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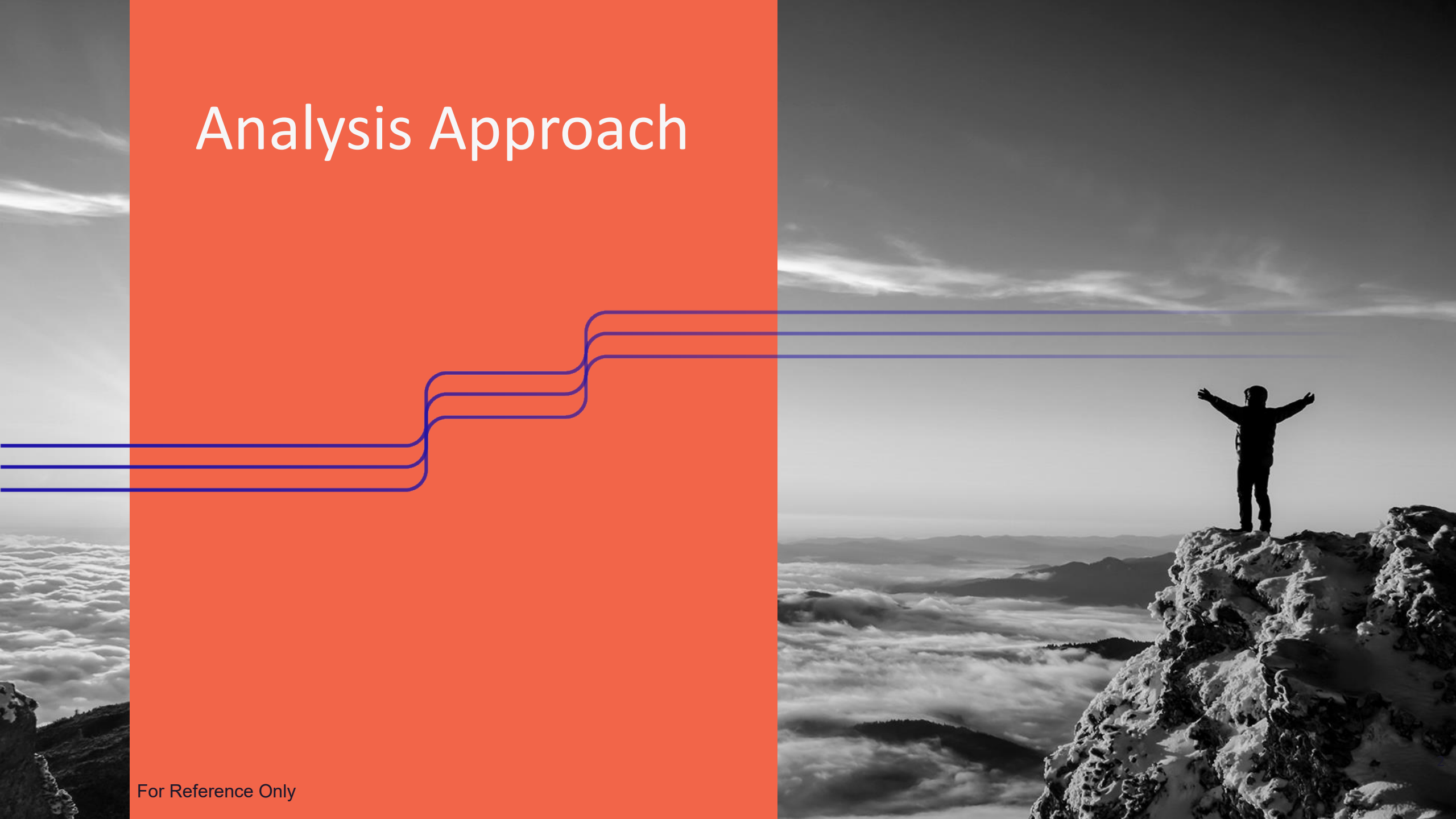
2022 Idaho Power DR Potential Study — For Reference Only

