Item#2024-114

GRU Electric Integrated Resource Plan (IRP) PART 2 Executive Summary

Outline

Part I: Background

Part: II: Preliminary IRP Results

- Summary of Scenarios and Sensitivities
- Transmission, Solar, and Battery Considerations
- Baseline Scenario Results
- Comparison of Results for Scenarios and Sensitivities
- Summary of Results
- Additional Sensitivities and Stress Tests
- Summary of Recent IRP Results from Other Utilities
- Next Steps

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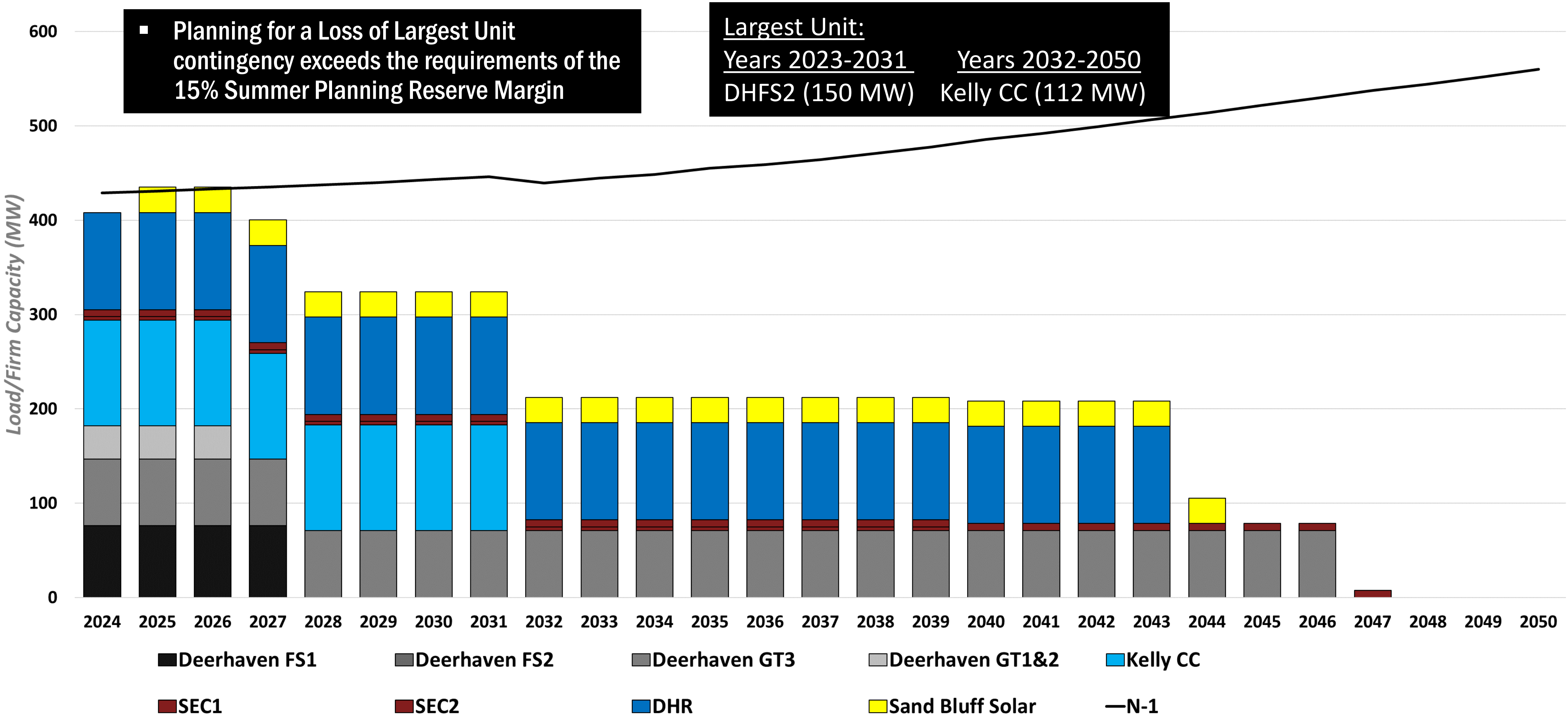
- Baseline Scenario – Model inputs based on most likely anticipated future based on industry forecasts
- 7 scenarios and sensitivities evaluate effects of variations in economic conditions, load growth, fuel pricing
- 2 sensitivities evaluate potential benefit of extending life of Deerhaven Steam Turbine 2 (DHFS2)
- 9 additional sensitivities and stress tests

