensive network upgrades increases, given the growing interdependence of each system modification.

Resource Options Benchmarking

TVA engaged Horizons Energy to review the IRP assumptions for resource characteristics and costs. In its review, Horizons Energy noted that TVA's assumptions were generally in line with typical assumptions in the industry. The most notable exception was the estimated cost of a first-of-a-kind SMR, where TVA's estimate was significantly higher than the industry average. TVA's estimate is based on its industry-leading experience exploring the potential for SMRs at the Clinch River site, and it also reflects the cost risk recently experienced with new nuclear builds in the industry. Appendix E – Utility Scale Resource Methodology includes a summary of Horizons Energy's findings.

3.7 Incorporating Modeling Assumptions

For the IRP, TVA used an industry-standard model for resource planning that applies a planning reserve margin and other key assumptions, forming the modeling framework for the analysis.

3.7.1 Modeling Software

TVA utilized the EnCompass capacity expansion and production cost simulation package, licensed through Anchor Power Solutions, as the primary modeling tool for the IRP analysis. In 2022, TVA upgraded to the EnCompass model to leverage its multi-user functionality and enhanced ability to consider the chronology of energy needs in resource selection. EnCompass is also used as the primary resource planning tool by a number of other utilities in the Southeast and across the nation.

Based on the set of assumptions and constraints applicable in a given analysis, the EnCompass model seeks to determine the lowest cost resource portfolio and the expected energy output for each resource in the portfolio. The model can also be used to calculate portfolio metrics to inform business decisions. Additional information on how the model works is included in the discussion on developing and evaluating portfolios.

3.7.2 Planning Reserve Margin

Planning reserve margin is the excess capacity that TVA maintains above forecasted peak load to provide reliable service to customers while keeping rates low. Maintaining additional capacity accounts for uncertainty in the amount of load and available generation on a future peak day. For example, future loads are uncertain due to variations in weather conditions, and electric generators can experience unplanned outages due to equipment failure. TVA has a dual-peaking power system, as peak demand for summer and winter is roughly the same. While forecasted peaks are similar, uncertainty and risks vary with the seasons, so TVA uses seasonal reserve margin targets to account for this. Periodically, TVA conducts a study reflecting the latest data on changes in electricity demand and the power system to establish updated planning reserve margin targets.

In the IRP analysis, TVA used the following assumptions:

- 18% planning reserve margin target in the summer
- 25% planning reserve margin target in the winter

These values were based on the 2020 Reserve Margin Study, a probabilistic study that estimates the amount of reserve capacity required to meet an industry best practice of a 1-in-10-year loss-of-load expectation for reliability. Weather is a key driver of load. The variability of weather in winter in the TVA region is much greater than in summer, and the region has a relatively high share of electric heat. Also, power generation performance varies by season. Overall, weather-related uncertainty is the primary contributor to the relatively higher winter reserve margin.

TVA is in the process of conducting an updated reserve margin study, which is not yet complete. While average winter temperatures are gradually warming, the region has recently experienced extreme winter temperatures, such as during Winter Storm Elliott in December 2022. Extreme winter events drive increased peak demand, and cold temperatures can also cause additional generator outages and impact market import capability. Other Southeast peer utilities are seeing similar trends. While weather factors are out of TVA's control, TVA has made significant investments during 2023 to harden its generating resources, which improved cold-weather performance during winter storms in early 2024. Given recent indications of increasing winter risk, TVA plans to conduct a sensitivity analysis using a higher winter reserve margin. Additional information on planning reserve margin and related studies can be found in Appendix D – Key Modeling Assumptions.

3.7.3 Discount Rate

The objective function of the EnCompass capacity expansion model is to minimize the present value of revenue requirements (PVRR) while meeting the reliability and operational needs of the power system. To calculate the PVRR of a given expansion path, the model applies a discount rate to the forecasted total system costs by year over the study window to reflect those costs in today's dollars. The current discount rate of 7% is based on TVA's weighted average cost of capital, and it reflects the time value of money and other factors such as investment risk. The model calculates and compares the PVRR of numerous expansion paths that meet power system needs and determines the least-cost option.

3.7.4 Other Supporting Studies

Net Dependable Capacity Study

TVA recently performed a study to evaluate the Net Dependable Capacity (NDC) of solar, wind, and storage resources. NDC is a measurement of a resource's ability to produce energy at times of peak demand, expressed as a percentage of nameplate capacity. The seasonal NDC of intermittent and storage resources can be determined by evaluating historical generation patterns and/or an Effective Load Carrying Capability (ELCC) study. NDC decreases over time with increasing penetration of solar, wind, and battery storage resources on the system. Solar output is relatively high at the typical summer peak late in the afternoon but is substantially less at the typical winter peak early in the morning. Wind generation is more variable overall and is generally higher in winter than in summer. Battery storage NDC is generally higher with more hours of storage duration. Results of the study indicated:

- NDC for incremental solar resources at the beginning of the study period was 68% in summer and 15% in winter, and NDC declines as penetration of solar resources on the system increases.
- NDC for incremental wind resources at the beginning of the study period was 19% in summer and 33% in winter, and NDC declines as the penetration of wind resources on the system increases.
- NDC for incremental 4-hour battery storage begins at 100% for up to 500 MW, falls to about 80% by 1,500 MW, and decreases further as penetration increases.
- NDC for incremental 8-to-10-hour storage assumes penetration of 4-hour battery storage, begins at 67% by 6,000 MW of total storage penetration, and decreases as penetration increases.

TVA applied NDC study results in the IRP to reflect the contribution of solar, wind, and storage resources to meeting peak demand over the planning horizon. More information on the NDC study can be found in Appendix D – Key Modeling Assumptions.

Coal End-of-Life Study

The 2019 IRP recommended that TVA evaluate engineering end-of-life dates for the aging fossil fleet, in particular for the coal fleet. The aging coal fleet is experiencing increasing cost and reliability challenges driven by age, condition, and system requirements for more flexible operations. Also, regulations such as the Effluent Limitations Guidelines Rule and the recently finalized GHG Rule would additionally impact costs and operations.

In a study completed in May 2021, TVA evaluated alternative timelines for retiring the remaining coal plants and potential impacts to emissions, resiliency, and other factors. Based on the study, TVA established planning dates for retiring the remaining coal units as they reach end-of-life, expected by 2035. Coal retirement planning dates used in the IRP analysis are reflected in the forecast for baseline firm supply from existing resources (see Table 3-1). See Appendix D – Key Modeling Assumptions for further information on the Coal End-of-Life Study.

Energy Program Potential Study

In 2022, DNV (a global leader in energy program consulting) conducted a study for the TVA region to evaluate the achievable potential for energy efficiency programs that incentivize investment in making homes and businesses more energy efficient. The study indicated a 10-year potential for energy efficiency gains in the region ranging from 2-7% of base sales and 2-9% and 4-16% of summer and winter peak demand, respectively. The residential sector accounts for most of the potential, particularly homes utilizing electric space heating. Potential in the less weather-sensitive commercial and industrial sectors is driven by linear fluorescent and high-intensity discharge lighting applications. The study was used to inform energy program resource options in the IRP. Additional details on the Energy Program Potential Study can be found in Appendix D – Key Modeling Assumptions.

3.8 Developing and Evaluating Portfolios

TVA utilized the EnCompass model to take the inputs related to the scenarios, strategies, resources options, and key modeling assumptions and develop portfolios for evaluation in the IRP. Combining the five business strategies in the six planning scenarios resulted in 30 portfolios, as shown in the matrix below.

STRATEGIES	SCENARIOS					
	1 Reference without GHG Rule	2 Higher Growth Economy	3 Stagnant Economy	4 Net-zero Regulation	5 Net-zero Regulation Plus Growth	6 Reference with GHG Rule
A Baseline Utility Planning	1A	2A	3A	4A	5A	6A
B Carbon-free Innovation Focus	1B	2B	3B	4B	5B	6B
C Carbon-free Commercial Ready Focus	1C	2C	3C	4C	5C	6C
D Distributed and Demand-side Focus	1D	2D	3D	4D	5D	6D
E Resiliency Focus	1E	2E	3E	4E	5E	6E

Figure 3-16: Portfolio Matrix

The process for developing the portfolios included capacity expansion and production cost modeling, stochastic modeling, and metrics development. Together, these elements provided the information necessary to evaluate and compare portfolio performance.

3.8.1 Capacity Expansion Modeling

Capacity expansion models are effective tools to assess a broad range of resource options and determine a resource mix that minimizes system costs under planning parameters that simulate real-world operations and availability of resources. The model:

- Considers assumptions for energy demand, fuel prices, and potential regulations in a scenario
- Applies a planning reserve margin to determine firm capacity requirements
- Considers resource options, along with promotion parameters applicable in a strategy

- Applies other key modeling assumptions, such as NDC
- Applies operational and other practical constraints
- Ensures compliance with existing state and federal laws and regulations
- Derives a lowest-cost resource portfolio for a unique scenario and strategy combination

The model seeks to identify a portfolio of resources that minimizes total system costs, including capital costs for new resources as well as ongoing operations, maintenance, and fuel costs. Given the complexity of all the possible resource combinations, the capacity planning model uses a simplified representation of hourly demand to develop the lowest cost resource portfolio for further evaluation. Total system cost is expressed as the present value of revenue requirements (PVRR). PVRR represents the present-day value of all future costs over the planning horizon, discounted at 7% to reflect the time value of money and other factors such as investment risk.

3.8.2 Production Cost Modeling

Next, each capacity plan was evaluated using an hourly production cost model, also using the EnCompass model. The production cost model uses detailed chronological, hourly granularity to simulate the commitment and dispatch of the system to meet hourly weather-normal loads on a least-cost operations basis. At this lower level of granularity, resource operating characteristics and constraints that apply can now be modeled. For each unique scenario and strategy combination, the production cost model provides the forecasted energy contribution for each resource in the portfolio. Also, the model calculates detailed production costs, including fuel and other variable operating costs, which are then combined with the construction and capital costs from the capacity model to derive total costs for a portfolio.

3.8.3 Stochastic Modeling and Risk Assessment

While scenarios explore step changes in possible futures, stochastic analysis evaluates the risk of uncertainty around multiple key assumptions. Fundamental forecasts for key variables, while useful in planning, will inevitably change over time. Variability is due to many factors such as weather, economic cycles, market conditions, supply/demand disruptions, and technology improvements. Stochastic analysis bounds the uncertainty in key assumptions and identifies the risk exposure that is inherent in long-term power supply planning.

A primary use of stochastic analysis in the IRP is to quantify financial risk. The first step is to identify the key drivers of portfolio costs associated with electricity demand, fuel prices, generating unit availability, unit operating and capital costs, and interest rates. Then, a distribution around the fundamental forecasts for each of the drivers is developed using scalars based on historical variability. As green hydrogen is an emerging fuel market with limited historical data that can be used to estimate future volatility, natural gas volatility was used as a proxy.

The stochastic model uses a Monte Carlo simulation (a form of repeated random sampling) to test the variability of key assumptions and understand the likely range of cost results, allowing for a comparison of financial risk across portfolios. Stochastic modeling can also be useful in evaluating non-financial risks. Stochastic modeling was used to calculate the risk-informed metrics and some of the operational metrics, which are described further in the following section. Additional information on stochastic analysis can be found in Appendix A – Integrated Resource Planning Fundamentals.

3.8.4 Metrics Development

TVA's least-cost planning program starts with low cost, complemented by evaluations of operational, environmental, and risk factors. Reflecting these planning principles and with input from the IRP Working

Group, TVA developed a set of metrics to assess the performance of the different strategies across the scenarios. Metrics cover the 2025-2050 study period, except for two metrics that focus on 2050, as noted.

Table 3-4: Metrics and Definitions

Metric Category	Metric	Definition
Low Cost	Present Value of Revenue Requirements (PVRR) ($B)	Total plan cost (capital and operating) expressed as expected present value of revenue requirements
	System Average Cost ($/MWh)	Average system cost expressed as levelized average annual revenue requirements divided by average annual sales
	Total Resource Cost ($B)	Total plan cost (capital and operating) expressed as PVRR plus participant costs net of bill savings and tax credits
Risk Informed	Risk / Benefit Ratio	PVRR above expected value divided by PVRR below expected value based on stochastic analysis
	Risk Exposure ($B)	PVRR above expected value based on stochastic analysis
Environmentally Responsible	CO_2 Direct Emissions (Million Tons)	Average annual tons of CO_2 emitted
	CO_2 Intensity (lbs/MWh)	Average annual CO_2 emissions divided by average annual energy generated and purchased
	Water Consumption Intensity (Million Gallons/MWh)	Average annual gallons of water consumed divided by average annual energy generated and purchased
	Waste Intensity (Million Tons/MWh)	Average annual quantity of coal ash and gypsum produced divided by average annual energy generated and purchased
	Land Use Intensity (Acres/MWh)	Acreage needed for expansion units divided by energy generated and purchased in 2050
Diverse, Reliable, and Flexible	Operating Cost Stability (%)	Stochastic volatility of operating cost ($/MWh) expressed as a percentage
	Flexible Resource Coverage Ratio	Flexible capacity available to meet maximum three-hour ramp divided by flexible capacity requirement in 2050
	Energy Curtailment Ratio (%)	Expected average annual curtailed energy divided by average annual energy generated and purchased

After capacity and energy plans were developed for the 30 portfolios, TVA leveraged the EnCompass model to produce metrics for each portfolio.

3.8.5 Portfolio Evaluation

Each IRP case represents a combination of expectations about the future environment and potential strategies TVA could employ that result in unique resource portfolios. Evaluating the portfolios starts with understanding the relative differences in incremental resources added to the system and how that impacts total capacity and energy plans. Then, metrics can be utilized to assess least-cost planning tradeoffs across the portfolios and strategies. For example, a particular portfolio may be lower in cost and fare better in operational metrics than another portfolio but have higher emissions. Looking at results for a particular strategy across all scenarios can indicate relative performance for that strategy with respect to a particular metric. Collectively, portfolio evaluations provide insights to overall strategy performance.

3.8.6 Life Cycle Analysis

A new development for the 2025 IRP was the inclusion of a greenhouse gas (GHG) life cycle analysis (LCA). The LCA identifies the full “cradle to grave” GHG emission forecasts associated with raw materials extraction and construction (upstream emissions), ongoing annual operations (annual non-combustion emissions), ongoing combustion of fossil fuels (annual combustion emissions), and plant decommissioning (downstream emissions), illustrated in the figure below. TVA engaged industry experts at the National Renewable Energy Laboratory (NREL) to develop a best-in-class approach for life cycle analysis. TVA's approach builds upon NREL's past work and forecasts estimated emissions of carbon dioxide, nitrous oxide, and methane for each life cycle phase across the TVA power system for all years within the study period. Additionally, for Scenarios 4 and 5 that incorporate the use of hydrogen-fueled CC facilities, TVA calculated annual upstream hydrogen leakage since it is an indirect greenhouse gas. To contextualize the results for interested stakeholders, TVA applied two estimates for the social cost of greenhouse gases (SC-GHG). For additional information, including summary results, see Section 5.5.2 of the draft EIS.

Figure 3-17: Generating Resource Life Cycle Emission Phases (source NREL)

3.9 Performing Sensitivity Analysis

A sensitivity analysis varies a key assumption to isolate the impact of a change in that assumption. When analyzing draft IRP results, TVA and the Working Group began to identify questions warranting further evaluation before finalizing the IRP study. Questions are typically related to key assumptions that have the potential to influence results. To explore impacts of changes in key assumptions and provide additional information for consideration in developing IRP recommendations, TVA and the IRP Working Group are beginning to develop a preliminary list of sensitivities to conduct. Questions arising from ongoing IRP Working Group and RERC discussions, along with public comments received during the draft IRP and EIS comment period, will help refine the final list of sensitivity analyses to be performed.

3.10 Developing Recommendations

All IRP findings, including evaluations of the portfolios in the draft report and insights gained from sensitivity analyses performed during the comment period, will be considered in developing the IRP recommendations. Recommendations will include power supply mix ranges by resource type, recommended strategic portfolio direction through 2035, and how key signposts will influence portfolio direction from 2035 to 2050. The more site-specific effects of actions that are later proposed to implement the IRP will be addressed in tiered environmental reviews.

3.11 Conclusion

With input from stakeholders, the 2025 IRP tests a broad range of external scenarios and business strategies, along with a robust set of resource options, to generate potential resource portfolios to be analyzed. The following chapter presents the portfolio results and assessments for review and consideration.

4 Portfolio Results and Assessments

This chapter describes the findings of the 2025 IRP. Applying five business strategies in six external scenarios generated 30 distinct resource portfolios. The results for the 30 resource portfolios are presented, along with associated scorecard measures that evaluate relative portfolio performance and tradeoffs. The six external scenarios and five business strategies evaluated in the IRP were:

SCENARIOS		STRATEGIES	
1	**Reference (without Greenhouse Gas Rule)** Represents TVA's current forecast that reflects moderate population, employment, and industrial growth, weather-normal trends, growing electric vehicle use, and increasing efficiencies	A	**Baseline Utility Planning** Represents TVA's current outlook based on least-cost planning, incorporating existing programs and a planning reserve margin target. This reserve margin target applies in all strategies
2	**Higher Growth Economy** Reflects a technology-driven increase in U.S. productivity growth that stimulates the national and regional economies, resulting in substantially higher demand for electricity	B	**Carbon-free Innovation Focus** Emphasizes and promotes emerging, firm and dispatchable carbon-free technologies through innovation, continued research and development, and strategic partnerships
3	**Stagnant Economy** Reflects rising debt and inflation that stifle consumer demand and business investment, resulting in weaker than expected economic growth and essentially flat electricity demand	C	**Carbon-free Commercial Ready Focus** Emphasizes proven carbon-free technologies like wind, solar, and storage, at both utility-scale and through customer partnerships, along with strategic transmission investment
4	**Net-zero Regulation** Reflects the impact of the May 2023 draft Greenhouse Gas Rule that targets significant reductions in electric utility CO_2 emissions beginning in 2030 and potential future utility regulations striving for net-zero by 2050	D	**Distributed and Demand-side Focus** Emphasizes existing and potentially expanded customer partnerships and programmatic solutions to reduce reliance on central station generation and promote virtual power plants
5	**Net-zero Regulation Plus Growth** Reflects the impact of the May 2023 draft Greenhouse Gas Rule and potential future utility regulations, along with substantial advancements in clean energy technologies, that spur economic growth and extensive electrification	E	**Resiliency Focus** Emphasizes smaller units and the promotion of storage, along with strategic transmission investment, to drive wider geographic resource distribution and additional resiliency across the system
6	**Reference (with Greenhouse Gas Rule)** Reflects TVA's current forecast and incorporates the impact of the Greenhouse Gas Rule finalized in May 2024 that targets significant reductions in electric utility CO_2 emissions beginning in 2030		

Figure 4-1: IRP Scenarios and Strategies

Throughout the discussion of results, scenarios are referred to by number and strategies by letter. Portfolios represent the combination of a scenario and a strategy, referred to by the relevant number and letter reference, as summarized in the table below. For example, the Reference without GHG Rule scenario and the Baseline Utility Planning strategy combination is referred to as 1A.

STRATEGIES		SCENARIOS					
		1 Reference without GHG Rule	2 Higher Growth Economy	3 Stagnant Economy	4 Net-zero Regulation	5 Net-zero Regulation Plus Growth	6 Reference with GHG Rule
A	Baseline Utility Planning	1A	2A	3A	4A	5A	6A
B	Carbon-free Innovation Focus	1B	2B	3B	4B	5B	6B
C	Carbon-free Commercial Ready Focus	1C	2C	3C	4C	5C	6C
D	Distributed and Demand-side Focus	1D	2D	3D	4D	5D	6D
E	Resiliency Focus	1E	2E	3E	4E	5E	6E

Figure 4-2: Portfolio Matrix

4.1 Capacity Needs

The six scenarios forecasted varying levels of electricity demand, which drove varying levels of capacity requirements and need for incremental resources in each scenario. The planning model also considers the ability of different resource types to contribute to meeting demand at peak times.

4.1.1 Firm Capacity Requirements and Capacity Gaps

As described in Chapter 3, TVA identified the firm capacity requirements for each scenario for both summer and winter, based on projected electricity demand and required reserves in each season. Firm requirements were highest in Scenario 5 and lowest in Scenario 3, and the remaining scenarios fell within this range.

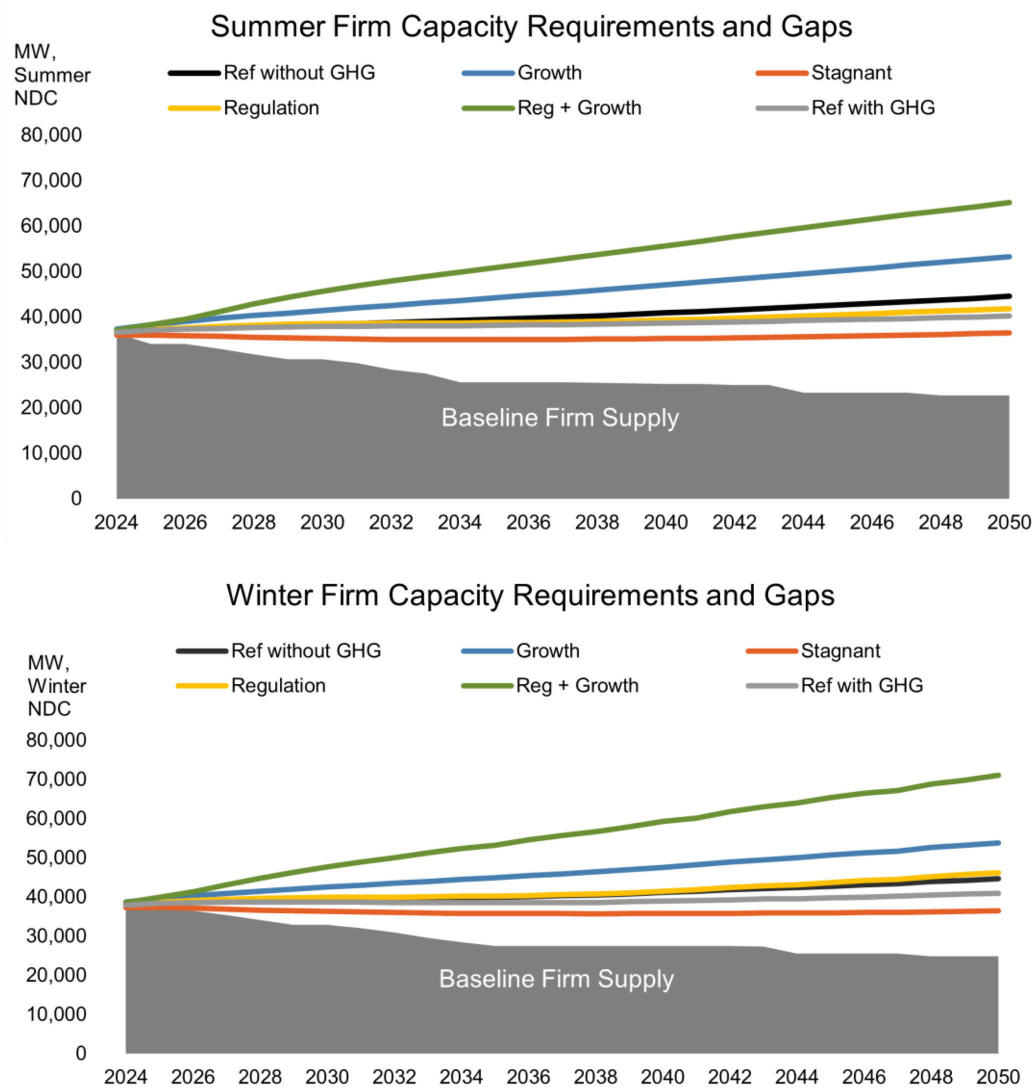


Figure 4-3: Summer and Winter Firm Capacity Requirements

Baseline firm supply – or the forecasted capacity available from existing resources – changes over time as generating units reach the end of their useful life and purchased power contracts expire. The figure below shows forecasted reductions in firm supply of coal, gas, and renewable resources by 2050. Over 10,000 GW and 13,000 GW of existing capacity is expected to retire or expire by 2035 and 2050, respectively.

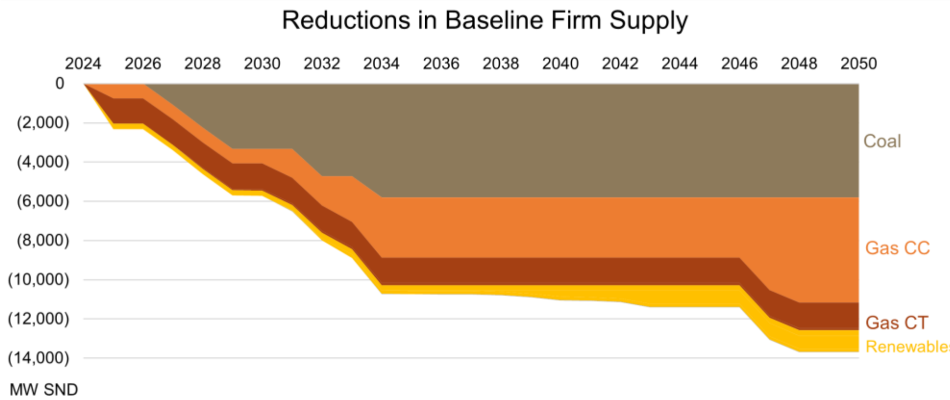


Figure 4-4: Significant Baseline Firm Supply Reductions by Resource Type

The difference between firm capacity requirements and baseline firm supply from existing resources represents the capacity gap, or the need for incremental resources, in each scenario. The capacity gap was highest in Scenario 5 and lowest in Scenario 3, and the remaining scenarios fell within this range. The capacity gap impacts the magnitude and timing of incremental resource additions.

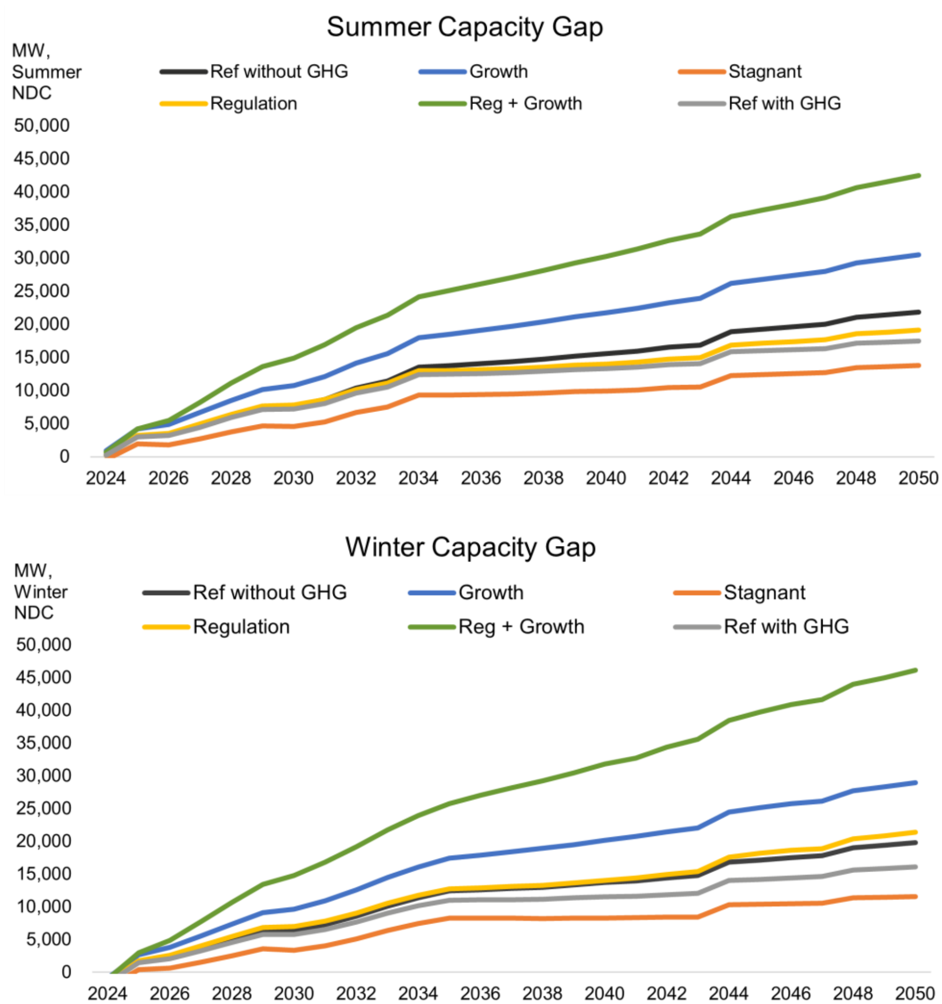


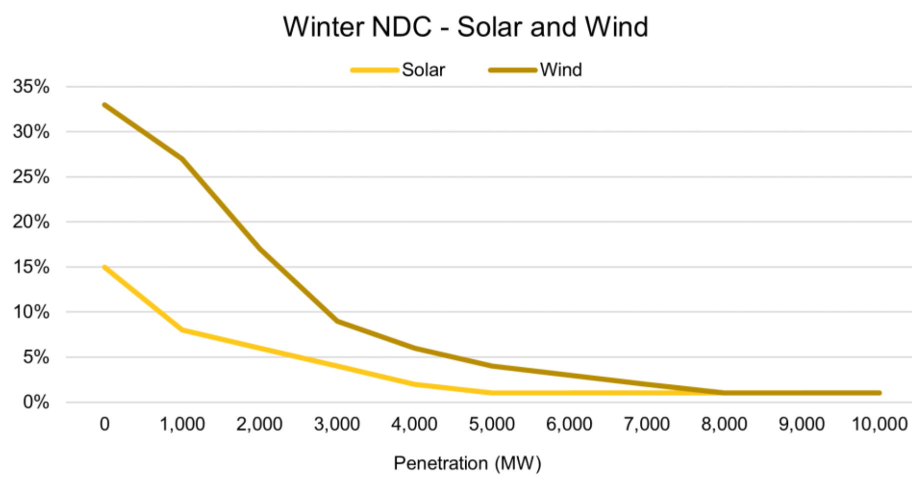
Figure 4-5: Summer and Winter Capacity Gaps

In addition to peak demand needs, the planning model also considers the pattern of energy required across the day, year, and planning horizon to determine the optimal mix of resources that meets system requirements at the lowest cost for each scenario and strategy combination.

4.1.2 Net Dependable Capacity of Renewables and Storage

When optimizing each portfolio, the planning model considers the cost and operating characteristics of all resource options and how each resource can help meet peak and energy demand. The figures included in the IRP show renewables and storage in nameplate capacity, which is typical for these resources. However, the model understands the ability of these resources to contribute to meeting summer and winter peak demand, expressed as a percentage of nameplate capacity. This percentage is determined by a study that evaluates the amount of solar, wind, and storage generation likely to be available at seasonal peak demand times compared to a fully dispatchable gas resource. This percentage is called net dependable capacity (NDC), and it differs by season and decreases as penetration of solar, wind, and storage resources increases. With higher capacity needs in winter, contribution to meeting winter peak demand is most relevant in the planning model.

The figures below show NDC for incremental solar, wind, and storage resources in winter. Given the negligible contribution to meeting winter peak demand at high penetrations, solar is being selected to meet energy needs.



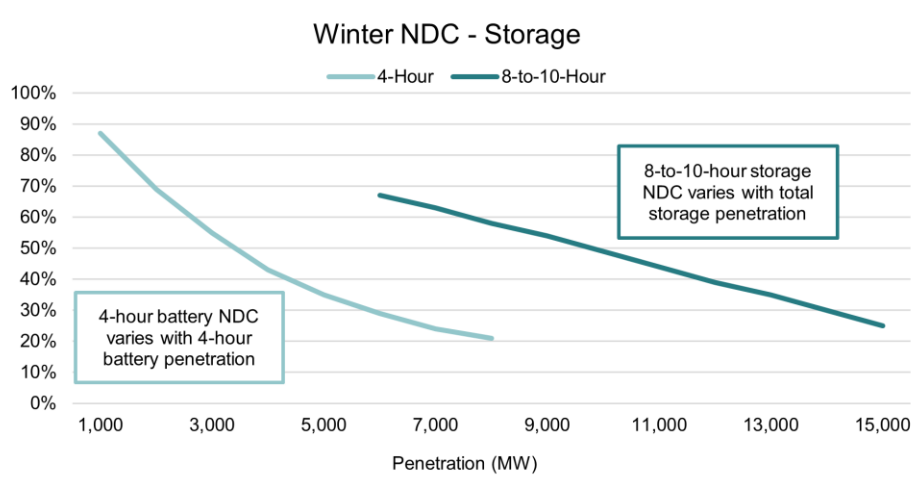


Figure 4-6: Winter NDC for Solar, Wind, and Storage

More information on the NDC study and resource characteristics can be found in Appendices D and E.

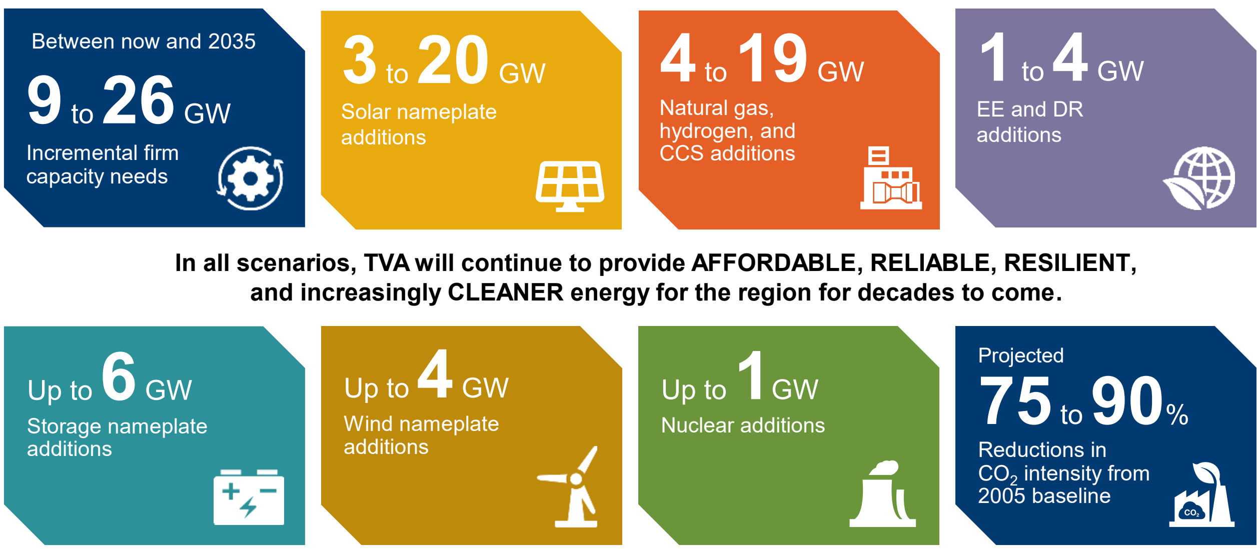
4.2 Expansion Plans

Considering the capacity needs and other parameters in each scenario, along with applying the resource promotions identified for each strategy, the planning model solved for the lowest cost portfolio for each unique scenario and strategy combination. This section summarizes key themes from the expansion plans and provides results for all 30 portfolios.

4.2.1 Key Themes

Uncertainty in electricity demand, environmental regulations, and available technologies increases with time. The IRP analyzes potential ways the resource portfolio might evolve between now and 2050 to respond to changes in these key drivers, and insights gained from evaluating the entire planning horizon will inform strategic portfolio direction between now and 2035. Key themes are expressed in gigawatts (GW), with one GW providing enough energy to power about 585,000 average homes.

Looking across all portfolios through 2035, draft IRP results suggest:



Power supply mix ranges, summarized in gigawatts (GW), vary based on energy demand, market conditions, policy and regulations , and technology advancements.

- New capacity is needed in all scenarios to replace retiring and expiring capacity, support economic growth, and enable further electrification of the economy.
- Firm, dispatchable technologies are needed to ensure system reliability throughout the year.
- Solar expansion plays an increasingly substantial role, providing economic, carbon-free energy.
- Gas expansion serves broad system needs, with the potential for emerging carbon capture and hydrogen options to enable deeper decarbonization.
- Energy efficiency deployment reduces energy needs, particularly between now and 2035, and demand response programs grow with the system and the use of smart technologies.
- Storage expansion accelerates, driven by evolving battery technologies and the potential for additional pumped storage.
- Wind additions have the potential to add more diversity and carbon-free energy to the resource mix.
- New nuclear technologies, with continued advancements, can also support load growth and deeper decarbonization.

As other sectors of the economy electrify, almost all resource types – both supply and demand-side – will be required to meet system needs. In all scenarios, TVA will continue to provide affordable, reliable, resilient, and increasingly cleaner energy for the region for years to come.

4.2.2 Incremental Capacity Changes

Incremental capacity changes – or the resources selected to fill the capacity gap – are presented below. The first chart shows incremental changes by 2035, and the second chart shows changes by 2050. These include all new resource additions, as well as any retirements beyond planned end-of-life retirements and contract expirations already reflected in the forecast for baseline firm supply. While both summer and winter capacity needs and capabilities factored into portfolio optimization, summer net dependable capacity results are being shown throughout the document, except for renewables and storage, which are shown in nameplate.

The results for each scenario are grouped together, and incremental capacity additions are grouped by resource type. Scenario 3 has the lowest demand forecast, driving the lowest amount of incremental capacity. Conversely, Scenario 5 has the highest demand forecast and the highest amount of incremental capacity need. Scenarios 4 and 5 assume the May 2023 draft Greenhouse Gas (GHG) Rule and the broad application of emerging technologies such as carbon capture and sequestration (CCS) and hydrogen blending, while Scenario 6 reflects the GHG Rule finalized in May 2024. Within each scenario, strategy results vary due to the impact of resource promotions on portfolio optimization.

The figure below compares the incremental capacity for all portfolios by 2035.

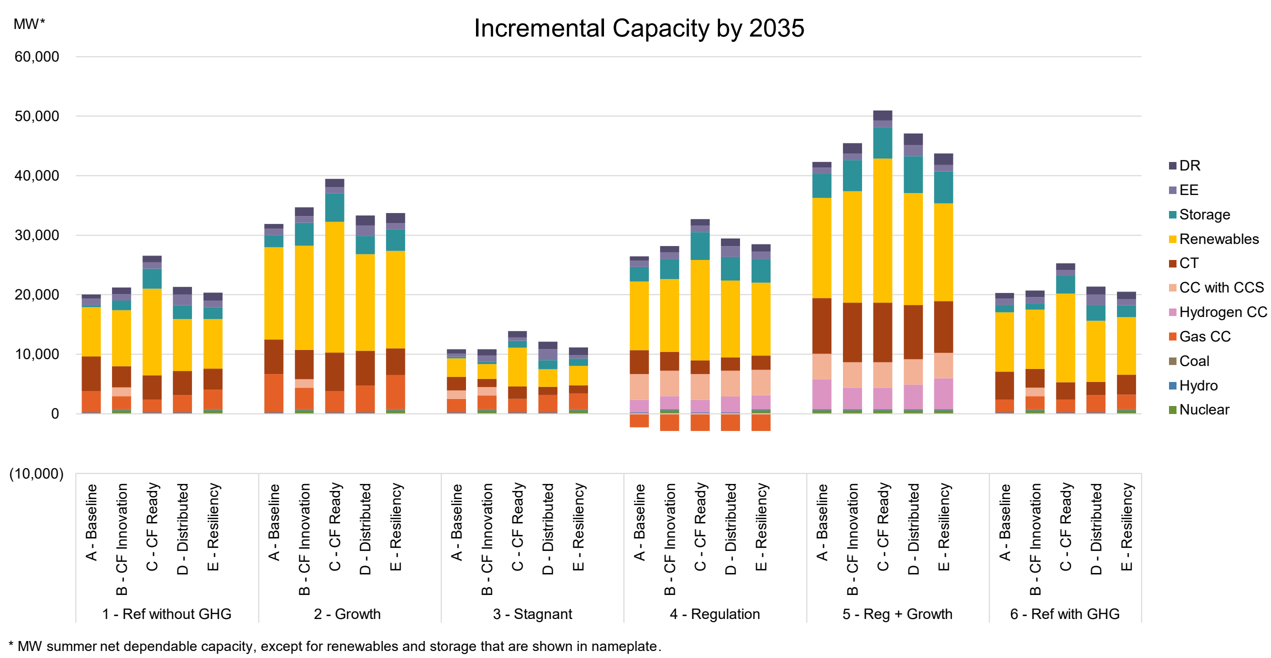


Figure 4-7: Incremental Capacity by 2035

Highlights of the incremental capacity changes by 2035 by resource type include:

Nuclear: About 600 MW of small modular reactors (SMRs) were selected in the early 2030s when promoted in Strategies B and E across all scenarios and in all Scenario 5 cases (highest energy demand, carbon regulations, and advanced technology assumptions).

Hydro: 200 MW of hydro expansion was selected by 2035 in all cases as part of an optimal portfolio mix.

Coal: No new coal plants were selected in any cases, and existing coal plants are expected to retire by 2035.

Gas CC: 2,200 MW to 6,500 MW of Gas CCs were added to the resource mix in Scenarios 1, 2, 3, and 6, driven by forecasted load and strategic focus. In Scenario 4, up to 2,900 MW of existing Gas CCs were retired earlier than estimated end-of-life dates driven by CO_2 emissions costs in this scenario.

Hydrogen CC: In Scenarios 4 and 5 that assume carbon regulation and declining hydrogen prices, 2,200 MW to 5,200 MW of CCs burning a hydrogen blend were selected, depending on load growth and strategic focus.

CC with CCS: In Scenarios 4 and 5 with assumed carbon regulations, about 4,300 MW of CCs with CCS were selected in the portfolios, and about 1,400 MW were selected in several other cases, mostly where promoted.

Gas CT: CT additions varied significantly due primarily to forecasted load in each scenario. About 1,400 MW to 6,500 MW of CTs were selected in Scenarios 1, 2, 3, 4, and 6, and an average of about 9,400 MW were selected in the Scenario 5 cases with the highest load growth.

Renewables: Renewable nameplate additions were primarily solar, and they varied with forecasted load and strategic focus. Additions ranged from about 3,000 MW in 3D to over 24,000 MW in 5C, were highest overall in Strategy C, and averaged about 12,400 MW (11,700 MW solar, 700 MW wind) across all 30 portfolios.

Storage: Storage additions ranged from 200 MW to 6,200 MW, averaged 2,900 MW across all cases, and were a mix of short and long duration. The four alternative strategies applied varying levels of storage promotion.

EE: Energy efficiency additions ranged from 600 MW to 1,800 MW and averaged 1,200 MW across all cases. Incremental EE was highest in Strategy D, which had the highest level of EE promotion.

DR: Demand response additions ranged from 700 MW to 2,000 MW and averaged 1,300 MW across all cases, with the four alternative strategies including varying levels of DR promotion.

The figure below compares incremental capacity for all portfolios by 2050 (note difference in scale from 2035).

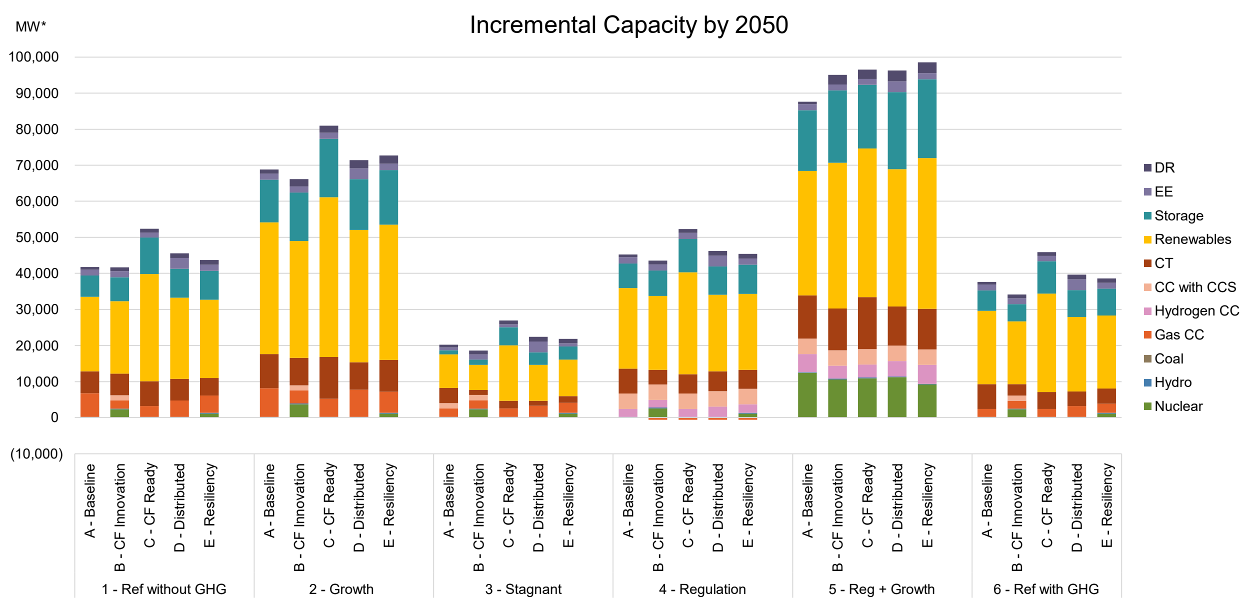


Figure 4-8: Incremental Capacity by 2050

Highlights of the incremental capacity changes by 2050 by resource type include:

Nuclear: A range of 1,100 MW to 2,600 MW of SMRs were selected when promoted in Strategies E and B. In Scenario 5 (highest energy demand, carbon regulations, and advanced technology assumptions), an average of 1,400 MW of SMRs and 9,400 MW of large advanced reactors were selected across all strategies.

Hydro: 200 MW of hydro expansion was selected in all cases as part of an optimal portfolio mix.

Coal: No new coal plants were selected in any cases, and existing coal plants are expected to retire by 2035.

Gas CC: About 2,200 MW to 7,900 MW of Gas CCs were added to the resource mix in Scenarios 1, 2, 3, and 6, depending on forecasted load and strategic focus. In Scenario 4, about 600 MW of existing Gas CCs were retired earlier than estimated end-of-life dates driven by CO_2 emissions costs in this scenario.

Hydrogen CC: In Scenarios 4 and 5 with assumed carbon regulations and hydrogen prices, 2,200 MW to 5,200 MW of hydrogen burning CCs were selected, depending on forecasted load and strategic focus.

CC with CCS: In Scenarios 4 and 5 with assumed carbon regulations, about 4,300 MW of CCs with CCS were selected in the portfolios, and about 1,400 MW were selected in several other cases, mostly where promoted.

Gas CT: CT additions varied significantly, ranging from about 1,400 MW to over 14,000 MW, driven primarily by forecasted load in each scenario.

Renewables: Renewable nameplate additions were primarily solar, and they varied with load growth and strategic emphasis. Additions ranged from about 6,900 MW in 3C to over 41,000 MW in 5C and 5E, were highest in Strategy C, and averaged 25,700 MW (24,000 MW solar, 1,700 MW wind) across all 30 portfolios.

Storage: Storage additions varied significantly with forecasted load and strategic focus, ranging from 1,100 MW to 22,000 MW and averaging 9,900 MW across all cases. Additions were a mix of short and long duration, with the four alternative strategies applying varying levels of storage promotion.

EE: Energy efficiency additions ranged from 800 MW to 3,000 MW and averaged 1,800 MW across all cases. Incremental EE was highest in the Strategy D cases, which had the highest level of EE promotion.

DR: Demand response additions ranged from 700 MW to 3,000 MW and averaged 1,400 MW across all cases, with the four alternative strategies including varying levels of DR promotion.

Further information on incremental capacity changes can be found in Appendix H – Capacity and Energy Plan Summaries.

4.3 Capacity Plans

Capacity plans and highlights are discussed in this section. Capacity plans are comprised of baseline firm supply plus incremental capacity changes, or the total megawatts (MW) available to meet firm requirements. Results are shown in summer net dependable capacity, except for renewables and storage, which are shown in nameplate. Capacity plan details can be found in Appendix H – Capacity and Energy Plan Summaries.

Total capacity plans for 2035 and 2050 are presented below, grouped by scenario and segmented by resource type. Driven by varying levels of forecasted demand, Scenario 3 (Stagnant Economy) portfolios have the lowest total capacity and Scenario 5 (Net-zero Regulation Plus Growth) portfolios have the highest total capacity. Scenarios 4 and 5 assume the May 2023 draft GHG Rule and the broad application of emerging technologies such as carbon capture and sequestration (CCS) and hydrogen blending, while Scenario 6 reflects the GHG Rule finalized in May 2024. The strategy results within each scenario differ based on promotion of resources.

The figure below compares the total capacity plans for all portfolios in 2035.

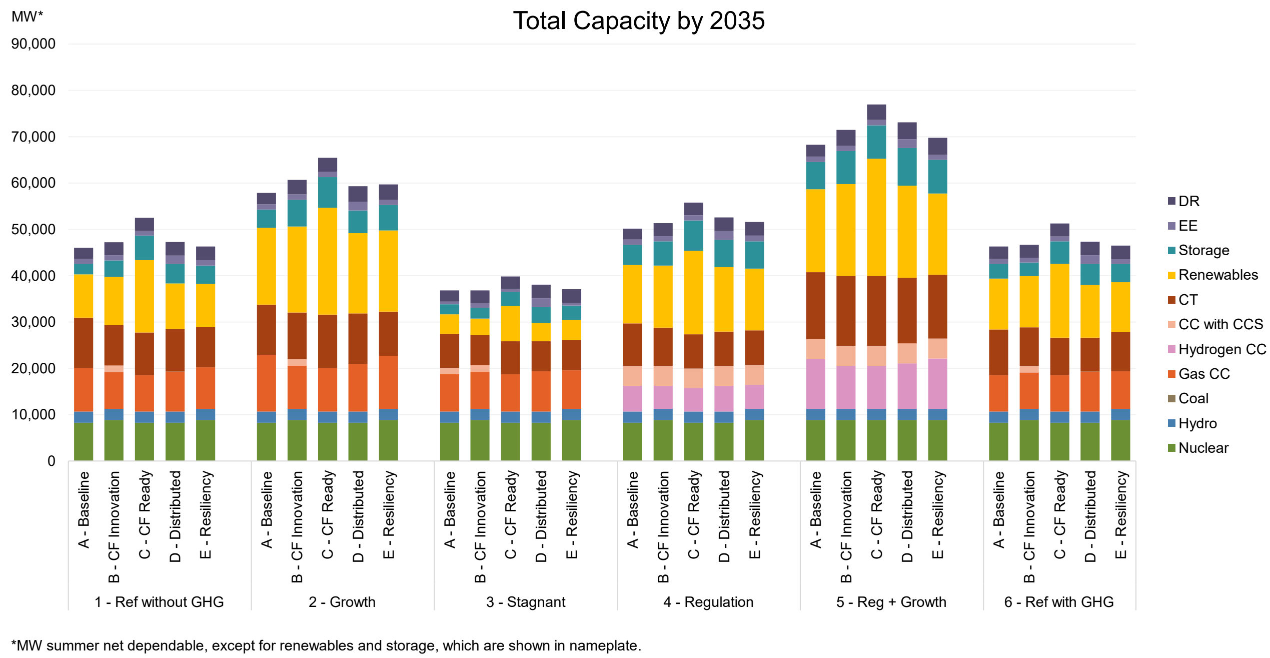


Figure 4-9: Total Capacity Plans in 2035

Highlights of the total capacity plans in 2035 are summarized below, driven by the impact of incremental capacity changes on total capacity across the portfolios.

Nuclear capacity is slightly higher with the addition of SMRs in Strategy B and E and all Scenario 5 cases.

Hydro capacity is slightly higher in all portfolios with the addition of hydro uprates.

Coal capacity is zero in all cases, with no new coal selected and existing coal plants expected to retire by 2035.

Gas CC capacity is highest in Scenario 2 and lowest in Scenario 3, with lesser variations by strategy.

Hydrogen CC and existing CCs are burning a hydrogen blend in Scenarios 4 and 5 based on assumed carbon regulations and declining hydrogen prices, with the highest amounts in Scenario 5.

CC with CCS are generally added to the resource mix in Strategy B and Scenarios 4 and 5 driven by the impact of assumed carbon regulations.

Gas CT capacity is highest in Scenario 5 due to high load growth and lowest in Scenario 3 with flat load.

Renewable nameplate capacity, primarily solar, is highest in Scenarios 2 and 5 and in Strategy C portfolios.

Storage capacity, which is a mix of short and long duration, is generally increasing in the portfolios and is highest in Scenarios 2 and 5.

EE increases in all portfolios and is highest in the Strategy D cases.

DR increases in all portfolios and is higher in the four alternative strategies.

The figure below compares total capacity plans for all portfolios in 2050 (note difference in scale from 2035).

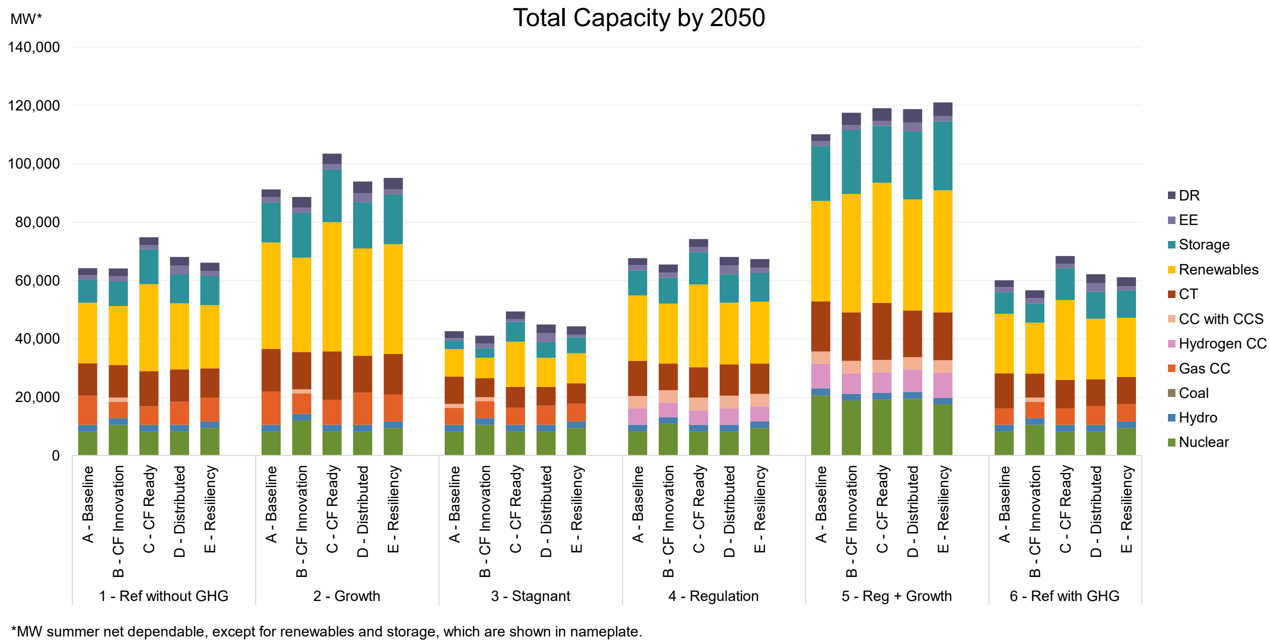


Figure 4-10: Total Capacity Plans in 2050

Highlights of the total capacity plans in 2050 are summarized below, driven by the impact of incremental capacity changes on total capacity across the portfolios. Trends are similar to the 2035 highlights but are generally higher in magnitude driven by the forecasted load growth in most of the scenarios.

Nuclear capacity is higher with the addition of SMRs in Strategy B and E cases and in Scenario 5 cases that also add large, advanced reactor units.

Hydro capacity is slightly higher in all portfolios with the addition of hydro uprates.

Coal capacity is zero in all cases, with no new coal selected and existing coal plants expected to retire by 2035.

Gas CC capacity is highest in Scenario 2 and lowest in Scenario 3, with lesser variations by strategy.

Hydrogen CCs and existing CCs are burning hydrogen in Scenarios 4 and 5 based on assumed carbon regulations and declining hydrogen prices, with the highest amounts in Scenario 5.

CCs with CCS are added to the resource mix in Scenarios 4 and 5 driven by the impact of assumed carbon regulations.

Gas CT capacity is highest in Scenarios 2 and 5 and lowest in Scenario 3 due to higher and lower levels of load growth, respectively.

Renewable nameplate capacity, primarily solar, is highest in Scenarios 2 and 5 and in Strategy C portfolios.

Storage capacity, which is a mix of short and long duration options, is increasing in all portfolios and is highest in Scenarios 2 and 5.

EE increases in all portfolios and is highest in the Strategy D cases.

DR increases in all portfolios and is higher in the four alternative strategies.

4.4 Energy Plans

Total energy plans are presented below, grouped by scenario and segmented by resource type. These plans represent the energy expected from the economic dispatch of the resources available in each capacity plan, shown in terawatt hours (TWh). Further information on energy plans can be found in Appendix H – Capacity and Energy Plan Summaries.

The figure below compares the total energy plans for all portfolios in 2035.

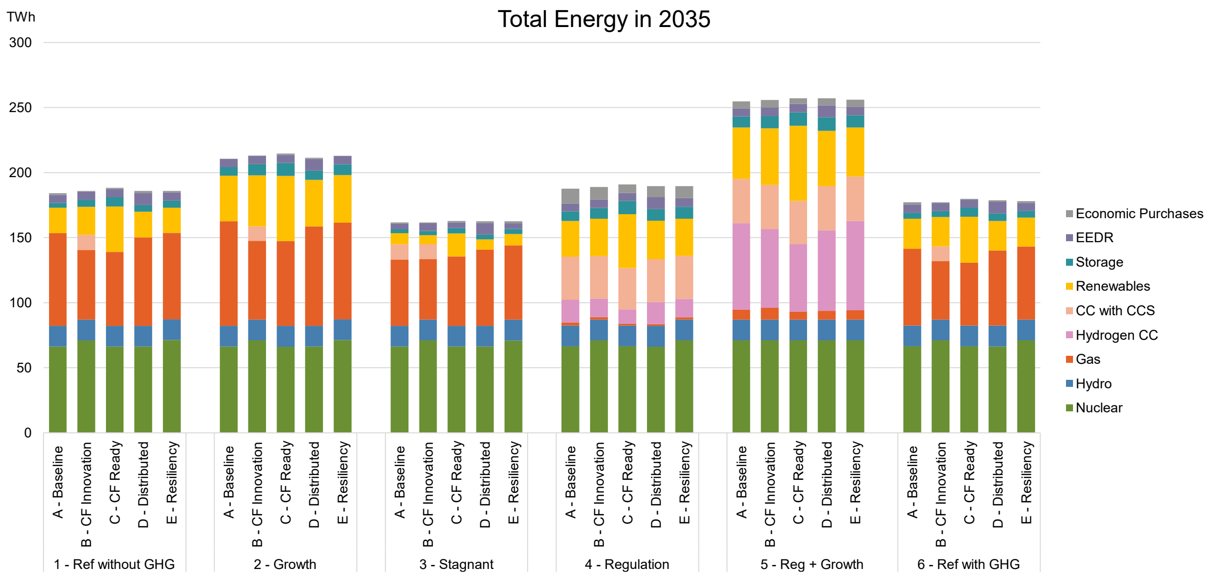


Figure 4-11: Total Energy Plans in 2035

Highlights of the total energy plans in 2035 are summarized below, driven by the impact of incremental capacity changes on total capacity across the portfolios.

Nuclear generation is highest in Strategies B and E and is also higher in all Scenario 5 cases.

Hydro generation is slightly higher in all portfolios with the addition of hydro uprates.

Gas generation is highest in Scenario 2, lowest in Scenario 4, and is typically lowest in Strategy C that has the highest renewable generation.

Hydrogen blended generation appears in the net-zero regulation scenarios (4 and 5), and it is highest in Scenario 5, which assumes the highest growth and lowest hydrogen prices.

CC with CCS generation is relatively similar in both net-zero regulation scenarios.

Renewable generation is primarily solar and is highest in Scenarios 2 and 5 and in Strategy C.

Storage generation is highest in Scenario 5 and in Strategy C portfolios, which also have the most renewables.

EE and DR energy impact is highest in Strategy D and lowest in Scenario 3.

Carbon-free energy increases over time in all portfolios. In Scenario 1, 2, 3, and 6 cases, carbon-free energy averages 67% in 2035, while Scenario 4 and 5 cases that assume increasing carbon regulations average 95%, including energy from CC plants using a hydrogen-blended fuel. Strategy B and C portfolios have the highest percentage of carbon-free energy in 2035 across all scenarios.

The figure below compares the total energy plans for all portfolios in 2050 (note difference in scale from 2035).

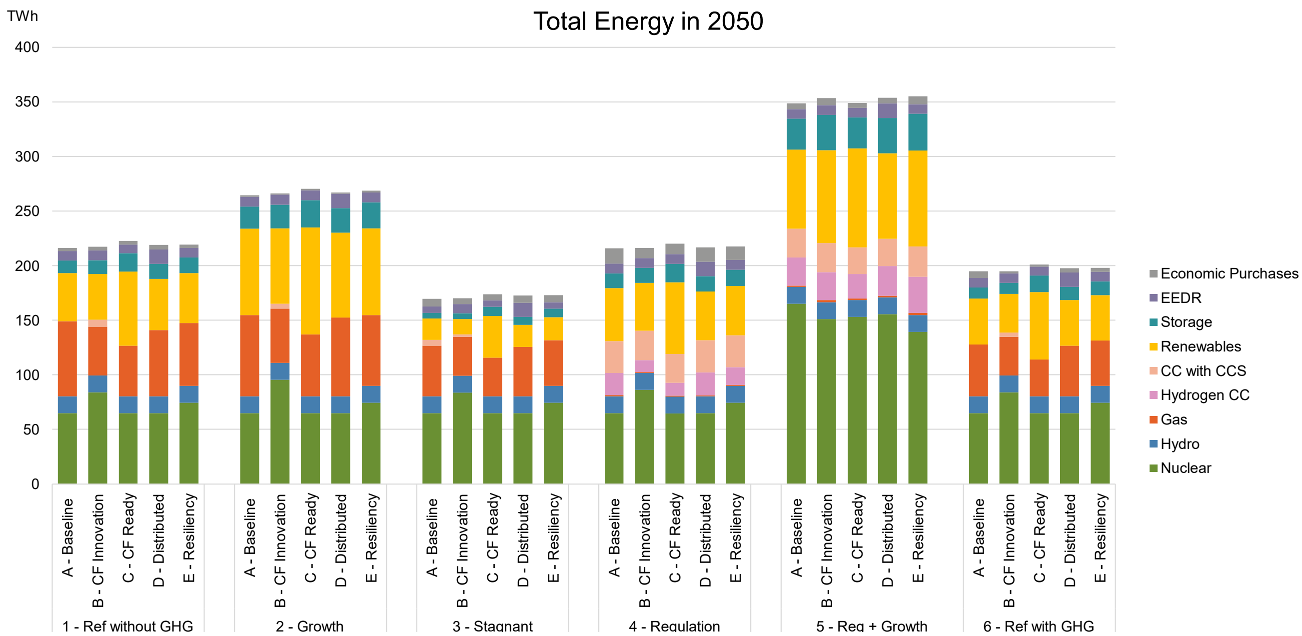


Figure 4-12: Total Energy Plans in 2050

Highlights of the total energy plans in 2050 are summarized below, driven by the impact of incremental capacity changes on total capacity across the portfolios. Trends are similar to the 2035 highlights but are generally higher in magnitude driven by the forecasted load growth in most of the scenarios.

Nuclear generation is highest in Strategies B and E and is also higher in all Scenario 5 cases.

Hydro generation is slightly higher in all portfolios with the addition of hydro uprates.

Gas generation is highest in Scenario 2, lowest in Scenario 4, and is typically lowest in Strategies B and C that have the highest combination of nuclear and renewable generation.

Hydrogen generation appears in the net-zero regulation scenarios and is highest in Scenario 5, which assumes the highest growth and lowest hydrogen prices.

CC with CCS generation is relatively similar in both net-zero regulation scenarios.

Renewable generation is primarily solar and is highest in Scenarios 2 and 5 and in Strategy C.

Storage generation is highest in Scenarios 2 and 5 and in Strategy C portfolios, which also have the most renewables.

EE and DR energy impact is highest in Strategy D and lowest in Scenario 3.

Carbon-free energy increases further by 2050 in all portfolios. In Scenario 1, 2, 3, and 6 cases, carbon-free energy averages 75% in 2050, while the Scenario 4 and 5 cases that assume increasing carbon regulations average 96%. Strategy B and C portfolios have the highest percentage of carbon-free energy in 2050 across all scenarios.

Further information on energy plans can be found in Appendix H – Capacity and Energy Plan Summaries.

4.5 Incremental Capacity by Resource Type

The following sections describe incremental capacity by resource type in more detail, providing additional insights into the specific technologies included in each optimized portfolio.

Incremental Hydro and Renewable Capacity

As described in Chapter 3, hydro uprates are offered as an expansion option in the IRP. Renewable resource options include utility scale solar, distributed solar, and three wind options – Midwest, Southeast high-hub, and High Voltage Direct Current (HVDC). The approach used to model distributed solar adoption and the impact of promotion in certain strategies is discussed in Appendix F – Distributed Generation Resource Methodology.

The charts below show incremental renewable additions by 2035 and 2050 (note differences in scale), grouped by scenario and segmented by renewable technology type.

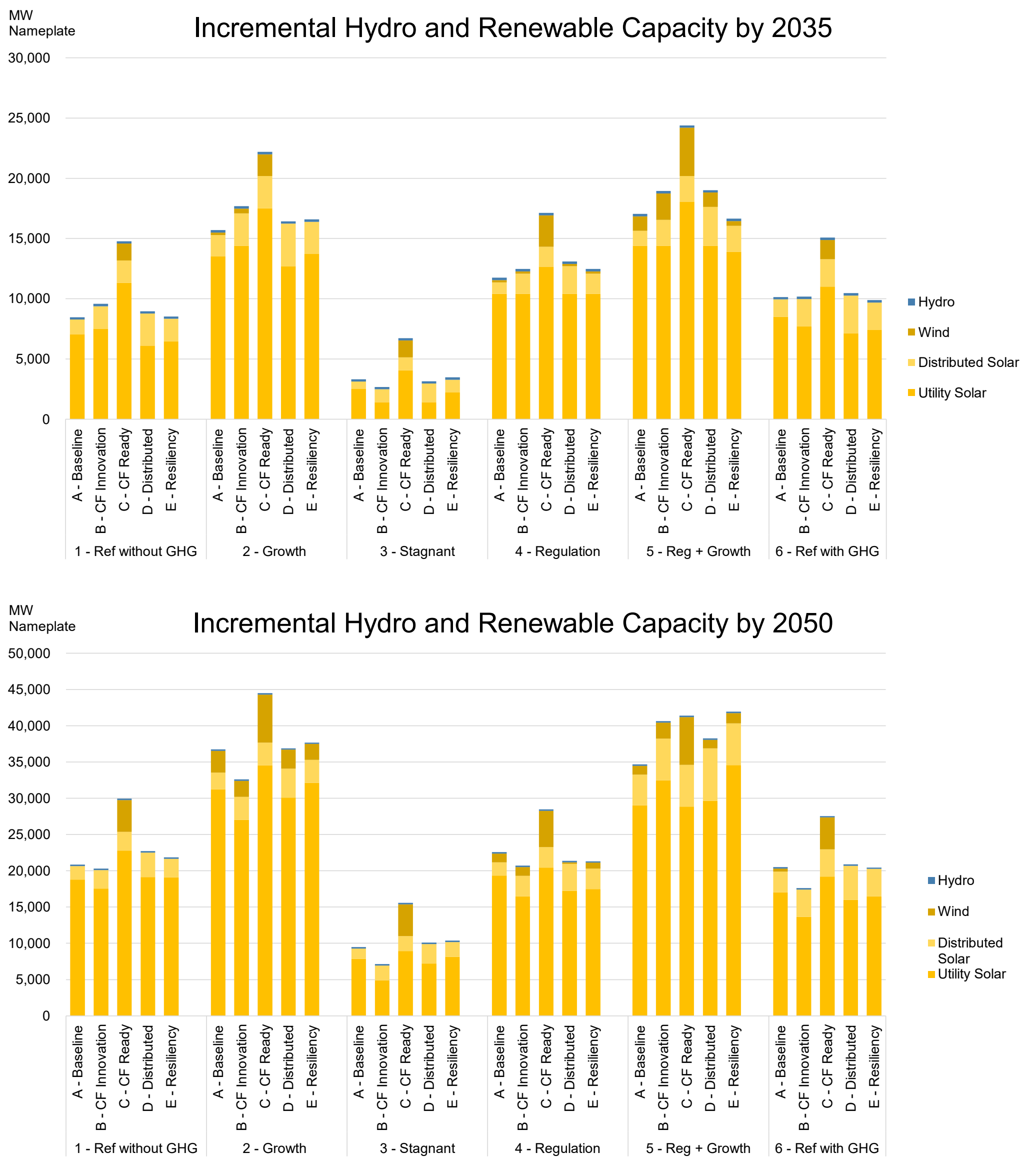


Figure 4-13: Incremental Hydro and Renewable Capacity by 2035 and 2050

Solar expansion is greatest in higher growth scenarios (2 and 5) and is prevalent in all strategies. Strategy C portfolios have the highest combined levels of renewables, including solar, wind, and hydro resources, while Strategy D cases have the highest levels of distributed solar expansion. Hydro expansion options on the system are limited but are selected in all portfolios by 2035.

Incremental Storage Capacity

Storage resource options in the IRP include pumped storage, lithium-ion battery, advanced chemistry battery, and distributed storage. The approach used to model distributed battery adoption and the impact of promotion in certain strategies is discussed in Appendix F – Distributed Generation Resource Methodology.

Incremental storage additions by 2035 and 2050 (note differences in scale), grouped by scenario and segmented by storage technology type, are shown below.

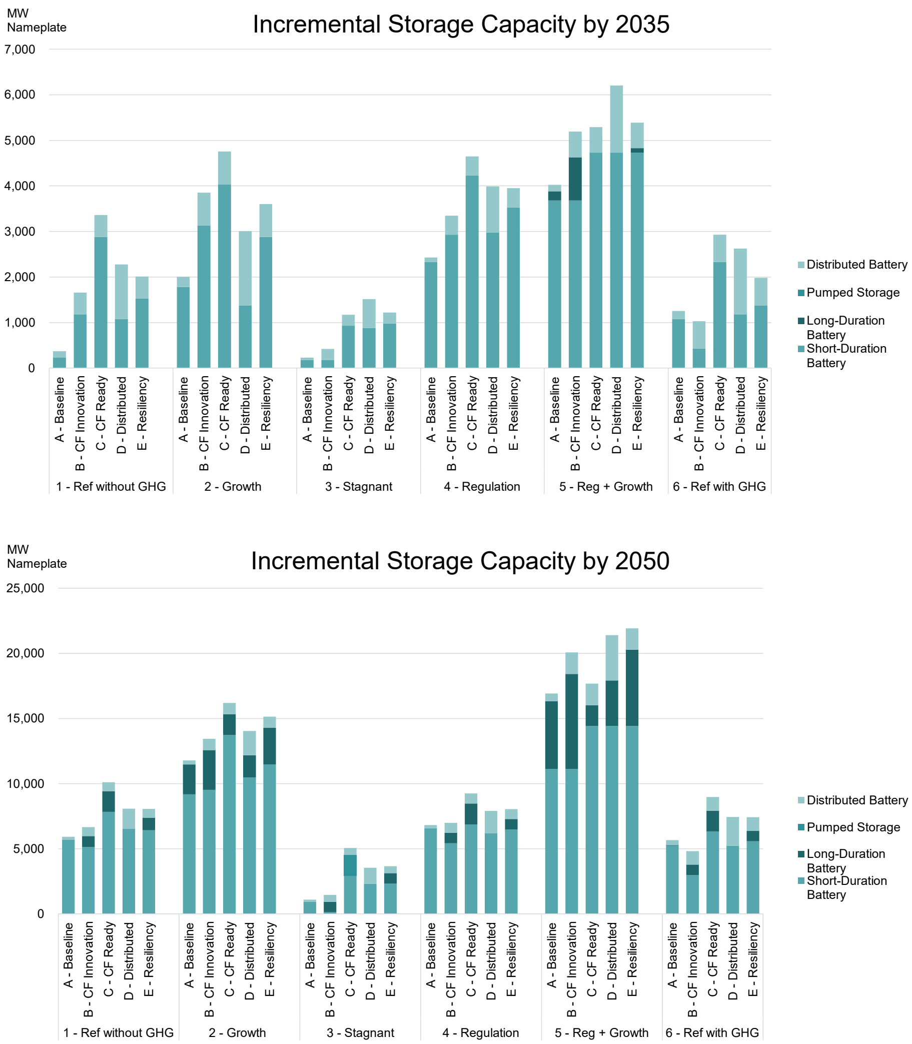


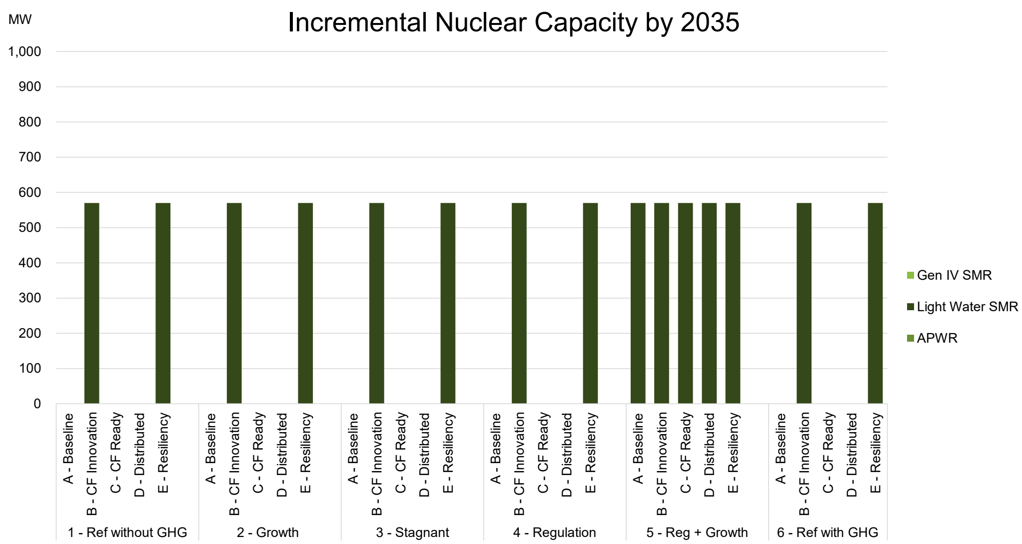
Figure 4-14: Incremental Storage Capacity by 2035 and 2050

Storage plays an increasing role in the resource mix, with continued advancements in battery technologies and the potential for additional pumped storage. Long-duration storage technologies, which include pumped storage and emerging advanced chemistry batteries, enable deeper penetration of renewables in the power supply. Storage expansion is promoted in the four alternative strategies and is highest in Scenarios 2 and 5. Strategy D, which emphasizes distributed resources, has the highest amount of distributed storage additions.

Incremental Nuclear Capacity

Nuclear resource options include advanced pressurized water reactors (APWR) and light water and next generation small modular reactors (SMRs). APWRs are assumed to be available in 2038 due to expected build time for large reactors. SMR technology for electric utility use is still developing. Leveraging work TVA has done to advance the potential to deploy SMRs at the Clinch River site, light water SMRs are assumed to be available in 2033, and Gen IV SMRs are assumed to be available in 2041. These assumptions impact the incremental additions by 2035 and 2050.

The charts below show incremental nuclear additions by 2035 and 2050 (note differences in scale), grouped by scenario and segmented by nuclear technology type.



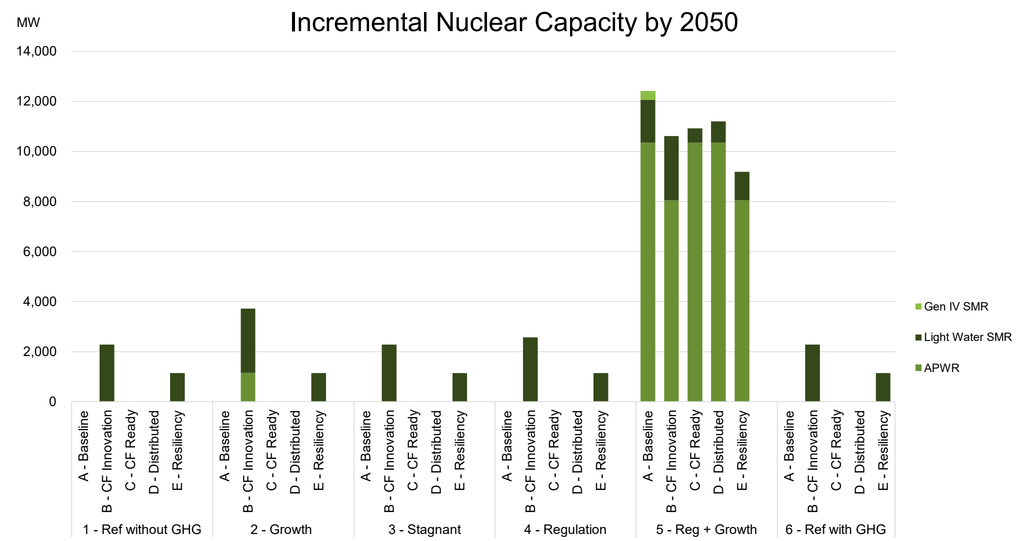


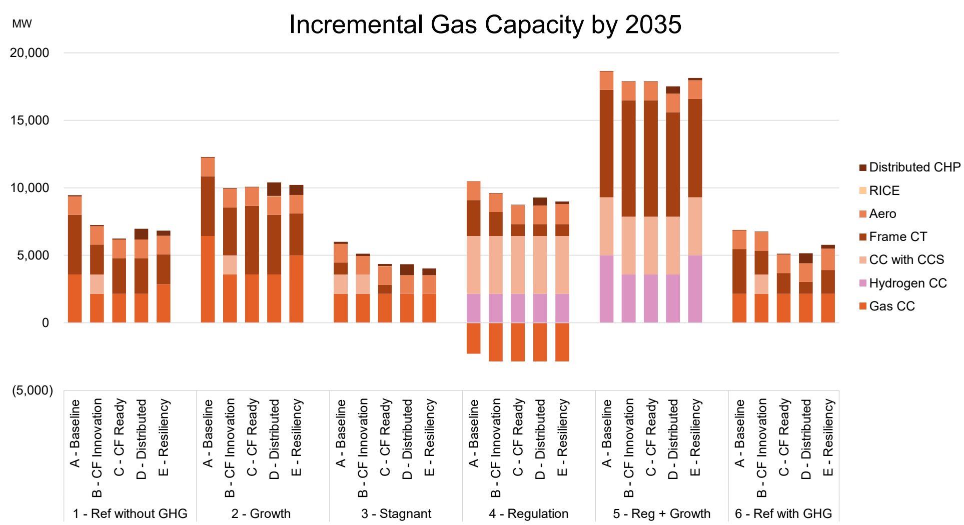
Figure 4-15: Incremental Nuclear Capacity by 2035 and 2050

Strategy B that promotes new clean energy technologies has the highest level of light water SMR expansion overall, followed by Strategy E that has a lesser level of promotion. In Scenario 5 that assumed the highest loads and a faster pace of technology development, large APWR units were selected in all portfolios by 2050, along with light water and Gen IV SMRs.

Incremental Gas Capacity

Resource options burning natural gas and/or hydrogen in the IRP include combined cycle (CC), hydrogen CC, CC with carbon capture and sequestration (CCS), frame combustion turbine (CT), aeroderivative CT (Aero), reciprocating internal combustion engine (RICE), and combined heat and power (CHP). All utility-scale gas units are assumed to be hydrogen capable, blending fuels according to the May 2023 draft GHG Rule as applicable. In Scenarios 4 and 5 that assume increasing carbon regulations, new CCs are assumed to be equipped with CCS, while a conventional CC or a CC with CCS could be selected in other scenarios. CHP adoption modeling and promotion is discussed in Appendix F – Distributed Generation Resource Methodology.

Incremental gas additions by 2035 and 2050 (note differences in scale), grouped by scenario and segmented by gas technology type, are shown below. In Scenario 4, some CC plants are retired earlier than estimated end-of-life dates.



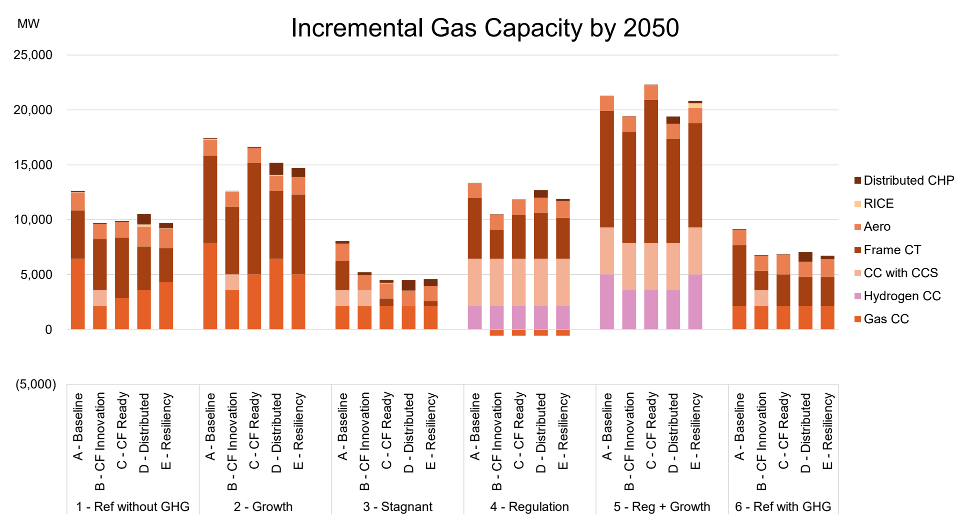


Figure 4-16: Incremental Gas Capacity by 2035 and 2050

Firm, dispatchable gas resources are selected in all cases to support system reliability, with relative magnitudes mainly driven by forecasted load in the scenarios. Scenarios 1, 2, 3, and 6 portfolios have a relatively equal mix of gas CCs and frame CTs, complemented by aero CTs and RICE. In Scenarios 4 and 5 that assume increasing carbon regulation and declining hydrogen prices, hydrogen CCs and CCs with CCS are selected.