Date: 11/03/2022
Prepared for: Idaho Power

Analysis Approach



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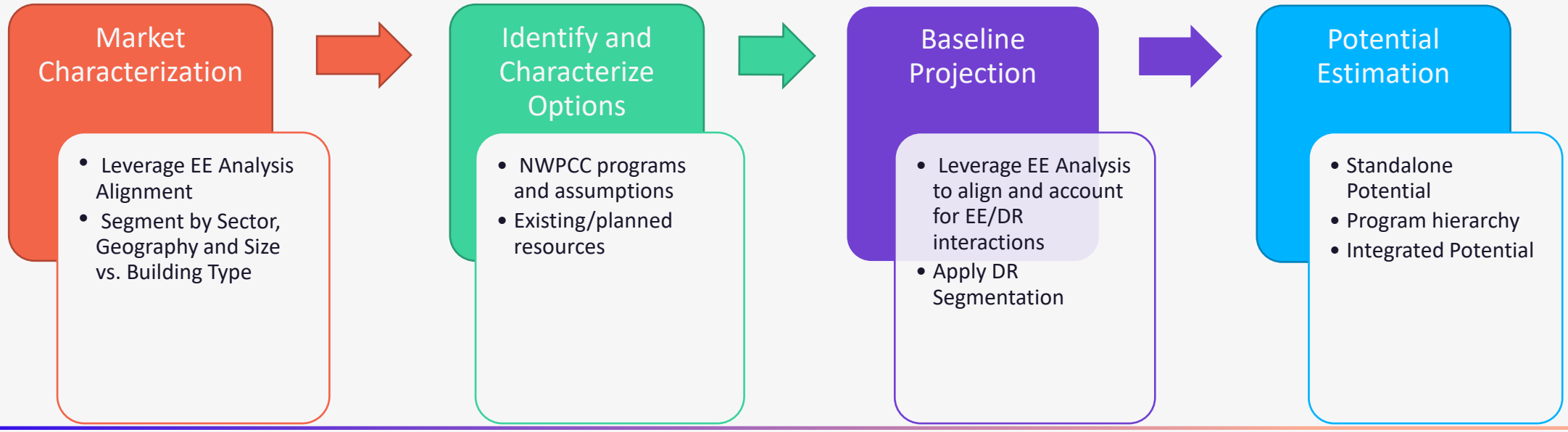
DR and DSR Potential Approach

- General methodology for estimating DR and DSR potential is similar to energy efficiency
- Key difference is that DR and DSR offerings do not exist outside of a programmatic structure i.e., there is no naturally occurring DR



Program Options and Characterization

Residential	Commercial	Industrial/Irrigation
Residential Critical Peak Pricing (CPP)	Commercial Critical Peak Pricing	Industrial Critical Peak Pricing
Residential Time of Use (TOU)	Small Commercial Bring-Your-Own-Thermostat (BYOT)	Industrial Real Time Pricing (RTP)
Residential Electric Vehicle Supply Equipment Control	Commercial Curtailable Load	Industrial Curtailable Load
Residential Electric Resistance Water Heater Control Grid and Switch	Commercial Small Building Control Switch Cool and Heat	Irrigation Control Large and Small/Medium Farms
Residential Heat Pump Water Heater Control Grid and Switch	Commercial Medium Building Control Switch Cool and Heat	Thermal Storage
Residential AC and Heat Control Switch	Battery Storage	
Residential Bring-Your-Own-Thermostat (BYOT)	Thermal Storage	
Battery Storage		

Data Sources/Collection

- **The Council's 2021 Power Plan demand response resource assumptions**
  - Updated for Idaho Power's territory and existing/planned program options
- **The 2022 EE Potential Assessment**
  - Market characterization informed C&I segmentation by size for DR analysis
  - Used peak demand potential forecast estimated in EE study as the baseline for the DR potential model
    - DR potential is incremental to peak demand reductions due to increased equipment efficiency
    - Compared to Idaho Power's peak demand forecast