Peak Load and Capacity (N-1 Requirement) – No Resource Additions



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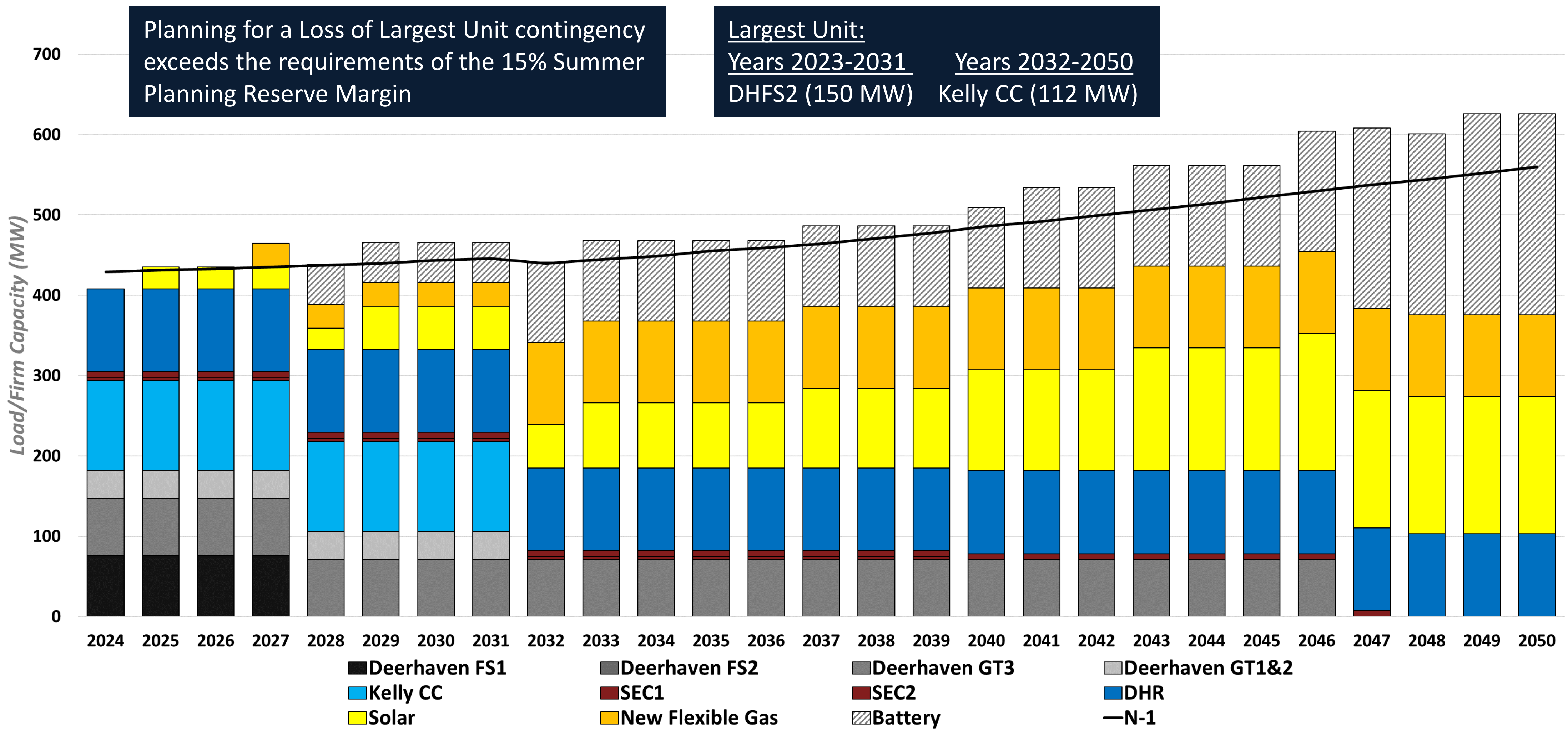

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Planning for a Loss of Largest Unit contingency exceeds the requirements of the 15% Summer Planning Reserve Margin

Largest Unit:

Years 2023-2031	Year 2032
DHFS2 (150 MW)	Kelly CC (112 MW)