Incremental Distributed Generation Capacity

Distributed resource options include distributed solar, storage, and combined heat and power. These resources are included in their respective resource types in the above sections and are collectively shown here. Distributed resources were available to be selected in all cases and were promoted in certain strategies, driving greater adoption of distributed resources than in the baseline behind-the-meter forecast in the Reference without GHG Rule scenario. The approach used to model the adoption of distributed resources is discussed further in Appendix F – Distributed Generation Resource Methodology.

The charts below summarize incremental distributed resources by 2035 and 2050 (note differences in scale), grouped by scenario and segmented by distributed generation type.

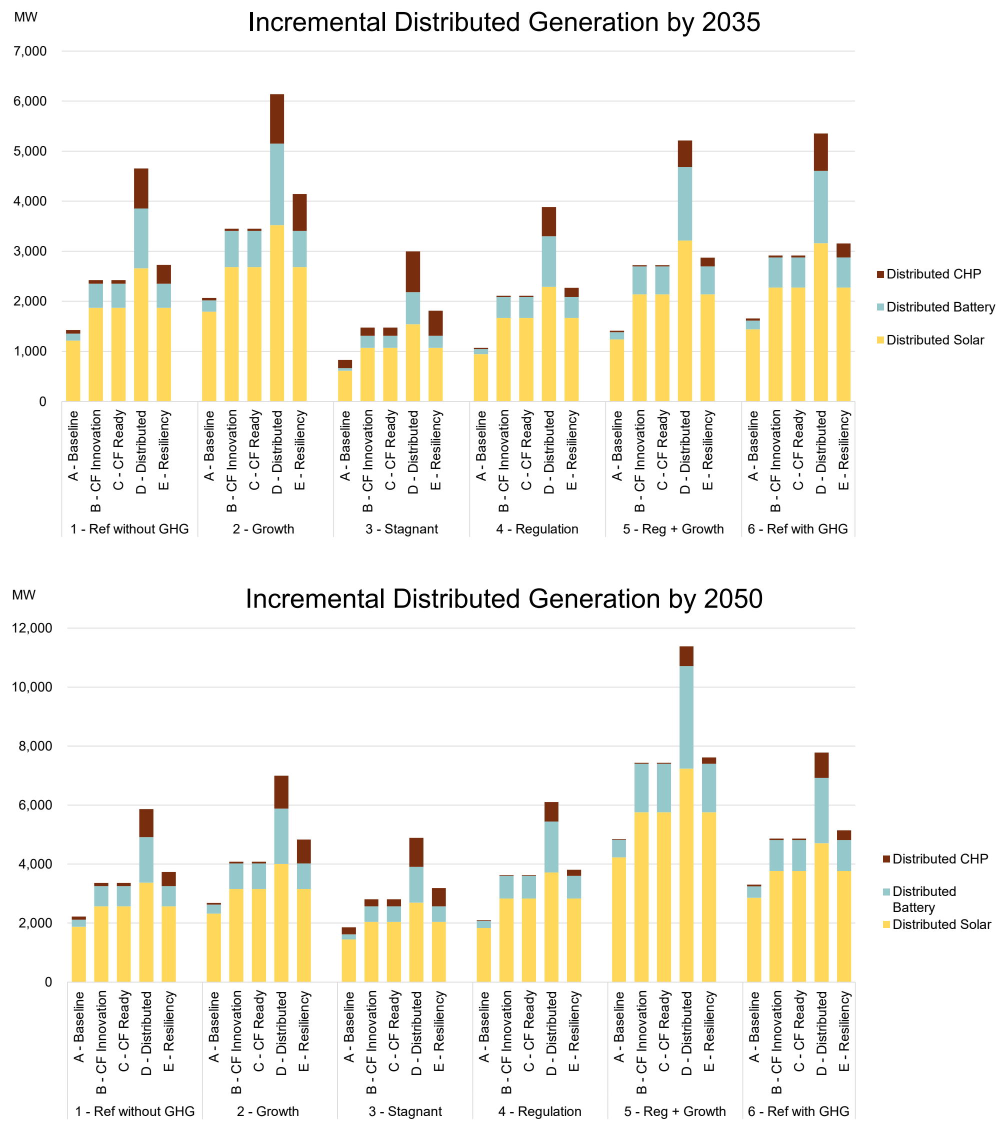


Figure 4-17: Incremental Distributed Generation Capacity by 2035 and 2050

Distributed generation additions are highest overall in Scenario 5 that has the fastest load growth and lower resource costs. Within each scenario, Strategy D portfolios have the most distributed generation due to the highest level of promotion across the strategies.

Incremental Demand-side Resources

Demand-side resource options in the IRP include energy efficiency (EE) and demand response (DR). Based on the Energy Program Potential Study, TVA developed tiers of EE and DR program offerings that were available to be selected in all portfolios. Certain strategies promoted demand-side resources, and in those cases, certain tiers were included in portfolio results. The approach used to promote EE and DR is discussed further in Appendix G – Demand-side Resource Methodology.

Through DR programs, TVA partners with businesses and residents to reduce usage at peak times, while EE programs encourage the adoption of more energy efficiency appliances and equipment that reduces energy use across many hours. EE estimates capture program impacts relative to the adoption of more efficient technologies expected without the influence of EE programs.

Incremental demand-side resource impacts forecasted for 2035 and 2050, grouped by scenario and segmented by DR and EE program type, are shown below.

Figure 4-18: Incremental Demand-side Resource Capacity by 2035 and 2050

Average EE and DR additions were relatively similar in magnitude across the scenarios, with the alternative strategies including various levels of promotion of these demand-side programs. All strategies saw value in EE and DR additions, particularly between now and 2035. Strategy D, which focused on distributed and demand-side resources, has the highest amount of EE and DR across the strategies.

4.6 Scorecard Metric Definitions

Definitions of the scorecard metrics are provided below. Metrics cover the 2025-2050 study period, except for two metrics that focus on 2050, as noted. Metrics are calculated based on the optimization results for the 30 portfolios. See Chapter 3 for a discussion on metrics development and Appendices I-K for further details on cost, risk, environmental, and operational metrics.

Table 4-1: Metrics and Definitions

Metric Category	Metric	Definition
Low Cost	Present Value of Revenue Requirements (PVRR) ($B)	Total plan cost (capital and operating) expressed as expected present value of revenue requirements
	System Average Cost ($/MWh)	Average system cost expressed as levelized average annual revenue requirements divided by average annual sales
	Total Resource Cost ($B)	Total plan cost (capital and operating) expressed as PVRR plus participant costs net of bill savings and tax credits
Risk Informed	Risk / Benefit Ratio	PVRR above expected value divided by PVRR below expected value based on stochastic analysis
	Risk Exposure ($B)	PVRR above expected value based on stochastic analysis
Environmentally Responsible	CO_2 Direct Emissions (Million Tons)	Average annual tons of CO_2 emitted
	CO_2 Intensity (lbs/MWh)	Average annual CO_2 emissions divided by average annual energy generated and purchased
	Water Consumption Intensity (Million Gallons/MWh)	Average annual gallons of water consumed divided by average annual energy generated and purchased
	Waste Intensity (Million Tons/MWh)	Average annual quantity of coal ash and gypsum produced divided by average annual energy generated and purchased
	Land Use Intensity (Acres/MWh)	Acreage needed for expansion units divided by energy generated and purchased in 2050
Diverse, Reliable, and Flexible	Operating Cost Stability (%)	Stochastic volatility of operating cost ($/MWh) expressed as a percentage
	Flexible Resource Coverage Ratio	Flexible capacity available to meet maximum three-hour ramp divided by flexible capacity requirement in 2050
	Energy Curtailment Ratio (%)	Expected average annual curtailed energy divided by average annual energy generated and purchased

4.7 Strategy Assessments

Assessing strategy performance across all scenarios by metric yields some key findings. A discussion of these assessments is grouped into four major categories – low cost, risk informed, environmental stewardship, and diverse, reliable, and flexible system operations. Additionally, comparing metrics across categories provides insights into key tradeoffs across the strategies and least-cost planning principles.

4.7.1 Low Cost

Cost metrics include Present Value of Revenue Requirements (PVRR), system average cost, and total resource cost. PVRR reflects costs incurred by TVA, while total resource cost also includes costs incurred by consumers for incremental distributed generation and energy efficiency investments. System average cost relates PVRR to average total energy for each portfolio and is directionally indicative of customer bill impacts.

The charts below compare PVRR, total resource cost and system average cost results for each strategy within the six scenarios.

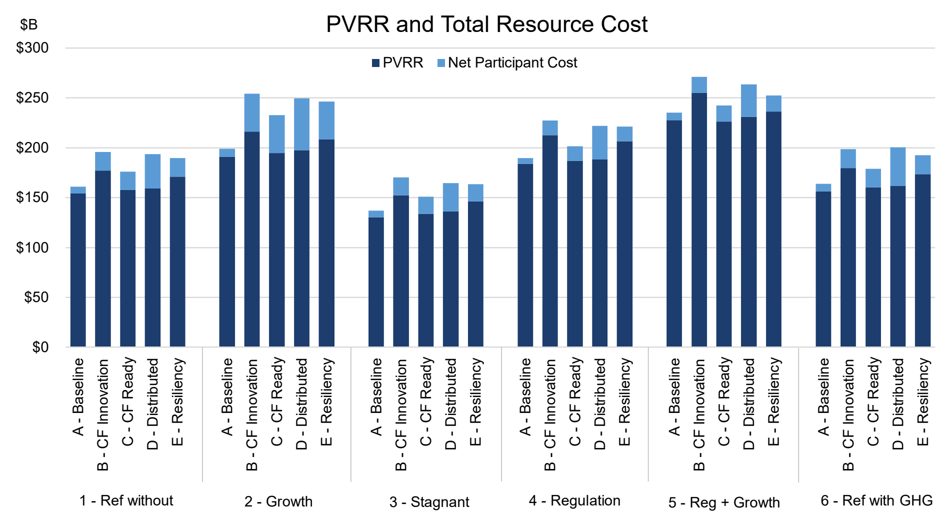


Figure 4-19: PVRR and Total Resource Cost

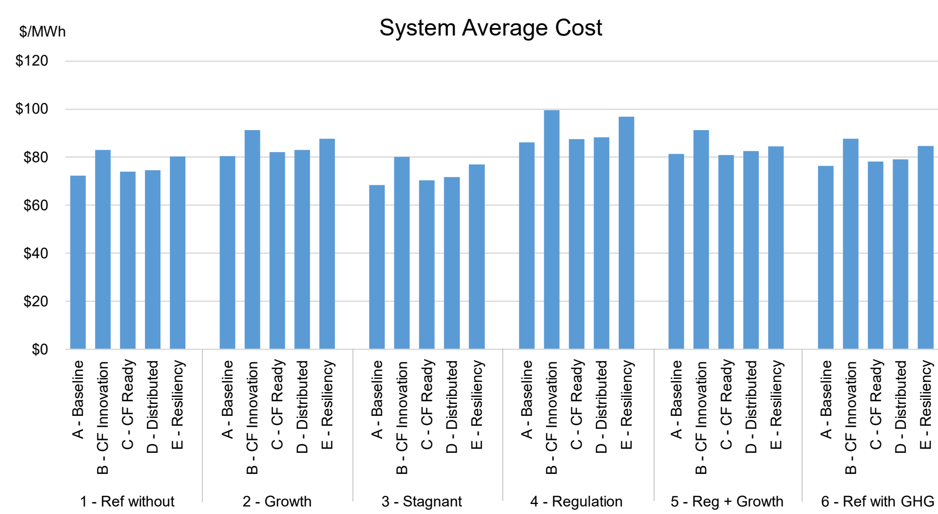


Figure 4-20: System Average Cost

Key takeaways from evaluating cost performance across the portfolios include:

- PVRR and total resource costs are highest in Scenario 5 that has the highest load growth and most advanced technology assumptions, and lowest in Scenario 3 where load remains essentially flat.
- System average cost is lowest in Scenario 3, as fewer new resources are needed with a flat load forecast, and it is highest in Scenario 4 due to costs to meet assumed net-zero CO_2 regulations.
- As Strategy A applies no resource promotions beyond baseline utility planning, it is the lowest cost strategy overall.
- Strategy C that focuses on carbon-free commercial ready technologies is the second lowest cost strategy.
- Strategy B is the most expensive strategy overall, as it requires upfront investments in clean energy technology innovation.
- Strategy D is the second most expensive strategy with respect to total resource cost when the cost of consumer investment in distributed generation and more efficient end-use technologies is included.

4.7.2 Risk Informed

When evaluating portfolios, it is helpful to assess execution and financial risk. Execution risk is driven by technology type and emphasis in each portfolio and by load growth. Financial risk can be measured using the risk/benefit ratio and risk exposure metrics. These metrics provide insights into the full range of potential costs for a portfolio as key uncertainties such as load and fuel prices vary. Risk/benefit ratio measures the potential for higher than estimated costs divided by the potential for lower than estimated costs for a given portfolio, while risk exposure measures the potential for higher than estimated costs.

The charts below compare risk/benefit ratio and risk exposure results for each strategy within the six scenarios.

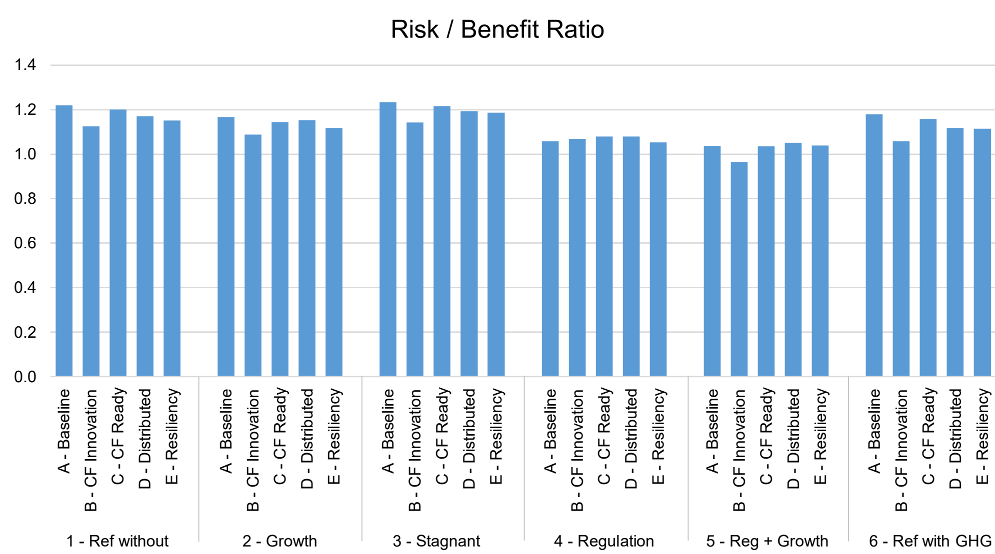


Figure 4-21: Risk/Benefit Ratio

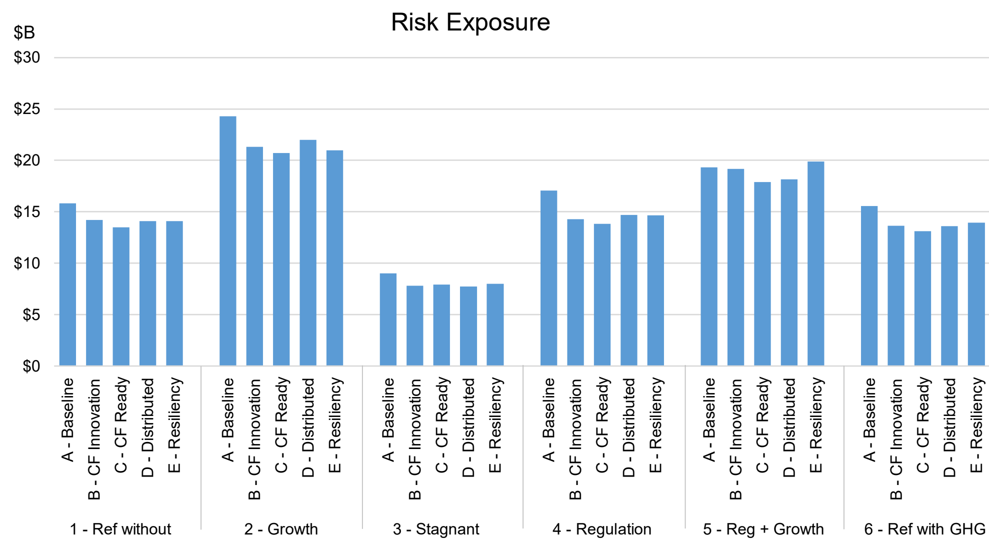


Figure 4-22: Risk Exposure

Key takeaways from evaluating risk performance across the portfolios include:

- Financial risk exposure is highest in Scenarios 2 and 5 that have higher load growth and resource additions, and it is lowest in Scenario 3 that has a flat load forecast.
- Strategy B, which has the highest promotion of new nuclear resources, has the most favorable financial risk/benefit ratio.
- Strategy C, which has the largest solar buildout, has the lowest financial risk exposure.
- While not included in the metrics above, all strategies include timeline, technological, transmission, and/or market depth uncertainty and execution risks, which are amplified by load growth and regulatory impacts.
- Transmission risks are greatest in portfolios with the largest solar buildouts (Strategy C), technological risks are greatest in portfolios with more reliance on new clean energy technologies (Strategy B), and timeline risks are greatest in the highest growth scenarios (Scenarios 2 and 5).

4.7.3 Environmental Responsibility

Five metrics related to environmental responsibility are included in the IRP analysis – direct CO_2 emissions, CO_2 intensity, water consumption intensity, waste intensity, and land use intensity. Intensity expresses environmental impacts in terms of how they relate to average total energy for each portfolio, which allows for a better comparison across all portfolios.

The chart below compares average CO_2 intensity for 2025-2050 for each strategy within the six scenarios.

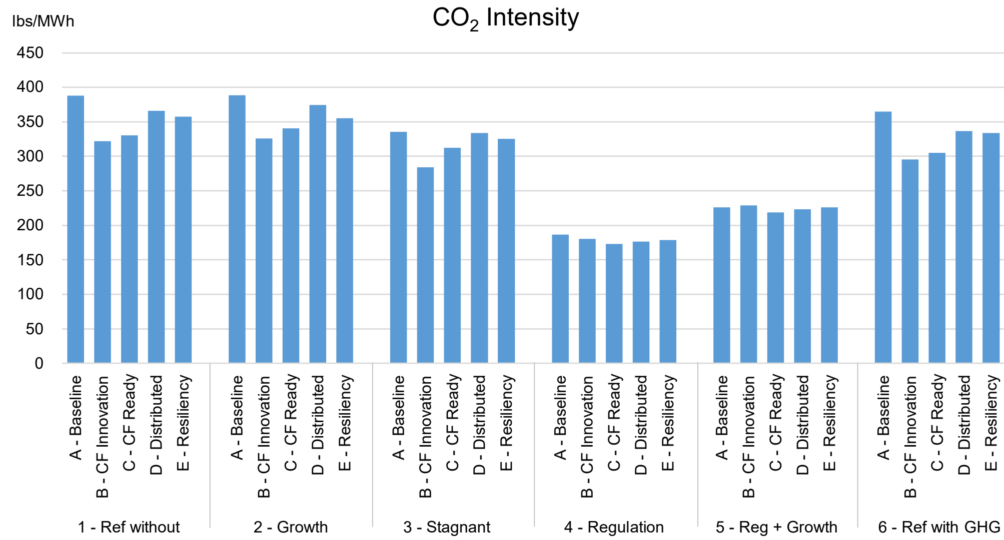


Figure 4-23: CO_2 Intensity (2025-2050, average annual)

Key takeaways from evaluating environmental performance across the portfolios include:

- All strategies lead to reductions in CO_2 emissions and intensity.
- Reductions in 2035 CO_2 intensity from a 2005 baseline range from 73% to 82% in Scenarios 1, 2, 3, and 6, and they average above 90% in Scenarios 4 and 5 with assumed regulatory impacts.
- Reductions in 2050 CO_2 intensity from a 2005 baseline range from 78% to 87% in Scenarios 1, 2, 3, and 6, and they average above 98% in Scenarios 4 and 5 with assumed regulatory impacts.
- Across most scenarios, Strategy C achieves the fastest near-term reductions in CO_2 intensity, while Strategy B achieves similar levels of decarbonization as Strategy C over the long term.
- In most portfolios, water consumption decreases between 2025 and 2050 due to expected coal retirements by 2035, except in Scenario 5 where new nuclear generation increases water consumption.
- Strategy C, which has the highest levels of renewable generation that displace thermal generation, has the lowest water consumption.
- Waste intensity is largely similar across the strategies, as all portfolios assume similar estimated end-of-life dates for coal plants.
- Land use intensity varies with the level of solar buildout in each portfolio and is highest in Strategy C.

4.7.4 Diverse, Reliable, and Flexible

Operational metrics help gauge impacts of resource additions on the diversity, reliability, and flexibility of the portfolio as a whole. Metrics include operating cost stability, flexible resource coverage ratio, and energy curtailment ratio.

Operating cost stability measures the variability of operating costs as load, fuel prices, and other key assumptions fluctuate. Portfolios that are more diverse are generally the most reliable and have less variance in operating costs. The chart below compares operating cost stability for each strategy within the six scenarios.

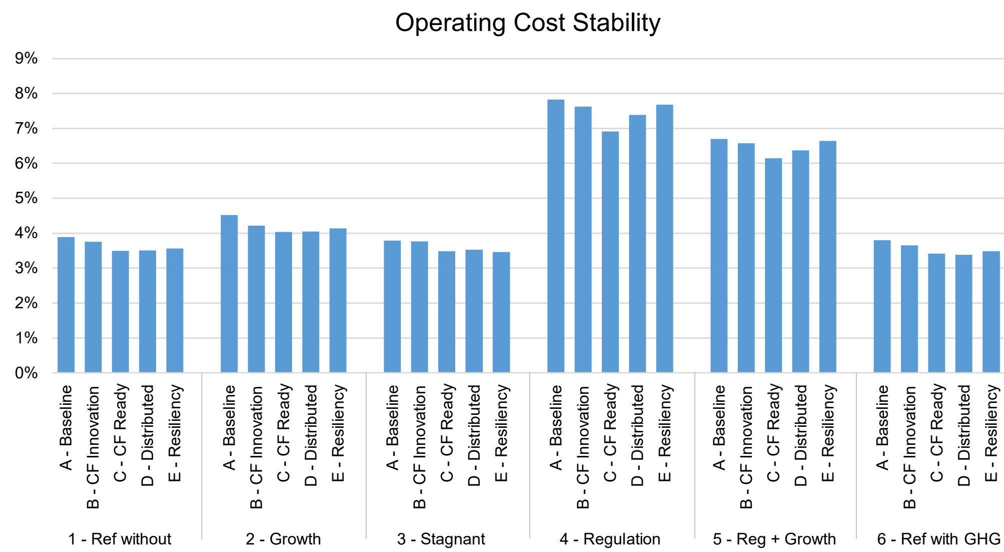


Figure 4-24: Operating Cost Stability

With expected growth in renewable resources that have variable energy output, having sufficient flexible resources on the system that can respond to hour-to-hour changes in demand net of renewables will be increasingly important. Flexible resource coverage ratio measures the amount of flexible capacity available compared to flexible capacity requirement in 2050 for each portfolio.

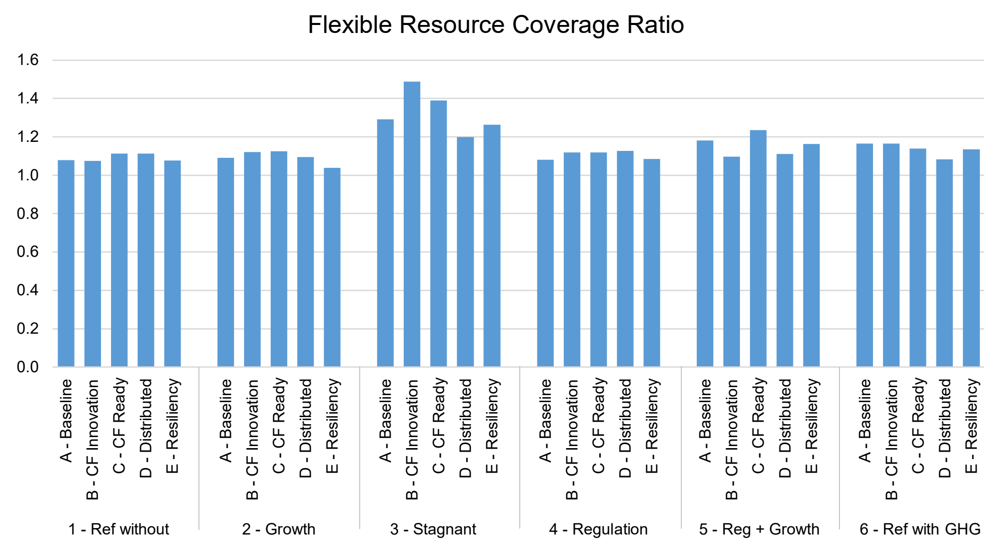


Figure 4-25: Flexible Resource Coverage Ratio

Key takeaways from evaluating operational metric performance across the portfolios include:

- Operating cost stability is more challenging in regulatory scenarios that include a CO_2 emissions tax.
- Strategy C portfolios have more stability in operating costs on average across scenarios.
- Flexible resource coverage is highest in the Stagnant Economy portfolios, which assume a flat load forecast and have a higher percentage of dispatchable resources.
- With modeled resource additions, all strategies perform adequately in 2050 flexible resource coverage.

- Maintaining sufficient system flexibility to meet dynamic changes in load will require balancing renewable and dispatchable resource additions over time, especially in growth scenarios.

4.7.5 Key Tradeoffs

With an understanding of strategy performance within metric categories, key tradeoffs across metric categories can then be assessed. It is especially useful to evaluate tradeoffs between cost and the other metric categories to understand the relative costs of different risk, environmental, and operational profiles, which help inform strategic direction.

Cost and Risk Tradeoffs

In resource planning and in specific asset decisions, cost and risk tradeoffs must be considered. A useful way to assess cost and financial risk tradeoffs is by comparing total resource cost to risk exposure, as shown below:

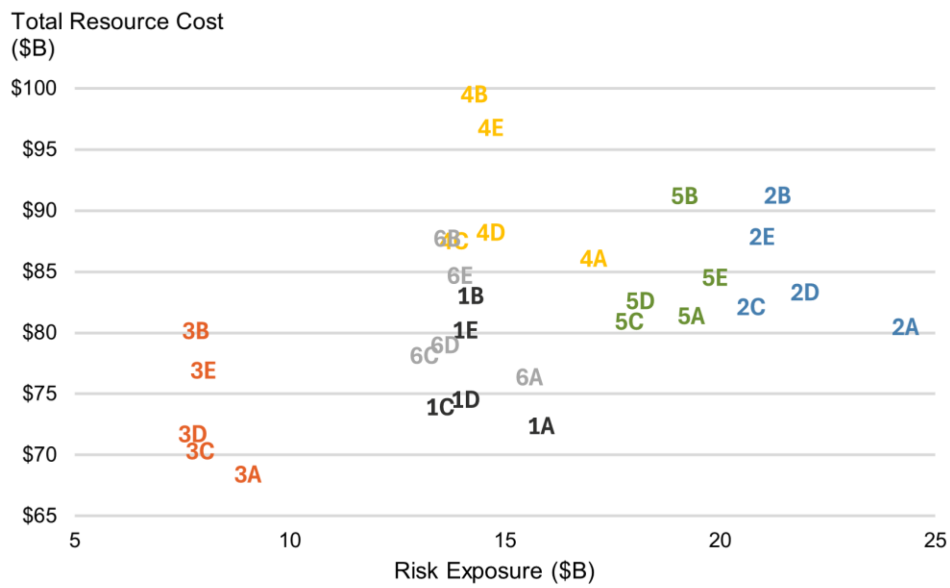


Figure 4-26: Total Resource Cost vs. Risk Exposure

- Results for the various scenarios are clustered, as the scenario that materializes for forecasted load and regulatory impacts is the primary driver of cost and risk profiles.
- Strategy C, which promotes carbon-free commercial ready resources, has the best tradeoff of cost and risk exposure overall.

Cost and Environmental Tradeoffs

While all environmental metrics are informative, CO_2 metrics are particularly informative to strategic direction. System average cost and CO_2 intensity performance are compared in the figure below to evaluate the relative cost of different CO_2 intensity profiles across the portfolios.

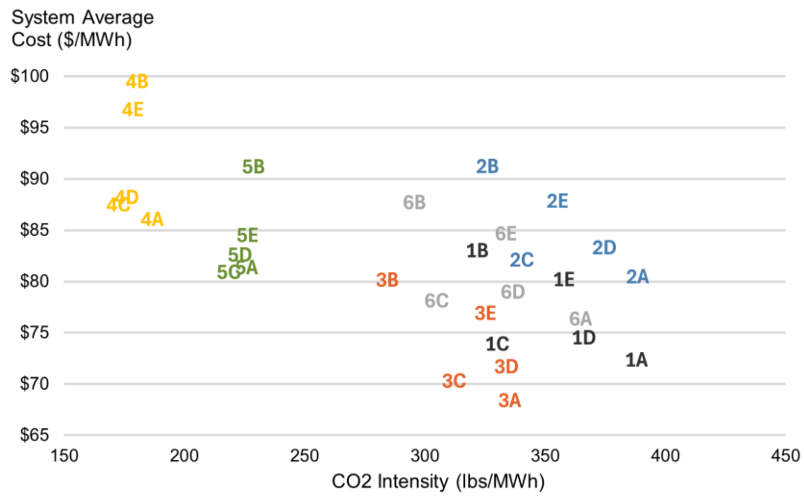


Figure 4-27: System Average Cost vs. CO_2 Intensity

- Results for the various scenarios are clustered, as the scenario that materializes for forecasted load and regulatory impacts is the primary driver of cost and CO_2 profiles.
- Within each scenario, Strategy A that applies baseline utility planning is the lowest cost overall, but it has less reduction in CO_2 intensity than alternative strategies that promote lower carbon resources.
- Strategy C, which focuses on commercial ready carbon-free technologies, is the second lowest in cost and achieves the fastest near-term reductions in CO_2 intensity.
- While Strategy B is the most expensive strategy overall, as it requires upfront investments in clean energy technology innovation, it achieves similar decarbonization as Strategy C over the long term.
- Strategies D and E generally fall somewhere in the middle for cost and intensity metrics.

Cost and Operational Tradeoffs

In resource planning and in specific asset decisions, cost and operational tradeoffs must be considered. The portfolio's ability to respond to dynamic changes in demand net of renewables will be increasingly important. To evaluate this, a comparison of total resource cost and flexible resource coverage ratio is shown below:

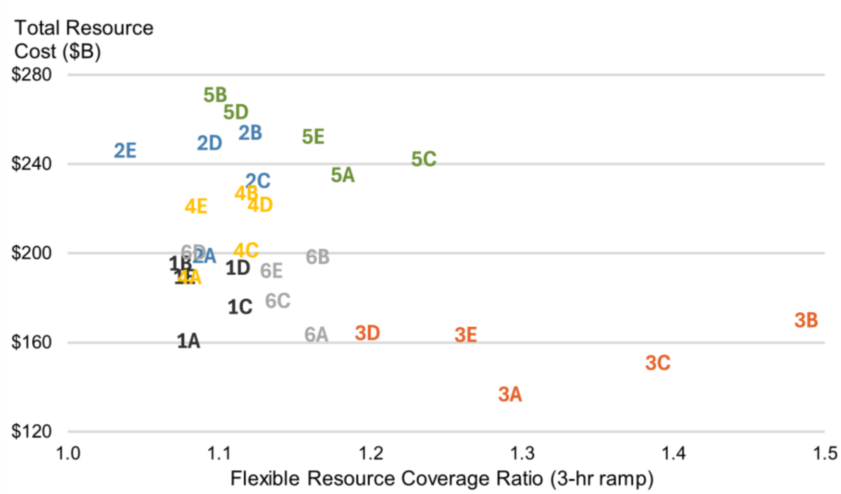


Figure 4-28: Total Resource Cost vs. Flexible Resource Coverage Ratio

- Results for the various scenarios are also clustered in this tradeoff comparison, as the scenario that materializes for forecasted load and regulatory impacts is a key driver of cost and resource additions.
- Flexible resource coverage is highest in the Stagnant Economy, or flat load scenario, and costs are also lowest in this scenario.
- Maintaining sufficient system flexibility to meet dynamic changes in load will require balancing renewable and dispatchable resource additions over time, especially in growth scenarios.

4.8 Summary Results by Strategy

Another useful way to view results is by strategy. Key findings, summarized by strategy, include:

Strategy A (Baseline Utility Planning): As Strategy A applies no resource promotions, it is the lowest cost strategy overall, and it has less reduction in CO_2 intensity than the alternative strategies that promote lower carbon resources. Strategy A portfolios have the highest natural gas generation and the lowest land use on average across the strategies.

Strategy B (Carbon-free Innovation Focus): Strategy B is the most expensive overall, as it would require upfront investments in clean energy technology innovation, and it achieves similar decarbonization levels as Strategy C over the long term. Technological risks are greatest in portfolios with more reliance on new clean technologies, and Strategy B portfolios have the highest amount of new nuclear and CC with CCS expansion.

Strategy C (Carbon-free Commercial Ready Focus): Strategy C is the second lowest in cost, and it achieves the fastest near-term reductions in CO_2 intensity. Strategy C portfolios have the highest renewable and storage additions on average. With the largest solar buildouts under this strategy, transmission risks and land use are greatest. Water consumption intensity is lowest as higher renewable generation displaces thermal generation.

Strategy D (Distributed and Demand-side Focus): Strategy D is the second most expensive strategy with respect to Total Resource Cost, which includes consumer investment in distributed generation and more efficient end-use technologies. EE and DR additions are highest in Strategy D, which promotes these resources. Strategy D portfolios generally rank in the middle for most other metrics.

Strategy E (Resiliency Focus): Strategy E portfolios generally rank in the middle across the metric categories. Strategy E portfolios have increased nuclear generation with the addition of SMRs. They also include the highest amount of smaller gas and storage units, supporting resilient operations with the potential for broader geographical distribution.

The following sections include summary dashboards for each strategy, which cover highlighted metrics and capacity additions and total energy by resource type.

4.8.1 Baseline Utility Planning

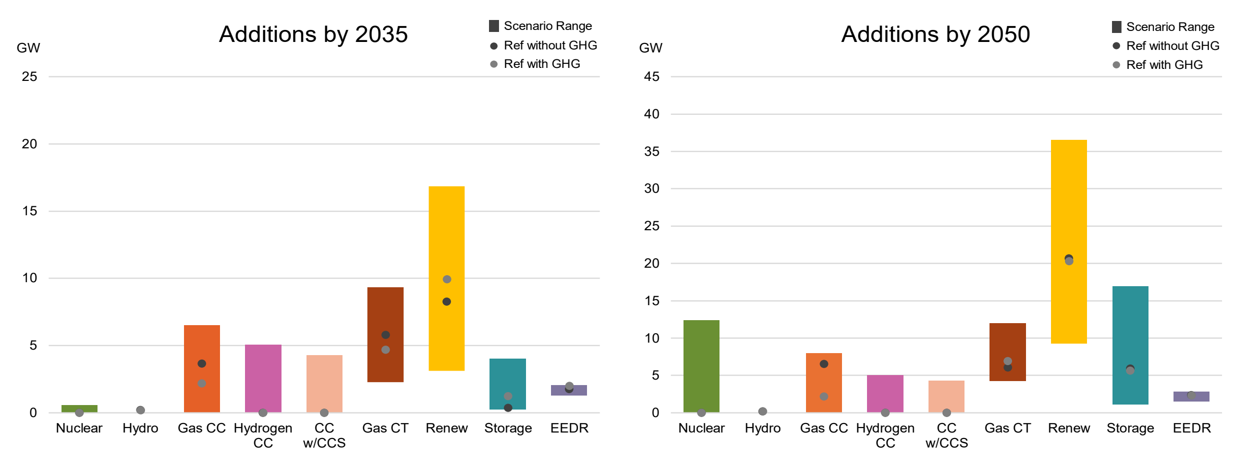
Strategy A: Baseline Utility Planning

Metric Highlights	Reference without GHG	Reference with GHG	Scenario Range	All Portfolios
PVRR ($B)	154	156	130-228	130-255
System Average Cost ($/MWh)	72	76	68-86	68-100
Risk / Benefit Ratio	1.22	1.18	1.04-1.23	0.97-1.23
CO_2 Intensity (lbs/MWh)	388	365	187-388	173-388
Operating Cost Stability (%)	3.9	3.8	3.8-7.8	3.4-7.8
Flexible Resource Coverage	1.08	1.16	1.08-1.29	1.04-1.49

- EE and DR
- Storage*
- Renewables*
- Gas CT
- Gas CC w/ CCS
- Hydrogen CC
- Gas CC
- Coal
- Hydro
- Nuclear

* Shown in nameplate, other sources in Summer NDC

Incremental Capacity Ranges across Scenarios



Total Energy Ranges across Scenarios

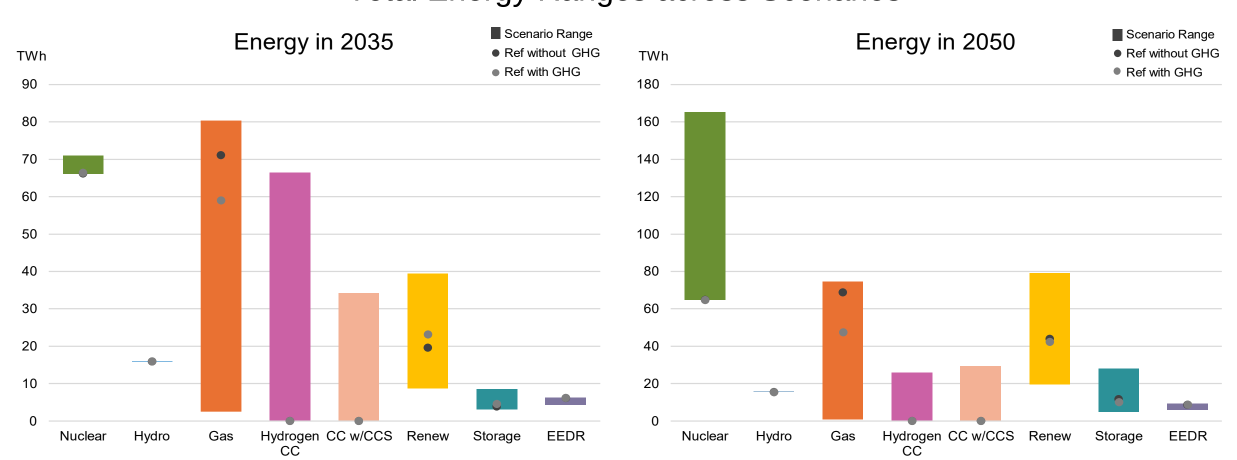


Figure 4-29: Strategy A Dashboard (Baseline Utility Planning)

4.8.2 Carbon-free Innovation Focus

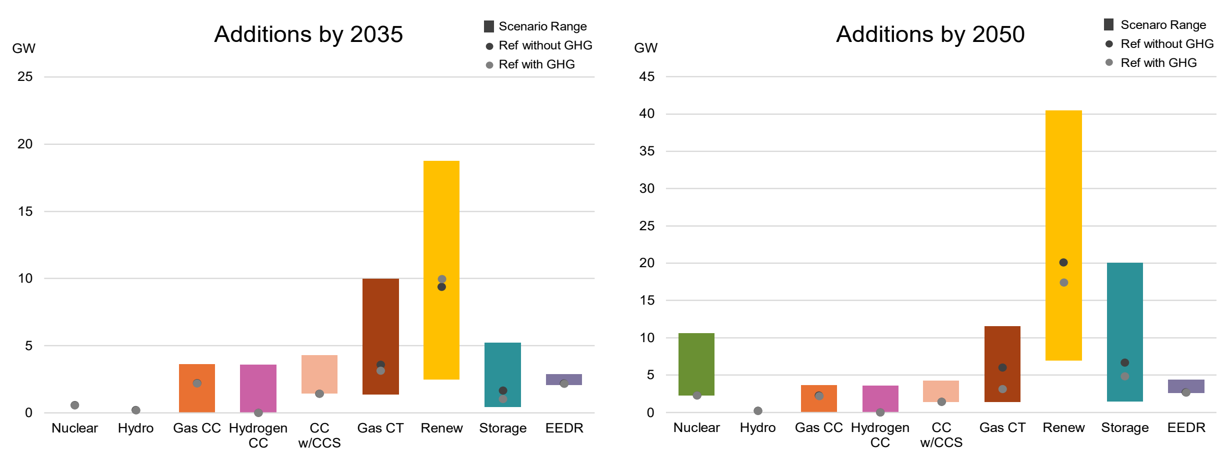
Strategy B: Carbon-free Innovation Focus

Metric Highlights	Reference without GHG	Reference with GHG	Scenario Range	All Portfolios
PVRR ($B)	177	180	152-255	130-255
System Average Cost ($/MWh)	83	88	80-100	68-100
Risk / Benefit Ratio	1.12	1.06	0.97-1.14	0.97-1.23
CO_2 Intensity (lbs/MWh)	322	296	180-326	173-388
Operating Cost Stability (%)	3.8	3.7	3.7-7.6	3.4-7.8
Flexible Resource Coverage	1.07	1.17	1.07-1.49	1.04-1.49

- EE and DR
- Storage*
- Renewables*
- Gas CT
- Gas CC w/ CCS
- Hydrogen CC
- Gas CC
- Coal
- Hydro
- Nuclear

* Shown in nameplate, other sources in Summer NDC

Incremental Capacity Ranges across Scenarios



Total Energy Ranges across Scenarios

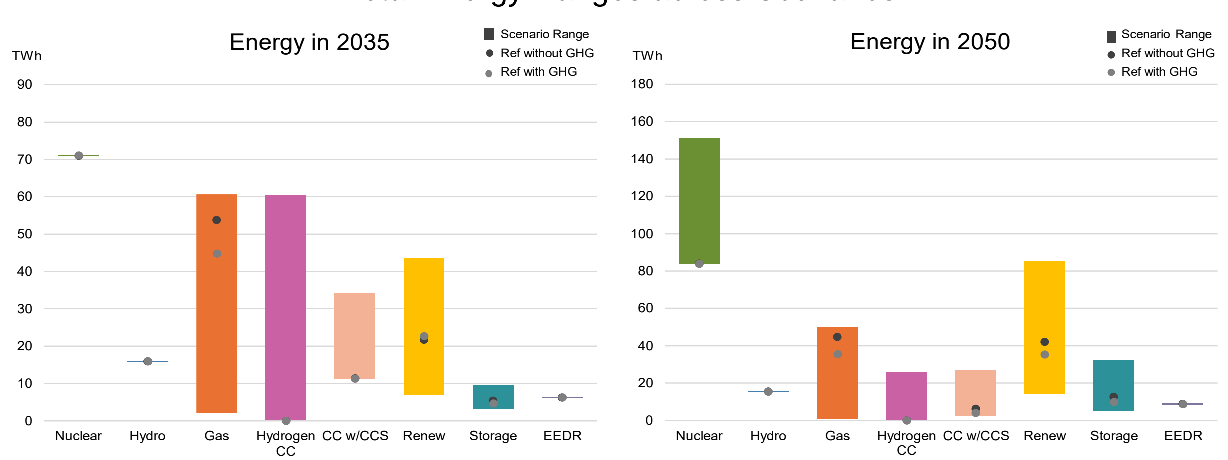


Figure 4-30: Strategy B Dashboard (Carbon-free Innovation Focus)

4.8.3 Carbon-free Commercial Ready Focus

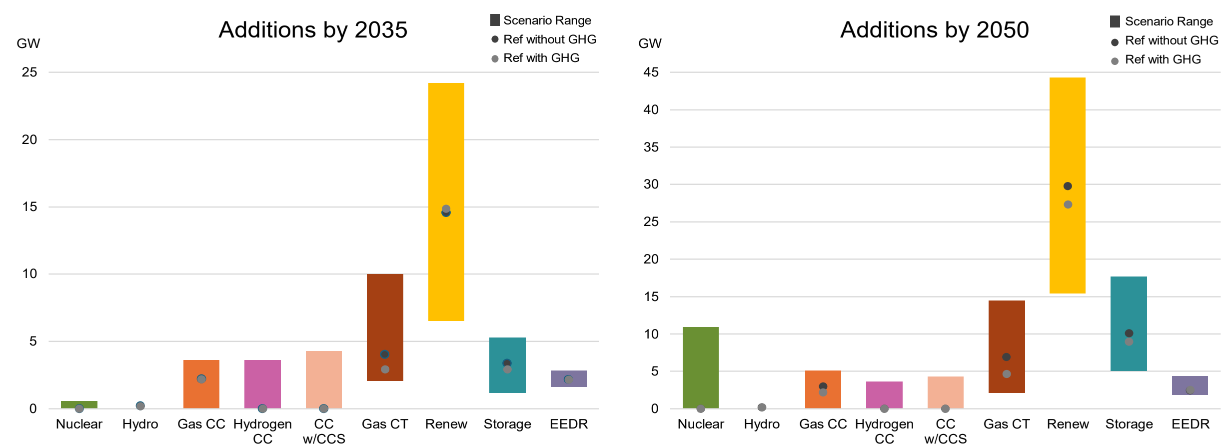
Strategy C: Carbon-free Commercial Ready Focus

Metric Highlights	Reference without GHG	Reference with GHG	Scenario Range	All Portfolios
PVRR ($B)	158	160	134-226	130-255
System Average Cost ($/MWh)	74	78	70-88	68-100
Risk / Benefit Ratio	1.20	1.16	1.04-1.22	0.97-1.23
CO_2 Intensity (lbs/MWh)	330	305	173-340	173-388
Operating Cost Stability (%)	3.5	3.4	3.4-6.9	3.4-7.8
Flexible Resource Coverage	1.11	1.14	1.11-1.39	1.04-1.49

- EE and DR
- Storage*
- Renewables*
- Gas CT
- Gas CC w/ CCS
- Hydrogen CC
- Gas CC
- Coal
- Hydro
- Nuclear

* Shown in nameplate, other sources in Summer NDC

Incremental Capacity Ranges across Scenarios



Total Energy Ranges across Scenarios

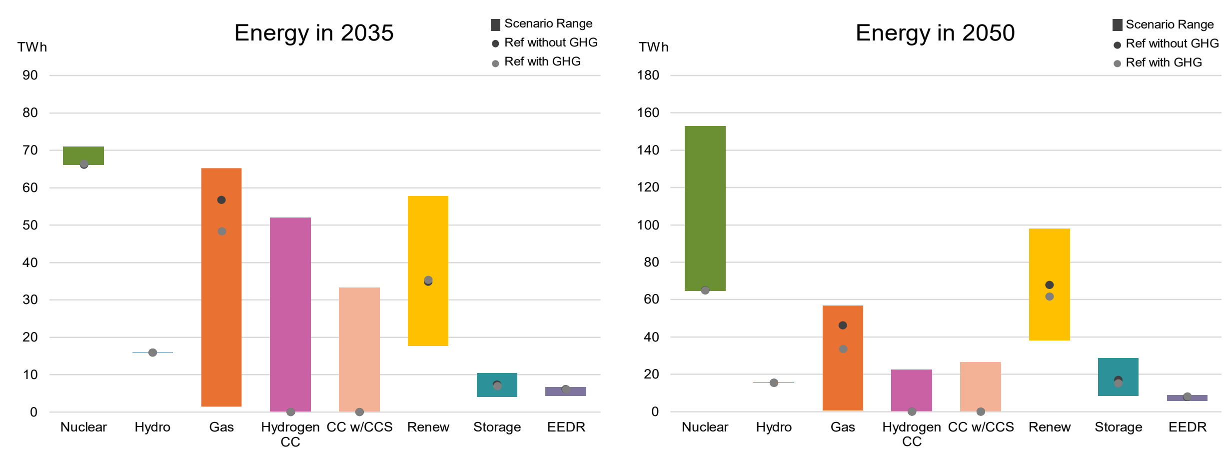


Figure 4-31: Strategy C Dashboard (Carbon-free Commercial Ready Focus)

4.8.4 Distributed Energy Resource Focus

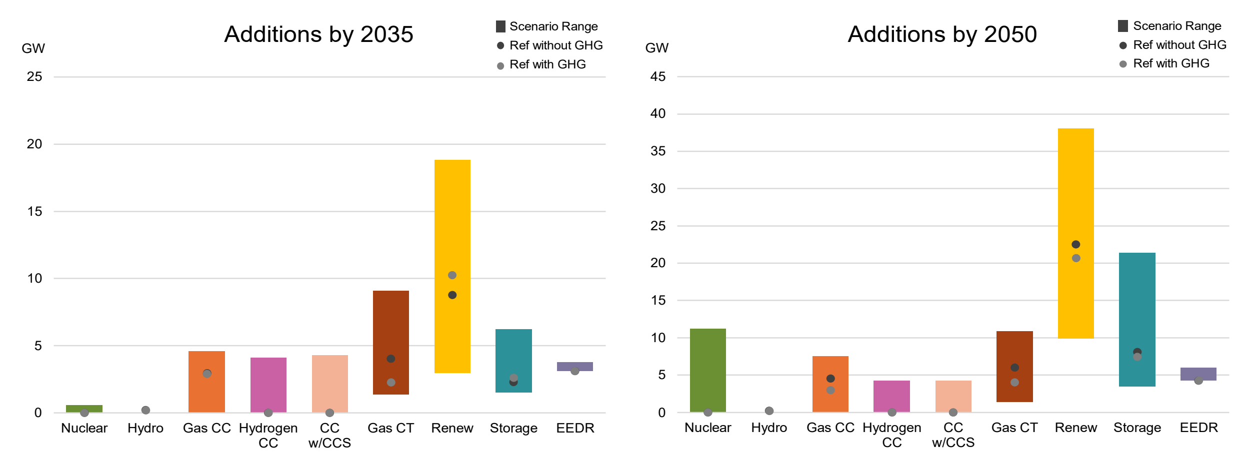
Strategy D: Distributed Energy Resource Focus

Metric Highlights	Reference without GHG	Reference with GHG	Scenario Range	All Portfolios
PVRR ($B)	159	162	136-231	130-255
System Average Cost ($/MWh)	75	79	72-88	68-100
Risk / Benefit Ratio	1.17	1.12	1.05-1.19	0.97-1.23
CO_2 Intensity (lbs/MWh)	366	337	176-375	173-388
Operating Cost Stability (%)	3.5	3.4	3.4-7.4	3.4-7.8
Flexible Resource Coverage	1.11	1.08	1.08-1.20	1.04-1.49

EE and DR
Storage*
Renewables*
Gas CT
Gas CC w/ CCS
Hydrogen CC
Gas CC
Coal
Hydro
Nuclear

* Shown in nameplate, other sources in Summer NDC

Incremental Capacity Ranges across Scenarios



Total Energy Ranges across Scenarios

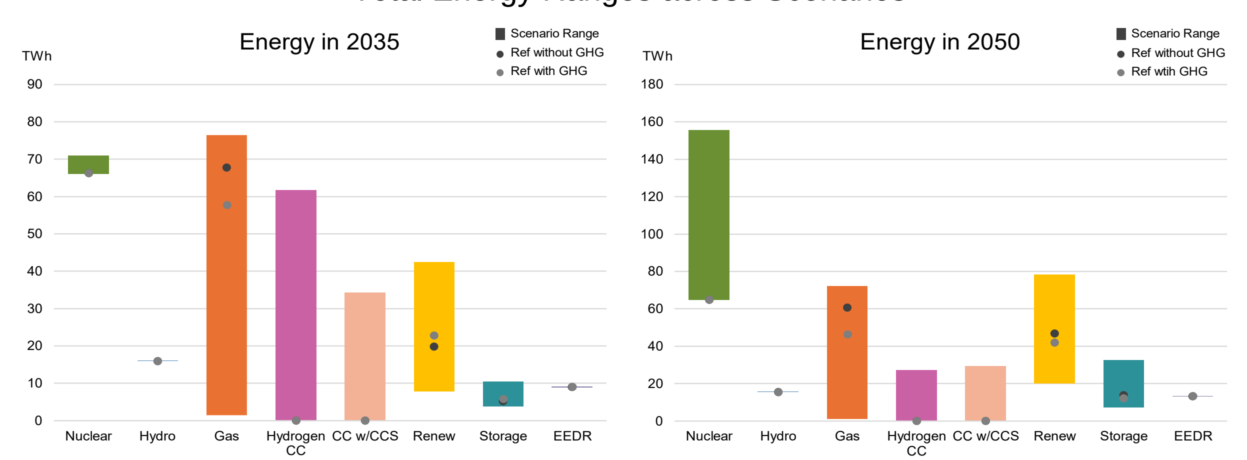


Figure 4-32: Strategy D Dashboard (Distributed and Demand-side Focus)

4.8.5 Resiliency Focus

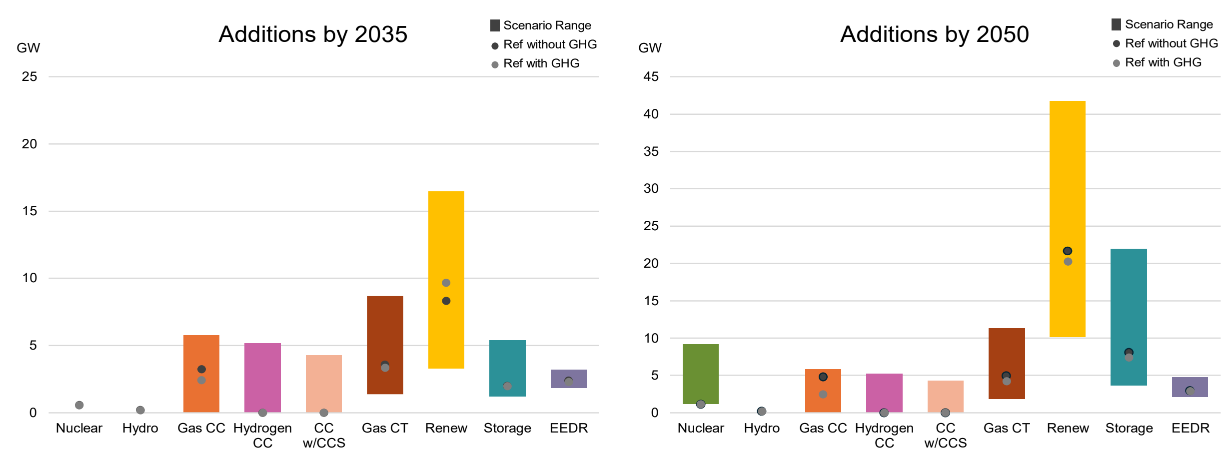
Strategy E: Resiliency Focus

Metric Highlights	Reference without GHG	Reference with GHG	Scenario Range	All Portfolios
PVRR ($B)	171	174	146-236	130-255
System Average Cost ($/MWh)	80	85	77-97	68-100
Risk / Benefit Ratio	1.15	1.11	1.04-1.19	0.97-1.23
CO_2 Intensity (lbs/MWh)	358	334	179-358	173-388
Operating Cost Stability (%)	3.6	3.5	3.5-7.7	3.4-7.8
Flexible Resource Coverage	1.08	1.13	1.04-1.26	1.04-1.49

- EE and DR
- Storage*
- Renewables*
- Gas CT
- Gas CC w/ CCS
- Hydrogen CC
- Gas CC
- Coal
- Hydro
- Nuclear

* Shown in nameplate, other sources in Summer NDC

Incremental Capacity Ranges across Scenarios



Total Energy Ranges across Scenarios

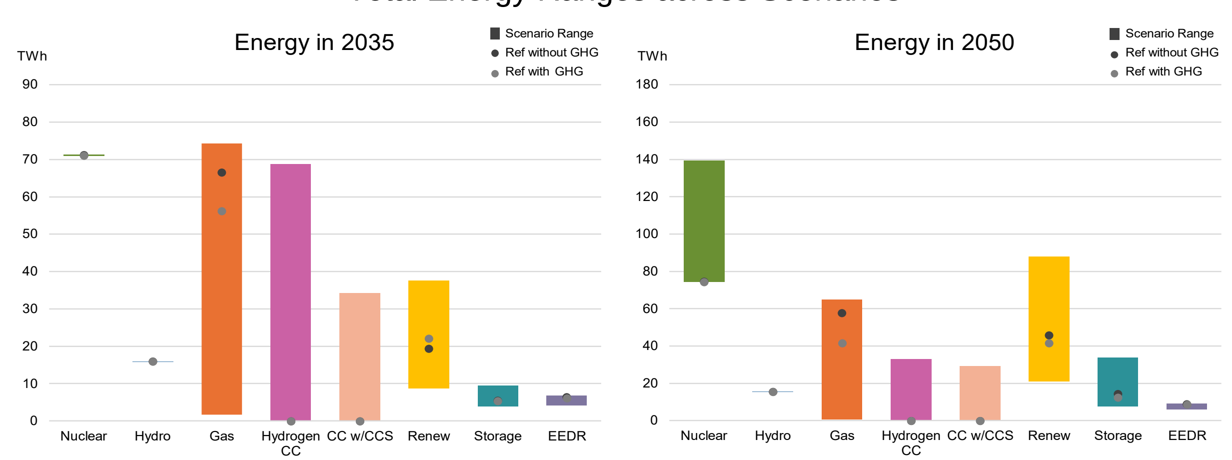


Figure 4-33: Strategy E Dashboard (Resiliency Focus)

4.9 Scorecard Results

Fully populated scorecards are included in this section with two views presented – by scenario and by metric. Metrics are calculated based on the optimization results for the 30 portfolios. Metrics cover the 2025-2050 study period, except for two metrics that focus on 2050, as noted. See Chapter 3 for a discussion on metrics development and Appendices I-K for further details on cost, risk, environmental, and operational metrics.

4.9.1 Scorecard Results by Scenario

Scorecard results by scenario, shown in the tables below, compare how the five strategies performed across all metrics within each scenario modeled in the IRP.

Table 4-2: Scenario 1 Scorecard (Reference without Greenhouse Gas Rule)

Scenario 1 – Reference (without Greenhouse Gas Rule)		Strategies				
Category	Metric	A	B	C	D	E
Low Cost	Present Value of Revenue Requirements (PVRR, $B)	$154	$177	$158	$159	$171
	System Average Cost ($/MWh)	$72	$83	$74	$75	$80
	Total Resource Cost ($B)	$161	$196	$176	$194	$190
Risk Informed	Risk / Benefit Ratio	1.22	1.12	1.20	1.17	1.15
	Risk Exposure ($B)	$15.8	$14.2	$13.5	$14.1	$14.1
Environmentally Responsible	CO_2 Direct Emissions (Million Tons)	34	28	29	30	30
	CO_2 Intensity (lbs/MWh)	388	322	330	366	358
	Water Consumption Intensity (Million Gallons/MWh)	280	304	266	286	296
	Waste Intensity (Million Tons/MWh)	1.3	1.3	1.2	1.3	1.3
	Land Use Intensity in 2050 (Acres/MWh)	0.7	0.7	0.9	0.8	0.7
Diverse, Reliable, and Flexible	Operating Cost Stability (% Variation)	3.9%	3.8%	3.5%	3.5%	3.6%
	Flexible Resource Coverage Ratio in 2050	1.08	1.07	1.11	1.11	1.08
	Energy Curtailment Ratio (%)	0.12%	0.14%	0.46%	0.19%	0.14%

Table 4-3: Scenario 2 Scorecard (Higher Growth Economy)

Scenario 2 – Higher Growth Economy		Strategies				
Category	Metric	A	B	C	D	E
Low Cost	Present Value of Revenue Requirements (PVRR, $B)	$191	$216	$195	$197	$208
	System Average Cost ($/MWh)	$81	$91	$82	$83	$88
	Total Resource Cost ($B)	$199	$254	$233	$250	$246
Risk Informed	Risk / Benefit Ratio	1.17	1.09	1.14	1.15	1.12
	Risk Exposure ($B)	$24.3	$21.3	$20.7	$22.0	$21.0
Environmentally Responsible	CO_2 Direct Emissions (Million Tons)	38	31	33	34	33
	CO_2 Intensity (lbs/MWh)	388	326	340	375	355
	Water Consumption Intensity (Million Gallons/MWh)	259	280	246	265	271
	Waste Intensity (Million Tons/MWh)	1.4	1.4	1.4	1.5	1.4
	Land Use Intensity in 2050 (Acres/ MWh)	1.0	0.9	1.1	1.0	1.1
Diverse, Reliable, and Flexible	Operating Cost Stability (% Variation in $/MWh)	4.5%	4.2%	4.0%	4.1%	4.1%
	Flexible Resource Coverage Ratio in 2050	1.09	1.12	1.13	1.09	1.04
	Energy Curtailment Ratio (%)	0.50%	0.54%	1.10%	0.54%	0.65%

Table 4-4: Scenario 3 Scorecard (Stagnant Economy)

Scenario 3 – Stagnant Economy		Strategies				
Category	Metric	A	B	C	D	E
Low Cost	Present Value of Revenue Requirements (PVRR, $B)	$130	$152	$134	$136	$146
	System Average Cost ($/MWh)	$68	$80	$70	$72	$77
	Total Resource Cost ($B)	$137	$170	$151	$164	$164
Risk Informed	Risk / Benefit Ratio	1.23	1.14	1.22	1.19	1.19
	Risk Exposure ($B)	$9.0	$7.8	$7.9	$7.7	$8.0
Environmentally Responsible	CO_2 Direct Emissions (Million Tons)	26	22	24	24	24
	CO_2 Intensity (lbs/MWh)	335	284	312	334	325
	Water Consumption Intensity (Million Gallons/MWh)	305	334	293	315	321
	Waste Intensity (Million Tons/MWh)	0.9	0.9	0.9	0.9	0.9
	Land Use Intensity in 2050 (Acres/MWh)	0.3	0.2	0.4	0.3	0.3
Diverse, Reliable, and Flexible	Operating Cost Stability (% Variation in $/MWh)	3.8%	3.8%	3.5%	3.5%	3.5%
	Flexible Resource Coverage Ratio in 2050	1.29	1.49	1.39	1.20	1.26
	Energy Curtailment Ratio (%)	0.00%	0.00%	0.01%	0.00%	0.00%

Table 4-5: Scenario 4 Scorecard (Net-zero Regulation)

Scenario 4 – Net-zero Regulation		Strategies				
Category	Metric	A	B	C	D	E
Low Cost	Present Value of Revenue Requirements (PVRR, $B)	$184	$213	$187	$188	$207
	System Average Cost ($/MWh)	$86	$100	$88	$88	$97
	Total Resource Cost ($B)	$190	$227	$202	$222	$221
Risk Informed	Risk / Benefit Ratio	1.06	1.07	1.08	1.08	1.05
	Risk Exposure ($B)	$17.1	$14.3	$13.8	$14.7	$14.7
Environmentally Responsible	CO_2 Direct Emissions (Million Tons)	16	15	15	15	15
	CO_2 Intensity (lbs/MWh)	187	180	173	176	179
	Water Consumption Intensity (Million Gallons/MWh)	263	289	255	270	279
	Waste Intensity (Million Tons/MWh)	1.3	1.3	1.3	1.3	1.3
	Land Use Intensity in 2050 (Acres/ MWh)	0.7	0.6	0.8	0.7	0.7
Diverse, Reliable, and Flexible	Operating Cost Stability (% Variation in $/MWh)	7.8%	7.6%	6.9%	7.4%	7.7%
	Flexible Resource Coverage Ratio in 2050	1.08	1.12	1.12	1.13	1.09
	Energy Curtailment Ratio (%)	0.20%	0.26%	0.50%	0.20%	0.17%

Table 4-6: Scenario 5 Scorecard (Net-zero Regulation Plus Growth)

Scenario 5 – Net-zero Regulation Plus Growth		Strategies				
Category	Metric	A	B	C	D	E
Low Cost	Present Value of Revenue Requirements (PVRR, $B)	$228	$255	$226	$231	$236
	System Average Cost ($/MWh)	$81	$91	$81	$83	$85
	Total Resource Cost ($B)	$235	$271	$242	$264	$253
Risk Informed	Risk / Benefit Ratio	1.04	0.97	1.04	1.05	1.04
	Risk Exposure ($B)	$19.3	$19.2	$17.9	$18.2	$19.9
Environmentally Responsible	CO_2 Direct Emissions (Million Tons)	24	24	23	23	24
	CO_2 Intensity (lbs/MWh)	226	229	219	223	226
	Water Consumption Intensity (Million Gallons/MWh)	317	302	294	314	305
	Waste Intensity (Million Tons/MWh)	1.0	1.0	1.0	1.0	1.0
	Land Use Intensity in 2050 (Acres/MWh)	0.7	0.8	0.8	0.8	0.9
Diverse, Reliable, and Flexible	Operating Cost Stability (% Variation in $/MWh)	6.7%	6.6%	6.2%	6.4%	6.6%
	Flexible Resource Coverage Ratio in 2050	1.18	1.10	1.24	1.11	1.16
	Energy Curtailment Ratio (%)	0.35%	0.48%	0.82%	0.49%	0.41%

Table 4-7: Scenario 6 Scorecard (Reference with Greenhouse Gas Rule)

Scenario 6 – Reference (with Greenhouse Gas Rule)		Strategies				
Category	Metric	A	B	C	D	E
Low Cost	Present Value of Revenue Requirements (PVRR, $B)	$156	$180	$160	$162	$174
	System Average Cost ($/MWh)	$76	$88	$78	$79	$85
	Total Resource Cost ($B)	$164	$199	$179	$201	$192
Risk Informed	Risk / Benefit Ratio	1.18	1.06	1.16	1.12	1.11
	Risk Exposure ($B)	$15.6	$13.7	$13.1	$13.6	$14.0
Environmentally Responsible	CO_2 Direct Emissions (Million Tons)	30	24	25	26	27
	CO_2 Intensity (lbs/MWh)	365	296	305	337	334
	Water Consumption Intensity (Million Gallons/MWh)	283	313	274	294	302
	Waste Intensity (Million Tons/MWh)	1.4	1.4	1.3	1.4	1.4
	Land Use Intensity in 2050 (Acres/MWh)	0.7	0.6	0.8	0.8	0.7
Diverse, Reliable, and Flexible	Operating Cost Stability (% Variation in $/MWh)	3.8%	3.7%	3.4%	3.4%	3.5%
	Flexible Resource Coverage Ratio in 2050	1.16	1.17	1.14	1.08	1.13
	Energy Curtailment Ratio (%)	0.22%	0.20%	0.53%	0.26%	0.22%

4.9.2 Scorecard Results by Metric

Scorecard results by metric, shown in the table below, compare how the five strategies performed across all scenarios for each metric.

Table 4-8: Scorecard Metrics by Scenario and Strategy

Metric / Strategy	Scenarios					
	1 Ref without GHG Rule	2 Growth	3 Stagnant	4 Regulation	5 Reg + Growth	6 Ref with GHG Rule
Present Value of Revenue Requirements (PVRR, $B)						
A	$154	$191	$130	$184	$228	$156
B	$177	$216	$152	$213	$255	$180
C	$158	$195	$134	$187	$226	$160
D	$159	$197	$136	$188	$231	$162
E	$171	$208	$146	$207	$236	$174
System Average Cost ($/MWh)						
A	$72	$81	$68	$86	$81	$76
B	$83	$91	$80	$100	$91	$88
C	$74	$82	$70	$88	$81	$78
D	$75	$83	$72	$88	$83	$79
E	$80	$88	$77	$97	$85	$85

Metric / Strategy	Scenarios					
	1 Ref without GHG Rule	2 Growth	3 Stagnant	4 Regulation	5 Reg + Growth	6 Ref with GHG Rule
Total Resource Cost ($B)						
A	$161	$199	$137	$190	$235	$164
B	$196	$254	$170	$227	$271	$199
C	$176	$233	$151	$202	$242	$179
D	$194	$250	$164	$222	$264	$201
E	$190	$246	$164	$221	$253	$192
Risk/Benefit Ratio						
A	1.22	1.17	1.23	1.06	1.04	1.18
B	1.12	1.09	1.14	1.07	0.97	1.06
C	1.20	1.14	1.22	1.08	1.04	1.16
D	1.17	1.15	1.19	1.08	1.05	1.12
E	1.15	1.12	1.19	1.05	1.04	1.11
Risk Exposure ($B)						
A	$15.8	$24.3	$9.0	$17.1	$19.3	$15.6
B	$14.2	$21.3	$7.8	$14.3	$19.2	$13.7
C	$13.5	$20.7	$7.9	$13.8	$17.9	$13.1
D	$14.1	$22.0	$7.7	$14.7	$18.2	$13.6
E	$14.1	$21.0	$8.0	$14.7	$19.9	$14.0
CO_2 Direct Emissions (Million Tons)						
A	34	38	26	16	24	30
B	28	31	22	15	24	24
C	29	33	24	15	23	25
D	30	34	24	15	23	26
E	30	33	24	15	24	27
CO_2 Intensity (lbs/MWh)						
A	388	388	335	187	226	365
B	322	326	284	180	229	296
C	330	340	312	173	219	305
D	366	375	334	176	223	337
E	358	355	325	179	226	334
Water Consumption Intensity (Million Gallons/MWh)						
A	280	259	305	263	317	283
B	304	280	334	289	302	313
C	266	246	293	255	294	274
D	286	265	315	270	314	294
E	296	271	321	279	305	302
Waste Intensity (Million Tons/MWh)						
A	1.3	1.4	0.9	1.3	1.0	1.4
B	1.3	1.4	0.9	1.3	1.0	1.4
C	1.2	1.4	0.9	1.3	1.0	1.3
D	1.3	1.5	0.9	1.3	1.0	1.4
E	1.3	1.4	0.9	1.3	1.0	1.4

Metric / Strategy	Scenarios					
	1 Ref without GHG Rule	2 Growth	3 Stagnant	4 Regulation	5 Reg + Growth	6 Ref with GHG Rule
Land Use Intensity in 2050 (Acres/MWh)						
A	0.7	1.0	0.3	0.7	0.7	0.7
B	0.7	0.9	0.2	0.6	0.8	0.6
C	0.9	1.1	0.4	0.8	0.8	0.8
D	0.8	1.0	0.3	0.7	0.8	0.8
E	0.7	1.1	0.3	0.7	0.9	0.7
Operating Cost Stability (%)						
A	3.9%	4.5%	3.8%	7.8%	6.7%	3.8%
B	3.8%	4.2%	3.8%	7.6%	6.6%	3.7%
C	3.5%	4.0%	3.5%	6.9%	6.2%	3.4%
D	3.5%	4.1%	3.5%	7.4%	6.4%	3.4%
E	3.6%	4.1%	3.5%	7.7%	6.6%	3.5%
Flexible Resource Coverage Ratio in 2050						
A	1.08	1.09	1.29	1.08	1.18	1.16
B	1.07	1.12	1.49	1.12	1.10	1.17
C	1.11	1.13	1.39	1.12	1.24	1.14
D	1.11	1.09	1.20	1.13	1.11	1.08
E	1.08	1.04	1.26	1.09	1.16	1.13
Energy Curtailment (%)						
A	0.12%	0.50%	0.00%	0.20%	0.35%	0.22%
B	0.14%	0.54%	0.00%	0.26%	0.48%	0.20%
C	0.46%	1.10%	0.03%	0.50%	0.82%	0.53%
D	0.19%	0.54%	0.00%	0.20%	0.49%	0.26%
E	0.14%	0.65%	0.00%	0.17%	0.41%	0.22%

4.10 Sensitivity Analysis

A sensitivity analysis varies a key assumption to isolate the impact of a change in that assumption. When analyzing draft IRP results, TVA and the IRP Working Group began to identify questions warranting further evaluation before finalizing the study. Questions typically related to key assumptions that have the potential to influence results. To explore impacts of changes in key assumptions and provide additional information for consideration in developing IRP recommendations, TVA and the Working Group are beginning to develop a preliminary list of sensitivities for further analysis, focused in the following areas:

- Load variations
- Weather risk
- TVA net-zero aspirations
- Variations in carbon regulations and emissions
- Commodity price risks
- Variations in resource costs and deployment

Questions arising from ongoing IRP Working Group and RERC discussions, along with public comments received during the draft IRP and EIS comment period, will help refine the final list of sensitivity analyses to be performed. Results of the sensitivity analyses will be included in the final IRP.

4.11 Conclusion

TVA encourages stakeholders and the public to review the draft IRP and EIS and provide comments on the analysis and what they would like to see in the evolving energy mix. TVA looks forward to stakeholder and public feedback on the IRP to help chart the course for the region’s future energy system.

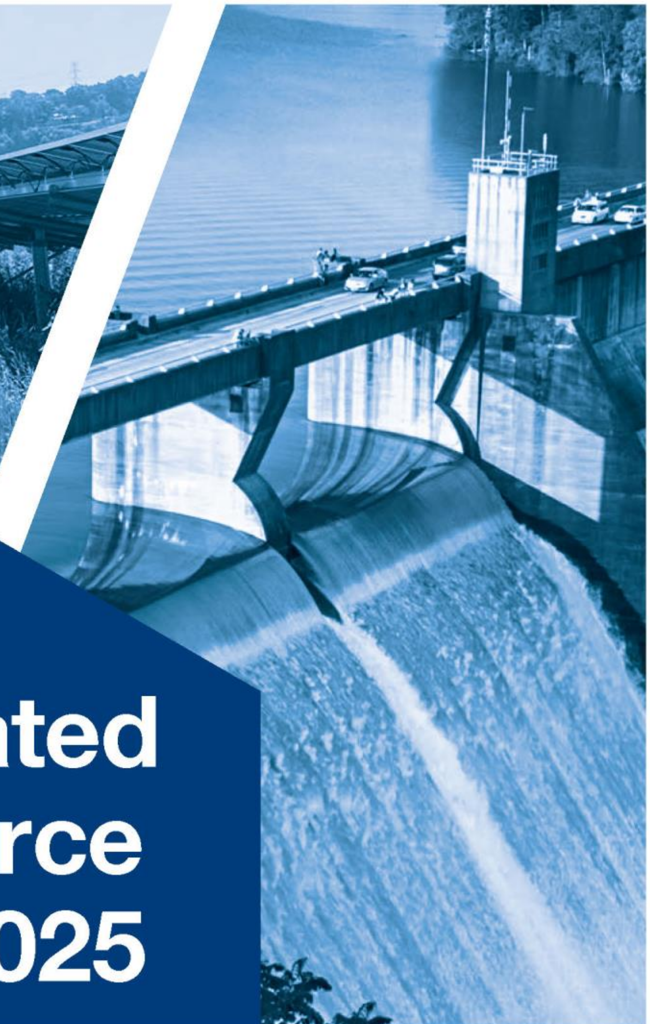
5 Next Steps

TVA, the IRP Working Group, and the Regional Energy Resource Council (RERC) are continuing to review and discuss key elements of the draft IRP and EIS results. After the public comment period concludes, TVA will review additional input received from the Working Group, the RERC, other key stakeholders, and the public. This input will help refine the list of additional analyses to be performed and considered in developing the IRP recommendations.

The final IRP will contain additional analysis and summarize the process for developing IRP recommendations, which will include:

- Power supply mix ranges by resource type
- Recommended strategic portfolio direction through 2035
- Key signposts and how they will influence portfolio direction from 2035 to 2050

The final IRP will also discuss implementation plans. In Spring/Summer 2025, the final IRP and EIS will be made available to the public for at least 30 days prior to consideration by the TVA Board. Subject to the Board's direction, an official Record of Decision will then be posted.



Integrated Resource Plan 2025

VOLUME 1 / APPENDIX

SEPTEMBER 2024

TENNESSEE VALLEY AUTHORITY

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Appendix A – Integrated Resource Planning Fundamentals

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Appendix A – Integrated Resource Planning Fundamentals

Integrated resource planning is a complex process that considers numerous inputs to produce potential resource plans for meeting the power supply needs of the TVA region, providing guidance for business decisions. This appendix covers the fundamentals of integrated resource planning, including descriptions of key concepts and steps in the process. The process involves forecasting electricity demand, determining capacity needs, identifying resource options, producing and testing resource plans, and analyzing business decisions.

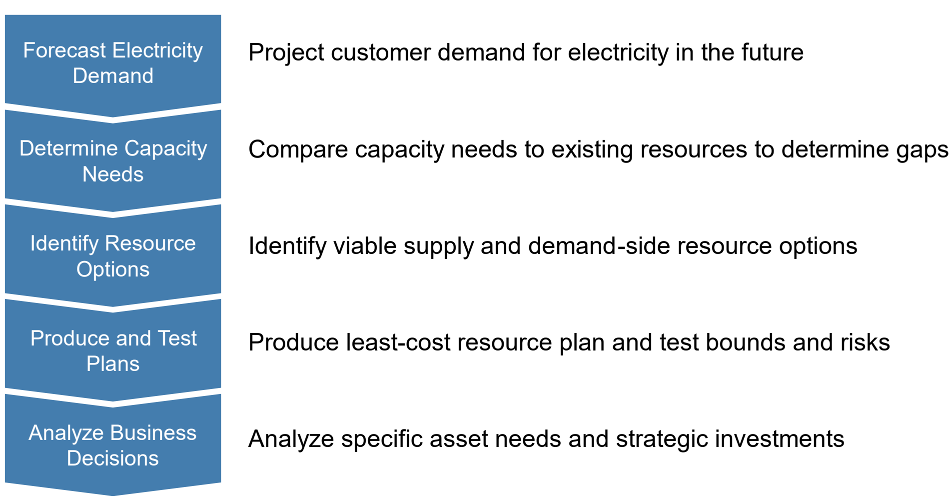
A.1 Objectives of Resource Planning

Resource planning at TVA is grounded in the following least-cost principles:

TVA applies these principles, in alignment with Section 113 of the Energy Policy Act of 1992, to develop plans for providing affordable, reliable, resilient, and increasingly cleaner energy to the region over the long term.

A.2 Resource Planning Process

Resource Planning is a common practice in the utility industry to identify the optimal solution to meet customer demand over a planning horizon, typically 20 years. TVA conducts an Integrated Resource Plan (IRP) to determine power supply mix ranges, which serve as guardrails, along with recommendations for strategic portfolio direction. Between IRP cycles, which is typically every four to five years, TVA annually updates plans based on current forecasts for key assumptions and analyzes sensitivities and stochastics to better understand risk. The IRP and annual plan updates provide information needed to initiate and evaluate site-specific asset decisions. Resource planning follows a similar process for the IRP and annual plan updates:



A.3 Capacity and Energy Definitions

Before stepping through the resource planning process, it is important to understand the difference between capacity and energy. Power system peaks are measured in terms of capacity, or the highest one-hour power requirement placed on the system. Resource planning ensures that there are sufficient resources to reliably meet that peak demand. As resource options are considered, the ability of a given resource to contribute to meeting peak demand is identified.

Capacity for a resource is the instantaneous maximum amount of energy that can be supplied by that generating unit. For long-term planning purposes, capacity is primarily referred to in two ways:

- Nameplate capacity – the theoretical design value or intended maximum megawatt (MW) output of a generator at the time of installation.
- Net dependable capacity – the maximum dependable capacity at seasonal peak demand times less all known adjustments, such as transmission restrictions, station service needs, and fuel derates.

Net dependable capacity, which is used in capacity planning models, is typically determined by performance testing during the respective season, because weather conditions and peak coincidence affect generating capability. For variable energy resources like solar and wind, net dependable capacities for each season are determined by looking at the historical output at typical seasonal peak times (late afternoon in the summer and early morning in the winter) as a percentage of nameplate capacity. TVA uses both summer and winter net dependable capacities of units in resource planning analysis, given the dual-peaking nature of the system.

While capacity measures power supplied at a given peak time, energy refers to the amount of power supplied over a given time. Overall power system production over a given period of time, such as a day or year, is called energy or generation and is measured in terms of megawatt-hours (MWh). The example below describes a generating unit that produced its maximum net dependable capacity of 100 MW at the peak hour and generated a total of 1,800 MWh over a 24-hour period.

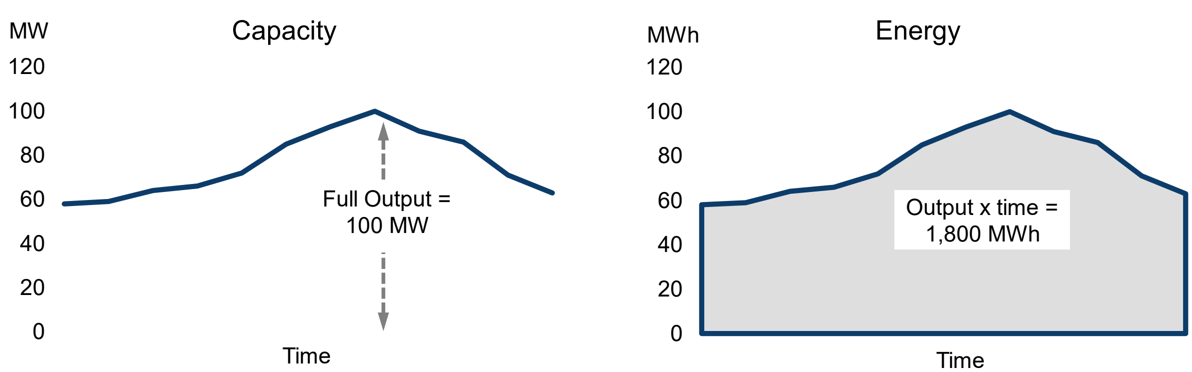


Figure A-1: Capacity and Energy Illustration

A.4 Forecasting Electricity Demand

The primary purpose of long-term resource planning is to determine the optimal mix of resources to supply power to the Valley region over the next 20-plus years and inform decision making. The process starts with estimating future electricity demand, sometimes also referred to as the load forecast.

In resource planning, electricity demand forecasts project the peak demand and energy requirements of the system on an hourly, daily, and annual basis for the next 20 years. Forecasts are typically expressed in terms of normal weather conditions. Normalizing for typical weather conditions allows load forecasters to identify the relationship between trends in electricity demand and long-term drivers, including economic activity, population changes, and climate trends. The TVA system is dual peaking, meaning that forecasted peak demand for summer and winter is roughly the same, so electricity demand forecasts are developed for both seasons.