Potential Assessment Results

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Key Assumptions

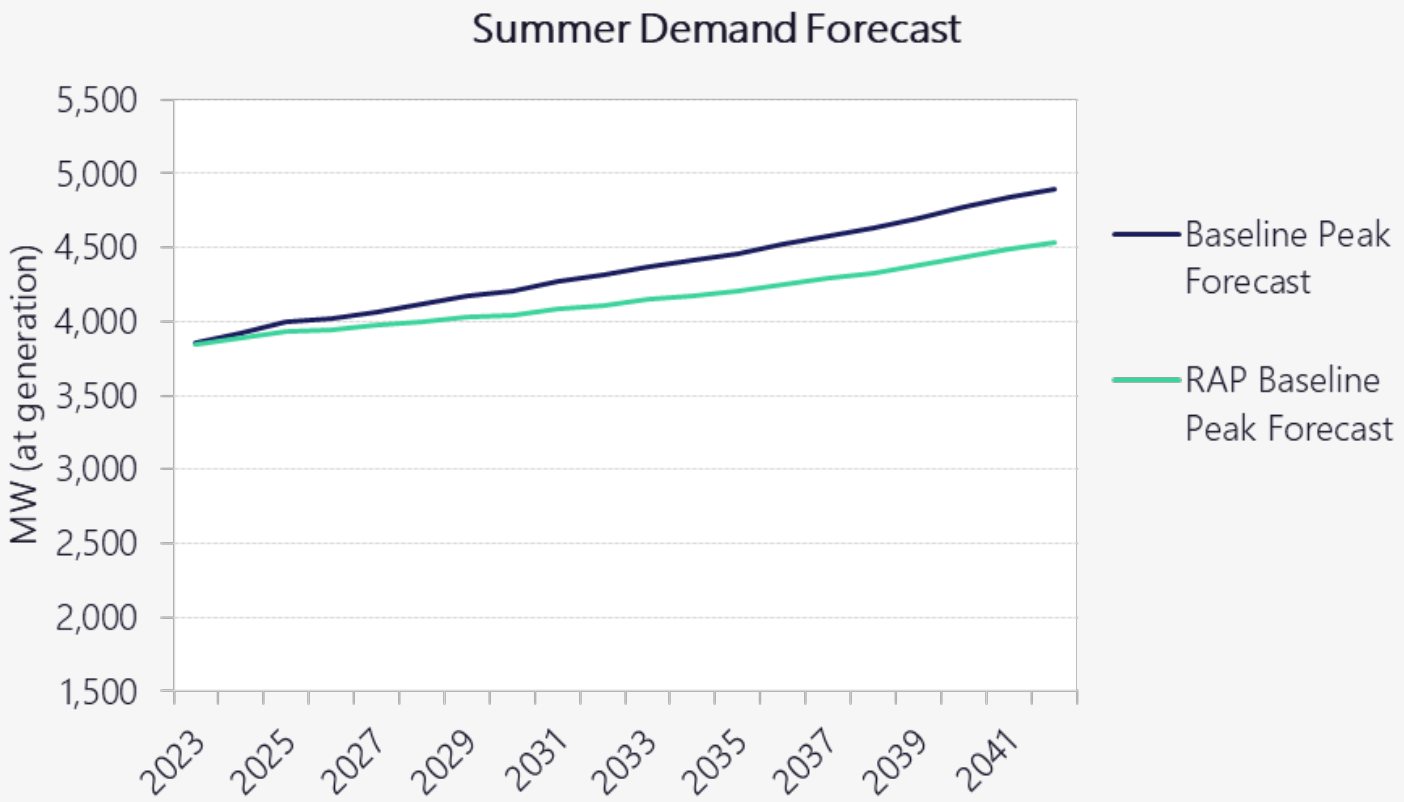
- **Program options have not been screened for cost-effectiveness**
- **Used a hierarchy to prioritize competing resources**
  - Prioritized existing programs over new/unplanned resources
  - Prioritized firm resources over less-firm resources (i.e., DR over DSR)
  - Assumed that customers cannot participate in DLCs and DSR
  - Allowed cross-participation between DLCs that target different/separately metered end uses, e.g., Smart Thermostats and EV DLC
- **Potential is cumulative, i.e., still includes existing/planned resources from AC Cool Credit, Flex Peak, and Irrigation Peak Rewards**
  - These impacts will be removed at the end to estimate incremental potential

Baseline Projection

The baseline projection aligned with Idaho Power's system peak demand forecast (blue) and then accounted for peak demand reductions from energy efficiency adoptions (green).

Used the peak demand potential forecast from the Realistic Achievable Potential scenario as the final baseline for the DR study.

