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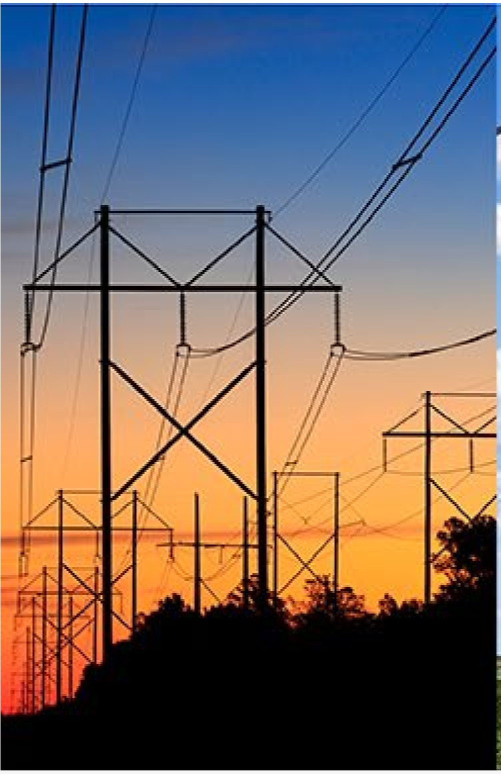



# 2023 Integrated Resource Plan (IRP)

## Public Stakeholder Meeting #4

## December 8, 2022

# Welcome

**Stewart Ramsay**
Meeting Facilitator
VANRY Associates

# Meeting Guidelines

## Principles to guide today's session

- Respectful dialogue
- Questions and comments are public
- Transparency of questions & answers
- Please limit questions and comments to IRP-related topics
- Email list is not being made public

# Meeting Protocols

**The value of this process is in your participation …**
**please ask questions and offer comments!**

1. Why are we using this format?
2. Use the **Q&A** for comments or questions during the presentation – we have a team of people helping to answer your questions
3. “**Raise Hand**” if you would like the chance to speak, we will get to you ASAP – we will open your mic when we can find the right spot

*Note: we are not using the Chat function; it is disabled*

# Why are we here today?

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*Review updates to major modeling assumptions, including discussion of potential impacts resulting from the Inflation Reduction Act, and review supporting studies to be used in Santee Cooper’s 2023 IRP.*

?

**To answer your questions and get your input**

# Today’s Presenters

**Greg McCormack**
Senior Manager,
Financial Forecast
Santee Cooper

**Stewart Ramsay**
Meeting Facilitator
VANRY Associates

**Jim Herndon**
Vice President, Utility Services
Resource Innovations

**Nick Wintermantel**
Principal
Astrapé Consulting

**Bob Davis**
Executive Consultant
nFront Consulting

# Summary of Post-meeting Survey Responses from Stakeholder Meeting #3

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**Stakeholders expressed …**

- Meetings were seen as largely valuable and worth the stakeholder time commitment
- Satisfaction with the level of detail, the ability to provide input, and the balance between presentations and Q&A
- That meetings were seen, by some, to be too technical and too long

**We learned there is interest in …**

- Assuring continued access to proven, reliable resources while transitioning to cleaner energy
- Mitigating the risk of over-reliance upon purchased power arrangements
- Continuing the focus on reaching out to non-technical stakeholders
- More detail about what is the impact of the nuclear debt on cost forecasts

**Today we …**

- Have shortened the meeting length, shifted the timing to the afternoon and focusing the discussion on impacts from new developments
- Will continue to balance presentations and Q&A
- Ask that you speak up if the conversation is excessively technical – this is difficult material, and many others will thank you for raising the point

# Agenda

| | |
|---|---|
| ✔ | Welcome |
| 1:10 | IRA Impacts on 2022 Load Forecast |
| 1:25 | DSM Market Potential Study |
| 2:00 | Solar Integration Study |
| 2:45 | BREAK |
| 3:00 | Major Assumptions and IRA Discussion |
| 3:45 | Resource Portfolios |
| 4:15 | Closing |

# IRA Impacts on 2022 Load Forecast

**Greg McCormack**
Senior Manager, Financial Forecast
Santee Cooper

# Inflation Reduction Act Impacts

## Electric Vehicles

"Clean vehicles must be assembled in the United States."[1]

**Credit terminates in 2032**

**Vehicle Requirements**

- Sourcing requirements for critical minerals and components of battery
- Vehicle cost limits ($80,000 trucks, $55,000 other)

**Income Limits:**

- $300,000 /year for married joint filing
- $225,000 /year for head of household
- $150,000 /year for individuals

1 – Inflation Reduction Act, Section 13401. Clean Vehicle Credit

## Rooftop Photovoltaic

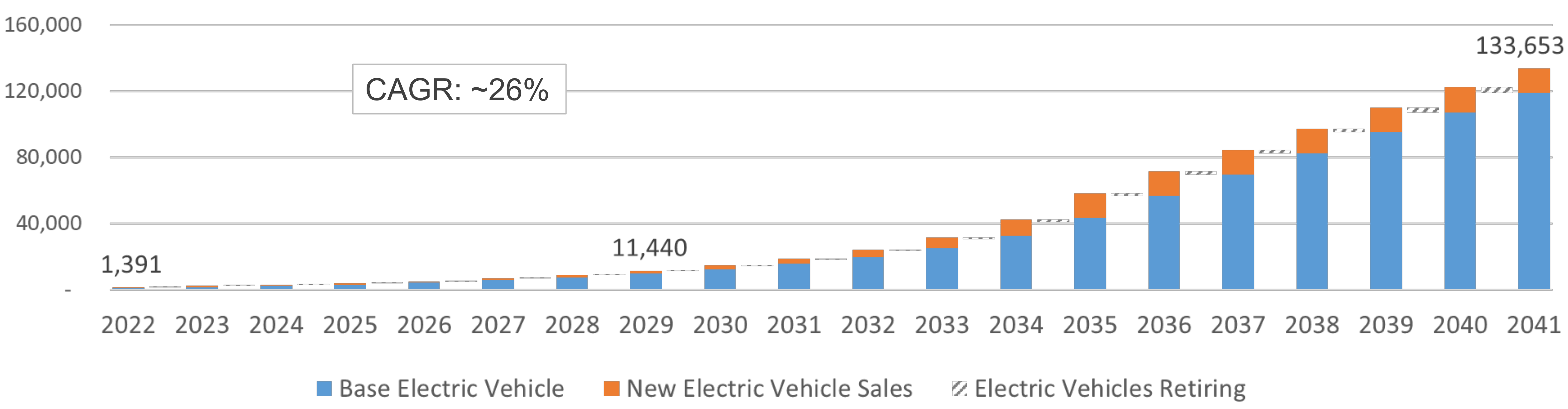
Beginning in 2022, the provision modifies and expands the credit, including by:

- Extending the tax credit of 30% of Residential Rooftop Solar through 2032 and phased out by 2034
- Expanding the credit to include battery storage technology

# Electric Vehicle Forecast

- High Case: Rapid Adoption
  - Updated EPA efficiency standards creates inflection point in 2026
  - 80% of new cars sold are plug-in electric by 2035
  - Horry County "moves up" adoption curve

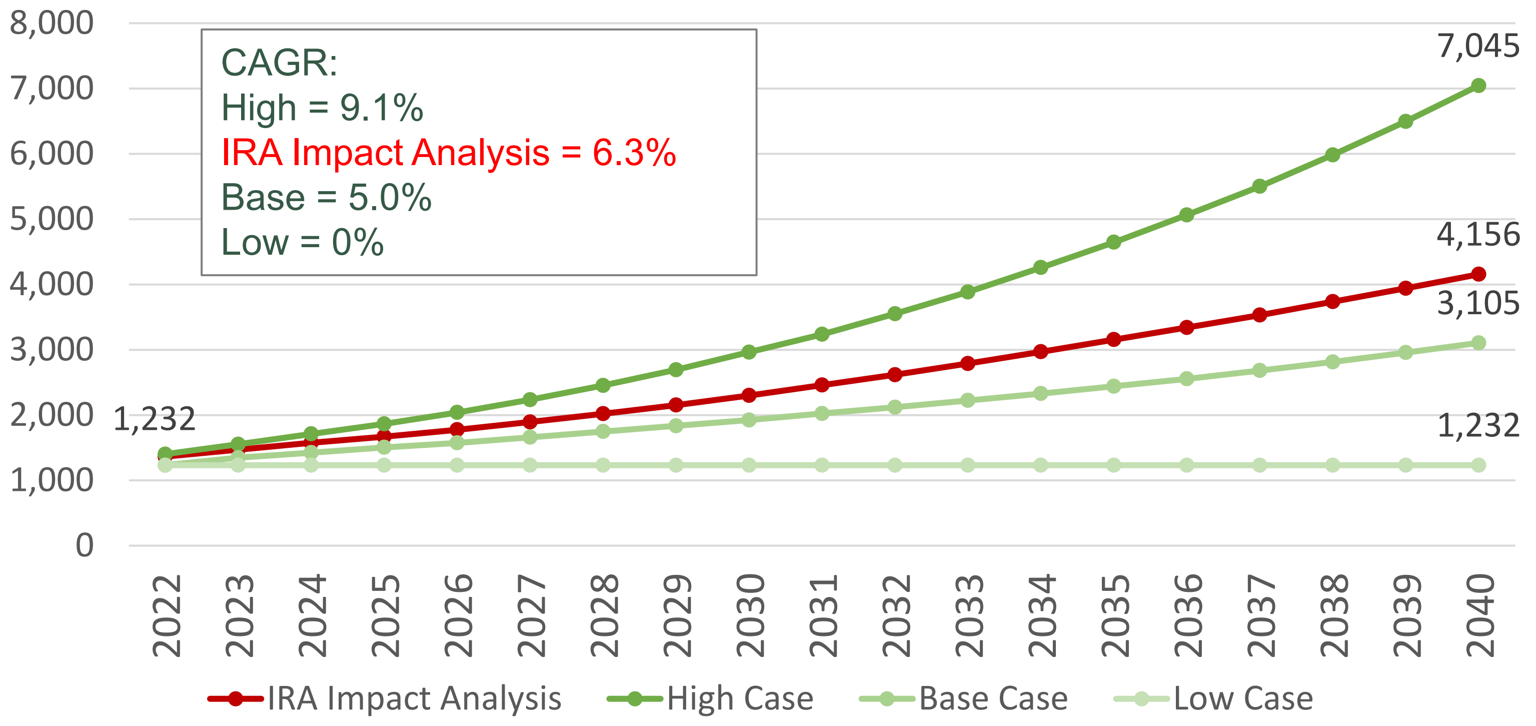
## Number of Electric Vehicles



# Rooftop (PV) Forecast

- High Case: Adoption and Battery Storage
  - 50% higher than EIA "Low Oil and Gas Supply" case
  - Widespread adoption of 20 kW selectively dispatched battery storage

## Total PV Customers




## IRA Scenario Assumptions

- Based on EIA "Battery Storage - Low Oil and Gas Supply" case
- IRA analysis case uses same methodology as High Case
  - Growth of customers based on national PV growth rate
- No changes to technology assumptions
- **Scenario results indicate no changes needed to existing cases**

# Update on DSM Projections

**Patricia Housand**
Manager, Program Development
Santee Cooper

**Jim Herndon**
Vice President, Utility Services
Resource Innovations

# Santee Cooper Demand Side Management (DSM) Points From Previous Stakeholder Meetings

- Currently working toward 89 GWh in cumulative EE savings by 2030 from program offers developed using Santee Cooper's 2019 Energy Efficiency Market Potential Study (EE MPS) which used Total Resource Cost (TRC)
- Historic incremental annual energy savings from EE programs as % of retail MWh consumption ranged from 0.35% to 0.91%
- Compared EE savings using TRC vs. Utility Cost Test (UCT) based on 2019 EE MPS assumptions
- Currently working toward 35 MW of dispatchable demand response capability by 2027 and 44 MW by 2035

# Santee Cooper Demand Side Management (DSM) Today's Topics

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- Santee Cooper's 2022 EE MPS Results
  - Based on 2022 load forecast and updated capacity and energy costs
  - Additional energy efficiency measures considered that were not available in 2019
  - UCT used to vet EE measures
- Santee Cooper's Demand Response Market Potential Study currently in progress
- Information on where to find Central's 2020 IRP filing

# 2022 Energy Efficiency Market Potential Study

## Develop current EE impact projections for Santee Cooper's residential and commercial retail customers based on currently available data and revised study assumptions