To forecast electricity demand, TVA uses statistical and mathematical models that link electricity sales to several key drivers, including growth in overall economic activity, changes in underlying demographics, energy substitution, and changes in consumer usage through technology. The system forecast is aggregated from individual forecasts by the major consuming sectors, including residential, commercial, industrial, and direct served customers. The hourly energy and daily peak forecasts are inputs into the resource planning and commodity forecasting models.

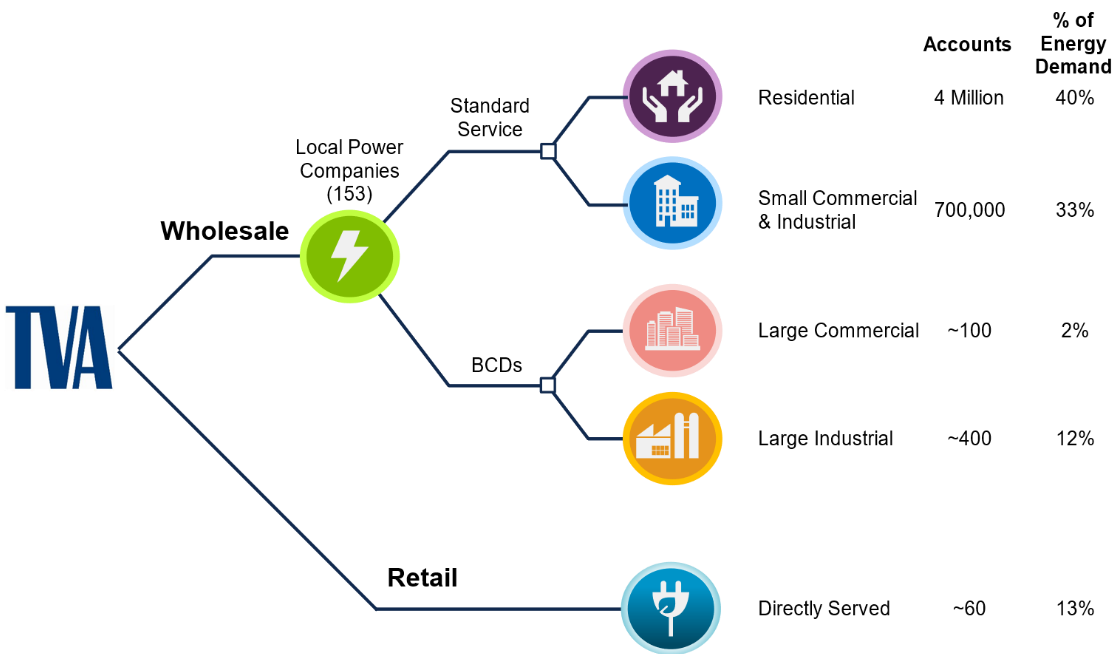


Figure A-2: Current Snapshot of Load Forecast Sectors

The load forecast is one of the most critical inputs to the planning process. Underestimating load growth can result in insufficient resources to meet electricity demand, while overestimating load growth can result in unnecessary or stranded assets.

A.5 Determining Capacity Needs

The next step in the resource planning process is determining capacity needs for both winter and summer. Capacity requirements represent the megawatts (MW) needed to serve forecasted electricity demand plus required planning reserve margins in each season. Capacity requirements can be compared to existing resources to identify the need for new capacity.

Planning Reserve Margin and Firm Requirements

To maintain reliability, power providers must have more generating capacity available than required to meet projected demand. This additional capacity accounts for uncertainty in the amount of forecasted demand and available generating capacity on a future peak day. For example, future demand is uncertain due to variations in weather conditions, and electric generators can experience unplanned outages due to equipment failure. To understand excess generating capacity needed, TVA conducts a reserve margin study. The reserve margin study is based on a probabilistic analysis that considers the uncertainty of weather, demand, and performance.

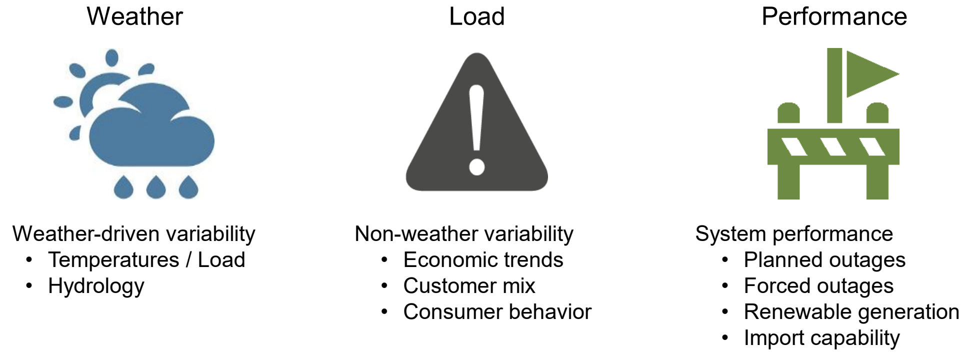


Figure A-3: Reserve Margin Study Elements

While forecasted peak demand for summer and winter is similar, uncertainty and risks vary with the seasons. Weather is a key driver of demand, and the variability of weather in winter is much greater than in summer. Generating unit performance also varies by season due largely to ambient temperatures and conditions, and amount of rainfall. To reliably serve customers, TVA must have sufficient resources to meet the peak demand in both seasons, accounting for changes in weather, generating unit availability, and other factors. Additional information on the reserve margin study can be found in Appendix D – Key Modeling Assumptions.

Based on the last reserve margin study, TVA established planning reserve margins for summer and winter that targeted industry best-practice levels of reliability. TVA's current planning reserve margin is 18% above peak demand requirements in the summer and 25% above peak demand requirements in the winter. Planning reserve margin targets are added to the forecast of electricity demand to derive firm requirements needed to reliably serve the power needs of TVA customers.

Capacity Gap

Simply put, a capacity gap is the difference between projected electricity demand and generating capacity supply. Calculating the capacity gap begins with forecasting baseline firm supply from existing resources, which declines over time due to anticipated retirements and contract expirations. Then firm capacity requirements, which reflect projected electricity demand plus required planning reserve margins in each season, are compared to capacity supply from existing resources. The difference between the two represents the capacity gap – or the need for incremental power resources, as illustrated below.

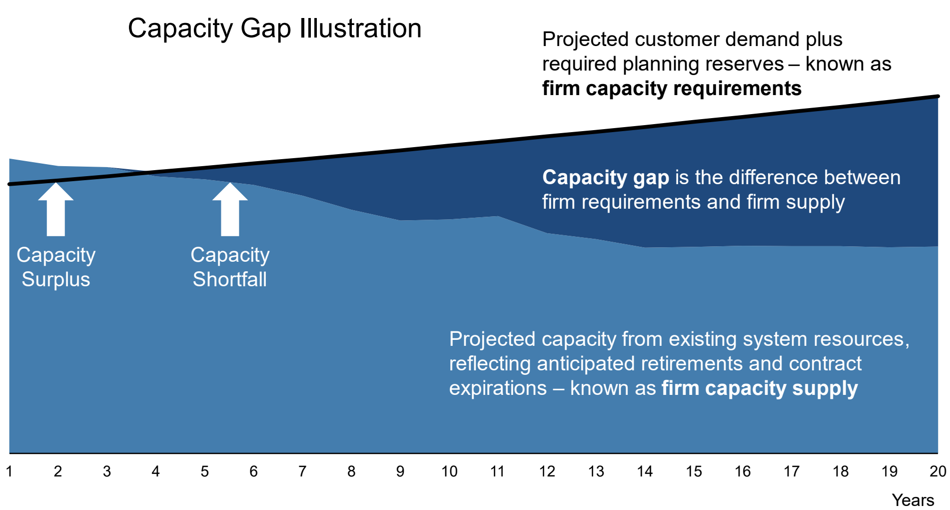


Figure A-4: Capacity Gap Illustration

A.6 Identifying Resource Options

Maintaining the diversity of energy resources is fundamental to TVA's ability to provide affordable, reliable and increasingly cleaner electric power to Valley residents, businesses and industries. For this reason, and consistent with Section 113 of the Energy Policy Act of 1992, TVA considers the addition of a wide range of supply-side generating resources as well as energy efficiency and other demand-side resource options to fill capacity gaps. TVA's power supply consists of existing TVA-owned resources, existing power purchase agreements, and approved projects such as new plant additions and upgrades to existing assets.

Commodity price forecasts are a key input when evaluating resource options. Commodity prices refer to the price of natural gas, coal, oil, imported electricity, and carbon dioxide (CO_2). The natural gas price forecast represents the market clearing price of a competitive market subject to infrastructure constraints. To create this forecast, TVA uses an industry standard gas model (GPCM) that simultaneously considers data such as pipeline capacity and transportation costs, expected consumption by sector, and cost of supply by basin. Changes in natural gas prices change the variable cost of gas units and may change the economics of different types of gas capacity relative to other resource options. TVA uses another industry standard model (Aurora) to forecast imported electricity prices, considering the interdependency of the gas and electricity markets. CO_2 prices are typically based on current policy and regulations, and alternative scenarios may evaluate potential future regulatory conditions. Higher carbon prices can influence the selection of more carbon-free capacity.

Resource Options

Electric generating assets are generally categorized in two ways – by technology type and by dispatch role. Resource technology type generally refers to fuel source, including nuclear, hydro, coal, natural gas, solar, wind, storage, and demand-side management. Dispatch role refers to whether a resource option is generally used to meet power demands around the clock, through a portion of the day, or during peak demand hours. Dispatch roles are:

- Baseload: Due to their lower operating costs and high availability, baseload resources are used primarily to provide continuous, reliable power over long periods of uniform demand. Large nuclear plants are a prime example of a baseload resource.
- Variable: Renewable energy sources are variable resources, as generation is available when the sun is shining, the wind is blowing, and the water is flowing. Renewable generation has patterns that can be reasonably forecasted based on historical data and incorporated into resource planning models.
- Intermediate: Intermediate resources are used primarily to fill the gap in generation between baseload and peaking needs. They also provide backup and balance the supply of energy from intermittent wind and solar generation. Natural gas combined cycle units are well suited to an intermediate dispatch role.
- Peaking: Typically used infrequently for short-duration, high demand periods, peaking resources play a key role in maintaining system reliability. For example, natural gas combustion turbines can start up quickly to meet sudden changes in demand or supply. Storage resources serve a similar function but use low-cost, off-peak electricity to store energy for generation at peak times.

The figure below illustrates how a mix of different resources "stack up" together to help meet system demand over the course of a typical, hot summer day.

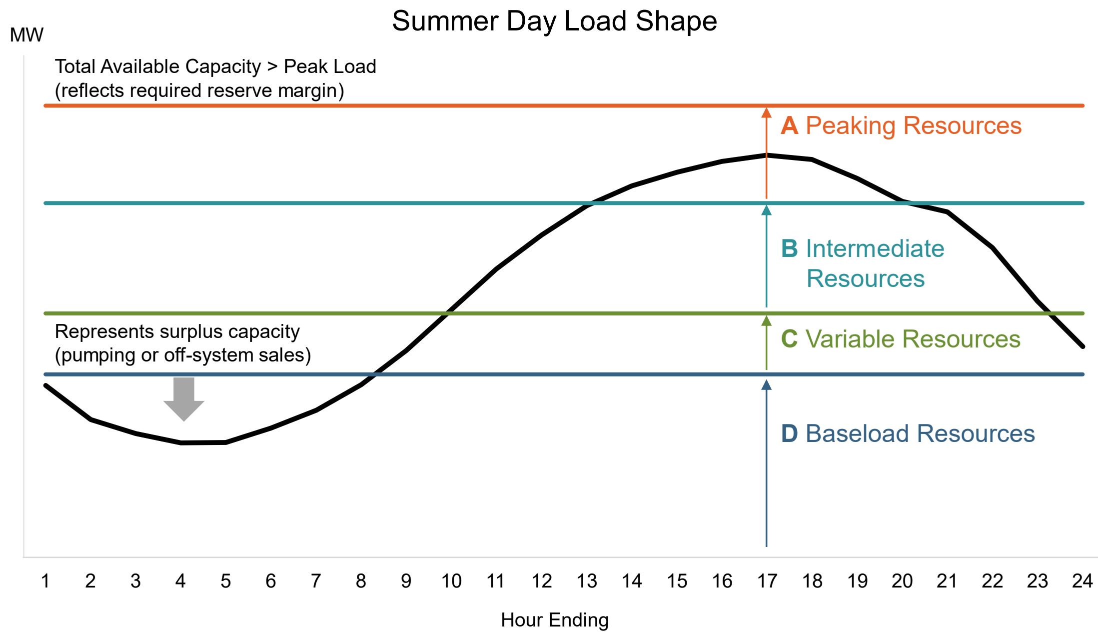


Figure A-5: Illustration of Resource Dispatch Roles

The figure below shows the actual dispatch of the TVA power system on a typical, hot summer day, categorized by resource type.

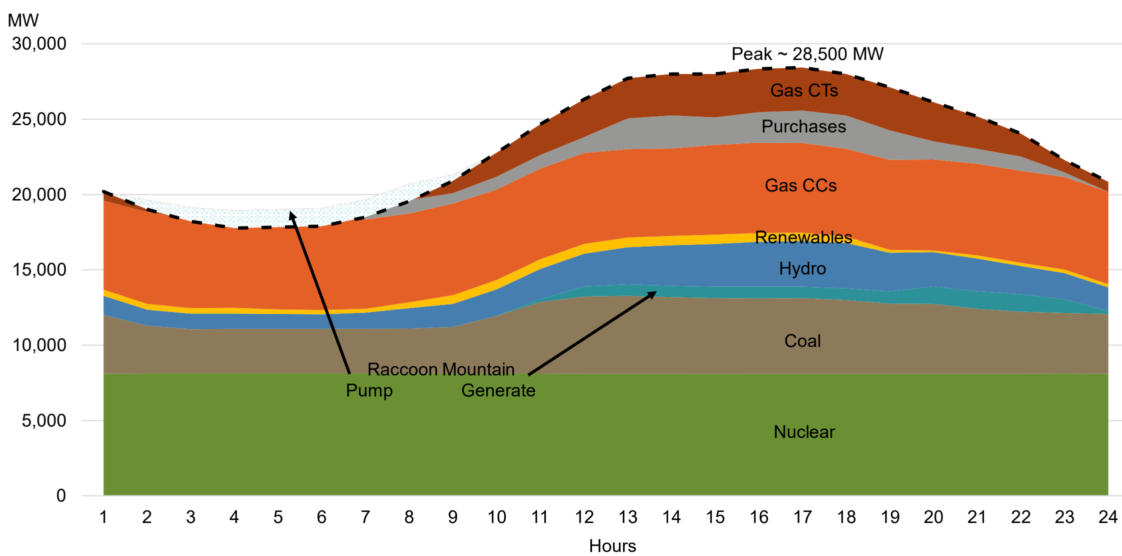


Figure A-6: TVA Power System Dispatch for Typical Hot Summer Day

Resource Characteristics

To objectively compare resource options, it is important to have consistent data regarding the cost and operating characteristics of each option. A description of the characteristics typically used to model resource options is included in the following tables. Additional information on resource costs and characteristics used in the 2025 IRP can be found in Appendix E – Utility Scale Resources Methodology, Appendix F – Distributed Generation Resources Methodology, and Appendix G – Demand-side Resources Methodology.

Table A-1: Cost Characteristics

Cost Characteristic	Description
Capital expenditures ($/kW)	Capital expenditures represent the total “overnight” costs for each project addition, including transmission costs, typically expressed in today’s dollars in relation to unit capacity.
Capital escalation rates (%)	Capital costs typically increase over time, escalating at the forecasted rate of inflation. For energy technologies that are rapidly evolving such as solar and battery storage, declining costs for these resources are typically assumed for some period of time.
Construction annual profile	This input represents the allocation of capital spending to construct a project to the years preceding the in-service date, aligned to a typical construction schedule for that resource.
Fixed operating and maintenance costs, or FOM ($/kW-year)	FOM is independent of hours of operation or energy generated, and it includes operating and maintenance labor, plant support equipment, administrative expenses, and regulatory fees. FOM is typically expressed as an annual cost per kW.
Variable operating and maintenance costs, or VOM ($/MWh)	VOM is dependent on hours of operation, and it includes consumables like raw water, chemicals and reagents, and waste and water disposal expenses. VOM is typically expressed in relationship to generation, and it does not include fuel expenses.
Fuel costs ($/MMBtu)	Fuel is the material consumed to generate electricity, such as uranium, coal, natural gas, and biomass. Fuel costs are expressed in terms of the heat content of the fuel, and they cover the fuel needed for operations, starts, and shutdowns and delivery charges.

Table A-2: Operating Characteristics

Operating Characteristic	Description
Book life (years)	Book life represents the number of years a new resource is expected to be in service for accounting purposes, and it determines the financial payback period and depreciation rate. License extensions beyond original asset life are not assumed with new generating options.
Unit availability (year)	Availability specifies the year a new unit would be available for operation, determined by technical feasibility, commercial availability, and permitting and construction times. For example, if it takes five years to build a new unit, availability would be five years from now.
Annual build limits	Annual limits model the practical ability to construct or procure new resources. Limits are based on recent experience designing, permitting, and constructing new generating assets and procuring new resources through Request for Proposal processes.
Net dependable capacity, or firm capacity (MW)	Each unit must have a summer and winter net dependable capacity, which represents the expected output of that unit under summer and winter peak load conditions.
Effective Load Carrying Capability, or ELCC (% of nameplate)	For variable energy resources like solar, wind, and storage, ELCC represents expected output at times of peak demand, expressed as a percentage of nameplate capacity. ELCC decreases as penetration of these variable resources increase on the system.
Full load heat rate (Btu/kWh)	Heat rate measures the consumption of fuel required to produce electricity at summer and winter full load conditions.
Annual outage rate (%)	Outage rate represents the percentage of time during the year where service interruptions are likely to occur for planned or unplanned maintenance.
Emissions Rates (lbs/MMBtu)	This input reflects the rate of carbon dioxide, sulfur dioxide, nitrous oxide, and mercury emissions that are released based on fuel usage.

A.7 Producing and Testing Resource Plans

The next step in the planning process is to produce and test resource plans. TVA utilizes an industry-standard model to consider a complex set of assumptions and solve for the lowest cost solution, and then plans are tested using stochastic and sensitivity analysis to evaluate uncertainty and risk.

Producing Resource Plans

TVA uses the EnCompass capacity expansion and production cost simulation package, licensed through Anchor Power Solutions, as the primary modeling tool for annual resource planning and IRP analysis. Based on the set of assumptions and constraints in an analysis, the EnCompass model seeks to determine the lowest cost resource plan. Assumptions include forecasts related to electricity demand, commodity prices, environmental regulations, and resource options, while constraints include planning reserve margin, operational limitations, and other factors. The resulting resource plan includes selected resources by year, expected energy output, and financial and operating data. The model can also be used to calculate metrics to inform business decisions. An illustration of how TVA utilizes industry-standard models in resource planning is shown below.

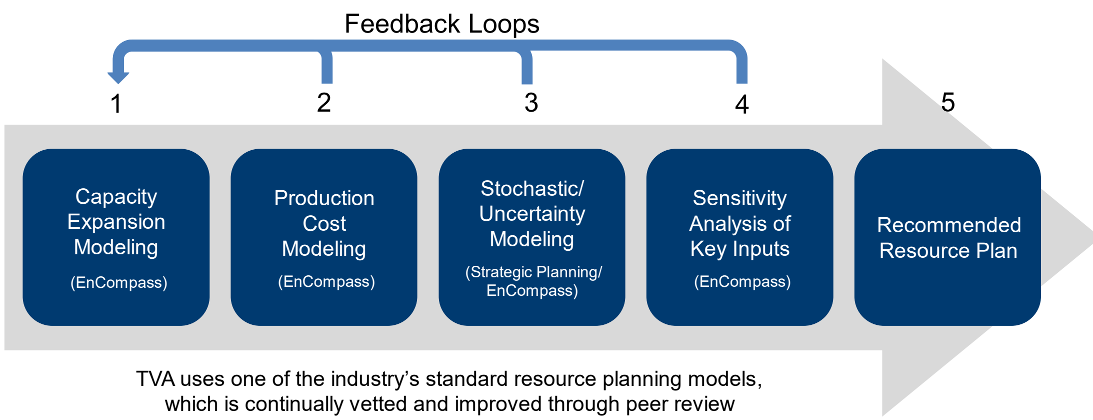


Figure A-7: Industry-standard Models Used in Resource Planning

Based on the assumptions and constraints provided, the model produces the lowest cost resource plan, and it can also help identify other resource plan options to evaluate that may be very similar in cost. Resource plans are not site-specific. They indicate the general type and timing of future resource needs at a system level, sending signals for future site-specific asset evaluations and decisions.

Testing Resource Plans

Fundamental forecasts for key variables, while useful in planning, will inevitably change over time. Variability is due to many factors such as weather, economic cycles, market conditions, supply/demand disruptions, evolving regulations, and technology improvements. Stochastic analysis and sensitivity analysis can provide insights to the impact of changes in key assumptions on resource plans.

Stochastic analysis evaluates the risk of uncertainty around multiple key assumptions and identifies the risk exposure inherent in long-term resource planning. A primary use of stochastic analysis is to quantify financial risk. The first step is to identify the key drivers of portfolio costs associated with electricity demand, fuel and market power prices, generating unit performance, and operating and capital costs. Then, a distribution around the fundamental forecasts for each of the drivers is developed using scalars based on historical variability. The stochastic model uses a Monte Carlo simulation (a form of repeated random sampling) to test the variability of key assumptions and understand the likely range of cost results, allowing for a comparison of financial risk across plans. Stochastic modeling can also be useful in evaluating non-financial risks.

The figure below illustrates a sample output from a stochastic analysis of the Present Value of Revenue Requirements (PVRR), comparing the cost results for two hypothetical portfolios. Where the two colors meet represents the expected PVRR result for each plan. The lighter colored bar to the right represents the potential risk exposure if assumptions change in an unfavorable direction overall, and the darker colored bar to the left represents the potential benefit if assumptions change in a favorable direction overall.

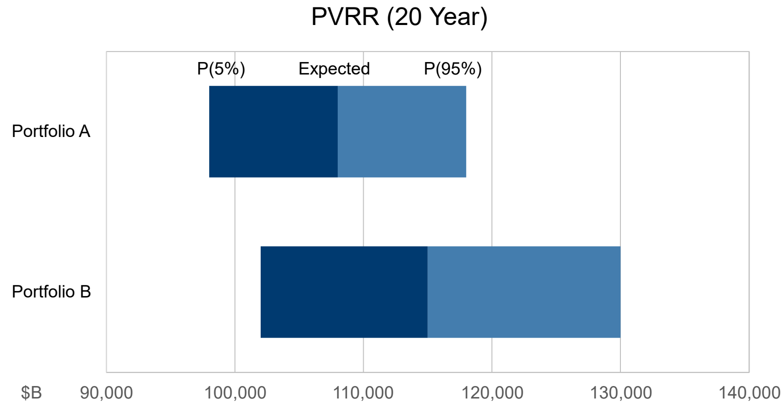


Figure A-8: Illustration of Stochastic Modeling Results

Sensitivity analysis is used in resource planning to isolate impacts of changes in a key assumption. One key assumption is varied at a time to study its impact on the outcome of the resource plan. For example, a sensitivity could be performed on higher natural gas prices to test changes in the resource plans and quantify associated cost risk.

In annual resource planning, TVA typically runs sensitivity analyses related to higher and lower natural gas prices, higher and lower electric demand loads, and potential regulatory changes. Stochastic analysis of the variability of loads and natural gas prices informs the changes modeled in those key assumptions. The figure below illustrates the typical sensitivity analysis approach for annual plan updates, with each block representing a distinct sensitivity analysis. Exploring the impacts of changes in many or certain key assumptions through stochastic and sensitivity analyses provides insights that can be used in making business decisions.

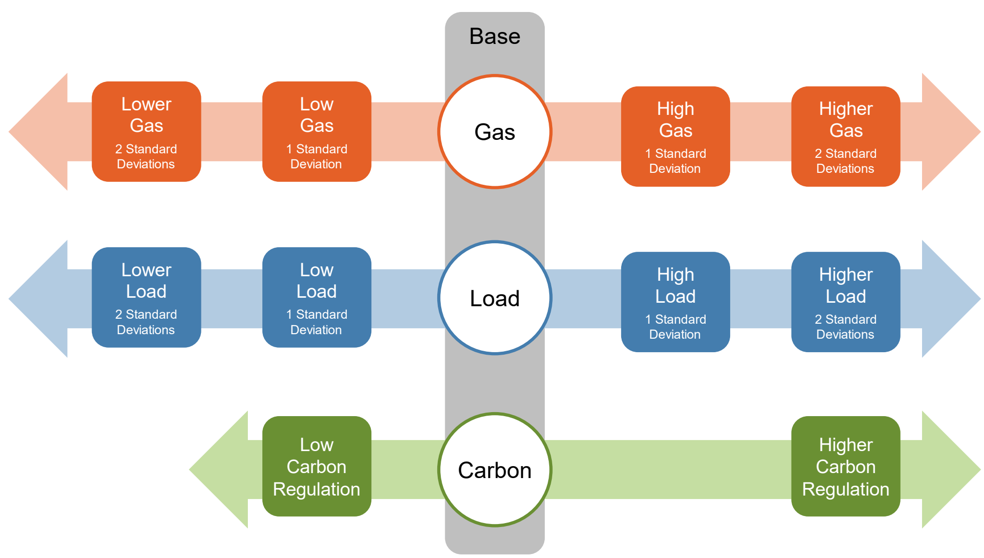


Figure A-9: Illustration of Sensitivity Analysis Approach

A.8 Analyzing Business Decisions

Resource plans are useful tools to inform business decisions such as asset needs and strategic investments in transmission and developing technologies. As illustrated below, planning is an iterative process, evolving with tactical experience and market signals. The first five to 10 years of a long-term plan are more tactical, as there is more certainty in forecasts and available resource options. Beyond 10 years is more strategic, sending signals for possible future needs as forecasts and technologies evolve. Effective planning helps drive sound, tactical decisions in the near term, while considering system needs, opportunities, and risks in the long term.

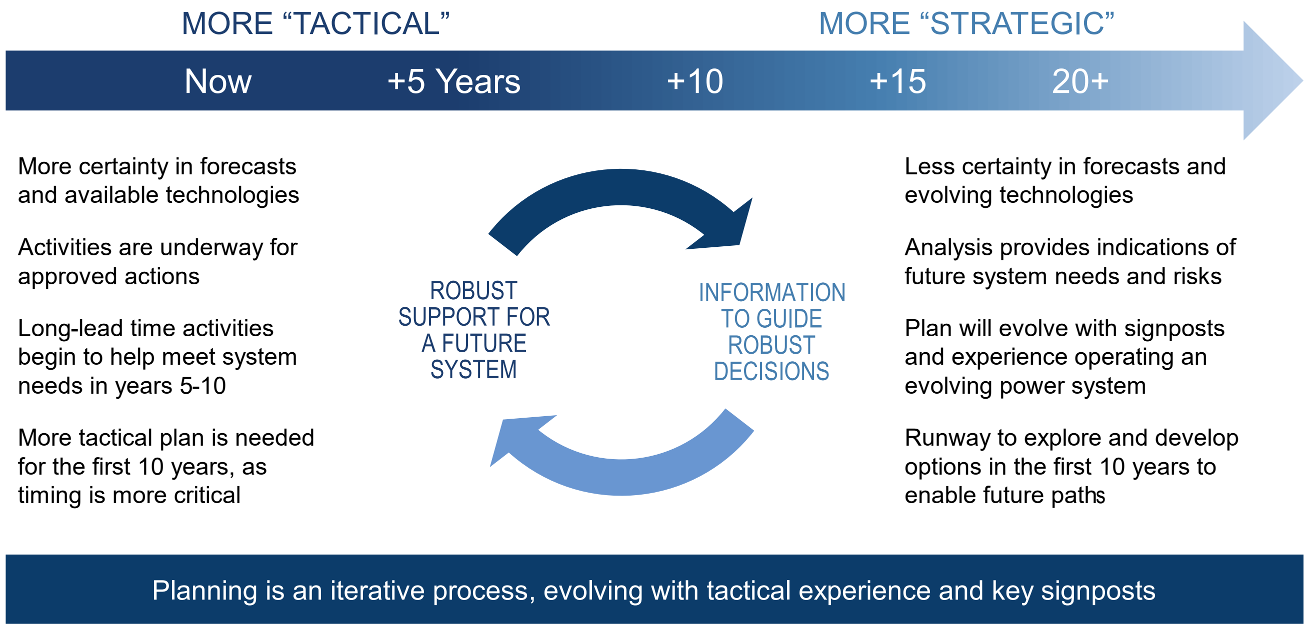


Figure A-10: Resource Planning Continuum

To test and implement strategy, TVA uses a variety of plans with different time horizons and methodologies to address uncertainty. The IRP provides guidance on long-term strategic direction for TVA. For example, the 2019 IRP signaled the need to evaluate the end-of-life of the coal fleet as well as modernize the existing gas fleet to prepare for renewable integration. TVA's long-term plans or annual planning processes are more specific and begin to signal build and retirement dates as they are identified. Business plans are used to establish and monitor near-term actions and targets. Environmental reviews are performed in accordance with NEPA to evaluate and ultimately approve asset strategy decisions. The figure below demonstrates how each plan varies in purpose and certainty.

To develop and implement resource strategy, TVA uses a variety of plans with different time horizons, purposes, methodologies, and levels of uncertainty that increase with time.

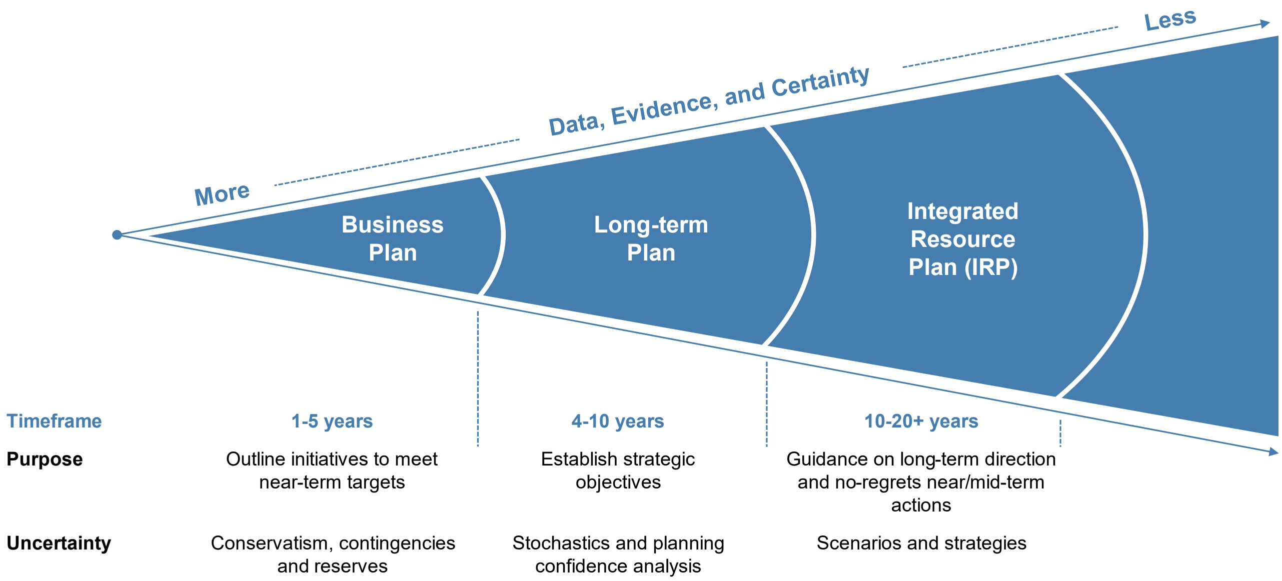


Figure A-11: Planning Horizons and Uncertainty

The IRP looks out 20-plus years and provides guidance on long-term strategic direction. The IRP establishes Board-approved guardrails for changes in the power supply mix and recommended near- to mid-term actions. Long-term plans, such as annual resource plan updates, leverage IRP direction and are used to initiate evaluations of specific asset needs, strategic investments, and associated environmental reviews. Business plans are used to outline initiatives to meet near-term targets that support strategic objectives.

A.9 Conclusion

This appendix reviewed the fundamentals of resource planning, a complex process that considers numerous inputs to generate resource plans for meeting the power supply needs of the TVA region. This discussion of planning fundamentals supplements the IRP process and methodology discussed in Chapter 3.

B

Appendix B – Scenario Design and Forecasts

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Appendix B – Scenario Design and Forecasts

TVA collaborated with the IRP Working Group to develop six scenarios for the IRP analysis. Generally defined, scenarios are the future world in which TVA may find itself operating. They are driven by factors outside of TVA's control but to which TVA must be prepared to respond. In the scenarios, key uncertainties were varied, such as electricity demand, environmental policy and regulations, commodity fuel prices, and technology advancements. TVA and the IRP Working Group collectively strove for a set of possible futures to evaluate that are relevant, informative, and diverse. This appendix covers the details of scenario design and forecasts of key variables.

B.1 Scenario Narrative Development

The first step in scenario design involves developing narratives to describe possible futures. The TVA team did some initial brainstorming, and then TVA and the Working Group refined scenario design, focusing on how the future might be shaped by changes in key uncertainties such as economic trends, electricity demand, consumer preferences, regulation, and technology. Themes emerged, leading to potential scenarios that combined key uncertainties and correlated impacts. The Working Group met several times to refine the scenarios and associated narratives to ensure that each one:

- Reflected a possible future in which TVA might be operating between now and 2050
- Was unique from the other scenarios being studied
- Provided a robust foundation for analyzing a range of resource selections
- Encompassed the relevant interests of key stakeholders

The Working Group aligned on six unique scenarios for study in the IRP analysis, with results and metrics from all scenarios reflected in a balanced manner. The six scenarios evaluated were:

1 **Reference (without Greenhouse Gas Rule)**
Represents TVA's current forecast that reflects moderate population, employment, and industrial growth, weather-normal trends, growing electric vehicle use, and increasing efficiencies

2 **Higher Growth Economy**
Reflects a technology-driven increase in U.S. productivity growth that stimulates the national and regional economies, resulting in substantially higher demand for electricity

3 **Stagnant Economy**
Reflects rising debt and inflation that stifle consumer demand and business investment, resulting in weaker than expected economic growth and essentially flat electricity demand

4 **Net-zero Regulation**
Reflects the impact of the May 2023 draft Greenhouse Gas Rule that targets significant reductions in electric utility CO_2 emissions beginning in 2030 and potential future utility regulations striving for net-zero by 2050

5 **Net-zero Regulation Plus Growth**
Reflects the impact of the May 2023 draft Greenhouse Gas Rule and potential future utility regulations, along with substantial advancements in clean energy technologies, that spur economic growth and extensive electrification

6 **Reference (with Greenhouse Gas Rule)**
Reflects TVA's current forecast and incorporates the impact of the Greenhouse Gas Rule finalized in May 2024 that targets significant reductions in electric utility CO_2 emissions beginning in 2030

Figure B-1: Scenario Narratives

While Scenario 6 incorporates the EPA's final GHG Rule, the net-zero regulation scenarios (4 and 5) reflect the draft rule, which also included regulations that may be adopted in the future related to existing gas plants.

B.2 Varying Uncertainties in Scenario Design

Each scenario represents a fundamentally different world from the Reference without Greenhouse Gas (GHG) Rule scenario. In designing these worlds, forecasted uncertainties were altered to explore a wide range of realistically possible and differentiated futures. For all scenarios, the uncertainties represent a correlated set of variables that combine to create a cohesive forecast. The table below shows how the key uncertainties were varied in the alternative scenarios relative to the Reference without GHG Rule forecast for each uncertainty.

Table B-1: Scenario Key Uncertainties

Key Uncertainties (Relative to Ref without GHG Rule)	Growth	Stagnant	Regulation	Reg + Growth	Ref with GHG Rule
Economic Outlook (Nation and Region)	High	Very Low	Low	High	Low
Electricity Demand	High	Very Low	Low	Very High	Low
Natural Gas Prices	Very High	Very Low	Same	Low	High
Market Power Prices	Very High	Very Low	Very High	High	High
CO_2 Regulations	Same	Same	Very High	High	Moderately High
Behind-the-Meter Generation and Storage	Moderately High	Moderately High	Low	Very High	High
Electric Vehicle Adoption	High	Low	High	Very High	Low
Electrification	Same	Same	High	Very High	Same
National Energy Efficiency Adoption	Same	Low	High	Same	High

Generally, scenario design began with forecasting broad economic and demographic conditions, which in turn influenced electricity demand and commodity price forecasts. Then, forecasts of potential regulatory changes and technological advancements were developed, which also had the potential to impact electricity demand.

B.3 Economic and Demographic Forecasts

Economic trends in the TVA region are highly correlated to the macroeconomic trends in the U.S. However, the large manufacturing base in the region tends to create potential for greater downward moves during periods of economic slowdown or recession. Similarly, demographic trends reflect this same volatility, where significant shifts in economic conditions directly influence population growth, household formation, and employment levels.

The economic measures utilized in creating the scenarios include:

- U.S. and TVA Region Real Gross Domestic Product
- U.S. Productivity (output per worker hour)
- Gross Domestic Product – Implicit Price Deflator
- Consumer Price Index
- TVA Region Total Population
- TVA Region Working-age Population
- TVA Region Households
- TVA Region Employment

Highlights of key economic forecasts for the scenarios are discussed below.

Gross Domestic Product

Historically, economic growth in the Valley region has an 84% correlation with U.S. economic growth. A key measure of economic growth is Gross Domestic Product (GDP). GDP represents the total monetary value of finished goods and services produced in the nation in a given time period. Movement in factors such as energy prices, productivity, and regulations can influence GDP, and GDP is a primary driver of industrial growth in the TVA region. Each scenario reflects a unique forecast for GDP.

- **Reference (without GHG Rule)**: Reflects short-term volatility in GDP as the Federal Reserve adjusts interest rates to rein in inflation, but real growth in long-term U.S. and TVA region GDP is expected to be about 2%.
- **Higher Growth Economy** and **Stagnant Economy**: These scenarios reflect 10% and 90% confidence intervals around the Scenario 1 GDP forecast, extrapolated using a Monte Carlo simulation based on the historical variance in U.S. productivity growth over the past 30 years.
- **Net-zero Regulation**: Reflects the impacts of decarbonization policies that drive higher electricity prices, which reduces national productivity and TVA's regional cost advantages and results in a moderately lower national and regional GDP forecast relative to Scenario 1.
- **Net-zero Regulation Plus Growth**: Reflects substantial advancements in clean energy generating technologies that lower the cost of environmental compliance with modest impacts on U.S. energy prices, resulting in high productivity and GDP growth similar to the Higher Growth Economy case.
- **Reference (with GHG Rule)**: Reflects the final GHG Rule, which drives higher electricity prices that have a dampening effect on productivity and economic growth relative to Scenario 1.

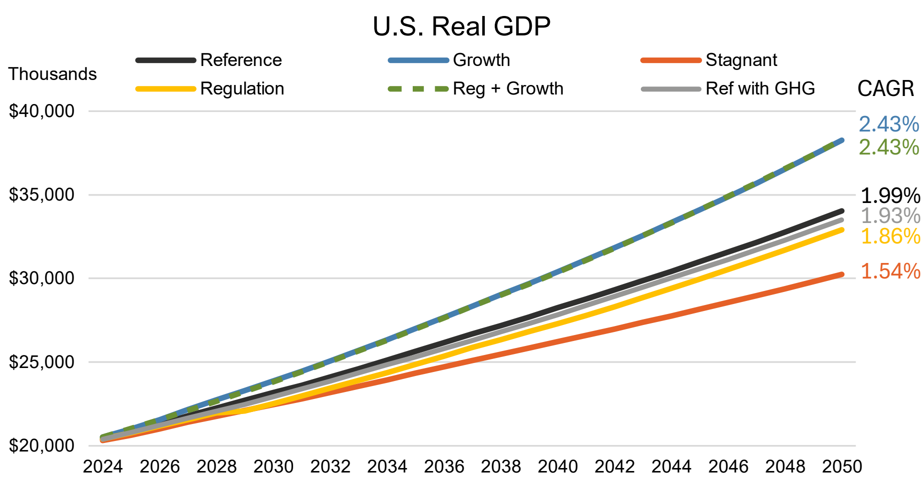

Figure B-2: U.S. GDP Forecasts ($B 2012$)

Inflation

Another key economic measure is inflation, which can be expressed in terms of the U.S. GDP – Implicit Price Deflator. Inflation represents the rate of increase in prices, or decline in the purchasing power of money, over a given period of time. Inflation impacts the outlook for all sectors, including residential, commercial, and industrial. Forecasts for inflation across the scenarios vary, as described below.

- **Reference (without GHG Rule)**: Reflects a short-term elevation in inflation and a return to the long-term Federal Reserve 2% inflation target beginning in 2025.
- **Higher Growth Economy** and **Stagnant Economy**: These scenarios reflect 10% and 90% confidence intervals around the Scenario 1 inflation forecast, extrapolated using a Monte Carlo simulation based on the historical variance over the past 30 years.
- **Net-zero Regulation**: Reflects efforts to decarbonize the electricity sector, resulting in increased energy prices and generally higher inflation forecasts.
- **Net-zero Regulation Plus Growth**: Reflects substantial advancements in clean energy generating technologies that lower the cost of environmental compliance with modest impacts on energy prices, resulting in an inflation forecast that is only slightly higher than in the Higher Growth Economy case.
- **Reference (with GHG Rule)**: Reflects the final GHG Rule, which increases electricity prices and overall inflation relative to Scenario 1.

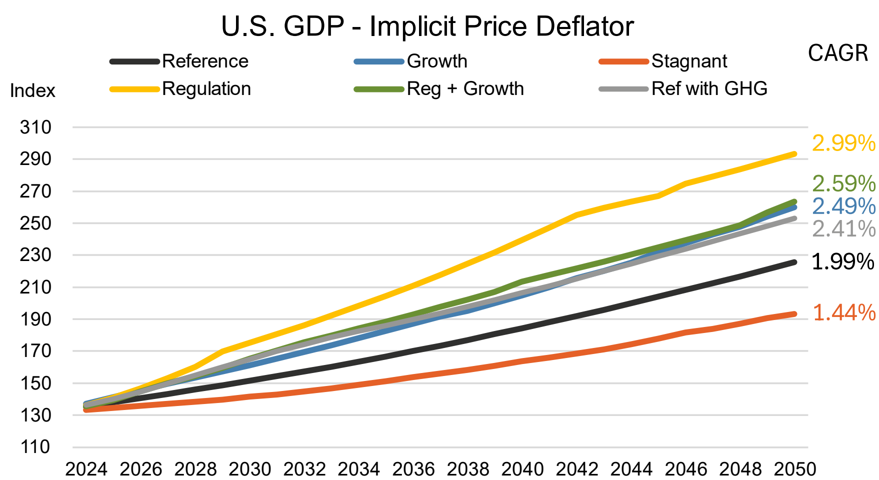

Figure B-3: U.S. GDP – Implicit Price Deflator (Index, 2012 = 100)

TVA Region Demographics

Key regional demographic measures include households and employment. Projected growth in households and employment levels are the primary drivers of local power company load growth in our forecast models. Forecasts for demographics across the scenarios vary, as described below.

- **Reference (without GHG Rule)**: Reflects continued growth in population and household formation, with a near-term boost in the working age population and a decline in household size over time; economic growth and in-migration to the region is anticipated to lift employment levels.
- **Higher Growth Economy** and **Stagnant Economy**: These scenarios reflect 10% and 90% confidence intervals around Scenario 1 forecasts for households and employment, extrapolated using a Monte Carlo simulation based on the historical variance over the past 30 years.
- **Net-zero Regulation**: Reflects lower productivity growth and higher inflation that results in slower economic growth, which in turn translates into lower growth in households and employment levels.
- **Net-zero Regulation Plus Growth**: Reflects investment in clean energy generating technologies, a lower cost of compliance, and modest impacts on energy prices that drive higher productivity growth and GDP, which result in higher household and employment forecasts than in Scenario 1.

- **Reference (with GHG Rule)**: Reflects the impact of higher inflation and lower economic growth than Scenario 1, resulting in slightly lower growth in household creation and total employment.

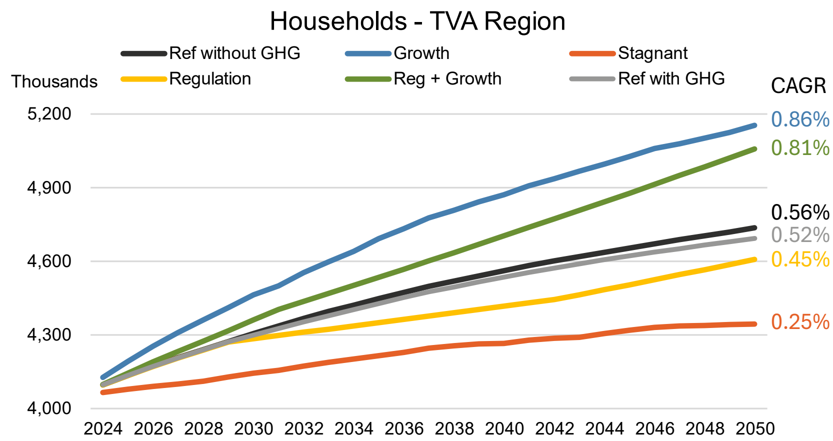

Figure B-4: Households – TVA Region

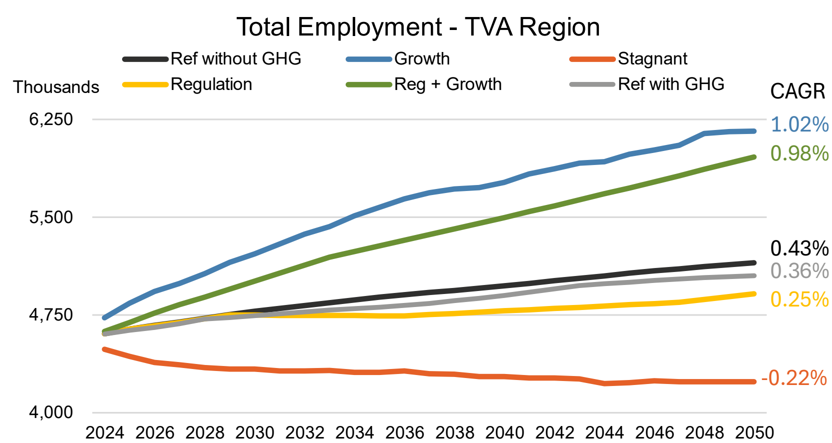

Figure B-5: Total Employment – TVA Region

B.4 Electricity Demand Forecasts

Forecasts for economic conditions and demographics in the region have a direct impact on electricity demand from TVA. The load forecast represents the region's future energy needs under normal weather conditions. In creating load forecasts, TVA uses a number of best-in-class forecasting techniques, including:

- Weather data from stations across the region
- County level economics and demographics
- Residential and commercial end-use intensities and saturations
- Appliance efficiency codes and standards
- Light and medium/heavy duty electric vehicle (EV) adoption with usage data and charging patterns
- Behind-the-meter solar adoption and technical specifications
- Discrete customer forecasts for direct served industrial customers

- Large industrial customer expansions and additions
- Hourly, regional, and customer level load data capturing behavioral patterns, levels, and trends

Trended Weather-Normal Forecasting

Weather is a key driver of electric load. Electricity demand forecasts are typically expressed in terms of normal weather conditions. Normalizing for typical weather conditions allows load forecasters to identify the relationship between trends in electricity demand and long-term drivers, including economic activity, population changes, and climate trends. TVA normalizes the load forecast for weather based on data from 23 weather stations located across the region with proportional load weights. The weather normalization process accounts for regional trends that show an increase in Cooling Degree Days (CDD) and a decrease in Heating Degree Days (HDD) over the period from 1960 to 2020. CDD and HDD represent the total number of degrees above 65°F or below 65°F, respectively, across all days for a given period, which drives space conditioning needs. This trend is incorporated in all IRP scenarios.

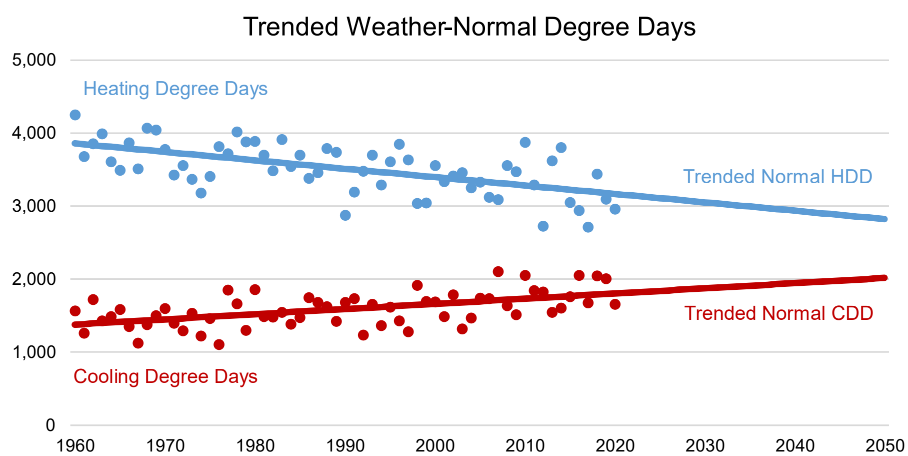

Figure B-6: Trended Weather-Normal Load Forecasting (Degree Days)

Load Forecast

Utilizing the data elements listed above combined with trended weather-normal expectations, TVA developed a load forecast for each of the modeled scenarios. These forecasts included annual expectations for energy and peak demand and hourly projections for 2024-2050. Load forecasts vary across scenarios, as described below.

- **Reference (without GHG Rule)**: After a decade of flat loads followed by post-pandemic growth, TVA expects moderate load growth of 0.8% on average per year driven by higher employment and population forecasts, industrial expansions and additions, and continued EV adoption. Increasing efficiency standards and behind-the-meter solar adoption had a moderating effect on load growth.
- **Higher Growth Economy** and **Stagnant Economy**: These scenarios represent bounding cases around Scenario 1 driven by significantly varying economic conditions. In the Higher Growth Economy scenario, load increases 1.4% on average per year, while load remains essentially flat in the Stagnant Economy scenario. Taken together with Scenario 1, these scenarios realistically depict a broad range of futures TVA could operate in without carbon regulation.
- **Net-zero Regulation**: This scenario foresees regulation of CO_2 emissions in the electricity sector, which is the primary motivation for load changes in this case. Regulations drive electrification of end uses that increases load, as well as increased electricity prices that decrease load, resulting in a long-term load outlook that is similar to Scenario 1.

- **Net-zero Regulation Plus Growth**: This scenario envisions a combination of carbon regulations and substantial investments in clean energy technologies to significantly decarbonize the economy. Technology advancements help keep electricity prices in check, driving strong economic growth and electrification of industry and transportation. These factors result in load growth of 2.3% per year, about three times higher than the Scenario 1, as well as more significant changes in daily and seasonal load shapes than the other scenarios.
- **Reference (with GHG Rule)**: This scenario reflects the final GHG Rule, which drives increased electricity prices that dampen growth in electricity demand relative to Scenario 1.

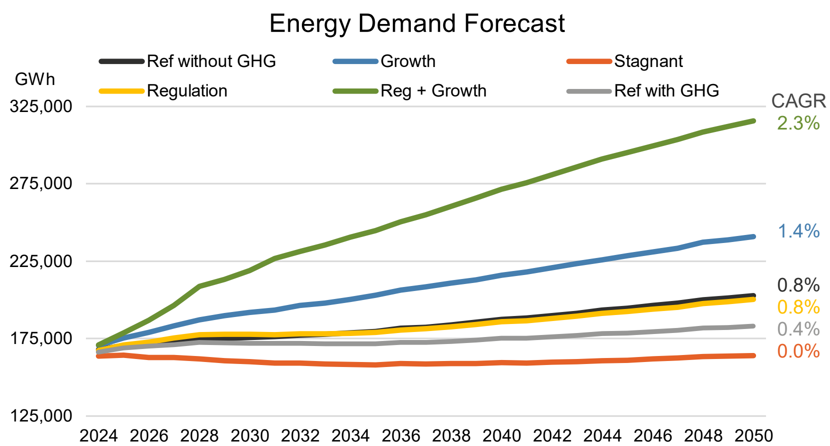

Figure B-7: Forecasted Annual Energy Demand

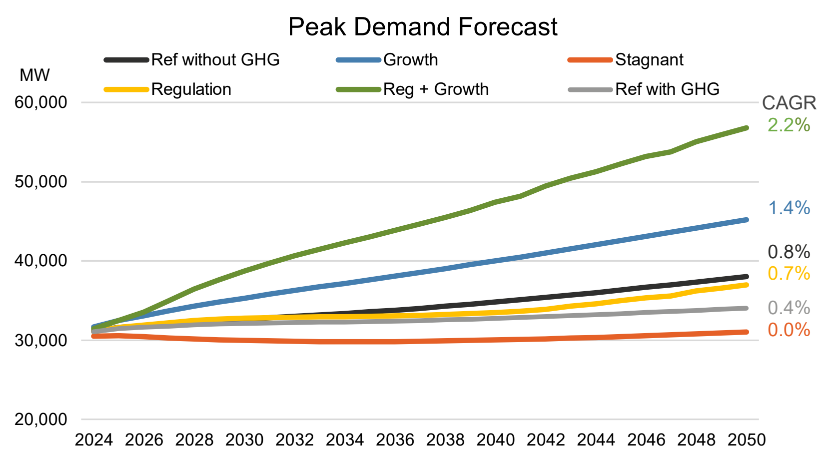

Figure B-8: Forecasted Annual Peak Demand

Key Drivers of Load Changes

Another way to look at load forecasts across the scenarios is by comparing the impacts of key drivers. Key drivers include behind-the-meter generation, electric vehicles (EV), industrial load, and residential and commercial load.

The chart below shows the forecasted changes in 2050 energy demand by key driver for the alternative scenarios relative to Scenario 1. Values below the line reflect reductions in demand relative to Scenario 1, while positive values indicate relative increases in demand. The behind-the-meter generation is primarily solar with some battery storage and combined heat and power (CHP). EV adoption varies primarily due to economic conditions and regulatory influences. Changes in industrial load are primarily driven by economic conditions and electrification and efficiency opportunities, while changes in residential and commercial loads are primarily driven by growth in the number of buildings offset by associated efficiencies.

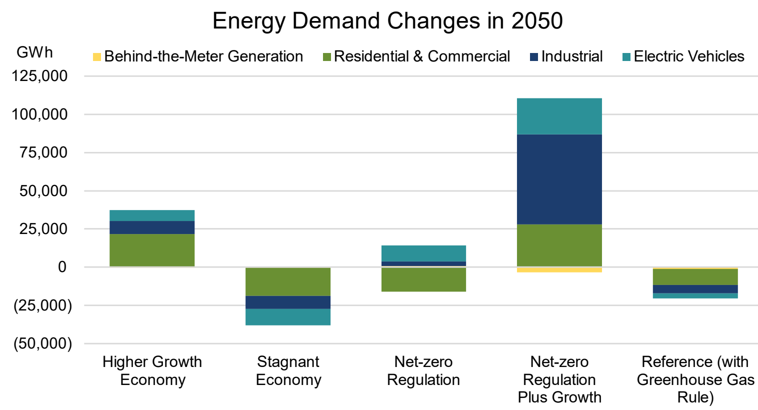

Figure B-9: Changes in Energy Demand by Key Driver in 2050 (relative to Scenario 1)

The figures below show the projections for electric vehicle energy usage and behind-the-meter generation impact for all scenarios prior to any resource promotions included in the alternative strategies.

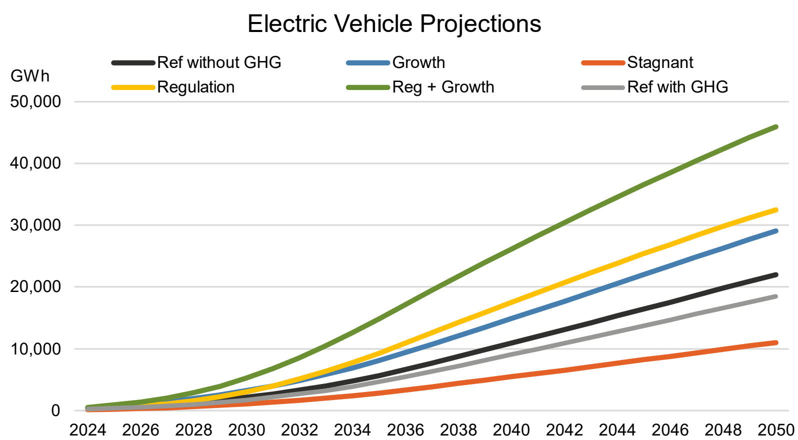

Figure B-10: Forecasted Electric Vehicle Annual Energy Usage

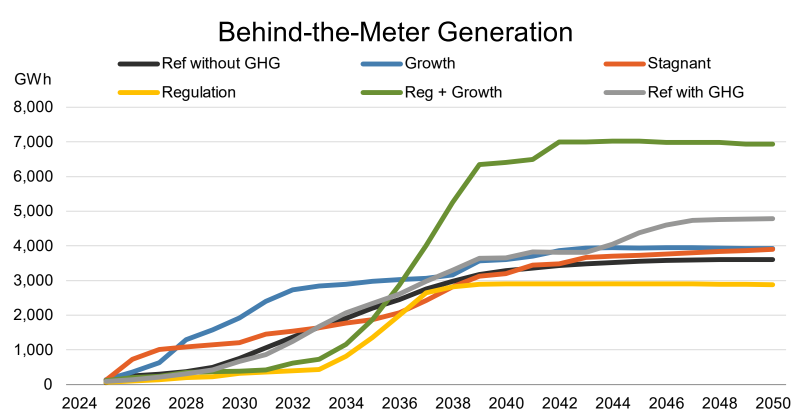

Figure B-11: Forecasted Behind-the-Meter Generation

Load Forecast Tables

The following tables provide energy and peak demand forecasts by year for all scenarios:

Table B-2: Scenario Energy Demand Forecasts (GWh)

Year	Ref without GHG	Growth	Stagnant	Regulation	Reg + Growth	Ref with GHG
2024	167,722	170,549	163,684	167,262	170,870	166,229
2025	170,583	175,443	164,276	170,806	178,777	168,892
2026	171,767	179,020	162,877	172,729	186,729	170,076
2027	173,338	183,205	162,734	175,236	196,261	171,051
2028	174,945	187,107	161,959	177,535	208,827	172,491
2029	175,049	189,674	160,500	177,809	213,100	172,048
2030	175,715	191,740	160,030	177,635	218,852	171,955
2031	176,239	193,508	159,155	177,531	226,582	171,771
2032	177,293	196,234	159,099	178,097	231,292	171,997
2033	177,748	197,981	158,549	177,956	235,309	171,566
2034	178,657	200,433	158,128	178,446	240,560	171,626
2035	179,636	202,927	157,972	178,992	244,814	171,674
2036	181,508	206,327	158,835	180,542	250,493	172,578
2037	182,381	208,432	158,407	181,348	255,020	172,643
2038	183,841	210,755	158,679	182,617	260,356	173,240
2039	185,438	212,987	158,884	184,093	265,767	174,018
2040	187,262	215,823	159,472	185,808	271,457	175,132
2041	188,135	218,137	159,215	186,515	275,757	175,268
2042	189,780	220,731	159,822	188,000	280,847	176,175
2043	191,318	223,331	160,101	189,427	285,756	177,025
2044	193,309	225,933	160,542	191,235	291,105	178,126
2045	194,588	228,422	161,010	192,380	295,161	178,521
2046	196,228	230,940	161,857	193,877	299,538	179,425
2047	197,777	233,250	162,291	195,326	303,681	180,229
2048	199,994	237,225	163,358	197,561	308,526	181,670
2049	201,159	238,831	163,546	198,700	311,928	182,101
2050	202,729	240,738	164,046	200,255	315,747	182,930
CAGR	0.8%	1.4%	0.0%	0.8%	2.3%	0.4%

Table B-3: Scenario Seasonal Peak Demand Forecasts (MW)

Year	Ref without GHG		Growth		Stagnant		Regulation		Reg + Growth		Ref with GHG	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
2024	30,447	31,176	30,961	31,703	29,851	30,523	30,453	31,105	30,868	31,453	30,390	31,093
2025	30,899	31,615	31,756	32,510	29,940	30,583	31,012	31,626	32,000	32,506	30,770	31,470
2026	31,075	31,819	32,276	33,101	29,743	30,441	31,286	31,908	33,131	33,560	30,884	31,622
2027	31,196	32,029	32,738	33,692	29,544	30,298	31,512	32,188	34,509	35,002	30,945	31,776
2028	31,306	32,271	33,203	34,285	29,370	30,173	31,737	32,498	35,873	36,438	31,005	31,963

Year	Ref without GHG		Growth		Stagnant		Regulation		Reg + Growth		Ref with GHG	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
2029	31,402	32,477	33,642	34,812	29,208	30,062	31,863	32,672	37,075	37,633	31,005	32,065
2030	31,489	32,640	34,054	35,317	29,063	29,973	31,923	32,791	38,151	38,733	30,970	32,139
2031	31,569	32,819	34,451	35,804	28,942	29,904	31,976	32,874	39,159	39,739	30,937	32,197
2032	31,662	32,993	34,833	36,267	28,838	29,854	32,013	32,913	40,084	40,634	30,899	32,233
2033	31,775	33,179	35,210	36,727	28,755	29,825	32,077	32,944	41,013	41,481	30,875	32,269
2034	31,893	33,380	35,598	37,185	28,695	29,815	32,152	32,977	41,907	42,296	30,860	32,311
2035	32,010	33,584	35,972	37,640	28,646	29,820	32,233	33,012	42,647	43,081	30,844	32,355
2036	32,153	33,802	36,353	38,104	28,616	29,842	32,350	33,072	43,674	43,868	30,861	32,417
2037	32,312	34,035	36,770	38,573	28,610	29,875	32,504	33,152	44,573	44,678	30,896	32,489
2038	32,465	34,278	37,149	39,045	28,599	29,917	32,638	33,250	45,403	45,497	30,918	32,570
2039	32,738	34,546	37,594	39,527	28,613	29,970	32,887	33,353	46,371	46,335	31,071	32,664
2040	32,989	34,843	38,098	40,017	28,638	30,031	33,217	33,514	47,418	47,153	31,193	32,764
2041	33,226	35,131	38,596	40,502	28,649	30,100	33,546	33,654	48,171	48,021	31,305	32,872
2042	33,473	35,386	39,112	41,015	28,696	30,178	33,924	33,837	49,470	48,862	31,448	32,988
2043	33,736	35,677	39,623	41,527	28,733	30,265	34,291	34,022	50,452	49,695	31,587	33,109
2044	33,953	35,997	40,032	42,047	28,742	30,359	34,574	34,222	51,262	50,528	31,691	33,233
2045	34,233	36,323	40,575	42,579	28,815	30,462	35,003	34,436	52,289	51,347	31,852	33,364
2046	34,500	36,694	41,057	43,098	28,865	30,571	35,368	34,644	53,176	52,137	31,999	33,499
2047	34,851	36,993	41,360	43,630	28,921	30,685	35,587	34,884	53,802	52,968	32,209	33,627
2048	35,117	37,333	42,102	44,165	29,014	30,805	36,203	35,113	55,090	53,688	32,404	33,774
2049	35,418	37,682	42,584	44,694	29,079	30,926	36,579	35,359	55,917	54,474	32,584	33,922
2050	35,751	38,040	43,102	45,228	29,164	31,049	37,004	35,613	56,845	55,281	32,800	34,072
CAGR	0.6%	0.8%	1.3%	1.4%	-0.1%	0.1%	0.8%	0.5%	2.4%	2.2%	0.2%	0.4%

The following table provides the elements of energy forecasts for the Reference without GHG Rule by year:

Table B-4: Reference without GHG Rule Scenario – Energy Demand Elements (GWh)

Year	Native Demand	Electric Vehicles	Market Driven EE	Line Losses	Energy Forecast	Behind-the-Meter Generation	TVA Program EE	Net Energy Demand at Generator
2024	168,897	326	(4,353)	2,852	167,722	-	-	167,722
2025	172,505	462	(5,285)	2,900	170,583	(55)	(406)	170,123
2026	174,527	650	(6,331)	2,921	171,767	(244)	(564)	170,958
2027	176,954	904	(7,466)	2,947	173,338	(300)	(1,467)	171,572
2028	179,327	1,249	(8,606)	2,975	174,945	(373)	(2,084)	172,489
2029	180,297	1,660	(9,884)	2,976	175,049	(499)	(2,677)	171,873
2030	181,715	2,135	(11,122)	2,988	175,715	(756)	(3,267)	171,692
2031	182,775	2,681	(12,213)	2,997	176,239	(1,056)	(3,853)	171,330
2032	184,113	3,295	(13,130)	3,014	177,293	(1,373)	(4,465)	171,455
2033	184,813	3,988	(14,075)	3,022	177,748	(1,655)	(5,018)	171,076

Year	Native Demand	Electric Vehicles	Market Driven EE	Line Losses	Energy Forecast	Behind-the-Meter Generation	TVA Program EE	Net Energy Demand at Generator
2034	185,755	4,776	(14,912)	3,038	178,657	(1,903)	(5,568)	171,186
2035	186,574	5,667	(15,660)	3,054	179,636	(2,206)	(6,080)	171,350
2036	188,012	6,646	(16,235)	3,086	181,508	(2,452)	(6,599)	172,457
2037	188,344	7,690	(16,754)	3,101	182,381	(2,758)	(6,985)	172,639
2038	189,042	8,753	(17,080)	3,126	183,841	(2,977)	(7,400)	173,464
2039	189,888	9,830	(17,432)	3,153	185,438	(3,171)	(7,806)	174,461
2040	191,023	10,909	(17,854)	3,184	187,262	(3,289)	(8,193)	175,779
2041	191,264	11,992	(18,319)	3,199	188,135	(3,360)	(8,474)	176,301
2042	192,157	13,075	(18,678)	3,227	189,780	(3,426)	(8,493)	177,861
2043	192,865	14,180	(18,979)	3,253	191,318	(3,485)	(8,534)	179,299
2044	193,927	15,298	(19,203)	3,287	193,309	(3,523)	(8,604)	181,182
2045	194,319	16,416	(19,454)	3,309	194,588	(3,560)	(8,666)	182,362
2046	194,989	17,538	(19,635)	3,336	196,228	(3,579)	(8,699)	183,950
2047	195,531	18,666	(19,783)	3,363	197,777	(3,597)	(8,664)	185,516
2048	196,704	19,791	(19,902)	3,400	199,994	(3,607)	(8,680)	187,707
2049	196,878	20,900	(20,039)	3,420	201,159	(3,610)	(8,669)	188,880
2050	197,388	22,002	(20,108)	3,447	202,729	(3,608)	(8,661)	190,460

B.5 Commodity Price Forecasts

Another key element in scenario design is the forecast for commodity prices. For the IRP, commodity price forecasts were developed for natural gas, hydrogen, and wholesale market power prices. These forecasts represent significant uncertainties that TVA will face, and they can vary significantly by scenario.

Natural Gas Prices

Natural gas is an important fuel source for U.S. power generation, and it is also exported to other countries. Forecasts for gas prices are driven by many factors, such as supply and demand, inflation, and export volumes.

- **Reference (without GHG Rule)**: Industrial demand and growing export volumes are the primary drivers of nominal natural gas price increases in this scenario, while prices adjusted for inflation remain relatively stable.
- **Higher Growth Economy** and **Stagnant Economy**: All things being equal, changes in economic activity will lead to increases or decreases in demand for energy of all types. These two scenarios highlight the significant price uncertainty due to changes in energy demand, representing the upper and lower bounds that TVA expects for natural gas prices.
- **Net-zero Regulation**: Reduction in natural gas demand from the power sector that tends to drive lower prices is largely offset by higher inflation in this scenario, resulting in a gas price forecast similar to the Reference without GHG Rule scenario in the long run.
- **Net-zero Regulation Plus Growth**: Natural gas prices in this scenario are lower than in Scenario 1, as the power sector sees significant reductions in natural gas demand and advances in low-carbon technologies drive down costs and keep inflation low.

- **Reference (with GHG Rule)**: The final GHG Rule drives increased retirement of national coal capacity, increased demand for natural gas, and generally higher inflation that result in higher natural gas prices than Scenario 1.

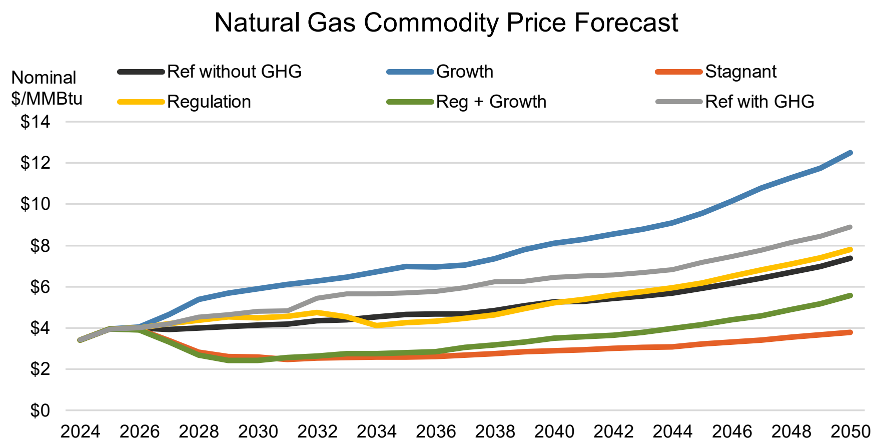

Figure B-12: Forecasted Nominal Price for Natural Gas

Hydrogen Prices

Scenarios including carbon regulation especially drive the need for an assumption on a future hydrogen market to support decarbonization of the economy. The IRP analysis assumed that a robust hydrogen market develops by the early 2030s, as described further below. Green hydrogen is an emerging fuel market with limited historical data that can be used to estimate future volatility. Additional research will be needed before including hydrogen volatility in stochastic analysis.

- **Net-zero Regulation**: The Department of Energy (DOE) has established Energy Earthshots™, including a goal for hydrogen price of $1/kg or $8.70/MMBtu. This scenario assumes that hydrogen prices fall slightly from current levels before a period of innovation in the 2030s drives dramatic price decreases until the $1/kg target is ultimately achieved in 2050.
- **Net-zero Regulation Plus Growth**: This scenario is also based on the DOE's Energy Earthshots™ hydrogen goal, but it assumes the innovation efforts needed to achieve the goal occur earlier and the $1/kg target is achieved by 2032 and remains flat for the balance of the study period.

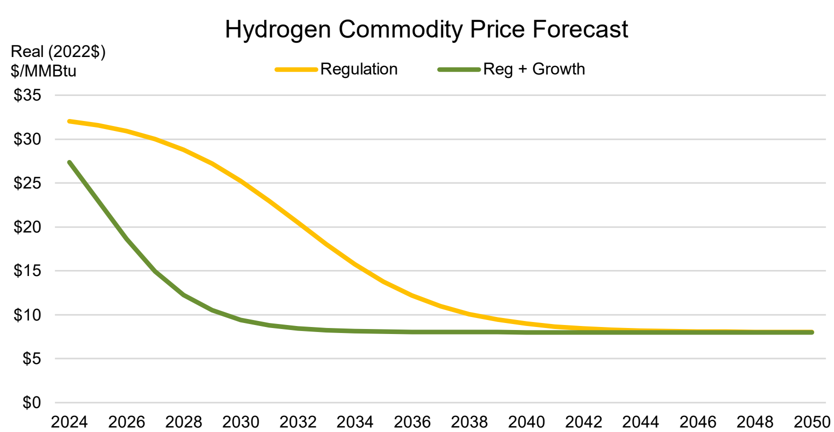

Figure B-13: Forecasted Real Price for Hydrogen

Wholesale Market Power Prices

Wholesale market power prices are an important input and a key uncertainty in scenario modeling. They represent the forecasted price TVA would pay to purchase power from neighboring utilities on the spot market. Annual trends in market power prices are largely a function of the price of natural gas, as natural gas-fired generation is frequently the marginal generator that sets the price of energy on the market. Low prices occur during periods of abundant solar production. Even in markets with currently high shares of renewable energy, such as in California, natural gas is still the key determining factor in annual average market power prices.

- **Reference (without GHG Rule)**: The trend in market power prices mirrors the trend in natural gas prices in this scenario.
- **Higher Growth Economy** and **Stagnant Economy**: Higher and lower market power prices are driven by higher and lower gas prices in these scenarios.
- **Net-zero Regulation**: Market power prices in this scenario are strongly influenced by the assumed hydrogen and natural gas prices, May 2023 draft GHG Rule, carbon tax, and higher inflation. They spike in the early 2030s due to implementation of proposed GHG performance standards for fossil-based electric generating units in 2032 and an assumed carbon tax beginning in 2034.
- **Net-zero Regulation Plus Growth**: Market power prices in this scenario are also driven by hydrogen and natural gas prices, the May 2023 draft GHG Rule, and a carbon tax. With lower hydrogen prices, a lower carbon tax, and a lower inflation rate, prices are lower than the Net-zero Regulation scenario.
- **Reference (with GHG Rule)**: Market power prices increase compared to Scenario 1 due to a combination of higher natural gas prices, national retirement of all coal units, and higher heat rates for low-capacity factor gas units.

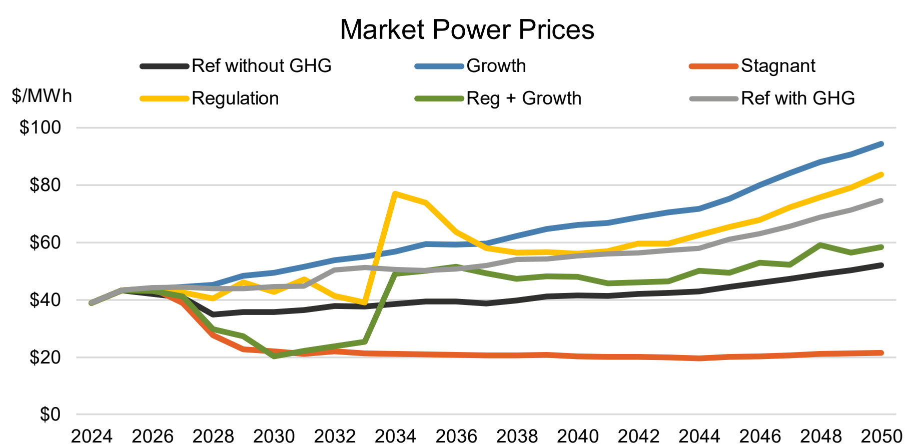

Figure B-14: Forecasted Market Power Prices, Annual Average All Hours

Coal Prices

Forecasted prices for coal varied across the IRP scenarios, primarily driven by projects for load growth combined with GHG emissions regulations.

- **Reference (without GHG Rule)**: This reference case forecast for both ILB and PRB coal prices is relatively stable throughout the forecast period.
- **Higher Growth Economy** and **Stagnant Economy**: The relatively higher and lower loads in these drive corresponding changes in the forecasted price for coal.

- **Net-zero Regulation** and **Net-zero Regulation Plus Growth**: Stricter national regulations on CO_2 emissions drive coal prices lower as demand for coal falls in these scenarios.
- **Reference (with GHG Rule)**: Higher inflation forecasts result in increased coal prices relative to Scenario 1.

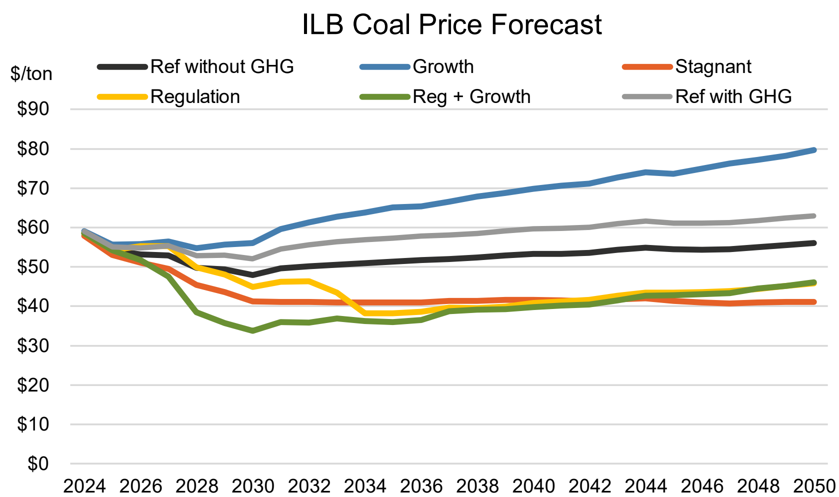

Figure B-15: Forecasted Illinois Basin (ILB) Coal Prices

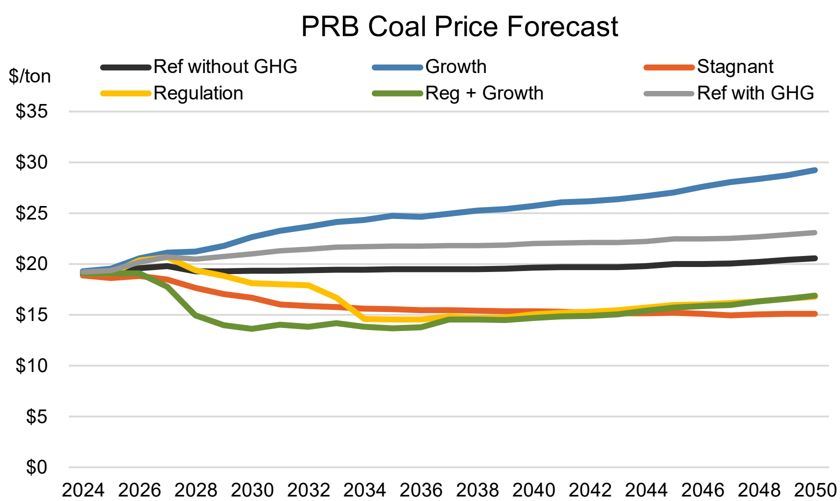

Figure B-16: Forecasted Powder River Basin (PRB) Coal Prices

Nuclear Fuel Prices

TVA's nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Nuclear fuel prices used across the IRP scenarios are based on TVA's existing supply contracts and may differ from current supply market conditions. As these contracts are commercially sensitive, nuclear fuel price assumptions are not included in this appendix.

B.6 Regulatory Forecasts

The changing regulatory landscape represents another key uncertainty in scenario design.

Inflation Reduction Act and Infrastructure Investment and Jobs Act

All IRP scenarios reflect the impacts of the IRA and IIJA on resource costs and national and regional energy prices. TVA generally assumed a 40% ITC for nuclear, renewable, and storage resources through the full study window. The IRA allows up to a 50% ITC if wage and apprenticeship standards, domestic content guidelines, and siting criteria (in an energy or low-income community) are met. To account for potential cost increases to meet requirements, siting challenges, and other risk factors, the IRP analysis applies a 40% ITC. In the Net-zero Regulation scenario, the national model projects that U.S. power sector emissions would drop below 25% of 2022 levels by 2034. In that scenario, ITC phase-out is triggered for projects initiating construction after 2034, with the final year of ITC availability based on the typical length of construction for each resource type. The Net-zero Regulation Plus Growth scenario assumes the maximum amount of ITC (50%) for all eligible resources through the full study window.

EPA Greenhouse Gas Rule

The Net-zero Regulation and Net-zero Regulation Plus Growth scenarios study the impact of the rule the EPA proposed in May 2023 under the Clean Air Act that seeks to reduce greenhouse gases (GHG) by establishing CO_2 emissions limits for fossil-fuel fired power plants. The draft rule included carbon capture and hydrogen cofiring as options for Best System of Emission Reduction (BSER). It also included regulations on existing gas plants that may be adopted in the future. The table below reflects selected highlights of the draft EPA Greenhouse Gas Rule that were modeled in these two net-zero regulation scenarios.

Table B-5: Selected Highlights of the May 2023 Draft EPA Greenhouse Gas Rule

Draft EPA GHG Performance Standards for Fossil-based Electric Generating Units					
	Through 12/31/2029	1/1/2030 – 12/31/2031	1/1/2032 – 12/31/2034	1/1/2035 – 12/31/2039	2040 and beyond
Existing Coal Units					
Retire by 12/31/2031	No applicable standard	Routine operations / no emissions increases	Unit retired		
Retire 2032-2034	No applicable standard	20% annual capacity factor restriction		Unit retired	
Existing Gas Combined Cycle Units – applies to units > 300 MW with capacity factor (CF) of 50%+					
CCS* option	1,000 lb. CO_2/MWh or current permit standard			CCS at 90% capture rate	
Hydrogen (H_2 option)			30% H_2 blending by volume (until 1/1/2038)		96% H_2 blending by volume (after 1/1/2038)
New Gas Units					
Base Load CC > 45-55% CF CCS Option	Highly efficient generation and operating/maintenance 770 lb. CO_2/MWh for > 2,000 MMBtu/h units 770-900 lb. CO_2/MWh for < 2,000 MMBtu/h units			CCS at 90% capture rate 90 lb. CO_2/MWh	
Base Load CC > 45-55% CF H_2 option			30% H_2 blending by volume 680 lb. CO_2/MWh (until 1/1/2038)		96% H_2 blending by volume 90 lb. CO_2/MWh (after 1/1/2038)
Intermediate CC < 45-55% CF CT < 33-40% CF	Efficient operations 1,150 lb. CO_2/MWh		30% H_2 blending by volume 1,000 lb. CO_2/MWh		
Low Utilization CT	Use of clean fuels (natural gas, number 1 & 2 fuel oil); 20% annual CF restriction; 120-160 lb. CO_2/MMBtu				

* Carbon capture and sequestration

In May 2024, the EPA published a final version of the Greenhouse Gas Rule that addresses existing coal and new gas units and includes a few revisions to the proposed standards. The following table summarizes selected highlights from the final rule, which considered carbon capture as the BSER but also allows for compliance by hydrogen cofiring. TVA developed an additional IRP scenario, Reference (with Greenhouse Gas Rule), based on the parameters of the final rule.