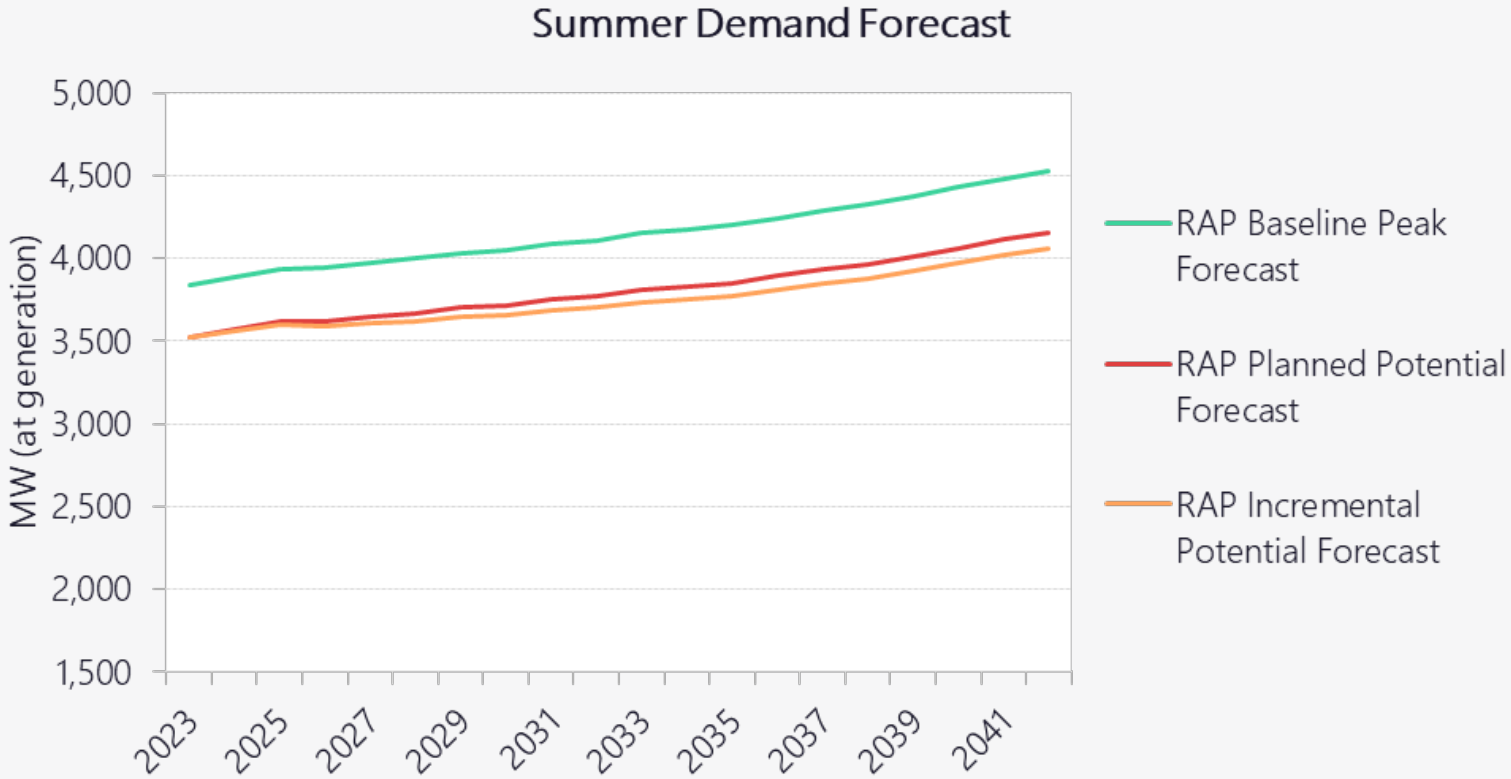
DR/DSR potential is incremental to peak demand impacts from EE.



Potential Estimates

Estimated cumulative potential reached 470 MW at generation in 2042 (10.4%). After removing existing/planned resources, incremental potential is estimated to reach 94 MW at generation (2.1%) in 2042.