**Study inputs align with current forecasts and market data:**

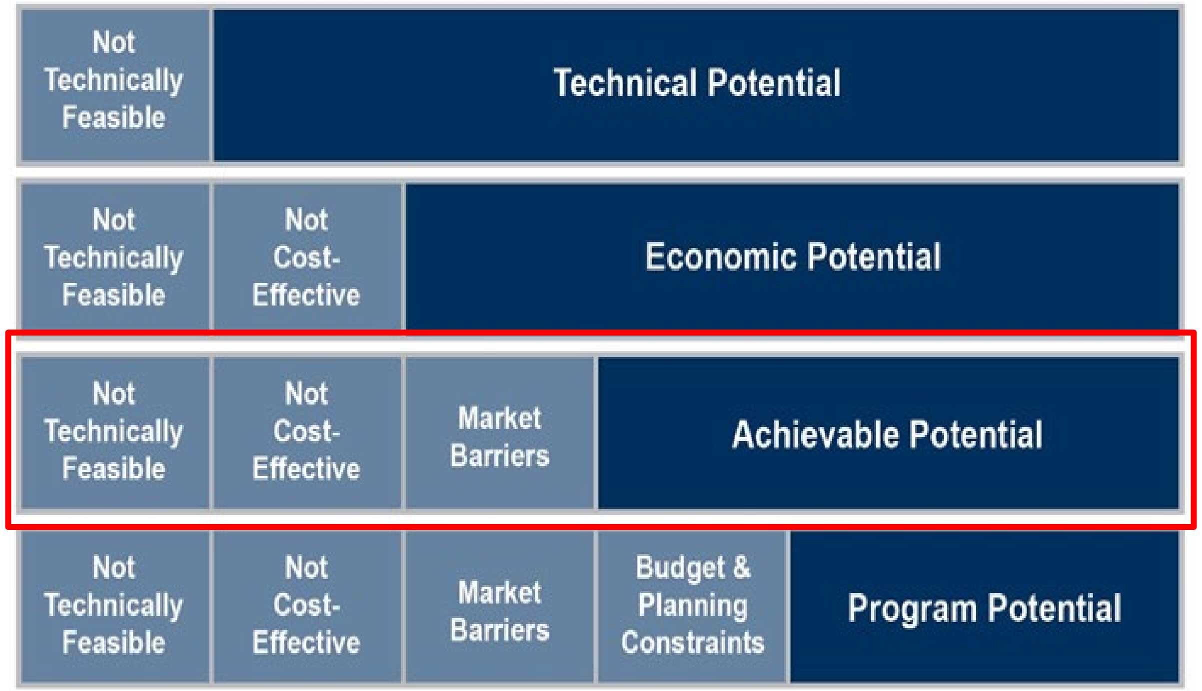
- Santee Cooper's 2022 energy sales and load forecast
- Current avoided energy and capacity estimates
- Updated EE measure list

**Use the Utility Cost Test (UCT) perspective for economic screening**

- Incorporates estimated utility incentives as percent of incremental cost and typical utility program administrative costs

**Analyze three achievable potential scenarios**

- Market-based adoption estimates for all cost-effective measures




EPA – National Guide for Resource Planning

# Study Assumptions for Market-based EE Potential

1. **Customers decide - market potential based on customer cost-benefit**
   - Measures offered are subject to UCT screening (<u>incremental price for higher efficiency product is reduced by incentives</u>)
   - To incorporate customer perspective, assumed EE measures are a normal market good
     - …because DSM program marketing and outreach reduces barriers, as with ENERGY STAR branding
2. **ENERGY STAR data captures tradeoffs between price and energy savings**
   - Up-front cost is roughly twice as influential as energy savings
   - Estimate from a developed market for EE products with relatively low up-front costs
   - Utility EE programs serve a similar function to the market by increasing awareness & reducing uncertainty of savings
3. **EE competes with other goods and services**
   - Base tech or “no action” is always an option, and we treat it just like any other measure
   - Optimistic in re: “status quo bias”
4. **Market barriers are “typical” (like those in other markets)**
   - Price, opportunity costs
   - Variety of product features for new; similarly, a mix of status quo products in market

# Achievable Potential EE Scenarios

## Low Scenario

- Align with current program incentive rates (25-30% of incremental costs) and program administrative costs on $/kWh basis
- Include all measures with a UCT of 1.0
- Market potential estimated using customer response to price and savings
- Rate of adoption driven by Bass parameters

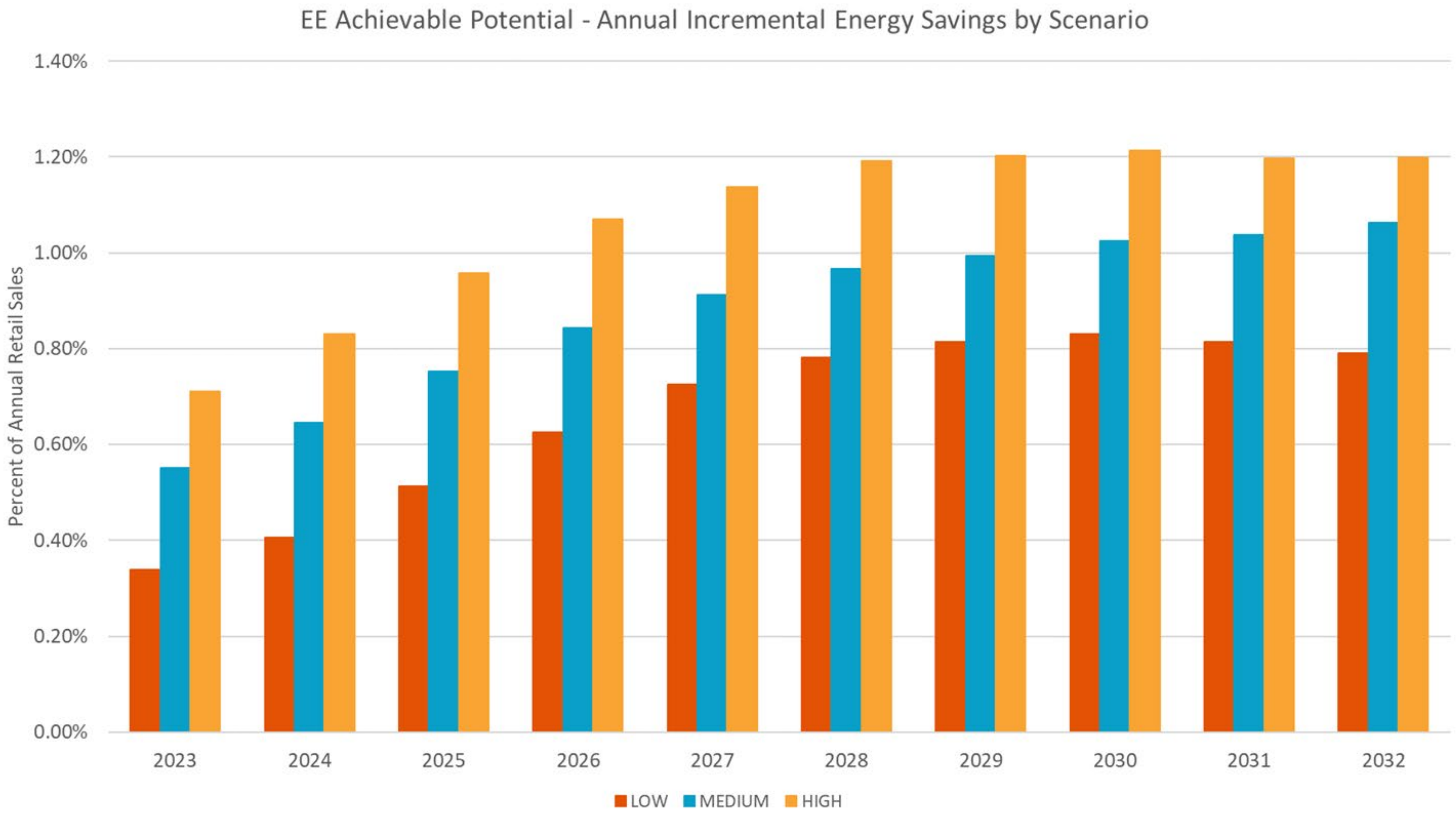
## Medium Scenario

- Increase incentive rates (approx. 50% of incremental costs)
  - Increasing incentive rates impacts adoption rates but also increases UCT costs
- Screening threshold adjusted to UCT of 0.7

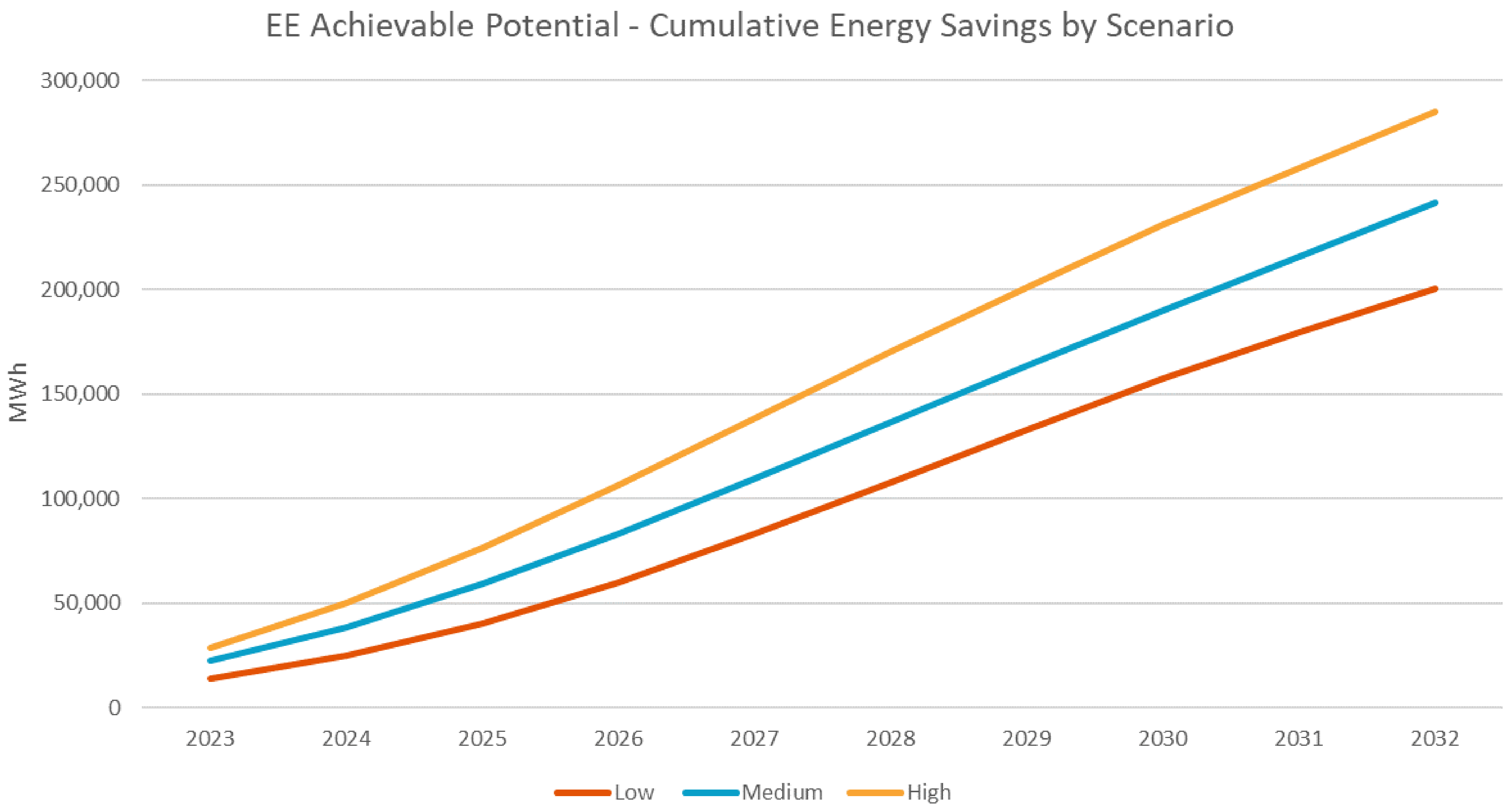
## High Scenario

- Additional increase to incentive rates (approx. 75% of incremental costs)
- Increased avoided marginal energy costs as sensitivity that anticipates factors that may impact energy costs in the future
- Screening threshold adjusted to UCT of 0.7

# 2022 EE Market Potential Study Results
# Annual Incremental Savings at Achievable Level



# 2022 EE Market Potential Study Results
# Cumulative Savings at Achievable Level



# 2022 Demand Response Market Potential Study

## Develop current DR impact projections for Santee Cooper's residential and commercial retail customers

- **DR potential based on load available from eligible sources during system peak hour**
  - Currently collecting & analyzing available Santee Cooper interval load data
- **Customer segments and end-use target loads**
  - **Residential**
    - Air conditioning (summer)
    - Space heating (winter)
    - Water heating (year-round)
    - Pool pumps (summer)
  - **Small & Medium Business**
    - Air conditioning (summer)
    - Space heating (winter)
  - **Large Commercial**
    - Total load (assumption that these customers will shed load based on economic offer)