Table B-6: Selected Highlights of the May 2024 Final EPA Greenhouse Gas Rule

EPA GHG Performance Standards for Fossil-based Electric Generating Units				
	Through 12/31/2029	1/12030 – 12/31/2031	1/1/2032 – 12/31/2038	2039 and beyond
Existing Coal Units				
Retire by 12/31/2031	Exempt from rule		Unit retired	
Retire by 1/1/2039	No applicable standard	Co-firing 40% natural gas to achieve 16% CO_2 reduction by January 1, 2030		Unit retired
Operating Beyond 1/1/2039	No applicable standard		CCS* with 90% capture of CO_2 by January 1, 2032	
New Gas Units				
Base Load Units >40% capacity factor (CF)	Highly efficient generation and operating/maintenance 800 lb. CO_2/MWh for > 2,000 MMBtu/h units (natural gas) 800-900 lb. CO_2/MWh for < 2,000 MMBtu/h units (natural gas)		Highly efficient generation and 90% CCS* with a standard emissions rate of 100 lb. CO_2/MWh-gross (natural gas)	
Intermediate Load Units 20-40% CF	Highly efficient combustion turbine technology and operating/maintenance; emissions rate of 1,170 lb. CO_2/MWh-gross (natural gas)			
Low Load Units <20% CF	Use of lower emitting fuels such as natural gas, ultra-low sulfur diesel, or hydrogen to achieve rates <160 lb. CO_2/MMBtu			

* Carbon capture and sequestration

CO_2 Emissions Tax

In addition to reflecting the EPA's May 2023 proposed GHG Rule, the two net-zero regulation scenarios also assume future regulatory actions are necessary to drive CO_2 emissions to net-zero by 2050. As a proxy for potential future regulations, these scenarios include an escalating tax on CO_2 emissions beginning in 2034. TVA relied on two different forecasts of the social cost of carbon as the basis for these potential future taxes. The Net-zero Regulation scenario uses the higher 2023 EPA social cost of carbon at a 2.5% discount rate as the basis for its carbon tax. The Net-zero Regulation Plus Growth scenario uses a lower tax based on the 2021 White House interim social cost of carbon at a 3% discount rate, as that scenario includes advancements in new clean energy technology costs.

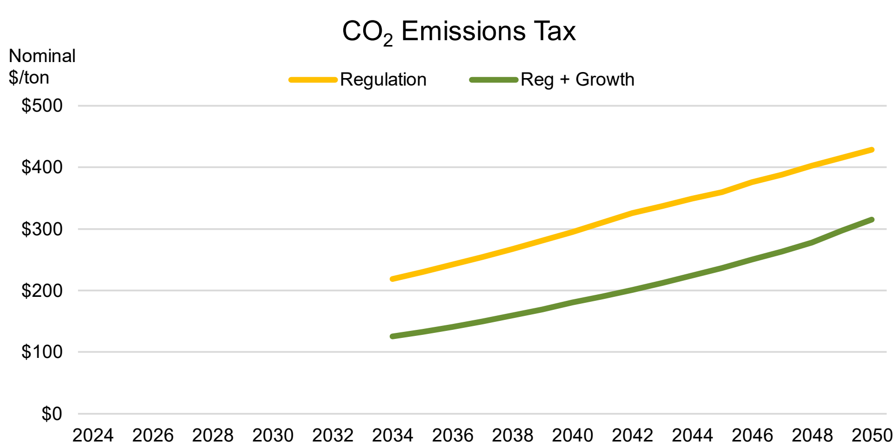

Figure B-17: Forecasted CO_2 Emissions Tax (Nominal $/Ton)

B.7 Technological Advancements Forecasts

Scenario development generally assumes the same resource technology cost baseline for all scenarios. The only exception in this IRP was the Net-zero Regulation Plus Growth scenario. This scenario assumes future carbon regulations combined with strong economic growth and broad electrification driving load growth and must consider market power prices that impact usage. Market power prices represent the average cost of electricity in the U.S. A primary driver of change in market power prices is the cost of incremental resource additions, so substantial investment in clean energy resource technologies was identified as a necessary key driver in this scenario.

To reflect this, Scenario 5 uses the advanced rather than the moderate levels of resource technology costs published by NREL as a baseline for determining market power prices that contribute to driving the highest energy demand in this possible future. This assumption of capital costs for power generating technologies influences forecasts for economic measures like GDP and inflation, commodity prices like natural gas, as well as demand for electricity and behind the meter generation.

B.8 Conclusion

Using uncertainties to inform scenario design is part of TVA's proactive approach to preparing for the future. Developing a wide range of future worlds to study with varying levels of electricity demand, commodity prices, environmental regulations, and technology advancements pushes the boundaries of TVA's planning processes. By considering a spectrum of possibilities, TVA will be better equipped to navigate an uncertain world and ensure an affordable, reliable, resilient, and increasingly cleaner power system for the region in the future.

C

Appendix C – Strategy Design and Application

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Appendix C – Strategy Design and Application

TVA collaborated with the IRP Working Group to develop five strategies to be evaluated. Where scenarios describe the potential futures TVA may find itself operating in, strategies depict business approaches TVA could employ to meet energy demand in these future worlds. The IRP analysis compares baseline utility planning with alternative strategies that promote certain resource types to evaluate tradeoffs. This appendix covers the details of strategy design and how they were applied in the analysis.

C.1 Strategy Narrative Development

To develop IRP strategies, TVA again leveraged the IRP Working Group to brainstorm ideas and ultimately identify a set of strategies to analyze. Baseline Utility Planning represents fundamental least-cost planning, and all strategies apply a planning reserve margin to provide sufficient resources to account for variations in load and generating unit availability. The alternative strategies emphasize specific themes – from promotion of carbon-free resources with an innovation or commercial-ready focus to promotion of distributed and demand-side resources or smaller, more dispersed resources that enhance local resiliency.

TVA, in collaboration with the IRP Working Group, landed on five distinct strategies to explore in the IRP analysis, supported by the following narratives that describe the promotion of certain resource types in each strategy:

A **Baseline Utility Planning**
Represents TVA's current outlook based on least-cost planning, incorporating existing programs and a planning reserve margin target. This reserve margin target applies in all strategies

B **Carbon-free Innovation Focus**
Emphasizes and promotes emerging, firm and dispatchable carbon-free technologies through innovation, continued research and development, and strategic partnerships

C **Carbon-free Commercial Ready Focus**
Emphasizes proven carbon-free technologies like wind, solar, and storage, at both utility-scale and through customer partnerships, along with strategic transmission investment

D **Distributed and Demand-side Focus**
Emphasizes existing and potentially expanded customer partnerships and programmatic solutions to reduce reliance on central station generation and promote virtual power plants

E **Resiliency Focus**
Emphasizes smaller units and the promotion of storage, along with strategic transmission investment, to drive wider geographic resource distribution and additional resiliency across the system

Figure C-1: Strategy Narratives

Strategy A: Baseline Utility Planning

Baseline Utility Planning represents fundamental least-cost planning. No specific resource types are promoted beyond existing programs. Resources are modeled and chosen economically to meet the reserve margin constraint for reliability. Planning reserve margins are included for both summer and winter peak seasons, and they apply in all strategies. These targets are developed separately from the IRP and employ an industry best-practice 1-in-10-year loss-of-load expectation level of reliability (see Appendix D – Key Modeling Assumptions for more information on planning reserve margins).

Strategy B: Carbon-free Innovation Focus

Under the Carbon-free Innovation Focus strategy, TVA focuses on developing emerging technologies that are firm and dispatchable, meaning that they can be reliably and predictably turned on and off to meet demand.

These technologies include advanced nuclear, carbon capture and sequestration, long duration storage, and demand response. Under this strategy, TVA would increase efforts in research and development to advance and deploy these new carbon-free technologies. This could be executed through partnerships with other organizations, such as universities, research labs, and startups, to share resources and expertise.

Strategy C: Carbon-free Commercial Ready Focus

The Carbon-free Commercial Ready Focus strategy emphasizes proven carbon-free technologies like wind, solar, and storage, at both utility-scale and through customer partnerships, along with strategic transmission investment. Under this strategy, TVA would focus on promoting renewable generation technologies that are mature and commercially viable today, potentially allowing for faster deployment of carbon free resources. Partnerships like TVA's existing Green Invest program, as well as strategic transmission investments, facilitate renewable growth. Storage technologies are essential enablers for renewable deployment, improving system integration and providing firm, dispatchable capacity.

Strategy D: Distributed and Demand-side Focus

The Distributed and Demand-side Focus emphasizes existing and potentially expanded customer partnerships and programmatic solutions to reduce reliance on central station generation and promote virtual power plants. Under this strategy, TVA would incentivize customers to install distributed generation and participate in demand-side management (DSM) programs. Distributed generation includes distributed solar, storage, and combined heat and power, and DSM options include energy efficiency and demand response programs. Program design would need to ensure that the incentive structure is balanced and fair, so that it does not disrupt the grid or lead to higher costs for other non-participating customers. The aggregation of these distributed and demand-side solutions would create virtual power plants, which can reduce the need for additional utility-scale resources.

Strategy E: Resiliency Focus

The Resiliency Focus strategy emphasizes the promotion of smaller units of all resource types, making the system more resilient and able to recover more quickly from disruptions. Strategic investments in the transmission system could allow for wider geographic distribution and the promotion of storage to drive additional resiliency throughout the system. In this strategy, TVA would shift its focus from large, centralized power plants to smaller generation units that can be more widely distributed geographically, which would reduce large unit contingencies and enhance reliability. A geographically diverse fleet with a variety of fuels would increase resiliency and fuel assurance through reduced risk from localized fuel supply disruptions. TVA would promote the use of energy storage such as batteries and pumped storage. Batteries could be strategically located across areas of the grid and respond quickly to support resiliency needs.

C.2 Strategy Design and Evaluation

The IRP analysis compared Baseline Utility Planning with the alternative strategies to evaluate tradeoffs based on least-cost planning principles. At a high level, the steps in the strategy design and evaluation process were:

- Develop Baseline Utility Planning cases for all scenarios (no resources promoted)
- Identify promotion of resource types to achieve objectives in each strategy
- Run cases with resource promotions for alternative strategies in all scenarios
- Evaluate tradeoffs across all scenarios and strategies using metrics based on planning principles

All resource options were available to be selected in each strategy, including those with no promotion, allowing the model to select and optimize the resource portfolio from the full suite of available resources.

C.3 Resource Promotion

The details of strategy design involved identifying the mechanism and level for promoting resources. Resource promotion is the modeling mechanism used in strategy design. With input from the IRP Working Group, TVA developed and refined promotion mechanisms and levels for the IRP analysis.

C.3.1 Promotion Mechanisms

There are two primary mechanisms for resource promotion – economic incentives and required minimums. An economic incentive artificially reduces the cost of a specific resource to promote selection. However, economic incentives used to reduce the cost of a resource are removed when metrics are calculated to accurately capture the true portfolio cost. Defining minimum amounts of a resource can be accomplished by specifying the amount to be selected in each year or the date by which some amount must be selected. TVA uses a mix of these two mechanisms, as each has modeling advantages to drive efficient and diverse portfolio outcomes.

C.3.2 Strategy Design Matrix

The next step in the process was to develop a Strategy Design Matrix to indicate the levels of promotion for resource types for each strategy. TVA and the IRP Working Group opted for base, moderate, and high levels of promotion to help drive differentiation across the strategies.

- Base: No level of promotion beyond existing programs (e.g., IRA tax credits)
- Moderate: Represents a smaller economic incentive or required minimum
- High: Represents a larger economic incentive or required minimum

TVA and the Working Group also worked together to identify which resources received moderate or high levels or promotion across the alternative strategies. Moderate and high levels of promotion for the same resource were consistently applied across the strategies.

The Strategy Design Matrix below provided the roadmap for how resource promotions were applied in the strategies. Resource types are shown across the top, grouped by distributed and demand-side and utility scale, and the rows indicate the promotion levels by resource for each strategy. This matrix translates the strategy narratives into a plan for resource promotion modeling. The resource technologies included in the matrix are not an exhaustive list. Resource types not shown, such as frame combustion turbines for example, were available for selection in all strategies but were not promoted in any strategy.

STRATEGY		UTILITY SCALE RESOURCES						DISTRIBUTED AND DEMAND-SIDE RESOURCES				
		Solar and Wind	Battery Storage	Long-duration Storage	Aero CTs and Recip Engines	Nuclear	CCS*	Distributed Solar	Distributed Storage	Combined Heat and Power	Energy Efficiency	Demand Response
A	Baseline Utility Planning	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
B	Carbon-free Innovation Focus	Moderate	Moderate	Moderate	Base	High	High	Moderate	Moderate	Base	Moderate	Moderate
C	Carbon-free Commercial Ready Focus	High	High	High	Base	Base	Base	Moderate	Moderate	Base	Base	Moderate
D	Distributed and Demand-side Focus	Base	High	Base	High	Base	Base	High	High	High	High	High
E	Resiliency Focus	Base	High	Moderate	High	Moderate	Base	Moderate	Moderate	Moderate	Base	High

*Carbon capture and sequestration

Figure C-2: Strategy Design Matrix

C.3.3 Promotion Levels for Utility Scale Resources

The figure below outlines the detailed promotion schemes for utility scale resources. In general, moderate and high promotion schemes are tied to cost reductions. For several resource types and promotion levels, required minimum quantities are also applied. For high promotion of solar, wind, and battery storage, the annual volume potential was increased, and annual minimum volumes were required. The model was free to choose volumes above the minimum if cost-effective. For long-duration storage, minimum volumes were required by 2040 at both moderate and high promotion levels, but the model was free to optimize the timing of the minimum additions. Similarly, promotion for new nuclear and CCS included minimums by 2040 or 2050.

	STRATEGY	Solar and Wind	Battery Storage	Long-duration Storage	Aero CTs and Recip Engines	Nuclear	CCS*
A	Baseline Utility Planning	Base	Base	Base	Base	Base	Base
B	Carbon-free Innovation Focus	Moderate: 15% cost reduction	Moderate: 15% cost reduction	Moderate: 15% cost reduction; 800 MW minimum by 2040	Base	High: 60% cost reduction (NREL moderate); 2,400 MW minimum by 2050	High: 25% cost reduction CCS 1,400 MW minimum by 2040
C	Carbon-free Commercial Ready Focus	High: 25% cost reduction; 200 MW/year minimum 2029-2050; annual solar limit increased by 25%	High: 25% cost reduction; 100 MW/year minimum 2029-2050; annual battery limit increased by 25%	High: 25% cost reduction; 1,600 MW minimum by 2040	Base	Base	Base
D	Distributed and Demand-side Focus	Base	High: Same as above	Base	High: 50% cost reduction	Base	Base
E	Resiliency Focus	Base	High: Same as above	Moderate: See above	High: Same as above	Moderate: 45% cost reduction; 1,200 MW minimum by 2040	Base

* Carbon capture and sequestration

Figure C-3: Strategy Design: Utility Scale Promotion Levels

C.3.4 Promotion Levels for Distributed and Demand-side Resources

The figure below provides the detailed promotion schemes for distributed and demand-side resources. Distributed storage was modeled at a 15% attachment rate to distributed solar at a base level of promotion, with higher attachment rates applied for moderate and high levels of distributed storage promotion. Incentives for solar and combined heat and power (CHP) are tied to short-term marginal cost. Energy efficiency and demand response are divided into three tiers representing distinct price points. Moderate and high promotion required the model to select a minimum number of tiers, increasing the volume selected when not promoted.

	STRATEGY	Distributed Solar	Distributed Storage	Combined Heat and Power	Energy Efficiency	Demand Response
A	Baseline Utility Planning	Base	Base: 15% solar capacity match	Base	Base	Base
B	Carbon-free Innovation Focus	Moderate: 50% of marginal cost incentive	Moderate: 30% solar capacity match	Base	Moderate: Tier 2 or higher required	Moderate: Tier 2 or higher required
C	Carbon-free Commercial Ready Focus	Moderate: Same as above	Moderate: Same as above	Base	Base	Moderate: Same as above
D	Distributed and Demand-side Focus	High: 100% of marginal cost incentive	High: 50% solar capacity match	High: 100% of marginal cost incentive	High: Tier 3 required	High: Tier 3 required
E	Resiliency Focus	Moderate: Same as above	Moderate: Same as above	Moderate: 50% of marginal cost incentive	Base	High: Same as above

Figure C-4: Strategy Design: Distributed and Demand-side Resource Promotion Levels

C.4 Conclusion

The strategy narratives, developed in collaboration with the IRP Working Group, supplied the roadmap for designing the strategies. The strategy design matrix translated the narratives into a plan for modeling resource promotion, and a consistent incentive mechanism provided the framework for promoting resources across the strategies. Applying the five business strategies in the six scenarios allows for comparison of resource portfolios and evaluation of tradeoffs between strategies that TVA could employ to meet the region’s future energy needs.

D

Appendix D – Key Modeling Assumptions

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Appendix D – Key Modeling Assumptions

TVA utilized an industry-standard model for the IRP that applies a planning reserve margin and other key assumptions, forming the modeling framework for the analysis. Other key assumptions included Net Dependable Capacity (NDC) and integration costs for solar and wind resources, flexibility benefits for storage resources, coal end-of-life planning dates, and achievable potential for energy programs. Collectively, these assumptions provided the framework necessary to plan for a reliable system and an actionable set of programs. This appendix discusses recent studies on these topics that informed the key modeling assumptions used in the IRP analysis.

D.1 Planning Reserve Margin Study

D.1.1 Overview and Background

Planning reserve margin is the excess capacity that TVA maintains beyond forecasted peak load to provide reliable service to customers while keeping rates low. Maintaining additional capacity accounts for uncertainty in the amount of load and available generation on a future peak day.

In real time, operating reserve capacity must be large enough to cover the loss of the largest single operating unit (contingency), be able to respond to instantaneous changes in system load (regulating) and be able to replace the largest operating unit should it fail (replacement). A planning reserve margin is the amount of generation capacity above forecasted peak loads that a utility plans to have in the future, which must include the contingency, regulating, and replacement reserves, as well as be sufficient to cover unplanned unit outages, severe weather events, and other variations in load. For example, a reserve margin of 15% means that a utility plans to have dependable peak-day generation equal to 115% of its forecasted future peak load.

TVA has a dual-peaking power system, meaning that peak demand for electricity is roughly the same in winter and in summer. While forecasted peaks are similar, weather and asset performance uncertainties vary by season, so seasonal reserve margins are used to account for this. TVA's planning reserve margins have changed over time as the power system and the load it serves have evolved. Recent studies and ongoing work indicate that the primary reliability risk to TVA's system is during the winter months. This risk stems from the variability of winter weather, cold-weather asset challenges, and potential limitations to market purchases. TVA used a 15% reserve margin for both summer and winter in the 2015 IRP, a 17% summer and 25% winter reserve margin in the 2019 IRP, and an 18% summer and 25% winter reserve margin in the 2025 IRP. TVA is in the process of conducting an updated reserve margin study.

D.1.2 2020 Reserve Margin Study

TVA conducted a planning reserve margin study in 2020 with the assistance of Astrapé Consulting. Periodically, TVA conducts a study reflecting the latest data on electricity demand and the power system to establish updated planning reserve margin targets. Higher reserve margins increase the reliability of the system but come at a cost, and an effective study evaluates and balances these considerations. The 2020 study examined reserve margins for both summer and winter to account for seasonal differences in supply, demand, and uncertainty.

Study Scope and Approach

TVA partnered with Astrapé Consulting to determine the appropriate reserve margin for its power system. Astrapé Consulting used its proprietary Strategic Energy and Risk Valuation Model (SERVM) to facilitate this analysis. SERVM is a widely used industry model that employs a probabilistic view of costs and risks. Reserve margin studies typically look ahead about five years, reflecting expected changes in electricity demand and the power supply mix. The 2020 study focused on 2026. The results of TVA's reserve margin analysis were primarily driven by weather uncertainty, load forecast error, generator availability, and market import capability.

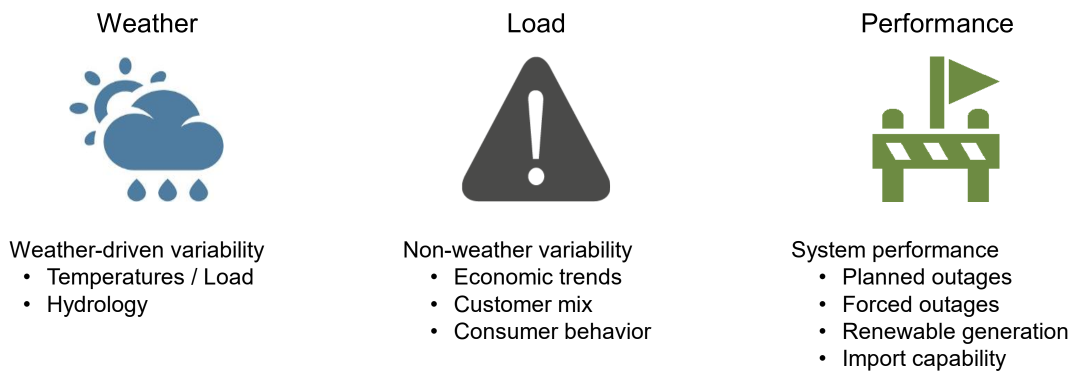

Figure D-1: Key Uncertainties in the Reserve Margin Study

The objective function of the study was to determine reserve margin targets that support an industry best practice level of reliability in both summer and winter. Industry best practice reliability is typically expressed as one loss of load event (LOLE) every ten years, or 0.1 LOLE for one year.

Summary of Inputs

SERVM is a resource adequacy and production cost model that captures the key drivers of electric load and available generation. The primary model inputs are:

- Load: 40-plus years of load shapes developed from historical weather that are adjusted for current and projected relationships between load and weather.
- Demand-side Resources: TVA's demand-side program capacities, contractual constraints, and dispatch rules; typical constraints for demand response programs include hours per day, week, month, season, year, and call duration.
- Supply-side Resources: TVA-owned and contracted generating assets, including nuclear, hydro, coal, natural gas, renewables, and storage; recent generating unit outage experience and the potential for reliability purchases during peak system conditions are also considered.
- Hydro Availability: Hydro generation is an energy constrained resource, meaning that the peak output and amount of energy it can produce is subject to hydrologic conditions and watershed management considerations; inputs include monthly capacity, energy, and minimum and maximum flows.
- Ancillary Services and Operating Reserve Requirements: These grid requirements support a continuous, reliable power supply by maintaining grid frequency, ensuring generation is available to follow load, and assuring available backup generation in the event of unplanned outages.
- Transmission: Physical import and export constraints of the transmission network between TVA and its neighboring utilities.

SERVM uses a probabilistic, Monte Carlo approach that randomly samples historical weather years and future economic conditions to create potential load scenarios, along with sampling unit outages, to predict the probability of a loss of load event. Over 40 years of weather history are combined with five potential non-weather sensitive load forecast errors to create over 200 possible load scenarios, each with an associated probability. The amount of available generation is also subject to a random outage probability. All generating resources are assigned a probability to fail as a function of temperature. These random unit outage draws are then run across all 200-plus load cases to create over 16,000 simulations of load-unit outage combinations, resulting in a probabilistic estimate of system reliability. More details of these steps are provided in the following sections.

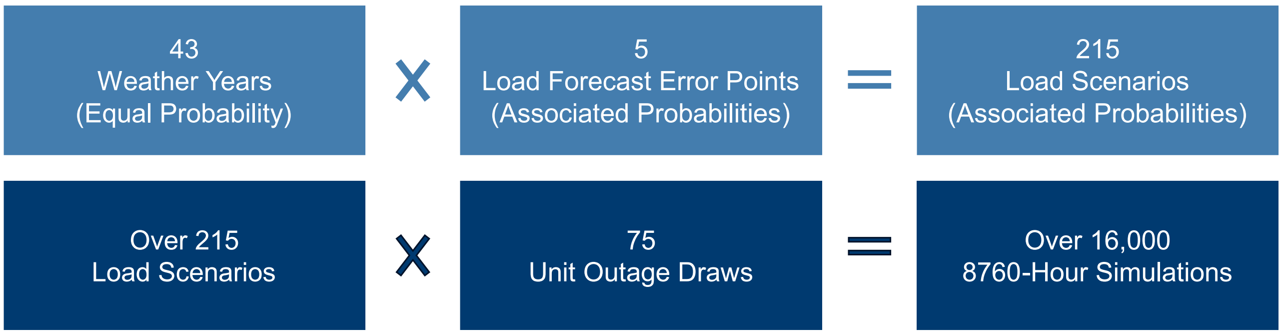

Figure D-2: SERVM Model Probabilistic Approach

Accounting for uncertainty requires a probabilistic assessment of the inputs, including the expected value of each input and to what extent it can vary from expectations based on historical experience. The table below summarizes the key uncertainties for model inputs that influence reserve margins. The uncertainties relate to variability in weather-related load drivers, non-weather-related load drivers such as changes in the economy, generating asset performance, and availability of market purchases during times of system stress.

Table D-1: Key Uncertainties in the Reserve Margin Study

Model Input	Key Uncertainty Drivers
Weather	40-plus years of hourly temperatures for five regional cities, indicating peak load variability up to -7% to +7% in summer and -13 to +18% in winter
Load Forecast Error	Peak load impact up to +/- 7% from non-weather-related load drivers
Hydro	40-plus years of historical hydro generation correlated to weather year, adjusted for the past five years of unit performance
Renewables	40-plus years of historical patterns of solar and wind correlated to weather year
Generating Unit Outages	Five recent years of North American Electric Reliability Corporation (NERC) Generator Availability Data System (GADS) forced outage information
Import Capability	Recent experience importing market purchases at times of peak demand

Weather-Related Load Uncertainty

Weather is a key driver of electric load, primarily due to heating and cooling requirements for buildings. Utilities model the relationship between outside temperature and electric load and develop a baseline peak load forecast based on an average winter or summer, otherwise known as a “weather normal” forecast.

The study evaluated weather-driven variability around peak loads, as shown in the figure below. The analysis projects seasonal peak loads as if the TVA system experienced the weather from any of the 40-plus historical weather years, calibrated to recent load response behaviors. The results have been expanded to include through 2022 and have been sorted from mildest to most extreme weather years. While summer peak loads have varied from -7% to +7% around normal weather conditions, winter peak loads have varied from -13% to +18%. Winter peak loads are influenced by the region's relatively high share of electric heat. Weather uncertainty – and consequently the required reserve margins to ensure reliability – are greater in winter.

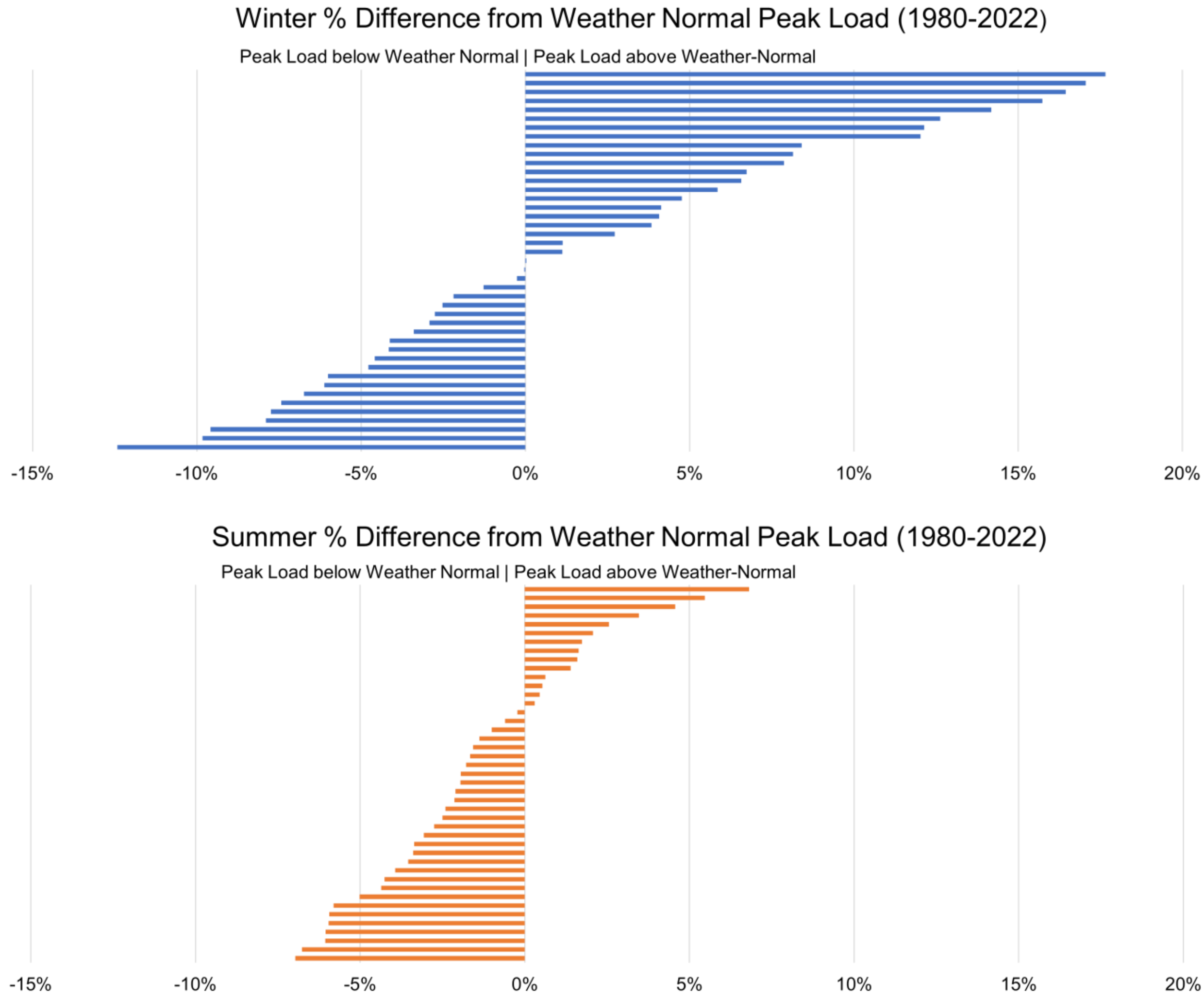

Figure D-3: Seasonal Weather-driven Peak Variability

Non-Weather-Related Load Uncertainty

While weather is a key uncertainty in estimating future peak loads, not all loads that TVA must serve are weather sensitive. A primary example of this is industrial customer load, which is not particularly weather sensitive and is more closely associated with macroeconomic conditions and other factors. The reserve margin study estimates the potential load forecast error for non-weather sensitive load using the uncertainty in economic forecasts.

The probability and magnitude of future economic load forecast error can be estimated using the Congressional Budget Office's historical forecasts for Gross Domestic Product (GDP). Five load forecast error multipliers were developed to simulate the expected probability that peak demand would differ due to changes in the forecast for economic growth. The study assumed peak demand sensitivity to changes in GDP of approximately 0.4% per 1% change in GDP, indicating a peak load uncertainty range of -7% to 7% due to economic factors.

Asset Performance

Generating asset performance varies with the seasons. All resource types except for solar have higher winter capacity. Thermal units (nuclear, coal, and gas) operate more efficiently in cooler temperatures and hydro generation is typically higher in the winter. Solar output is relatively high at the time of the summer peak that typically occurs in late afternoon, but there is often little to no solar output at the time of the winter peak that typically occurs early in the morning. More information on the contribution of renewable resources to meeting peak demand is discussed in the section on the Effective Load Carrying Capability Study.

Although thermal units generally operate more efficiently in cooler temperatures, extreme winter conditions can have detrimental impacts on generator performance. For instance, freezing temperatures can create shortages in the fuel supply or cause control equipment to fail. TVA's fuel supply is highly resilient due to a diverse generation fleet, firm gas supply and storage contracts, and fuel oil backup at combustion turbine sites. Asset performance is impacted by temperature, but there are steps utilities can take to improve performance. During 2023, TVA invested nearly $123 million and completed 3,400 winter readiness activities to harden the system and enhance reliability and resiliency at its coal, gas and hydro facilities.

The SERVM tool takes a probabilistic approach to generation outages in the reserve margin study. Potential unit failures are modeled by estimating a range of equivalent forced outage rates (EFOR) based on historical experience captured by NERC's Generating Availability Data System (GADS) and an incremental probability of failure as a function of temperature.

Market Purchases

A robust transmission network can increase reliability and lower costs for consumers. Utilities often buy and sell power from one another to help maintain electric reliability and for economic reasons. When utilities are not experiencing peak demand, they may have spare generating capacity to sell to other utilities. Weather patterns and generating unit performance will generally vary for TVA and its neighboring utilities. As a result, there may be some amount of spare capacity on the bulk power system that can be utilized to meet peak demand.

In addition to TVA's owned and contracted resources, SERVM models neighboring utilities and the transmission network. Neighboring utilities were modeled at target reserve margin levels. The study considered the available import capability for market purchases based on historical experience at peak times. The distribution of market purchases ranged from 1,000 to 4,750 MW during the summer and 0 to 4,500 MW during the winter, with the quantity drawn randomly in each simulation. The figure below shows the schematic used in SERVM to capture the regional transmission network.

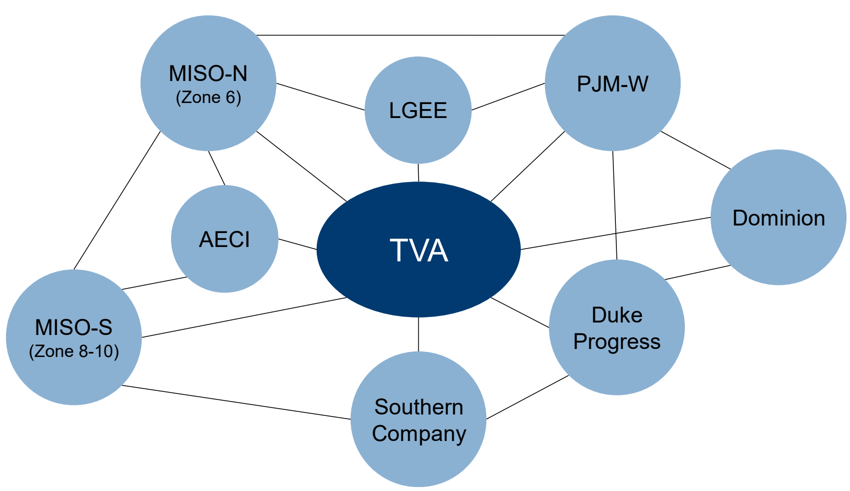

Figure D-4: Schematic of Regional Transmission Network

Study Results

As mentioned above, the goal of the reserve margin study was to estimate the amount of reserves TVA should maintain to meet the industry best practice of one loss of load event every ten years, or 0.1 LOLE per year. Applying a probabilistic approach, the study randomly sampled inputs from the key areas of uncertainty, including weather-related load, non-weather-related load, asset performance, and market purchases. This process produced over 16,000 simulations that informed the analysis.

The 2020 study results indicated that TVA should target an 18% summer reserve margin and 25% winter reserve margin to provide a seasonally balanced, industry best-practice level of reliability. Other combinations of summer and winter reserve margins would shift the seasonal risk, as shown in the figure below.

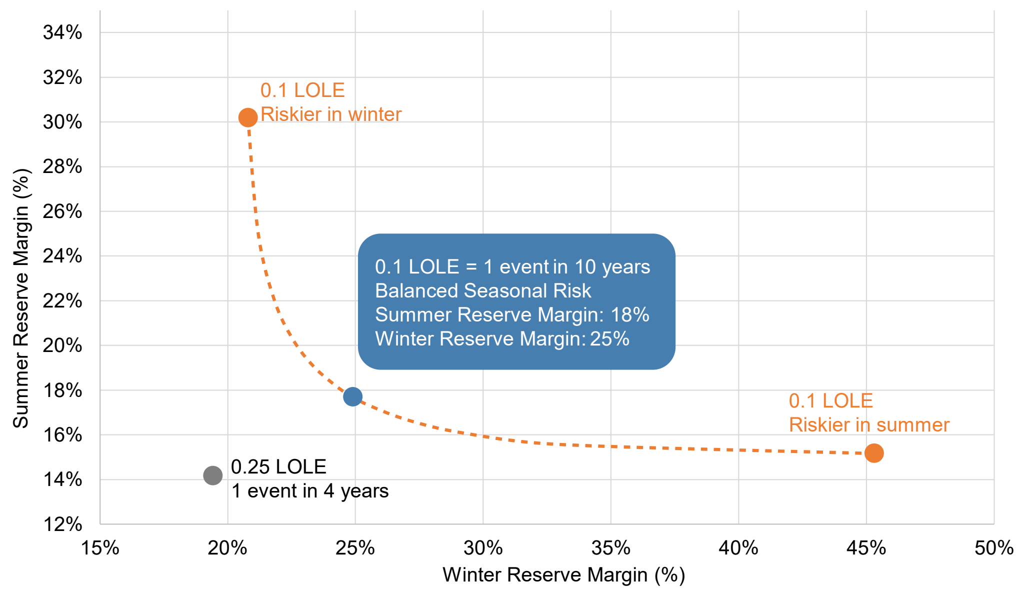

Figure D-5: Reserve Margin Combinations to Achieve LOLE (2020 Reserve Margin Study)

TVA's reserve margin targets are in line with industry peers. Notably, the target reserve margins of many other regional utilities have increased over time. Higher winter reserve margins in surrounding regions show a shift towards winter risk, which could result in less available market assistance during extreme winter conditions.

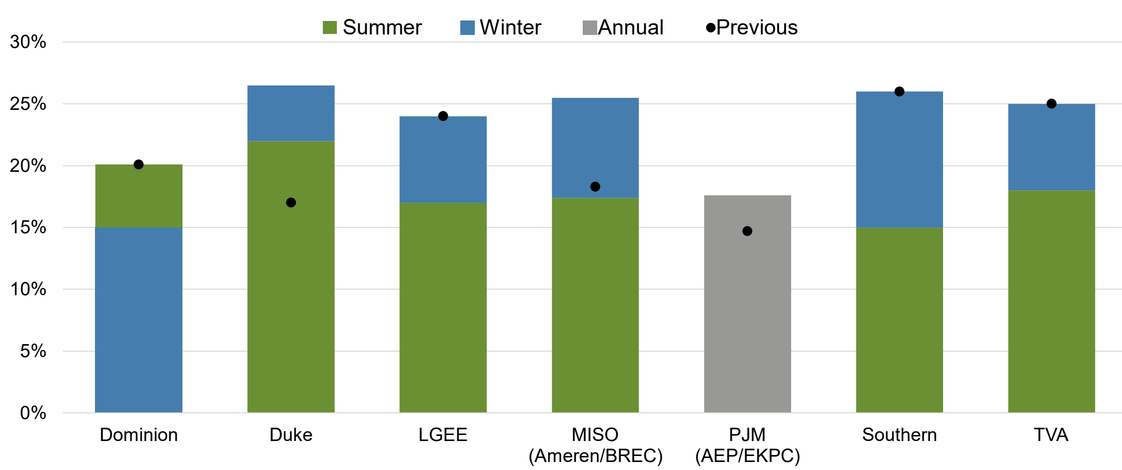

Figure D-6: Reserve Margin Benchmark Comparisons

Sensitivity Analysis

As part of the 2020 study, TVA performed a sensitivity analysis to understand how the target reserve margin varied with changes in key uncertainties. Asset performance and market import availability proved to be particularly important to the reserve margin value. The equivalent forced outage rate (EFOR) for generating assets was stressed by assuming the rate would match the worst performance in the five years leading up to the study, which drove about a 1-to-1 impact on the reserve margin. Several market import capability cases were run, exploring a modest reduction, a 50% reduction, and an island case where no market imports were available. The 50% reduction case drove a 3% increase in reserve margin, and an extreme island case more than doubled that amount. In December 2022, TVA was still able to leverage some market imports during Winter Storm Elliott.

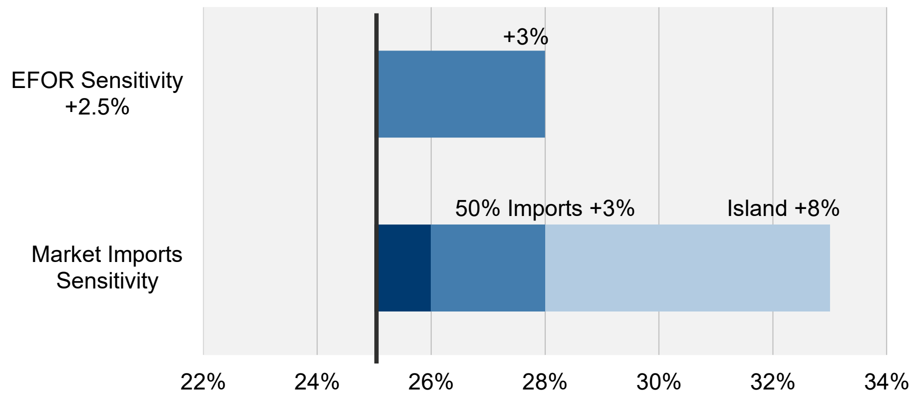

Figure D-7: Key 2020 Reserve Margin Study Sensitivities

D.1.3 Signals of Increasing Winter Risk

TVA is in the process of conducting an updated reserve margin study, which is not yet complete. While average winter temperatures are gradually warming, the region has recently experienced extreme winter events such as Winter Storm Elliott in December 2022. Widespread cold temperatures increase load and impact asset performance, not only for TVA but also for other regional utilities. While weather factors are out of TVA's control, TVA has made significant investments during 2023 to harden its generating resources and improve cold-weather performance. Given indications of increasing winter risk, TVA plans to conduct a sensitivity analysis using a higher winter reserve margin, as compared to 25% in the primary analysis. The IRP sensitivity analysis will be informed by the 2020 Reserve Margin Study, preliminary indications from the ongoing reserve margin study, and recent experience. Results of this sensitivity, along with other sensitivity analyses, will be included in the final IRP.

D.2 Net Dependable Capacity Study

Overview and Background

TVA periodically analyzes the reliability contribution of renewable and storage resources. It is important to account for solar and wind generation profiles when planning to serve peak load, especially as TVA expects to bring significantly more renewable generation online in the coming years. Solar and wind output varies hourly and seasonally, and daily load profiles vary throughout the year, so it is essential to understand the relationship between renewable generation and hourly load. Solar output is relatively high at the typical summer peak late in the afternoon but is substantially less at the typical winter peak early in the morning. Wind generation is more variable overall and is generally higher in winter than in summer. TVA also expects to add more storage capacity to complement renewables, so the ability of storage to help meet peak load is also important to quantify. Storage's ability to contribute to meeting peak load is related to hours of storage duration.

Study Approach

In 2023, TVA performed a study to determine the NDC of solar, wind, and storage resources. NDC is a measurement of a resource's ability to produce energy at times of peak demand, expressed as a percentage of nameplate capacity. The seasonal NDC of intermittent and storage resources can be determined by evaluating historical generation patterns and/or an Effective Load Carrying Capability (ELCC) study.

To determine the NDC for solar and wind, TVA utilized the historical generation method. TVA used 43 years of hourly historical generation for utility-scale solar and wind installations in the region, which was also used in the reserve margin study. For the historical summer and winter peak months, the study looked at the peak hour of the top six days to determine the expected solar and wind generation at summer and winter peak times as a percentage of nameplate, based on a 50% confidence level.

To determine the NDC for storage, TVA applied the ELCC method using Astrape's SERVM reliability model. Storage capacity is added to a reference case while dispatchable peaking capacity is removed until the loss of load expectation (LOLE) is equal to the reference case. ELCC is reported as the ratio of dispatchable peaking capacity removed to the storage capacity added to achieve the same LOLE estimated in the model. ELCC calculations are complex because a resource's effectiveness to help meet peak load also depends on the existing system and the amount of the intermittent or storage resource already present on the system.

Study Results

As mentioned above, the goal of the NDC study was to estimate the contribution of solar, wind, and storage resources to meeting peak demand as a percentage of nameplate. Highlights of study results include:

- NDC for incremental solar resources at the beginning of the study period was 68% in summer and 15% in winter, and NDC declines as the penetration of solar resources on the system increases.
- NDC for incremental wind resources at the beginning of the study period was 19% in summer and 33% in winter, and NDC declines as the penetration of wind resources on the system increases.
- NDC for incremental 4-hour battery storage begins at 100% for up to 500 MW, falls to about 80% by 1,500 MW, and decreases further as penetration increases.
- NDC for incremental 8-to-10-hour storage assumes penetration of 4-hour battery storage, begins at 67% by 6,000 MW of total storage penetration, and decreases as penetration increases.

As solar, wind, and storage penetration increases, the system peak net of renewables shifts and the ability of incremental additions to contribute to meeting peak demand decreases. Based on study results, the expected peak contributions for solar, wind, and storage as penetration of each resource increases are shown below:

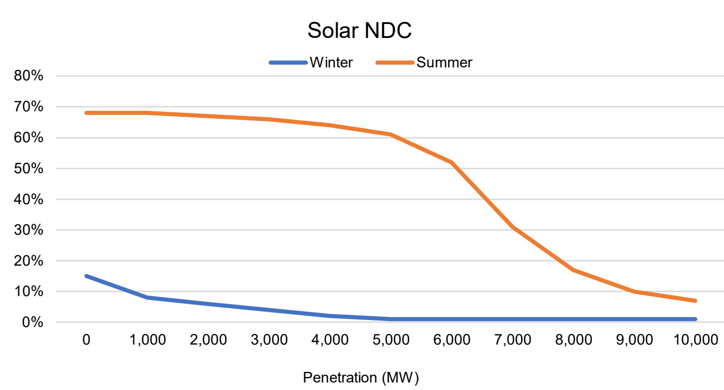

Figure D-8: Solar NDC at Increasing Penetration Levels (% of Nameplate)

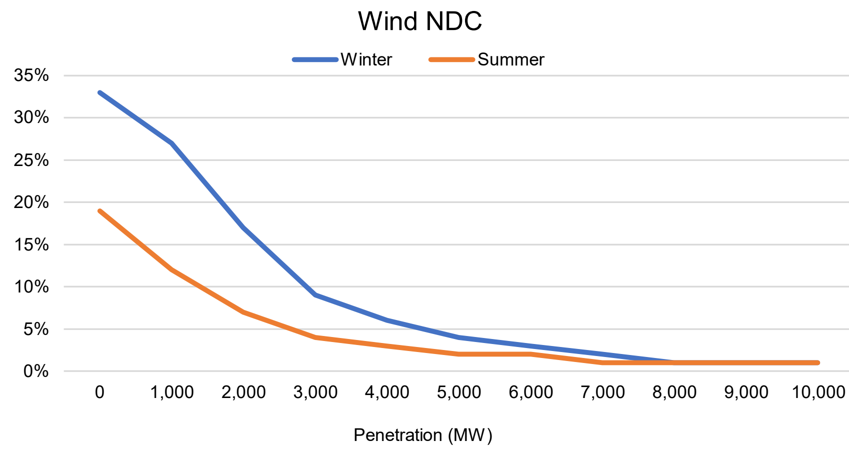

Figure D-9: Wind NDC at Increasing Penetration Levels (% of Nameplate)

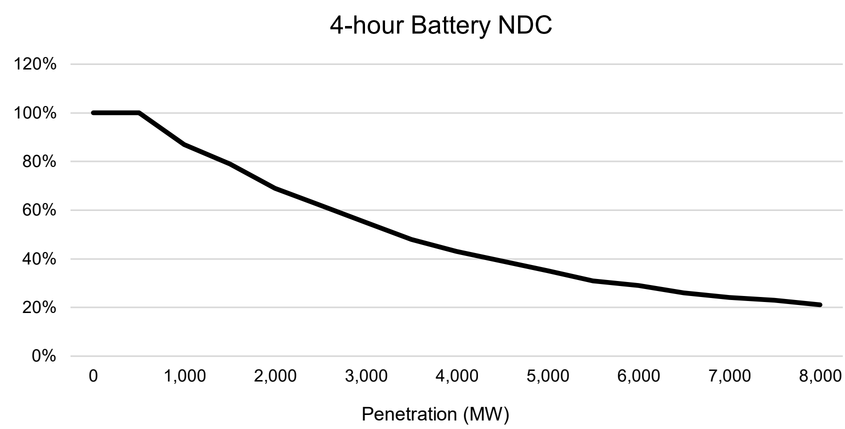

Figure D-10: 4-Hour Battery NDC at Increasing Penetration (% of Nameplate)

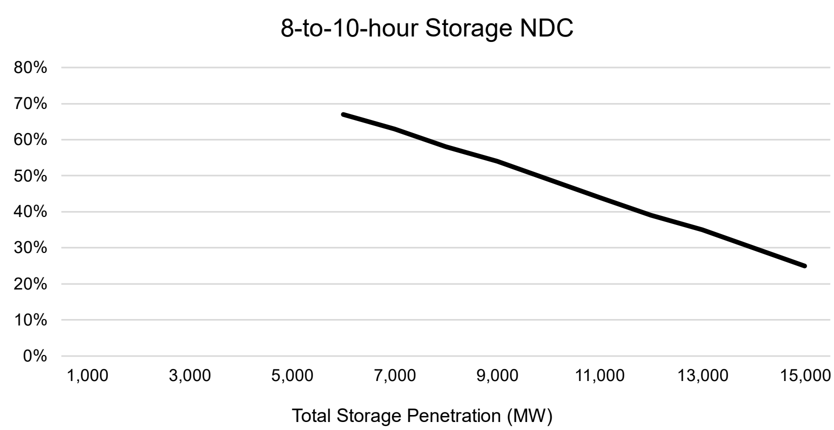

Figure D-11: 8-to-10-Hour Storage NDC at Increasing Penetration (% of Nameplate)

TVA applied these NDC study results in IRP modeling to reflect the contribution of solar, wind, and storage resources to meeting peak demand over the planning horizon.

D.3 Flexibility Cost / Benefit Study

Overview and Background

As TVA expects to see increasing renewables and storage on the system, it is important to understand the full cost and value of these resources. Solar and wind intermittency requires other resources to provide additional load following and cycling to absorb fluctuations in renewable generation. Clear days have lower solar volatility, cloudy days have higher solar volatility, and wind generation is more variable overall. Increasing renewable volumes generally have a smoothing effect due to locational diversity. Conversely, storage adds operational flexibility to absorb intermittency impacts. While the EnCompass model effectively captures the hourly impacts of renewable and storage additions, a study was needed to evaluate the sub-hourly impacts for modeling. The sub-hourly impact of renewable and storage is expressed as flexibility cost or benefit, respectively.

Study Approach

The Flexibility Cost / Benefit Study focused on 2026 and evaluated the sub-hourly impacts of intermittent and storage resource additions on operating costs and maintenance costs, explained further below. Intermittent solar and wind resource additions increase these costs, with the net change representing a flexibility cost. Storage resource additions reduce these costs, with the net change representing a flexibility benefit.

- Operating costs – costs incurred from additional load following, curtailments, and cycling of gas, hydro, and storage resources to maintain system balance with sub-hourly variations in intermittent generation.
- Maintenance costs – costs incurred for maintenance on equipment such as turbines, generators, boilers, and switchyards from the additional cycling of resources that help maintain system balance.

Impacts were studied at increasing levels of solar, wind, and storage penetration on the system:

- Incremental solar capacity at 4,000 MW, 8,000 MW, and 13,000 MW penetration levels
- Incremental wind capacity at 1,000 MW and 3,000 MW penetration levels
- Incremental storage capacity at 200 MW, 1,000 MW, and 2,000 MW penetration levels, studied with 4,000 MW, 8,000 MW, and 13.000 MW of solar penetration

For intermittent resources, historical generation data (five-minute granularity) from TVA contracted solar and wind sites and from larger non-TVA solar portfolios was used to assess the intra-hour volatility of solar and wind generation, as illustrated below.

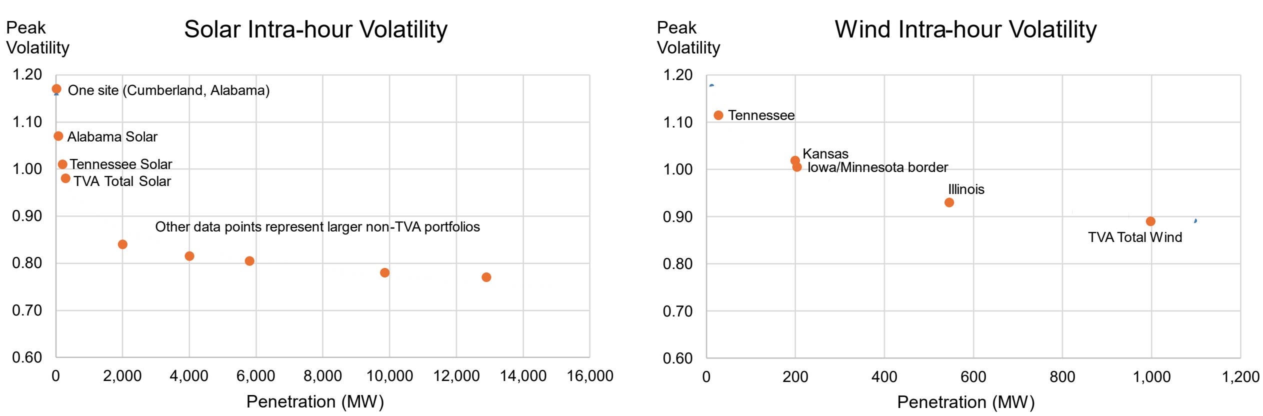

Figure D-12: Solar and Wind Generation Intra-hour Volatility

The sub-hourly flexibility impact of storage additions was evaluated in comparison to a gas frame combustion turbine (CT). Key assumptions are shown in the table below. Compared to a frame CT, storage has a broader operating range, faster ramp rate, and no start costs.

Table D-2: Key Study Parameters for Frame CT and Storage

Parameter	Gas Frame CT (4 units)	Lithium-ion Battery (4-hour)	Advanced Chemistry Battery (8-hour)	Pumped Storage (12-hour)
Maximum Capacity (MW)	884	50	50	1,600
Operating Capacity Range (%)	27% to 100%	-100% to 100%	-100% to 100%	-107% to -77% (pumping) 37% to 100% (generating)
Storage Efficiency (%)	N/A	85	85	81
Ramp Rate (MW/minute)	5	15	15	10
Start Costs ($/start – cold / hot)	14,790 / 6,322	0	0	0
Variable Operating and Maintenance ($/MWh)	0.00	0.00	0.00	2.80
Fixed Operating and Maintenance ($/kW-year)	5.50	46.61	46.61	20.64

The study calculates the impact of renewable and storage additions on operating and maintenance costs at sub-hourly and hourly levels, and the cost difference between the two levels represents the sub-hourly flexibility cost or benefit, respectively.

Study Results

As mentioned above, the goal of the study was to estimate the sub-hourly flexibility cost of intermittent solar and wind resources and the sub-hourly flexibility benefit of storage resources. Incremental impact results were derived from average impact assessments in the study.

Study results for incremental solar and wind flexibility cost at various penetration levels are summarized below. Solar flexibility cost is relatively small at $3/MWh up to 4,000 MW of solar additions, increasing to $8/MWh for 8,000 MW or more of solar additions. Wind flexibility cost is $2/MWh up to 3,000 MW of wind additions. Values hold at higher volumes, as solar and wind locational diversity smooths out intermittency impacts.

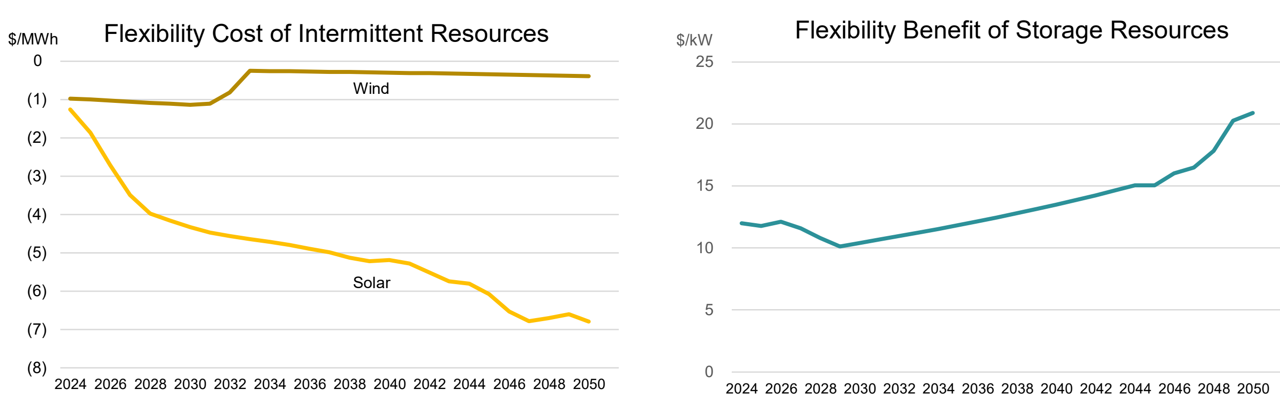

Figure D-13: Incremental Solar and Wind Flexibility Cost

Study results for incremental storage flexibility benefit at varying levels of storage and solar penetration are shown below. Initial storage additions provide the greatest flexibility benefit. Benefits increase as solar penetration grows from 4,000 MW to 8,000 MW, and then decrease as solar locational diversity expands. For up to 2,000 MW of 4-hour battery additions, the flexibility benefit averages about $12/kW-year. For up to 2,000 MW of 8-hour storage additions, the flexibility benefit averages about $6/kW-year.

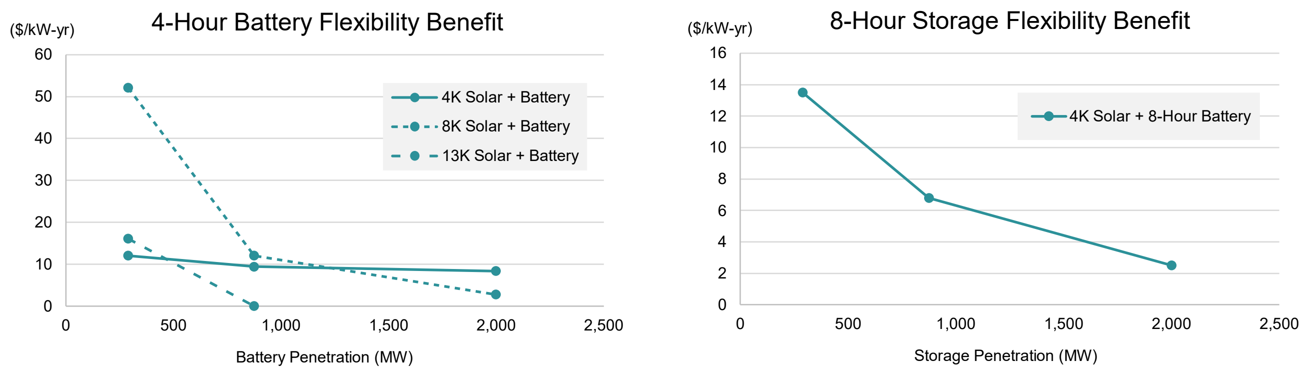

Figure D-14: Incremental Storage Flexibility Benefit

Applying Flexibility Study Results in the IRP

In EnCompass and other resource planning models, it is difficult to model assumptions like flexibility cost and benefit that dynamically change with the penetration of certain resources. Given this limitation, TVA used the study results to estimate annual values for the incremental sub-hourly flexibility cost of intermittent resources and flexibility benefit of storage based on the trajectory of these resources in Scenario 1. Solar flexibility cost increases with anticipated penetration. Wind flexibility cost remains relatively constant as existing wind contracts expire, and the potential to shape some future wind contracts would reduce intermittency impacts. Storage flexibility benefit increases with renewable penetration. The storage benefit is applied to both battery and pumped storage resources, as new pumped storage options would have variable speed pumps.

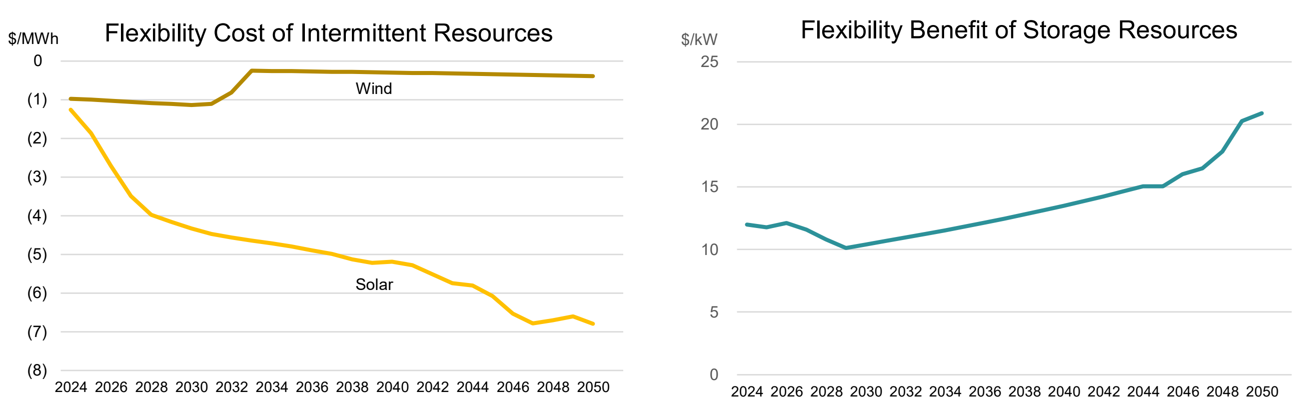

Figure D-15: Incremental Flexibility Cost/Benefit of Intermittent and Storage Resources

TVA applied these incremental sub-hourly values in IRP modeling to more fully capture the flexibility cost of intermittent resources and the flexibility benefit of storage resources over the planning horizon.

D.4 Aging Coal Fleet Evaluation

Overview and Background

The 2019 IRP recommended evaluating engineering end-of-life dates for the aging coal fleet to inform long-term planning. Key drivers for conducting the aging coal fleet evaluation included:

- Substantial performance and cost risk associated with operating a coal fleet reaching the end of its useful life;
- Increasing public, political, regulatory, and marketplace pressures to reduce coal generation and environmental impacts;
- Integration of increasing amounts of renewable and distributed resources drives the need for increased system flexibility;
- Risks associated with the long-term financial health of the coal mining industry and the ability to procure coal and/or the price of coal; and
- Developing a plan to systematically replace coal plants reaching end-of-life allows for more proactive management of financial, logistical, and workforce impacts.

TVA's coal plants are operating well beyond their original book life and are among the oldest still operating in the nation. Driven in large part by age and material condition, coal fleet performance is challenged, driving cost and system reliability pressure.

Study Scope and Approach

As recommended in the 2019 IRP, TVA initiated an evaluation of the aging coal fleet. TVA assessed coal fleet demographics, age, material condition, and cost and performance challenges. Based on these assessments, TVA evaluated three different timelines for phased coal unit retirements – by 2030, by 2035, and by 2040. Common themes across the three different timelines were:

- Cumberland and Kingston would retire sooner primarily due to Cumberland's lack of flexibility and Kingston's high cost and challenged condition;
- Gallatin and Shawnee would retire later due to relatively better condition;
- Shawnee was projected to retire by 2034 to meet anticipated air quality compliance requirements; and
- All three cases significantly reduced carbon emissions and other environmental impacts compared to the base resource plan without coal retirements.

To support the evaluation, IHS Markit conducted a 2019 study that assessed the fuel resiliency of TVA's generating fleet and concluded that TVA's overall fuel supply is among the most resilient in the nation. Key drivers for this were a well-diversified portfolio, access to hydro resources, a resilient program to secure nuclear fuel, and access to multiple major gas transportation pipelines. The study recognized that many utilities are reducing coal capacity, and that TVA is well positioned with a diverse fleet and resilient gas supply. TVA's evaluation also considered execution risks associated with retiring the coal plants over the studied time frames.

Study Results and Recommendation

The evaluation concluded that planning for coal fleet end-of-life by 2035 was aligned with least-cost planning and reduces economic, reliability, and environmental risks. Based on the 2019 IRP and end-of-life evaluations, the recommendation was made to TVA leadership and the Board to incorporate assumptions for coal plant retirements into resource planning. Each coal plant retirement and corresponding replacement generation will be further evaluated in environmental reviews under the National Environmental Policy Act (NEPA). Further information on the Aging Coal Fleet Evaluation can be found on TVA's website.

D.5 Energy Programs Potential Study

Overview and Background

The 2019 IRP recommended that TVA conduct a market potential study for energy efficiency and demand response. TVA's last potential study was completed in 2012 and is now outdated due to changes in codes and standards, as well as technology advancements since that time. In 2021, TVA initiated a new potential study leveraging third-party support and analysis conducted by DNV. Study results will be used to inform program development and system planning projects, including the IRP. A potential study offers a detailed snapshot of regional opportunities for influencing electric load through various utility programs. This snapshot is the first step in program planning, and it helps identify high-value opportunities for further exploration and development.

Study Scope and Approach

The Energy Programs Potential Study considers three resource types – energy efficiency, demand response, and electrification. The objective of the analysis was to estimate the range of possibilities for the three resource types in the TVA region for each of the primary sectors – residential, commercial, and industrial. The project team assessed the potential for each resource at multiple levels:

- Technical Potential – Includes all available technology with no cost considerations and assumes consumer willingness to adopt all measures.
- Economic Potential – Is a subset of technical potential that includes measures that are cost-effective when compared to supply-side alternatives and considers consumer costs.
- Achievable Potential – Is best described as realistic potential, or what would occur in response to specific program funding, marketing, and incentive levels. Achievable potential takes into consideration market and program barriers, impacts of evolving codes and standards, and naturally occurring market adoption that would have happened without programs.

The analysis began with the collection of model input data and the creation of a baseline market characterization, leveraging region-specific building and economic data. Measure-level analysis was conducted using accepted cost estimates and region-specific impacts. Technical and economic potential were then calculated, followed by estimations of naturally occurring and achievable potential. This approach was used for all resource types, considering costs and nuances specific to each resource type and overlapping measures between resources.

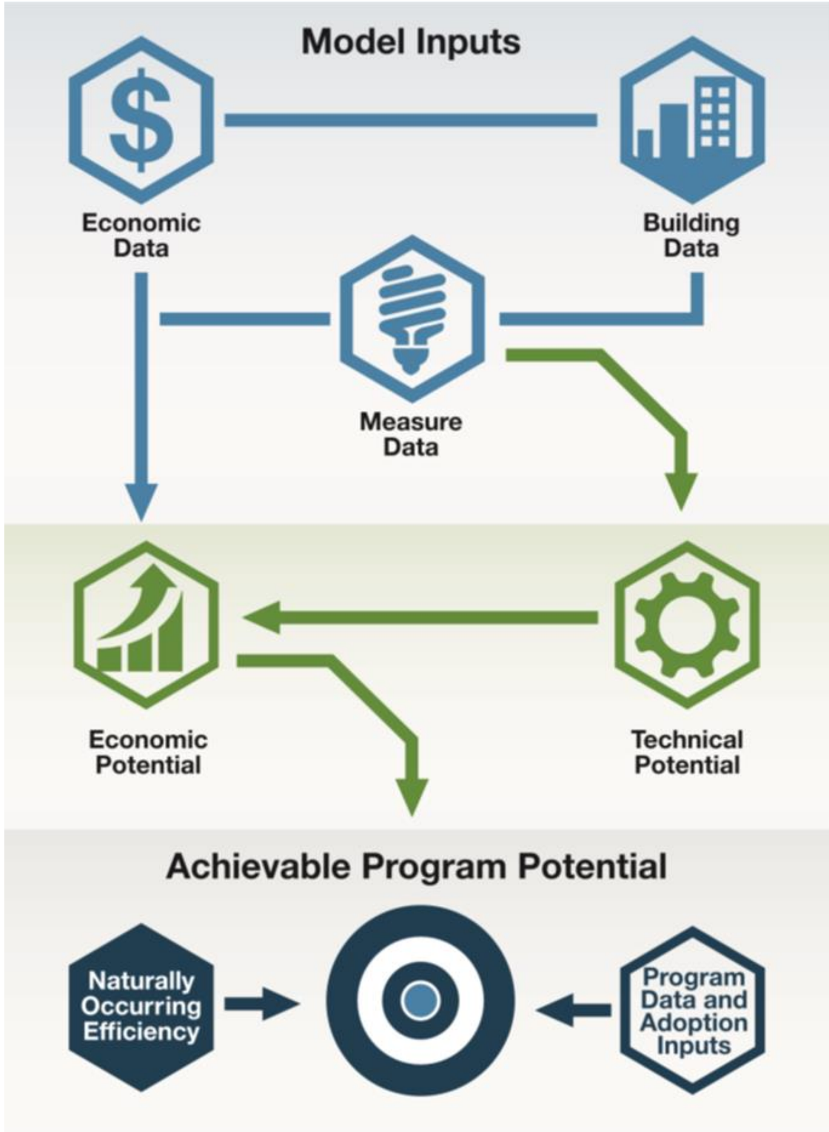

Figure D-16: Energy Program Potential Study Approach

Study Results

Study results cover achievable potential for the three resource types. As electrification is explored in the IRP scenarios, this discussion of study results will focus on energy efficiency and demand response, which are offered as resource options in the IRP analysis.

The study indicated a 10-year potential for regional energy efficiency gains ranging from 2-7% of base sales and 2-9% and 4-16% of summer and winter peak demand, respectively. The residential sector accounts for most of the potential, particularly homes utilizing electric heating. Potential in the less weather-sensitive commercial and industrial sectors is driven by linear fluorescent and high-intensity discharge lighting applications.

Highlights from the energy efficiency portion of the study were:

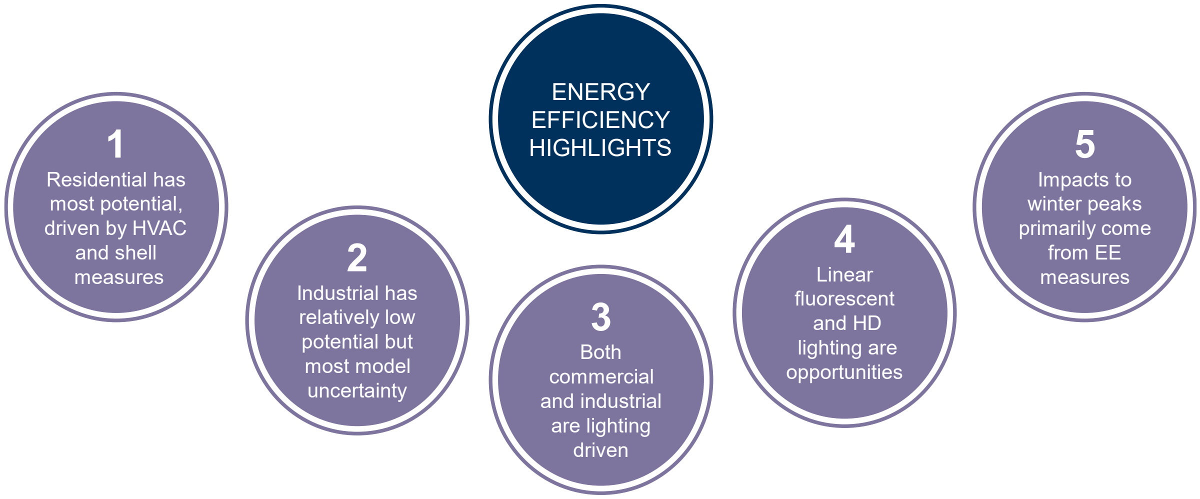

Figure D-17: Energy Efficiency Highlights from the Potential Study

Highlights from the demand response portion of the study were:

Figure D-18: Demand Response Highlights from the Potential Study

The study was used to inform energy program resource options in the IRP. More information on the Energy Programs Potential Study can be found on the energyright.com website.

D.6 Conclusion

This appendix provided additional information on these key studies that informed TVA's modeling assumptions for planning reserve margins, NDC for renewable and storage resources, coal end-of-life planning dates, and the achievable potential for energy efficiency and demand response programs. Together with the EnCompass model, these assumptions establish the framework for the IRP analysis.

E

Appendix E – Utility Scale Resource Methodology

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Appendix E – Utility Scale Resource Methodology

Maintaining diversity in the resource mix is fundamental to TVA's ability to provide affordable, reliable, resilient, and increasingly cleaner energy to the residents, businesses, and industries in the region. To facilitate this, the IRP analysis considered the addition of a wide range of supply-side generating resources, distributed generation resources, and demand-side management resources. To benchmark methodology, TVA engaged Horizons Energy to review the IRP assumptions for resource characteristics and costs. Chapter 3 summarized key assumptions for the resource options considered in the IRP. This appendix includes Horizons Energy's benchmarking report and additional details on how utility scale resource options are modeled in the IRP.

E.1 Horizons Energy Benchmarking Report

In Spring/Summer 2023, TVA engaged Horizons Energy to review IRP assumptions for resource characteristics and costs. A summary report of their findings is included in the balance of this section.

E.1.1 Background

Tennessee Valley Authority (TVA) engaged Horizons Energy (Horizons) to conduct a comprehensive review of its Integrated Resource Plan (IRP) capacity expansion EnCompass model, in preparation for the 2025 TVA IRP update. Horizons Energy partnered with CDG Engineers to prepare this evaluation. This review assesses TVA's resource expansion characteristics, costs, modeling setup, and underlying assumptions. The project involved analysis of the data, comparison with industry sources and standards. This appendix provides an overview of the findings from the review of potential generation options used in the 2025 TVA IRP.

E.1.2 Independent Review Process

To review TVA's potential resource options, Horizons first reviewed the raw files from TVA's capacity expansion EnCompass model to determine both the validity of the input data and the methods in which the characteristics are modeled. The generation additions included natural gas-fired resources (combined cycle, combustion turbines, and aeroderivative combustion turbines), solar PV (photovoltaic) purchase agreements, wind generation, battery energy storage, pumped hydro energy storage, nuclear generation (small modular reactors and pressurized water reactors), and energy efficiency programs. Horizons reviewed each resource by comparing its cost and characteristics to an equivalent industry estimate which references both publicly available data and Horizon's own analysis.

E.1.3 Key Findings

Overall Potential Resource Modeling

Horizons found that in general, TVA's modeling of potential resource options was reasonable for a long-term generation expansion planning model and sufficient to provide actionable results. Detailed findings about assumptions for individual resource types are noted in the following sections.

Natural Gas – Combustion Turbine

TVA's combustion turbine modeling, including GE 7EA and 7FA turbines, had project characteristics within industry expectations and as compared to existing generation. The assessment noted some differences from Horizon's estimate for fixed and variable O&M costs, but in those cases, costs are consistent with existing TVA generation.

Natural Gas – Aeroderivative Combustion Turbine

Analysis of combustion turbines based on GE LM2500 and LM6000 designs indicated reasonable assumptions for project parameters and costs.

Natural Gas – Combined Cycle

The review of TVA's combined cycle projects, including GE 7HA-based plants and converted 7FA CTs, demonstrated capital costs that were approximately 15% lower in comparison to the generic example provided by Horizons Energy. Site-specific considerations and economies of scale could have contributed to these variations. While fixed costs were higher and variable O&M costs were lower than expected, this is a function of how TVA classifies certain costs, and all costs are accounted for.

Solar Generation

TVA's solar PV projects were modeled as power purchase agreements (PPAs), which is consistent with industry practices. An evaluation of PPA prices, using generic solar project cost assumptions, demonstrated alignment with TVA's assumptions.

Wind Generation

TVA modeled three types of wind generation defined primarily by where they are sited. The three potential wind locations include Southeast High Hub wind, MISO wind, and wind transported across a HVDC transmission line. The MISO wind capital cost and capacity factor was consistent with Horizons' estimates. The Southeast wind and HVDC wind had higher costs attributed to the capacity factor for Southeast wind and the cost for transmission for the HVDC wind. The MISO wind has a higher fixed cost to account for its transmission costs. These higher costs are reasonable given the cost of transmission to the TVA system and the cost and performance of local wind generation.

Storage Projects

Potential projects for battery storage modeled by TVA showed project characteristics that were in line with industry expectations, including round trip efficiency, fixed O&M, cycles per day, and storage potential. The costs for potential battery storage projects were reasonable and consistent with Horizon's estimates.

Nuclear

Three types of expansion nuclear power plants are modeled in TVA's IRP database: small modular reactors (SMR), pressurized water reactors (PWR), and molten-salt storage reactors. The PWR units are currently commercially available, while the molten salt and SMR units are less established. Because of the limited installations of these resources, there are few comparable cost estimates and plant characteristics. Based on available information and other plant examples, Horizons Energy has determined that the TVA cost assumptions are higher than industry estimates. Horizons acknowledges that TVA has specific experience developing site specific cost estimates and operating nuclear generation that it is relying on for its forecasts.

Energy Efficiency

TVA's energy efficiency programs are modeled as fixed generation schedules with annual fixed costs. Forty-one energy efficiency programs are included at three levels of penetration. It was determined that the programs are modeled consistent with other integrated resource plans.

E.2 Optimizing Asset Decisions

When evaluating how to best meet future needs for electricity, TVA optimizes decisions using least-cost planning models. These models require inputs such as capacity amounts, upfront capital costs, asset life, fuel usage parameters, ongoing operating and maintenance costs, and many others. The model integrates all the variables associated with the scenarios (demand projections, fuel prices, regulatory environments, etc.) and strategies (resource promotions) with all the variables associated with the resource options to select the mix of expansion units that meet overall portfolio needs at the lowest system cost. The following sections provide the assumptions for key operating characteristics for the various resource options modeled in the IRP (see Appendix A – Integrated Resource Planning Fundamentals for definitions of operating characteristics).

E.3 Overnight Resource Costs

A key assumption contributing to resource selection is the cost to construct a particular resource. Overnight capital costs represent the total estimated cost to build a given resource in the first year available, restated in 2024 dollars and divided by its capacity in kilowatts ($/kW). For utility scale options, TVA utilized the moderate case from the National Renewable Energy Laboratory's Annual Technology Baseline (2023 NREL ATB) as the primary source for resource costs, with a few exceptions. Informed by direct experience exploring designs for potential small modular reactors (SMRs) at the Clinch River Nuclear Site, TVA used refined forecasts for SMRs that are higher than NREL estimates. Certain resource costs, such as for hydro expansion, were based on internal estimates specific to opportunities across the TVA power system. In the Net-zero Regulation Plus Growth scenario, TVA assumed the lower cost estimates from NREL's advanced case to represent the potential for more rapid technology advancements in that future world.

The table below summarizes overnight capital costs for the utility scale resource options considered in the IRP.

Table E-1: Overnight Capital Costs (2024 $/kW before tax credits)

Resource Type	Resource Technology	Summer NDC or Nameplate (MW)	Overnight Capital Cost (2024 $/kW)
Nuclear	Advanced Pressurized Water Reactor (APWR)	1,150	12,928
	Small Modular Reactor – Light Water (First-of-a-Kind)	285	17,949
	Small Modular Reactor – Light Water (Nth-of-a-Kind)	285	12,471
	Small Modular Reactor – Gen IV with Integrated Storage (500 MW w/ storage)	345	9,175
Hydro	Hydro Uprates	200	942
Coal	Coal Supercritical Pulverized	650	3,176
	Coal Supercritical Pulverized with Carbon Capture and Sequestration	650	4,762
Natural Gas	Combined Cycle – 2x1x1	1,430	1,372
	Combined Cycle with Carbon Capture and Sequestration – 2x1x1	1,430	3,017
	Frame Combustion Turbine – 4x*	884	744
	Aeroderivative Combustion Turbine – 20x*	1,060	1,642
	Reciprocating Internal Combustion Engine – 24x*	426	1,287
Solar (nameplate)	Solar Single-Axis Tracking	50	1,300
Wind (nameplate)	Wind – Midcontinent Independent System Operator (MISO)	200	1,625
	Wind – Valley High-Hub	200	2,358
	Wind – High Voltage Direct Current (HVDC)	200	3,171
Storage (nameplate)	Pumped Storage	1,600	2,088
	Battery – Lithium-ion 4-Hour	50	1,445
	Battery – Advanced Chemistry	50	3,106

Resource Type	Resource Technology	Summer NDC or Nameplate (MW)	Overnight Capital Cost (2024 $/kW)
EE and DR	Energy Efficiency and Demand Response Programs	Varies by program – refer to Appendix G for program options and details	
Distributed Generation	Distributed Solar, Storage, and Combined Heat and Power	Varies by resource – refer to Appendix F for modeling details	

* Smaller configurations of these resources were also offered as available options.

E.4 Benchmarking Comparison

As part of their review, Horizons Energy developed benchmark comparisons for the resource options in the IRP. The figures below show generic resource cost assumptions based on industry benchmarks alongside TVA's assumptions for the various resource technologies. Based on benchmarking insights and subsequent information gathered from internal and external partners, TVA revised preliminary assumptions to the those used in the draft IRP analysis, shown in blue bars.

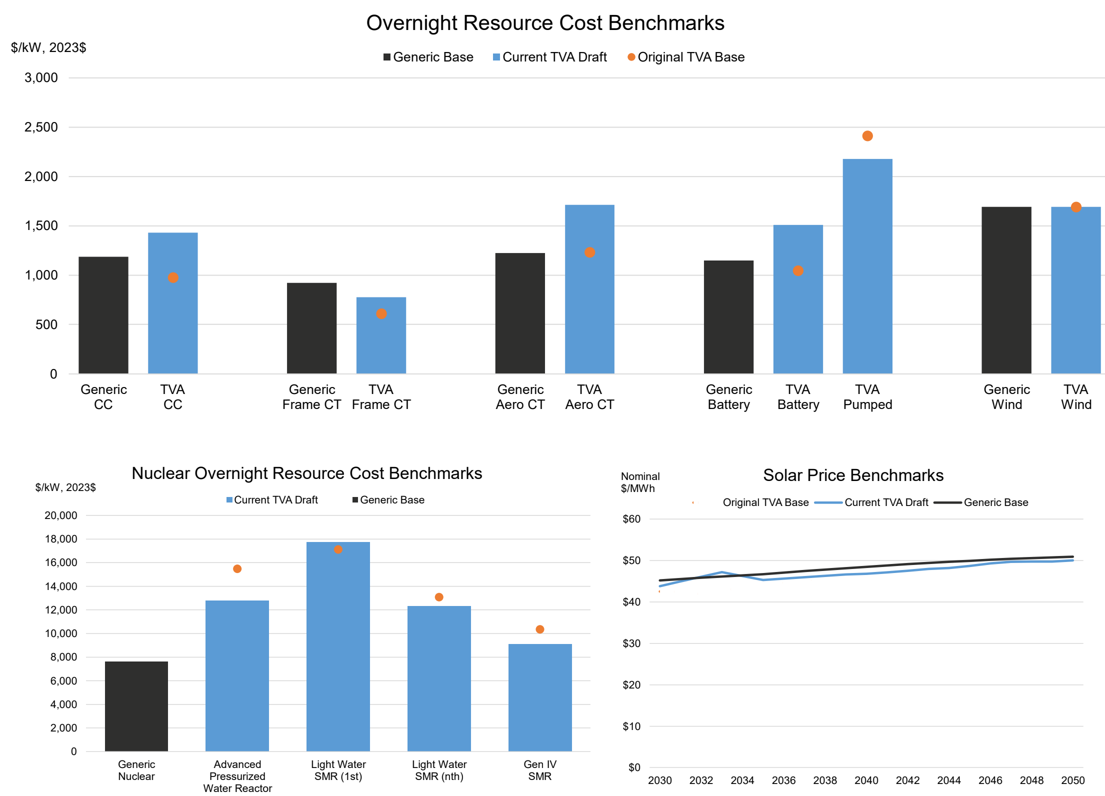

Figure E-1: Benchmarking Comparison of Overnight Capital Costs and Solar Prices

Horizons found that, in general, TVA's modeling of potential resource options was reasonable for a long-term generation expansion planning model and sufficient to provide actionable results. For frame and aero CTs, packages with the highest number of units are most cost-effective due to investment in components required regardless of the number of units in a package, therefore these are the basis for the cost shown in Figure E-1.