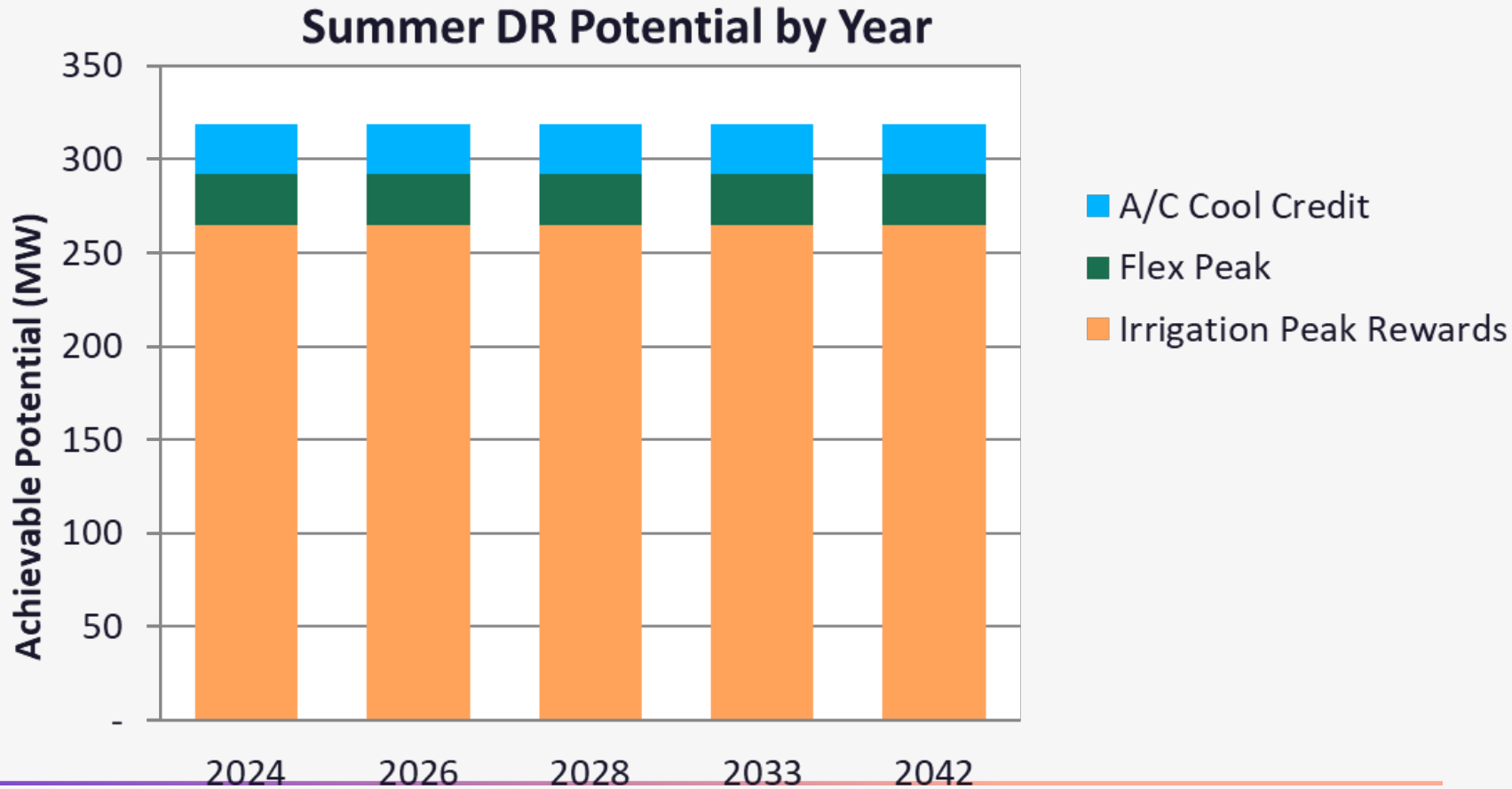
- **RAP Baseline → RAP Planned Potential:** modeled potential from existing programs
- **RAP Planned Potential → RAP Incremental Potential:** modeled potential from new/unplanned programs



Potential Estimates – Existing Resources

Most potential from existing resources are generated through the Irrigation Peak Rewards program (265 MW, 83%).

Potential from existing resources is held constant over the forecast period.