# Residential/Small & Mid-Sized Business Air Conditioning and Heating Load Shapes

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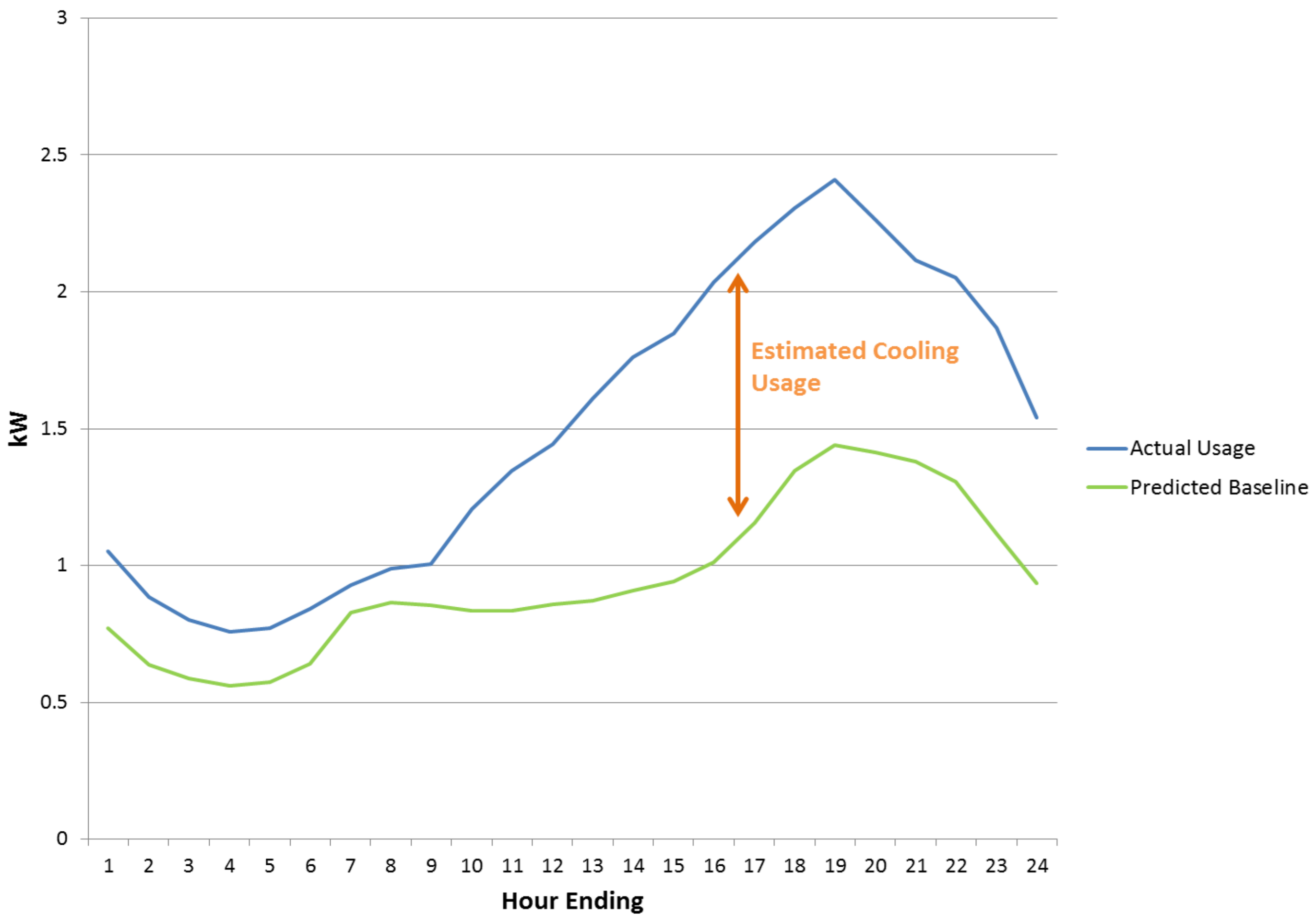
**Analysis based on interval data or average load shapes from load research sample**

- To estimate cooling load, develop model to predict usage based on CDD, HDD, month, hour and weekday/weekend
- Determine baseline usage without cooling for each day by setting CDD=0 and predicting usage based on estimated coefficients
- Estimate of cooling load is difference between baseline and observed usage

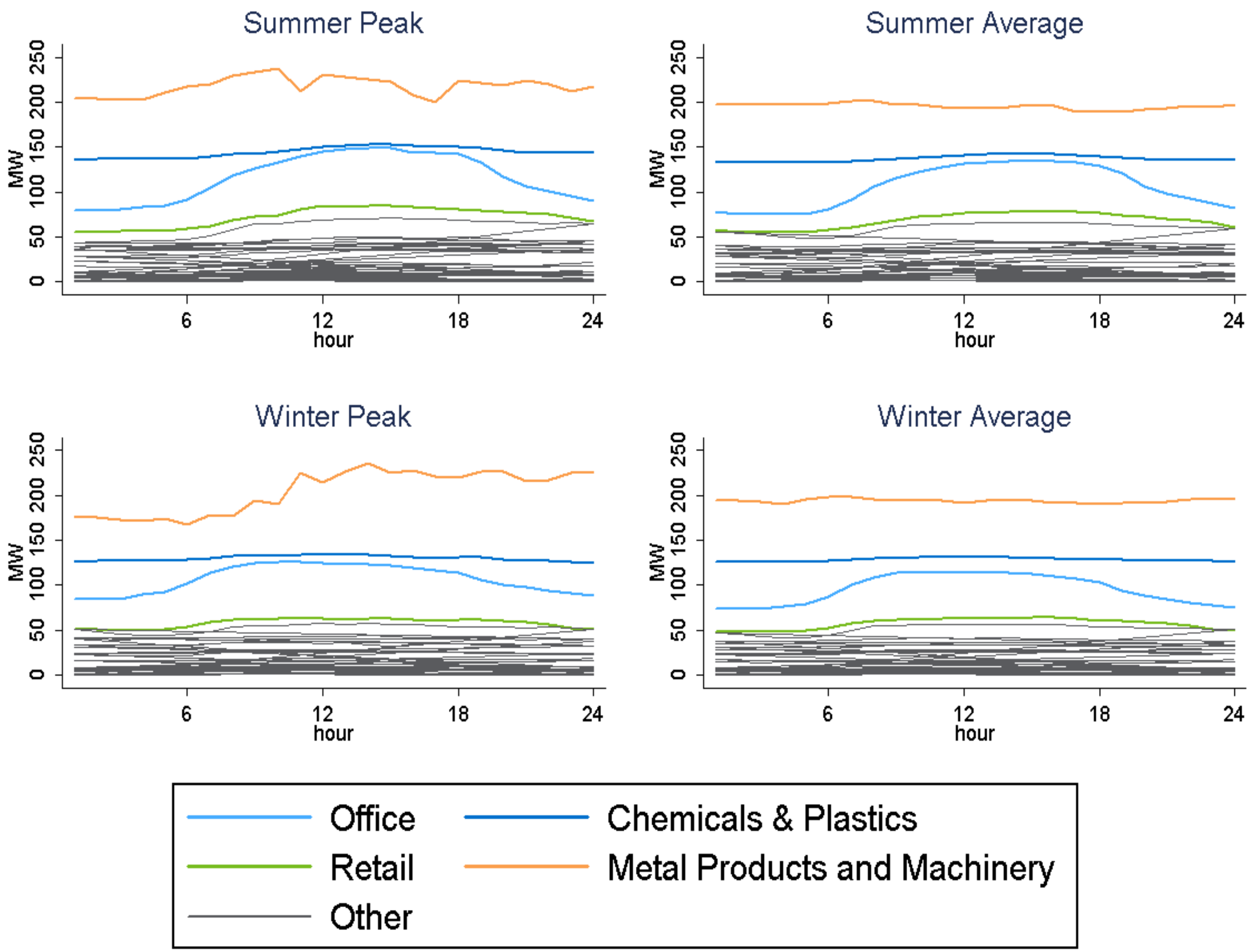
*Similar methodology is used to estimate heating load*



# Large Commercial Customer Load Shapes

**Based on interval data from customers with demand > 300 kW**

- Average load shapes not used due to large amount of variation seen with large customers
- Load aggregated into total historic load based on customer segment
- Technical potential defined as total load available for each segment during system peak



# Central DSM

- In accordance with Act 62, Central is required to submit an IRP every three years to the SC Energy Office
- In 2020, Central completed and submitted an IRP to the SC Energy Office
- Within that IRP, Central evaluates DSM with high, medium, and low scenarios
- To access Central's IRP, please go to:
  - https://energy.sc.gov/files/view/Central%202020%20IRP.pdf

# Solar Integration Study Update Meeting

Presented By
Astrapé Consulting

12/8/2022

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# SERVM Framework – Same as PRM Study

- **Base Case Study Year (2029) – Begin with PRM Study Database**
  - Simulate @ 5-minute increments
  - Weather (41 years of weather history)
    - Impact on Load
    - Impact on Intermittent Resources
  - Economic Load Forecast Error (distribution of 5 points)
  - Unit Outage Modeling (thousands of iterations)
    - Multi-State Monte Carlo
    - Frequency and Duration
  - Model Santee Cooper with traditional capacity added to get to 0.1 LOLE Cap
    - System modeled as an island with “market capacity” to maintain reliability

- Base Case Total Scenario Breakdown: 41 weather years x 5 LFE points = 205 scenarios
- Base Case Total Iteration Breakdown: 205 scenarios * 100 unit outage iterations = 20,500
  - Exact iterations to be determined



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# Resource Commitment and Dispatch

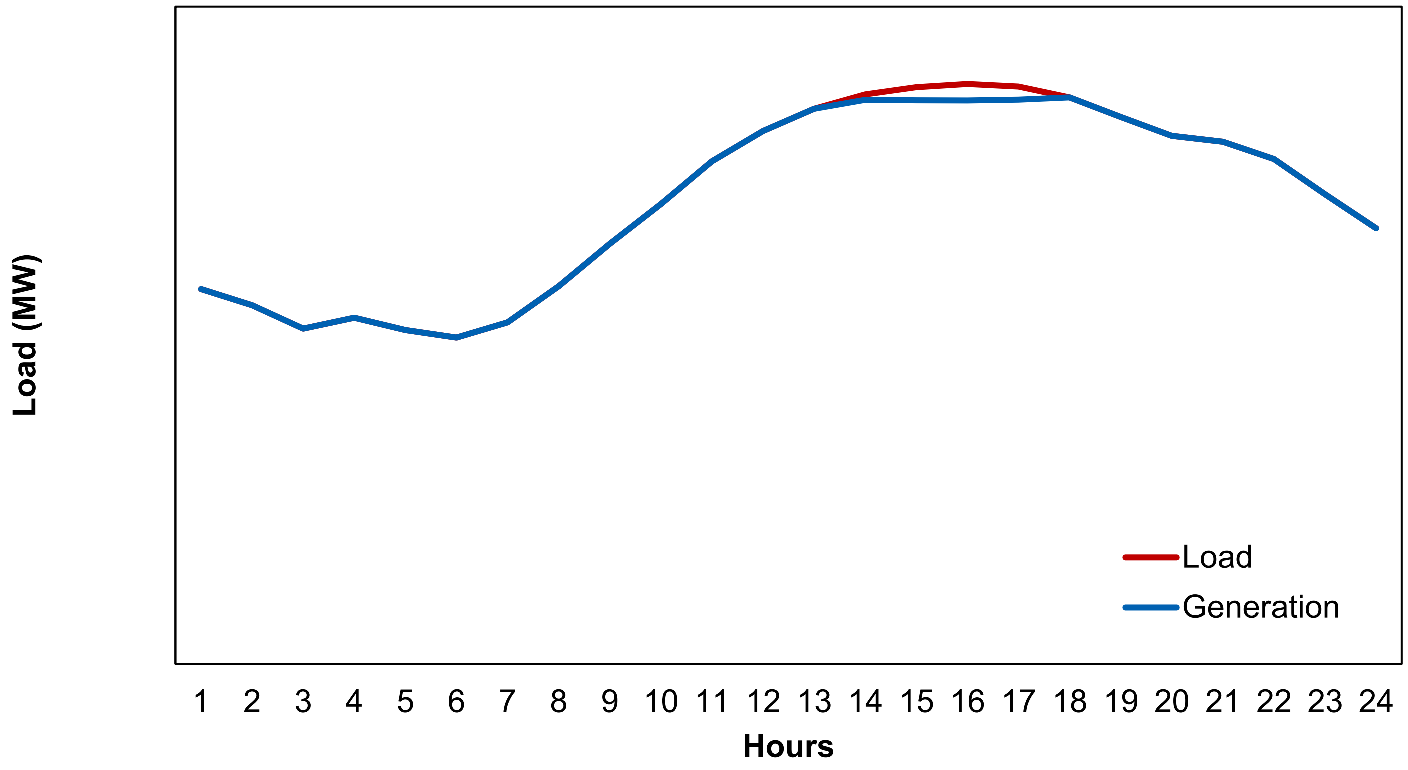
- **Chronological Commitment and Dispatch Model**
  - **Simulated at 5-minute dispatch increments**
- **Simulates 1 year allowing for thousands of scenarios to be simulated which vary weather, load, unit performance**
- **Respects all unit constraints**
  - Capacity maximums and minimums
  - Heat rates
  - Startup times and costs
  - Variable O&M
  - Emissions
  - Minimum up times, minimum down times
  - Must run designations
  - Ramp rates
- **Load and solar volatility modeled which removes perfect foresight**
  - Based on historical datasets

# Operating Reserves

- **Operating reserves are input into SERVM**
  - Regulation Up/Down Requirement – served by units designated with AGC capability
  - Spinning Reserves Requirement – served by units who have minimum load less than maximum load
  - Load Following Up/Down Reserves – identical to spinning reserves; served by units who have minimum load less than maximum load
  - Quick Start Reserves – served by units who are offline and have quick start capability
- **SERVM commits resources to serve load and ancillary service requirements entered by user**

# LOLE$_{CAP}$ – Example Only

- **LOLE$_{CAP}$:**
  - **Traditional LOLE; number of loss of load events due to capacity shortages, calculated in events per year.**
  - **Used for Reserve Margin Planning and Capacity Value of Resources**