Typically, the optimization model selects the most cost-effective configuration but will at times choose a smaller configuration to close a small gap. In the case of wind, MISO is the most cost-effective option, and HVDC is the least cost-effective option. With respect to nuclear, Horizons acknowledged that TVA has specific experience developing site specific cost estimates and operating nuclear generation that it is relying on for its forecasts.

E.5 Technology and Adoption Readiness

The ability to successfully deploy a technology is dependent upon the maturity of that technology from a fundamental perspective, as well as the readiness to adopt that technology throughout its entire value chain. To better assess adoption readiness, the Department of Energy (DOE) has developed a Commercial Adoption Readiness Assessment Tool (CARAT) that establishes an Adoption Readiness Level (ARL) framework to complement the existing Technology Readiness Level (TRL) framework. Taken together, they provide a more complete view of the readiness to deploy various generating and storage technologies in the energy sector.

In DOE's framework, technology readiness assesses the level of technological breakthroughs required and developmental challenges to overcome. Technology readiness is assessed with a 1 to 9 TRL score that ranges from research to development and demonstration to commissioning and operations, as described below.

Table E-2: DOE Technology Readiness Level Scale

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
System Operations	TRL 9	Actual system operated over the full range of expected conditions	Actual operation of the technology in its final form, under the full range of operating conditions. Examples include using the actual system with the full range of wastes.
System Commissioning	TRL 8	Actual system completed and qualified through test and demonstration	Technology has been proven to work in its final form and under expected conditions. In almost all cases, this TRL represents the end of true system development. Examples include developmental testing and evaluation of the system with real waste in hot commissioning.
	TRL 7	Full-scale, similar (prototypical) system demonstrated in a relevant environment	Prototype full-scale system. Represents a major step up from TRL 6, requiring demonstration of an actual system prototype in a relevant environment. Examples include testing the prototype in the field with a range of simulants and/or real waste and cold commissioning.
Technology Demonstration	TRL 6	Engineering/pilot-scale, similar (prototypical) system validation in a relevant environment	Representative engineering scale model or prototype system, which is well beyond the lab scale tested for TRL 5, is tested in a relevant environment. Represents a major step up in a technology's demonstrated readiness. Examples include testing a prototype with real waste and a range of simulants.
Technology Development	TRL 5	Laboratory scale, similar system validation in a relevant environment	The basic technological components are integrated so that the system configuration is similar to (matches) the final application in almost all respects. Examples include testing a high-fidelity system in a simulated environment and/or with a range of real waste and simulants.
	TRL 4	Component and/or system validation in laboratory environment	Basic technological components are integrated to establish that the pieces will work together. This is relative "low fidelity" compared with the eventual system. Examples include integration of "ad hoc" hardware in a laboratory and testing with a range of simulants.

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
Research to Prove Feasibility	TRL 3	Analytical and experimental critical function and/or characteristic proof of concept	Active research and development is initiated. This includes analytical studies and laboratory-scale studies to physically validate the analytical predictions of separate elements of the technology. Examples include components that are not yet integrated or representative. Components may be tested with simulants.
Research to Prove Feasibility / Basic Technology Research	TRL 2	Technology concept and/or application formulated	Invention begins. Once basic principles are observed, practical applications can be invented. Applications are speculative, and there may be no proof or detailed analysis to support the assumptions. Examples are still limited to analytic studies.
Basic Technology Research	TRL 1	Basic principles observed and reported	Lowest level of technology readiness. Scientific research begins to be translated into applied research and development (R&D). Examples might include paper studies of a technology's basic properties.

The ARL framework establishes a rubric for evaluating the commercial factors related to a technology's value proposition, market acceptance, resource maturity, and license to operate, resulting in an overall 1 to 9 ARL score that reflects a readiness level across the adoption value chain. Descriptions of the 17 risk dimensions across four core areas included in the assessment are summarized in the table below. In ARL scoring, each risk dimension receives a rating of low, medium, or high risk using fact-based parameters. Further information on DOE's Adoption Readiness Levels and the CARAT tool can be found here.

Table E-3: DOE Commercial Adoption Readiness Assessment Tool (CARAT) Risk Dimensions

Adoption Risk Core Areas	Dimensions of Adoption Risk	Description
Value Proposition	Delivered Cost	Risks associated with achieving delivered cost competitiveness when produced at full scale, including amortization of incurred development and capital costs, and accounting for switching costs (if any).
	Functional Performance	Risks associated with the ability of the technology solution to meet or exceed the performance and feature-set of incumbent solutions or create new end-use markets.
	Ease of Use / Complexity	Risks associated with operational switching costs; the ability of a new user (individual, company, system integrator) to adopt and operationalize the technology with limited training, few new requirements, or special resources (e.g., tools, workforce, contract structures).
Market Acceptance	Demand Maturity / Market Openness	Risks associated with demand certainty and access to standardized sales and contracting mechanisms (if required), as well with natural (e.g., network effects, first-mover-advantages) and/or structural (e.g., existing monopolies / oligopolies) barriers to entry in the market(s) to which the technology solution can be applied.
	Market Size	Risks associated with the overall size of the market that can be served by the technology, and the level of uncertainty with which it will materialize.
	Downstream Value Chain	Risks associated with the projected path to get the product from a producer to a customer along the value chain (e.g., considering split incentives, technology acceptance, business model changes).

Adoption Risk Core Areas	Dimensions of Adoption Risk	Description
Resource Maturity	Capital Flow	Risks associated with the availability of capital needed to move the technology solution from its current state to production at scale, including total investment required, availability of willing investors, availability of associated financial and insurance products, and the speed of capital flow.
	Project Development, Integration, and Management	Risks associated with the existence of processes and capabilities to successfully and repeatably execute projects using the technology solution.
	Infrastructure	Risks associated with the physical and digital large-scale systems that need to be in place to support, enable, or facilitate deployment at full scale (e.g., pipelines, transmission lines, roads and bridges, etc.)
	Manufacturing and Supply Chain	Risks associated with all the entities and processes that will produce the end-product, including integrators, component, and sub-component manufacturers and providers.
	Materials Sourcing	Risks associated with the availability of critical materials required by the technology (e.g., rare earth and other limited availability materials).
	Workforce	Risks associated with the human capital and capabilities required to design, produce, install, maintain, and operate the technology solution at scale.
License to Operate	Regulatory Environment	Risks associated with local, state, and federal regulations or other requirements/standards that must be met to deploy the technology at scale.
	Policy Environment	Risks associated with local, state, and federal government policy actions that support or hinder the adoption of the technology at scale.
	Permitting and Siting	Risks associated with the process to secure approvals to site and build equipment and infrastructure associated with deploying the technology at scale.
	Environmental and Safety	Risks associated with the potential for hazardous side effects or adverse events inherent to the production, transport, or use of the technology solution or end product in the absence of sufficient controls.
	Community Perception	Risks associated with the general perception by global and local communities of the technology solution and its risks or impact, whether founded or unfounded.

Using the low, medium, and high scores for each risk dimension, an overall ARL score is developed for each technology based on the following criteria established by DOE.

Table E-4: DOE Overall Adoption Readiness Scoring Table

Overall Adoption Readiness Score		Number of High Risk Dimensions								
		0	1	2	3	4	5	6	7	8+
Number of Medium Risk Dimensions	0	9	8	7	5	3	1	1	1	1
	1	8	7	6	4	2	1	1	1	1
	2	8	7	6	4	2	1	1	1	1
	3	7	6	5	3	1	1	1	1	1
	4	7	6	5	3	1	1	1	1	1
	5	6	5	4	2	1	1	1	1	1
	6	5	4	3	1	1	1	1	1	1
	7	3	2	1	1	1	1	1	1	1
	8+	1	1	1	1	1	1	1	1	1

TVA assessed the technology and adoption readiness of the resource technology options in the IRP analysis using DOE's TRL and ARL rubrics and tools. TVA referenced industry-led risk registers to help identify technology-specific risk types and levels. For the ARL assessment, TVA considered production, transportation, and distribution infrastructure in a 3-to-5-year commercialization window and assumed the current policy environment including the recently finalized Greenhouse Gas Rule. A summary of the TRL and ARL assessment results can be found in Chapter 3, section 3.6.3.

Further information on DOE's Technology and Adoption Readiness Levels and the detailed CARAT tool scoring parameters can be found here.

E.6 Nuclear Resource Modeling

Existing Nuclear Resources

TVA operates seven nuclear reactors – three at Browns Ferry Nuclear Plant, two at Sequoyah Nuclear Plant, and two at Watts Bar Nuclear Plant. These plants have a combined generating capability of 8,232 MW. The three units at Browns Ferry have license expiration dates of 2033, 2034, and 2036, respectively. In January 2024, TVA applied to the Nuclear Regulatory Commission (NRC) for a second license renewal for all three units, which if approved, would extend unit operation another 20 years for each unit. The two units at Sequoyah are licensed for operation through 2040 and 2041, respectively, and TVA plans to apply for second license renewal. Watts Bar Units 1 and 2 are licensed for operation through 2035 and 2056, respectively (initial 40-year licenses), and TVA plans to apply for license renewal. TVA has an Early Site Permit to potentially construct and operate small modular reactors (SMRs) at TVA's Clinch River Nuclear Site in Oak Ridge, Tennessee. In 2022, the TVA Board approved a programmatic approach to exploring advanced nuclear technology.

Nuclear Resource Options

In the IRP analysis, three nuclear expansion options are available to fill the expected capacity gap:

- Advanced Pressurized Water Reactor (APWR)
- Light Water SMR (first and nth-of-a-kind)
- Gen IV SMR

SMRs are a new type of nuclear reactor in which the components are manufactured in a factory and then assembled onsite. The individual units are smaller in size, allowing for increased flexibility in installation and use. New units could be located at existing nuclear sites or at other sites beneficial to the transmission system and local resiliency. Two SMR options are included. The first option is a light water-cooled SMR that leverages proven technology and is furthest along from a licensing perspective. The second option is a Gen IV SMR that is non-water-cooled (e.g., liquid sodium, molten salt) with an integrated thermal energy storage system.

The table below shows the key operating characteristics used to model the nuclear expansion options.

Table E-5: Nuclear Expansion Options and Key Assumptions

Resource Option	APWR	Light Water SMR	Gen IV SMR
Summer Net Dependable Capacity (MW) – without/with storage	1,150	285	345/500
Unit Availability (First Year)	2038	2033	2041
Annual Build Limit (Units)	1	1	1
Book Life (Years)	60	60	60

Resource Option	APWR	Light Water SMR	Gen IV SMR
Overnight Capital Cost ($/kW) – first/nth-of-a kind	12,928	17,949 / 12,471	9,175
Summer Full-load Heat Rate (Btu/kWh)	10,132	10,713	8,308
Annual Outage Rate (%)	8	5	10
Variable Operating and Maintenance ($/MWh)	1.35	1.10	4.22
Fixed Operating and Maintenance ($/kW-year)	127.90	147.73	272.64

Numerical values for nuclear resource options were developed internally based on TVA's estimated range of all-in costs using information from preliminary estimate determination efforts. Costs in Scenario 5 were reduced to NREL ATB estimates to reflect an overall technology breakthrough and economic productivity that could drive additional opportunities for carbon-free resources in that scenario.

The figure below shows the trend in overnight capital costs for the nuclear resource options including the impact of inflation and IRA investment tax credits (Reference without GHG Rule scenario).

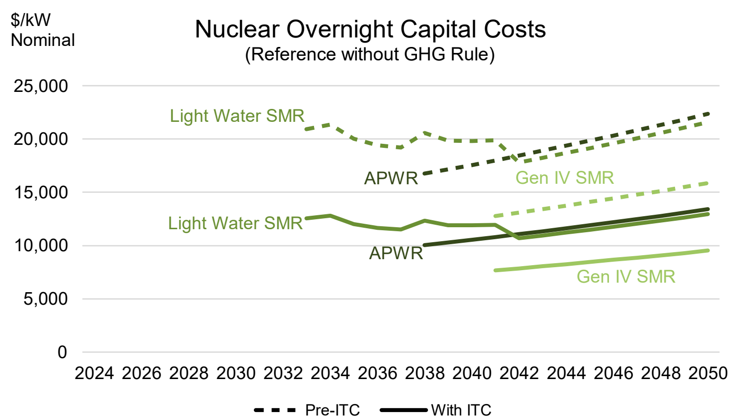

Figure E-2: Nuclear Overnight Capital Costs (Reference without GHG Rule scenario)

E.7 Hydro Resource Modeling

Existing Hydro Resources

TVA operates 109 conventional hydro generating units at 29 dams with a generating capability of 3,739 MW of electricity. All IRP portfolios reflect investing in and maintaining TVA's existing hydro fleet. Through its Hydro Life Extension program, TVA plans to modernize two to three units per year, and the program is perpetual in nature to maintain capacity over time. Based on a model that simulates the operation of the river system and the operational constraints of the hydro units, TVA anticipates about 70% of the combined hydro capability to be available at the summer peak hour. Also, TVA has long-term power purchase agreements for output from multiple dams on the Cumberland and Tennessee River systems. These facilities provide 779 MW of capability.

Hydro power is not dispatched based on price alone, because water releases in the Tennessee River system also are required for municipal and industrial uses, navigation, flood damage reduction, recreation, water quality, and other purposes. To account for this, TVA includes a fixed amount of monthly energy in the model for conventional hydro units, and the model uses the hydro energy to level the load shape served by other units within high-level constraints, resulting in total hydro generation that approximates if it were modeled as a collection of individually linked resources.

Hydro Resource Options

In the IRP analysis, one hydro expansion option is available to fill the expected capacity gap:

- Hydro Uprates

The hydro uprates expansion option was developed based on TVA's Hydro Life Extension (HLE) program assessments and is specific to opportunities across the TVA system. HLE projects provide the best opportunity to take advantage of the limited water supply by increasing the productivity of the existing hydroelectric dams. While performing activities required to maintain existing capacity, opportunities to improve upon original design capabilities with incremental capital were identified and modeled as a resource. The incremental capacity available and incremental spend above the cost of the base HLE program became the cost basis. While cost synergies are tied to uprate work being performed at the same time as HLE work, the model has some latitude to shift the timing of the uprates to achieve the best overall fit in each portfolio.

The table below shows the key operating characteristics used to model the hydro expansion option.

Table E-6: Hydro Expansion Options and Key Assumptions

Resource Option	Hydro Uprates
Summer Net Dependable Capacity (MW)	200
Unit Availability (First Year)	2026
Book Life (Years)	30
Overnight Capital Cost ($/kW)	942
Variable Operating and Maintenance ($/MWh)	2.61
Fixed Operating and Maintenance ($/kW-year)	N/A

As hydro uprates expand the capacity of existing units, there is additional variable but no additional fixed operating and maintenance costs. Since hydro plants do not use fuel, a heat rate is not needed for modeling.

The figure below shows the trend in overnight capital costs for the hydro resource option including the impact of inflation and IRA investment tax credits (Reference without GHG Rule scenario).

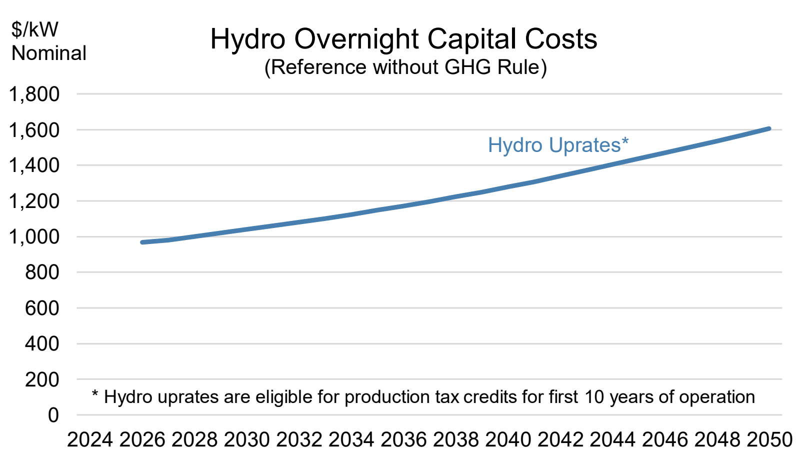

Figure E-3: Hydro Overnight Capital Costs (Reference without GHG Rule scenario)

E.8 Coal Resource Modeling

Existing Coal Resources

TVA operates four coal-fired plants with 24 active generating units and a total capability of 5,815 MW. In planning, TVA uses a number somewhat lower than the capability of a resource, based on expected output at the summer and winter peaks (net dependable capacity). Informed by the Aging Coal Fleet Evaluation (see Appendix D.3), TVA used the following planning dates for coal plant retirements in the IRP analysis:

- Cumberland Coal Plant (two units) – retiring by end of 2026 and end of 2028, respectively
- Kingston Coal Plant (nine units) – all units retiring by the end of 2027
- Gallatin Coal Plant (four units) – all units retiring by the end of 2031
- Shawnee Coal Plant (nine units) – all units retiring by the end of 2033

In addition to TVA's four coal plants, TVA has access to the output from a coal-fired plant with a generating capability of 440 MW through a long-term power purchase agreement that expires in 2032.

Coal Resource Options

In the IRP analysis, two coal expansion options are available to fill the expected capacity gap:

- Supercritical Pulverized Coal
- Supercritical Pulverized Coal with Carbon Capture and Sequestration (CCS)

The table below shows the key operating characteristics used to model the coal expansion options.

Table E-7: Coal Expansion Options and Key Assumptions

Resource Option	Supercritical Pulverized Coal	Supercritical Pulverized Coal w/CCS
Summer Net Dependable Capacity (MW)	650	650
Unit Availability (First Year)	2029	2033
Annual / Cumulative Build Limit (Units)	2	1 / 11
Book Life (Years)	30	30
Overnight Capital Cost ($/kW)	3,176	4,762
Summer Full-load Heat Rate (Btu/kWh)	10,548	10,548
Annual Outage Rate (%)	25	25
Variable Operating and Maintenance ($/MWh)	2.12	19.39
Fixed Operating and Maintenance ($/kW-year)	103.56	162.74

Cost estimates for new coal units were derived from the NREL ATB. For coal with CCS, TVA applied the cost estimates developed for CCS systems for CC units to a conventional coal unit to reflect the additional cost of CCS technology. Coal units typically have a CO_2 emissions rate of 205 pounds per million BTUs of coal burned. CCS technology capturing 90% of the emissions would reduce the CO_2 rate to 20.5 pounds per million BTUs of coal burned. In scenarios that include a carbon tax, the modeled coal units incur emissions charges based on a dollar-per-ton emission penalty.

The figure below shows the trend in overnight capital costs for the coal resource options including the impact of inflation and IRA investment tax credits (Reference without GHG Rule scenario).

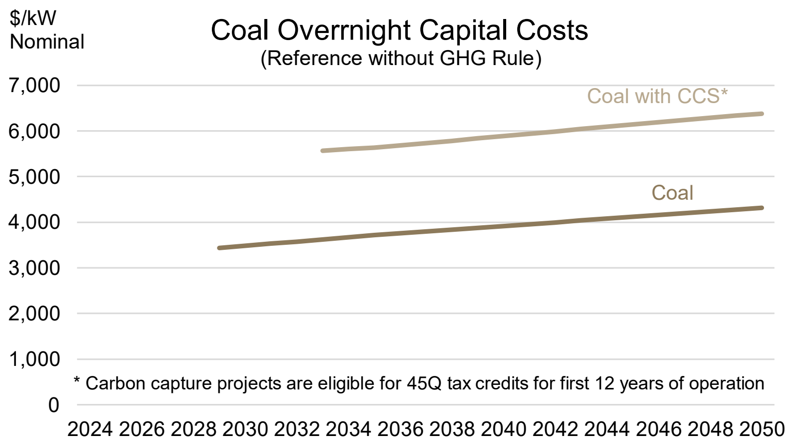

Figure E-4: Coal Overnight Capital Costs (Reference without GHG Rule scenario)

E.9 Natural Gas and Hydrogen Resource Modeling

Existing Natural Gas Resources

As of FY 2023, TVA operates 90 natural gas-fired combustion turbines (CT) at nine power plants with a combined generating capability of 5,680 MW (including co-generation) and 14 combined cycle (CC) units at eight power plants with 6,958 MW of generating capability. A new simple-cycle combustion turbine plant in Paradise, KY, entered commercial operations in December 2023, adding 681 MW to the power system. TVA has power purchase agreements with merchant gas-fired plants for 3,805 MW of capability, with current agreements expiring by the mid-2020s.

Natural Gas and Hydrogen Resource Options

In the IRP analysis, five gas expansion options are available to fill the expected capacity gap:

- Combined Cycle (CC) – 2x1x1 (two sets of one gas turbine and one steam generator)
- CC with Carbon Capture and Sequestration (CCS) – CC with CCS capturing 90% of CO_2 emissions
- Frame Combustion Turbine (Frame CT) – 3x and 4x
- Aeroderivative Combustion Turbine (Aero CT) – 2x, 4x, 10x, 20x
- Reciprocating Internal Combustion Engine (RICE) – 1x, 2x, 6x, 12x, 24x

Frame CTs are available with two, three or four turbines, Aero CTs are available in packages of two, four, 10 or 20 turbines, and RICE are available in packages of one, two, six, 12, or 24 turbines (largest configurations shown in the table below). New gas units would be capable of burning natural gas or hydrogen.

Table E-8: Gas Expansion Options and Key Assumptions

Resource Option	CC	CC w/CCS	Frame CT	Aero CT	RICE
Summer Net Dependable Capacity (MW)	1,430	1,430	884	1,060	426
Unit Availability (First Year)	2029	2033	2029	2029	2029

Resource Option	CC	CC w/CCS	Frame CT	Aero CT	RICE
Annual / Cumulative Build Limit (Units)	2	1 / 11	2	2	1
Book Life (Years)	30	30	30	30	30
Overnight Capital Cost ($/kW)	1,372	3,017	744	1,642	1,287
Summer Full-load Heat Rate (Btu/kWh)	6,665	7,832	10,087	9,392	8,607
Annual Outage Rate (%)	8.19	8.19	4.68	2.22	4.68
Variable Operating and Maintenance ($/MWh)	0.90	5.00	0.00	8.12	6.67
Fixed Operating and Maintenance ($/kW-year)	42.24	94.01	5.50	21.93	41.22

Cost estimates for gas units are based on TVA's recent experience with gas build projects. Variable costs for Frame CTs and RICE are modeled using a start cost mechanism. In addition to the options listed above, the model has the option to accelerate the retirement of TVA's older combined cycle plants.

The CO_2 emissions rate for a typical gas unit is 117 pounds per million BTUs of gas burned. CCS technology capturing 90% of the emissions would reduce the CO_2 rate to 11.7 pounds per million BTUs of gas burned. In scenarios that include a carbon tax, the modeled gas units incur emissions charges based on a dollar-per-ton emission penalty. Hydrogen blending reduces the carbon content commensurate with the blend percentage.

The figure below shows the trend in overnight capital costs for the gas resource options including the impact of inflation and IRA investment tax credits (Reference without GHG Rule scenario).

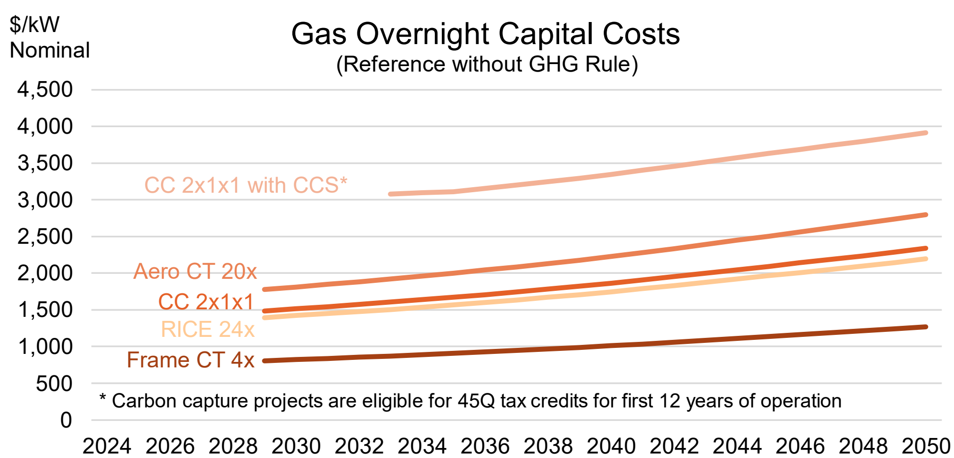

Figure E-5: Gas Overnight Capital Costs (Reference without GHG Rule scenario)

Carbon Capture and Sequestration Modeling

CCS modeling is built on research identifying storage locations near or within the TVA footprint, the necessary pipeline length, and other costs to capture carbon at existing CC sites. The model, however, is allowed to build incremental CCS units at these sites, while retaining the existing unit, effectively co-locating them.

Hydrogen Blending Modeling

Scenarios 4 and 5 assume that a robust hydrogen market develops by the early 2030s, based on DOE's Energy Earthshot™ goal for a hydrogen price of $1/kilogram. Scenario 4 assumes hydrogen prices reach this level by 2050, while Scenario 5 assumes achieving this level by 2032. This input assumes that all infrastructure and production costs are embedded in that price. After 2033, an increasing amount of hydrogen blending is required for CC units without CCS or operating above a 20% capacity factor. In the model, CTs can operate fully on natural gas or use a hydrogen blend, as they are not operating above 20%. Because of seasonality assumptions between hydrogen and natural gas, there is opportunity to lower costs by periodically choosing to burn hydrogen at a CT and not incur the scenario's carbon penalty.

E.10 Solar Resource Modeling

Existing Solar Resources

Through several programs, TVA purchases renewable power (primarily solar, some biomass) totaling 322 MW of capability. As of FY23, TVA has long-term power purchase agreements for 715 MW of operating solar nameplate capacity and has contracted for an additional 1,867 MW of solar nameplate capacity expected to come online over the next few years. As of the last procurement cycle concluded in early 2024, the total solar amount contracted through these agreements (operating and in development) totaled approximately 3,400 MW. Operating solar installations were included in existing assets for the IRP analysis. TVA obtains renewable energy credits from these sites, and the existing agreements extend through the late 2030s to early 2040s. TVA also owns approximately 1 MW of solar capability across nine operating solar installations.

Solar Resource Options

In the IRP analysis, one solar expansion resource option is available to fill the expected capacity gap:

- Single-axis Tracking Solar

Single-axis tracking solar allows the solar panels to follow the sun. Solar generation is weather and location dependent, and solar is an energy and capacity limited resource. TVA uses an hourly energy production profile to dispatch solar to reflect the amount of solar generation expected to occur across daylight hours for each season. The figure below illustrates how seasonal load shapes and solar generation compare. Solar output in the TVA region is lower than in other regions in the U.S. due to lower overall levels of solar irradiance, which is driven by factors such as the number of sunny days and humidity levels. TVA also applies a capacity credit since only a portion of the nameplate capacity of a solar unit can be expected at the time of the system peak. Currently, TVA anticipates 68% and 15% of incremental solar nameplate capacity to be available to meet summer and winter peak requirements, respectively, and these amounts decrease as solar penetration on the system increases (see Appendix D.2 for more information on solar capacity contribution).

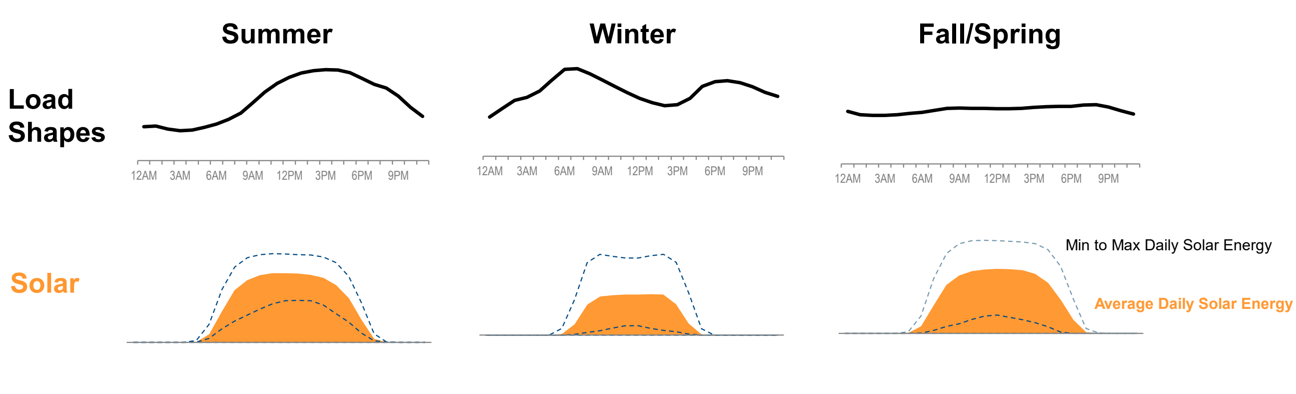

Figure E-6: Illustration of Load and Solar Generation Profiles

The table below shows the key operating characteristics used to model the solar expansion option. This option is modeled as a power purchase agreement, but TVA could choose to pursue a combination of contracted solar expansion and self-directed solar builds. All capacities are stated in alternating current (AC) terms.

Table E-9: Solar Expansion Options and Key Assumptions

Resource Option	Single-Axis Tracking
Nameplate Capacity (MW)	50
Summer Net Dependable Capacity (first 500 MW at 68% NDC, declines thereafter)	34
Winter Net Dependable Capacity (first 500 MW at 15% NDC, declines thereafter)	7
Capacity Factor (%)	25
Unit Availability (First Year)	2027
Annual Build Limit (MW) – Reference Case to Highest Promotion Case	1,000 – 1,850
Book Life (Years)	20
Overnight Capital Cost ($/kW)	1,300

Solar resource costs in the near term were market-based using recent offers, blending into NREL moderate case estimates in the longer term. As solar resource options were modeled as power purchase agreements (PPA), operating and maintenance costs are included in the PPA cost.

The figure below shows the trend in overnight capital costs for the solar resource option including the impact of inflation and IRA investment tax credits (Reference without GHG Rule scenario).

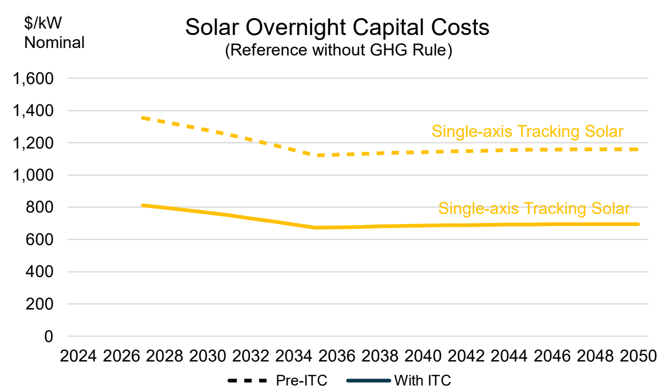

Figure E-7: Solar Overnight Capital Costs (Reference without GHG Rule scenario)

E.11 Wind Resource Modeling

Existing Wind Resources

TVA has long-term power purchase agreements with eight wind farms, one located in Tennessee and seven located in the Midwest, which expire by the early 2030s. These facilities provide 1,240 MW of nameplate capacity.

Wind Resource Options

In the IRP analysis, three wind expansion options are available to fill the expected capacity gap:

- Midwest Wind – Midcontinent Independent System Operator (MISO)
- Southeast High-hub Wind
- High Voltage Direct Current (HVDC) Wind

MISO wind primarily comes from wind farms in the Midwest. For the in-Valley option, higher hub heights are necessary due to the relatively lower wind speeds in the region. The HVDC option would use a direct current (DC) bulk transmission system. The HVDC transmission system would reduce power losses that are typical of the more common alternating current (AC) transmission systems. The HVDC option would require a third party to permit and build a new transmission line, driving a later availability date than the other options.

Wind generation is also weather and location dependent, and it is more variable across all hours than solar. As wind is an energy and capacity limited resource, TVA uses an hourly energy production profile to dispatch wind energy to reflect the amount of wind generation expected to occur across the day for each season. This “wind shape” for existing sites is based on actual data for those sites, and TVA assumed somewhat higher overall output for future MISO and HVDC options to reflect the newer technology of wind turbines. The figure below illustrates how seasonal load shapes and wind generation compare. TVA also applies a capacity credit since only a portion of the total nameplate capacity of a wind turbine can be expected at the time of the system peak. Currently, TVA anticipates 19% and 33% of incremental wind nameplate capacity to be available to meet summer and winter peak requirements, respectively, and these amounts decrease as wind penetration on the system increases (see Appendix D.2 for more information on wind capacity contribution).

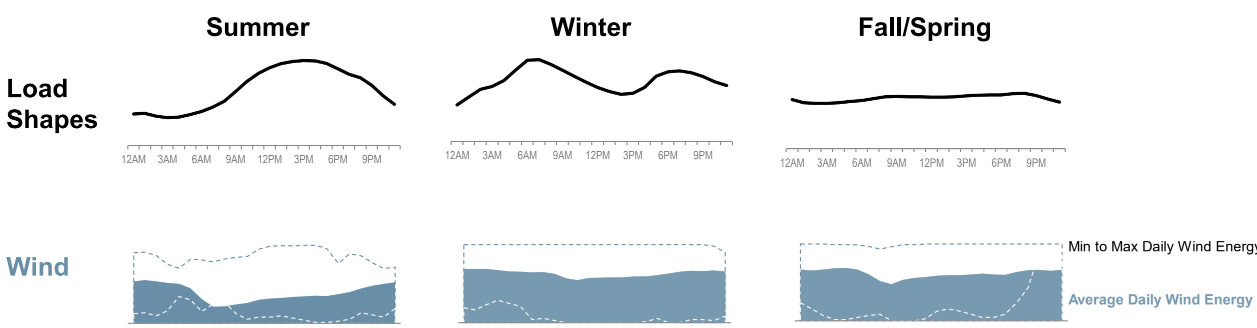

Figure E-8: Illustration of Load and Wind Generation Profiles

The table below shows the key operating characteristics used to model the wind expansion options. The MISO and HVDC options are modeled as power purchase agreements, and TVA could choose to contract or the Southeast high-hub option or pursue a self-directed build.

Table E-10: Wind Expansion Options and Key Assumptions

Resource Option	Midwest Wind	Southeast High-hub Wind	HVDC Wind
Nameplate Capacity (MW)	200	200	200
Summer Net Dependable Capacity (first 500 MW at 19%)	38	38	38
Winter Net Dependable Capacity (first 500 MW at 33%)	66	66	66
Capacity Factor (%)	40	30	55
Unit Availability (First Year)	2029	2029	2029
Annual / Cumulative Build Limit (MW)	1,000	1,000	3,000 / 3,000
Book Life (Years)	20	20	20
Overnight Capital Cost ($/kW)	1,625	2,358	3,171

MISO and Southeast high-hub estimates were developed from the NREL ATB moderate case. HVDC resource was developed from a vendor offer received for a project delivering wind from Southwest Power Pool into TVA at a $/MWh all-in cost. As wind resource options were modeled as power purchase agreements (PPA), operating and maintenance costs are included in the PPA cost.

The figure below shows the trend in overnight capital costs for the wind resource options including the impact of inflation and IRA investment tax credits (Reference without GHG Rule scenario).

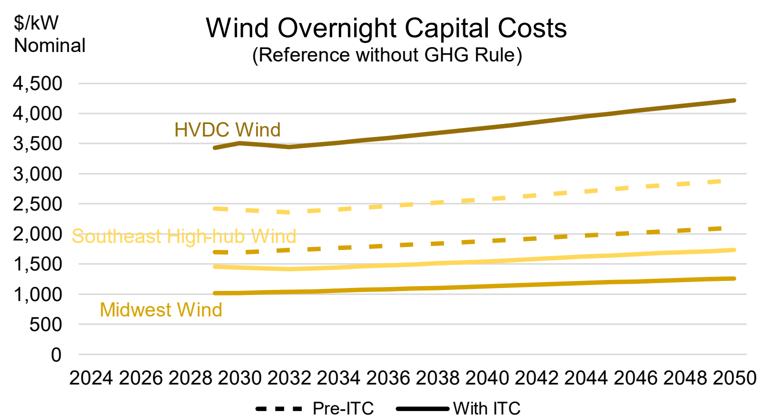

Figure E-9: Wind Overnight Capital Cost (Reference without GHG Rule scenario)

E.12 Storage Resource Modeling

Existing Storage Resources

TVA operates one large storage facility. The Raccoon Mountain Pumped Storage Plant has four generating units with a capability of 1,700 MW, providing critical flexibility to the TVA system by storing water at off-peak times for use when demand is high. In conjunction with several solar contracts, TVA has contracted for 150 MW of battery storage expected to come online in the next few years. Also, TVA is constructing a 20 MW battery facility in Vonore, Tennessee, to gain direct operational experience with battery storage operation.

Storage Resource Options

In the IRP analysis, three storage expansion options are available to fill the expected capacity gap:

- Pumped Storage
- Lithium-ion Battery (4-hour)
- Advanced Chemistry Battery (10-hour)

The pumped storage option would use reversible turbine generators to pump water up to a higher altitude reservoir during periods of excess power and use water flowing from the upper to lower reservoir to power the turbines when energy is needed. Two different types of battery storage technologies were modeled. Lithium-ion is the prevalent technology today, and it is best suited for shorter durations, so a four-hour version was modeled. Advanced chemistry battery storage technologies are developing that would enable longer durations of storage, so a 10-hour version was modeled. Storage efficiency is modeled for all of these options due to the energy losses inherent in the conversion process and the loss of water during storage. Storage efficiency represents the efficiency of one cycle (i.e., pumping/releasing water, charging/releasing battery power).

The table below shows the key operating characteristics used to model the storage expansion options.

Table E-11: Storage Expansion Options and Key Assumptions

Resource Option	Pumped Storage	Lithium-ion Battery (4-hour)	Advanced Chemistry Battery (10-hour)
Nameplate Capacity (MW)	1,600	50	50
Unit Availability (First Year)	2033	2029	2029
Annual / Cumulative Build Limit (MW)	1,600 / 1,600	500 (650 in highest promotion case)	500 (650 in highest promotion case)
Book Life (Years)	40	20	20
Overnight Capital Cost ($/kW)	2,088	1,445	3,106
Storage Efficiency (%)	81	85	85
Annual Outage Rate (%)	7	5	5
Variable Operating and Maintenance ($/MWh)	2.80	0.00	0.00
Fixed Operating and Maintenance ($/kW-year)	20.64	46.61	46.61

Pumped storage cost estimates were created "in-house" using information from the evaluation of potential pumped storage sites. Lithium-ion and advanced chemistry batteries were derived from NREL's moderate case. Batteries are modeled as fixed augmentation and maintenance agreements, so anticipated variable operating and maintenance costs are negligible.

The figure below shows the trend in overnight capital costs for the storage resource options including the impact of inflation and IRA investment tax credits (Reference without GHG Rule scenario).

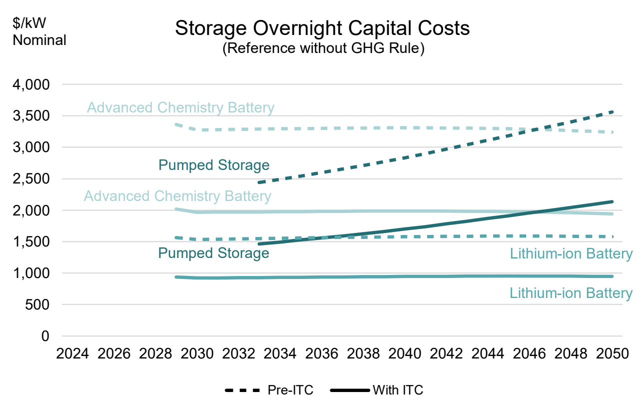

Figure E-10: Storage Overnight Capital Cost (Reference without GHG Rule scenario)

E.13 Existing Biomass Resources

TVA's Allen Combined Cycle Facility has 5 MW of nonrenewable biomass capability. TVA also has a long-term power purchase agreement for 5 MW of renewable landfill gas generating capability, with the current agreement expiring in the early 2030s. No new biomass resource options were included in the IRP.

E.14 Existing Diesel Resources

TVA operates one diesel site with a generating capability of 9 MW. TVA also has long-term power purchase agreements for 115 MW of diesel generating capability at 7 sites, with current agreements expiring by the mid-2030s. No new diesel resource options were included in the IRP.

E.15 Environmental Parameters for Resource Options

To analyze the environmental impacts of the supply-side resource options evaluated in the IRP, assumptions for rate of fuel usage, emissions, and land requirements are needed. The table below provides the assumptions for these factors by resource type and technology.

Table E-12: Environmental Parameters for Resource Options

	Resource Option	Summer NDC or Nameplate (MW)	Summer Full-Load Heat Rate (Btu/kWh)	Storage Efficiency (%)	CO_2 Emissions (lbs/MWh)	SO_2 Emissions (lbs/MWh)	NOx Emissions (lbs/MWh)	Hg Emissions (lbs/MWh)	Process Water Use (Gallons/MWh)	Process Water Consumption (Gallons/MWh)	Facility Land Requirements (Acres/MW)	Facility Land Requirements Permanently Disturbed (Acres)
Nuclear	APWR	1,150	10,132	-	-	-	-	-	1,289	859	0.40	460
	SMR – Light Water (First-of-a-Kind)	285	10,713	-	-	-	-	-	719	539	0.63	180
	SMR ‐ Light Water (Nth-of-a-Kind)	285	10,713	-	-	-	-	-	719	539	0.63	180
	SMR ‐ Gen IV (reactor / with storage)	345/500	8,308	-	-	-	-	-	719	539	0.63/ 0.08	229
Hydro	Hydro Uprates	200	-	-	-	-	-	-	-	-	-	-
Coal	Coal Supercritical Pulverized	650	10,548	-	1,160	0.333	1.194	2.98E-09	82,445	329	0.69	449
	Coal Supercritical Pulverized with CCS	650	10,548	-	116	0.333	1.194	2.98E-09	82,445	329	0.69	449
Gas	CC – 2x1x1	1,430	6,665	-	397	-	0.081	-	250	195	0.08	114
	CC with CCS – 2x1x1	1,430	7,832	-	40	-	0.081	-	250	195	0.08	114
	Frame CT– 4x	884	10,087	-	590	-	0.363	-	130	130	0.10	88
	Aero CT – 20x	1,060	9,392	-	548	-	0.337	-	130	130	0.08	85
	RICE – 24x	426	8,607	-	504	-	0.310	-	130	130	0.15	64
Solar	Solar Single-Axis Tracking (nameplate capacity)	50	-	-	-	-	-	-	-	-	7.30	365
Wind	Wind - MISO	200	-	-	-	-	-	-	-	-	0.80	160
	Wind – Valley High-hub	200	-	-	-	-	-	-	-	-	1.00	200
	Wind – HVDC	200	-	-	-	-	-	-	-	-	0.80	160
Storage	Pumped Storage	1,600	-	81	-	-	-	-	-	-	0.88	1,408
	Battery – Lithium-ion (4-hour)	50	-	85	-	-	-	-	-	-	0.08	4
	Battery – Advanced Chemistry (8-hour)	50	-	85	-	-	-	-	-	-	0.08	4

E.16 Conclusion

This appendix provided further information on resource options benchmarking and the key assumptions and methodology used to model utility scale resources. The following two sections provide additional information on the key assumptions and methodology used to model distributed generation and demand-side resources.

F

Appendix F – Distributed Generation Resource Methodology

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Appendix F – Distributed Generation Resource Methodology

In addition to utility scale resources, the IRP also considers distributed generation (DG) resource options. Recent technology advancements and consumer preference have led to increased interest in DG. The IRP focuses on three sources of DG – solar, storage, and combined heat and power (CHP). The IRP analysis includes baseline forecasts for DG adoption for each scenario and forecasts for higher levels of adoption when promoted in alternative strategies. To complement Chapter 3 that summarized key assumptions for the resource options, this appendix covers the evolution of TVA's DG programs and the modeling approach for DG in the IRP analysis.

F.1 Overview and Background

At TVA, DG was introduced through the Dispersed Power Program (DPP) in 1981 to comply with provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA). DPP's primary aim was to allow commercial and industrial customers the ability to sell back excess generation to the grid. Over time, TVA's DG programs have evolved with the maturity of the technology and the marketplace. In 2003, TVA introduced a small-scale distributed generation program, most recently known as Green Power Providers, to incentivize small-scale renewable installations and grow the market. Today, in a more mature market, TVA matches homeowners with qualified contractors through the Green Connect program. TVA's mid-scale programs, such as Generation Flexibility, facilitate local power company (LPC) community solar offerings for TVA's long-term partners, a more convenient and cost-effective alternative to rooftop installations for consumers to support renewable DG.

TVA utilizes an adoption model to forecast the growth of DG technologies over time. First, the base level of market penetration for each distributed resource type is calculated based on assumptions present in the various scenarios. Next, the level of incentives that will apply in certain strategies to reduce payback on investment is determined. Then, an adoption curve approach is used to simulate higher penetration levels achieved through improved economics. Next, these new penetration levels are applied in the capacity expansion model as a required resource. Finally, the capacity planning model optimizes the remainder of the resource portfolio in a least cost manner. This DG methodology allows TVA to gain insights into the roles DG could have on the TVA system under a variety of different futures. The individual steps are discussed in greater detail in the following sections.

Figure F-1: Distributed Generation (DG) Resources Modeling Process

F.2 Step 1: Model Base Level of Adoption in Each Scenario

Distributed generation is expected to continue to grow, due to increasing customer demand for energy choice, improved pricing, or both. TVA system planners and forecasters, with input from TVA stakeholders, worked together to determine likely levels of distributed solar, distributed battery, and CHP penetration across the various scenarios modeled. These scenarios include levels of DG that would occur in the market based on unique scenario assumptions before any TVA strategies are employed. For example, Scenario 5 includes higher assumed Inflation Reduction Act (IRA) tax credits based on an additional bonus credit offered by the federal government to encourage solar and storage purchases by decreasing their costs. The Net-zero Regulation plus Growth scenario shows the highest levels of forecasted DG, whereas the Stagnant Economy scenario shows the lowest levels of DG. The figure below shows projected base levels of DG, by resource type, deployed by 2035 and 2050 in each scenario, prior to any additional TVA incentives.

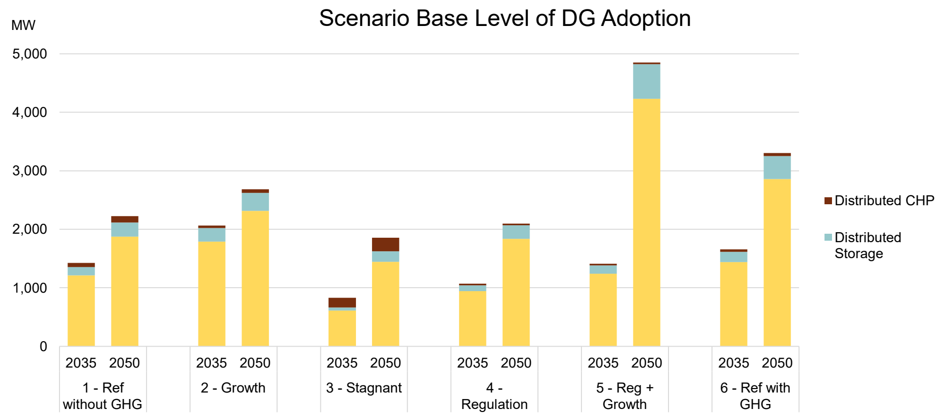

Figure F-2: Base Levels of DG in Each Scenario by 2035 and 2050

See Appendix B – Scenario Design and Forecasts for further information on how unique assumptions around DG were developed for each scenario. As each strategy is applied in a scenario, the base level of adoption in each scenario sets the baseline comparison.

F.3 Step 2: Determine Incentive Level to Apply in a Strategy

Except for Baseline Utility Planning, all strategies used in the IRP promote increased DG adoption. Monetary incentives are used to increase penetration levels by reducing the payback period for a given resource. While resources can provide energy and capacity, IRP modeling takes a simplified approach to use marginal energy cost for DG incentives for solar and CHP. Distributed storage is modeled using a percentage capacity match to distributed solar, as they are often paired for improved resiliency and economics. A base incentive level aligns to no additional incentive beyond existing programs. At a base level, distributed storage is assumed to be installed at a 15% capacity match. This means that for every 100 MW of distributed solar, an additional 15 MW of battery storage is included. Moderate incentives for distributed solar and CHP are modeled at 50% of marginal energy cost, and distributed storage is assumed to be installed at a higher 30% capacity match of the distributed solar capacity. Finally, high incentives for distributed solar and CHP are modeled at 100% of marginal energy cost, and distributed storage is assumed to be installed at a 50% capacity match of the distributed solar capacity.

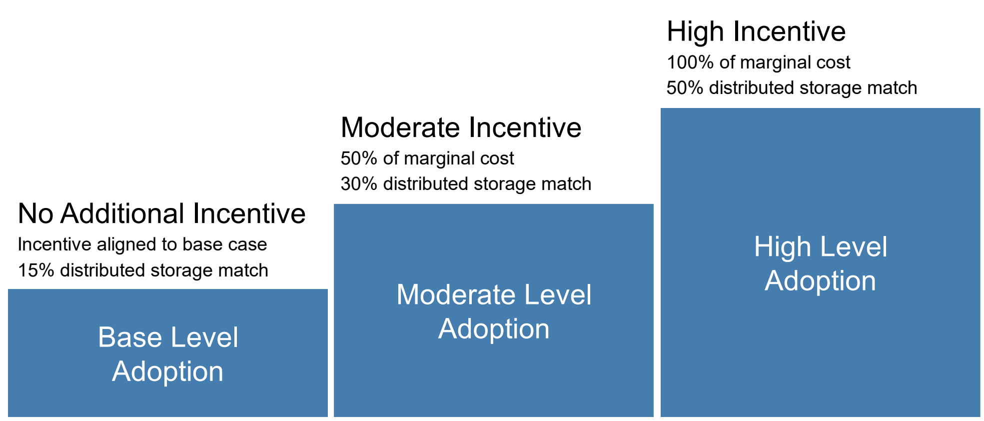

Figure F-3: Description of DG Promotion Levels

Applying various levels of incentives across the strategies allows TVA to test the impacts of increased DG penetration. The matrix below shows the incentive levels by DG resource type for each strategy.

Table F-1: Distributed Generation Promotion Levels by Strategy

Strategy	Distributed Solar	Distributed Storage	Distributed CHP
Baseline Utility Planning	Base	Base	Base
Carbon-free Innovation Focus	Moderate	Moderate	Base
Carbon-free Commercial Ready Focus	Moderate	Moderate	Base
Distributed and Demand-side Focus	High	High	High
Resiliency Focus	Moderate	Moderate	Moderate

For additional information on rationale behind incentive levels for DG in each strategy, see Appendix C – Strategy Design and Application.

F.4 Step 3: Develop New Adoption Level based on Economics

Base, moderate, and high penetration levels for DG resources were determined using an adoption curve approach. The approach used is similar to the National Renewable Energy Laboratory's (NREL) Distributed Market Demand Model, which simulates potential adoption of a given resource as a function of payback period. Factors specific to each scenario and strategy combination were fed into a TVA-developed DG model to create a unique adoption level for each resource for the long-term planning horizon.

The key elements in NREL's model are the payback period, maximum market share and adoption curve. The payback period determines the maximum market share, or depth, for a DG technology. It also influences the pace of adoption. The concept behind the NREL model is illustrated below, and a simplified application of this model in the IRP is further explained in the following sections.

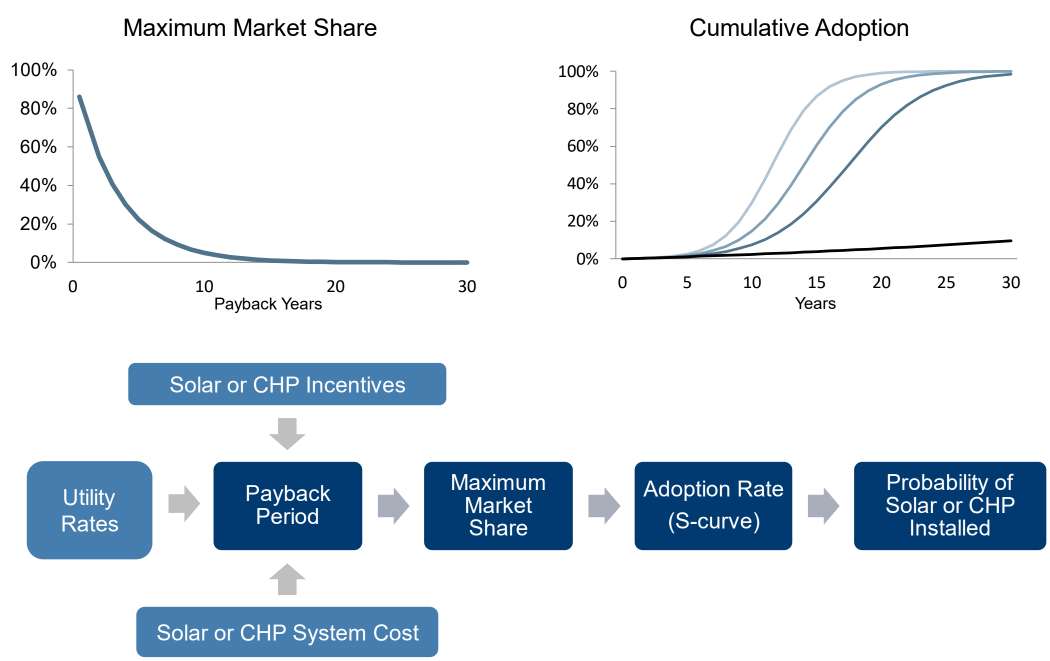

Figure F-4: Concept Illustration of NREL's Distributed Market Demand Model

Payback Period

A key element in the model is the payback period, which is simply the number of years required for a consumer to recoup the upfront costs of an investment. Ignoring discount rates, an example project requiring an upfront capital investment of $10,000 that saves a net $1,000/year will have a payback period of 10 years. The lower the payback, the greater the market depth, as more Valley residents see value in adopting a particular technology. Even with an acceptable payback, not all consumers will adopt the technology at the same time. This occurs for a variety of reasons. Some consumers are more comfortable using new technologies than others and are likely to adopt sooner, while others will wait. Also, a consumer must have access to the capital required to cover the initial costs of the technology investment. Even with the necessary capital, whether or when a consumer purchases a technology depends on competing uses for the funds and other practical considerations. All these factors impact the pace of DG adoption, which happens over the course of years and is generally faster with quicker paybacks.

Payback Components

There are two primary components in calculating payback for a DG investment – electricity bill savings and DG investment. To estimate electricity bill savings, forecasts for residential and commercial average effective rates were applied to the average annual energy output of a DG system. Next, it was necessary to estimate projected prices for distributed solar, storage and CHP systems. Pricing information for DG resources was derived from a variety of sources, both internal and external to TVA. Distributed solar and storage prices were based on NREL projections found in the 2023 Annual Technology Baseline (ATB).

CHP prices were derived from a combination of information sourced from the Southeast CHP Technical Assistance Partnership and internal TVA surveys of universities, hospitals, and commercial entities. Escalation rates for all DG resources can vary by scenario, driven by assumptions around tax policy and pace of technology advancement. The figure below shows assumptions for distributed solar and storage cost projections. Cost projections are listed in real 2021 dollars, as this is the format provided in the 2023 NREL ATB.

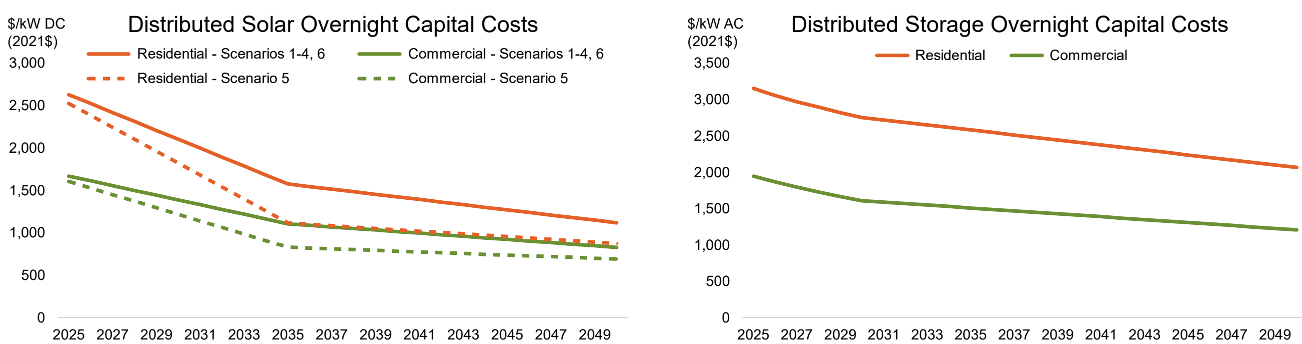

Figure F-5: Distributed Solar and Storage Price Forecast

Adoption Levels

Using assumptions for payback, considering assumptions unique to each scenario and strategy combination, the DG model provides forecasts for the following:

- Base levels of DG, considering TVA programs and payback without additional incentives
- Level of DG with moderate incentives
- Level of DG with high incentives

An example of the DG model output illustrating the resulting levels of DG adoption through time for Scenario 1 (Reference without GHG Rule) is shown in the figures below.

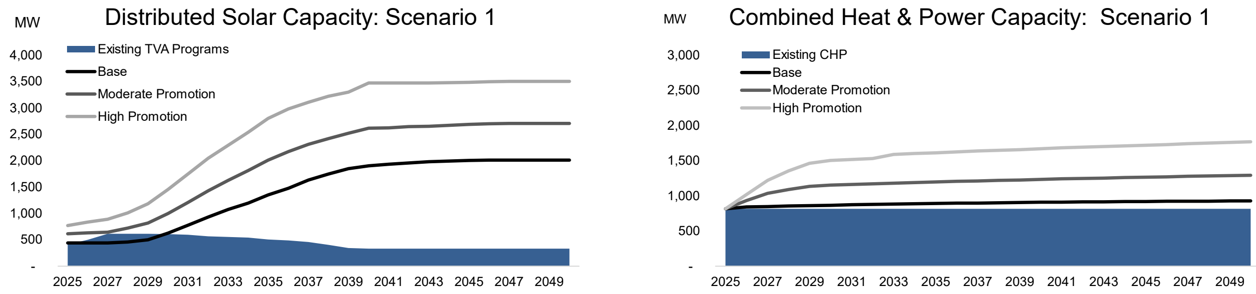

Figure F-6: Distributed Solar and CHP Capacity, Reference without GHG Rule Scenario

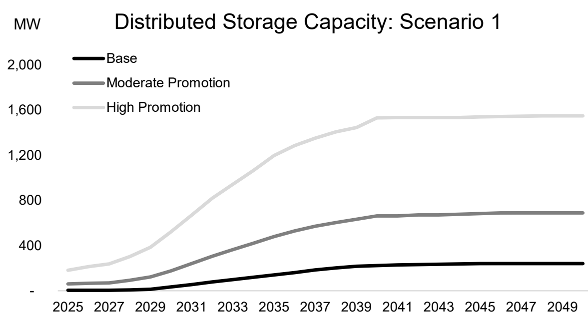

Figure F-7: Distributed Storage Capacity, Reference without GHG Rule Scenario

F.5 Step 4: Apply New Adoption Level in Expansion Model

Once the DG profiles are created for distributed solar, distributed storage, and CHP, they are imported into the expansion model. A unique set of DG adoption levels is fed into the expansion model for each scenario and strategy combination. The DG adoption levels are treated as required resources, or effectively a constraint the model considers prior to optimization of other resources. Forecasted DG adoption by resource type for all 30 portfolios by 2050 is shown below.

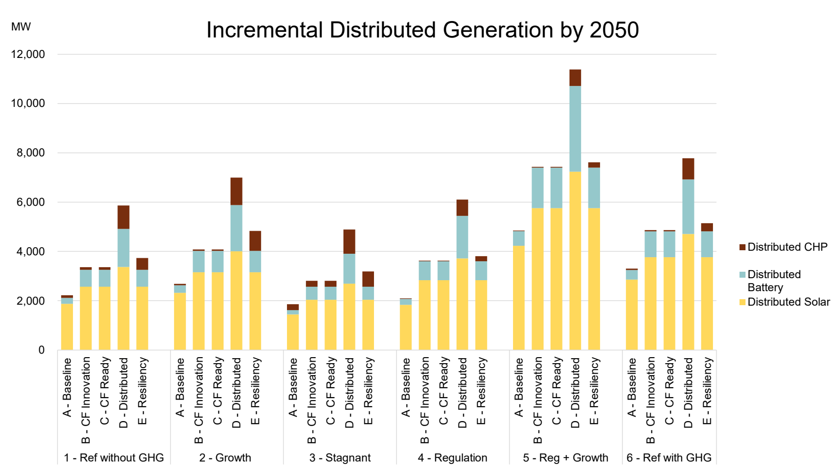

Figure F-8: Distributed Generation Capacity by 2050

F.6 Step 5: Optimize Balance of Resources for the Portfolio

After the DG profiles for distributed solar, distributed storage, and CHP are imported into the expansion model as required resources, the expansion model will then be run to optimize the remainder of the portfolio. This action is performed for each scenario and strategy combination, considering the aims and bounds of the strategy and all available generation and programmatic resources. The reserve margin is an important consideration in this step, ensuring that the expansion path chosen results in a portfolio that meets or exceeds seasonal reserve margin requirements to support a reliable system at the lowest feasible cost for a given strategy.

F.7 Conclusion

TVA's 2025 IRP builds on the innovative methodology first used in the 2019 IRP to forecast the impact of different strategies on DG penetration across various future scenarios. The method simulates the effect of monetary incentives reducing payback and driving higher adoption of DG technologies. Results from the model provide insights into the impact that DG could have on the TVA system under a variety of different futures. These insights will inform future planning and program design as part of the region's future energy system.

G

Appendix G – Demand-side Resource Methodology

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Appendix G – Demand-side Resource Methodology

In addition to utility scale and distributed generation resources, the IRP also considers demand-side options. Demand-side resource options evaluated in the IRP include energy efficiency (EE) and demand response (DR) programs. These offerings can include incentive programs, pricing products, and educational efforts to encourage informed consumer choice and reduction in energy usage. Leveraging the recent potential study, the IRP evaluates a set of EE and DR program options, with programs promoted in some alternative scenarios. To complement Chapter 3 that summarized key assumptions for the resource options, this appendix discusses the evolution of TVA's energy programs and the modeling approach used for EE and DR in the analysis.

G.1 Background

TVA's EE and DR programs offered under the EnergyRight® brand span residential, commercial, and industrial sectors. Over the years, TVA programs evolved to suit the changing energy landscape, as depicted in Figure G-1. For over 30 years, TVA has offered DR programs that incent commercial and industrial customers to reduce loads during periods of high demand. Since the mid-2000s, TVA has facilitated EE programs that incentivize energy efficiency across all sectors.

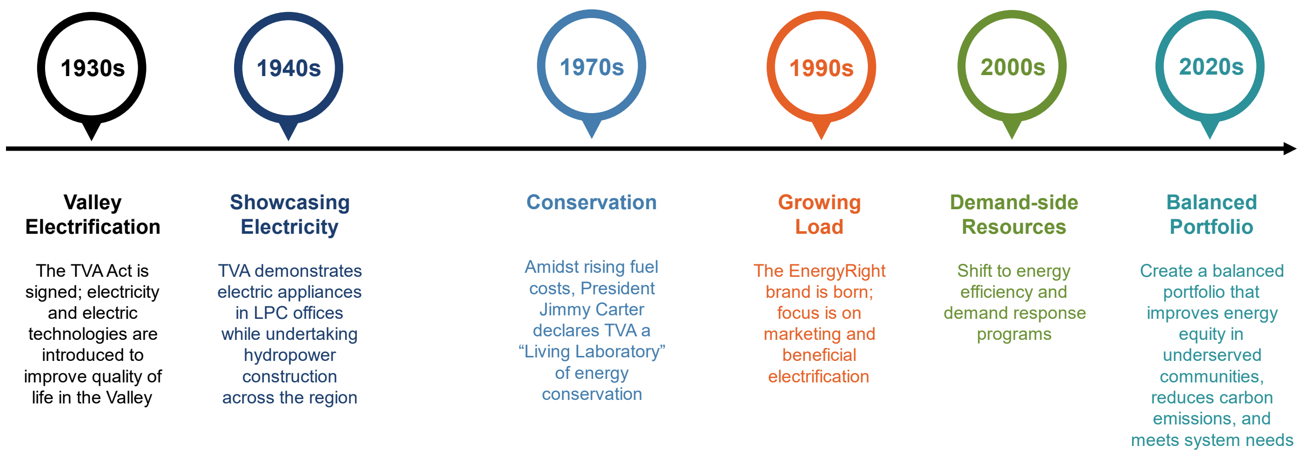

Figure G-1: TVA Energy Program History

G.2 Demand-side Resource Overview

EE programs target efficiency upgrades and improvements to reduce system load across many hours. Programs provide incentives or educational opportunities to spur consumers to make efficiency improvements in their homes or businesses above and beyond current codes and standards. By reducing inefficient energy use, EE programs help lower costs and decrease emissions. A key focus is reducing energy burden in the low-income residential sector, which has more limited opportunity to adopt energy efficiency technologies. In 2016, TVA initiated an Energy Efficiency Information Exchange stakeholder group to work together to develop a sustainable and equitable low-income energy efficiency and education model in the region. In 2018, TVA launched a pilot program called Home Uplift. Home Uplift focused on education and outreach in the low-income sector, coupled with incentives for home upgrades, and leveraged matching funds from federal programs, LPCs and local communities. This program has since been expanded Valley-wide. As of FY 2023, Home Uplift has assisted 5,400 Valley residences and reduced system energy needs by nearly 19,000 megawatt hours, benefiting those with high energy burdens. Additional equity programs have also been recently developed to help schools and small businesses, particularly in underserved communities.

DR programs reduce system load at peak hours and potentially offset or delay the need for more expensive peaking generation or power purchases. Various programs provide incentives or price structure changes to commercial and industrial customers in exchange for them suspending a portion of their load during peak periods. These programs act as a zero emissions resource for the TVA system.

In 2023, TVA announced plans for energy efficiency and demand management expansion, including over $1.5 billion in funding for the energy efficiency and demand management portfolio through FY 2028.

G.3 Tiered Approach to Modeling Demand-Side Program Options

To model demand-side program options for the IRP, TVA leveraged an updated potential study and historical experience data to estimate load changes and costs of potential EE and DR programs. In 2022, TVA partnered with industry expert DNV to create an updated Energy Programs Potential Study to inform TVA on the achievable potential of EE and DR programs within the Valley. TVA also partners with DNV to evaluate, measure, and verify program impacts, and provide insights on the potential impacts of new programs based on their experience working with TVA and other utilities. Additionally, TVA typically conducts a Residential Saturation Survey and a Commercial Saturation Survey every other year to understand market depth and potential reach of programmatic efforts, which vary from region to region. TVA is also an active participant in and member of multiple industry trade organizations that specialize in energy programs, including the Electric Power Research Institute, Association of Energy Services Professionals, and others.

Energy program adoption by customers varies based on a number of factors, with a key driver being the level of financial incentive offered. In the potential study, higher levels of EE adoption or DR participation were forecasted when financial incentives to participate were increased. To simulate this effect in modeling, TVA created several tiers, or buckets, of EE and DR program levels that included increasing numbers of participants along with increasing incentives required to achieve these higher levels of participation. The tiered program offerings are described in the figure below. In each year, the model could select an appropriate level of program participation above Tier 0, or base level, based on TVA's system needs. Alternative strategies explored the impact of increased emphasis on demand-side resources by implementing higher tiers over the study period.

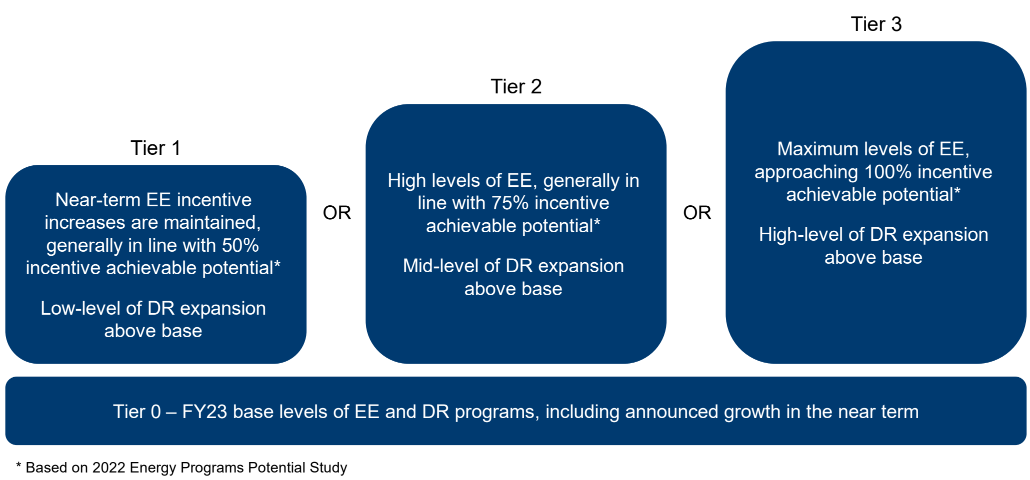

Figure G-2: Programmatic EE and DR Three-Tiered Structure

Tier 0 reflects base levels of demand-side programmatic engagement that are expected to continue into the future, regardless of the strategy employed. Tier 0 includes EE programs that are focused on educational resources, base levels of energy equity program funding, and smaller levels of targeted incentives for the highest value programs. Also, Tier 0 reflects TVA's current DR portfolio of over 1,500 MW and forecasted growth over the next three years.

Tier 1 offerings represent the first tranche of optional EE and DR expansion above the base level. For EE programs, Tier 1 reflects a continuation of EE expansion efforts begun in 2024 and generally aligns with the 50% incentive level in the latest potential study. For DR programs, TVA would expand participation through increased marketing efforts or increased pricing. At a Tier 2 level, EE program options model a higher participation through higher incentives, generally aligning with the 75% incentive level in the potential study. For DR programs, Tier 2 opens up additional levels of DR capacity at a higher incentive rate. Finally, at a Tier 3 level, EE and DR program achievable potentials are maximized. For EE, volumes approach the 100% incentive level, and DR capacity is maximized based on TVA’s expectation of total market depth.

G.4 Demand-side Resource Promotion in IRP Strategies

Strategy design applies a base, moderate or high level of promotion aligned to each strategy narrative. The table below summarizes the level of EE and DR promotion applicable in each strategy. A base level of promotion assumes continuation of Tier 0 programs, and moderate and high levels of promotion layer on additional incentives to increase program participation. Moderate promotion models the impacts of TVA investment in EE and DR at a Tier 2 or higher level across the entire study period and also assumes increased investment in energy equity programs that support disadvantaged communities. High promotion explores the impact of maximizing TVA investment in EE and DR programs at the Tier 3 level across the entire study period and further increases investment in energy equity programs.

Table G-1: Demand-side Resource Promotion by Strategy

Strategy	Energy Efficiency	Demand Response
Baseline Utility Planning	Base	Base
Carbon-free Innovation Focus	Moderate	Moderate
Carbon-free Commercial Ready Focus	Base	Moderate
Distributed and Demand-side Focus	High	High
Resiliency Focus	Base	High

G.5 TVA Program Characteristics

G.5.1 Energy Efficiency (EE)

EE programs span all customer segments and focus on reducing overall electrical consumption. Since temperature is the largest driver of peak loads, particularly in the residential sector, many EE programs focus on space conditioning (HVAC) and weatherization improvements. Programs may also include more efficient lighting, variable frequency drives, and other custom options tailored to a specific industry.

TVA’s residential EE programs are administered through the Residential Services suite of offerings. EnergyRight.com serves as a centralized online portal for residential customers to explore available rebates, as an educational tool, and to build and reinforce consumer trust. Additionally, consumers can use this platform to ensure their contractor has been trained and approved and that their installation has been performed to program standards. Residential customers can also set up appointments for home efficiency evaluations. Following a home efficiency inspection, the customer will receive a detailed report, including pictures of problem areas and recommendations. Contractor search and validation enables customers to find contractors who have been vetted and trained by TVA, providing peace of mind when selecting a contractor for home improvements. Tiers 1, 2, and 3 in the IRP all include financial incentives to encourage end-use customer participation. These incentives are generally in the form of customer rebates following verification that certain home efficiency projects were completed by TVA-vetted contractors. Examples of rebates include window upgrades, HVAC replacements, and additional insulation.

TVA's energy equity EE programs are an important component of residential EE offerings. Since 2009, TVA has partnered with the state of Tennessee's Weatherization Assistance Program (TN WAP) to provide home energy audit and upgrade services to families with incomes less than or equal to 200% of the federal poverty level for the household size. The DOE provides funding for this program, which is then administered locally by the state of Tennessee. TVA continues to provide administrative and technical support to TN WAP to ensure the state takes advantage of all available DOE funds. TVA's Home Uplift initiative, which was expanded Valley-wide in 2020, augments TN WAP by working with LPCs and local communities to create a sustainable program for making weatherization improvements in low-income households. TVA matches the funds contributed by LPCs, local governments, and non-profit agencies. Continued support for Home Uplift is included in base EE spending, and increases in these energy equity programs are included in strategies with moderate or high EE promotion.

Commercial and industrial (C&I) EE programs include some standard rebates but focus more on customized solutions. Tier 0 includes continued support of Strategic Energy Management (SEM), which provides a forum to allow companies to work together to identify and develop solutions for common energy efficiency challenges. For example, a company might discuss the advantages and lessons learned from installing smart thermostats at their facility. SEM has traditionally focused on the industrial sector but is being expanded to include the commercial sector. Tiers 1, 2, and 3 include incentives for C&I programs. Example programs include LED lighting retrofits, variable frequency drives, or HVAC upgrades. Industrial projects tend to be highly customized based on a given customer's use case. For custom projects, the customer would provide TVA with a proposed plan, obtain approval for the plan, implement improvements, and receive rebates following verification for completed projects.

The impact of EE programs on TVA's load will vary by customer segment, season, and time of day, as illustrated below. Residential EE programs have the greatest impact in late afternoon summer hours when residents are returning home from work, and in early winter morning hours when preparing for the day. Generally, these times align with the highest hours of cooling or heating load. Commercial EE load impacts are typically higher during traditional business hours. Due to round-the-clock shifts, industrial EE impacts are generally more consistent throughout all hours. Sector impacts also vary depending on whether a program targets HVAC, lighting, other equipment, or a combination of these aspects.

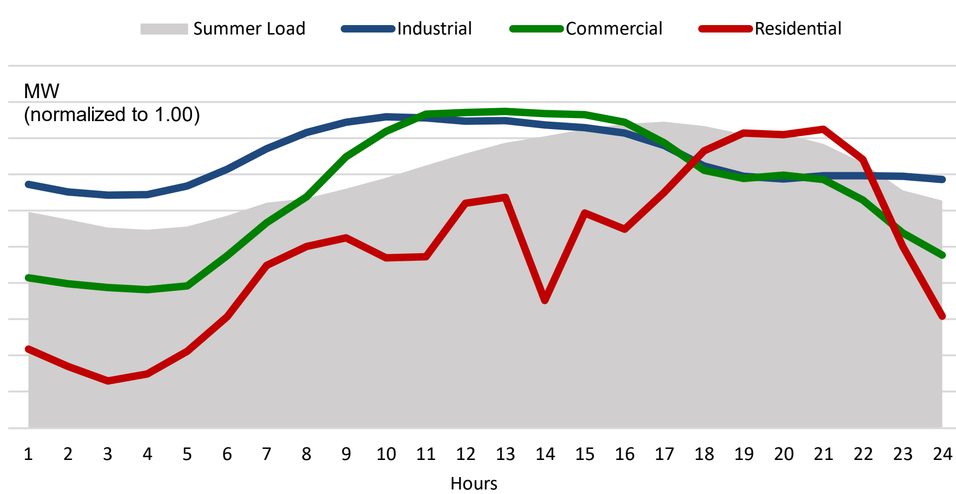

Figure G-3: Illustrative Energy Efficiency Summer Load Shapes (normalized)

G.5.2 Demand Response (DR)

DR resources reduce system load at peak hours. Figure G-4 illustrates summer and winter load shapes, and typical peak or near-peak demand hours around which DR is most likely to be called upon for economic or reliability reasons.

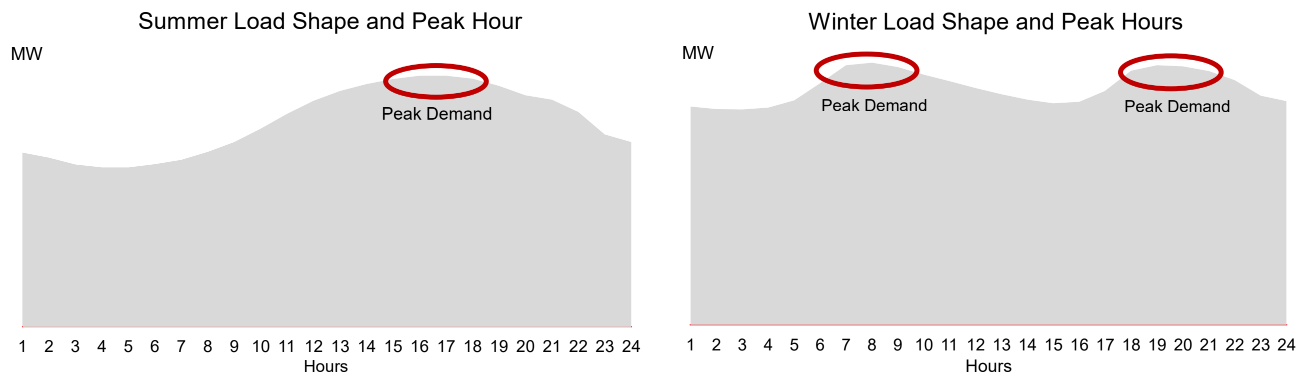

Figure G-4: Seasonal Load Shapes and Typical Peak Demand Hours

Current TVA DR programs include the Interruptible Power Program (IP), Peak Power Partners, and Voltage Optimization. The IRP assumes existing programs will continue through their respective program lives.

IP is TVA's largest DR segment and currently includes the IP30 and IP5 sub-programs. Large industrial customers allow TVA to call on them to reduce their electric load during peak hours when supply is tight or costly, in exchange for a pricing reduction. When called upon, participants in the IP30 program are given 30 minutes' notice to reduce their load to a specified amount. The IP30 program may be used for economic or system reliability reasons. Participants in the IP5 program are given 5 minutes' notice to reduce their load to a specified amount. The IP5 program can only be used for system reliability. IP currently supplies about 1,400 MW of load reduction. These programs evolve over time to meet system and customer needs.

Peak Power Partners utilizes third-party program administrators to aggregate smaller commercial and industrial customers to meet load reduction targets. While similar in concept to IP, Peak Power Partners is smaller and currently supplies about 50 MW of net load reduction. The Peak Power Partners program may be used for economic or system reliability reasons.

The Voltage Optimization program works in partnership with LPCs to lower the voltage on their respective systems to the lower half of the acceptable voltage range. While the current, existing version of this program is being phased out as contracts end, assumptions around an updated version of the program are included in the IRP study.

Finally, the IRP study also includes a residential smart thermostat program. Tier 0 includes spending associated with lower volumes of smart thermostat deployment as part of a pilot effort, while Tiers 1-3 include potential expansion of this program.

G.6 Model Inputs and Assumptions

For demand-side programs to be offered for selection in the optimization model, certain characteristics must be defined that are comparable to supply-side resources, such as:

- Capacity and energy – typically a known size in MW and MWh, respectively
- Installation cost – typically non-site specific $/kW

- Construction lead time – years to build from initial project consideration
- Operational characteristics – variable energy cost $/MWh, capacity factor, etc.
- Service life – years

Demand-side program characteristics must be developed that are comparable to supply-side resources. Traditional supply-side characteristics are modified to meet the unique attributes of demand-side programs. For example, a traditional generating unit may have a service life of 30 years, whereas the lifespan of an energy efficiency program will be based on the lifespan of the individual measure elements included in that program. Characteristics for programs included in the IRP are further detailed in table G-3.

Characteristics of each program in each sector were developed for all tiers, including additional costs to expand delivery system infrastructures and encourage greater participation. Tier 0 programs generally represent costs for platform infrastructure and business as usual, and as such, have known costs. The steps in cost for Tiers 1 through 3 are similar to a supply stack concept, where programs with more potential are lower cost programs and programs with less potential are higher cost programs. As market depth is exhausted from the lower cost programs, the optimization model moves up the supply stack to the next lowest cost program. Energy equity EE programs are the exception, where volumes are enforced at base, moderate and high levels as applicable in each strategy, before applying least-cost optimization. The figure below illustrates the range of costs for each segment and demand-side program type across all three tiers. C&I programs are typically lower cost on a $/MWh basis compared to residential programs due to economies of scale.