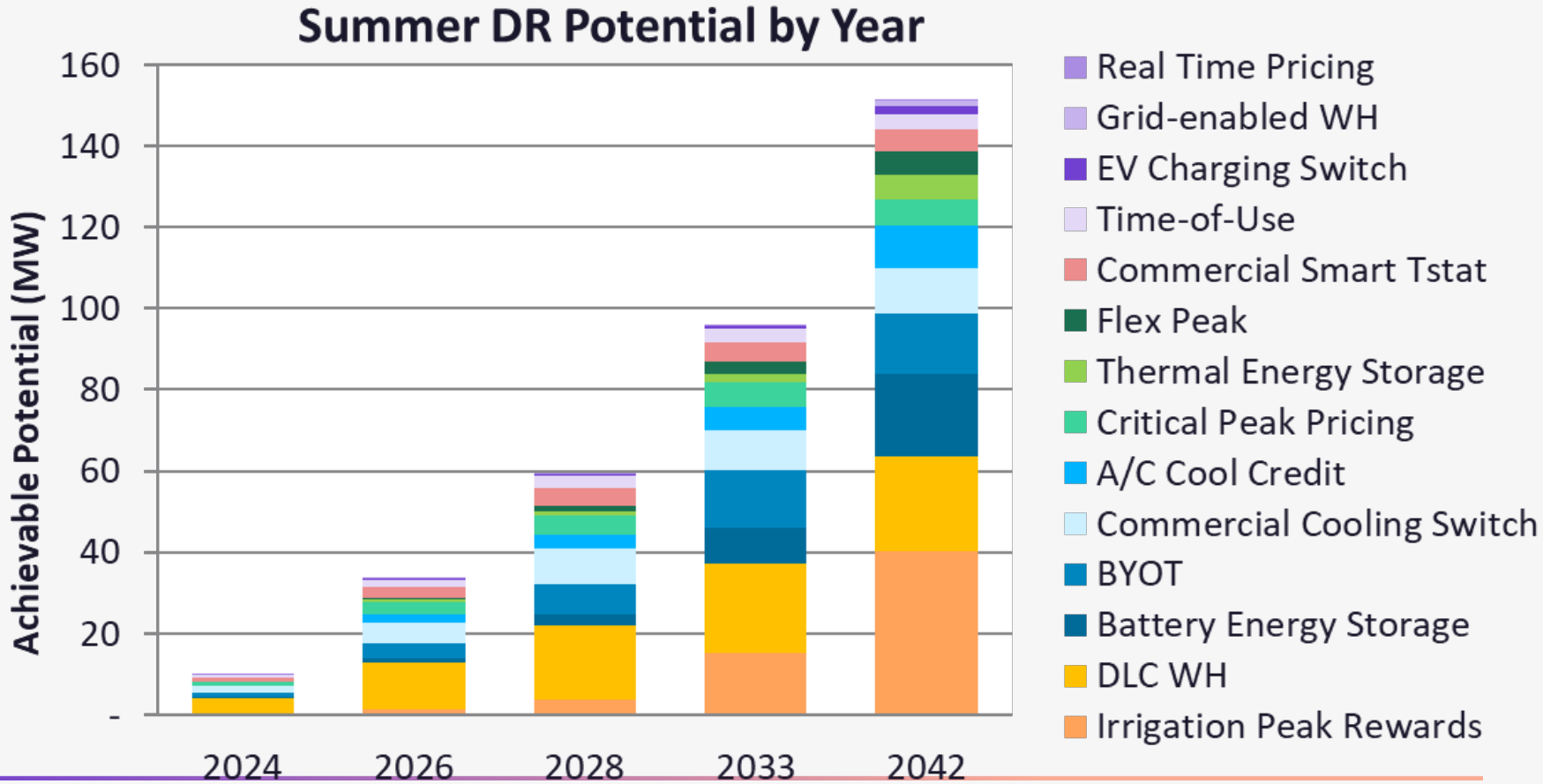


Potential Estimates – New Resources

Potential from new resources (incremental potential) reaches 151 MW in 2042. Sector growth drives the incremental potential for existing programs.