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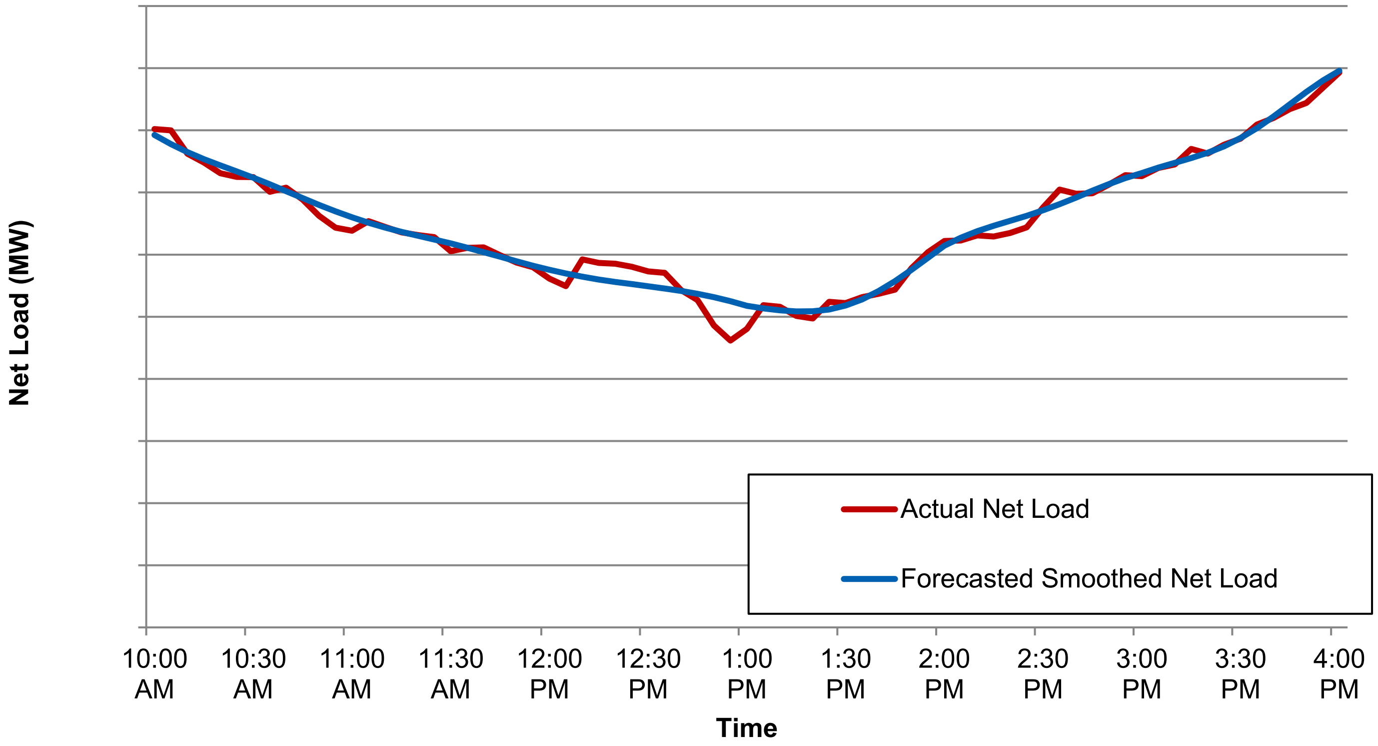
# Flexibility Violation – Example Only

- **Flexibility Violations:**
  - **Number of events where generators modeled in SERVM could not meet the next 5-minute net load.  There was enough capacity installed but not enough flexibility to meet the net load ramps.**
  - **Resolved by adding online ramping capability to meet the volatility of additional solar**

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# Scope of Study

- **Solar Tranches Evaluated**

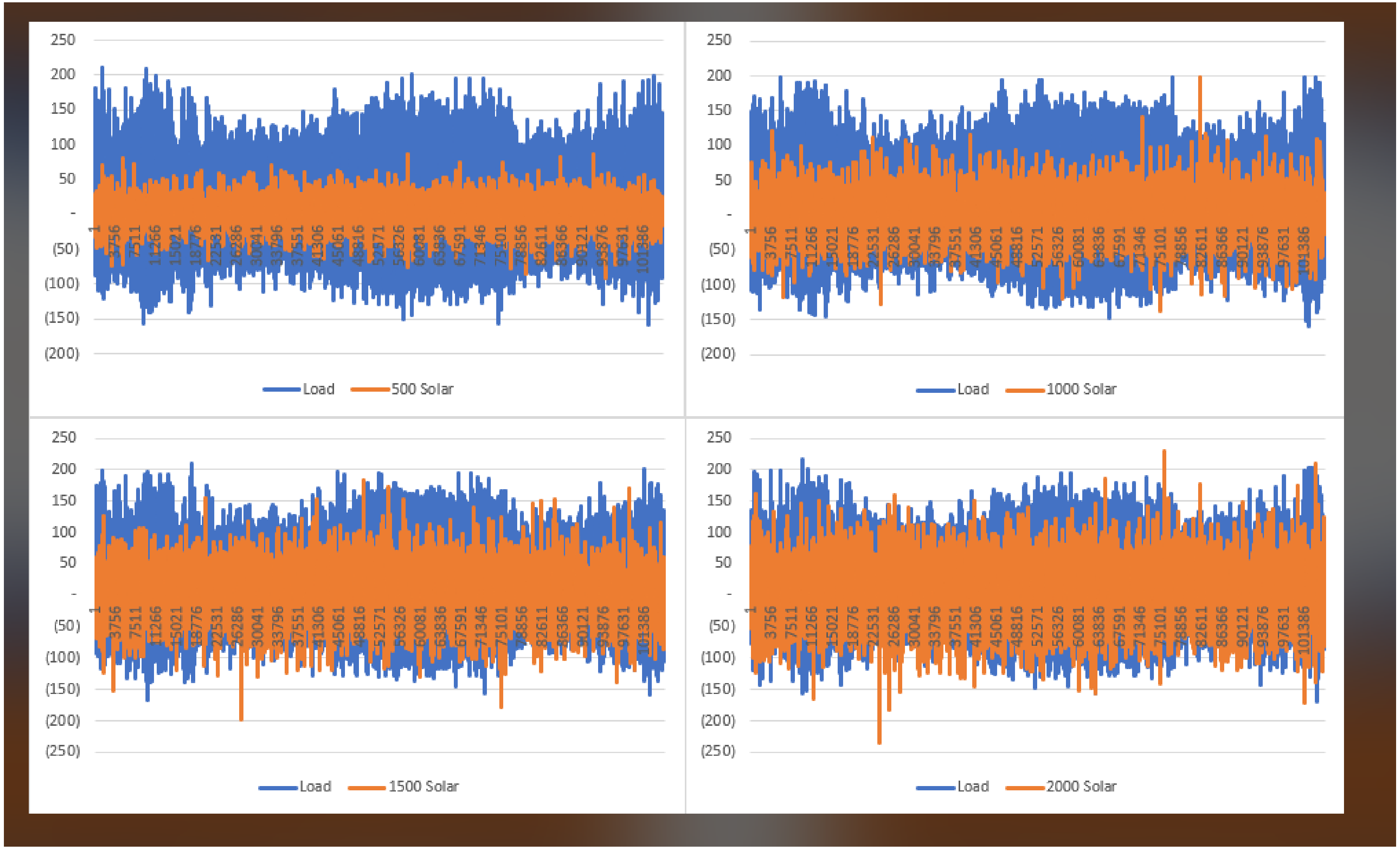
| | Santee Cooper Solar |
|---|---|
| Tranche 1 MW | 500 |
| Tranche 2 MW | 1,000 |
| Tranche 3 MW | 1,500 |
| Tranche 4 MW | 2,000 |

- **Scenarios Evaluated**
  - 2026 Study Year
  - Base Scenario: 2x1 CC
  - Alternative Scenario 2: 2x1 CC with 350MW of BESS
- **Additional Sensitivities**
  - Base Scenario with an additional flexible unit that simulates the SEEMS market

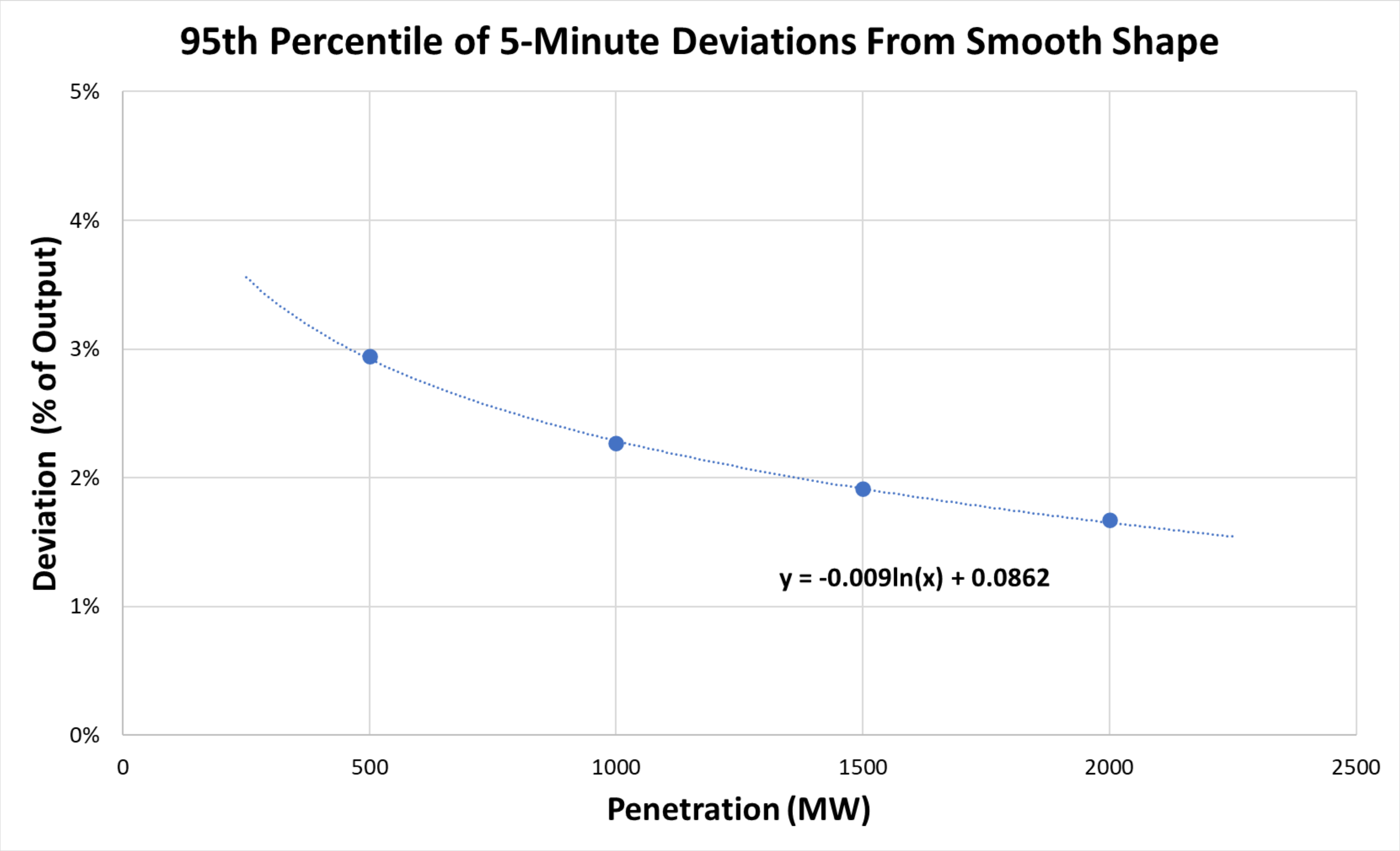
# Study Procedure

- **Step 1:Run Base Case:**
  - Establish a non-renewables base case at 0.1 LOLE
  - Simulate with reasonable operating reserves to determine flexibility violations without solar (e.g. no solar case produced 3 flexibility events per year)
- **Step 2:  Add Solar:**
  - Return system to 0.1 LOLE
  - As solar is added flexibility violations increase due to the increase in net load volatility
  - Determine the hours where flexibility violations occur
- **Step 3:  Add ancillary services:**
  - Add additional ancillary services in the form of load following to get back to the number of flexibility violations in the base case
  - Target hours where flexibility violations occur
- **Step 4:  Calculate the solar integration cost:**
  - Calculate the cost increase of the additional ancillary services between Step 2 and Step 3.  Then divide by the incremental solar generation to calculate the solar integration cost