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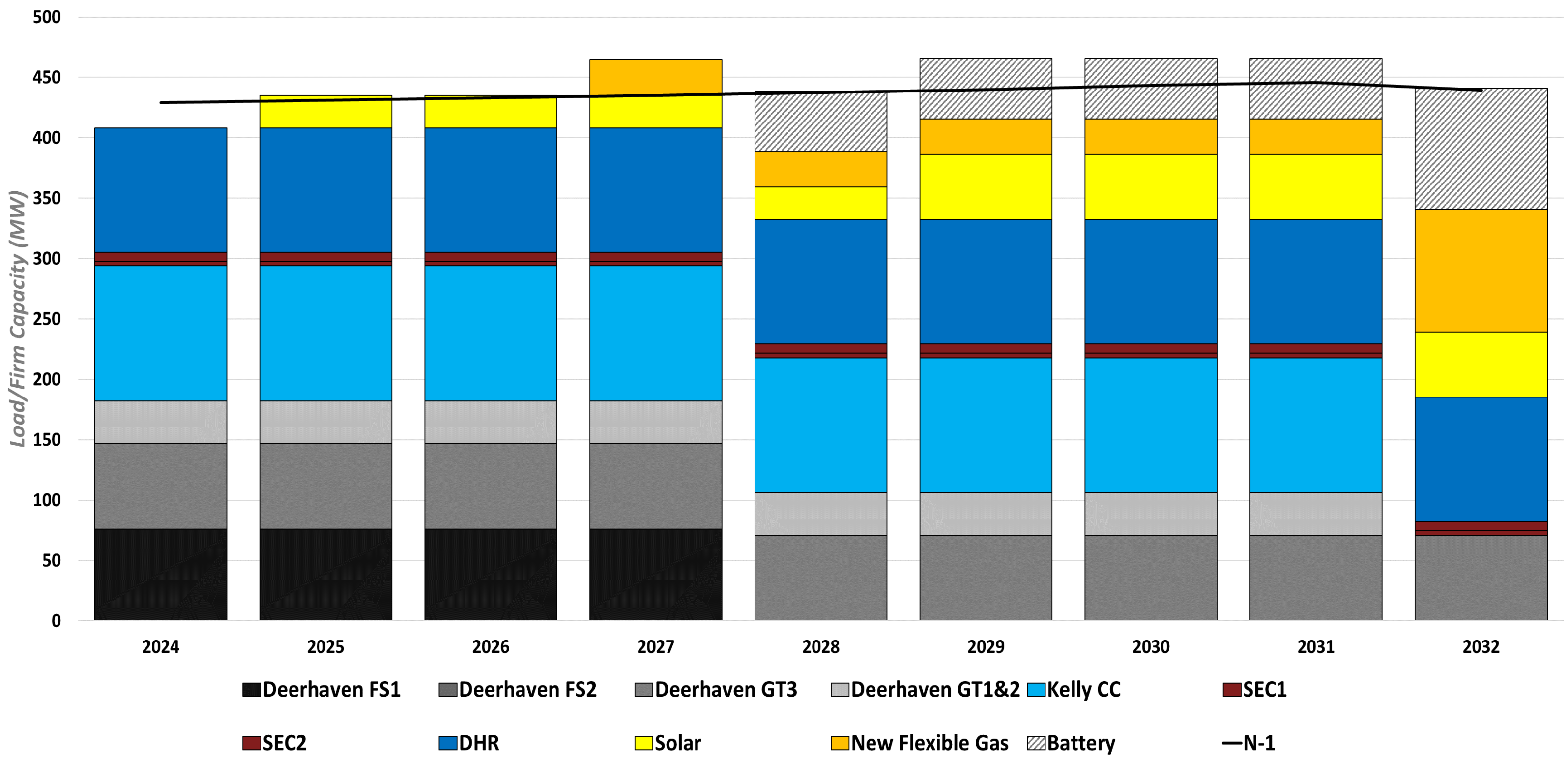

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Building Customer Trust
Infrastructure Reliability

Additional Sensitivities and Stress Tests

1. Does utility-scale solar reduce overall cost?
   - No solar
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2. Would it be cheaper to rely on market power purchases and not build new GRU units?
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3. What would be the impacts of imposing environmental constraints?
   - 2018 resolution net-zero carbon emissions by 2045
   - Carbon tax (based on stakeholder request)
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Comparison of Preliminary Results

	Resource Plan Cost			Capacity Added as of 2050 (MW)					
Scenario / Sensitivity	Net Present Value (Millions $)	Difference from Baseline (Millions $)	Difference from Baseline (percent)	Total (MW)	Solar	Natural Gas	Small Modular Reactor	Firm Capacity	Battery Storage
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Summary of Recent IRP Results from other Utilities

- Electric utilities of varying sizes have resource plans with some combination of the following:
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Approximate Planned Resource Changes by 2030

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GRU Baseline (Prelim.)	410	111	30	150	37%

**Operating Standby*

Summary of Results

- All scenarios and sensitivities call for mix of solar, batteries, and flexible natural gas-fired resources – unless intentionally excluded
  - No solar and Market Reliance sensitivities do not allow PLEXOS to pick solar
- Delayed retirements may reduce lifecycle cost and defer capital expenditures
  - Deerhaven CT1 and CT2
  - Deerhaven 2 (DHFS2) – *requires further engineering evaluation*
- Market Reliance on import power results in higher cost
- Additional capacity needed within 3-4 years
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Next Steps

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  - Develop Internally
  - January - March
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Thank you!

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CONTACT US

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Appendix

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Transmission Considerations

- Current firm import capability
  - 75 MW Summer
  - Up to 200 MW beginning 2028
- Can be utilized to import solar energy or other purchased power
- Additional import capability requires transmission upgrade
  - +200 MW additional capacity (400 MW total)
  - Estimated cost of $131M NPV (2023 dollars)
  - Modeled as an option in all scenarios and sensitivities

Solar Integration Considerations

- Firm capacity required in conjunction with solar
  - 1:2 ratio of Firm capacity to Solar PV
  - Firm capacity options include thermal generation and batteries
- Contribution of Solar PV rated capacity available to meet peak demand
  - 36% Summer; 0% Winter
- Solar PV additions limited to 75MW
- Must be at least 4 years apart for Tier 1 (Local)
  - 1 year to familiarize use of increasing inverter-based resources (i.e. Solar PV and Battery Storage)
  - 3 years for ACE study/RFP process/permitting/construction
- Must be at least 3 years apart for Tier 2 (Imported)

Solar Integration Timeline Capability

Resource Location	Incremental Cost	Year Ranges Solar Can be Added	Maximum Incremental Nameplate Capacity Added (MW)	Maximum Cumulative Nameplate Capacity (MW)
Local (Tier 1)	PPA Cost	2025-2028 (Sand Bluff) 2029-2032 2033-2036 2037+	75 75 75 50	75 150 225 275
External (Tier 2)	PPA Cost + Wheeling Cost	2040-2042 2043-2045 2046+	75 75 50	350 425 475
External (Tier 3)	PPA Cost + Wheeling Cost + Transmission Upgrade Cost ($131M in 2023$)	2049+	75	550