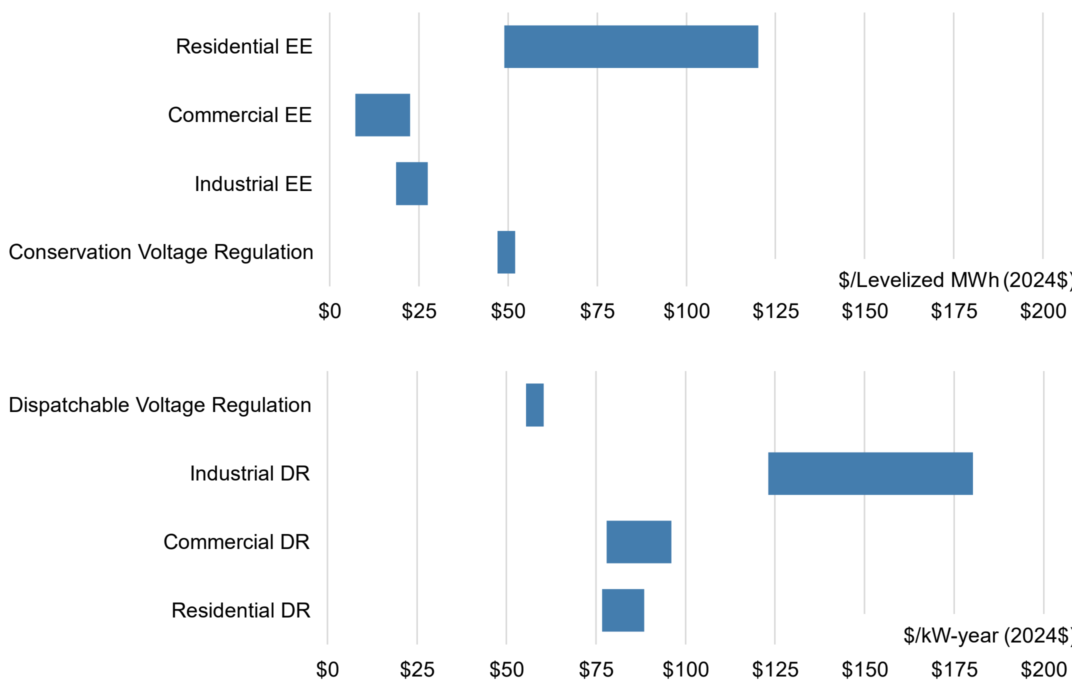

Figure G-5: Summary of Demand-side Program Options and Costs

Much like supply-side counterparts, demand-side programs also have operational-like limits on maximum energy reductions or additions. The limits are driven by program development, customer awareness, market penetration, participant acquisition, and other factors. Demand response capability is assumed to grow with the size of the system. TVA calculates an estimated participation rate for each program tier based on the incentives provided, using historical data and the recent potential study. The optimization model can select Tier 1, 2, or 3, based on which tier allows for the least-cost overall portfolio composition, with certain tiers enforced based on strategy design. New demand-side program resources are available for selection in the model starting in 2027. Details for the individually modeled programs are shown in the tables below.

Table G-2: Energy Efficiency Detailed Program Characteristics

Segment	Program Name	Tier	Life Span (years)*	Summer Firm Capacity (MW)	Winter Firm Capacity (MW)	Program Costs and Incentives ($000)	Energy (MWh)	$/Levelized MWh (2024$)
Residential EE	New Homes	Tier 1	20	3.8	3.5	4,497	8,670	49
		Tier 2		6.8	6.2	10,092	15,574	61
		Tier 3		13.5	12.3	34,307	30,676	106
	Residential Services	Tier 1	7-20	12.7	13.5	31,233	44,686	82
		Tier 2		49.6	52.7	107,327	174,203	72
		Tier 3		127.0	135.0	459,471	446,542	120
Commercial EE	Custom Commercial	Tier 1	10-15	4.8	3.6	5,290	31,204	20
		Tier 2		5.0	3.8	5,954	33,071	21
		Tier 3		5.3	4.0	6,669	34,938	23
	Standard Rebate Commercial	Tier 1	12-15	13.4	9.2	7,771	121,726	7
		Tier 2		14.3	9.8	8,315	129,829	7
		Tier 3		15.2	10.4	8,909	137,932	7
Industrial EE	Custom Industrial	Tier 1-3	12-15	2.0	1.7	3,819	15,874	28
	Standard Rebate Industrial	Tier 1-3	12-15	7.6	5.2	11,883	70,449	19
Local Power Company EE	Conservation Voltage Regulation	Tier 1	10	1.7	0.6	7,095	21,484	47
		Tier 2		2.6	0.9	10,860	32,225	48
		Tier 3		4.3	1.4	19,230	53,709	51

* Range reflects lifespans of the shortest and longest individual measures included within the program

Table G-3: Demand Response Detailed Program Characteristics

Segment	Program Name	Tier	Contract Length	Capacity (MW)	Annual Energy (MWh)	One-Time Cost (2024$)	Annual Fixed Cost ($/kW-year, 2024$)	Energy Cost ($/MWh, 2024$)
Residential DR	Smart Thermostat	Tier 1	5	20	1,600	1,460,000	77	0
		Tier 2		40	3,200	2,860,000	81	0
		Tier 3		60	4,800	5,190,000	88	0
Commercial DR	Aggregated Commercial	Tier 1	1	30	960	0	78	37
		Tier 2		60	1,920	0	78	37
		Tier 3		90	2,880	0	96	39
Industrial DR	Aggregated Industrial	Tier 1	5	30	720	4,800	123	60
		Tier 2		170	4,080	27,200	144	60
		Tier 3		300	7,200	48,000	180	60
Local Power Company DR	Dispatchable Voltage Regulation	Tier 1	5	30	4,800	45,000	55	37
		Tier 2		60	14,400	315,000	58	37
		Tier 3		120	28,800	720,000	60	37

G.7 Program Methodology in System Planning

Planning Approach

Since 2015, TVA has modeled EE and DR as selectable resources in its IRPs. Demand-side programs are modeled in a manner consistent with how supply-side resources are modeled, as applicable. Characteristics include a defined energy pattern similar to renewable resources, known as a load shape. The tiered approach (see Figure G-2) defines offerings, associated impacts, and costs at various levels of program uptake. This allows TVA to model selectable EE and DR resources for full optimization and promotion in certain strategies.

EE programs are non-dispatchable, meaning that system operators cannot directly control impacts based on system needs. Key input parameters are monthly avoided capacity, $/kW (cost divided by summer peak kW), and an hourly energy pattern. DR programs are dispatchable and can be called upon by system operators during peak periods or other times of system need. Typically, DR programs include an annual fixed capacity cost ($/kW-year) and an associated energy cost ($/MWh) used during event hours.

EE and DR programs have estimated energy and capacity impacts based on program load shapes. EE programs have a larger energy impact, and DR programs primarily have a capacity impact.

- Avoided energy calculation – Energy not consumed means fuel not burned, resulting in savings in variable costs. Since program impacts are realized at the consumer meter, they avoid transmission and distribution (thermal) losses, which can average 6.5% by the time energy reaches an end user.
- Avoided capacity calculation – Capacity is avoided, as reduced electricity demand translates into reduced need for incremental capacity additions.

For the 2025 IRP, planners took a “bottom-up” approach to modeling EE by first generating hourly demand profiles for individual program measures using engineering models, calibrated through program evaluation. An EE measure represents a specific energy reduction technology or customer behavior that can be combined with other measures to form a program. For example, a residential EE program might include a variety of individual measures addressing insulation, heating and cooling, window replacement, etc. Each measure has a unique energy reduction impact, as well as a uniquely defined lifespan based on its expected useful life. EE program inputs include 8,760 hourly profile shapes, which are regressed on weather and calendar variables, revealing the relationship between temperature, day of week, season, etc. EE program models then forecast forward using TVA weather and load forecasts as inputs. The final result is an hourly net energy reduction forecast synced to the TVA load forecast for each measure. Programs included in the IRP study represent a bundle of EE measures that represent total program impacts for a typical residential, commercial, or industrial customer.

Modeling Uncertainty

For supply-side resources in the IRP, unit performance is expected to be something less than 100%, and this delivery risk is captured in an outage rate for the unit. Demand-side programs do not have a comparable outage rate, meaning that program impacts are assumed to be available 100% of the time. Efficiency programs are dependent on variables such as equipment reliability and service life, operating conditions, and other factors that can impact operability, similar to an outage rate. Additionally, demand-side programs have other potential uncertainties that are not captured, such as variations in project costs and escalation rates.

The two major sources of uncertainty for demand-side programs are design and delivery. Design uncertainty is introduced by the creation of programs today that may have different costs, lifespans, or load shape impacts over time. Delivery uncertainty results from differences in estimated and evaluated energy savings, program implementation effectiveness though TVA’s 153 LPCs, and changes in codes and standards.

Example Sources of Uncertainty	
Energy Efficiency	Demand Response
Cost Variation	Claimed vs. Evaluated Impact
Measure Life	LPC Delivery Risk
Fixed Shape	Codes and Standards

Figure G-6: Design and Delivery Uncertainties

EE impacts manifest themselves in load, as do other variables such as forecasted adoption of distributed solar, CHP, and electric vehicles. Stochastic analysis, discussed earlier in the IRP document, will evaluate risks of load uncertainty driven by demand-side programs and many other factors.

G.8 Conclusion

TVA's 2025 IRP evaluates a robust set of EE and DR program options. The options are modeled using a tiered approach of program offerings, informed by the recent potential study, and the tiers were also used to define levels of EE and DR promotion in some alternative scenarios. Results from the model provide insights into the impact that demand-side resources could have on the TVA system under a variety of different futures. These insights will inform future planning and energy program design.

H

Appendix H – Capacity and Energy Plan Summaries

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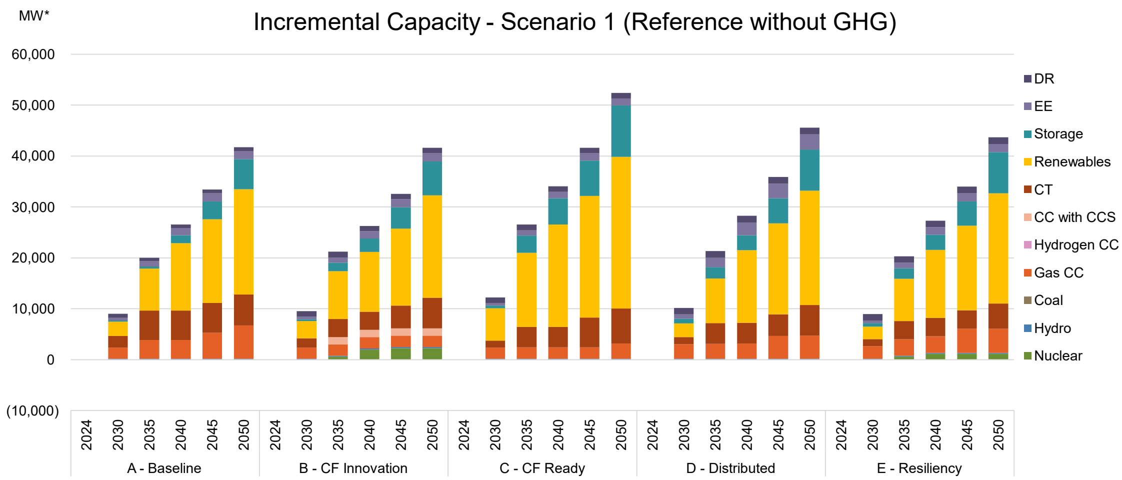
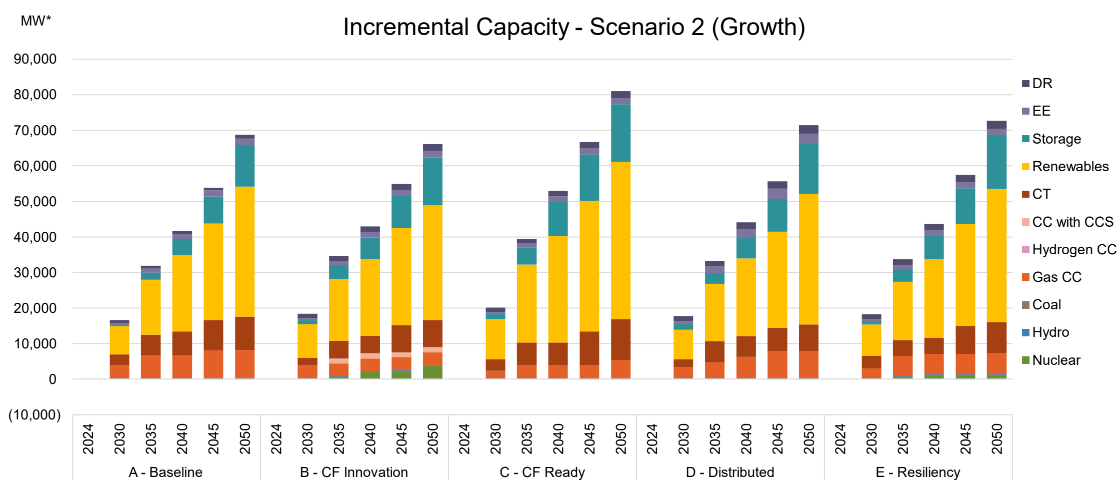
Appendix H – Capacity and Energy Plan Summaries

Combining the six external scenarios with the five business strategies modeled in the IRP resulted in 30 resource portfolios for evaluation. This appendix compares the portfolios on an incremental capacity, total capacity and total energy basis, along with forecasted summer and winter reserve margin positions. Additionally, incremental capacity, total capacity, and total energy details are included in tables for reference.

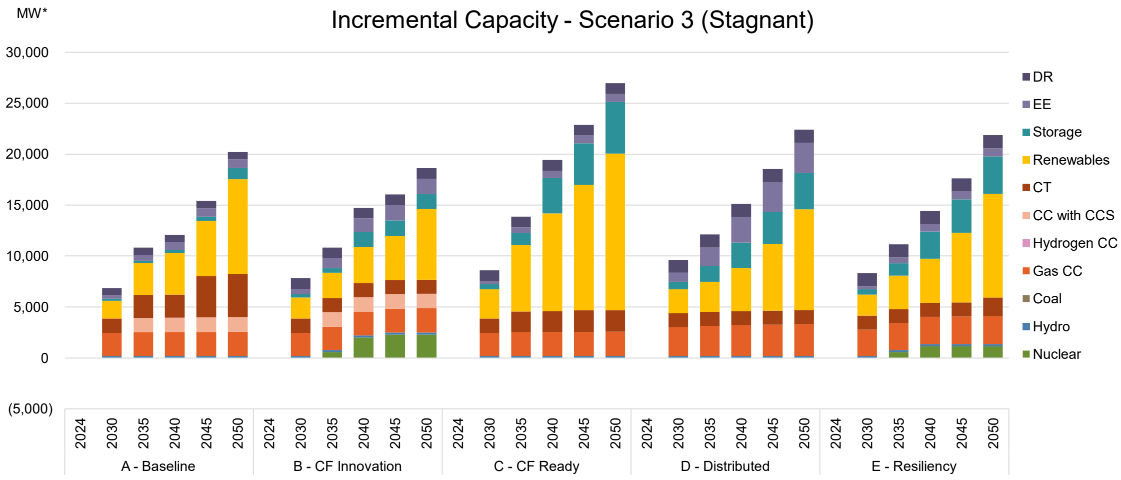
H.1 Incremental Capacity Plans



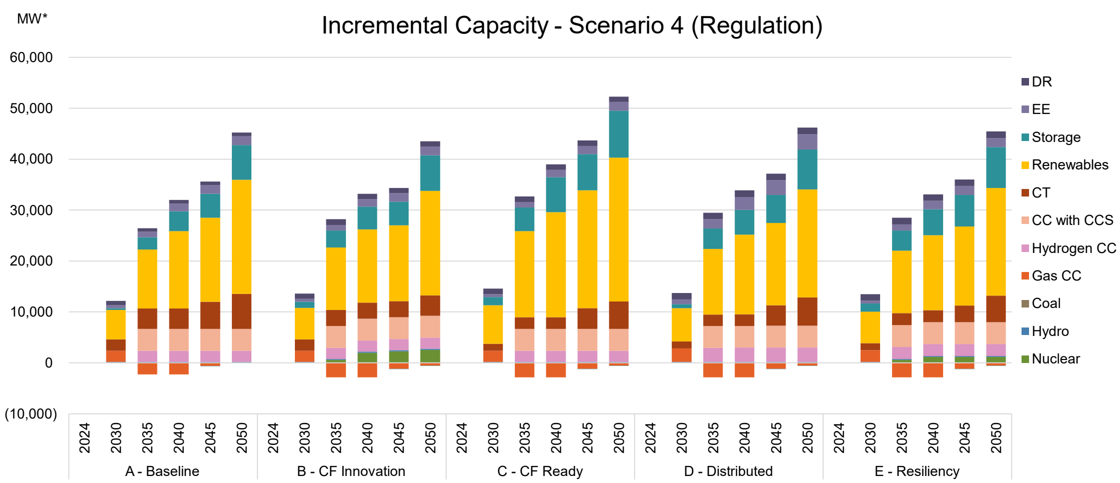
* MW summer net dependable capacity, except for renewables and storage that are shown in nameplate.



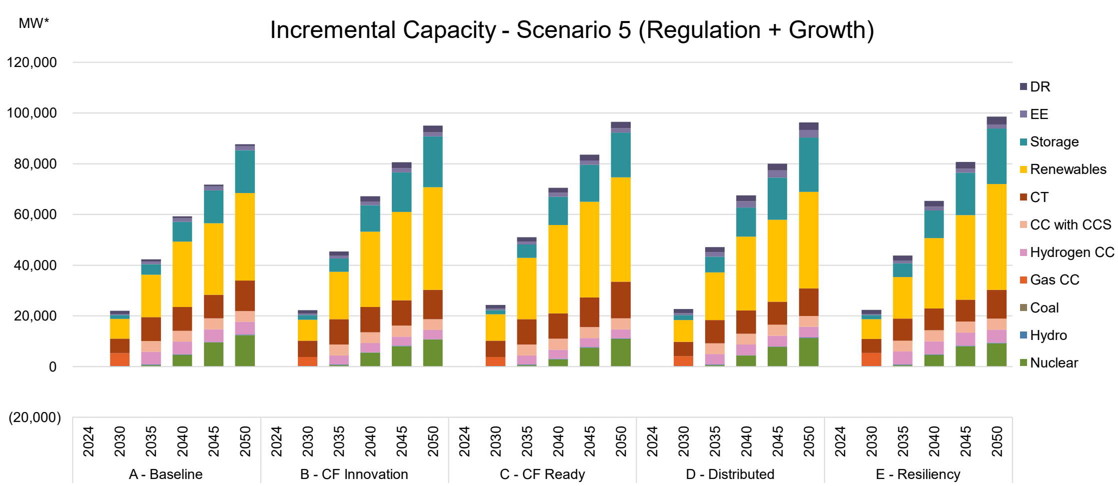
* MW summer net dependable capacity, except for renewables and storage that are shown in nameplate.



* MW summer net dependable capacity, except for renewables and storage that are shown in nameplate.



* MW summer net dependable capacity, except for renewables and storage that are shown in nameplate.



* MW summer net dependable capacity, except for renewables and storage that are shown in nameplate.

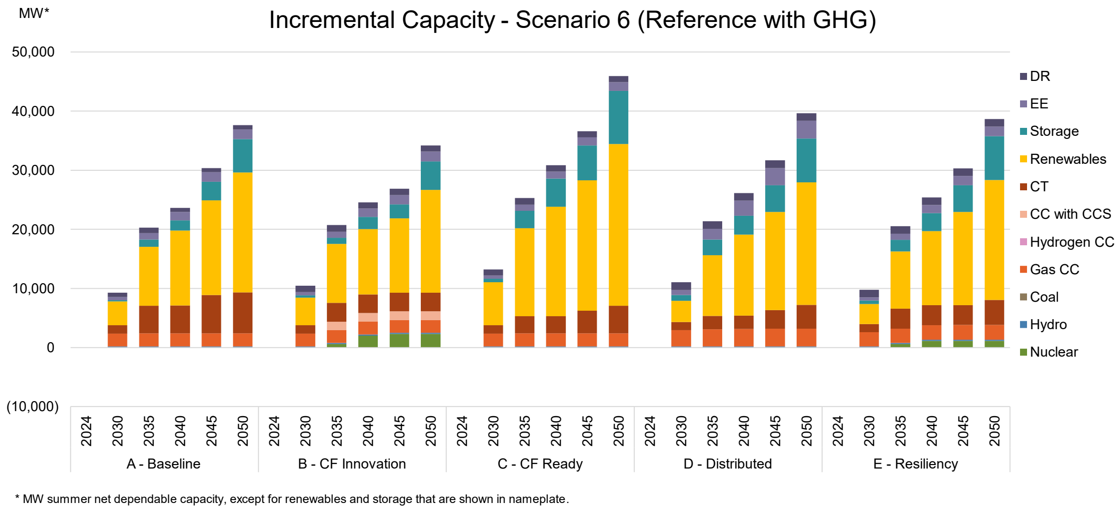
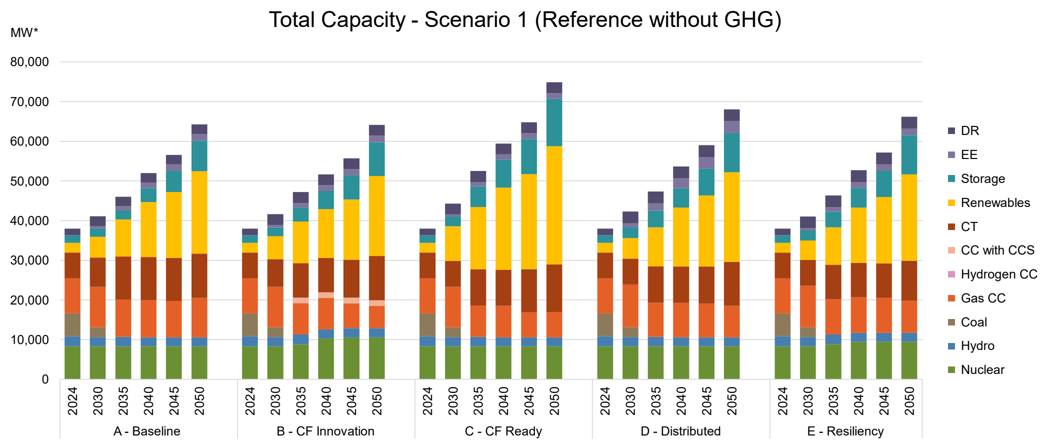


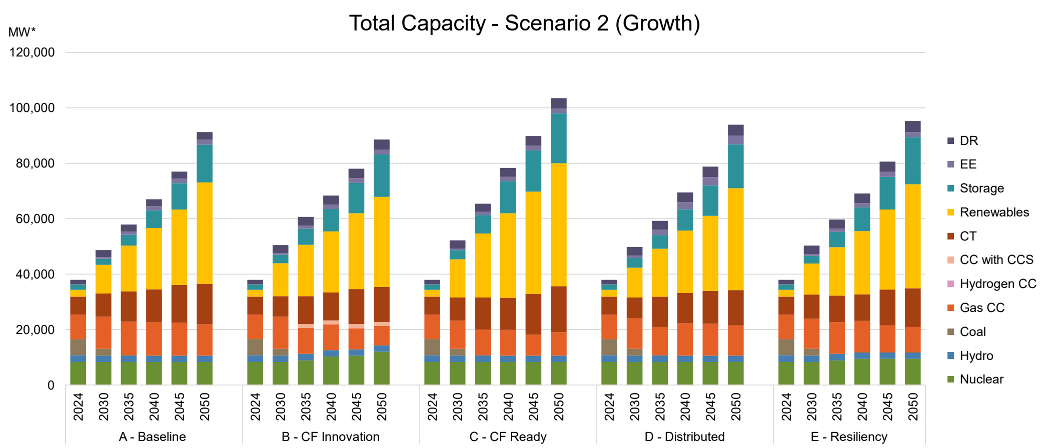
Figure H-1: Incremental Capacity Plans

H.2 Total Capacity Plans

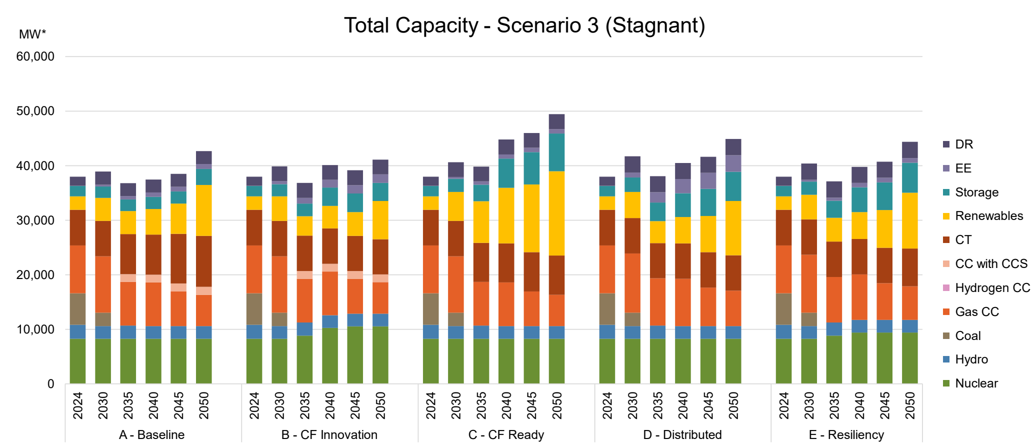
The capacity plans provided below reflect the results for each scenario for all five strategies. Results are grouped by resource type for time increments over the planning horizon. Capacity is shown in gigawatts (GW) and is generally based on summer net dependable capacity, except for renewables and storage that are shown in nameplate capacity. The planning model considers summer and winter capacity needs and resource capabilities, as well as the pattern of energy needs across all hours, in portfolio optimization.



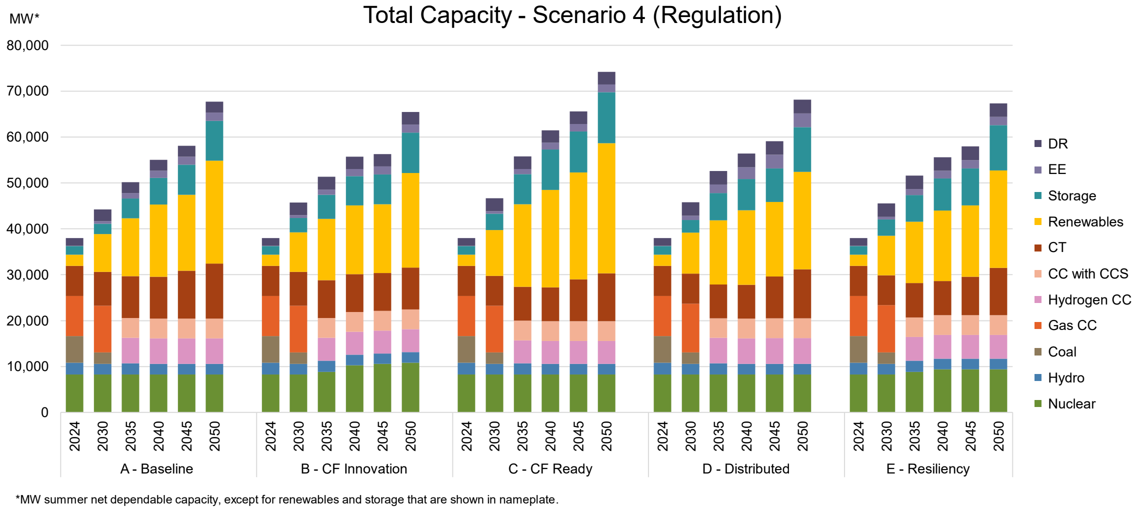
*MW summer net dependable capacity, except for renewables and storage that are shown in nameplate.

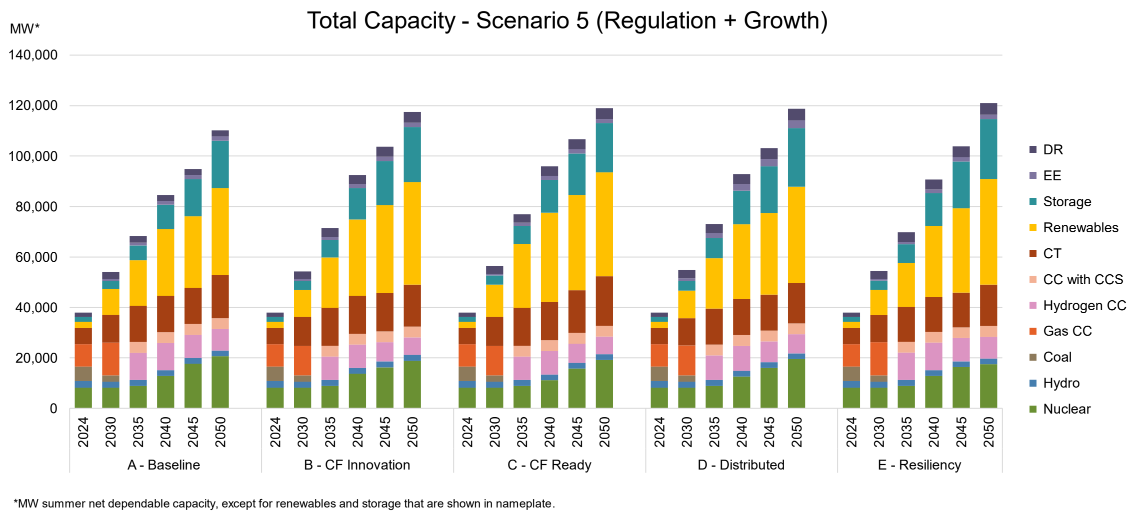


*MW summer net dependable capacity, except for renewables and storage that are shown in nameplate.



*MW summer net dependable capacity, except for renewables and storage that are shown in nameplate.





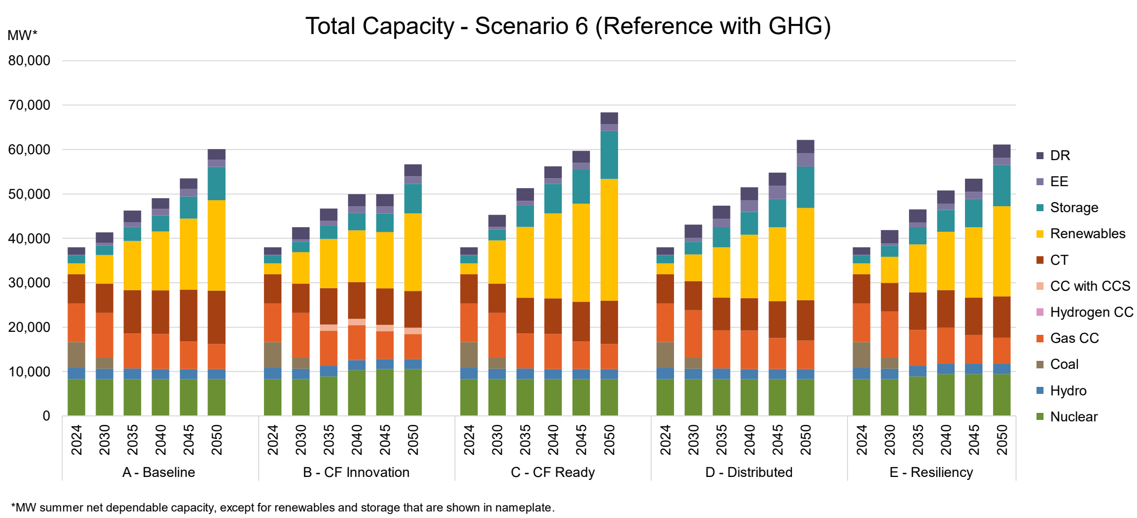
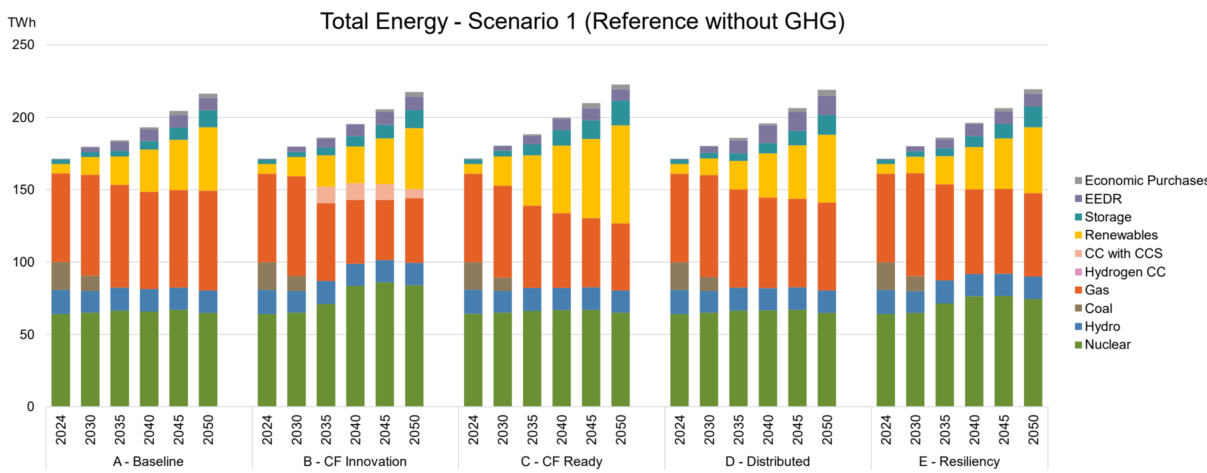
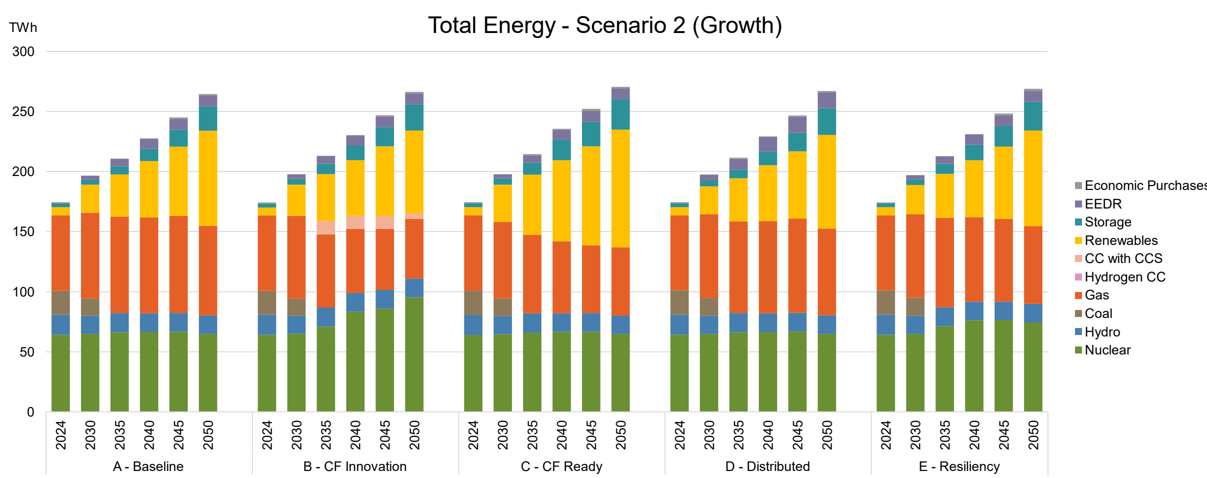


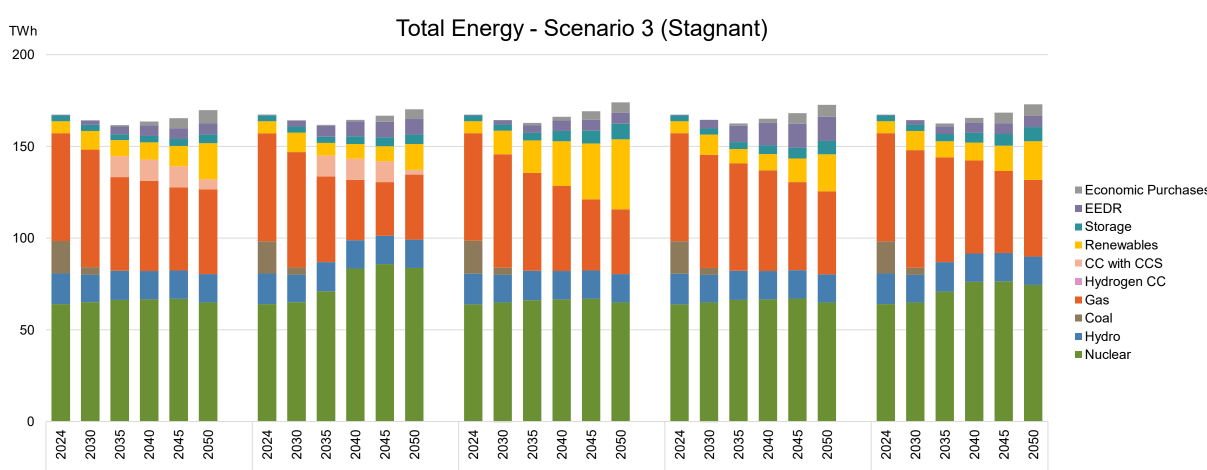
Figure H-2: Total Capacity Plans

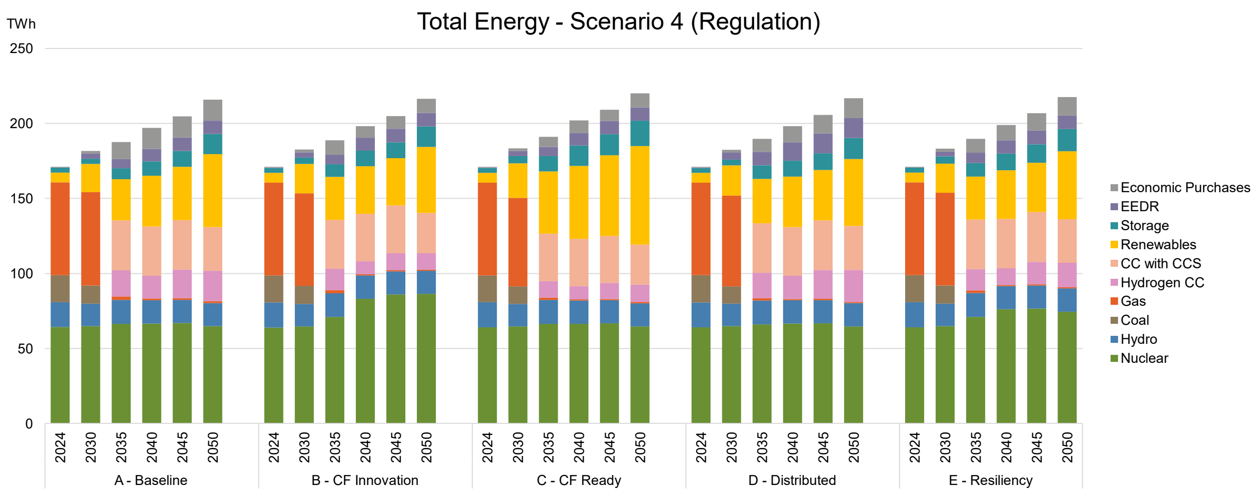
H.3 Total Energy Plans

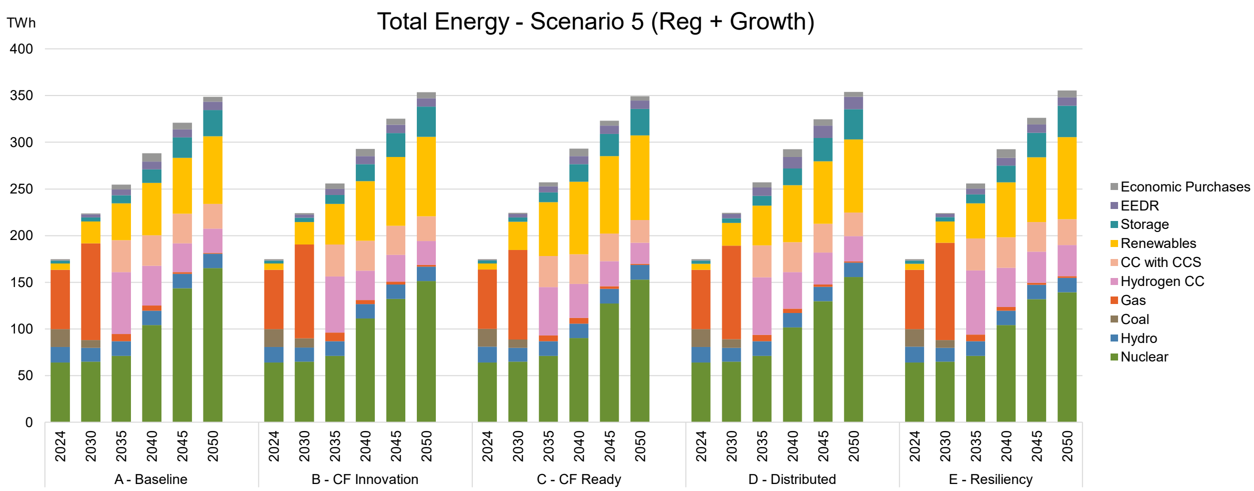
The energy plans provided below reflect the results for each scenario for all five strategies. Results are grouped by resource type for time increments over the planning horizon. Energy is shown in terawatt hours (TWh), which is equal to 1,000 gigawatt hours.











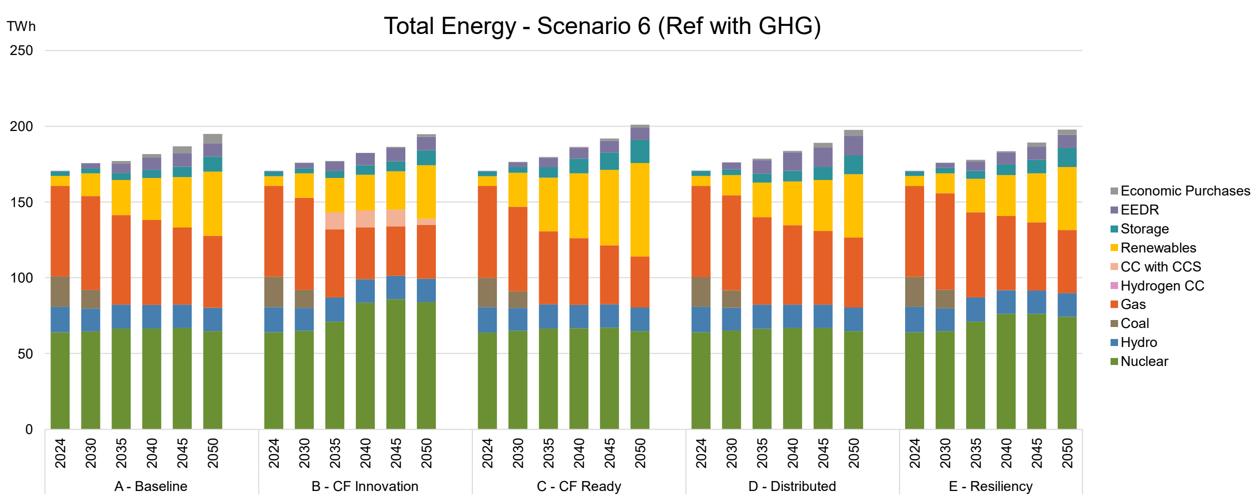
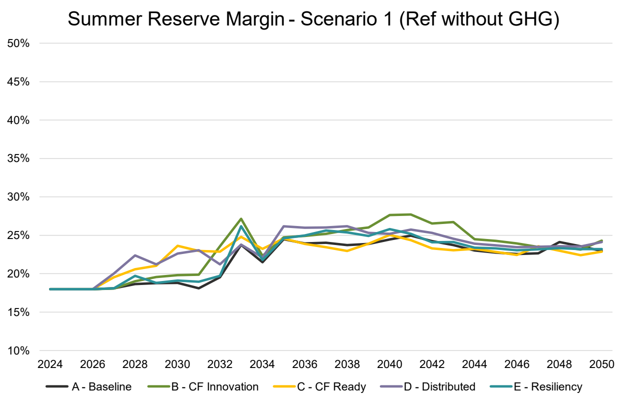
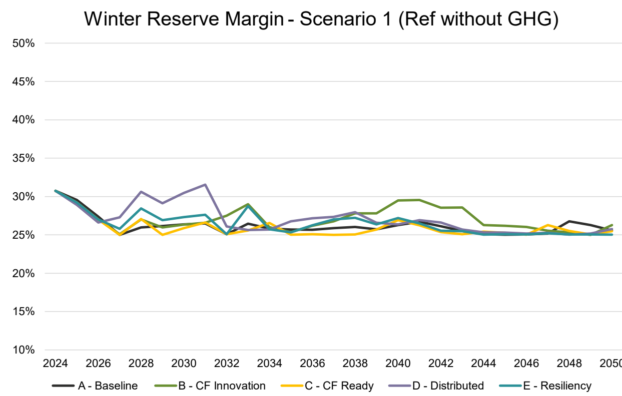


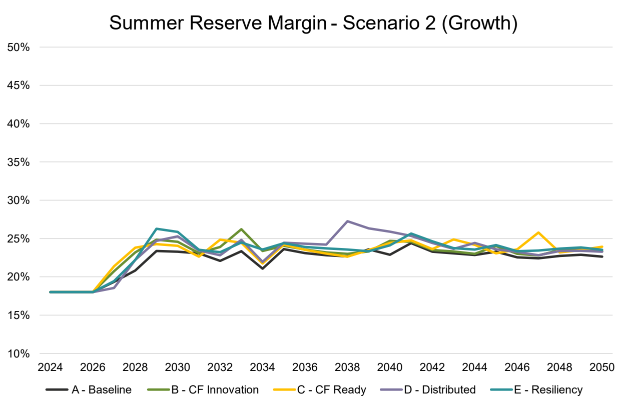
Figure H-3: Total Energy Plans

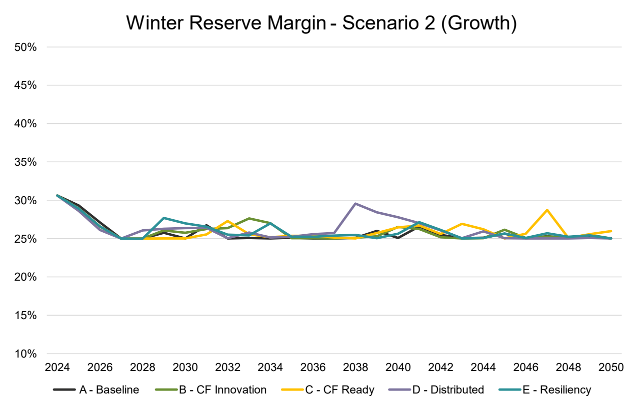
H.4 Reserve Margin Comparisons

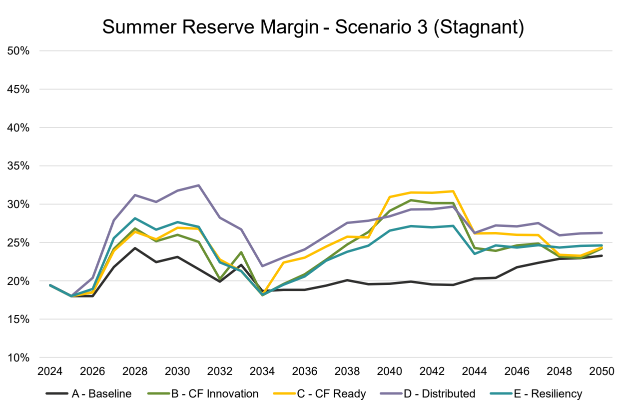
The summer and winter reserve margin charts provided below correspond to the capacity plans. Results are grouped by scenario. For this IRP, TVA used an 18% reserve margin target for summer and a 25% reserve margin target for winter.

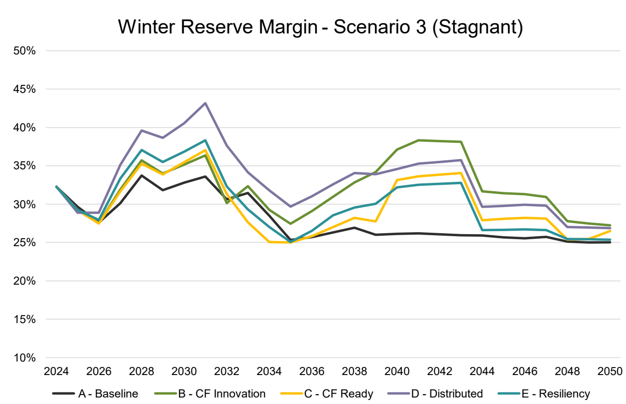












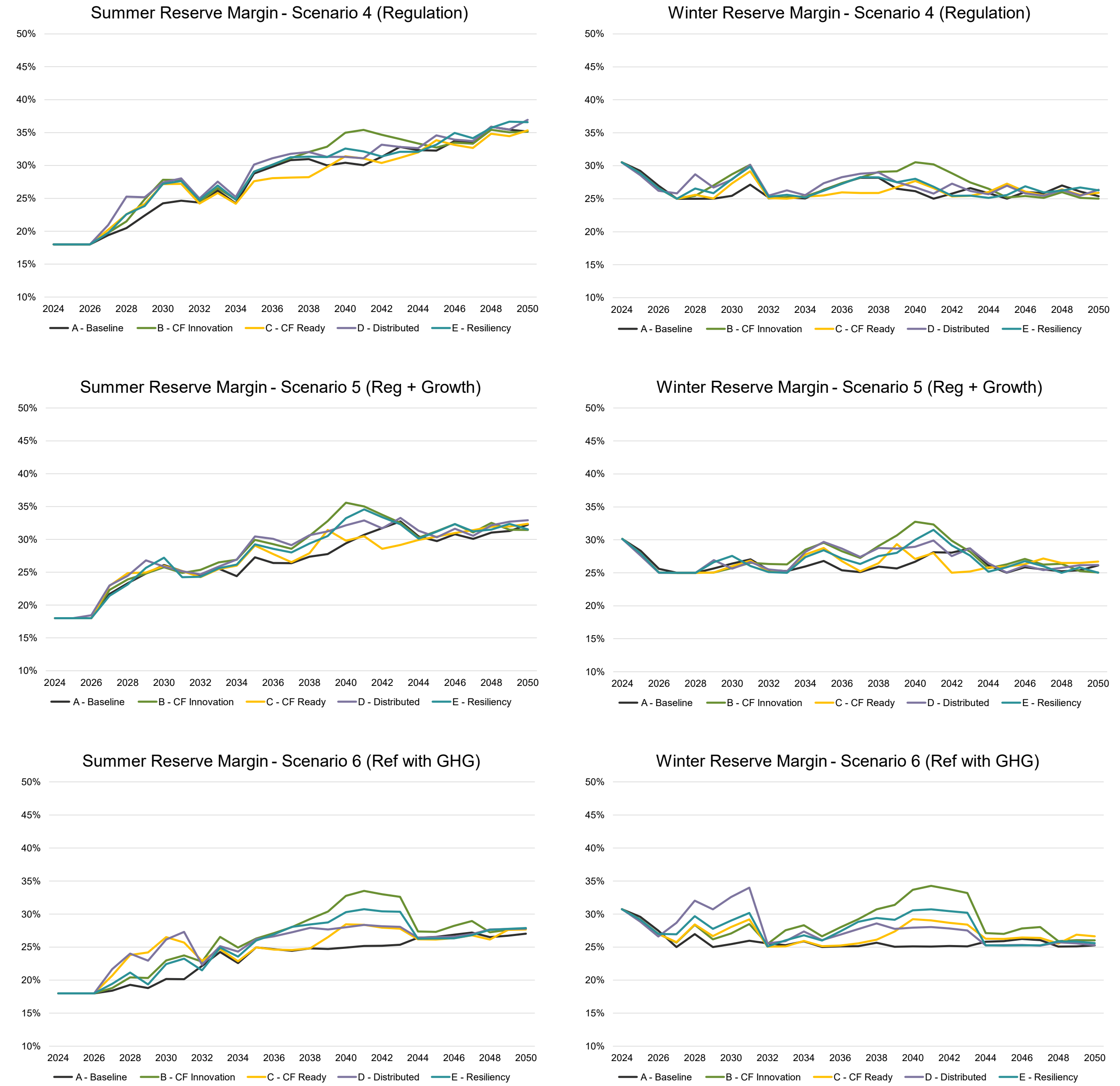


Figure H-4: Reserve Margin Comparisons

H.5 Incremental Capacity Changes

The tables provided below show incremental capacity for all 30 portfolios for 2024-2050. Results are grouped by scenario. Scenarios are represented by number (1 to 6) and strategies by letter (A to E). Data is shown in summer net dependable gigawatts (GW SND), except for renewables and storage which are in nameplate.

Table H-1: Incremental Capacity Tables

1A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.5	2.2	2.2	2.2	2.2	3.6	3.6	3.6	3.6	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	5.1	5.1	5.1	5.1	6.5	6.5	6.5
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	2.3	2.3	2.3	2.3	4.0	4.9	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.9	6.1	6.1	6.1	6.1
Renewables	0.0	0.7	1.0	2.1	2.6	2.7	2.8	3.7	4.8	6.0	7.1	8.3	9.4	10.6	11.5	12.4	13.2	14.3	14.8	14.9	16.1	16.5	17.5	18.5	18.7	19.7	20.7
Storage	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.5	0.5	1.0	1.6	2.1	2.3	2.5	3.0	3.5	4.0	4.5	4.9	5.4	5.9
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.9	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6
DR	0.0	0.3	0.4	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	0.0	1.6	2.0	5.2	7.4	8.7	9.0	10.0	12.7	15.8	17.9	20.0	21.3	22.7	23.7	25.2	26.6	28.2	29.0	29.3	32.4	33.4	35.0	36.7	38.7	40.2	41.7

1B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	1.4	1.7	2.0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.5	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CT	0.0	0.5	0.5	0.5	1.4	1.8	1.8	1.8	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	4.5	4.5	4.5	4.5	5.4	5.4	6.0
Renewables	0.0	0.9	1.2	2.1	2.2	3.2	3.4	4.6	5.8	7.0	8.2	9.4	10.5	10.8	11.0	11.2	11.7	11.8	12.2	12.9	14.1	15.1	16.1	17.1	18.1	19.1	20.1
Storage	0.0	0.1	0.1	0.2	0.3	0.3	0.4	0.4	0.8	0.9	1.1	1.7	1.7	1.8	1.8	2.1	2.6	2.6	2.7	3.2	3.7	4.2	4.7	5.2	5.6	6.1	6.6
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.1	1.2	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
DR	0.0	0.3	0.4	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total	0.0	1.8	2.3	5.5	7.4	9.2	9.5	10.9	14.5	17.6	19.1	21.2	22.8	23.4	24.0	24.9	26.3	26.7	27.1	28.4	31.0	32.6	34.1	35.6	37.9	39.5	41.6

1C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.5	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	3.0	3.0	3.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	2.3	3.1	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	5.8	5.8	5.8	6.5	6.5	6.5	6.9
Renewables	0.0	0.9	1.2	2.9	3.0	4.7	6.3	8.0	9.6	11.3	12.9	14.6	15.9	16.6	17.3	18.8	20.1	20.5	21.3	21.7	23.3	23.9	25.4	26.6	27.0	28.3	29.8
Storage	0.0	0.1	0.1	0.2	0.3	0.4	0.6	0.7	1.2	1.9	2.7	3.4	3.4	3.5	3.5	4.3	5.1	5.1	5.2	5.6	6.3	6.9	7.6	8.2	8.8	9.4	10.1
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.9	0.9	1.0	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.4	1.4	1.4
DR	0.0	0.3	0.4	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total	0.0	1.8	2.3	6.3	8.2	10.3	12.2	14.1	17.4	20.8	24.1	26.6	28.0	28.8	29.5	31.9	34.0	34.6	35.4	36.3	40.4	41.6	43.7	46.2	47.8	49.9	52.4

1D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.2	1.8	2.7	2.8	2.8	2.8	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	1.4	2.3	3.1	4.0	4.0	4.0	4.0	4.0	4.0	4.2	4.2	4.2	4.2	4.2	4.2	4.5	5.3	5.6	6.0
Renewables	0.0	1.0	1.4	2.0	2.2	2.4	2.7	3.7	5.0	6.3	7.5	8.8	9.9	11.2	12.4	13.6	14.3	15.2	15.6	15.9	17.1	17.9	18.9	19.9	20.5	21.5	22.5
Storage	0.0	0.2	0.3	0.3	0.5	0.7	0.9	1.1	1.4	1.7	1.8	2.3	2.4	2.4	2.6	2.7	2.9	3.2	3.6	3.6	4.2	4.9	5.5	6.2	6.8	7.4	8.1
EE	0.0	0.0	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.8	2.0	2.2	2.3	2.4	2.5	2.7	2.7	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.0
DR	0.0	0.3	0.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Total	0.0	2.1	2.8	6.2	8.5	9.4	10.2	11.6	13.4	16.1	18.6	21.3	22.8	24.2	25.8	27.2	28.3	29.8	30.6	31.0	34.4	35.9	37.6	39.5	41.6	43.4	45.6

1E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.1	1.6	2.4	2.5	2.5	2.5	2.5	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.3	4.7	4.7	4.7	4.8	4.8	4.8	4.8
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	2.3	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.8	4.7	4.7	4.9
Renewables	0.0	0.9	1.2	1.7	1.9	2.3	2.5	3.5	4.7	5.9	7.1	8.3	9.5	10.7	12.0	12.2	13.3	13.9	14.3	14.5	15.6	16.7	17.7	18.7	19.7	20.7	21.7
Storage	0.0	0.1	0.1	0.2	0.3	0.6	0.7	0.7	0.9	1.1	1.3	2.0	2.1	2.1	2.1	2.5	3.0	3.0	3.1	3.6	4.1	4.7	5.4	6.0	6.6	7.4	8.0
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.6	1.5	1.6	1.6	1.6	1.6	1.7	1.6	1.6	1.6
DR	0.0	0.3	0.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Total	0.0	1.8	2.4	5.5	7.5	8.6	9.0	10.2	12.7	16.6	18.0	20.3	21.9	23.6	24.9	25.6	27.3	28.0	28.4	29.1	32.3	34.0	35.7	37.6	40.0	41.8	43.7

2A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	3.6	3.6	3.6	5.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	3.1	3.1	4.0	4.0	4.0	4.9	5.8	5.8	5.8	5.8	6.7	6.7	7.6	7.6	7.6	7.6	8.5	8.6	8.6	9.5	9.5	9.5
Renewables	0.0	0.7	1.1	2.9	4.3	6.1	8.0	9.7	10.9	12.4	14.0	15.5	17.0	18.4	19.9	20.5	21.5	22.4	22.9	24.4	26.8	27.1	29.0	30.5	32.8	34.3	36.6
Storage	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.4	0.7	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5	6.3	7.2	7.7	8.2	9.1	10.0	10.8	11.8
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7
DR	0.0	0.3	0.4	0.9	0.9	0.9	0.9	0.9	0.7	0.7	0.8	0.8	0.8	0.8	0.9	0.8	0.8	0.8	0.8	0.8	0.9	0.7	0.7	0.7	0.7	1.1	1.1
Total	0.0	1.6	2.2	6.1	9.4	14.6	16.6	19.4	22.4	25.8	28.8	31.9	34.0	36.0	38.1	40.2	41.7	44.2	45.2	47.5	52.3	53.8	56.3	58.7	62.8	65.5	68.8

2B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	1.4	1.7	2.0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	3.4	3.7	3.7
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CT	0.0	0.5	0.5	0.5	1.4	2.3	2.3	2.3	4.0	4.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	6.7	7.6	7.6	7.6	7.6	7.6	7.6
Renewables	0.0	0.9	1.4	3.7	5.9	7.7	9.4	11.3	12.9	14.4	15.9	17.5	18.4	18.5	19.2	20.5	21.5	22.0	22.5	24.1	26.9	27.3	28.8	30.3	30.6	31.6	32.4
Storage	0.0	0.1	0.2	0.3	0.6	0.9	1.2	1.8	2.3	2.8	3.3	3.9	4.0	4.3	4.3	5.2	6.2	6.7	7.2	7.9	8.5	9.0	9.5	10.5	11.4	12.4	13.4
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.8	1.7	1.7	1.8
DR	0.0	0.3	0.4	1.1	1.2	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.5	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0
Total	0.0	1.9	2.6	7.2	11.5	16.3	18.4	21.1	25.2	29.1	32.2	34.7	36.2	36.8	38.0	40.6	42.9	44.4	45.5	47.8	53.0	54.9	57.0	59.6	61.9	64.2	66.1

2C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	2.2	2.2	2.2	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	5.1	5.1	5.1	5.1
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	3.1	3.1	3.1	4.0	4.7	5.6	6.5	6.5	6.5	6.5	6.5	6.5	6.9	6.9	7.8	9.6	9.6	10.2	10.2	10.2	10.9	11.6
Renewables	0.0	0.9	1.4	4.0	6.6	8.9	11.4	13.6	15.9	18.0	19.5	22.0	22.6	23.8	25.6	27.9	29.9	31.2	32.1	33.7	36.1	36.8	38.8	39.7	41.7	42.3	44.3
Storage	0.0	0.1	0.2	0.3	0.6	1.2	1.4	2.1	2.8	3.4	4.1	4.8	5.4	6.1	6.7	8.3	9.7	10.4	11.0	11.7	12.4	13.0	13.7	14.3	14.9	15.5	16.2
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7
DR	0.0	0.3	0.4	1.1	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0
Total	0.0	1.9	2.6	7.6	12.2	17.3	20.1	23.2	28.5	32.1	35.3	39.5	40.9	42.9	45.5	49.4	53.0	55.5	57.1	60.4	65.2	66.7	70.1	73.1	75.7	77.6	81.0

2D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.2	1.9	3.0	3.1	3.1	3.1	4.5	4.5	4.6	4.6	4.6	4.6	6.0	6.0	6.0	6.1	6.1	6.1	7.5	7.5	7.5	7.5	7.5	7.5	7.6
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	2.3	2.3	2.3	2.3	4.1	5.0	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	6.7	6.7	6.7	6.7	7.6	7.6	7.6
Renewables	0.0	1.1	1.6	2.5	4.6	6.5	8.3	10.3	11.6	13.2	14.7	16.2	17.7	18.9	19.6	21.0	21.9	22.7	23.3	24.6	26.1	27.0	29.1	30.8	32.9	34.6	36.7
Storage	0.0	0.3	0.4	0.6	1.0	1.3	1.6	1.9	2.2	2.3	2.5	3.0	3.7	4.3	4.5	5.2	5.8	6.5	7.2	7.9	8.5	9.2	9.9	10.8	11.7	12.9	14.0
EE	0.0	0.0	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.8	2.0	2.2	2.3	2.4	2.5	2.7	2.7	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.0
DR	0.0	0.3	0.4	1.3	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3
Total	0.0	2.2	3.3	7.1	11.8	15.4	17.8	20.3	23.6	27.3	30.2	33.3	35.7	37.7	40.2	42.5	44.1	45.9	47.2	49.3	54.0	55.6	58.6	61.2	65.2	68.1	71.4

2E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.2	1.8	2.8	2.8	2.8	2.9	4.3	4.3	5.7	5.7	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	3.6	3.6	3.6	3.6	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	5.4	5.4	5.4	7.1	7.8	7.8	7.8	8.7	8.9	8.9
Renewables	0.0	0.9	1.4	3.0	5.2	7.0	8.7	10.6	11.8	13.3	14.8	16.4	17.4	17.5	18.8	20.6	22.1	23.4	23.9	25.2	27.7	28.8	30.9	32.8	34.5	36.0	37.5
Storage	0.0	0.1	0.2	0.3	0.6	0.8	0.9	1.1	1.6	2.3	2.9	3.6	3.7	3.8	4.5	5.5	6.7	7.3	8.0	8.6	9.3	10.0	10.6	11.8	12.8	14.0	15.1
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7
DR	0.0	0.3	0.4	1.3	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3
Total	0.0	1.9	2.8	7.1	11.6	16.3	18.2	20.5	23.8	27.3	31.1	33.7	35.2	35.9	38.0	41.0	43.7	46.7	47.9	49.9	54.9	57.5	60.3	63.4	67.1	70.0	72.7

3A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.1	1.5	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	4.0	4.0	4.0	4.0	4.2	4.2	4.2
Renewables	0.0	0.7	1.0	1.6	1.7	1.8	1.8	1.9	2.0	2.0	3.1	3.1	3.2	3.5	3.8	4.1	4.1	4.2	4.6	4.6	5.2	5.5	6.4	6.7	7.7	8.3	9.3
Storage	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.9	1.0	1.1
EE	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
DR	0.0	0.3	0.4	0.7	0.7	0.7	0.7	0.7	0.8	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	0.0	1.6	2.2	4.6	6.4	6.8	6.8	7.0	8.2	9.7	10.8	10.8	11.0	11.3	11.8	12.1	12.1	12.3	12.6	12.8	15.1	15.4	16.4	16.8	18.4	19.1	20.2

3B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	1.4	1.7	2.0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.1	1.5	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Renewables	0.0	0.9	1.3	1.9	2.0	2.1	2.1	2.3	2.4	2.4	2.4	2.5	2.6	2.9	3.3	3.5	3.6	3.7	4.1	4.1	4.3	4.3	4.8	5.2	5.8	5.9	6.9
Storage	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.6	0.9	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.4	1.4	1.4
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
DR	0.0	0.3	0.4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total	0.0	1.9	2.6	5.4	7.3	7.7	7.8	8.2	8.4	10.3	10.4	10.8	11.4	12.1	13.0	13.9	14.7	15.3	15.7	15.8	16.0	16.0	16.6	16.9	17.4	17.6	18.6

3C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.1	1.5	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Renewables	0.0	0.9	1.3	1.9	2.0	2.5	2.9	3.5	4.0	4.4	5.6	6.5	7.0	7.8	8.5	9.2	9.6	10.1	10.9	11.4	11.9	12.3	12.7	13.2	13.5	13.9	15.4
Storage	0.0	0.1	0.2	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.1	1.2	1.3	1.4	1.6	1.7	3.4	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.2	4.4	5.0
EE	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
DR	0.0	0.3	0.4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total	0.0	1.9	2.6	5.4	7.2	8.0	8.6	9.5	10.1	10.7	12.2	13.9	14.5	15.5	16.5	17.3	19.4	20.2	21.0	21.6	22.3	22.9	23.3	23.9	24.3	24.8	26.9

3D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.3	1.9	2.7	2.8	2.8	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Renewables	0.0	1.1	1.6	2.2	2.3	2.4	2.4	2.7	2.8	2.8	2.9	2.9	3.1	3.5	3.9	4.2	4.2	4.3	4.7	4.8	5.9	6.6	6.5	6.9	7.9	8.9	9.9
Storage	0.0	0.3	0.4	0.4	0.5	0.6	0.7	1.0	1.1	1.2	1.4	1.5	1.7	1.9	2.2	2.4	2.5	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.3	3.4	3.5
EE	0.0	0.0	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.8	2.0	2.2	2.3	2.4	2.5	2.7	2.7	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.0
DR	0.0	0.3	0.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Total	0.0	2.2	3.2	6.7	8.7	9.3	9.6	10.6	10.9	11.3	11.8	12.1	12.6	13.4	14.3	14.9	15.1	15.6	16.1	16.4	17.7	18.5	18.7	19.2	20.1	21.3	22.4

3E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.2	1.8	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.8	1.8	1.8
Renewables	0.0	0.9	1.3	1.9	2.0	2.1	2.1	2.3	2.4	2.4	3.2	3.3	3.4	3.7	4.1	4.3	4.4	4.5	4.9	4.9	6.1	6.8	6.8	7.2	8.2	9.2	10.2
Storage	0.0	0.1	0.2	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.2	1.2	1.3	1.4	1.6	2.0	2.6	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.4	3.5	3.6
EE	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
DR	0.0	0.3	0.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Total	0.0	1.9	2.7	5.9	7.7	8.1	8.3	8.8	9.0	9.5	10.8	11.1	11.6	12.5	13.1	13.8	14.4	14.8	15.2	15.4	16.7	17.6	17.7	18.2	19.6	20.7	21.9

4A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	2.2	2.2	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.5	0.5	0.5	1.4	2.3	2.3	2.3	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.7	5.4	5.4	5.4	6.0	6.0	6.9	6.9	6.9
Renewables	0.0	0.7	1.0	2.5	3.6	4.7	5.8	6.8	8.0	9.0	10.2	11.5	12.9	14.4	15.0	15.1	15.2	15.2	15.5	15.5	15.7	16.5	17.5	18.7	20.0	21.0	22.4
Storage	0.0	0.1	0.1	0.1	0.2	0.2	0.3	0.8	1.4	1.5	1.9	2.4	3.0	3.5	3.5	3.5	3.9	3.9	3.9	4.0	4.2	4.7	4.9	5.4	5.8	6.3	6.8
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7
DR	0.0	0.3	0.4	0.8	0.9	0.9	0.9	0.9	1.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Subtotal Addi	0.0	1.6	2.0	5.6	8.6	10.9	12.2	13.8	17.5	19.9	23.1	26.5	28.5	30.6	31.3	31.5	32.0	32.1	33.1	33.9	34.3	35.6	37.5	39.2	41.8	43.3	45.2
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC Retir	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.8	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-0.6	-0.6	-0.6	-0.6	0.0	0.0	0.0
Total	0.0	1.6	2.0	5.6	8.6	10.9	12.2	13.8	16.4	18.8	21.3	24.2	26.2	28.3	29.0	29.2	29.7	29.8	30.8	31.6	33.6	35.0	36.8	38.6	41.8	43.3	45.2

4B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	1.4	1.7	2.0	2.3	2.3	2.3	2.3	2.3	2.6	2.6	2.6	2.6	2.6
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	2.2	2.2	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.5	0.5	0.5	1.4	2.3	2.3	2.3	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	4.0	4.0	4.0
Renewables	0.0	0.9	1.2	2.7	3.9	5.0	6.2	7.2	8.4	9.4	10.8	12.3	13.5	14.1	14.3	14.4	14.4	14.4	14.8	14.8	14.9	14.9	15.9	16.9	17.5	18.5	20.5
Storage	0.0	0.1	0.1	0.1	0.3	0.7	1.2	1.7	2.2	2.2	2.8	3.3	3.5	3.7	3.7	4.0	4.5	4.5	4.5	4.5	4.5	4.6	5.1	5.6	6.0	6.5	7.0
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7
DR	0.0	0.3	0.4	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Subtotal Addi	0.0	1.8	2.3	6.1	9.2	11.9	13.6	15.2	18.1	20.9	24.4	28.2	29.9	31.0	31.6	32.4	33.2	33.6	34.0	34.0	34.2	34.4	36.1	37.6	39.5	41.0	43.5
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC Retir	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.3	-2.0	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-1.2	-1.2	-1.2	-1.2	-0.6	-0.6	-0.6
Total	0.0	1.8	2.3	6.1	9.2	11.9	13.6	15.2	17.0	19.5	22.3	25.3	27.1	28.2	28.7	29.5	30.4	30.7	31.1	31.1	33.0	33.2	34.9	36.4	38.9	40.4	42.9

4C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	2.2	2.2	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.7	3.2	4.0	4.0	4.0	4.9	4.9	5.4
Renewables	0.0	0.9	1.2	3.0	4.4	6.0	7.6	9.0	11.9	13.2	15.2	16.9	18.5	19.3	19.7	20.2	20.6	21.0	21.8	22.2	22.8	23.2	24.0	25.0	25.6	26.8	28.3
Storage	0.0	0.1	0.1	0.1	0.3	0.9	1.6	2.3	2.9	3.1	3.8	4.6	5.1	5.3	5.3	6.1	6.9	6.9	6.9	6.9	7.1	7.1	7.1	7.4	7.9	8.6	9.2
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7
DR	0.0	0.3	0.4	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Subtotal Addi	0.0	1.8	2.3	6.4	9.7	12.2	14.6	16.8	21.4	24.3	28.6	32.7	34.8	35.8	36.3	37.7	39.0	39.5	40.2	41.1	42.3	43.7	44.5	45.8	47.8	49.7	52.3
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC Retir	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.3	-2.0	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-1.2	-1.2	-1.2	-1.2	-0.6	-0.6	-0.6
Total	0.0	1.8	2.3	6.4	9.7	12.2	14.6	16.8	20.3	23.0	26.6	29.8	32.0	33.0	33.4	34.9	36.1	36.6	37.4	38.3	41.1	42.4	43.2	44.6	47.2	49.1	51.7

4D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.1	1.7	2.6	2.6	2.6	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	3.1	3.1	3.1	4.0	4.0	4.0	4.9	4.9	5.6
Renewables	0.0	1.0	1.4	3.0	4.3	5.4	6.5	7.6	8.8	9.8	11.3	12.9	14.6	15.3	15.5	15.6	15.6	15.6	16.0	16.0	16.2	16.2	17.2	18.2	19.2	20.2	21.2
Storage	0.0	0.2	0.3	0.3	0.5	0.6	0.8	1.5	2.1	2.1	3.0	4.0	4.5	4.9	4.9	4.9	4.9	4.9	4.9	5.1	5.5	5.5	5.5	6.0	6.6	7.2	7.9
EE	0.0	0.0	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.8	2.0	2.2	2.3	2.4	2.5	2.7	2.7	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.0
DR	0.0	0.3	0.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Subtotal Addi	0.0	2.1	2.8	7.1	10.5	12.1	13.7	15.6	18.6	21.2	25.3	29.5	31.9	33.1	33.5	33.8	33.9	34.0	35.3	35.6	36.2	37.2	38.2	39.8	42.2	43.9	46.2
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC Retir	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-2.3	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-1.2	-1.2	-1.2	-1.2	-0.6	-0.6	-0.6
Total	0.0	2.1	2.8	7.1	10.5	12.1	13.7	15.6	17.5	20.2	23.0	26.6	29.1	30.2	30.6	30.9	31.0	31.2	32.5	32.7	35.0	36.0	37.0	38.6	41.6	43.3	45.6

4E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.1	1.6	2.3	2.3	2.3	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.8	2.8	3.3	4.1	4.1	4.8	5.2	5.2
Renewables	0.0	0.9	1.2	2.7	3.9	5.0	6.2	7.2	8.4	9.4	10.8	12.3	13.8	14.4	14.6	14.7	14.7	14.7	15.1	15.1	15.3	15.5	16.5	17.5	18.5	19.5	21.1
Storage	0.0	0.1	0.1	0.1	0.3	0.9	1.6	2.3	2.9	2.9	3.3	3.9	4.1	4.3	4.3	4.6	5.1	5.1	5.1	5.1	5.7	6.2	6.2	6.2	6.7	7.4	8.0
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.7	0.9	1.1	1.1	1.2	1.3	1.4	1.5	1.6	1.6	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.7	1.7	1.8
DR	0.0	0.3	0.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Subtotal Addi	0.0	1.8	2.3	6.4	9.5	11.6	13.5	15.3	18.4	21.3	24.5	28.5	30.6	31.7	32.0	32.5	33.1	33.2	33.5	34.0	34.8	36.0	37.9	38.9	41.1	43.2	45.4
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC Retir	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.3	-2.0	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-1.2	-1.2	-1.2	-1.2	-0.6	-0.6	-0.6
Total	0.0	1.8	2.3	6.4	9.5	11.6	13.5	15.3	17.4	19.9	22.5	25.6	27.7	28.9	29.2	29.7	30.2	30.3	30.7	31.1	33.6	34.8	36.7	37.7	40.5	42.6	44.9

5A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	2.3	3.4	4.6	5.7	6.9	8.0	9.2	9.5	10.6	10.9	10.9	12.1	12.4
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	5.0	5.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.5	0.5	0.5	1.4	4.9	5.8	6.7	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	11.1	11.1	12.0
Renewables	0.0	0.7	1.0	3.1	4.7	6.3	7.8	9.3	11.2	13.2	14.9	16.8	18.9	21.2	23.5	25.8	25.8	26.8	27.5	27.5	27.8	28.2	29.7	31.1	31.5	33.0	34.5
Storage	0.0	0.1	0.1	0.1	0.2	0.9	1.4	1.9	2.4	2.9	3.5	4.0	4.6	5.7	6.3	6.9	7.8	8.8	9.9	10.9	11.9	12.9	13.9	14.9	15.8	16.1	16.9
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.7	1.6	1.6	1.6
DR	0.0	0.3	0.4	0.9	1.0	1.1	1.2	1.3	1.4	1.5	0.9	0.9	0.9	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Subtotal Addi	0.0	1.6	2.1	6.3	9.7	18.9	22.0	25.0	30.4	34.8	38.0	42.3	45.4	48.9	53.0	57.1	59.2	62.5	65.3	67.5	70.0	71.8	75.4	78.1	81.2	84.1	87.6
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	1.6	2.1	6.3	9.7	18.9	22.0	25.0	29.3	33.7	38.0	42.3	45.4	48.9	53.0	57.1	59.2	62.5	65.3	67.5	70.0	71.8	75.4	78.1	81.2	84.1	87.6

5B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	2.6	4.0	5.4	5.7	5.7	5.7	6.9	8.0	9.2	9.2	10.3	10.6	10.6
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	3.6	3.6	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.5	0.5	0.5	1.4	5.6	6.5	7.3	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.9	10.9	11.5
Renewables	0.0	0.9	1.3	3.5	5.1	6.7	8.2	9.9	12.3	14.7	16.6	18.7	21.2	23.7	26.3	28.5	29.6	31.1	33.2	34.0	34.6	34.9	36.4	37.5	37.5	39.0	40.5
Storage	0.0	0.1	0.2	0.2	0.3	1.3	1.8	2.3	3.3	3.9	4.5	5.2	6.0	6.8	7.5	9.0	10.5	11.5	12.6	13.6	14.6	15.6	16.6	17.6	18.5	19.1	20.1
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7
DR	0.0	0.3	0.4	1.1	1.3	1.3	1.4	1.5	1.6	1.7	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.4	2.5	2.6	2.6
Subtotal Addi	0.0	1.9	2.5	7.0	10.6	19.1	22.2	25.5	31.8	36.6	40.7	45.4	49.1	52.8	57.7	63.0	67.1	70.1	73.2	75.2	78.0	80.6	84.3	86.5	89.5	91.8	95.0
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	1.9	2.5	7.0	10.6	19.1	22.2	25.5	30.8	35.6	40.7	45.4	49.1	52.8	57.7	63.0	67.1	70.1	73.2	75.2	78.0	80.6	84.3	86.5	89.5	91.8	95.0

5C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.6	0.6	1.7	2.9	2.9	4.0	4.0	5.2	6.3	7.5	8.6	9.8	9.8	9.8	10.9
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	3.6	3.6	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.5	0.5	0.5	1.4	5.6	6.5	7.3	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	11.8	11.8	11.8	11.8	13.5	14.4	14.4
Renewables	0.0	0.9	1.3	3.8	5.8	8.5	10.4	12.3	15.5	18.2	21.7	24.2	27.0	29.9	32.3	34.4	34.9	35.4	36.4	36.8	37.3	37.7	38.5	38.9	39.3	40.7	41.2
Storage	0.0	0.1	0.2	0.2	0.3	1.0	1.6	2.3	3.0	3.7	4.4	5.3	6.2	7.2	8.1	10.5	11.2	11.8	12.5	13.2	13.9	14.5	15.2	15.8	16.4	17.0	17.7
EE	0.0	0.0	0.1	0.3	0.4	0.5	0.6	0.7	0.9	1.0	1.1	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.6	1.6	1.6
DR	0.0	0.3	0.4	1.2	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.9	1.9	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.4	2.5	2.6	2.6
Subtotal Addi	0.0	1.9	2.5	7.4	11.3	20.8	24.3	27.9	34.6	40.0	45.7	51.0	54.8	58.8	63.5	69.3	70.5	73.0	74.7	77.0	81.2	83.5	86.2	88.4	91.2	94.1	96.5
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	1.9	2.5	7.4	11.3	20.8	24.3	27.9	33.6	38.9	45.7	51.0	54.8	58.8	63.5	69.3	70.5	73.0	74.7	77.0	81.2	83.5	86.2	88.4	91.2	94.1	96.5

5D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	0.9	2.0	3.2	4.3	5.5	5.5	6.6	7.8	7.8	8.9	8.9	10.1	11.2	11.2
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.2	1.7	2.5	3.9	3.9	3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.9	3.9	4.0	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.5	0.5	0.5	1.4	5.6	5.6	6.5	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	10.0	10.0	10.9
Renewables	0.0	1.1	1.6	3.8	5.5	7.1	8.6	10.1	12.6	14.2	16.3	18.8	21.4	24.3	26.9	29.1	29.1	29.9	31.4	31.4	31.5	32.3	33.8	35.1	35.1	36.6	38.1
Storage	0.0	0.3	0.4	0.5	0.6	1.3	1.9	2.6	3.4	4.1	5.1	6.2	7.4	8.7	9.8	10.8	11.5	12.1	13.1	14.2	15.4	16.5	17.7	18.8	19.9	20.5	21.4
EE	0.0	0.0	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.8	2.0	2.2	2.3	2.4	2.5	2.7	2.7	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.0
DR	0.0	0.3	0.4	1.3	1.4	1.5	1.6	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.9	2.9	3.0
Subtotal Addi	0.0	2.2	3.2	8.2	11.9	20.3	22.7	26.1	32.2	36.5	41.5	47.1	51.4	55.8	61.0	65.5	67.5	70.3	72.9	75.3	77.9	80.0	83.9	86.5	89.6	92.9	96.3
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	2.2	3.2	8.2	11.9	20.3	22.7	26.1	31.2	35.4	41.5	47.1	51.4	55.8	61.0	65.5	67.5	70.3	72.9	75.3	77.9	80.0	83.9	86.5	89.6	92.9	96.3

5E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	2.3	3.4	4.6	5.7	5.7	5.7	6.9	8.0	9.2	9.2	9.2	9.2	9.2
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.1	1.6	2.3	5.1	5.2	5.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.5	0.5	0.5	1.4	4.7	5.6	5.6	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	10.0	11.3	11.3
Renewables	0.0	0.9	1.3	3.0	4.6	6.2	7.7	9.2	10.6	12.4	14.3	16.4	18.9	21.4	24.0	26.2	27.7	28.8	30.9	32.2	32.9	33.3	34.8	36.3	37.8	39.3	41.8
Storage	0.0	0.1	0.2	0.2	0.3	1.0	1.6	2.3	3.0	3.8	4.5	5.4	6.3	7.3	8.2	9.3	10.9	12.1	13.3	14.4	15.6	16.8	17.9	19.1	20.1	20.8	21.9
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.9	1.0	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6
DR	0.0	0.3	0.4	1.3	1.4	1.5	1.6	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.9	2.9	3.0
Subtotal Addi	0.0	1.9	2.6	6.7	10.3	19.1	22.4	24.7	30.1	34.6	38.9	43.8	47.5	51.5	56.3	60.9	65.3	68.9	72.2	74.8	77.9	80.7	84.5	87.3	91.2	94.8	98.5
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	1.9	2.6	6.7	10.3	19.1	22.4	24.7	29.1	33.5	38.9	43.8	47.5	51.5	56.3	60.9	65.3	68.9	72.2	74.8	77.9	80.7	84.5	87.3	91.2	94.8	98.5

6A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	3.8	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	6.5	6.5	6.5	6.5	6.9	6.9	6.9
Renewables	0.0	0.7	1.0	2.4	2.5	3.3	4.0	5.1	6.3	7.6	8.8	9.9	11.1	11.4	12.4	12.7	12.7	13.5	13.9	14.4	15.6	16.0	16.4	17.5	17.9	18.9	20.3
Storage	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.4	0.7	0.7	1.3	1.3	1.3	1.3	1.6	1.7	1.8	2.0	2.3	2.8	3.2	3.7	4.2	4.6	5.1	5.6
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6
DR	0.0	0.3	0.4	0.8	0.7	0.8	0.7	0.7	0.9	0.9	0.9	1.0	0.9	0.7	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Subtotal Addi	0.0	1.6	2.0	5.4	7.3	8.5	9.3	10.5	14.6	17.1	18.4	20.3	21.5	21.7	22.9	23.5	23.6	24.7	25.3	26.0	29.6	30.3	31.3	32.9	34.1	35.7	37.6
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	1.6	2.0	5.4	7.3	8.5	9.3	10.5	13.5	16.0	18.4	20.3	21.5	21.7	22.9	23.5	23.6	24.7	25.3	26.0	29.6	30.3	31.3	32.9	34.1	35.7	37.6

6B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	1.4	1.7	2.0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Renewables	0.0	0.9	1.2	2.2	2.4	3.5	4.7	5.9	7.2	8.5	9.8	10.0	10.1	10.4	10.8	11.0	11.1	11.1	11.5	11.5	12.4	12.6	13.7	14.8	15.4	16.4	17.4
Storage	0.0	0.1	0.2	0.2	0.3	0.3	0.4	0.7	0.8	0.9	1.0	1.0	1.1	1.1	1.2	1.6	2.1	2.1	2.1	2.1	2.1	2.3	2.9	3.4	3.8	4.3	4.8
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.1	1.3	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
DR	0.0	0.3	0.4	1.0	1.0	1.0	1.0	1.0	1.2	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Subtotal Addi	0.0	1.9	2.4	5.7	7.6	9.1	10.4	12.0	15.4	18.7	20.2	20.7	21.3	22.0	22.7	23.7	24.6	25.0	25.4	25.4	26.4	26.8	28.5	30.1	31.1	32.6	34.2
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	1.9	2.4	5.7	7.6	9.1	10.4	12.0	14.3	17.6	20.2	20.7	21.3	22.0	22.7	23.7	24.6	25.0	25.4	25.4	26.4	26.8	28.5	30.1	31.1	32.6	34.2

6C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.0	1.4	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	2.3	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.8	3.8	3.8	3.8	4.2	4.7	4.7
Renewables	0.0	0.9	1.2	3.2	4.1	5.7	7.3	8.9	10.9	12.5	13.3	14.9	15.2	15.9	16.7	17.5	18.5	19.0	19.7	20.1	21.4	22.1	22.8	24.1	24.5	25.9	27.4
Storage	0.0	0.1	0.2	0.2	0.3	0.4	0.6	0.7	1.4	2.1	2.2	2.9	3.0	3.0	3.1	4.0	4.8	4.8	4.8	4.9	5.6	5.9	6.4	7.1	7.6	8.3	9.0
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.9	0.9	1.0	1.1	1.1	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.5
DR	0.0	0.3	0.4	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Subtotal Addi	0.0	1.9	2.4	6.6	9.3	11.3	13.2	15.1	18.7	21.9	22.9	25.3	25.7	26.5	27.3	29.0	30.8	31.4	32.2	32.7	35.6	36.6	37.9	39.8	41.2	43.8	45.9
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	1.9	2.4	6.6	9.3	11.3	13.2	15.1	17.7	20.8	22.9	25.3	25.7	26.5	27.3	29.0	30.8	31.4	32.2	32.7	35.6	36.6	37.9	39.8	41.2	43.8	45.9

6D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.2	1.8	2.6	2.7	2.7	2.7	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	1.4	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	3.1	3.1	3.1	3.1	4.0	4.0	4.0
Renewables	0.0	1.1	1.4	2.2	2.4	2.6	3.6	4.8	6.2	7.7	9.1	10.3	11.4	12.3	13.4	13.7	13.7	14.6	14.9	14.9	16.3	16.6	17.1	18.2	18.7	19.7	20.7
Storage	0.0	0.3	0.3	0.4	0.6	0.7	1.0	1.2	1.5	1.9	2.1	2.6	2.7	2.8	2.9	3.1	3.2	3.3	3.4	3.5	4.2	4.5	4.8	5.5	6.1	6.8	7.4
EE	0.0	0.0	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.8	2.0	2.2	2.3	2.4	2.5	2.7	2.7	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.0
DR	0.0	0.3	0.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Subtotal Addi	0.0	2.2	2.9	6.6	8.7	9.6	11.0	12.7	14.6	17.7	19.5	21.4	22.8	24.0	25.3	25.9	26.1	27.3	27.8	28.0	30.9	31.6	32.5	34.4	36.3	37.9	39.6
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	2.2	2.9	6.6	8.7	9.6	11.0	12.7	13.6	16.6	19.5	21.4	22.8	24.0	25.3	25.9	26.1	27.3	27.8	28.0	30.9	31.6	32.5	34.4	36.3	37.9	39.6

6E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	0.0	0.1	1.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	0.0	0.5	0.5	0.5	1.4	1.4	1.4	1.4	2.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	4.2	4.2	4.2
Renewables	0.0	0.9	1.2	1.9	2.1	2.2	3.4	4.6	5.9	7.2	8.5	9.7	10.6	10.9	11.6	12.1	12.6	13.6	14.0	14.2	15.5	15.8	16.3	17.5	18.2	19.2	20.3
Storage	0.0	0.1	0.2	0.2	0.3	0.4	0.6	0.8	1.3	1.5	1.6	2.0	2.0	2.1	2.1	2.5	3.0	3.2	3.3	3.5	4.2	4.5	4.9	5.5	6.1	6.7	7.4
EE	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.9	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6
DR	0.0	0.3	0.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Subtotal Addi	0.0	1.9	2.5	5.8	7.7	8.3	9.8	11.2	14.1	17.1	18.6	20.5	21.9	22.6	23.4	24.4	25.4	26.8	27.3	27.7	29.8	30.3	31.2	33.1	35.3	36.9	38.6
Coal Retireme	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.1	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	1.9	2.5	5.8	7.7	8.3	9.8	11.2	13.0	16.0	18.6	20.5	21.9	22.6	23.4	24.4	25.4	26.8	27.3	27.7	29.8	30.3	31.2	33.1	35.3	36.9	38.6

H.6 Total Capacity Plan Tables

The tables provided below show total capacity for all 30 portfolios for 2024-2050. Results are grouped by scenario. Scenarios are represented by number (1 to 6) and strategies by letter (A to E). Data is shown in summer net dependable gigawatts (GW SND), except for renewables and storage which are in nameplate.