# Model Volatility – 1 year sample size



# Solar Volatility as a Function of Penetration



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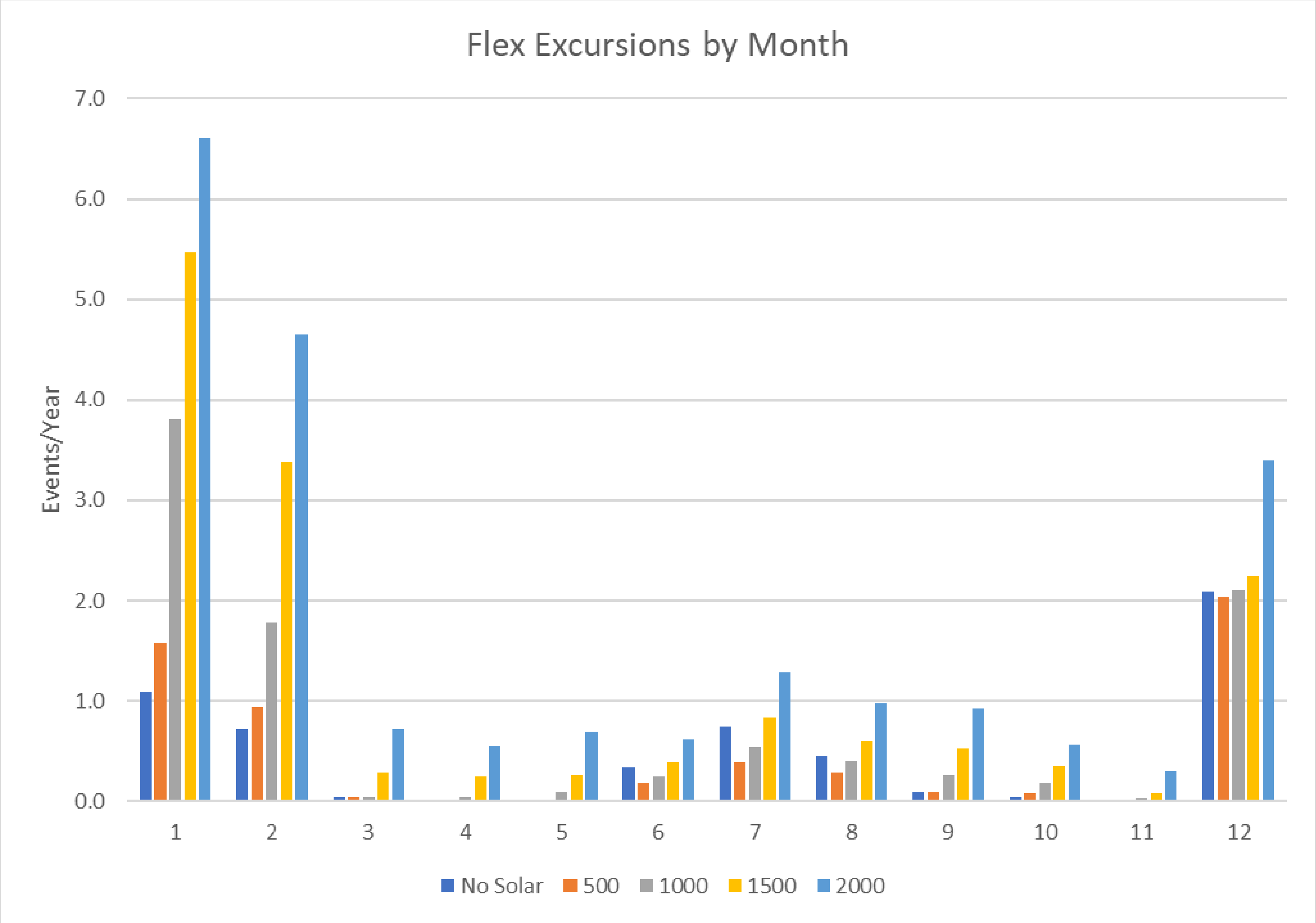
# 2026 Existing System



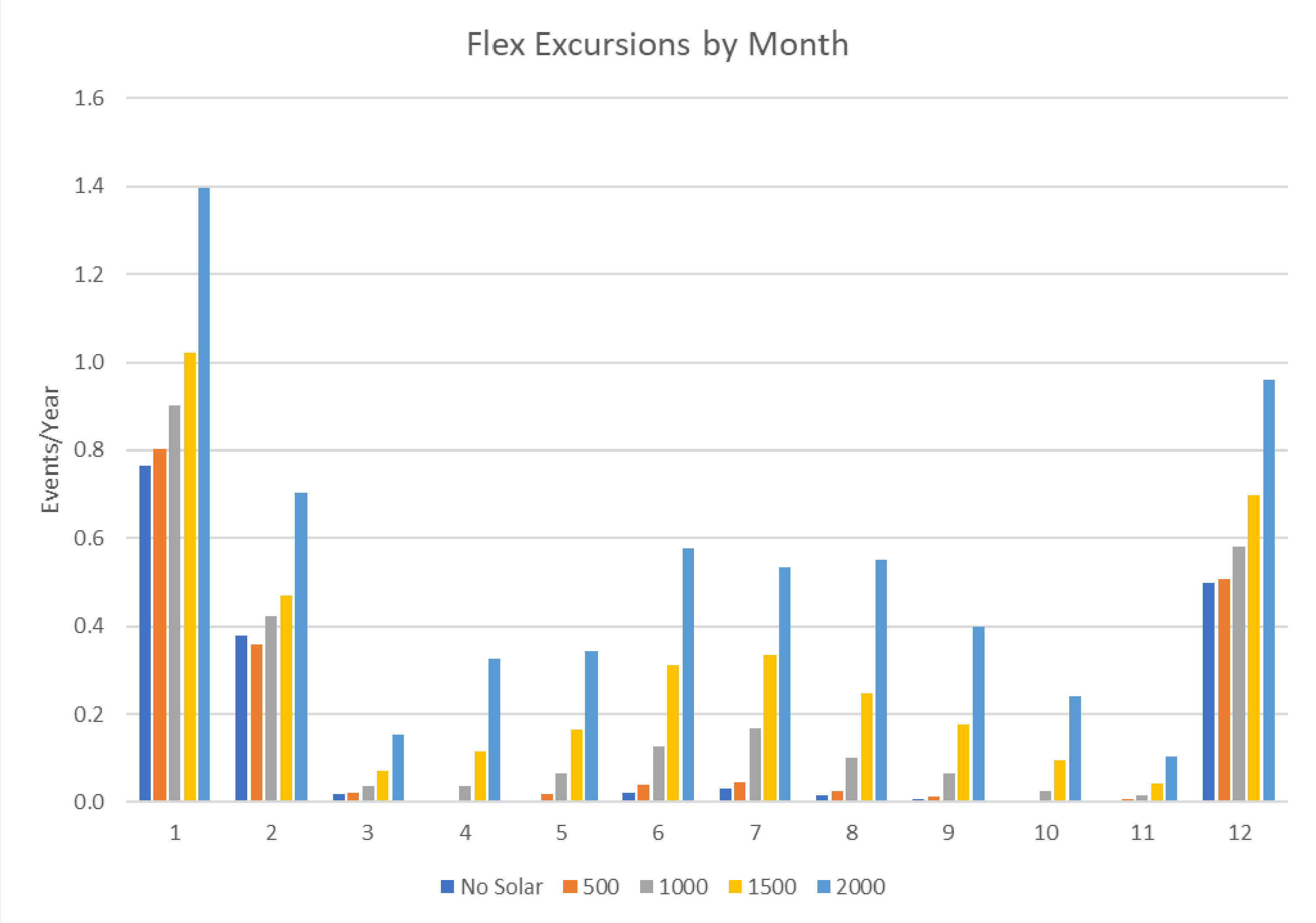
# 2026 Existing System

| Unoptimized | Integration Costs $/MWH | Incremental Cost $/MWH | Inc OR MW (Average over 8,760 hours) | Inc Solar Curtailment MWH | Integration Curtailment MWH | % Curtailment |
|---|---|---|---|---|---|---|
| 500 Solar | 0.08 | 0.08 | 2 | (41) | 6 | 0.0% |
| 1000 Solar | 3.32 | 6.57 | 17 | 5,856 | 2,680 | 0.4% |
| 1500 Solar | 4.85 | 7.69 | 43 | 86,211 | 32,889 | 3.2% |
| 2000 Solar | 9.86 | 24.15 | 50 | 380,003 | 199,819 | 11.7% |

| Optimized | Integration Costs $/MWH | Incremental Cost $/MWH | Inc OR MW (Average over 8,760 hours) | Inc Solar Curtailment MWH | Integration Curtailment MWH | % Curtailment |
|---|---|---|---|---|---|---|
| 500 Solar | 0.08 | 0.08 | 2 | (41) | 6 | 0.0% |
| 1000 Solar | 2.38 | 4.68 | 16 | 5,856 | 2,666 | 0.4% |
| 1500 Solar | 3.20 | 4.73 | 29 | 86,211 | 19,073 | 3.0% |
| 2000 Solar | 6.26 | 14.99 | 39 | 380,003 | 145,826 | 10.6% |

Unoptimized adds operating reserves uniformly across solar hours
Optimized adds operating reserves in a targeted basis in the hours needed

# 2029 2x1 CC Scenario



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# 2029 2x1 CC Scenario

| Unoptimized | Integration Costs $/MWH | Incremental Cost $/MWH | Inc OR MW (Average over 8,760 hours) | Inc Solar Curtailment MWH | Integration Curtailment MWH | % Curtailment |
|---|---|---|---|---|---|---|
| 500 Solar | 0.40 | 0.40 | 7 | 490 | 52 | 0.0% |
| 1000 Solar | 0.71 | 1.01 | 33 | 24,296 | 828 | 1.0% |
| 1500 Solar | 1.31 | 2.53 | 55 | 144,205 | 5,289 | 4.0% |
| 2000 Solar | 2.46 | 5.89 | 74 | 459,984 | 29,075 | 9.9% |

| Optimized | Integration Costs $/MWH | Incremental Cost $/MWH | Inc OR MW (Average over 8,760 hours) | Inc Solar Curtailment MWH | Integration Curtailment MWH | % Curtailment |
|---|---|---|---|---|---|---|
| 500 Solar | 0.40 | 0.40 | 7 | 490 | 52 | 0.0% |
| 1000 Solar | 0.57 | 0.75 | 30 | 24,296 | 928 | 1.0% |
| 1500 Solar | 0.92 | 1.61 | 50 | 144,205 | 6,302 | 4.1% |
| 2000 Solar | 1.70 | 4.06 | 63 | 459,984 | 26,129 | 9.9% |

Unoptimized adds operating reserves uniformly across solar hours
Optimized adds operating reserves in a targeted basis in the hours needed

# Results – 2029 2x1 CC Scenario Add 350 MW Battery Sensitivity

| Unoptimized | Integration Costs $/MWH | Incremental Cost $/MWH | Inc OR MW (Average over 8,760 hours) | Inc Solar Curtailment MWH | Integration Curtailment MWH | % Curtailment |
|---|---|---|---|---|---|---|
| 500 Solar | 0.86 | 0.86 | 11 | 86 | (34) | 0.0% |
| 1000 Solar | 1.15 | 1.43 | 45 | 2,372 | 60 | 0.1% |
| 1500 Solar | 1.61 | 2.54 | 79 | 38,316 | 3,722 | 1.1% |
| 2000 Solar | 3.20 | 7.99 | 119 | 205,816 | 26,923 | 4.7% |

| Optimized | Integration Costs $/MWH | Incremental Cost $/MWH | Inc OR MW (Average over 8,760 hours) | Inc Solar Curtailment MWH | Integration Curtailment MWH | % Curtailment |
|---|---|---|---|---|---|---|
| 500 Solar | 0.86 | 0.86 | 11 | 86 | (34) | 0.0% |
| 1000 Solar | 0.72 | 0.57 | 43 | 2,372 | 333 | 0.1% |
| 1500 Solar | 1.57 | 3.28 | 77 | 38,316 | 7,353 | 1.2% |
| 2000 Solar | 2.76 | 6.33 | 110 | 205,816 | 31,091 | 4.8% |

Battery was included in the no solar case and the with solar case making the flexibility violations a lower baseline in the no solar case. This resulted in slightly higher integration costs.

Unoptimized adds operating reserves uniformly across solar hours
Optimized adds operating reserves in a targeted basis in the hours needed



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# Results – 2029 2x1 CC Scenario Add 350 MW Battery Sensitivity

Battery was included in the no solar case and the with solar case, but the baseline flexibility excursions were targeted to the original 2x1 CC no solar case.