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- **Battery storage additions limited to 50 MW every 3 years until 2033**
  - **Integration of inverter-based resource**
  - **Battery technology expected to advance in 10-year horizon**

Resource Location	Incremental Cost	Year Ranges	Maximum Incremental Nameplate Capacity Added (MW)	Maximum Cumulative Nameplate Capacity (MW)
Local	PPA Cost	2027-2029	50	50
Local	PPA Cost	2030-2032	50	100
Local	PPA Cost	2033+	No Limit	No Limit

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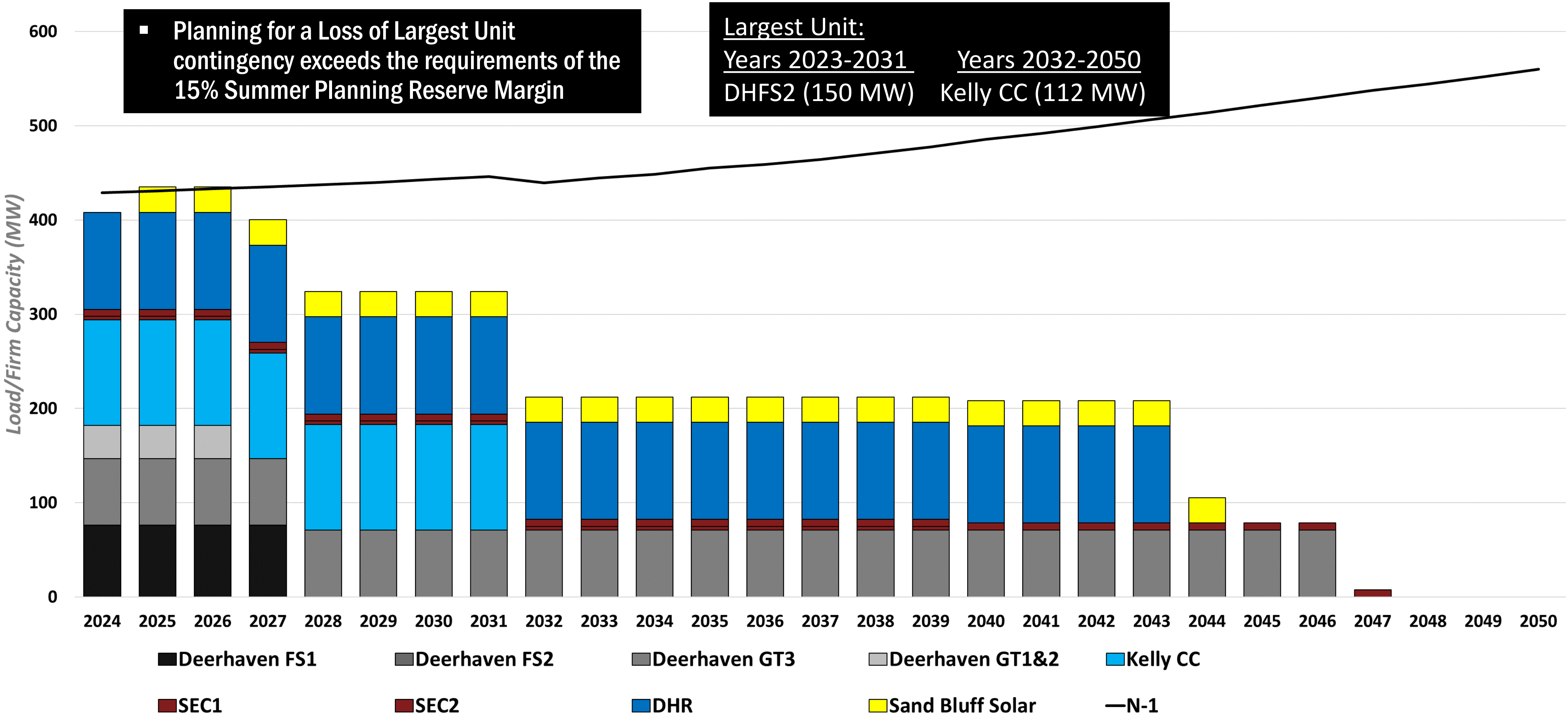