Most of 2042 potential is generated by:

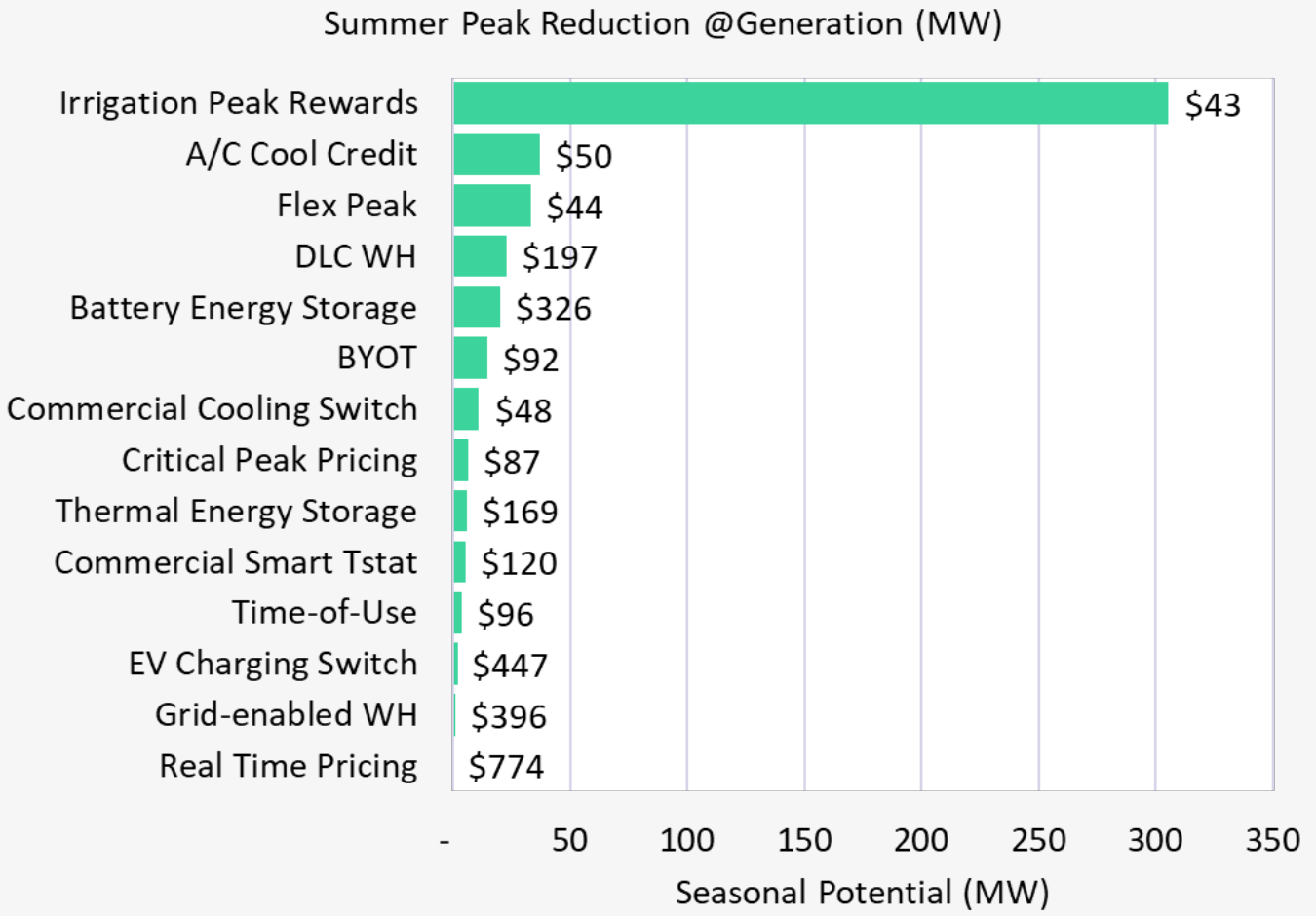
- Irrigation Peak Rewards (27%)
- DLC WH (15%)
- Battery Storage (14%)



Levelized Costs

Calculated levelized costs based on 20-year summer-potential forecast.

- Started with cost assumptions from the Council's 2021 Power Plan
- Calibrated costs for existing programs to align with actual expenditures
- Included software implementation and update costs for Critical Peak Pricing (CPP) and Real Time Pricing (RTP) options
- Counted TOU rate differentials as customer incentives



Thank You.

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