This sensitivity was not optimized so should be compared to the 2x1 CC unoptimized results.

| Unoptimized | Integration Costs $/MWH | Incremental Cost $/MWH | Inc OR MW | Inc Solar Curtailment MWH | Integration Curtailment MWH | % Curtailment |
|---|---|---|---|---|---|---|
| 500 Solar | 0.69 | 0.69 | 8 | 127 | (7) | 0.0% |
| 1000 Solar | 0.71 | 0.73 | 38 | 2,206 | 122 | 0.1% |
| 1500 Solar | 1.42 | 2.85 | 67 | 36,086 | 2,825 | 1.1% |
| 2000 Solar | 2.24 | 4.68 | 95 | 198,041 | 11,455 | 4.2% |

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# Results – 2029 2x1 CC Scenario SEEMS Sensitivity

- 200 MW of flexible market MWs were introduced and given 100% flexibility with a 20 minute start time to reflect current SEEMS expectations.
- This unoptimized version should be compared to the unoptimized 2x1 CC Scenario.

| Unoptimized | Integration Costs $/MWH | Incremental Cost $/MWH | Inc OR MW (Average over 8,760 hours) | Inc Solar Curtailment MWH | Integration Curtailment MWH | % Curtailment |
|---|---|---|---|---|---|---|
| 1000 Solar | 0.59 | 0.59 | 40 | 25,923 | 1,425 | 1.1% |
| 1500 Solar | 1.19 | 2.40 | 63 | 111,653 | 6,820 | 3.9% |
| 2000 Solar | 2.45 | 6.22 | 72 | 428,323 | 20,311 | 9.1% |



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# Break

# Returning:  3:00 pm

# Major Assumptions

**Bob Davis**
Executive Consultant
nFront Consulting

# Major Assumptions

*The following section depicts major assumptions that Santee Cooper is proposing for use in its 2023 IRP. Santee Cooper will continue to monitor market conditions and available data and may modify assumptions as additional information becomes available. Should there be significant changes to major assumptions, updates will be posted to IRP Stakeholder Forum.*

# Financing and Economic Assumptions

| Assumption | Annual Rate | Source |
|---|---|---|
| Santee Cooper Weighted Cost of Debt | 5.25% | Santee Cooper's financial advisor |
| Weighted Cost of Short-term Commercial Paper | 4.25% | Santee Cooper's financial advisor |
| Santee Cooper Discount Rate | 5.25% | Same as weighted cost of debt |
| General Inflation Rate | 2.30% | Philly Fed survey |

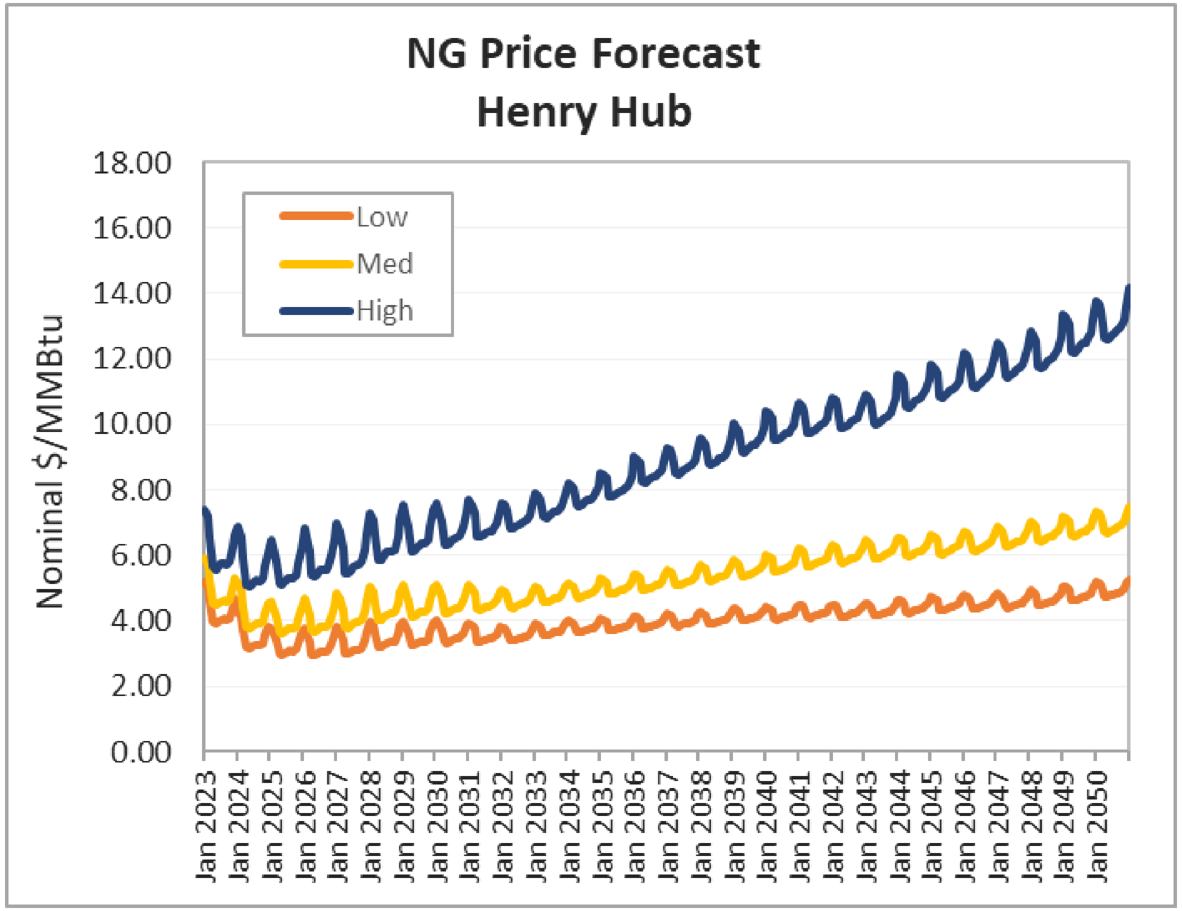
# Fuel Prices

# Fuel Price Forecast

- Use of fundamental forecasts throughout IRP study period
- NG and coal prices based on average of forecasts from EIA 2022 Annual Energy Outlook (AEO) and S&P Global
  - Reflects recent market conditions, including price increases caused by the war in Ukraine
- V.C. Summer nuclear fuel price forecast prepared by DESC

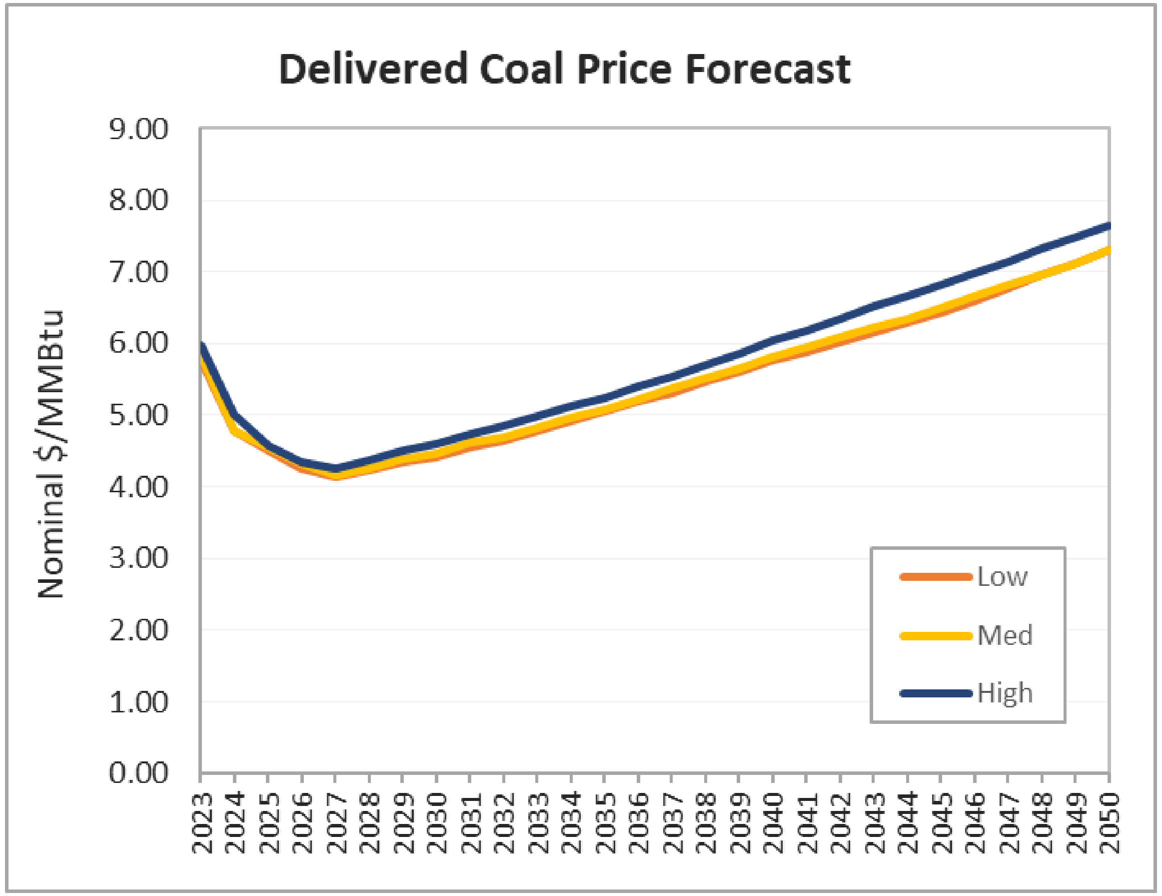
# Natural Gas Price Forecast

- Henry Hub price forecast computed from average of annual price forecasts from:
  - 2022 AEO Reference Case, March 3, 2022
  - S&P Global Platts, North American Long-term Prices, published September 9, 2022
- Variable delivery charges based on existing pipeline fees from Gulf Coast area to South Carolina
- Relative monthly price patterns based on current CME/NYMEX forward prices for Henry Hub as of October 28, 2022
- Low and High sensitivity cases based on relative difference between AEO Reference Case and High and Low Oil and Gas Supply cases, respectively
- New NG combined cycle resources will be modeled to include firm NG reservation charges as a fixed operating expense



# Coal Price Forecast

- Coal basin prices for Central Appalachian, Northern Appalachian, and Illinois Basin computed from average of:
  - 2022 AEO Reference Case, March 3, 2022
  - S&P Global, SNL Coal Basin Forecast, September 30, 2022
- Forecast of coal rail delivery costs to South Carolina
- Low and High sensitivity cases based on relative difference between AEO Reference Case and High and Low Oil and Gas Supply cases, respectively



# Resource Options

# New Generating Resource Options
# CC, CT, RICE, and SMR

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- Capital cost, capacity ratings, performance, and operating characteristics for combined cycle (CC), combustion turbine (CT), reciprocating internal combustion engine (RICE), and small modular reactor (SMR) resource options based on information from EPRI TAGWeb, equipment vendors, and engineering estimates developed by Santee Cooper and others
- Capital and O&M real cost escalation based on NREL Annual Technology Baseline (ATB) Moderate Case

# New Generating Resource Options
# CC, CT, RICE, and SMR

| Technology/Configuration 2022 $'s | Full Load Net Output MW | Capital Cost $/kW | Full Load Net Heat Rate Btu/kWh | Fixed O&M $/kW-Yr | Non-Fuel Variable O&M $/MWh | Forced Outage Rate % | Annual Scheduled Maintenance % |
|---|---|---|---|---|---|---|---|
| 1x1 7FA.05 w/ACC | 357 | $1,702 | 6,668 | $11.05 | $3.11 | 2.5% | 5.5% |
| 1x1 7HA.03 w/ACC | 630 | $1,103 | 6,136 | $7.31 | $2.68 | 2.5% | 5.5% |
| 2x1 7HA.03 w/ACC | 1,264 | $792 | 6,116 | $4.86 | $2.68 | 2.5% | 5.5% |
| 1x0 7HA.02 | 402 | $699 | 9,160 | $4.80 | $11.42 | 2.0% | 4.5% |
| 1x0 7FA.05 | 230 | $744 | 10,021 | $7.70 | $8.53 | 2.0% | 4.5% |
| 12x18 RICE | 220 | $1,291 | 8,335 | $9.30 | $11.14 | 2.0% | 3.0% |
| 1x LMS100 | 102 | $1,309 | 8,957 | $17.90 | $7.63 | 2.0% | 4.5% |
| 12x60 MW SMR | 683 | $5,986 | 10,900 | $95.50 | $11.65 | 1.4% | 6.7% |

Notes:
- Capacity ratings and per-unit cost depict average ambient conditions.
- Capital costs exclude costs for land, transmission interconnection, and NG interconnection.
- Fixed O&M costs exclude property taxes (or payments in lieu of taxes) and insurance.