Table H-2: Total Capacity Plan Tables

1A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	10.2	10.2	9.5	10.9	10.1	9.3	9.3	9.3	9.3	9.4	9.4	9.4	9.4	9.4	9.4	9.1	9.1	9.1	9.1	9.9	9.9	9.9
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	7.4	7.4	7.4	7.4	9.1	10.0	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	11.0	11.2	11.2	11.2	11.2
Renewables	2.5	3.1	3.4	4.6	5.0	5.1	5.3	5.8	6.4	7.1	8.2	9.3	10.5	11.6	12.3	13.0	13.8	14.9	15.0	15.1	16.1	16.5	17.5	18.5	18.7	19.7	20.7
Storage	1.9	1.9	2.0	2.0	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.9	3.5	4.0	4.2	4.4	4.8	5.3	5.8	6.3	6.7	7.2	7.7
EE	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.7	1.6	1.6	1.7
DR	1.7	2.0	2.0	2.5	2.5	2.5	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Subtotal	38.0	37.1	37.5	39.6	40.5	40.8	41.1	41.1	41.7	43.6	43.8	46.0	47.2	48.5	49.4	50.5	51.9	53.6	53.9	54.3	55.6	56.5	58.1	59.9	61.2	62.7	64.2

1B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	9.7	10.0	10.3	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	10.2	10.2	9.5	9.5	8.7	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	6.3	6.3	6.3	6.3	5.7	5.7	5.7
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CT	6.5	5.7	5.7	5.7	6.5	7.0	6.9	6.9	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	9.6	9.6	9.6	9.6	10.5	10.5	11.1
Renewables	2.5	3.3	3.6	4.5	4.7	5.6	5.8	6.7	7.3	8.1	9.3	10.5	11.6	11.7	11.8	11.8	12.3	12.3	12.4	13.1	14.1	15.2	16.2	17.2	18.2	19.2	20.2
Storage	1.9	2.0	2.0	2.0	2.2	2.2	2.3	2.3	2.7	2.8	3.0	3.6	3.6	3.6	3.7	4.0	4.5	4.5	4.5	5.1	5.5	6.0	6.5	7.0	7.4	8.0	8.5
EE	0.0	0.1	0.1	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7
DR	1.7	2.0	2.0	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Subtotal	38.0	37.3	37.8	39.8	40.5	41.2	41.6	42.0	43.5	45.4	45.0	47.2	48.7	49.2	49.7	50.2	51.6	52.1	52.1	53.4	54.2	55.7	57.2	58.8	60.4	61.9	64.1

1C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	10.2	10.2	9.5	9.5	8.7	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	6.3	6.3	6.3	6.3	6.4	6.4	6.4
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	7.4	8.3	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	10.9	10.9	10.9	11.6	11.6	11.6	12.0
Renewables	2.5	3.3	3.6	5.3	5.5	7.1	8.7	10.1	11.2	12.4	14.1	15.7	17.0	17.5	18.1	19.4	20.7	21.1	21.5	21.9	23.4	24.0	25.4	26.6	27.0	28.4	29.8
Storage	1.9	2.0	2.0	2.0	2.2	2.3	2.5	2.6	3.1	3.8	4.5	5.3	5.3	5.3	5.4	6.2	7.0	7.0	7.0	7.5	8.1	8.8	9.4	10.1	10.6	11.3	11.9
EE	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.3	1.3	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.4
DR	1.7	2.0	2.0	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Subtotal	38.0	37.3	37.8	40.6	41.3	42.4	44.3	45.2	46.4	48.5	50.0	52.5	53.9	54.5	55.2	57.2	59.4	59.9	60.3	61.2	63.5	64.8	66.9	69.4	70.3	72.4	74.9

1D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.2	9.9	10.7	10.8	10.9	10.1	10.1	9.4	8.6	8.6	8.6	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.5	8.5	8.5	8.5	7.9	7.9	7.9
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	6.5	7.4	8.3	9.1	9.1	9.1	9.1	9.1	9.1	9.3	9.3	9.3	9.3	9.3	9.3	9.6	10.4	10.7	11.1
Renewables	2.5	3.4	3.8	4.4	4.6	4.9	5.1	5.8	6.5	7.4	8.6	9.8	11.0	12.1	13.2	14.2	14.9	15.8	15.8	16.1	17.1	17.9	18.9	19.9	20.6	21.6	22.6
Storage	1.9	2.1	2.2	2.2	2.4	2.6	2.8	3.0	3.3	3.6	3.7	4.2	4.3	4.3	4.5	4.6	4.8	5.1	5.5	5.5	6.1	6.7	7.4	8.1	8.6	9.3	9.9
EE	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.0	2.2	2.3	2.5	2.6	2.7	2.8	2.8	2.9	3.0	3.0	3.0	3.0	3.0	3.0
DR	1.7	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Subtotal	38.0	37.6	38.3	40.6	41.6	41.5	42.3	42.7	42.4	43.9	44.5	47.3	48.7	50.0	51.5	52.5	53.6	55.2	55.6	56.0	57.5	59.0	60.7	62.6	64.1	65.9	68.1

1E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.1	9.7	10.4	10.5	10.5	9.8	9.8	9.7	8.9	8.9	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0	8.8	8.8	8.8	8.8	8.2	8.2	8.2
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	7.4	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.9	9.8	9.8	10.0
Renewables	2.5	3.3	3.6	4.2	4.3	4.7	4.9	5.6	6.3	7.1	8.3	9.4	10.6	11.7	12.7	12.9	13.9	14.5	14.5	14.7	15.7	16.7	17.7	18.7	19.7	20.7	21.7
Storage	1.9	2.0	2.0	2.0	2.2	2.5	2.6	2.6	2.8	3.0	3.2	3.9	4.0	4.0	4.0	4.4	4.9	4.9	4.9	5.5	5.9	6.6	7.2	7.9	8.4	9.2	9.9
EE	0.0	0.1	0.1	0.2	0.3	0.4	0.6	0.7	0.9	1.0	1.1	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7
DR	1.7	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Subtotal	38.0	37.3	37.9	39.9	40.6	40.7	41.0	41.3	41.7	44.3	44.0	46.3	47.8	49.3	50.6	50.9	52.7	53.3	53.4	54.1	55.4	57.1	58.8	60.7	62.5	64.3	66.2

2A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	11.6	11.6	10.9	12.3	12.9	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.0	12.0	12.0	12.0	11.3	11.3	11.3
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	8.3	8.3	9.2	9.1	9.1	10.0	10.9	10.9	10.9	10.9	11.8	11.8	12.7	12.7	12.7	12.7	13.6	13.7	13.7	14.6	14.6	14.6
Renewables	2.5	3.2	3.6	5.3	6.8	8.5	10.4	11.8	12.4	13.6	15.1	16.6	18.1	19.4	20.6	21.1	22.1	23.0	23.1	24.6	26.9	27.2	29.0	30.5	32.8	34.3	36.6
Storage	1.9	2.0	2.0	2.0	2.2	2.2	2.2	2.3	2.6	2.9	3.4	3.9	4.4	4.9	5.4	5.9	6.4	6.9	7.4	8.2	9.0	9.5	10.0	10.9	11.8	12.6	13.6
EE	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8
DR	1.7	2.0	2.0	2.6	2.6	2.5	2.5	2.5	2.4	2.4	2.5	2.5	2.5	2.5	2.6	2.5	2.5	2.5	2.5	2.5	2.6	2.4	2.4	2.4	2.4	2.8	2.8
Subtotal	38.0	37.2	37.7	40.5	42.5	46.7	48.7	50.5	51.4	53.5	54.8	57.9	59.8	61.8	63.8	65.5	67.1	69.5	70.2	72.5	75.5	77.0	79.4	81.9	85.3	88.0	91.3

2B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	9.7	10.0	10.3	10.6	10.6	10.6	10.6	10.6	10.6	10.6	11.7	12.0	12.0
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	11.6	11.6	10.9	10.9	10.1	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	7.7	7.7	7.7	7.7	7.0	7.0	7.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CT	6.5	5.7	5.7	5.7	6.5	7.4	7.4	7.4	9.1	9.2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	11.8	12.7	12.7	12.7	12.7	12.7	12.7
Renewables	2.5	3.4	3.8	6.1	8.3	10.1	11.8	13.4	14.4	15.6	17.1	18.6	19.5	19.5	20.0	21.1	22.1	22.6	22.7	24.3	26.9	27.4	28.9	30.4	30.6	31.6	32.5
Storage	1.9	2.0	2.1	2.2	2.5	2.8	3.1	3.7	4.2	4.7	5.2	5.8	5.9	6.2	6.2	7.1	8.1	8.6	9.1	9.8	10.4	10.9	11.4	12.4	13.3	14.3	15.3
EE	0.0	0.1	0.1	0.3	0.4	0.5	0.6	0.7	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8
DR	1.7	2.0	2.0	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.1	3.2	3.2	3.1	3.2	3.2	3.2	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.6	3.6	3.7
Subtotal	38.0	37.4	38.1	41.6	44.6	48.4	50.5	52.2	54.2	56.9	58.1	60.7	62.0	62.6	63.7	65.9	68.3	69.7	70.5	72.8	76.2	78.1	80.1	82.7	84.4	86.7	88.6

2C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	10.2	10.2	9.5	10.9	10.1	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	7.7	7.7	7.7	9.1	8.5	8.5	8.5
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	8.3	8.3	8.3	9.1	9.8	10.7	11.6	11.6	11.6	11.6	11.6	11.6	12.0	12.0	12.9	14.7	14.7	15.3	15.3	15.3	16.0	16.7
Renewables	2.5	3.4	3.8	6.5	9.0	11.4	13.8	15.8	17.4	19.1	20.6	23.1	23.7	24.8	26.3	28.5	30.5	31.8	32.3	33.9	36.1	36.8	38.9	39.7	41.8	42.3	44.4
Storage	1.9	2.0	2.1	2.2	2.5	3.1	3.3	4.0	4.7	5.3	6.0	6.7	7.3	8.0	8.6	10.2	11.6	12.3	12.9	13.6	14.2	14.9	15.5	16.2	16.7	17.4	18.0
EE	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.7	1.8
DR	1.7	2.0	2.0	2.8	2.8	2.9	2.9	3.0	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.6	3.6	3.7
Subtotal	38.0	37.4	38.1	41.9	45.3	49.4	52.2	54.3	57.5	59.9	61.3	65.5	66.8	68.7	71.1	74.7	78.4	80.9	82.1	85.3	88.4	89.8	93.2	96.2	98.2	100.1	103.5

2D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.3	10.0	11.0	11.1	11.1	10.4	11.8	11.0	10.2	10.3	10.3	10.3	11.7	11.7	11.7	11.7	11.8	11.8	11.5	11.6	11.6	11.6	10.9	10.9	11.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	7.4	7.4	7.4	7.4	9.2	10.1	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	11.8	11.8	11.8	11.8	12.7	12.7	12.7
Renewables	2.5	3.5	4.1	4.9	7.0	8.9	10.8	12.4	13.1	14.3	15.8	17.3	18.8	19.8	20.4	21.6	22.5	23.3	23.5	24.8	26.2	27.1	29.2	30.9	33.0	34.7	36.8
Storage	1.9	2.2	2.3	2.5	2.9	3.2	3.5	3.8	4.1	4.2	4.4	4.9	5.6	6.2	6.4	7.1	7.7	8.4	9.1	9.7	10.4	11.0	11.8	12.6	13.6	14.7	15.9
EE	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.0	2.2	2.3	2.5	2.6	2.7	2.8	2.8	2.9	3.0	3.0	3.0	3.0	3.0	3.0
DR	1.7	2.0	2.0	3.0	3.0	3.1	3.1	3.1	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6	3.6	3.6	3.7	3.7	3.8	3.8	3.9	3.9	4.0
Subtotal	38.0	37.8	38.7	41.4	44.9	47.4	49.8	51.4	52.6	55.1	56.1	59.3	61.6	63.5	65.9	67.8	69.5	71.2	72.2	74.3	77.1	78.8	81.7	84.3	87.7	90.6	93.9

2E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.2	9.8	10.8	10.9	10.9	10.1	11.6	10.8	11.4	11.4	11.4	11.5	11.5	11.5	11.5	11.5	11.5	11.5	9.8	9.8	9.8	9.8	9.2	9.2	9.2
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	8.7	8.7	8.7	8.7	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	10.5	10.5	10.5	12.2	12.9	12.9	12.9	13.8	14.0	14.0
Renewables	2.5	3.4	3.8	5.4	7.6	9.4	11.1	12.7	13.3	14.5	16.0	17.5	18.5	18.5	19.6	21.2	22.7	24.0	24.1	25.4	27.7	28.9	31.0	32.9	34.6	36.1	37.6
Storage	1.9	2.0	2.1	2.2	2.5	2.7	2.8	3.0	3.5	4.2	4.8	5.5	5.6	5.7	6.4	7.4	8.6	9.2	9.9	10.5	11.2	11.8	12.5	13.6	14.7	15.8	17.0
EE	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8
DR	1.7	2.0	2.0	3.0	3.0	3.1	3.1	3.1	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6	3.6	3.6	3.7	3.7	3.8	3.8	3.9	3.9	4.0
Subtotal	38.0	37.4	38.2	41.4	44.7	48.3	50.3	51.6	52.8	55.1	57.0	59.7	61.1	61.7	63.7	66.3	69.1	72.1	72.9	74.9	78.1	80.6	83.4	86.6	89.6	92.5	95.2

3A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.1	9.6	10.3	10.3	10.3	9.6	9.6	8.7	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	6.4	6.4	6.4	6.4	5.8	5.8	5.8
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	9.1	9.1	9.1	9.1	9.3	9.3	9.3
Renewables	2.5	3.2	3.5	4.0	4.1	4.2	4.2	4.0	3.5	3.2	4.2	4.2	4.3	4.4	4.6	4.7	4.7	4.8	4.8	4.9	5.3	5.5	6.5	6.8	7.8	8.4	9.4
Storage	1.9	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.2	2.2	2.2	2.4	2.8	2.8	2.9
EE	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.9	0.8	0.8	0.9	0.9	0.8	0.9	0.9	0.9	0.9
DR	1.7	2.0	2.0	2.4	2.4	2.4	2.4	2.4	2.5	2.4	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Subtotal	38.0	37.1	37.6	39.0	39.5	38.8	38.9	38.1	37.2	37.4	36.8	36.8	36.9	37.1	37.4	37.4	37.5	37.7	37.6	37.8	38.3	38.5	39.5	40.0	40.9	41.6	42.7

3B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	9.7	10.0	10.3	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.1	9.6	10.3	10.3	10.3	9.6	9.6	8.7	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	6.4	6.4	6.4	6.4	5.8	5.8	5.8
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Renewables	2.5	3.4	3.8	4.3	4.4	4.5	4.5	4.4	3.9	3.5	3.6	3.6	3.7	3.9	4.1	4.2	4.1	4.3	4.3	4.3	4.3	4.4	4.9	5.2	5.8	6.0	7.0
Storage	1.9	2.0	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.5	2.8	3.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.3	3.3	3.3
EE	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.1	1.2	1.3	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.5	1.5	1.6
DR	1.7	2.0	2.0	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Subtotal	38.0	37.4	38.0	39.8	40.4	39.8	39.9	39.3	37.4	38.1	36.4	36.8	37.3	37.9	38.6	39.2	40.1	40.7	40.7	40.8	39.1	39.2	39.7	40.0	39.9	40.1	41.1

3C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.1	9.6	10.3	10.3	10.3	9.6	9.6	8.7	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	6.4	6.4	6.4	6.4	5.8	5.8	5.8
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	6.5	6.5	6.5	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Renewables	2.5	3.4	3.8	4.3	4.4	4.9	5.3	5.6	5.5	5.5	6.8	7.6	8.1	8.7	9.3	9.8	10.2	10.7	11.1	11.6	12.0	12.4	12.8	13.2	13.6	14.0	15.4
Storage	1.9	2.0	2.1	2.1	2.2	2.3	2.4	2.6	2.7	2.8	3.0	3.1	3.2	3.3	3.5	3.6	5.3	5.5	5.6	5.7	5.8	5.9	6.0	6.1	6.1	6.2	6.9
EE	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
DR	1.7	2.0	2.0	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Subtotal	38.0	37.4	38.0	39.7	40.3	40.1	40.7	40.6	39.1	38.5	38.1	39.8	40.4	41.3	42.1	42.6	44.8	45.5	46.0	46.6	45.5	46.0	46.5	47.0	46.8	47.3	49.4

3D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.3	9.9	10.8	10.8	10.8	10.2	10.2	9.4	8.6	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	7.1	7.1	7.1	7.1	6.5	6.5	6.5
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Renewables	2.5	3.5	4.0	4.6	4.7	4.8	4.8	4.8	4.3	3.9	4.0	4.0	4.2	4.4	4.7	4.8	4.8	4.9	4.9	5.0	6.0	6.6	6.6	7.0	8.0	9.0	10.0
Storage	1.9	2.2	2.3	2.3	2.4	2.5	2.6	2.9	3.0	3.1	3.3	3.4	3.6	3.8	4.1	4.3	4.4	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.2	5.3	5.4
EE	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.0	2.2	2.3	2.5	2.6	2.7	2.8	2.8	2.9	3.0	3.0	3.0	3.0	3.0	3.0
DR	1.7	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Subtotal	38.0	37.8	38.7	41.0	41.8	41.4	41.7	41.7	39.9	39.1	37.7	38.1	38.5	39.2	40.0	40.2	40.5	41.0	41.1	41.4	40.9	41.7	41.8	42.3	42.6	43.8	44.9

3E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.2	9.8	10.6	10.6	10.6	9.9	9.9	9.1	8.3	8.3	8.3	8.4	8.4	8.4	8.4	8.4	8.4	8.4	6.8	6.8	6.8	6.8	6.1	6.2	6.2
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.9	6.9	6.9
Renewables	2.5	3.4	3.8	4.3	4.4	4.5	4.5	4.4	3.9	3.5	4.4	4.4	4.5	4.7	4.9	5.0	4.9	5.1	5.1	5.1	6.1	6.9	6.9	7.3	8.2	9.2	10.2
Storage	1.9	2.0	2.1	2.1	2.2	2.3	2.4	2.6	2.7	2.8	3.1	3.1	3.2	3.3	3.5	3.9	4.5	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.3	5.4	5.5
EE	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.8	0.8	0.9
DR	1.7	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Subtotal	38.0	37.4	38.2	40.2	40.8	40.2	40.4	39.9	38.0	37.3	36.7	37.1	37.5	38.2	38.7	39.1	39.8	40.1	40.2	40.4	39.9	40.7	40.8	41.3	42.1	43.2	44.4

4A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	10.2	10.2	9.5	9.5	8.6	6.1	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	6.5	5.7	5.7	5.7	6.5	7.4	7.4	7.4	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.8	10.5	10.5	10.5	11.1	11.1	12.0	12.0	12.0
Renewables	2.5	3.1	3.4	5.0	6.1	7.2	8.2	8.9	9.5	10.2	11.4	12.6	14.0	15.3	15.8	15.8	15.7	15.7	15.7	15.7	15.7	16.6	17.5	18.8	20.0	21.0	22.4
Storage	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.7	3.2	3.3	3.8	4.3	4.9	5.4	5.4	5.4	5.8	5.8	5.8	5.9	6.0	6.5	6.7	7.2	7.6	8.1	8.6
EE	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8
DR	1.7	2.0	2.0	2.5	2.6	2.6	2.6	2.6	2.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Subtotal	38.0	37.1	37.5	39.9	41.7	43.0	44.2	44.9	45.4	46.6	47.2	50.2	52.1	54.1	54.7	54.5	55.1	55.1	55.8	56.6	56.8	58.1	60.0	61.7	64.3	65.8	67.7

4B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	9.7	10.0	10.3	10.6	10.6	10.6	10.6	10.6	10.8	10.8	10.8	10.8	10.8
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	10.2	10.2	9.5	9.5	8.3	5.8	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	6.5	5.7	5.7	5.7	6.5	7.4	7.4	7.4	8.3	8.3	8.3	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	9.1	9.1	9.1
Renewables	2.5	3.3	3.6	5.2	6.4	7.5	8.6	9.3	9.9	10.5	11.9	13.3	14.5	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	16.0	17.0	17.6	18.6	20.6
Storage	1.9	2.0	2.0	2.0	2.2	2.6	3.1	3.6	4.1	4.1	4.7	5.2	5.4	5.6	5.6	5.9	6.4	6.4	6.4	6.4	6.4	6.5	6.9	7.4	7.8	8.3	8.8
EE	0.0	0.1	0.1	0.3	0.4	0.5	0.6	0.7	0.9	1.0	1.1	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.8	1.7	1.7	1.8
DR	1.7	2.0	2.0	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Subtotal	38.0	37.3	37.8	40.5	42.3	44.0	45.7	46.4	46.0	47.3	48.3	51.3	53.0	53.9	54.4	54.8	55.7	56.1	56.1	56.1	56.2	56.3	58.0	59.6	61.4	62.9	65.4

4C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	10.2	10.2	9.5	9.5	8.3	5.8	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.8	8.3	9.1	9.1	9.1	10.0	10.0	10.5
Renewables	2.5	3.3	3.6	5.4	6.9	8.4	10.0	11.1	13.4	14.3	16.3	18.0	19.6	20.3	20.5	20.8	21.2	21.6	22.0	22.4	22.8	23.2	24.0	25.1	25.6	26.9	28.3
Storage	1.9	2.0	2.0	2.0	2.2	2.8	3.5	4.2	4.8	5.0	5.7	6.5	7.0	7.2	7.2	8.0	8.8	8.8	8.8	8.8	8.9	8.9	8.9	9.2	9.8	10.4	11.1
EE	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7
DR	1.7	2.0	2.0	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Subtotal	38.0	37.3	37.7	40.7	42.8	44.3	46.7	47.9	49.3	50.7	52.5	55.8	57.9	58.8	59.1	60.2	61.5	62.0	62.4	63.3	64.3	65.6	66.4	67.8	69.7	71.6	74.2

4D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.1	9.8	10.6	10.6	10.6	9.9	9.9	9.1	6.1	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	8.2	8.2	8.2	9.1	9.1	9.1	10.0	10.0	10.7
Renewables	2.5	3.5	3.8	5.4	6.7	7.8	9.0	9.7	10.3	10.9	12.4	14.0	15.7	16.3	16.3	16.2	16.2	16.2	16.2	16.2	16.2	16.2	17.2	18.2	19.2	20.2	21.2
Storage	1.9	2.1	2.2	2.2	2.4	2.5	2.7	3.4	4.0	4.0	4.9	5.9	6.4	6.8	6.8	6.8	6.8	6.8	6.8	7.0	7.3	7.3	7.3	7.9	8.4	9.1	9.7
EE	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.0	2.2	2.3	2.5	2.6	2.7	2.8	2.8	2.9	3.0	3.0	3.0	3.0	3.0	3.0
DR	1.7	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Subtotal	38.0	37.6	38.2	41.4	43.6	44.2	45.8	46.7	46.5	47.9	49.0	52.6	54.9	56.0	56.3	56.2	56.4	56.6	57.5	57.7	58.2	59.1	60.1	61.7	64.1	65.8	68.1

4E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.1	9.6	10.3	10.3	10.3	9.6	9.6	8.5	6.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.9	7.9	8.4	9.2	9.2	9.9	10.3	10.3
Renewables	2.5	3.3	3.6	5.2	6.4	7.5	8.6	9.3	9.9	10.5	11.9	13.3	14.9	15.4	15.4	15.3	15.3	15.3	15.3	15.3	15.3	15.6	16.6	17.6	18.6	19.6	21.2
Storage	1.9	2.0	2.0	2.0	2.2	2.8	3.5	4.2	4.8	4.8	5.2	5.8	6.0	6.2	6.2	6.5	7.0	7.0	7.0	7.0	7.5	8.0	8.0	8.0	8.6	9.2	9.9
EE	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.8	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
DR	1.7	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Subtotal	38.0	37.3	37.8	40.8	42.6	43.6	45.6	46.4	46.4	47.7	48.5	51.6	53.6	54.7	54.8	55.0	55.6	55.7	55.7	56.1	56.7	57.9	59.8	60.8	63.0	65.1	67.4

5A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	10.6	11.7	12.9	14.0	15.2	16.3	17.5	17.8	18.9	19.2	19.2	20.3	20.7
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	13.0	13.0	12.3	12.3	11.5	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	9.1	9.1	9.1	9.1	8.4	8.4	8.4
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	6.5	5.7	5.7	5.7	6.5	10.1	10.9	11.8	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	16.2	16.2	17.1
Renewables	2.5	3.2	3.5	5.5	7.1	8.7	10.2	11.4	12.8	14.3	16.1	17.9	20.0	22.1	24.3	26.4	26.4	27.4	27.7	27.7	27.8	28.2	29.7	31.2	31.5	33.0	34.5
Storage	1.9	2.0	2.0	2.0	2.1	2.8	3.3	3.8	4.3	4.8	5.4	5.9	6.5	7.6	8.2	8.8	9.7	10.7	11.8	12.8	13.8	14.8	15.8	16.8	17.7	18.0	18.8
EE	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7
DR	1.7	2.0	2.0	2.6	2.6	2.8	2.9	2.9	3.1	3.2	2.6	2.6	2.6	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Subtotal	38.0	37.1	37.6	40.6	42.8	50.9	54.0	56.1	58.3	61.5	64.0	68.3	71.2	74.7	78.7	82.4	84.6	87.9	90.3	92.5	93.2	94.9	98.5	101.3	103.7	106.6	110.1

5B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	10.9	12.3	13.7	14.0	14.0	14.0	15.2	16.3	17.5	17.5	18.6	18.9	18.9
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	11.6	11.6	10.9	10.9	10.1	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	7.6	7.6	7.6	7.6	7.0	7.0	7.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	6.5	5.7	5.7	5.7	6.5	10.7	11.6	12.5	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	16.0	16.0	16.6
Renewables	2.5	3.4	3.8	5.9	7.5	9.1	10.6	12.0	13.8	15.8	17.7	19.8	22.2	24.7	27.0	29.1	30.2	31.7	33.4	34.2	34.6	34.9	36.4	37.6	37.6	39.0	40.5
Storage	1.9	2.0	2.1	2.1	2.2	3.2	3.7	4.2	5.2	5.8	6.4	7.1	7.9	8.7	9.4	10.9	12.4	13.4	14.5	15.5	16.5	17.5	18.5	19.5	20.4	20.9	21.9
EE	0.0	0.1	0.1	0.3	0.4	0.5	0.6	0.7	0.9	1.0	1.1	1.2	1.2	1.4	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
DR	1.7	2.0	2.0	2.8	2.9	3.0	3.1	3.2	3.3	3.3	3.4	3.4	3.5	3.5	3.5	3.6	3.7	3.7	3.8	3.9	3.9	4.0	4.1	4.1	4.2	4.2	4.3
Subtotal	38.0	37.4	38.0	41.3	43.7	51.2	54.3	56.6	59.8	63.3	66.7	71.4	74.9	78.6	83.4	88.3	92.5	95.5	98.2	100.2	101.2	103.7	107.4	109.7	112.0	114.3	117.5

5C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	8.9	8.9	10.0	11.2	11.2	12.3	12.3	13.5	14.6	15.8	16.9	18.1	18.1	18.1	19.2
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	11.6	11.6	10.9	10.9	10.1	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	7.6	7.6	7.6	7.6	7.0	7.0	7.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	6.5	5.7	5.7	5.7	6.5	10.7	11.6	12.5	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	16.9	16.9	16.9	16.9	18.6	19.5	19.5
Renewables	2.5	3.4	3.8	6.2	8.2	11.0	12.8	14.4	17.0	19.3	22.8	25.3	28.0	30.8	33.1	35.0	35.4	36.0	36.6	37.0	37.4	37.8	38.6	39.0	39.4	40.7	41.3
Storage	1.9	2.0	2.1	2.1	2.2	2.9	3.5	4.2	4.9	5.6	6.3	7.2	8.1	9.1	10.0	12.4	13.1	13.7	14.4	15.1	15.7	16.4	17.0	17.7	18.2	18.9	19.5
EE	0.0	0.1	0.1	0.3	0.4	0.5	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7
DR	1.7	2.0	2.0	2.8	2.9	3.0	3.1	3.2	3.2	3.3	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.7	3.8	3.9	3.9	4.0	4.1	4.1	4.2	4.2	4.3
Subtotal	38.0	37.4	38.0	41.8	44.4	52.8	56.4	59.0	62.6	66.7	71.7	76.9	80.7	84.6	89.2	94.6	95.9	98.4	99.7	102.0	104.4	106.6	109.3	111.6	113.7	116.6	119.0

5D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.1	10.3	11.4	12.6	13.7	13.7	14.9	16.0	16.0	17.2	17.2	18.3	19.5	19.5
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.2	9.8	10.5	11.9	11.9	11.2	11.2	10.4	9.7	9.8	9.8	9.8	9.9	9.9	9.9	9.9	9.9	9.9	8.2	8.3	8.3	8.3	7.6	7.6	7.6
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	6.5	5.7	5.7	5.7	6.5	10.7	10.7	11.6	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	15.1	15.1	16.0
Renewables	2.5	3.5	4.0	6.3	7.9	9.5	11.0	12.2	14.1	15.3	17.5	19.9	22.4	25.2	27.7	29.7	29.7	30.5	31.6	31.6	31.6	32.4	33.9	35.2	35.1	36.6	38.1
Storage	1.9	2.2	2.3	2.4	2.5	3.2	3.8	4.5	5.3	6.0	7.0	8.1	9.3	10.6	11.7	12.7	13.4	14.0	15.0	16.1	17.2	18.4	19.5	20.7	21.7	22.4	23.2
EE	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.0	2.2	2.3	2.5	2.6	2.7	2.8	2.8	2.9	3.0	3.0	3.0	3.0	3.0	3.0
DR	1.7	2.0	2.0	3.0	3.1	3.2	3.3	3.4	3.4	3.5	3.6	3.6	3.7	3.8	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.3	4.4	4.5	4.5	4.6	4.7
Subtotal	38.0	37.8	38.6	42.5	45.0	52.3	54.8	57.2	60.2	63.2	67.4	73.1	77.2	81.6	86.7	90.8	92.9	95.7	97.9	100.3	101.1	103.2	107.1	109.6	112.1	115.4	118.8

5E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	10.6	11.7	12.9	14.0	14.0	14.0	15.2	16.3	17.5	17.5	17.5	17.5	17.5
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.1	9.6	10.3	13.2	13.2	12.4	12.4	11.6	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	9.2	9.2	9.2	9.2	8.6	8.6	8.6
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	6.5	5.7	5.7	5.7	6.5	9.8	10.7	10.7	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	15.1	16.4	16.4
Renewables	2.5	3.4	3.8	5.4	7.0	8.6	10.1	11.3	12.1	13.5	15.4	17.5	19.9	22.4	24.7	26.8	28.3	29.4	31.1	32.4	32.9	33.3	34.8	36.3	37.8	39.3	41.8
Storage	1.9	2.0	2.1	2.1	2.2	2.9	3.5	4.2	4.9	5.7	6.4	7.3	8.2	9.2	10.1	11.2	12.8	14.0	15.2	16.3	17.5	18.6	19.8	20.9	22.0	22.6	23.8
EE	0.0	0.1	0.1	0.2	0.3	0.4	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.5	1.6	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7
DR	1.7	2.0	2.0	3.0	3.1	3.2	3.3	3.4	3.4	3.5	3.6	3.6	3.7	3.8	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.3	4.4	4.5	4.5	4.6	4.7
Subtotal	38.0	37.4	38.1	41.1	43.4	51.2	54.5	55.8	58.1	61.3	64.8	69.7	73.4	77.3	82.0	86.2	90.7	94.3	97.2	99.8	101.0	103.8	107.7	110.5	113.7	117.3	121.0

6A, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	10.2	10.2	9.5	9.5	8.6	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	6.2	6.2	6.2	6.2	5.6	5.6	5.6
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	8.9	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	11.6	11.6	11.6	11.6	12.0	12.0	12.0
Renewables	2.5	3.1	3.4	4.8	4.9	5.8	6.5	7.2	7.9	8.7	9.9	11.0	12.2	12.3	13.2	13.3	13.3	14.1	14.1	14.6	15.7	16.1	16.5	17.5	17.9	19.0	20.4
Storage	1.9	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.3	2.6	2.6	3.2	3.2	3.2	3.2	3.5	3.6	3.7	3.9	4.2	4.7	5.0	5.5	6.0	6.4	7.0	7.5
EE	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.6	1.6	1.7
DR	1.7	2.0	2.0	2.5	2.4	2.5	2.4	2.4	2.6	2.6	2.6	2.6	2.6	2.4	2.4	2.4	2.4	2.4	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Subtotal	38.0	37.1	37.5	39.8	40.4	40.6	41.4	41.6	42.5	43.8	44.4	46.3	47.3	47.5	48.5	48.8	49.0	50.1	50.3	51.0	52.8	53.5	54.4	56.0	56.6	58.2	60.1

6B, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	9.7	10.0	10.3	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	10.2	10.2	9.5	9.5	8.6	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	6.2	6.2	6.2	6.2	5.6	5.6	5.6
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	8.3	8.3	8.3	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
Renewables	2.5	3.4	3.7	4.7	4.8	6.0	7.1	8.0	8.7	9.6	11.0	11.1	11.2	11.4	11.5	11.7	11.6	11.7	11.7	11.7	12.5	12.7	13.8	14.8	15.4	16.5	17.5
Storage	1.9	2.0	2.1	2.1	2.2	2.2	2.3	2.6	2.7	2.8	2.9	2.9	3.0	3.0	3.1	3.5	4.0	4.0	4.0	4.0	4.0	4.2	4.7	5.2	5.6	6.2	6.7
EE	0.0	0.1	0.1	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7
DR	1.7	2.0	2.0	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Subtotal	38.0	37.4	37.9	40.0	40.7	41.1	42.5	43.1	43.3	45.4	46.1	46.7	47.2	47.8	48.4	49.0	49.9	50.4	50.4	50.4	49.6	50.0	51.6	53.2	53.6	55.1	56.7

6C, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.0	9.5	10.2	10.2	10.2	9.5	9.5	8.6	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	6.2	6.2	6.2	6.2	5.6	5.6	5.6
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	7.4	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.9	8.9	8.9	8.9	9.3	9.8	9.8
Renewables	2.5	3.4	3.7	5.6	6.5	8.1	9.7	11.0	12.4	13.6	14.4	16.0	16.3	16.9	17.4	18.2	19.1	19.5	19.9	20.3	21.5	22.1	22.9	24.1	24.5	26.0	27.4
Storage	1.9	2.0	2.1	2.1	2.2	2.3	2.5	2.6	3.3	4.0	4.1	4.8	4.9	4.9	5.0	5.9	6.7	6.7	6.7	6.8	7.5	7.8	8.3	8.9	9.5	10.2	10.8
EE	0.0	0.1	0.1	0.2	0.3	0.4	0.6	0.7	0.8	0.9	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5
DR	1.7	2.0	2.0	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Subtotal	38.0	37.4	37.8	40.9	42.4	43.4	45.3	46.2	46.7	48.6	48.8	51.3	51.6	52.2	52.9	54.3	56.2	56.8	57.1	57.7	58.8	59.7	61.0	63.0	63.7	66.3	68.4

6D, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.2	9.8	10.6	10.7	10.7	10.0	10.0	9.3	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.7	7.0	7.0	7.0	7.0	6.4	6.4	6.4
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	6.5	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	8.2	8.2	8.2	8.2	9.1	9.1	9.1
Renewables	2.5	3.5	3.9	4.6	4.8	5.0	6.0	6.9	7.8	8.8	10.2	11.3	12.5	13.3	14.2	14.3	14.3	15.2	15.2	15.2	16.3	16.7	17.2	18.3	18.7	19.8	20.8
Storage	1.9	2.2	2.2	2.3	2.5	2.6	2.9	3.1	3.4	3.8	4.0	4.5	4.6	4.7	4.8	5.0	5.1	5.2	5.3	5.4	6.0	6.4	6.7	7.4	8.0	8.6	9.3
EE	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.0	2.2	2.3	2.5	2.6	2.7	2.8	2.8	2.9	3.0	3.0	3.0	3.0	3.0	3.0
DR	1.7	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Subtotal	38.0	37.7	38.4	40.9	41.8	41.7	43.1	43.8	42.6	44.4	45.4	47.3	48.7	49.8	51.0	51.2	51.5	52.6	52.8	53.0	54.0	54.8	55.6	57.5	58.8	60.4	62.1

6E, SND GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.6	8.6	8.9	9.1	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Hydro	2.5	2.2	2.1	2.1	2.0	2.3	2.3	2.4	2.3	2.3	2.3	2.4	2.3	2.3	2.4	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Coal	5.8	5.8	5.8	4.7	3.6	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	8.8	8.0	8.1	9.6	10.4	10.4	10.4	9.7	9.7	8.9	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.2	8.2	6.5	6.5	6.5	6.5	5.9	5.9	5.9
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT	6.5	5.7	5.7	5.7	6.5	6.5	6.5	6.5	7.4	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	9.3	9.3	9.3
Renewables	2.5	3.4	3.7	4.4	4.5	4.7	5.8	6.7	7.4	8.3	9.7	10.8	11.7	11.8	12.3	12.8	13.1	14.2	14.2	14.4	15.6	15.8	16.4	17.5	18.3	19.3	20.3
Storage	1.9	2.0	2.1	2.1	2.2	2.3	2.5	2.7	3.2	3.4	3.5	3.9	3.9	4.0	4.0	4.4	4.9	5.1	5.2	5.4	6.1	6.4	6.7	7.4	7.9	8.6	9.3
EE	0.0	0.1	0.1	0.2	0.3	0.4	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.6	1.6	1.7	1.6	1.6	1.7
DR	1.7	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Subtotal	38.0	37.4	38.0	40.1	40.8	40.4	41.8	42.3	42.0	43.8	44.6	46.5	47.7	48.4	49.1	49.7	50.8	52.1	52.3	52.7	52.9	53.4	54.4	56.2	57.8	59.4	61.1

H.7 Total Energy Plan Tables

The tables provided below show total energy for all 30 portfolios for 2024-2050. Results are grouped by scenario. Scenarios are represented by number (1 to 6) and strategies by letter (A to E). Data is shown in terawatt hours (TWh), which is equal to 1,000 gigawatt hours (GWh).

Table H-3: Total Energy Plan Tables

1A, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.0	66.4	63.9	65.8	65.1	66.0	65.1	68.1	65.3	67.0	66.4	66.3	66.0	67.7	65.3	67.1	66.7	66.4	66.0	67.7	65.5	66.8	66.4	66.2	66.1	67.9	64.9
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.8	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.4
Coal	19.3	25.1	27.4	17.3	15.2	10.0	10.4	10.3	6.4	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	61.2	56.0	56.4	63.7	66.8	69.1	69.8	65.0	71.8	70.2	72.4	71.1	70.6	67.6	68.9	67.5	67.3	66.1	67.4	67.1	68.2	67.3	67.0	66.5	69.2	67.2	68.9
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.0	8.8	11.1	12.1	12.3	12.4	13.4	14.1	14.9	17.2	19.6	22.0	24.3	25.8	27.4	29.2	31.4	31.7	31.8	34.1	34.9	37.1	39.3	39.6	41.7	43.9
Storage	3.2	3.2	3.4	3.4	3.4	3.4	3.4	3.4	3.5	3.6	3.6	3.8	3.9	4.1	4.2	5.0	5.7	6.5	6.8	7.0	7.8	8.3	9.1	9.8	10.4	11.0	11.6
EEDR	0.3	0.5	0.6	1.5	2.1	2.7	3.3	3.9	4.5	5.0	5.6	6.1	6.6	7.0	7.4	7.8	8.2	8.5	8.5	8.5	8.6	8.7	8.7	8.7	8.7	8.7	8.7
Economic Purchases	0.2	0.4	0.6	0.1	0.1	0.2	0.4	0.4	0.3	0.4	1.5	1.2	1.2	0.8	1.1	1.1	1.4	1.4	1.9	1.9	2.8	2.8	3.2	3.3	2.7	2.1	2.9
Subtotal	171.5	174.2	175.7	177.3	178.9	179.0	179.7	180.2	181.4	182.0	182.8	184.1	186.1	187.2	188.8	191.3	193.9	195.8	197.8	199.5	202.4	204.3	206.9	209.3	212.2	214.0	216.4

1B, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.1	66.5	64.0	66.0	65.2	65.7	65.0	68.0	65.4	69.3	68.9	71.0	73.0	77.1	77.4	81.2	83.4	85.4	84.7	86.5	84.6	85.9	85.3	85.2	85.3	86.7	84.0
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.4
Coal	19.1	25.4	27.0	17.1	15.5	10.0	10.3	10.0	7.7	4.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	61.3	55.4	56.5	63.8	67.3	68.3	69.0	63.7	68.3	55.1	57.1	53.7	50.9	47.5	48.0	45.9	44.2	42.8	44.8	42.9	43.0	41.5	46.4	45.9	44.9	43.5	44.7
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	11.5	11.4	11.4	11.4	11.3	11.4	11.5	11.3	11.3	11.3	11.2	11.1	5.5	5.4	6.0	5.8	6.2
Renewables	6.6	8.2	9.1	10.8	11.2	13.1	13.3	15.1	15.9	16.8	19.2	21.7	24.1	24.2	24.3	24.4	25.4	25.5	25.5	27.1	29.4	31.5	33.7	35.9	37.8	39.8	42.1
Storage	3.2	3.3	3.5	3.4	3.5	3.5	3.6	3.6	3.9	4.2	4.5	5.4	5.7	5.6	5.7	6.2	7.0	7.1	7.2	7.7	8.4	9.3	9.9	10.6	11.2	11.9	12.6
EEDR	0.3	0.5	0.7	1.6	2.2	2.8	3.4	4.0	4.6	5.2	5.8	6.3	6.8	7.2	7.6	7.9	8.3	8.6	8.6	8.7	8.7	8.8	8.8	8.8	8.8	8.8	8.9
Economic Purchases	0.3	0.3	0.5	0.1	0.1	0.2	0.3	0.3	0.6	0.2	0.9	0.6	0.4	0.2	0.2	0.3	0.2	0.3	0.6	0.7	2.3	1.9	2.8	2.9	3.6	3.1	3.5
Subtotal	171.5	174.3	175.8	177.3	179.1	179.1	179.9	180.5	181.8	182.7	184.0	186.0	188.1	189.0	190.6	192.6	195.4	196.5	198.2	200.4	203.2	205.5	207.8	210.2	213.1	215.0	217.5

1C, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.2	66.6	63.8	66.0	65.1	65.9	64.9	68.0	65.3	66.9	66.6	66.2	66.0	67.7	65.3	66.9	66.6	66.4	66.1	67.7	65.5	67.0	66.7	66.2	65.9	67.5	65.0
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.4	15.4
Coal	18.9	25.4	27.5	16.7	14.8	9.3	9.3	8.7	6.5	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	61.4	55.3	56.1	62.7	66.4	65.5	63.5	57.2	60.7	57.9	59.1	56.8	55.7	53.7	55.3	52.9	51.7	51.2	52.0	50.7	49.2	48.0	47.0	46.6	47.7	45.5	46.2
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.2	9.1	12.6	12.9	16.6	20.3	23.3	25.4	27.5	31.2	34.9	37.9	38.9	40.4	43.6	46.6	47.7	48.7	49.9	53.3	54.6	57.9	60.7	61.8	64.5	67.9
Storage	3.3	3.2	3.5	3.5	3.5	3.7	4.0	4.2	4.8	5.5	6.4	7.4	7.8	7.9	8.0	9.4	10.7	10.9	11.0	11.3	12.1	13.0	13.9	14.8	15.3	16.3	17.0
EEDR	0.3	0.5	0.6	1.5	2.1	2.7	3.3	3.9	4.5	5.0	5.6	6.1	6.6	6.9	7.2	7.3	7.7	8.0	8.0	8.1	8.2	8.3	8.3	8.1	8.0	8.0	7.9
Economic Purchases	0.3	0.3	0.5	0.0	0.1	0.1	0.1	0.1	0.2	0.4	1.2	1.0	0.9	0.7	1.0	0.8	1.0	1.1	1.5	1.4	3.7	3.5	3.3	3.3	3.7	2.9	3.2
Subtotal	171.5	174.3	175.8	177.4	179.0	179.4	180.4	181.1	182.9	184.2	186.2	188.3	190.7	191.6	193.3	196.4	199.8	200.9	202.6	204.5	207.5	209.7	212.6	215.1	217.9	220.2	222.7

1D, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.1	66.5	63.7	65.7	65.2	65.9	64.9	68.0	65.2	67.2	66.4	66.3	65.8	67.7	65.4	66.9	66.5	66.1	65.8	67.6	65.4	67.0	66.4	66.2	66.1	67.7	64.9
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.4	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.4
Coal	19.0	25.4	26.8	16.4	13.8	9.5	9.7	9.3	7.1	5.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	61.4	55.1	56.9	65.1	68.7	69.8	70.4	65.4	69.4	67.0	69.2	67.8	67.2	63.8	64.5	62.6	62.5	61.5	62.9	61.9	62.9	61.2	61.2	60.9	60.9	59.1	60.7
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.5	9.4	10.5	10.9	11.3	11.6	12.9	13.8	14.8	17.3	19.8	22.3	24.6	26.8	29.1	30.6	32.5	32.4	33.1	35.4	36.9	39.2	41.3	42.6	44.6	46.8
Storage	3.2	3.4	3.6	3.5	3.6	3.7	3.9	3.9	4.2	4.4	4.6	5.2	5.6	5.9	6.4	6.8	7.1	7.7	8.1	8.1	9.0	9.9	10.8	11.7	12.2	13.1	13.7
EEDR	0.3	0.5	0.7	2.0	2.9	3.8	4.7	5.5	6.5	7.4	8.2	9.0	9.8	10.4	11.1	11.6	12.2	12.6	12.7	12.8	13.0	13.2	13.2	13.2	13.2	13.3	13.2
Economic Purchases	0.3	0.3	0.2	-0.1	0.0	0.1	0.1	0.1	0.5	0.9	2.4	1.7	1.6	1.3	1.3	1.1	1.4	1.4	2.0	1.9	2.9	2.7	2.9	2.9	4.0	3.4	4.2
Subtotal	171.4	174.5	175.9	177.5	179.2	179.3	180.3	180.9	182.3	183.0	184.1	185.8	188.2	189.4	191.4	193.5	195.7	197.3	199.5	200.9	204.1	206.4	209.1	211.6	214.4	216.6	219.0

1E, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.0	66.4	63.8	65.7	65.2	65.6	64.8	67.9	65.2	69.4	69.0	71.2	73.0	77.2	74.6	76.5	76.2	75.7	75.3	77.3	75.1	76.4	76.0	75.8	75.6	77.3	74.5
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.4
Coal	19.0	25.3	27.1	17.2	15.0	10.0	10.4	9.9	7.4	5.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	61.4	55.5	56.7	64.9	68.7	70.5	71.3	66.3	70.5	67.7	69.7	66.5	64.0	58.7	59.7	59.2	58.7	58.6	60.1	59.3	60.3	58.6	58.5	58.1	58.0	56.2	57.6
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.2	9.1	10.1	10.4	11.1	11.3	12.8	13.6	14.5	16.9	19.4	21.8	24.1	26.3	26.7	29.0	30.2	30.2	30.5	32.8	34.9	37.1	39.3	41.2	43.3	45.6
Storage	3.2	3.2	3.4	3.4	3.5	3.6	3.8	3.8	4.0	4.2	4.4	5.4	5.6	5.8	6.2	6.7	7.6	7.8	7.9	8.3	9.1	10.0	11.0	11.9	12.5	13.5	14.3
EEDR	0.3	0.5	0.6	1.5	2.1	2.7	3.3	3.9	4.8	5.3	5.9	6.4	6.9	7.2	7.7	8.0	8.4	8.7	8.6	8.7	8.8	8.9	8.9	8.8	8.8	8.8	8.8
Economic Purchases	0.3	0.4	0.4	0.0	0.0	0.2	0.3	0.4	0.9	0.5	1.8	1.1	1.0	0.5	0.5	0.7	0.7	0.9	1.4	1.5	2.4	2.1	2.1	2.4	3.0	2.4	3.2
Subtotal	171.4	174.3	175.7	177.3	179.0	179.3	180.1	180.7	181.9	182.6	183.9	186.0	188.1	189.2	191.1	193.2	196.1	197.3	199.0	201.0	204.0	206.3	209.1	211.7	214.7	216.9	219.4

2A, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.1	66.5	63.9	65.9	65.1	65.8	64.9	67.9	65.3	66.9	66.5	66.2	66.0	67.6	65.3	66.9	66.6	66.2	65.9	67.8	65.5	66.8	66.5	66.3	66.1	67.7	64.9
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.4	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	20.0	26.1	28.7	22.3	22.7	14.6	14.5	14.1	8.5	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	63.0	59.5	61.7	65.8	67.5	72.3	71.4	66.3	76.3	75.4	81.0	80.3	80.4	78.3	79.5	79.3	79.8	80.3	82.9	80.9	80.1	80.9	79.8	79.1	78.0	75.7	74.5
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.0	9.0	12.6	15.6	19.2	23.2	26.2	26.9	28.6	31.9	35.2	38.4	41.0	43.7	44.7	46.8	48.7	48.8	51.8	57.2	57.6	61.7	65.0	70.3	73.2	79.1
Storage	3.3	3.3	3.6	3.6	3.9	3.9	4.1	4.2	4.8	5.2	5.8	6.6	7.3	8.0	8.7	9.4	10.2	10.9	11.4	12.4	13.6	14.2	15.1	16.4	17.4	18.6	20.2
EEDR	0.3	0.5	0.6	1.6	2.2	2.8	3.4	4.0	4.6	5.1	5.7	6.3	6.8	7.2	7.7	8.0	8.4	8.7	8.8	8.8	8.9	9.0	9.0	9.0	9.0	9.1	9.1
Economic Purchases	0.5	0.6	1.0	1.2	0.5	0.1	0.1	0.0	0.0	-0.2	0.2	0.1	0.2	0.0	0.1	0.3	0.5	0.6	0.9	0.7	1.0	1.2	1.0	1.2	1.2	0.9	1.2
Subtotal	174.4	179.2	183.2	187.4	191.6	194.2	196.5	198.4	201.8	204.0	207.2	210.6	214.9	217.8	221.0	224.0	227.8	230.9	234.1	237.9	241.9	245.0	248.6	252.4	257.6	260.6	264.5

2B, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.1	66.7	64.0	65.8	65.4	65.7	65.0	67.8	65.2	69.2	68.9	71.0	73.1	77.2	77.2	81.2	83.4	85.3	84.9	86.7	84.6	85.9	85.3	85.1	94.4	98.3	95.5
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	19.9	26.1	28.8	22.1	22.4	14.5	14.2	13.9	8.8	7.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	62.9	59.0	61.1	64.8	64.7	69.5	69.0	63.9	71.9	57.6	63.2	60.7	59.9	58.1	58.6	55.3	53.5	52.7	55.2	52.8	50.4	50.9	55.6	55.1	50.7	48.1	49.7
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	11.4	11.1	11.1	11.0	10.9	10.8	10.9	10.7	10.9	10.9	10.6	10.7	5.4	5.4	4.8	4.1	4.4
Renewables	6.6	8.4	9.4	14.0	18.5	22.3	25.8	29.0	30.8	32.5	35.7	39.1	40.9	40.7	41.8	44.0	46.2	47.3	47.5	50.9	57.6	58.2	61.4	64.6	64.7	66.6	69.1
Storage	3.2	3.3	3.7	3.7	4.2	4.6	5.0	5.8	6.4	7.2	7.8	8.7	9.2	9.3	9.5	10.9	12.3	13.0	13.5	14.3	15.2	15.8	16.5	18.0	19.3	20.5	21.7
EEDR	0.3	0.5	0.7	1.7	2.3	2.9	3.5	4.1	4.8	5.4	5.9	6.5	7.0	7.4	7.8	8.2	8.6	8.9	8.9	9.0	9.1	9.2	9.2	9.2	9.2	9.2	9.2
Economic Purchases	0.7	0.6	1.0	1.0	0.3	0.0	0.0	0.0	0.3	-0.2	0.5	0.2	0.2	0.0	0.0	-0.1	-0.1	0.0	0.2	0.0	0.8	0.9	1.4	1.5	1.1	0.6	1.2
Subtotal	174.2	179.3	183.3	187.6	192.0	195.0	197.6	200.3	203.7	206.4	209.6	213.1	217.1	219.3	221.9	225.7	230.2	233.4	236.6	240.0	243.7	246.9	250.3	254.4	259.8	262.9	266.2

2C, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.0	66.7	63.6	65.8	65.0	65.9	64.7	68.0	65.5	67.0	66.4	66.1	65.7	67.7	65.3	66.8	66.6	66.4	65.7	67.9	65.6	66.8	66.3	66.3	66.0	67.8	64.8
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.8	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	20.2	26.4	29.0	22.2	22.3	15.4	14.9	14.3	8.3	7.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	62.8	58.6	61.2	64.1	63.7	65.4	63.5	57.5	65.4	62.8	68.0	65.2	66.6	64.4	65.0	61.7	59.9	59.4	61.3	58.5	56.7	56.5	55.7	56.7	57.1	56.2	56.9
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.4	9.4	14.8	20.1	25.3	31.0	34.9	38.2	41.3	44.6	50.2	52.2	54.8	58.2	62.8	67.5	70.3	71.6	75.4	80.9	82.3	86.5	88.7	92.6	93.7	97.9
Storage	3.3	3.3	3.6	3.8	4.2	4.8	5.3	6.2	7.1	8.1	8.8	9.9	10.6	11.4	12.4	14.7	16.8	17.6	18.3	19.1	19.7	20.4	21.4	22.6	23.6	24.3	25.3
EEDR	0.3	0.4	0.6	1.6	2.2	2.8	3.4	4.0	4.6	5.2	5.7	6.3	6.8	7.3	7.7	8.1	8.5	8.8	8.8	8.9	9.0	9.0	9.1	9.0	9.0	9.0	9.0
Economic Purchases	0.6	0.6	1.1	1.0	0.5	0.2	0.2	0.1	0.0	0.1	1.1	0.9	1.0	0.6	0.7	0.7	0.7	0.8	1.0	0.5	1.7	1.8	1.7	0.9	1.0	0.9	1.2
Subtotal	174.4	179.3	183.2	187.6	192.0	195.3	197.9	200.8	204.6	207.5	210.7	214.6	218.8	221.8	225.3	230.2	235.5	238.8	242.2	245.7	249.0	252.3	256.1	259.7	264.9	267.3	270.4

2D, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.2	66.5	63.9	66.0	65.2	65.8	64.8	67.8	65.4	66.8	66.5	66.2	65.8	67.6	65.4	67.1	66.6	66.2	65.7	67.8	65.4	67.0	66.5	66.3	66.0	67.7	64.8
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.8	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.4	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.4	15.4
Coal	20.3	26.2	28.4	21.8	21.9	15.1	14.9	14.3	8.7	7.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	62.5	58.7	61.3	67.5	68.1	70.8	69.9	64.4	73.8	72.1	77.3	76.5	76.5	74.6	77.8	75.9	76.8	77.2	79.8	78.0	79.3	78.5	76.9	76.0	75.6	72.7	72.1
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.6	9.8	11.3	15.4	19.4	23.1	26.4	27.3	29.1	32.3	35.7	38.8	40.9	42.1	44.6	46.5	48.3	48.6	51.2	54.2	55.9	60.8	64.4	68.9	72.7	78.0
Storage	3.3	3.4	3.8	3.9	4.3	4.5	4.9	5.5	6.0	6.1	6.4	7.2	8.1	9.0	9.5	10.6	11.4	12.3	13.0	13.7	14.6	15.5	16.6	18.0	19.0	20.7	22.3
EEDR	0.3	0.5	0.7	2.0	2.9	3.8	4.7	5.6	6.5	7.4	8.3	9.1	9.9	10.5	11.1	11.6	12.3	12.7	12.8	12.9	13.1	13.2	13.3	13.3	13.3	13.3	13.3
Economic Purchases	0.6	0.7	1.0	0.9	0.2	0.1	0.2	0.1	0.0	0.2	1.1	0.9	1.0	0.8	0.1	0.2	0.4	0.5	0.8	0.6	1.2	1.2	0.9	1.1	1.3	0.7	1.1
Subtotal	174.4	179.4	183.4	187.7	192.1	194.9	197.5	200.0	203.3	205.2	208.1	211.5	216.0	219.0	222.1	225.5	229.3	232.6	236.1	239.5	243.2	246.7	250.6	254.4	259.6	263.2	267.1

2E, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.2	66.5	63.9	65.9	65.1	65.9	65.0	68.1	65.3	69.3	68.9	71.2	73.2	77.2	74.9	76.3	76.2	75.8	75.3	77.2	75.0	76.3	75.9	75.8	75.8	77.1	74.3
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.4
Coal	20.3	26.0	28.5	21.9	22.1	15.0	15.0	14.3	8.7	7.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	62.5	59.2	61.6	66.5	67.1	70.4	69.7	64.6	74.8	70.9	77.5	74.3	73.5	71.6	73.0	70.9	70.4	70.1	73.0	71.4	69.5	68.8	67.5	66.0	66.1	64.0	65.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.4	9.4	12.5	17.0	20.8	24.3	27.5	28.2	29.9	33.2	36.5	38.5	38.4	40.8	44.2	47.4	50.2	50.3	52.8	58.3	60.2	64.9	69.1	72.9	75.9	79.5
Storage	3.3	3.3	3.7	3.7	4.0	4.3	4.6	5.0	5.6	6.4	7.3	8.4	8.7	8.8	9.7	11.2	12.9	13.8	14.5	15.3	16.1	16.9	17.8	19.6	20.9	22.5	23.9
EEDR	0.3	0.5	0.6	1.6	2.2	2.8	3.4	4.0	4.6	5.2	5.8	6.3	6.8	7.3	7.7	8.1	8.5	8.8	8.8	8.9	9.0	9.0	9.1	9.1	9.1	9.1	9.1
Economic Purchases	0.6	0.6	1.0	1.0	0.3	0.1	0.2	0.1	0.1	0.2	0.3	0.1	0.0	-0.1	0.0	-0.1	0.1	0.1	0.4	0.2	1.4	1.4	1.2	1.2	1.4	1.1	1.7
Subtotal	174.4	179.3	183.3	187.5	191.8	194.6	197.1	199.3	202.8	205.5	209.0	212.7	216.6	218.7	222.2	226.2	230.9	234.3	237.8	241.3	244.9	248.3	251.8	256.3	261.8	265.2	268.8

3A, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.0	66.5	63.6	65.9	65.3	65.7	65.1	68.0	65.3	67.0	66.4	66.3	65.9	67.8	65.4	67.1	66.6	66.4	66.0	67.7	65.7	66.9	66.5	66.4	66.0	67.6	65.0
Hydro	16.7	14.8	14.6	14.5	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	17.8	23.3	23.3	11.5	5.4	4.1	4.1	4.4	2.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	58.7	51.6	52.5	60.9	66.3	63.8	64.1	59.6	65.6	54.0	51.2	51.0	51.6	49.0	50.5	48.8	49.1	48.4	48.7	47.0	46.7	45.2	49.8	49.8	47.7	46.1	46.1
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	11.5	11.4	11.6	11.5	11.4	11.5	11.5	11.4	11.5	11.5	11.5	11.5	5.2	5.3	5.7	5.2	5.6
Renewables	6.6	8.0	8.9	9.9	10.1	10.2	10.1	9.6	8.1	6.5	8.7	8.7	8.8	9.0	9.3	9.4	9.4	9.6	9.6	9.7	10.6	11.1	13.3	13.9	16.1	17.4	19.6
Storage	3.1	3.1	3.4	3.4	3.4	3.2	3.3	3.1	3.1	3.1	3.1	3.2	3.1	3.2	3.3	3.3	3.5	3.5	3.6	3.7	3.7	3.7	3.8	4.0	4.5	4.7	4.9
EEDR	0.3	0.5	0.6	1.2	1.6	2.0	2.4	2.8	3.2	3.6	3.9	4.3	4.6	5.0	5.3	5.5	5.8	6.0	5.9	5.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Economic Purchases	0.1	0.1	-0.1	-0.5	-0.3	-0.2	-0.3	-0.4	-0.1	-0.2	0.8	0.8	1.0	1.0	1.3	1.6	2.1	2.6	3.1	3.3	5.3	5.4	6.2	6.2	7.1	6.6	7.2
Subtotal	167.3	167.9	166.8	166.7	165.9	164.2	163.9	162.7	162.7	162.1	161.7	161.7	162.5	162.1	162.4	162.7	163.5	163.3	164.0	164.3	164.8	165.3	166.3	167.0	168.6	169.0	169.7

3B, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.1	66.6	63.8	65.8	65.2	65.8	65.0	67.9	65.4	69.3	68.6	71.0	72.9	77.1	77.1	81.2	83.4	85.2	84.5	86.7	84.6	85.9	85.4	85.5	85.2	86.6	83.8
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	17.5	22.7	23.0	11.5	5.3	4.1	4.0	4.0	2.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	58.9	51.9	52.1	60.2	65.6	62.5	62.9	58.4	63.7	50.1	49.2	46.6	44.8	39.7	39.1	35.1	33.0	30.2	31.1	28.8	29.9	29.1	37.1	36.8	35.7	34.6	35.5
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	11.5	11.4	11.6	11.5	11.4	11.5	11.5	11.3	11.4	11.4	11.4	11.4	2.3	2.4	2.8	2.5	2.5
Renewables	6.6	8.4	9.3	10.4	10.6	10.7	10.6	10.3	8.6	7.0	7.0	7.0	7.2	7.5	7.8	7.9	7.9	8.1	8.1	8.2	8.3	8.2	9.5	10.1	11.5	11.8	14.0
Storage	3.1	3.2	3.5	3.4	3.5	3.3	3.3	3.2	3.3	3.2	3.2	3.2	3.2	3.3	3.4	3.8	4.3	4.6	4.6	4.8	4.8	4.9	5.0	5.1	5.2	5.1	5.2
EEDR	0.3	0.5	0.7	1.5	2.1	2.7	3.3	3.9	4.5	5.0	5.6	6.1	6.6	7.0	7.4	7.7	8.1	8.4	8.4	8.4	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Economic Purchases	0.2	0.0	-0.1	-0.5	-0.3	-0.3	-0.3	-0.5	-0.1	-0.2	0.7	0.5	0.6	0.5	0.5	0.7	0.9	1.3	1.6	1.8	3.3	3.3	4.6	4.5	5.0	4.9	5.2
Subtotal	167.3	168.0	166.9	166.7	166.0	164.3	163.9	162.9	162.9	162.3	161.9	161.8	162.7	162.3	162.7	163.3	164.6	164.6	165.3	165.7	166.2	166.8	167.8	168.3	169.4	169.5	170.2

3C, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	63.9	66.5	63.9	66.0	65.4	65.8	64.9	67.9	65.4	66.7	66.3	66.2	66.0	67.8	65.2	66.9	66.6	66.3	66.0	67.7	65.5	66.8	66.6	66.3	66.2	67.7	64.9
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.4
Coal	17.9	22.9	23.0	11.6	5.2	3.9	4.0	4.0	1.6	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	58.6	51.8	52.1	60.2	66.0	62.4	61.7	56.2	61.0	59.0	55.4	53.4	52.9	49.1	49.9	47.4	46.3	44.7	44.1	41.2	40.7	38.9	38.7	38.2	37.4	35.3	35.4
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.4	9.3	10.4	10.6	11.8	12.9	13.7	13.1	12.7	15.6	17.7	19.1	20.5	21.9	23.2	24.4	25.7	26.8	28.1	29.3	30.4	31.5	32.7	33.8	34.9	38.2
Storage	3.2	3.2	3.4	3.4	3.5	3.4	3.5	3.4	3.7	3.7	3.9	4.1	4.2	4.3	4.5	4.8	5.7	6.0	6.3	6.4	6.7	7.0	7.3	7.5	7.5	7.6	8.5
EEDR	0.3	0.5	0.6	1.2	1.6	2.0	2.4	2.8	3.2	3.5	3.9	4.3	4.6	4.9	5.2	5.5	5.7	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Economic Purchases	0.2	0.0	-0.1	-0.5	-0.3	-0.3	-0.3	-0.5	-0.1	0.0	1.4	1.1	1.1	1.1	1.2	1.2	2.0	2.2	2.6	2.9	4.9	4.8	5.0	5.1	5.9	5.7	5.7
Subtotal	167.4	168.0	166.9	166.7	166.0	164.4	164.0	163.1	163.4	162.8	162.6	162.8	163.7	163.4	163.9	164.5	166.1	166.2	167.1	167.6	168.4	169.2	170.5	171.0	172.2	172.4	174.0

3D, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	63.9	66.6	63.8	66.0	65.2	65.8	64.9	68.0	65.3	67.1	66.5	66.3	65.9	67.6	65.3	67.0	66.6	66.2	65.9	67.8	65.4	67.0	66.5	66.2	65.9	67.7	64.9
Hydro	16.7	14.8	14.6	14.5	14.1	15.4	15.0	15.8	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	17.7	22.8	22.3	10.6	4.8	3.6	3.8	3.6	1.3	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	58.9	51.4	52.5	60.1	65.0	61.7	61.7	56.6	62.3	60.8	59.3	58.5	58.8	55.9	56.6	55.0	54.8	53.8	54.1	52.0	50.5	48.2	48.7	49.0	47.3	44.3	45.2
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.6	9.7	10.8	11.0	11.1	11.0	10.9	9.2	7.7	7.8	7.8	8.0	8.4	8.8	9.0	9.0	9.2	9.2	9.3	11.5	12.8	12.8	13.6	15.7	17.9	20.1
Storage	3.1	3.3	3.6	3.6	3.5	3.4	3.5	3.5	3.6	3.6	3.7	3.8	3.9	3.9	4.1	4.3	4.7	4.8	4.9	5.0	5.5	5.9	5.9	6.2	6.5	6.8	7.3
EEDR	0.3	0.5	0.7	1.9	2.8	3.7	4.6	5.5	6.4	7.3	8.2	9.0	9.7	10.4	11.0	11.5	12.2	12.6	12.6	12.8	12.9	13.1	13.2	13.1	13.2	13.2	13.1
Economic Purchases	0.1	0.0	-0.2	-0.6	-0.4	-0.3	-0.4	-0.6	-0.2	-0.1	1.1	1.2	1.4	1.3	1.7	1.7	2.3	3.0	3.5	3.7	5.8	5.7	6.4	6.2	7.0	6.4	6.6
Subtotal	167.3	168.1	167.0	166.9	166.1	164.5	164.1	163.3	163.4	162.8	162.6	162.6	163.5	163.1	163.6	164.1	165.1	165.0	165.6	166.1	167.2	168.1	169.0	169.7	171.2	171.6	172.7

3E, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.0	66.5	63.9	65.9	65.1	65.8	64.9	68.0	65.3	69.3	68.8	70.9	73.1	77.3	74.8	76.5	76.2	75.8	75.0	77.3	74.8	76.5	75.9	75.7	75.7	77.2	74.5
Hydro	16.7	14.8	14.6	14.5	14.1	15.4	15.0	15.7	15.5	16.0	16.1	15.9	15.8	15.7	16.0	15.5	15.4	15.5	15.5	15.5	15.4	15.4	15.5	15.5	15.5	15.5	15.4
Coal	17.6	22.8	22.8	10.8	5.0	3.9	3.9	4.0	1.8	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	58.9	51.8	52.3	61.2	66.5	63.5	64.1	59.4	65.3	61.9	59.5	57.1	55.6	50.6	52.4	50.5	50.8	49.9	50.8	48.4	47.1	44.7	45.5	45.4	43.6	41.1	41.8
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.4	9.3	10.4	10.6	10.7	10.6	10.3	8.6	7.0	8.8	8.8	8.9	9.2	9.5	9.7	9.7	9.9	9.9	10.0	12.2	13.8	13.8	14.6	16.8	19.0	21.2
Storage	3.2	3.2	3.4	3.4	3.5	3.3	3.4	3.4	3.6	3.5	3.9	3.9	4.0	4.0	4.3	4.7	5.2	5.5	5.5	5.6	6.1	6.4	6.6	6.8	7.0	7.3	7.7
EEDR	0.3	0.5	0.6	1.2	1.6	2.0	2.4	2.8	3.2	3.5	3.9	4.3	4.6	4.9	5.2	5.5	5.7	5.9	5.9	5.9	5.9	5.9	5.9	5.9	6.0	5.9	5.9
Economic Purchases	0.2	0.0	-0.2	-0.5	-0.3	-0.3	-0.3	-0.5	-0.1	0.0	1.6	1.6	1.4	1.2	1.4	2.0	2.5	3.0	3.6	3.9	6.0	5.7	6.2	6.2	6.9	6.1	6.5
Subtotal	167.4	168.0	166.8	166.7	166.0	164.3	164.0	163.1	163.2	162.6	162.6	162.5	163.5	163.1	163.7	164.3	165.5	165.5	166.2	166.6	167.6	168.4	169.4	170.1	171.4	172.0	173.0

4A, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.2	66.5	63.5	65.7	65.2	65.6	65.0	68.1	65.3	66.9	66.5	66.4	65.9	67.8	65.4	67.0	66.7	66.3	65.8	67.6	65.6	66.9	66.3	66.4	66.0	67.8	64.8
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.4	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	18.0	25.0	27.1	19.4	17.8	12.5	12.1	12.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	61.8	55.5	56.6	61.8	63.4	64.7	62.2	55.3	50.6	17.3	4.6	2.5	1.8	1.3	1.5	1.3	1.2	1.1	1.2	1.3	1.4	1.2	1.2	1.3	1.2	1.0	1.3
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.4	25.3	17.4	16.5	13.6	14.3	14.6	15.2	15.7	17.3	16.7	18.9	19.1	19.0	19.0	19.5	18.4	20.2
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	22.6	33.1	32.9	32.3	32.1	32.4	32.8	32.6	32.9	32.9	33.0	33.0	30.6	30.2	30.3	29.7	29.3
Renewables	6.6	8.0	8.8	12.0	14.4	16.7	18.9	20.4	21.8	22.4	24.9	27.5	30.2	32.8	33.8	33.8	33.8	33.8	33.8	33.7	33.9	35.5	37.8	40.4	43.2	45.3	48.6
Storage	3.2	3.2	3.5	3.3	3.5	3.3	3.5	4.0	2.8	3.2	6.0	7.3	8.2	9.0	9.0	9.2	9.5	9.6	9.7	9.7	9.9	10.5	10.6	11.5	12.1	12.6	13.3
EEDR	0.3	0.4	0.6	1.5	2.1	2.7	3.3	3.9	4.6	5.1	5.7	6.2	6.8	7.2	7.7	8.0	8.4	8.7	8.8	8.8	8.9	9.0	9.0	9.0	9.0	9.0	9.0
Economic Purchases	0.3	1.0	2.1	1.0	1.0	0.7	1.9	2.9	19.8	18.0	13.9	11.2	12.1	12.1	13.5	13.1	14.0	14.5	14.5	14.6	15.8	14.2	16.4	15.5	14.9	14.1	14.0
Subtotal	171.0	174.5	176.8	179.1	181.6	181.6	181.7	182.3	181.3	181.7	185.5	187.5	190.2	191.9	193.2	194.9	197.0	197.8	199.4	200.9	202.8	204.8	206.3	208.8	211.8	213.5	215.9

4B, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.0	66.6	63.8	65.8	65.2	65.6	64.6	68.0	65.1	69.3	68.9	71.0	73.0	77.2	77.0	81.1	83.2	85.3	84.8	86.6	84.6	85.9	87.9	87.6	87.6	88.8	86.4
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.4	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.4
Coal	18.0	24.8	27.1	19.1	17.7	12.5	12.1	12.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	61.8	55.3	56.0	61.8	63.1	64.1	61.8	54.8	50.0	15.7	3.7	2.1	1.5	1.1	1.0	0.8	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.2	23.3	14.0	12.2	9.8	9.7	9.1	8.6	7.9	9.2	9.2	10.6	11.3	9.9	10.3	10.9	10.8	10.9
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	22.6	32.8	32.3	31.6	31.5	31.6	31.8	31.3	31.7	31.5	31.9	32.0	27.4	27.5	28.1	27.1	26.9
Renewables	6.6	8.3	9.1	12.3	14.9	17.2	19.5	21.0	22.4	23.0	25.7	28.6	30.8	31.4	31.4	31.4	31.5	31.5	31.4	31.4	31.5	31.5	33.7	35.8	37.1	39.0	43.9
Storage	3.3	3.3	3.6	3.4	3.5	3.7	4.3	4.8	3.4	3.9	7.0	8.4	8.9	9.2	9.3	9.9	10.5	10.7	10.6	10.5	10.6	10.6	11.2	11.9	12.5	13.0	13.7
EEDR	0.3	0.5	0.7	1.6	2.2	2.8	3.4	4.0	4.8	5.3	5.9	6.4	6.9	7.4	7.8	8.1	8.5	8.8	8.8	8.9	8.9	9.0	9.1	9.0	9.1	9.0	9.0
Economic Purchases	0.4	1.0	2.1	0.8	1.0	0.7	1.9	2.9	19.8	17.7	13.5	9.6	9.6	8.7	9.8	8.3	7.8	7.4	7.8	7.5	9.3	8.4	11.6	10.8	10.7	9.8	9.3
Subtotal	171.1	174.6	176.9	179.2	181.6	182.2	182.6	183.2	182.1	182.5	186.7	188.9	191.0	192.2	193.6	195.7	198.2	199.1	200.5	201.8	203.7	204.9	207.1	209.3	212.2	213.9	216.4

4C, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.1	66.6	63.8	65.8	64.9	65.9	64.7	68.0	65.3	67.0	66.2	66.4	65.9	67.7	65.5	66.8	66.5	66.4	65.9	67.6	65.5	66.8	66.6	66.3	65.9	67.7	64.7
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	18.0	24.8	26.8	19.0	17.5	12.4	11.7	11.5	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	61.8	55.5	56.3	61.5	62.6	61.9	58.9	50.8	41.3	13.8	2.6	1.5	1.2	1.0	0.9	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.3	18.7	10.9	10.1	8.9	9.4	9.0	8.9	8.6	9.8	9.2	10.4	10.7	10.4	10.8	11.5	10.7	11.6
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.3	22.1	31.8	31.1	30.5	30.6	31.2	31.6	31.4	31.5	31.2	31.5	31.3	27.0	26.8	27.3	26.3	26.6
Renewables	6.6	8.3	9.1	12.8	16.0	19.6	23.1	25.8	32.4	33.5	38.1	41.5	44.3	45.2	45.7	47.0	48.4	49.5	50.5	51.4	52.8	53.7	55.8	58.3	59.6	62.3	65.7
Storage	3.3	3.3	3.6	3.4	3.6	4.1	4.9	5.6	4.5	5.3	8.6	10.2	11.1	11.3	11.5	12.6	13.7	13.8	13.9	13.8	14.1	14.1	14.0	14.5	15.3	15.9	16.9
EEDR	0.3	0.5	0.6	1.6	2.1	2.7	3.3	3.9	4.6	5.2	5.7	6.2	6.7	7.2	7.6	7.9	8.3	8.6	8.6	8.7	8.8	8.8	8.9	8.9	8.9	8.9	8.9
Economic Purchases	0.4	1.0	2.1	0.8	0.9	0.7	1.8	2.8	18.8	15.9	10.4	6.5	7.2	7.2	9.0	8.2	8.3	8.3	8.0	7.6	8.6	7.3	11.4	10.5	10.6	9.3	9.5
Subtotal	171.0	174.6	177.0	179.2	181.8	182.6	183.4	184.1	183.3	184.2	188.5	191.0	193.6	194.7	196.1	198.9	202.0	202.7	204.4	205.7	207.8	209.0	210.3	212.3	215.5	217.4	220.1