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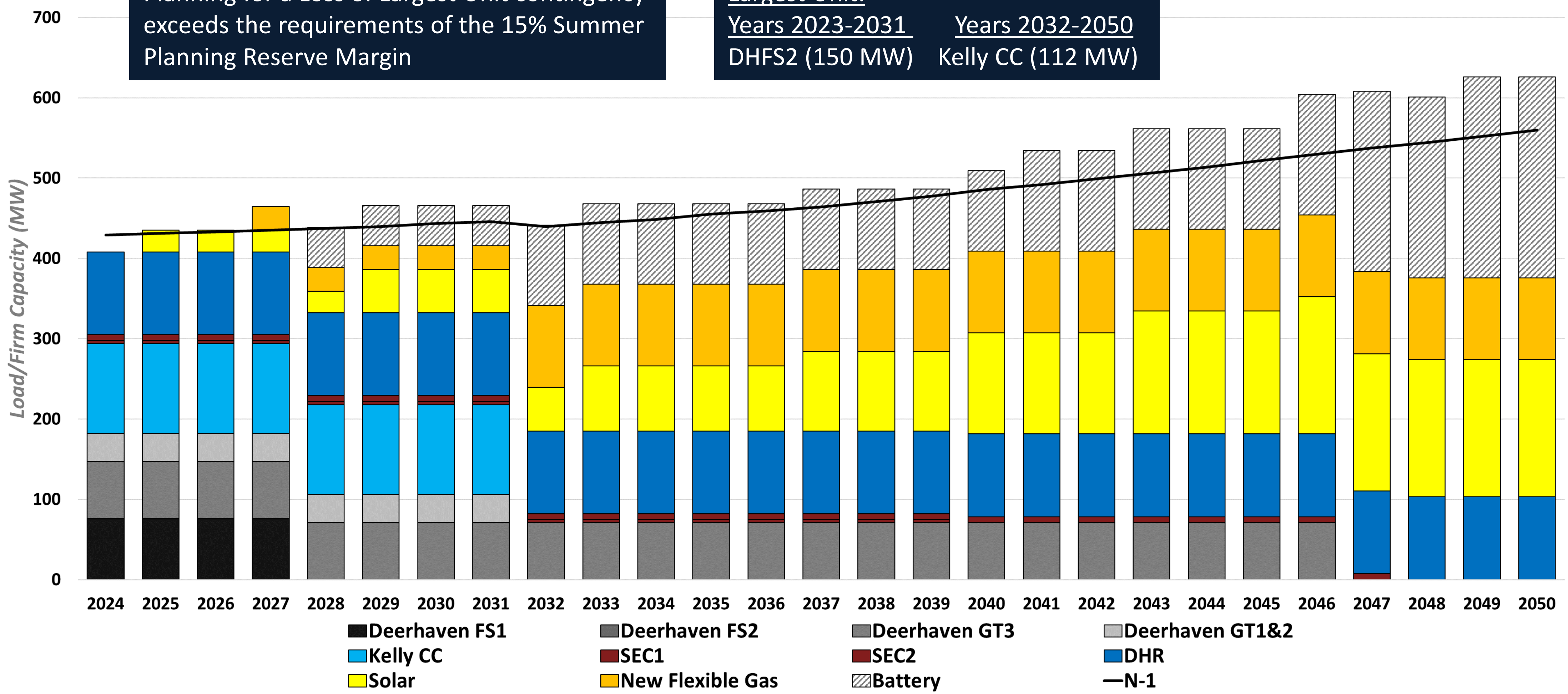

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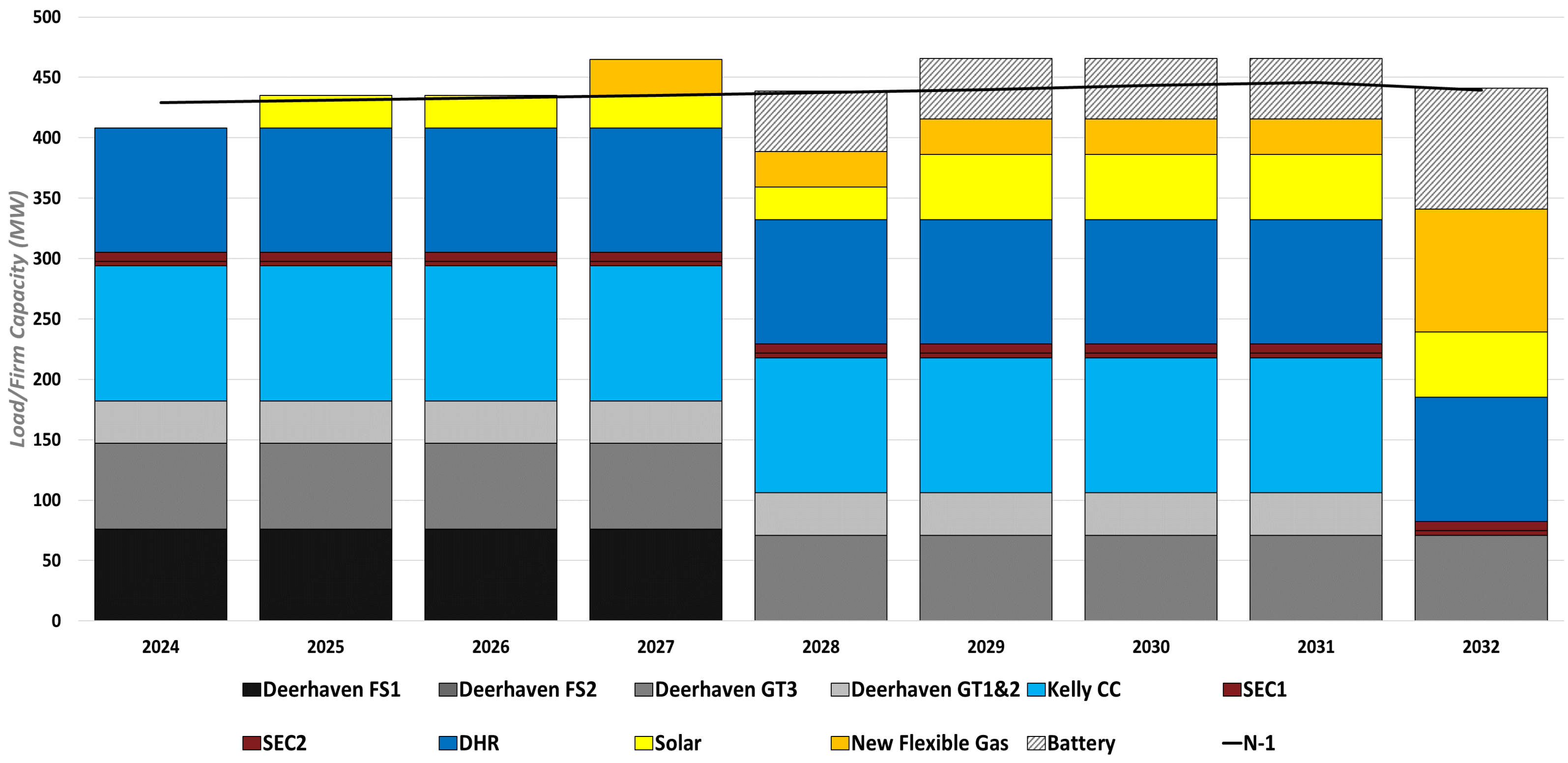