# Renewable Resource Options

# Inflation Reduction Act
# Components Relevant to Utility-scale Renewables

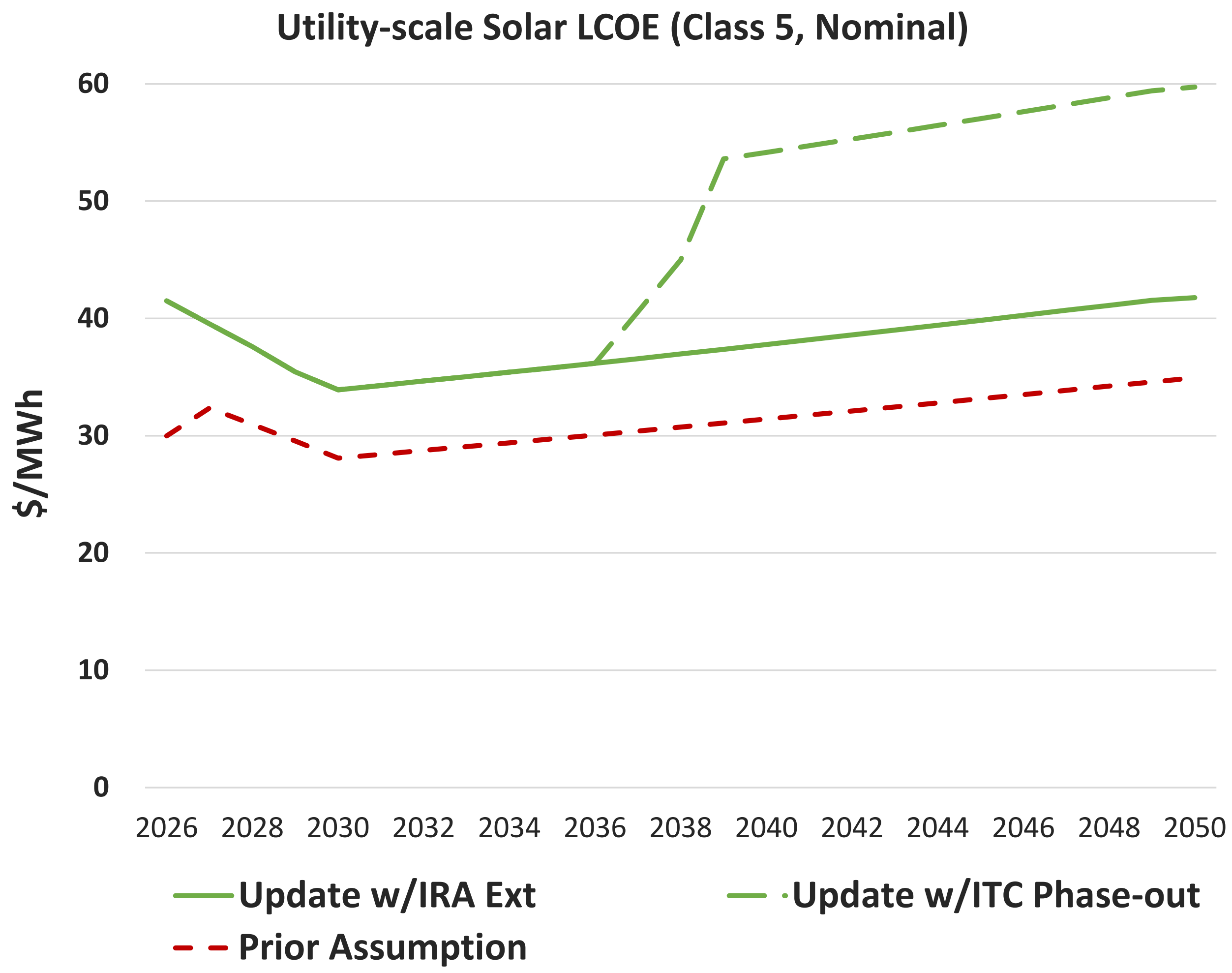
- Investment and production tax credits extended through the latter of 2033 or the year after the U.S. meets the goal of a 75% reduction in GHG emissions from 2022 levels
  - ITC is 30%; PTC is $26/MWh (subject to inflation indexing)
  - Tax credits step down to 75% for the 2nd year after 2032 or year in which GHG targets are met, decreasing to 50% in the 3rd year after, and zero in the 4th year
  - Stand-alone ITC is available for battery storage systems (does not need to be associated or co-located with other renewable installations)
  - Wage/apprenticeship requirements must be met
  - Bonus credits available for domestic content and energy communities
- Credit monetization options available (though with limitations and some uncertainty pending Treasury Dept. guidance)
- Santee Cooper's IRP will assume PPA pricing for renewable resources that incorporates an ITC consistent with the IRA, <u>extended through the end of IRP study period</u>

# Renewable PPA Pricing

- Recently, renewable PPA pricing has moved higher, driven by a combination of factors
  - Import restrictions
  - Equipment cost escalation (both industry-specific and general inflation)
  - Higher interest rates
- Updates to Renewable PPA Pricing Assumptions
  - NREL Annual Technology Baseline (ATB) update for 2022 (released June 2022)
  - Significantly higher inflation over 2021-2022
  - Currently higher capital costs for solar and batteries (15% higher)
    - Based on NREL's 2022Q1 Solar and Storage Cost Benchmark (released September 2022)
    - For IRP, higher costs are assumed to abate over the next several years (declining to no increase by 2029)
  - Higher interest rates based on trend in Treasury rates (assumed to impact both cost of debt and return on equity)
  - Refinements to the use and interpretation of NREL ATB model and assumptions based on consultation with NREL staff
  - Impacts of the Inflation Reduction Act

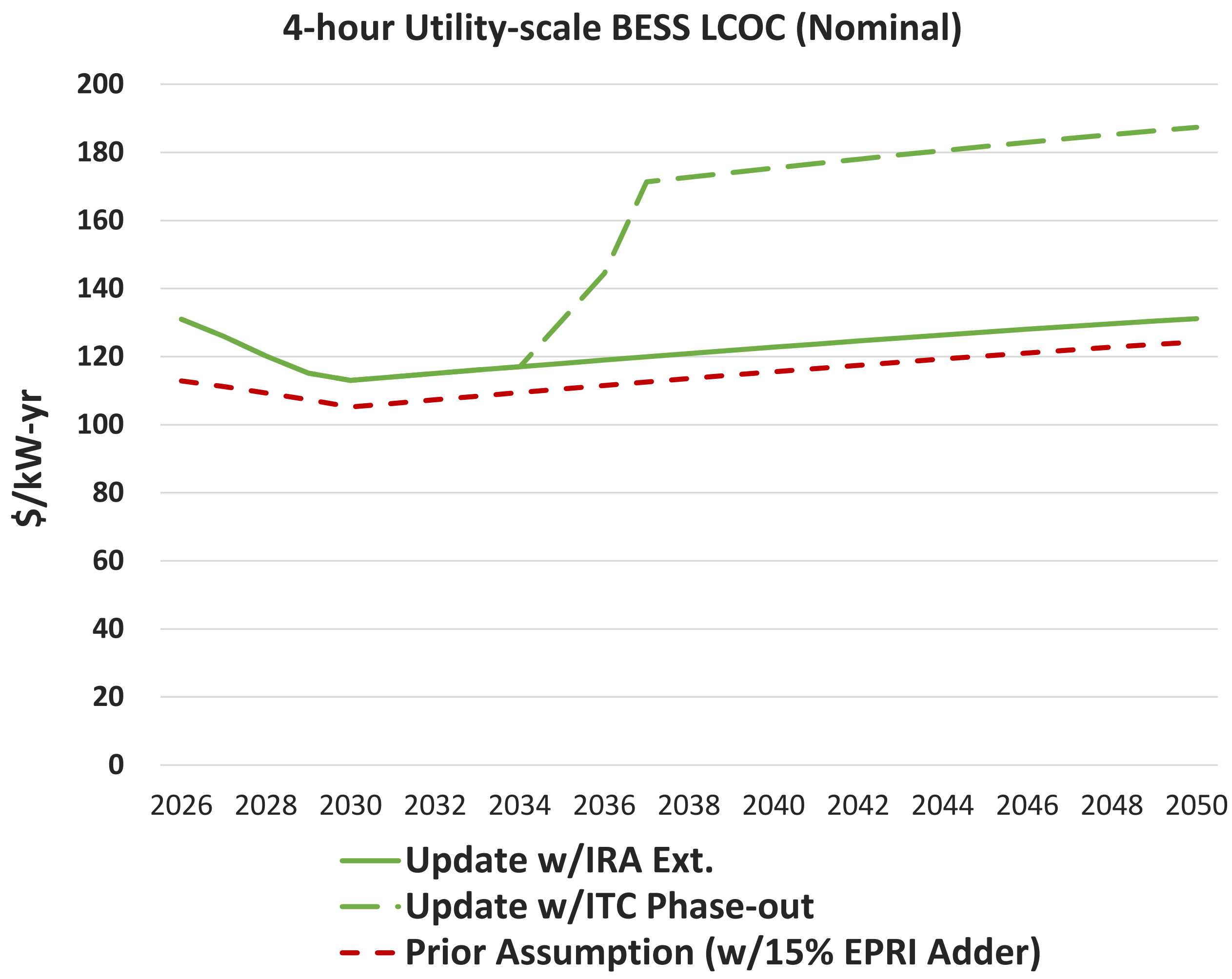
# New Solar Resources

- Utility-scale solar PV resources modeled as PPA resource options
  - PPA energy rate based on average LCOE
  - Class 5 solar irradiance (primarily southern portion of SC)
- Technology cost trend
  - NREL ATB Moderate Case for capital and O&M costs
  - Assume 30-year technology life
- Develop diversified production profiles based on NREL System Advisor Model (SAM)
- Model ELCC and cost of integration based on Astrapé studies



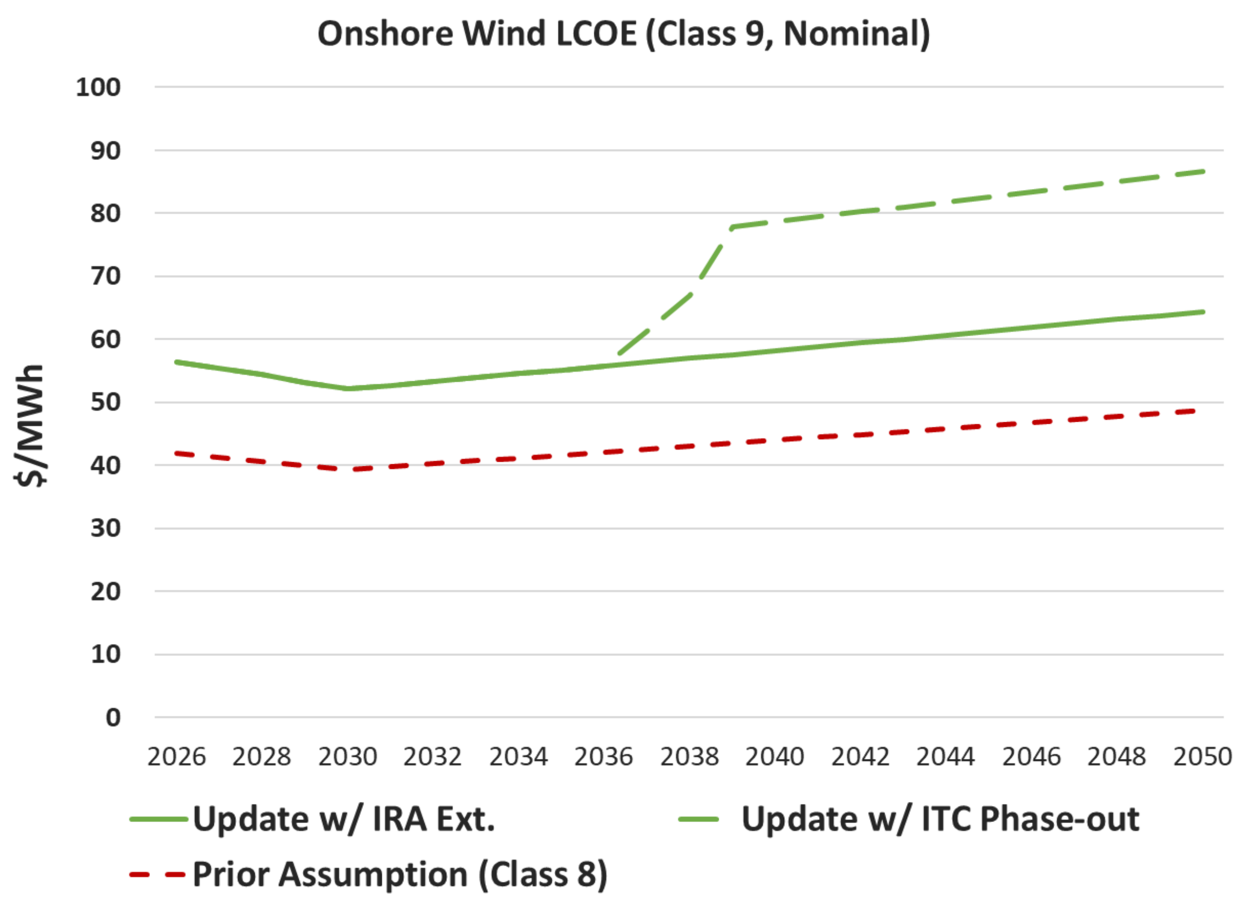
# Battery Energy Storage System

- BESS resources modeled as PPA resource options
  - Assume 30% ITC
  - PPA pricing based on LCOC
  - Charging and discharging modeled as a system energy cost/value
- Technology cost trend
  - NREL ATB Moderate Case for capital and O&M costs
  - Assume 20-year technology life
- Industry standard technical operating characteristics
- Model ELCC based on Astrapé studies
- IRP will include options covering multiple BESS durations