4D, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.1	66.6	63.8	65.9	65.1	65.9	64.8	68.0	65.0	67.0	66.5	66.1	65.9	67.6	65.3	67.0	66.7	66.3	65.8	67.6	65.5	66.8	66.5	66.3	66.0	67.7	64.8
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.4	15.5	15.5	15.5	15.4
Coal	18.1	24.6	26.3	18.4	16.6	11.8	11.6	11.3	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	61.7	55.4	56.5	61.9	63.2	63.3	60.5	53.5	48.3	14.0	3.1	1.4	1.1	1.0	0.9	0.8	0.9	0.8	0.8	0.9	0.9	0.8	0.9	0.9	1.0	0.8	0.9
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.3	24.5	17.0	15.6	14.1	14.6	15.2	15.5	15.7	17.2	16.8	18.7	19.2	19.1	19.5	20.2	19.4	21.2
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.4	22.5	32.9	32.2	31.8	32.1	32.2	32.4	32.3	32.6	32.5	32.9	33.1	29.8	29.8	29.8	29.4	29.4
Renewables	6.6	8.5	9.4	12.6	15.4	17.7	20.1	21.6	23.0	23.6	26.5	29.6	32.9	33.7	33.7	33.7	33.8	33.7	33.7	33.7	33.8	33.7	36.0	38.1	40.2	42.3	44.5
Storage	3.2	3.4	3.7	3.6	3.7	3.7	4.0	4.7	3.6	4.2	7.4	9.0	9.9	10.3	10.4	10.5	10.5	10.5	10.6	10.7	11.1	11.1	11.0	11.7	12.6	13.1	14.0
EEDR	0.3	0.5	0.7	1.9	2.8	3.7	4.6	5.5	6.5	7.4	8.3	9.1	9.9	10.5	11.1	11.6	12.2	12.6	12.7	12.9	13.0	13.2	13.3	13.2	13.3	13.3	13.2
Economic Purchases	0.4	0.9	2.0	0.7	0.9	0.6	1.8	2.8	19.4	17.1	12.4	8.6	9.0	8.8	10.9	10.1	10.9	11.5	11.6	11.5	13.1	12.2	14.9	14.1	13.9	12.7	13.3
Subtotal	171.0	174.7	177.0	179.4	181.9	182.1	182.3	183.1	182.3	182.9	187.2	189.7	192.3	193.6	195.0	196.6	198.3	199.0	200.6	202.1	204.5	205.6	207.0	209.2	212.5	214.2	216.9

4E, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.2	66.6	63.8	65.7	65.3	65.7	64.9	68.1	65.5	69.4	68.7	71.0	73.0	77.1	74.9	76.5	76.2	75.8	75.5	77.2	75.0	76.5	75.8	75.8	75.6	77.2	74.5
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	18.0	25.0	26.5	18.6	17.5	12.5	12.0	11.9	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	61.8	55.2	56.6	62.4	63.3	64.3	61.9	54.7	49.3	14.3	3.2	1.7	1.1	1.0	0.9	0.8	0.7	0.8	0.8	0.8	0.8	0.7	0.9	0.9	0.9	0.7	0.8
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.2	23.7	14.2	12.6	10.2	11.1	11.2	11.2	11.6	13.0	12.9	14.6	15.0	14.7	15.2	16.0	15.2	16.3
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	22.6	33.0	32.2	31.4	31.5	32.0	32.8	32.5	32.7	32.7	33.1	33.2	30.1	29.8	29.9	29.4	29.1
Renewables	6.6	8.3	9.1	12.3	14.9	17.2	19.5	21.0	22.4	23.0	25.7	28.7	31.6	32.2	32.2	32.3	32.4	32.4	32.3	32.3	32.4	32.9	35.1	37.3	39.3	41.5	45.3
Storage	3.2	3.3	3.5	3.4	3.6	4.0	4.7	5.3	3.8	4.4	7.5	9.1	9.6	9.9	9.9	10.4	11.1	11.2	11.2	11.2	11.8	12.2	12.2	12.4	13.2	13.9	14.8
EEDR	0.3	0.5	0.6	1.5	2.1	2.6	3.2	4.1	5.2	5.7	6.3	6.8	7.4	7.8	8.2	8.5	8.9	9.1	9.0	9.1	9.2	9.3	9.2	9.1	9.1	9.1	9.1
Economic Purchases	0.3	1.0	2.1	0.8	0.9	0.7	1.9	3.0	19.8	17.7	13.4	9.2	8.5	7.8	9.6	9.1	10.1	10.9	11.2	10.9	12.7	11.5	14.8	14.0	13.5	12.4	12.3
Subtotal	171.0	174.6	176.8	179.2	181.8	182.5	183.1	183.8	182.5	183.2	187.3	189.7	191.9	193.0	194.3	196.4	198.9	199.6	201.2	202.5	205.1	206.8	208.2	209.9	213.0	215.0	217.5

5A, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.1	66.7	63.8	65.7	65.1	65.7	64.9	68.0	65.2	69.1	69.0	71.0	73.1	77.1	84.0	94.8	104.1	112.9	121.5	132.8	140.1	143.7	152.6	154.7	154.6	165.3	165.2
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	19.1	27.2	30.3	21.2	18.2	7.4	8.3	9.4	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	63.6	60.2	66.2	80.1	92.6	101.9	103.6	103.0	109.5	25.0	10.9	7.6	7.8	6.5	10.4	7.8	5.6	4.5	3.4	2.4	2.3	1.8	1.4	1.4	1.9	1.2	1.0
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	72.6	74.6	66.5	65.4	62.3	49.5	44.9	42.6	39.0	36.8	32.5	30.3	30.6	26.7	27.0	28.7	24.8	25.9
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	23.1	34.2	34.5	34.2	33.3	32.5	32.6	31.8	32.1	31.7	31.4	31.8	28.5	27.8	29.1	26.1	26.4
Renewables	6.6	8.0	8.8	13.1	16.7	20.1	23.3	25.9	29.1	31.9	35.5	39.4	43.6	47.7	52.0	56.1	56.2	58.1	58.6	58.4	59.1	59.9	62.9	66.0	66.8	69.4	72.6
Storage	3.3	3.2	3.4	3.3	3.5	3.8	4.3	5.0	3.6	4.6	6.9	8.5	9.4	11.2	11.3	12.8	14.5	16.1	17.8	19.1	20.5	21.8	23.5	25.0	26.2	26.9	28.1
EEDR	0.3	0.5	0.6	1.5	2.1	2.7	3.3	3.9	4.5	5.1	5.7	6.3	6.8	7.2	7.6	7.9	8.3	8.6	8.6	8.7	8.7	8.8	8.8	8.8	8.8	8.8	8.7
Economic Purchases	1.1	1.9	2.8	0.6	0.5	0.4	1.1	1.5	7.3	4.9	6.8	5.4	5.1	6.2	9.3	8.6	9.0	8.0	7.5	6.9	7.4	6.9	7.1	6.9	7.6	5.5	5.4
Subtotal	174.7	182.5	190.7	200.1	212.8	217.6	223.9	232.4	235.4	240.7	248.6	254.8	261.5	268.1	273.6	280.8	288.4	294.7	301.7	308.2	315.3	320.9	327.1	333.0	339.1	343.4	348.8

5B, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.0	66.5	63.8	66.0	65.2	65.7	65.0	68.0	65.2	69.4	68.6	71.0	72.9	77.3	86.3	99.8	111.2	113.1	112.7	114.6	121.6	132.3	140.9	141.0	150.2	153.9	151.2
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	19.2	27.0	30.6	21.0	17.8	9.3	10.0	11.2	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	63.6	60.2	65.4	79.4	92.2	98.9	100.5	99.3	105.1	26.5	13.4	9.1	8.9	7.5	11.3	6.7	4.2	4.4	4.9	4.4	4.9	3.0	2.0	2.3	2.2	1.8	1.9
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	66.1	67.5	60.3	59.3	55.8	41.7	36.3	31.6	32.0	33.5	34.2	31.4	28.7	25.6	26.7	24.5	23.8	25.7
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	23.1	34.2	34.5	34.0	32.9	32.4	32.1	31.5	31.8	32.0	31.5	31.1	27.6	27.6	26.8	25.7	26.4
Renewables	6.6	8.4	9.3	13.7	17.3	20.7	23.9	27.0	31.4	35.2	39.1	43.4	48.2	52.8	57.3	61.3	63.7	66.8	70.1	72.1	73.3	73.6	76.7	79.2	78.9	81.7	85.3
Storage	3.4	3.3	3.6	3.4	3.7	4.0	4.6	5.1	4.0	5.0	7.5	9.5	10.8	12.2	12.6	15.6	18.2	19.7	21.2	22.6	24.0	25.7	27.3	28.8	30.3	30.9	32.3
EEDR	0.3	0.5	0.7	1.6	2.2	2.8	3.4	4.0	4.7	5.3	5.9	6.4	7.0	7.4	7.8	8.2	8.6	8.8	8.9	8.9	9.0	9.1	9.1	9.1	9.1	9.0	9.0
Economic Purchases	1.1	1.9	2.8	0.6	0.6	0.8	1.7	2.1	9.2	6.3	8.1	6.0	5.7	6.5	9.0	8.2	7.7	7.1	7.2	7.8	8.1	6.4	6.9	7.4	6.6	5.8	6.4
Subtotal	174.8	182.6	190.9	200.2	213.1	217.7	224.2	232.5	235.9	241.2	249.3	255.9	263.1	269.3	275.1	284.1	292.8	298.9	305.8	312.2	319.2	325.3	331.5	337.4	344.0	348.1	353.6

5C, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.2	66.6	63.8	65.7	65.3	65.9	64.9	68.2	65.3	69.2	68.7	71.0	70.6	72.5	79.4	90.2	90.1	99.0	98.2	109.5	116.7	127.4	135.9	145.1	145.2	146.5	153.0
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.4
Coal	19.3	27.6	30.3	21.0	17.3	8.1	8.9	10.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	63.4	59.7	65.6	78.7	90.9	94.7	96.0	94.4	99.0	26.0	10.0	6.0	7.2	6.7	10.6	6.3	6.3	5.1	6.1	3.7	4.5	3.0	2.0	1.4	2.1	1.9	1.5
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	59.7	60.1	52.0	52.0	49.8	38.3	34.0	36.2	33.6	36.1	32.8	29.5	26.7	24.6	22.1	23.6	23.5	22.5
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	22.8	33.3	33.1	32.4	31.1	31.2	31.7	31.0	31.6	31.0	30.3	29.5	26.5	24.8	25.6	25.7	24.3
Renewables	6.6	8.4	9.3	14.5	18.9	26.1	30.0	33.4	39.5	44.2	52.6	57.7	63.0	68.1	72.2	76.5	78.0	79.1	80.5	81.4	82.7	83.0	84.6	85.4	86.8	89.5	90.7
Storage	3.3	3.3	3.6	3.5	3.7	3.9	4.7	5.5	4.4	5.7	8.4	10.4	11.7	13.0	13.7	17.9	18.7	19.8	20.4	21.7	22.5	23.8	24.8	26.0	26.5	27.4	28.4
EEDR	0.3	0.5	0.6	1.8	2.4	3.0	3.6	4.2	4.8	5.4	6.0	6.5	7.0	7.4	7.8	8.2	8.6	8.8	8.7	8.8	8.9	8.9	9.0	8.9	8.9	8.8	8.8
Economic Purchases	1.0	1.8	2.9	0.7	0.5	0.6	1.2	1.6	7.1	4.4	5.6	4.2	3.8	4.7	7.3	7.0	8.2	7.1	7.7	6.8	7.0	5.2	5.8	5.0	5.4	5.2	4.6
Subtotal	174.8	182.6	190.9	200.4	213.1	217.7	224.3	233.0	236.5	242.0	250.4	257.0	264.2	270.3	276.4	286.7	293.3	299.0	304.8	311.1	317.5	323.0	328.7	334.2	339.7	344.1	349.2

5D, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.0	66.5	63.9	65.7	65.0	65.8	64.9	68.0	65.4	69.2	68.9	71.1	73.0	74.8	81.7	92.6	101.7	110.4	110.0	121.2	128.4	129.6	138.4	138.4	147.5	158.4	155.7
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	19.1	27.7	30.4	20.8	17.2	8.3	9.2	10.7	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	63.5	59.3	65.1	78.8	91.8	98.6	100.0	98.7	104.2	25.0	11.4	6.8	6.7	5.8	9.4	6.3	4.5	3.5	4.0	2.4	2.6	2.7	1.9	1.8	1.6	1.1	1.3
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.1	69.2	61.7	60.5	58.0	45.6	41.5	39.4	36.7	38.9	35.1	33.2	34.1	30.2	31.4	28.9	25.3	27.1
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	23.1	34.2	34.3	33.9	32.9	32.1	31.9	30.8	31.4	31.2	30.7	31.0	28.0	28.0	27.6	24.2	25.1
Renewables	6.6	8.6	9.7	14.3	18.0	21.4	24.6	27.1	31.6	33.4	37.7	42.5	47.4	52.6	57.3	61.2	61.3	62.5	64.7	64.7	65.1	66.9	69.9	72.8	72.5	74.8	78.3
Storage	3.3	3.4	3.7	3.7	3.9	4.0	4.8	5.4	4.0	5.1	8.0	10.4	12.0	13.8	14.6	16.6	17.9	19.0	20.4	22.1	23.5	24.9	26.7	28.3	29.9	31.2	32.4
EEDR	0.3	0.5	0.7	1.9	2.8	3.7	4.6	5.5	6.4	7.3	8.3	9.1	9.9	10.5	11.1	11.7	12.3	12.7	12.8	12.9	13.1	13.3	13.3	13.3	13.4	13.3	13.3
Economic Purchases	1.2	1.8	2.8	0.8	0.5	0.6	1.4	1.8	8.1	5.9	7.4	5.4	5.0	6.1	8.9	7.9	8.2	7.1	7.3	6.6	6.8	6.8	7.1	7.6	6.9	4.7	5.2
Subtotal	174.7	182.7	191.0	200.6	213.4	217.7	224.5	233.0	236.0	241.4	250.0	257.1	264.6	271.3	277.5	285.4	292.6	298.2	305.0	311.8	318.8	324.6	331.0	337.0	343.7	348.6	354.0

5E, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.2	66.6	63.7	65.8	65.3	65.6	64.9	68.0	65.4	69.3	68.9	71.0	73.1	77.2	84.2	94.8	104.1	113.0	112.6	114.2	121.8	132.0	140.9	140.7	140.5	142.1	139.4
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	18.9	27.5	30.3	21.1	17.8	7.3	8.3	9.6	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	63.5	59.6	65.8	80.7	93.3	102.7	104.4	103.2	111.1	23.9	10.8	7.1	6.8	5.6	9.3	6.1	4.0	3.0	3.3	3.2	3.3	2.0	1.3	1.5	1.9	1.8	1.8
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.7	76.8	68.7	67.7	63.9	51.0	46.6	42.0	38.3	40.0	40.3	37.4	33.4	30.0	30.9	32.6	32.4	33.1
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	23.1	34.2	34.6	34.3	33.4	32.9	32.6	31.8	32.2	32.1	31.6	31.6	28.2	28.2	28.4	28.1	27.7
Renewables	6.6	8.4	9.3	12.6	16.2	19.6	22.8	25.4	27.1	29.4	33.3	37.6	42.3	47.0	51.6	55.7	59.0	61.2	64.5	67.5	68.8	69.5	72.5	75.7	78.7	81.8	87.9
Storage	3.3	3.2	3.6	3.4	3.6	3.8	4.6	5.3	3.8	5.0	7.6	9.6	11.0	12.6	13.0	15.3	17.9	19.8	21.5	23.2	24.6	26.3	28.0	29.8	31.3	32.2	33.8
EEDR	0.3	0.5	0.6	1.5	2.0	2.6	3.2	3.8	4.5	5.0	5.7	6.2	6.7	7.2	7.6	7.9	8.3	8.6	8.6	8.7	8.7	8.8	8.8	8.8	8.9	8.9	8.9
Economic Purchases	1.3	1.9	3.0	0.7	0.6	0.4	1.1	1.8	7.6	5.3	7.3	5.7	5.3	6.4	9.5	8.9	9.0	7.8	7.9	8.3	8.4	7.1	7.1	7.5	7.4	7.0	7.3
Subtotal	174.7	182.5	190.9	200.3	213.0	217.6	224.2	232.8	235.7	241.2	249.4	256.0	263.3	269.8	275.6	283.7	292.5	298.9	306.1	312.8	320.0	326.1	332.4	338.6	345.2	349.6	355.4

6A, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.1	66.5	63.6	65.8	65.2	65.7	64.7	67.9	65.3	67.1	66.5	66.4	65.8	67.7	65.3	67.0	66.6	66.3	65.7	67.7	65.4	66.9	66.4	66.4	66.2	67.6	64.8
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	20.2	25.6	27.2	18.3	18.5	12.4	12.3	11.4	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	59.6	54.4	55.7	60.2	61.4	62.6	62.0	56.4	68.1	64.6	61.3	59.1	57.7	55.7	56.3	55.4	56.1	54.9	56.0	54.3	52.1	50.8	51.1	49.9	49.4	47.4	47.4
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.0	8.8	11.6	11.8	13.6	15.0	16.6	17.3	18.3	20.8	23.2	25.6	25.7	27.4	27.7	27.7	29.4	29.4	30.3	32.7	33.3	34.2	36.4	37.1	39.1	42.4
Storage	3.0	3.2	3.5	3.4	3.3	3.3	3.3	3.3	3.4	3.7	3.8	4.6	4.8	4.8	5.0	5.4	5.4	5.8	6.0	6.3	6.5	6.9	7.6	8.3	8.3	9.2	10.0
EEDR	0.3	0.5	0.6	1.5	2.1	2.7	3.3	3.9	4.5	5.1	5.6	6.1	6.7	7.0	7.4	7.8	8.2	8.5	8.5	8.5	8.6	8.7	8.7	8.7	8.7	8.7	8.7
Economic Purchases	0.1	0.1	0.3	0.1	0.0	0.1	0.2	0.2	0.9	1.2	2.0	1.7	2.0	1.8	1.8	1.8	2.2	2.0	2.4	2.0	5.1	4.8	5.0	5.1	6.5	5.7	6.2
Subtotal	170.5	173.1	174.2	175.3	176.4	175.8	175.8	175.5	175.9	175.9	176.1	177.1	178.3	178.4	179.2	180.5	181.7	182.2	183.4	184.6	185.9	186.8	188.5	190.2	191.7	193.1	194.9

6B, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.0	66.4	63.8	65.8	65.2	65.8	65.0	68.1	65.3	69.3	68.9	71.1	73.0	77.3	77.1	81.3	83.5	85.3	85.0	86.7	84.4	85.9	85.5	85.4	85.1	86.6	84.0
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	20.0	25.6	26.9	18.6	18.9	12.3	12.1	11.2	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	59.9	54.1	55.3	60.5	61.3	62.2	60.7	55.2	66.6	50.2	47.3	44.8	43.3	39.0	39.0	35.7	34.3	32.5	33.6	32.7	33.6	32.6	38.3	37.5	36.9	35.0	35.4
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	11.4	11.3	11.3	11.1	11.0	11.1	11.2	11.1	11.1	11.2	11.0	11.0	3.7	3.5	4.3	3.6	4.0
Renewables	6.6	8.4	9.2	11.0	11.3	13.8	16.1	17.9	18.8	19.9	22.5	22.7	22.9	23.2	23.3	23.6	23.6	23.7	23.6	23.6	25.2	25.4	27.8	29.9	31.0	33.0	35.4
Storage	3.1	3.2	3.5	3.4	3.3	3.3	3.5	3.8	3.8	4.3	4.5	4.7	4.7	4.8	4.9	5.4	6.1	6.2	6.2	6.2	6.3	6.6	7.3	8.0	8.5	9.2	10.0
EEDR	0.3	0.5	0.7	1.6	2.2	2.9	3.4	4.0	4.7	5.2	5.8	6.3	6.8	7.2	7.6	7.9	8.3	8.6	8.6	8.7	8.7	8.8	8.8	8.8	8.8	8.8	8.8
Economic Purchases	0.1	0.1	0.2	0.0	0.1	0.2	0.2	0.2	0.9	0.2	0.4	0.4	0.4	0.2	0.3	0.1	0.0	0.0	0.0	0.0	0.9	0.8	1.3	1.3	1.8	1.4	1.9
Subtotal	170.6	173.2	174.2	175.4	176.4	175.8	176.0	176.1	176.4	176.5	176.9	177.1	178.2	178.4	179.1	180.5	182.5	182.7	183.7	184.4	185.7	186.5	188.2	189.9	191.9	193.1	194.8

6C, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	63.9	66.7	63.7	65.7	65.1	65.7	65.0	68.1	65.4	67.0	66.4	66.4	65.8	67.7	65.5	66.9	66.6	66.2	65.9	67.6	65.6	67.0	66.4	66.2	66.2	67.7	64.9
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.4
Coal	19.4	25.2	27.0	17.9	17.7	11.4	11.0	9.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	60.4	54.3	55.4	59.3	59.2	58.6	55.9	49.6	58.0	54.2	52.0	48.4	49.1	46.2	47.1	45.3	44.2	43.4	43.6	41.8	40.6	39.0	38.3	36.9	36.6	33.6	33.7
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.4	9.2	13.1	15.1	18.7	22.4	25.3	28.2	29.8	31.6	35.4	36.0	37.2	38.5	40.4	42.7	44.0	44.9	45.9	48.7	49.8	51.7	54.5	55.6	58.4	61.7
Storage	3.2	3.3	3.4	3.4	3.5	3.6	3.9	4.1	4.9	5.8	6.0	7.0	7.2	7.2	7.4	8.5	9.6	9.8	10.0	10.0	10.8	11.3	12.0	12.9	13.3	14.4	15.3
EEDR	0.3	0.4	0.6	1.5	2.1	2.7	3.3	3.8	4.5	5.0	5.6	6.1	6.4	6.6	6.8	7.0	7.3	7.6	7.6	7.7	7.8	7.8	8.0	8.0	8.1	8.1	8.1
Economic Purchases	0.2	0.1	0.3	0.0	-0.1	0.0	0.0	0.0	0.3	0.5	0.9	0.7	0.8	0.7	0.7	0.6	0.5	0.4	0.6	0.5	2.0	1.6	1.8	1.6	2.2	1.4	1.9
Subtotal	170.6	173.2	174.1	175.4	176.6	176.2	176.4	176.4	177.6	178.3	178.6	179.9	181.1	181.1	182.0	184.2	186.5	186.9	188.0	188.9	190.9	192.0	193.7	195.5	197.5	199.2	201.1

6D, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.1	66.7	64.0	65.9	65.0	65.7	65.1	67.9	65.2	66.9	66.5	66.3	65.9	67.5	65.6	66.9	66.8	66.4	66.0	67.8	65.5	66.9	66.3	66.1	66.2	67.8	64.9
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.7	15.5	16.0	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.4	15.5	15.5	15.5	15.5	15.4
Coal	19.7	25.1	26.4	18.1	18.2	11.8	11.7	10.6	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	60.1	54.1	55.3	61.0	61.9	64.3	62.7	57.4	67.5	63.7	60.3	57.7	56.1	52.9	52.8	52.1	52.5	51.0	52.2	51.2	49.7	48.7	48.8	47.8	47.4	45.4	46.2
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.6	9.5	10.8	11.2	11.5	13.4	15.2	16.3	17.6	20.4	22.8	25.3	26.8	28.6	28.8	28.8	30.7	30.5	30.5	33.0	33.5	34.6	36.8	37.7	39.7	41.9
Storage	3.2	3.3	3.6	3.5	3.5	3.5	3.6	3.8	4.2	4.6	5.0	5.8	6.1	6.3	6.8	7.0	7.1	7.4	7.6	7.6	8.3	8.7	9.2	10.1	10.5	11.4	12.2
EEDR	0.3	0.5	0.7	1.9	2.9	3.8	4.7	5.5	6.5	7.4	8.3	9.0	9.8	10.4	11.1	11.6	12.2	12.6	12.7	12.8	13.0	13.2	13.2	13.2	13.2	13.2	13.2
Economic Purchases	0.0	0.1	0.2	-0.1	-0.1	0.0	0.0	0.0	0.8	0.9	1.0	0.9	1.0	0.7	0.6	0.7	0.8	0.8	0.9	0.8	3.2	2.7	3.0	3.0	3.8	2.9	3.8
Subtotal	170.7	173.3	174.3	175.5	176.7	176.1	176.2	176.2	176.9	177.0	177.6	178.6	180.0	180.3	181.4	182.5	183.7	184.3	185.5	186.2	188.1	189.1	190.5	192.4	194.3	195.8	197.6

6E, SND TWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	64.1	66.5	63.7	65.9	65.0	65.7	64.8	68.0	65.2	69.3	68.8	71.1	73.0	77.3	74.7	76.4	76.3	75.8	75.3	77.2	75.2	76.2	76.1	75.9	75.6	77.3	74.4
Hydro	16.7	14.8	14.6	14.4	14.1	15.4	15.0	15.8	15.5	15.9	16.1	15.9	15.8	15.7	16.0	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.4
Coal	19.9	25.5	26.8	18.3	18.7	12.6	12.5	11.4	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	59.9	54.2	55.5	61.4	62.5	65.0	63.5	58.1	69.4	63.8	60.6	56.3	53.4	49.1	50.5	49.0	49.1	47.5	48.7	47.3	45.8	45.0	44.8	43.9	43.1	41.1	41.7
Hydrogen CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	6.6	8.4	9.2	10.4	10.7	10.9	13.3	15.0	15.9	17.1	19.7	22.1	23.9	24.1	25.1	26.0	26.9	29.1	29.2	29.6	32.0	32.3	33.5	35.8	37.3	39.2	41.6
Storage	3.1	3.2	3.5	3.4	3.4	3.4	3.5	3.7	4.0	4.2	4.6	5.3	5.7	5.8	5.8	6.4	7.1	7.6	7.8	7.9	8.6	8.9	9.5	10.4	10.9	11.9	12.5
EEDR	0.3	0.5	0.6	1.5	2.1	2.7	3.3	3.9	4.5	5.1	5.6	6.1	6.6	7.0	7.4	7.7	8.1	8.3	8.4	8.4	8.6	8.6	8.6	8.6	8.7	8.7	8.7
Economic Purchases	0.1	0.1	0.2	-0.1	0.0	0.2	0.1	0.2	1.2	1.2	1.6	1.2	0.9	0.5	0.7	0.7	0.6	0.6	0.7	0.6	2.7	2.7	2.8	2.6	3.6	2.6	3.5
Subtotal	170.6	173.1	174.2	175.4	176.5	175.9	175.9	176.0	176.6	176.5	177.0	177.9	179.3	179.5	180.2	181.7	183.5	184.4	185.5	186.4	188.3	189.2	190.8	192.7	194.6	196.2	197.9

H.8 Conclusion

Details on incremental capacity, total capacity, and total energy plans included in this appendix provide the underlying data supporting the 30 portfolios discussed in Chapter 4. Additionally, the annual and time increment data provides useful insights into trends across the planning horizon.

Appendix I – Cost and Risk Metrics

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Appendix I – Cost and Risk Metrics

TVA's least-cost planning program starts with low cost, complemented by evaluations of operational, environmental, and risk factors. Reflecting these planning principles and with input from the IRP Working Group, TVA developed metrics to assess the performance of the 30 resource portfolios resulting from applying the five strategies in the six scenarios. This appendix discusses the cost and risk metrics used in the IRP analysis, the methodology employed to derive them, and some trend comparisons.

I.1 Cost and Risk Metric Definitions

To evaluate portfolio performance with respect to cost and risk, TVA and the IRP Working Group identified three cost metrics and two risk metrics, as described below. These metrics can be compared across portfolios and strategies to evaluate relative cost and risk profiles, as well as tradeoffs. Metrics cover the 2025-2050 study period.

Table I-1: Cost and Risk Metrics

Metric Category	Metric	Good	Definition
Low Cost	Present Value of Revenue Requirements (PVRR) ($B)	Lower	Total plan cost (capital and operating) expressed as the present value of revenue requirements
	System Average Cost ($/MWh)	Lower	Average system cost expressed as levelized average annual revenue requirements divided by average annual sales
	Total Resource Cost ($B)	Lower	Total plan cost (capital and operating) expressed as PVRR plus participant costs net of bill savings and tax credits
Risk Informed	Risk / Benefit Ratio	Lower	PVRR above expected value divided by PVRR below expected value based on stochastic analysis
	Risk Exposure ($B)	Lower	PVRR above expected value based on stochastic analysis

I.2 Cost and Risk Metric Scorecard Results

Table I-2 below shows a comparison of the five cost and risk metrics for each strategy and scenario.

Table I-2: Cost and Risk Metric Scorecard

Metric / Strategy	1 Ref without GHG	2 Growth	3 Stagnant	4 Regulation	5 Reg + Growth	6 Ref with GHG
PVRR ($B)						
A	$154	$191	$130	$184	$228	$156
B	$177	$216	$152	$213	$255	$180
C	$158	$195	$134	$187	$226	$160
D	$159	$197	$136	$188	$231	$162
E	$171	$208	$146	$207	$236	$174

Metric / Strategy	1 Ref without GHG	2 Growth	3 Stagnant	4 Regulation	5 Reg + Growth	6 Ref with GHG
System Average Cost ($/MWh)						
A	$72	$81	$68	$86	$81	$76
B	$83	$91	$80	$100	$91	$88
C	$74	$82	$70	$88	$81	$78
D	$75	$83	$72	$88	$83	$79
E	$80	$88	$77	$97	$85	$85
Total Resource Cost ($B)						
A	$161	$199	$137	$190	$235	$164
B	$196	$254	$170	$227	$271	$199
C	$176	$233	$151	$202	$242	$179
D	$194	$250	$164	$222	$264	$201
E	$190	$246	$164	$221	$253	$192
Risk / Benefit Ratio						
A	1.22	1.17	1.23	1.06	1.04	1.18
B	1.12	1.09	1.14	1.07	0.97	1.06
C	1.20	1.14	1.22	1.08	1.04	1.16
D	1.17	1.15	1.19	1.08	1.05	1.12
E	1.15	1.12	1.19	1.05	1.04	1.11
Risk Exposure ($B)						
A	$15.8	$24.3	$9.0	$17.1	$19.3	$15.6
B	$14.2	$21.3	$7.8	$14.3	$19.2	$13.7
C	$13.5	$20.7	$7.9	$13.8	$17.9	$13.1
D	$14.1	$22.0	$7.7	$14.7	$18.2	$13.6
E	$14.1	$21.0	$8.0	$14.7	$19.9	$14.0

I.3 Present Value of Revenue Requirements

The Present Value of Revenue Requirements (PVRR) represents the total portfolio costs, both capital and operating, to TVA over the planning horizon, expressed in today's dollars. The formula for PVRR is:

$$NPV(Annual\ Revenue\ Requirements\ (2025\ -2050))$$

Because Strategy A that reflects baseline utility planning has the fewest constraints or resource promotions, it generally results in the lowest cost portfolio within each of the scenarios, with the exception of Scenario 4 where Strategy C allows for increased availability of utility scale renewables along with promotion of behind-the-meter generation which reduces costs to the TVA system. The Carbon-free Innovation strategy is the highest cost due to the large capital requirements needed for the new innovative technologies like nuclear.

I.4 System Average Cost

System average cost expresses revenue requirements in terms of a levelized rate per unit of energy sales and is directionally indicative of overall trends in customer bills. The formula for system average cost, which derives a levelized annual average system cost rate in \$/MWh, is:

$$\frac{NPV\ Revenue\ Requirements\ (2025\ -2050)}{NPV\ Sales\ (2025\ -2050)}$$

Within each scenario, the relative performance of each strategy is the same in system average cost as it is in PVRR. Strategy A is the lowest system average cost except for Scenario 4, where behind-the-meter generation drives slightly lower system costs. Scenarios 4 and 5, which assume carbon regulations, show an increase in system average cost in the early 2030s as the impacts of the draft Greenhouse Gas Rule are realized.

The following charts provide additional details on the forecasted trajectory of system average cost over time.

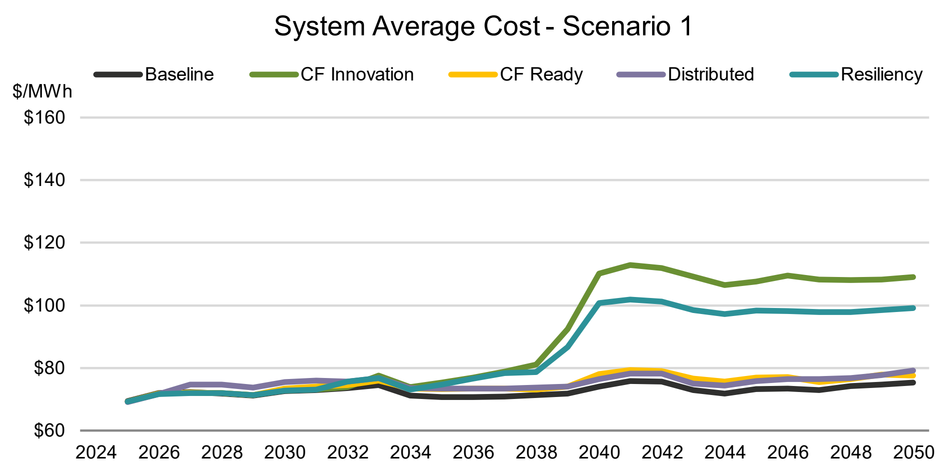

Figure I-1: Annual System Average Cost, Scenario 1 (Reference without GHG)

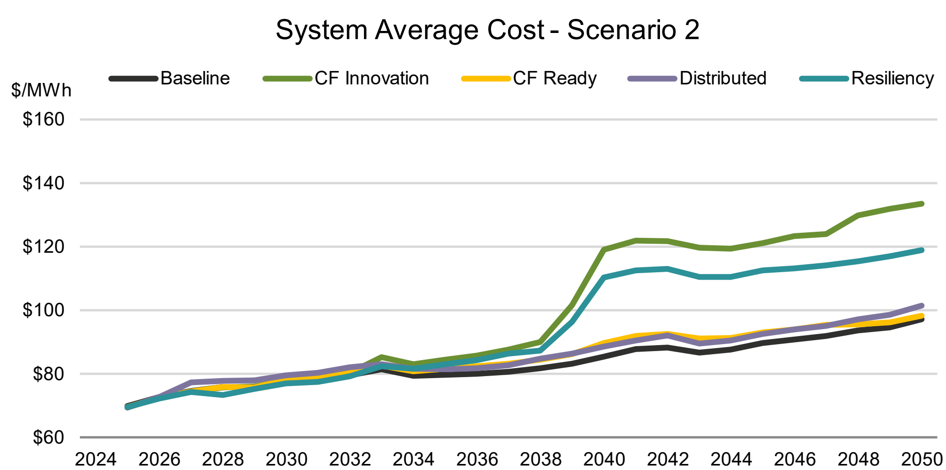

Figure I-2: Annual System Average Cost, Scenario 2 (Higher Growth Economy)

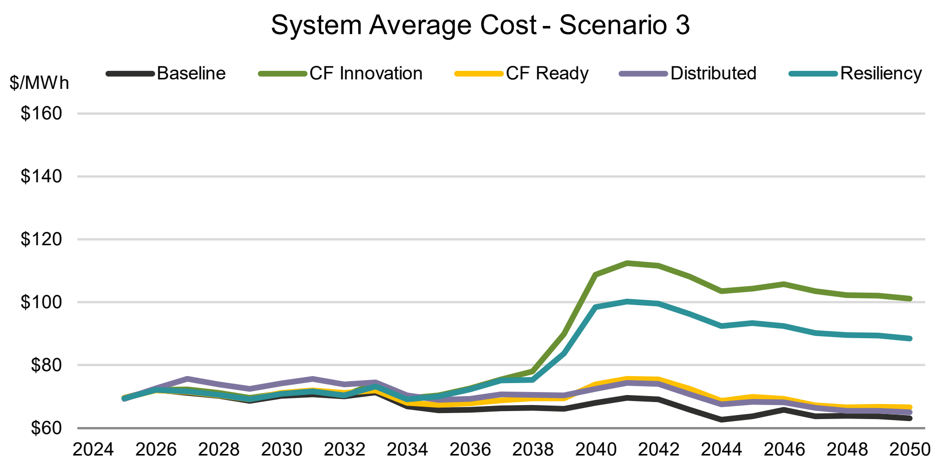

Figure I-3: Annual System Average Cost, Scenario 3 (Stagnant Economy)

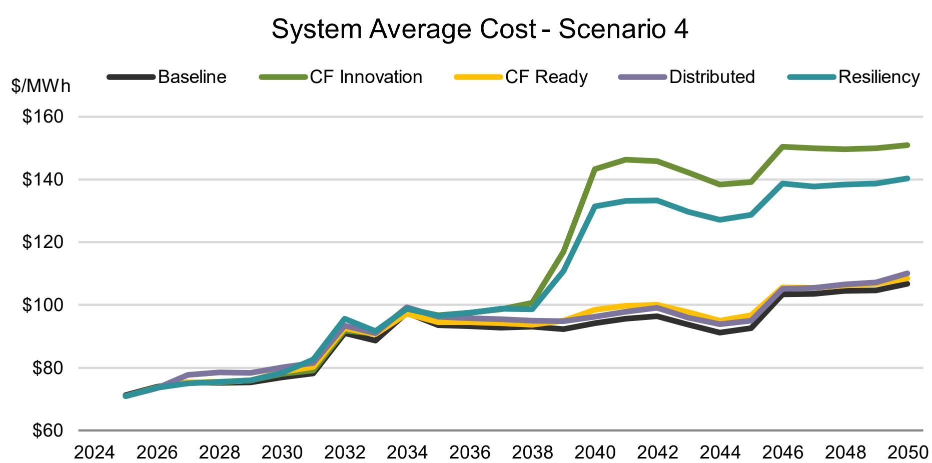

Figure I-4: Annual System Average Cost, Scenario 4 (Net-zero Regulation)

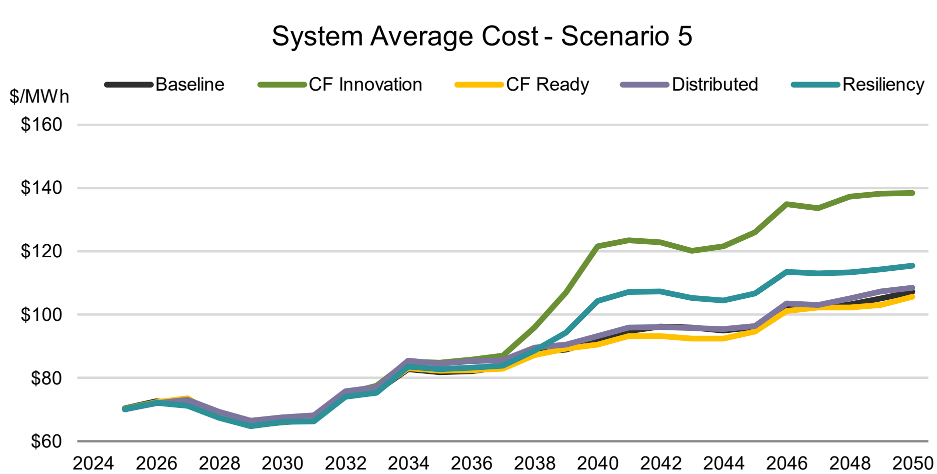

Figure I-5: Annual System Average Cost, Scenario 5 (Net-zero Regulation Plus Growth)

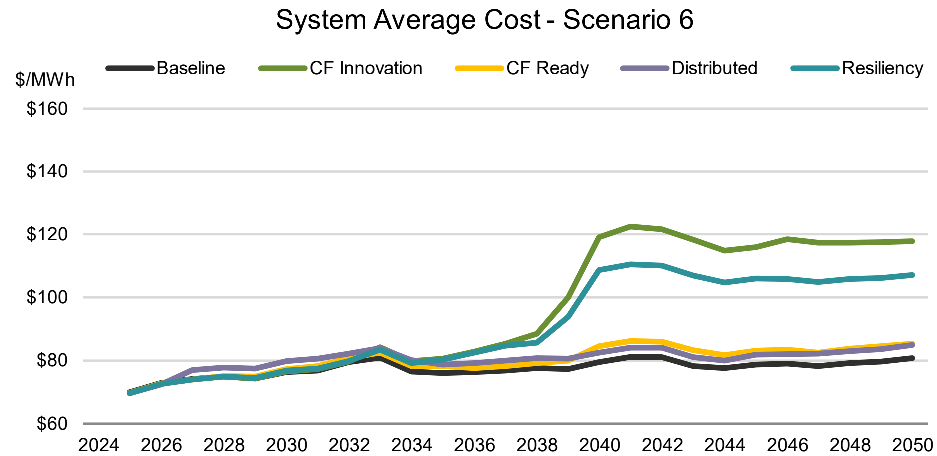

Figure I-6: Annual System Average Cost, Scenario 6 (Reference without GHG)

I.5 Total Resource Cost

Total resource cost starts with PVRR and adds the costs paid by participants to install distributed generation or invest in energy efficient measures, net of bill savings and tax credits. The formula for total resource cost is:

$$PVRR + Participant\ Cost\ Net\ of\ Savings\ (bill\ savings,\ tax\ credits)$$

This metric provides a view of the total costs associated with a resource portfolio, whether paid by TVA or program participants.

Because total resource cost accounts for both the TVA system cost and the participant costs of behind-the-meter generation and energy efficiency, Strategy A is consistently the least cost within each scenario. Strategy D, which promotes distributed and demand side resources, moves to the highest cost strategy within each scenario.

I.6 Risk/Benefit Ratio

The two risk metrics express financial risk in different ways. Risk/benefit ratio looks at the potential for higher costs as a ratio of the potential for lower costs. The formula for risk/benefit ratio is:

$$\frac{95th\ (PVRR) - Expected\ (PVRR)}{Expected\ (PVRR)\ - 5th\ (PVRR)}$$

This metric is based on stochastic analysis, which takes a probabilistic view of variations in key assumptions to understand the range of potential costs for a given portfolio. A ratio of one indicates an equal chance of having higher or lower costs than estimated, a ratio less than one indicates better odds of having lower costs than estimated, and a ratio more than one indicates better odds of having higher costs than estimated.

The figure below illustrates the 5th percentile, 50th percentile, and 95th percentile in a lognormal distribution.

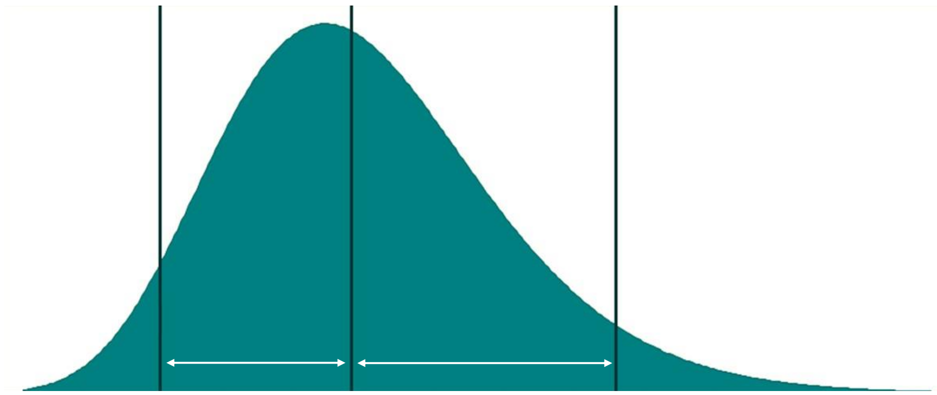

Figure I-7: Illustrative Lognormal Distribution showing P5, P50, P95

I.7 Risk Exposure

Another way of describing risk is risk exposure, or the potential for higher costs. The risk exposure formula is:

$$95th\ (PVRR) - Expected\ (PVRR).$$

A wider distribution indicates higher risk that costs could increase above the expected value and ratepayers could be negatively impacted. This metric is also based on stochastic analysis, and it represents the risk of higher costs based on variations in key assumptions.

I.8 Conclusion

The cost and risk metrics each capture a different aspect of portfolio performance. They provide insights into cost and risk tradeoffs across portfolios, as well as across broader metric categories. See Chapter 4 for a discussion of key tradeoffs across portfolios and strategies based on the metric results.

J

Appendix J – Environmental Metrics

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Appendix J – Environmental Metrics

TVA's least-cost planning program starts with low cost, complemented by evaluations of operational, environmental, and risk factors. Reflecting these planning principles and with input from the IRP Working Group, TVA developed metrics to assess the performance of the 30 resource portfolios resulting from applying the five strategies in the six scenarios. This appendix discusses environmental metrics used in the IRP analysis, the methodology employed to derive them, and some trend comparisons.

J.1 Environmental Metric Definitions

To evaluate portfolio performance with respect to environmental impacts, TVA and the IRP Working Group identified five metrics, as described below. These metrics can be compared across portfolios and strategies to evaluate relative environmental profiles and tradeoffs. Metrics cover the 2025-2050 study period, except for one metric that focuses on 2050, as noted.

Table J-1: Environmental Metrics

Metric Category	Metric	Good	Definition
Environmentally Responsible	CO_2 Direct Emissions (Million Tons)	Lower	Average annual tons of CO_2 emitted
	CO_2 Intensity (lbs/MWh)	Lower	Average annual CO_2 emissions divided by average annual energy generated and purchased
	Water Consumption Intensity (Million Gallons/MWh)	Lower	Average annual gallons of water consumed divided by average annual energy generated and purchased
	Waste Intensity (Million Tons/MWh)	Lower	Average annual quantity of coal ash and gypsum produced divided by average annual energy generated and purchased
	Land Use Intensity (Acres/MWh)	Lower	Acreage needed for expansion units divided by energy generated and purchased in 2050

J.2 Environmental Metric Scorecard Results

Table J-2 below shows a comparison of the five environmental metrics for each strategy and scenario.

Table J-2: Environmental Metrics Scorecard

Metric / Strategy	1 Ref without GHG	2 Growth	3 Stagnant	4 Regulation	5 Reg + Growth	6 Ref with GHG
CO_2 Direct Emissions (Million Tons)						
A	34	38	26	16	24	30
B	28	31	22	15	24	24
C	29	33	24	15	23	25
D	30	34	24	15	23	26
E	30	33	24	15	24	27

Metric / Strategy	1 Ref without GHG	2 Growth	3 Stagnant	4 Regulation	5 Reg + Growth	6 Ref with GHG
CO_2 Intensity (lbs/MWh)						
A	388	388	335	187	226	365
B	322	326	284	180	229	296
C	330	340	312	173	219	305
D	366	375	334	176	223	337
E	358	355	325	179	226	334
Water Intensity (Million Gallons/MWh)						
A	280	259	305	263	317	283
B	304	280	334	289	302	313
C	266	246	293	255	294	274
D	286	265	315	270	314	294
E	296	271	321	279	305	302
Waste Intensity (Million Tons/MWh)						
A	1.3	1.4	0.9	1.3	1.0	1.4
B	1.3	1.4	0.9	1.3	1.0	1.4
C	1.2	1.4	0.9	1.3	1.0	1.3
D	1.3	1.5	0.9	1.3	1.0	1.4
E	1.3	1.4	0.9	1.3	1.0	1.4
Land Use Intensity (Acres/MWh)						
A	0.7	1.0	0.3	0.7	0.7	0.7
B	0.7	0.9	0.2	0.6	0.8	0.6
C	0.9	1.1	0.4	0.8	0.8	0.8
D	0.8	1.0	0.3	0.7	0.8	0.8
E	0.7	1.1	0.3	0.7	0.9	0.7

J.3 CO_2 Direct Emissions

CO_2 direct emissions represent the emissions directly attributable to generating units through combustion of fuels, expressed in millions of tons. This metric does not include life cycle or embedded emissions. While this metric is expressed as the average annual tons of CO_2 emitted over the planning period, annual amounts are expected to decline significantly across the study period. The formula for CO_2 direct emissions is:

$$Millions\ of\ Tons\ of\ CO2\ (2025\ -2050)$$

Different resource types contribute to system emissions based on the CO_2 content of the fuel they burn. The table below denotes the typical CO_2 content for different fuel types and blends.

Table J-3: CO_2 Content of Various Fuels and Fuel Blends

Fuel	CO_2 Content (lbs/MMBtu)
Coal	205
Natural Gas	117
Natural Gas with 90% CCS	11.7
Hydrogen 30% blend	81.9
Hydrogen 96% blend	4.7

The charts below provide additional details on the forecasted trajectory of CO_2 emissions over time.

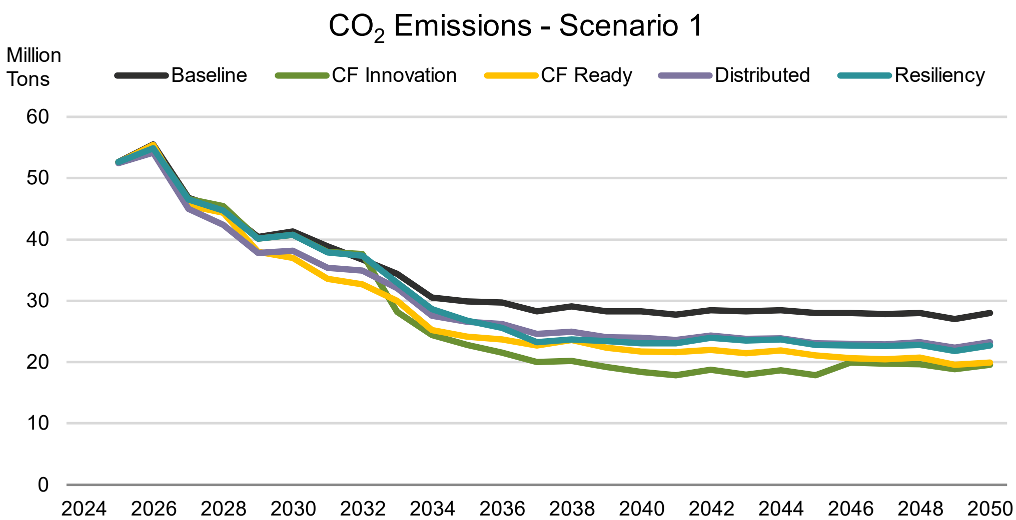

Figure J-1: CO_2 Direct Emissions (Million Tons), Scenario 1 (Reference without GHG)

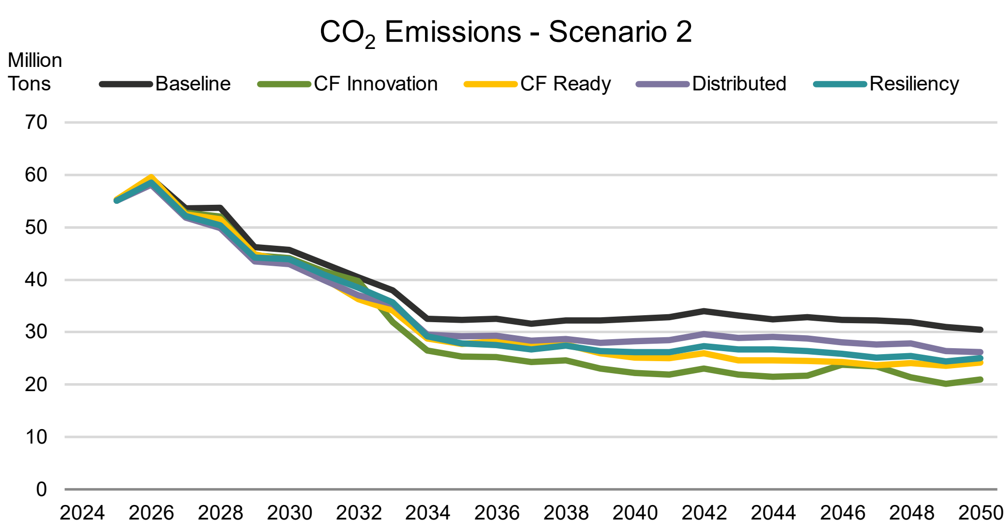

Figure J-2: CO_2 Direct Emissions (Million Tons), Scenario 2 (Higher Growth Economy)

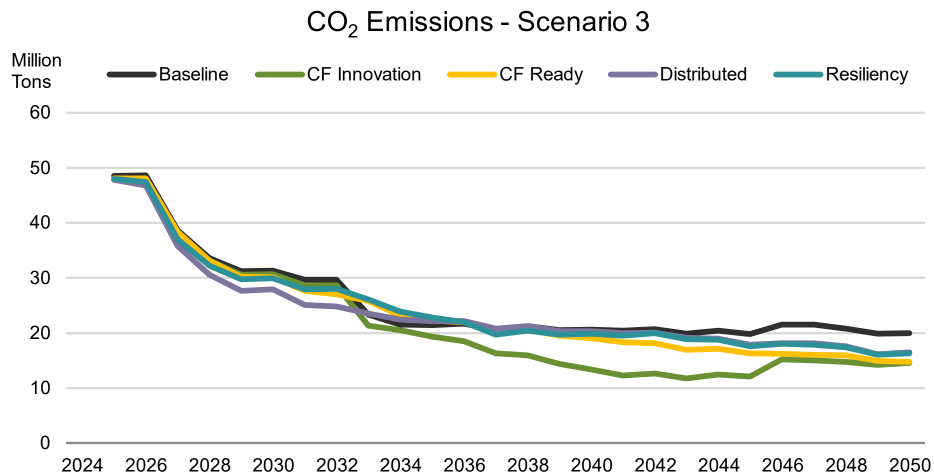

Figure J-3: CO_2 Direct Emissions (Million Tons), Scenario 3 (Stagnant Economy)

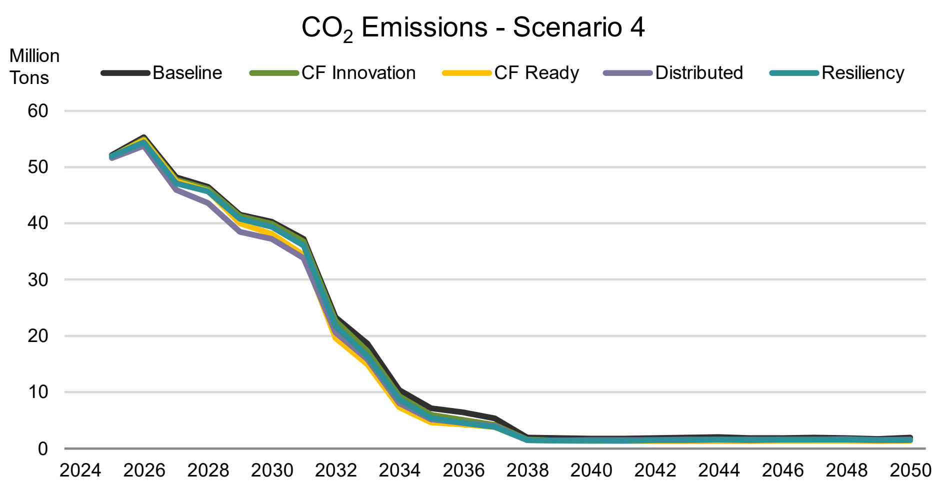

Figure J-4: CO_2 Direct Emissions (Million Tons), Scenario 4 (Net-zero Regulation)

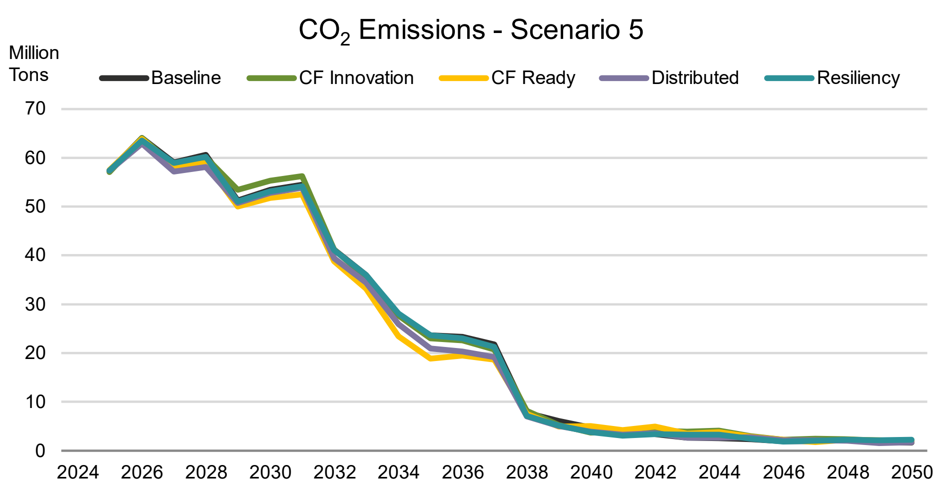

Figure J-5: CO_2 Direct Emissions (Million Tons), Scenario 5 (Net-zero Regulation Plus Growth)

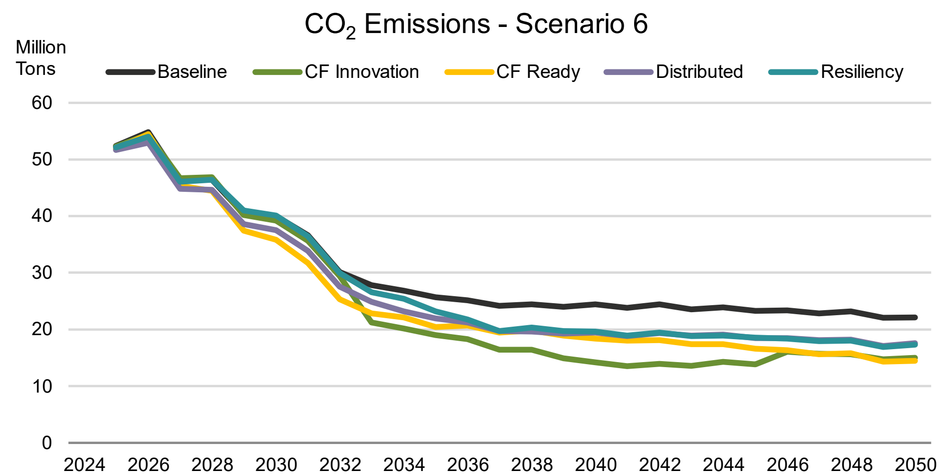

Figure J-6: CO_2 Direct Emissions (Million Tons), Scenario 6 (Baseline with GHG)

J.4 CO_2 Intensity

The variations in load levels across scenarios naturally lead to variations in direct CO_2 emissions. CO_2 intensity represents direct emissions expressed as a rate per unit of annual energy. This allows for better comparisons across all portfolios. The formula for CO_2 intensity is:

$$\frac{Pounds\ of\ CO2\ (2025\ -2050)}{MW\text{h}\ Generated\ \&\ Purchased\ (2025\ -2050)}$$

The figures below show the CO_2 intensities for each scenario and strategy, including reference lines showing 70%, 80%, and 90% reductions from a 2005 baseline.

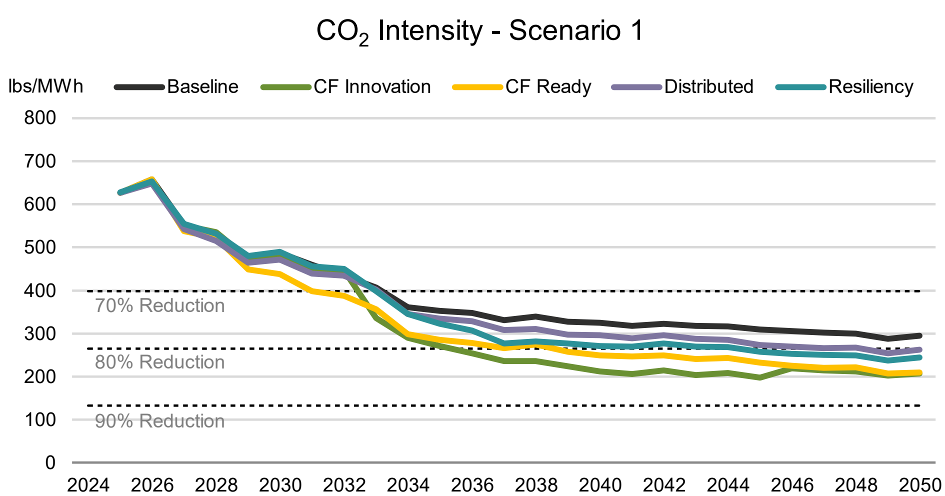

Figure J-7: CO_2 Intensity Trajectory, Scenario 1 (Reference without GHG Rule)

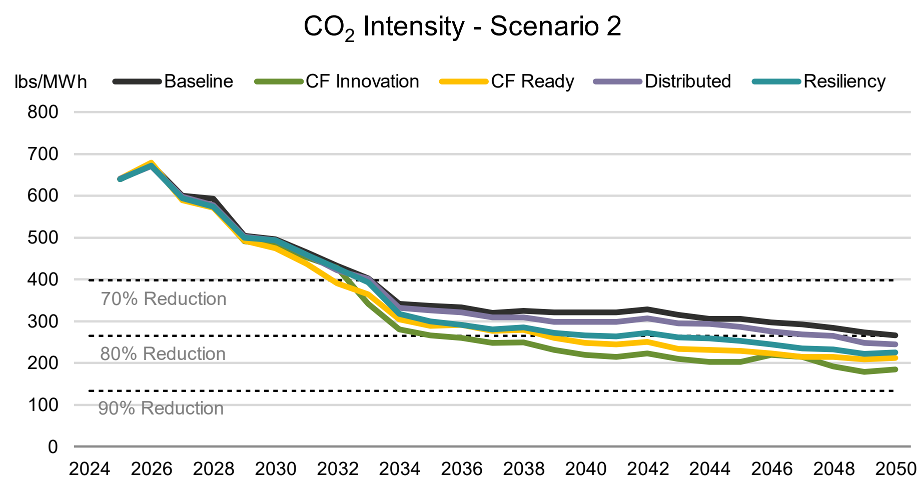

Figure J-8: CO_2 Intensity Trajectory, Scenario 2 (Higher Growth Economy)

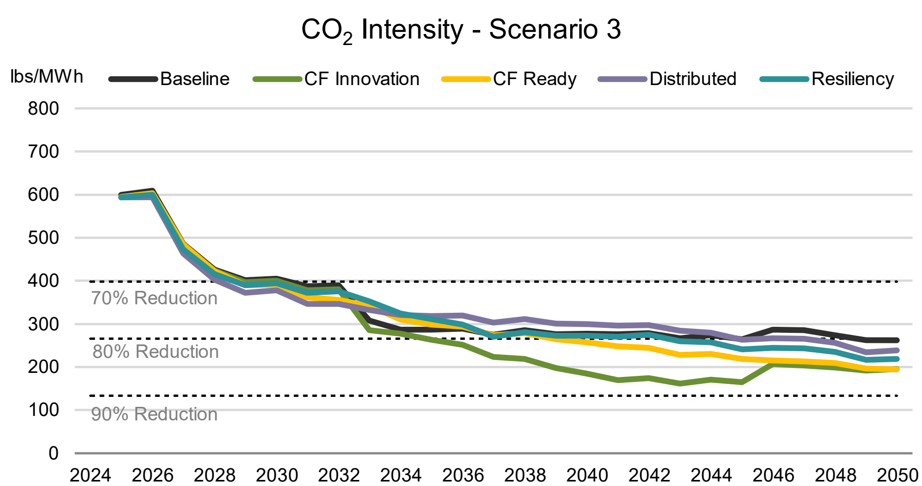

Figure J-9: CO_2 Intensity Trajectory, Scenario 3 (Stagnant Economy)

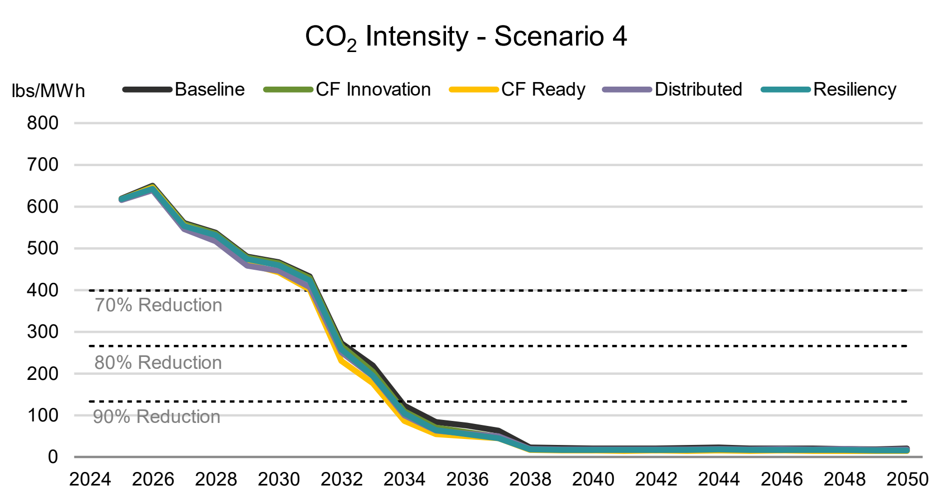

Figure J-10: CO_2 Intensity Trajectory, Scenario 4 (Net-zero Regulation)

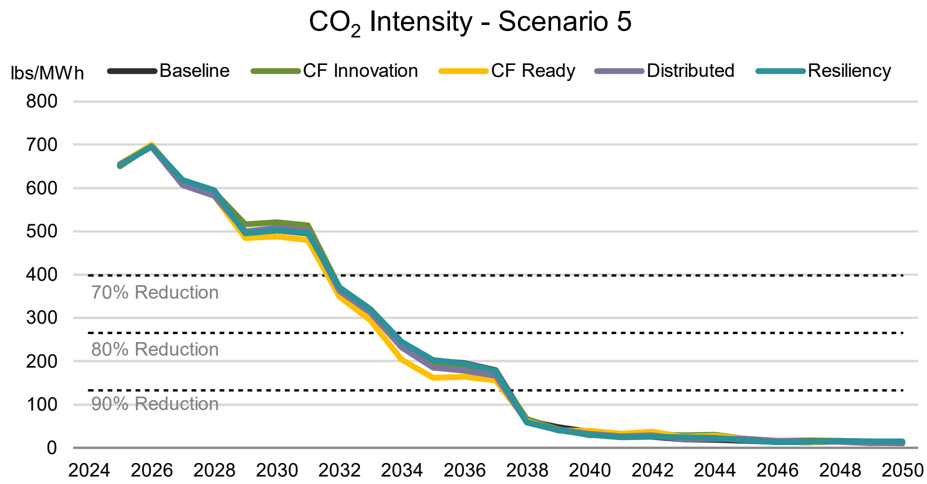

Figure J-11: CO_2 Intensity Trajectory, Scenario 5 (Net-zero Regulation Plus Growth)

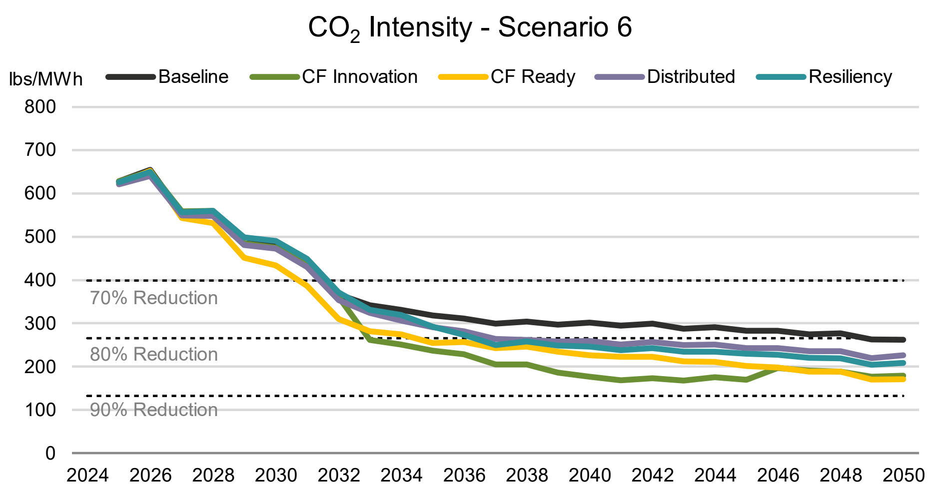

Figure J-12: CO_2 Intensity Trajectory, Scenario 6 (Reference with GHG)

J.5 Water Consumption Intensity

Water consumption intensity represents the gallons of water consumed expressed as a rate per unit of annual energy. The formula for water consumption intensity is:

$$\frac{Millions\ of\ Gallons\ of\ Water\ Consumed\ (2025\ -2050)}{MWh\ Generated\ \&\ Purchased\ (2025\ -2050)}$$

The variations in load levels across scenarios naturally lead to variations in water consumption, so expressing this as a rate allows for better comparison across scenarios as well as between strategies. Water consumption includes only water lost to evaporation in the production of electricity and associated thermal cooling systems. Water used in the production of hydrogen fuel is not included in this metric.

As the scenario that materializes primarily drives the differences in water consumption intensity, the chart below shows how water intensity varied by scenario in Strategy A.

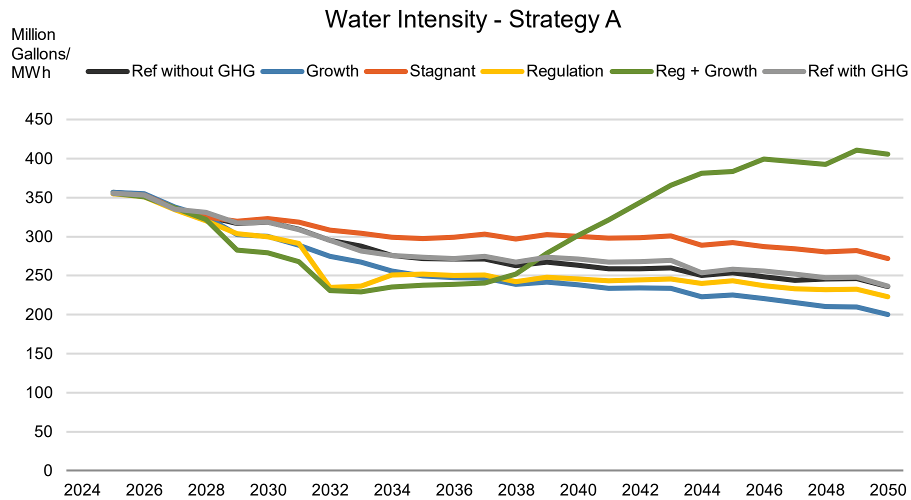

Figure J-13: Annual Water Consumption Intensity, All Scenarios with Strategy A (Baseline)

J.6 Waste Intensity

Waste intensity represents the millions of tons of coal ash and gypsum produced expressed as a rate per unit of annual energy. The formula for waste intensity is:

$$\frac{\mathit{Millions\ of\ Tons\ of\ Waste\ Produced}\ (2025\ -2050)}{\mathit{MWh\ Generated}\ \&\ \mathit{Purchased}\ (2025\ -2050)}$$

The variations in load levels across scenarios naturally lead to variations in waste production, so expressing this as a rate allows for better comparison across scenarios as well as between strategies. Waste intensity falls to zero in all scenarios after the last coal units are retired.

As the scenario that materializes primarily drives the differences in waste intensity, the chart below shows how waste intensity varied by scenario in Strategy A.

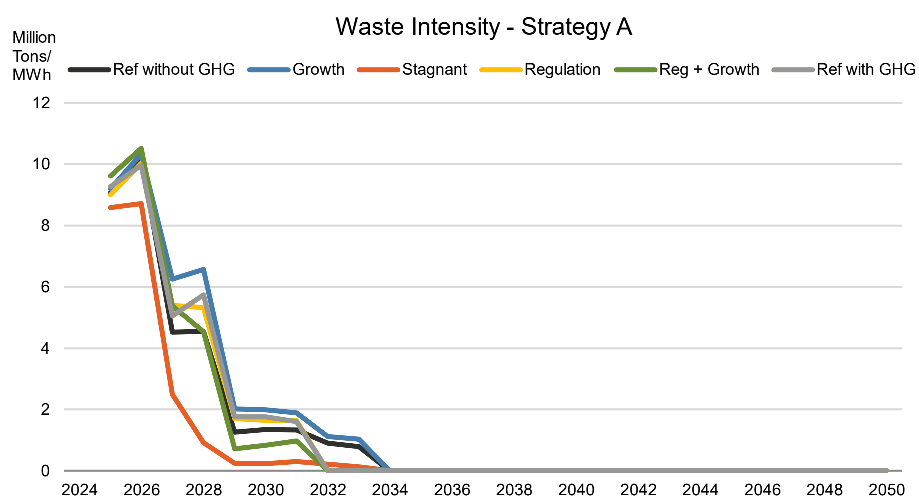

Figure J-14: Annual Waste Intensity, All Scenarios with Strategy A (Baseline)

J.7 Land Use Intensity

Land use intensity represents the acres of land needed for expansion units expressed as a rate per unit of annual energy. The formula for land use intensity is:

$$\frac{\mathit{Acres\ Needed\ for\ New\ Units}\ (2025\ -2050)}{\mathit{MWh\ Generated\ \&\ Purchased}\ (2050)}$$

The variations in load levels across scenarios also naturally lead to variations in land usage. Expressing this as a rate allows for better comparison across scenarios as well as between strategies. In general, generating units that are less energy dense use more land. Strategies that promote resources like solar and wind will use more land than alternative strategies. Only land used directly for expansion generating resources owned or controlled by TVA is included in this metric. Land used by distributed resources or green hydrogen production is not considered to be owned or controlled by TVA. Because land use is cumulative across the study period, this metric looks at total land use for all expansion units through 2050 divided by the energy generated or purchases in that final year.

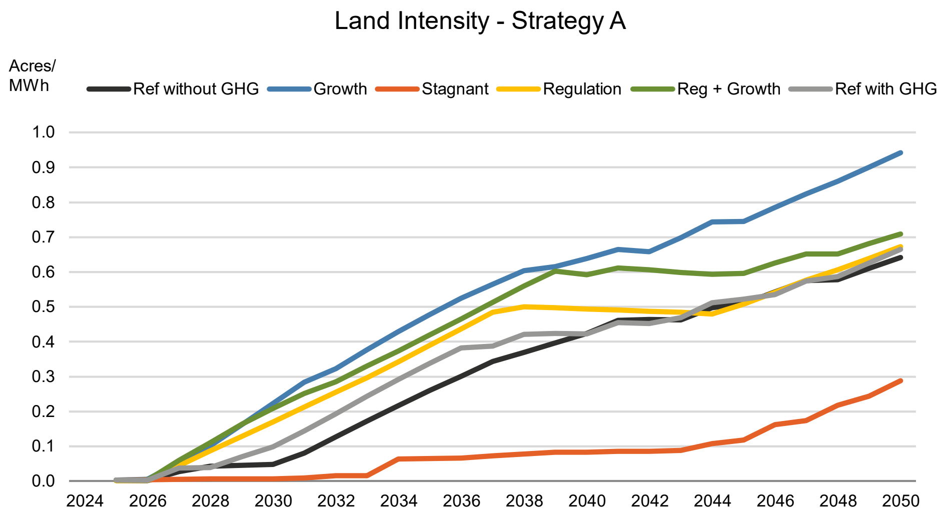

Figure J-15: Annual Land Intensity, All Scenarios with Strategy A (Baseline)

J.8 Conclusion

Each of these metrics describes a different aspect of environmental performance. They provide insights into environmental tradeoffs across portfolios, as well as across broader metric categories. See Chapter 4 for a discussion of key tradeoffs across portfolios and strategies based on the metric results.

K

Appendix K – Operational Metrics

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Appendix K – Operational Metrics

TVA's least-cost planning program starts with low cost, complemented by evaluations of operational, environmental, and risk factors. Reflecting these planning principles and with input from the IRP Working Group, TVA developed metrics to assess the performance of the 30 resource portfolios resulting from applying the five strategies in the six scenarios. This appendix discusses the operational metrics used in the IRP analysis and the methodology employed to derive them.

K.1 Operational Metric Definitions

To evaluate portfolio operational performance, TVA and the IRP Working Group identified three metrics, as described below. They capture various aspects of operational performance including diversity, reliability, and flexibility and can be compared across portfolios and strategies to evaluate relative operational profiles and tradeoffs. Metrics cover the 2025-2050 study period, except for one metric that focuses on 2050, as noted.

Table K-1: Operational Metrics

Metric Category	Metric	Good	Definition
Diverse, Reliable, and Flexible	Operating Cost Stability (%)	Lower	Stochastic volatility of operating cost ($/MWh) expressed as a percentage
	Flexible Resource Coverage Ratio	Higher	Flexible capacity available to meet maximum three-hour ramp divided by flexible capacity requirement in 2050
	Energy Curtailment Ratio (%)	Lower	Expected average annual curtailed energy divided by average annual energy generated and purchased

K.2 Operational Metric Scorecard

The table below shows a comparison of the three operational metrics for each strategy and scenario.

Table K-2: Operational Metrics Scorecard

Metric / Strategy	1 Ref without GHG	2 Growth	3 Stagnant	4 Regulation	5 Reg + Growth	6 Ref with GHG
Operating Cost Stability (%)						
A	3.9%	4.5%	3.8%	7.8%	6.7%	3.8%
B	3.8%	4.2%	3.8%	7.6%	6.6%	3.7%
C	3.5%	4.0%	3.5%	6.9%	6.2%	3.4%
D	3.5%	4.1%	3.5%	7.4%	6.4%	3.4%
E	3.6%	4.1%	3.5%	7.7%	6.6%	3.5%
Flexible Resource Coverage Ratio						
A	1.08	1.09	1.29	1.08	1.18	1.16
B	1.07	1.12	1.49	1.12	1.10	1.17
C	1.11	1.13	1.39	1.12	1.24	1.14
D	1.11	1.09	1.20	1.13	1.11	1.08
E	1.08	1.04	1.26	1.09	1.16	1.13

Metric / Strategy	1 Ref without GHG	2 Growth	3 Stagnant	4 Regulation	5 Reg + Growth	6 Ref with GHG
Energy Curtailment Ratio (%)						
A	0.12%	0.50%	0.00%	0.20%	0.35%	0.22%
B	0.14%	0.54%	0.00%	0.26%	0.48%	0.20%
C	0.46%	1.10%	0.03%	0.50%	0.82%	0.53%
D	0.19%	0.54%	0.00%	0.20%	0.49%	0.26%
E	0.14%	0.65%	0.00%	0.17%	0.41%	0.22%

K.3 Operating Cost Stability

A diverse portfolio is not only more reliable; it also has less variability in expected operating costs. The ability to switch between resource or fuel types and take advantage of changing fuel costs and comparative economics over time is a key benefit to having a diverse portfolio of generating assets. This results in higher operating cost stability over time.

Operating cost stability measures the expected volatility in operating costs. Operating cost includes total production cost, program cost, energy settlements, ancillary services cost, fixed costs, capacity settlements, and contract costs. It is based on stochastic analysis, which takes a probabilistic view of variations in key assumptions to understand the range of potential operating costs for a given portfolio. As a volatility calculation, it measures the standard deviation of the annual change, or rate of return, in operating costs. This calculation uses the expected or average of the 120 stochastic cases run for each portfolio.

$$\sigma(Rate\ of\ Return\ of\ Annual\ Operating\ Costs\ (2025-2050, Expected\ Case)$$

Sudden shifts in fuel types can cause a sizable increase in volatility. This is seen in Scenarios 4 and 5 when several natural gas units convert to hydrogen blends.

K.4 Flexible Resource Coverage Ratio

A portfolio that is flexible has sufficient capacity available to ramp up and down as energy demand and renewable output changes from hour to hour. In periods where load net of renewables ramps up quickly, flexible resources will be called on to fill the need.

The flexible resource coverage ratio measures how much flexible capacity is available to meet the maximum three-hour ramp in 2050. While the amount of flexible capacity will vary for each portfolio, the maximum three-hour ramp will only vary across scenarios. The formula for calculating flexible resource coverage ratio is:

$$\frac{Flexible\ Capacity\ Available\ for\ Max\ 3-Hour\ Ramp\ (2050,\ Strategy)}{Capacity\ Required\ for\ Max\ 3-Hour\ Ramp\ (2050,\ Scenario)}$$

As power supply shifts from conventional, fully dispatchable units to a mix of dispatchable and non-dispatchable resources, including intermittent solar and wind, ensuring sufficient flexibility is a key consideration. TVA will need sufficient flexible resources to cover rapid changes in load net of renewable generation. In general, strategies that promote inflexible or non-dispatchable resource types will have a lower flexible resource coverage ratio.

K.5 Energy Curtailment Ratio

A portfolio that is flexible has sufficient capacity available to ramp up and down as energy demand and renewable output changes from hour to hour. In periods where load net of renewable generation drops below the amount of non-dispatchable energy being generated, a portion of that generation will need to be sold, stored, or curtailed. Energy curtailment represents a lost opportunity cost to TVA customers, and minimizing this is good for both the system and ratepayers.

The energy curtailment ratio measures expected curtailed energy as a rate per unit of annual energy. The formula for calculating energy curtailment ratio is:

$$\frac{Total\ Curtailed\ MWh\ (2025-2050)}{MW\mathrm{h}\ Generated\ \&\ Purchased\ (2025-2050)}$$

This measure is calculated from the expected case, or average, of the 120 stochastic cases run for each portfolio. It is measured across all future years of the study period, though generally it is a growing concern through time.

K.6 Conclusion

These operational metrics each capture a different aspect of portfolio performance. They provide insights into operational tradeoffs across portfolios, as well as across broader metric categories. See Chapter 4 for a discussion of key tradeoffs across portfolios and strategies based on the metric results.