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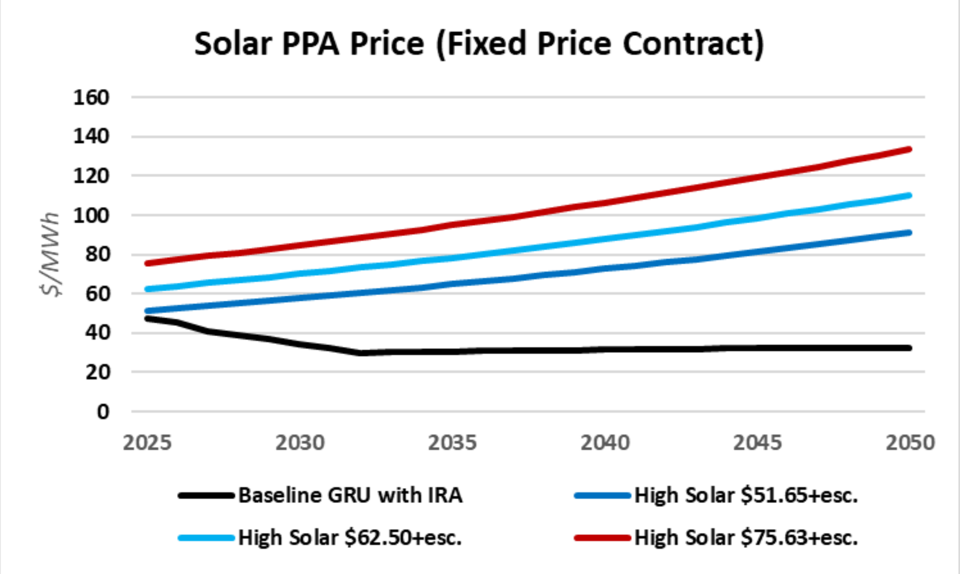
No Solar Sensitivity

- Objective: Determine impacts of eliminating all utility-scale solar on lifecycle NPV cost
- Model constrained to not allow any solar addition
- Includes removing Sand Bluff solar farm
- Result
  - No Solar increases NPV by $320M

High Solar Price Sensitivity

- Objective: Determine the impact if future solar prices are higher than expected
- 3 sensitivities evaluated in addition to baseline

Scenario	Modeled 2025 Price $/MWh	PLEXOS Result Tier 1 MW	PLEXOS Result Tier 2 MW
Baseline	$47.35	275	200
A	$51.65	275	25
B	$62.50	275	0
C	$75.63	0	0



- Sand Bluff cost $40.56/MWh
- Result: Utility scale solar price would have to increase substantially before model chooses different resources

Market Reliance Sensitivity

- Objective: Evaluate cost impact of Market Reliance
- Retirements of existing generating units over same timeline as Baseline
- No new GRU generating units
- No new GRU solar PPA projects
- Resource needs met by firm capacity PPAs (5 yr term)
- Transmission upgrade required $131M (2023 $)