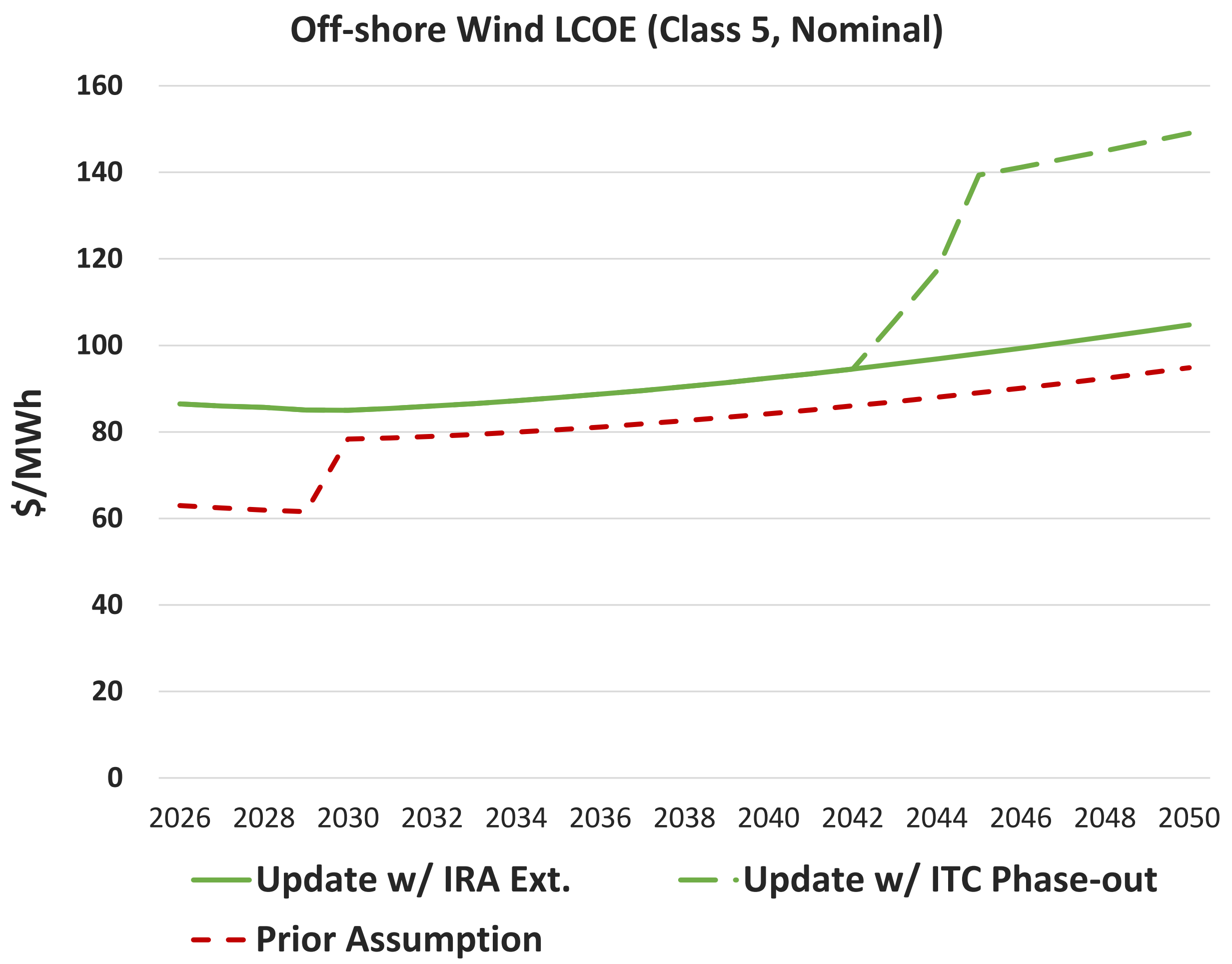
# Onshore Wind Resource Option

- Onshore wind resources modeled as PPA resource options
  - Assume 30% ITC
  - PPA energy rate to be based on LCOE
  - Class 9 wind resource
- Technology cost trend
  - NREL ATB Moderate Case for capital and O&M costs
  - Assume 30-year technology life
- Production profiles derived from NREL's System Advisor Model (SAM)
- ELCC and cost of integration derived from prior Duke and DESC IRP filings and other industry sources



# Off-shore Wind Resource Option

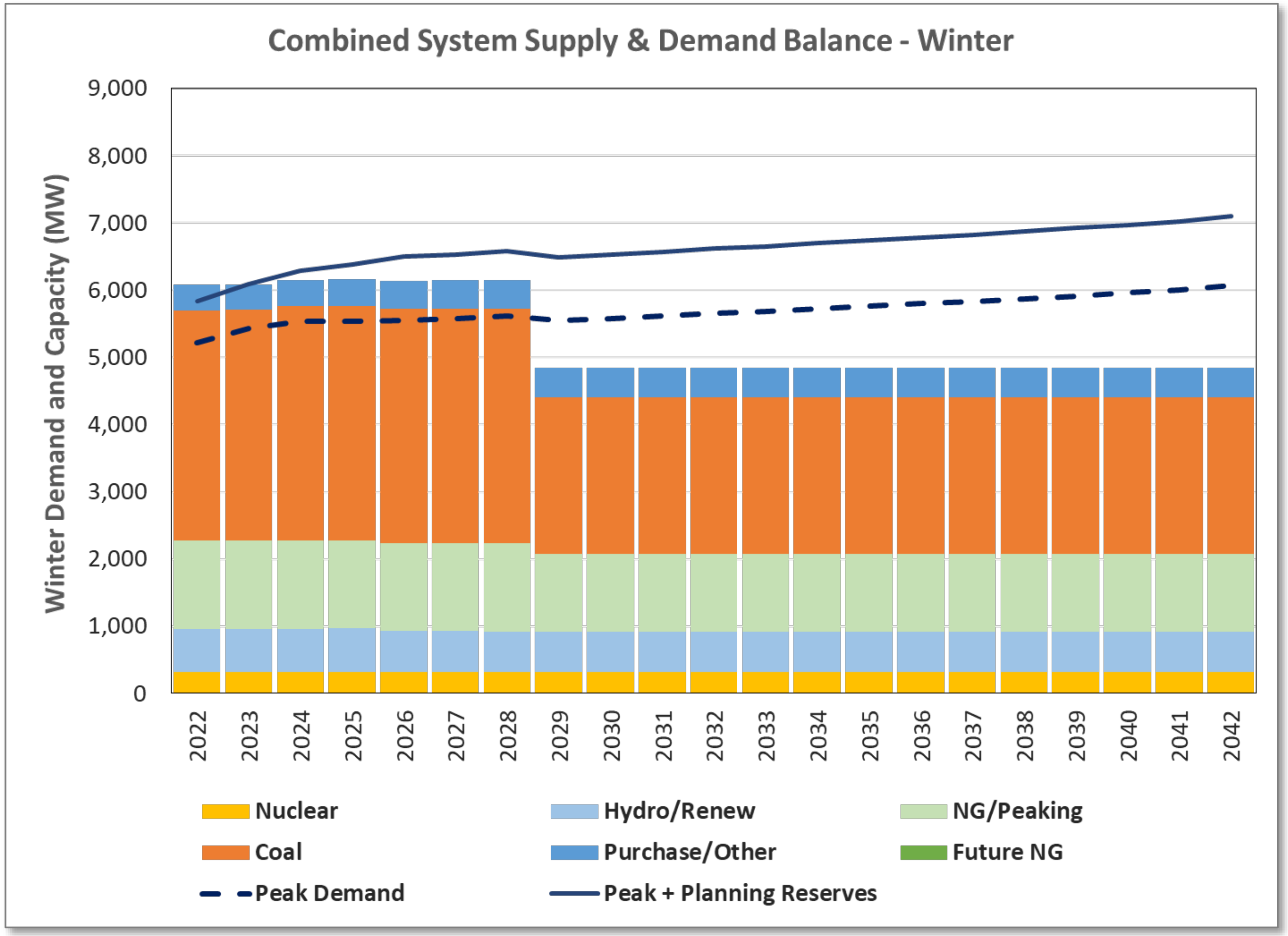
- Wind resource options modeled in portfolio optimization
- Model as PPA resource
  - Capture ITC
  - PPA energy rate based on average LCOE over multi-year tranches
- Technology cost assumptions
  - NREL ATB Moderate Case for capital and O&M costs
  - Assume 30-year technology life
- Production profiles derived from NREL's System Advisor Model (SAM) for onshore coastal wind, adjusted to reflect higher off-shore production levels
- ELCC and cost of integration to be derived from prior Duke and DESC IRP filings and other industry sources



# Resource Portfolios

# Santee Cooper Resource Need

- Santee Cooper needs approximately 1,650 MW of firm capacity by 2029 to accommodate load growth, planning reserves, and the retirement of the Winyah Generating Station and Hilton Head and Myrtle Beach combustion turbines
- Assumes achieving a 17% planning reserve margin by 2026
- Portfolio optimization evaluations will consider short-term PPA and renewable resource options through 2028
- Longer-term resource additions will be evaluated under multiple portfolio scenarios



# Resource Portfolios to be Studied

## Economically optimized resource plan

- Consider all resource options

## Future coal retirements

- Assess earliest practical retirement of Cross
- Assess potential for avoided ELG costs

## Environmentally constrained

- Earliest practical retirement of coal resources
- No new fossil generation additions

## Net-zero CO2 by 2050

- Targeted CO2 emissions (mass) reductions
- Achieve 70% reduction from 2005 levels by 2030
- Allow for CO2 offsets

*The results of the portfolio analyses, along with sensitivity and risk analyses, will guide Santee Cooper toward a Preferred Portfolio*

# Initial Learnings

**Directional results reflect initial, simplified portfolio optimization analyses. Additional, refined portfolio modeling and analysis will likely produce different results. Analysis of portfolio strategies will be further evaluated for sensitivity and risk considerations to help inform the Santee Cooper's preferred portfolio.**

*Portfolio model testing indicates the following*

- Economically Optimized portfolio
  - 2x1 CC, frame CT, and solar installed to meet capacity and energy needs created by the retirement of Winyah
  - Additional solar, onshore wind, and BESS installed through the planning horizon
- Future Coal Retirement portfolio
  - CCs, CTs, solar, onshore wind, and BESS installed to meet capacity and energy needs created by the retirement of Winyah of Cross Generating Station and through the planning horizon
- Environmentally Constrained portfolio
  - Solar, onshore wind, and BESS installed through planning horizon

# Next Steps for Portfolio Evaluations

- Updates for EE and DR market potential studies
- Ongoing review and possible adjustments to major assumptions
- Refinement of optimum portfolios
  - Consideration of offshore wind and SMR resources
  - Assessment of system reliability
  - Need for additional operating reserves and fast response resources
- Evaluation of net-zero $CO_2$ portfolio
- Evaluation of portfolios for sensitivity assumptions and risk considerations

# Next Steps for IRP Process

**Meeting #1**

**March 1, 2022**

Stakeholder Process & Santee Cooper Resource Planning

**Meeting #2**

**April 29, 2022**

Resource Need, Resource Options, Evaluation Approach, Major Assumptions, Additional Studies

**Meeting #3**

**June 28, 2022**

Review of Load and DSM Forecasts, Supporting Studies, Transmission System, Major Assumptions, and Portfolio Analysis

**Meeting #4**

**December 8, 2022**

Load Forecast Review, DSM Market Potential Study, Solar Integration Study Results, Updates to Major Assumptions

**Meeting #5**

**[TBD]**

IRP Final Results

**IRP Filing with Commission**
May 15, 2023

# Closing

**Stewart Ramsay**
Meeting Facilitator
VANRY Associates

# In closing…

**Any questions we haven't answered today?**

- Comments can be provided:
  - IRP Stakeholder Forum - provide comments, feedback, and post documents at www.santeecooper.com/IRP
  - stewart@vanry.com - for thoughts and input on meeting structure and engagement
- Meeting summaries and other materials will be posted and made available at www.santeecooper.com/IRP

# Thank you!

We would like to hear from you about your experience at this session.

**Please complete our survey**
**that will appear in your browser as you leave the meeting**

# Appendix

# Acronyms

- AEO: Annual Energy Outlook
- AGC: automatic generation control
- AMEA: Alabama Municipal Electric Authority
- ASAI: Average substation availability index
- ATB: annual technology baseline
- BE: beneficial electrification
- BESS: battery energy storage systems
- BEV: battery electric vehicle
- CAGR: compound annual growth rate
- CC: combined cycle
- CDD: cooling degree day
- CME: Chicago Mercantile Exchange
- CO2: carbon dioxide
- Co-op: electric cooperative
- CT: combustion turbine
- DEC: Duke Energy Carolinas
- DER: distributed energy resources
- DERMS: distributed energy resource management system
- DESC: Dominion Energy South Carolina
- DG: distributed generation
- DOE: Department of Energy
- DR: demand response
- DSM: demand-side management
- EE: energy efficiency
- EIA: Energy Information Administration
- ELCC: effective load carrying capability
- ELG: effluent limitation guidelines
- EPA: Environmental Protection Agency
- EPRI: Electric Power Research Institute
- EV: electric vehicle
- GADS: Generating Availability Data System
- GHG: greenhouse gas
- GOFER: Give Oil for Energy Recovery
- GWh: gigawatt-hour
- HDD: heating degree day
- HH: household
- IC: internal combustion (engine)
- IRA: Inflation Reduction Act
- IRP: integrated resource plan
- ITC: investment tax credit
- kV: kilovolt
- kW: kilowatt
- kWh: kilowatt-hour
- LCOE: levelized cost of energy
- LCOC: levelized cost of capacity
- LED: light-emitting diode
- LF: load forecast
- LFE: load forecast error
- LFG: landfill gas
- LOLE: loss of load expectation
- mgd: millions of gallons per day
- MMBtu: 1 million British thermal unit
- MPS: market potential study
- MW: megawatt
- MWh: megawatt-hour
- NERC: North American Electric Reliability Corporation
- NG: natural gas
- NGCC: natural gas combined cycle
- NOAA: National Oceanic and Atmospheric Administration
- NREL: National Renewable Energy Laboratory
- NUC: nuclear (resource)
- NYMEX: New York Mercantile Exchange
- O&M: operations and maintenance
- PMPA: Piedmont Municipal Power Agency
- PPA: power purchase agreement
- PRM: planning reserve margin
- PSC: Public Service Commission
- PSR: Proposed Shared Resource
- PCT: production tax credit
- PV: photovoltaic
- PVRR: present value revenue requirement
- QF: qualifying facility
- RECS: Residential Energy Consumption Survey
- RICE: reciprocating Internal Combustion Engine
- RFI: request for information
- RFP: request for proposals
- RNG: renewable natural gas
- SAIDI: system average interruption duration index
- SAE: statistically adjusted end-use model
- SAM: System Advisor Model
- SEPA: Southeastern Power Administration
- SERVM: Strategic Energy & Risk Valuation Model
- SME: subject matter expert
- SMR: small modular reactor (nuclear reactor)
- ST: steam turbine
- TEA: The Energy Authority
- TRC: total resource cost (test)
- UCT: utility cost test
- V2G: vehicle to grid