Reduced Capacity Pricing PPA Sensitivity

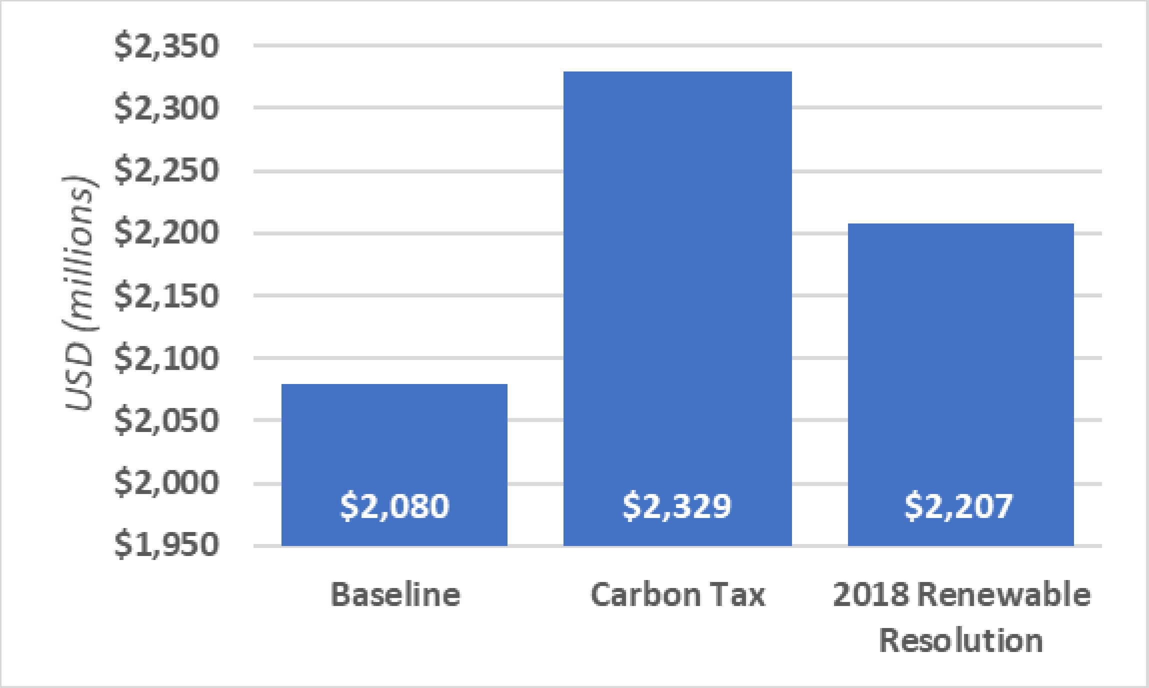
- Objective: Determine if reducing the capacity PPA price would make Capacity PPA a preferred resource
- Capacity PPA Option Selected in Only 2 Sensitivities:
  - High Natural Gas Price
  - Market Reliance – No New GRU Generation
- For Reduced Capacity Pricing Sensitivity the Capacity PPA price was reduced from \$6.50/kW-mo (Baseline) to \$2.50/kW-mo (well below current market)
- Result: No change to the lowest cost resource portfolio from the Baseline Scenario

Market Reliance Sensitivity (continued)

- Firm Capacity PPA pricing based on:
  - $6.50/kW-month capacity charge (2023 $)
  - Natural gas-fired combined cycle unit with 7 MMBtu/MWh heat rate and $1.50 variable O&M (2023 $)
  - Delivered natural gas price (FGTZ3+usage+fuel) + $0.55 adder (2023 $)
  - $2.67/kW-month wheeling rate
- Result
  - Market Reliance increases NPV by $380M

Impacts of Imposing Environmental Constraints

- Carbon Tax Sensitivity increases NPV $249M but does not change the resource plan from Baseline
- Most scenarios/sensitivities reduce CO_2 emissions from 2005 levels by more than 75% (Baseline reduction is 85%)
- Reduction of CO_2 emissions to "net zero" by 2045 increases NPV by $127M



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Next Steps

- Develop preferred resource plan that will mitigate risks across multiple futures and fit within debt defeasance plan
  - Addition of mix of efficient natural gas, solar and batteries
- Long Term: Evaluate remaining life of Deerhaven Unit 2 (DHFS2)
  - DHFS2 set to retire in 2032
  - May defer resource additions that are after 2032

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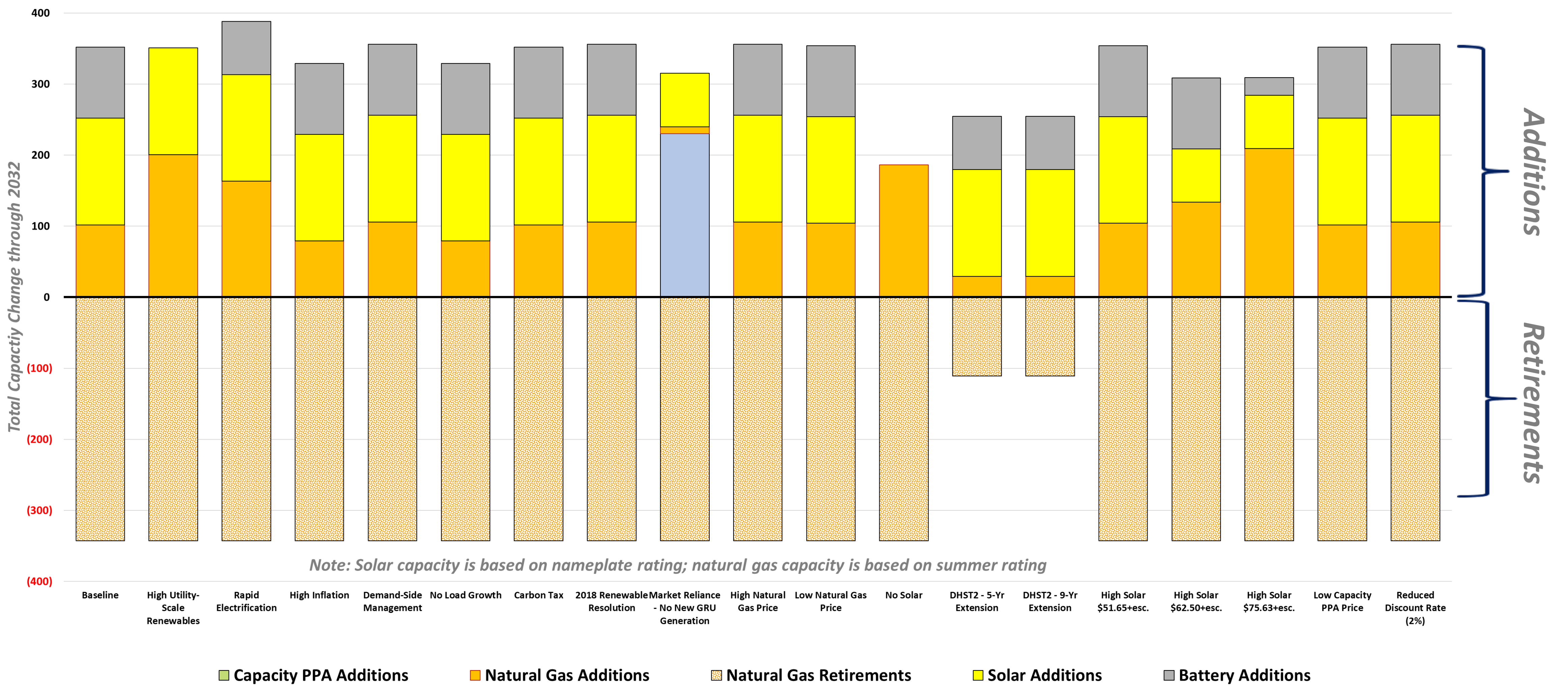
2032 Comparison of Resource Additions and Retirements for All Scenarios and Sensitivities



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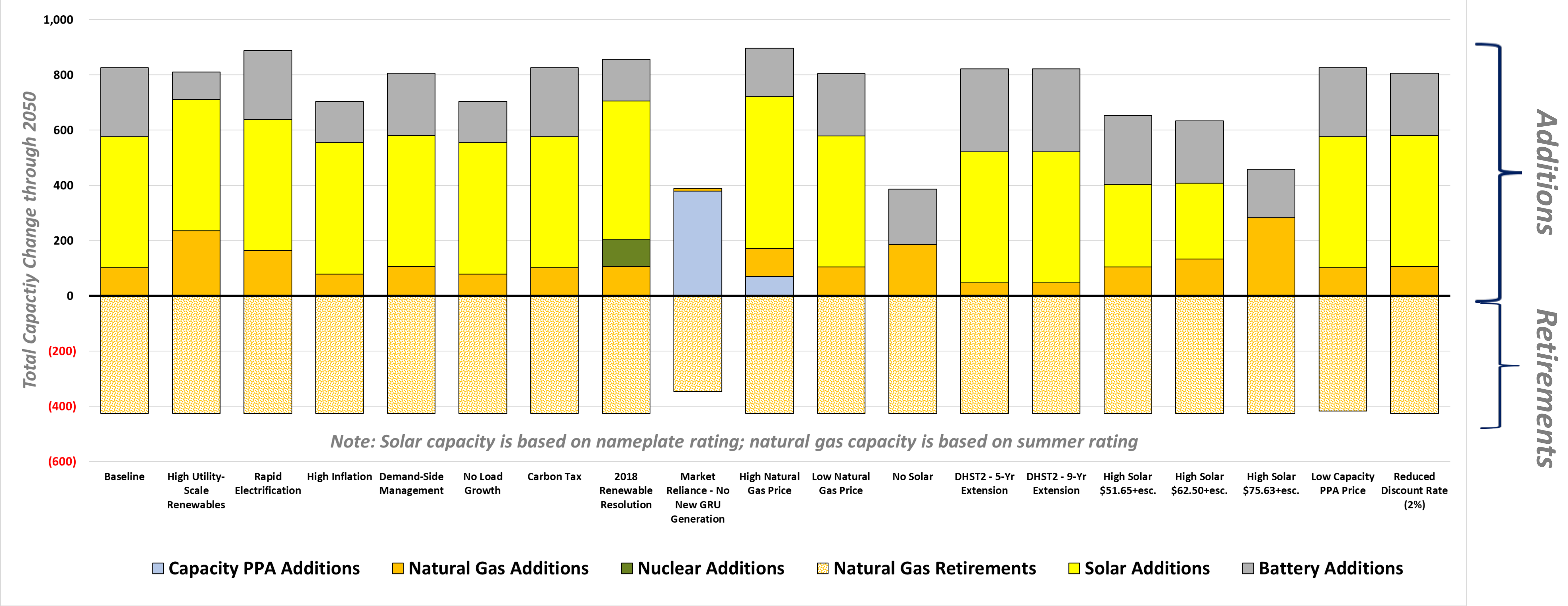
2050 Comparison of Resource Additions and Retirements for All Scenarios and Sensitivities



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