BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

FILED
01/28/26
03:01 PM
R2106017

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	R.21-06-017 (Filed June 24, 2021)

SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) FINAL ELECTRIFICATION IMPACT STUDY PART 2

Roger A. Cerda
8330 Century Park Court, CP32D
San Diego, CA 92123-1530
Telephone: (858) 654-1781
Email: rcerda@sdge.com

Attorney for:
SAN DIEGO GAS & ELECTRIC COMPANY

January 28, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	R.21-06-017 (Filed June 24, 2021)

SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) FINAL ELECTRIFICATION IMPACT STUDY PART 2

I. INTRODUCTION

Pursuant to California Public Utilities Commission ("CPUC" or "Commission") Decision ("D.") 24-10-030, San Diego Gas & Electric Company ("SDG&E") hereby submits its Final Electrification Impact Study ("EIS") Part 2 Report ("Report") (provided as **Attachment A** hereto). In accordance with Rule 16.6 of the Commission's Rules of Practice and Procedure, SDG&E, along with Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE"), requested an extension of the original September 30, 2025 deadline for submitting the draft Report. On September 24, 2025, the Commission's Executive Director granted this request in part, establishing a new deadline of October 31, 2025 for submission of the draft Report and January 28, 2026 for submission of the Report.

II. DISCUSSION

Ordering Paragraph ("OP") 19 of D.24-10-030 states:

> "No later than September 30, 2025, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) must prepare a load flexibility distribution planning process (DPP) assessment within the Electrification Impact Study Part 2 (Study) authorized by the Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future and file a draft report on the Study in this proceeding."

OP 19 continues:

> "No later than 30 days after the filing of the Study's draft report in this proceeding, Utilities shall participate and present at a public workshop the draft findings and receive stakeholder comment on how the findings should be incorporated into the distribution planning and execution process."

OP 20 then orders:

> "No later than 120 days after the filing of the draft report on the Electrification Impact Study Part 2 (Study) authorized by the Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future,

> Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall file in this proceeding: (1) the Study's final report; (2) a description of how the Study's final report meets the requirements and objectives of the Load Flexibility Distribution Planning Process assessment proposed in the Staff Proposal to Improve the Distribution Planning and Execution Process and other Commission requirements; and (3) a detailed proposal and timeline of how the Load Flexibility Distribution Planning Process assessment and equity scenario assessment will be integrated into the Distribution Planning and Execution Process to inform distribution planning and execution in the future."

On September 18, 2025, PG&E, SCE, and SDG&E ("Utilities") submitted a request for an extension of time from September 30, 2025 to October 31, 2025 to comply with OP 19. The Utilities also requested that subsequent deadlines set in OPs 19 and 20 be pushed back by 31 days.

On September 24, 2025, the Utilities' request was partially granted by the Commission's Executive Director. Pursuant to the September 24, 2025 Executive Director's Letter Partially Granting the Utilities' Request:

> "…the Utilities' new deadline to file a draft Study is October 31, 2025. Additionally, the Utilities must participate in and present their draft Study at a public workshop held by December 1, 2025, where they will receive public comment on how the findings should be incorporated into the distribution planning and execution process. Parties will have until December 15, 2025 to file comments on the draft Study. By January 28, 2026, the Utilities must file the Study's final report, the Description of How the Study Meets Requirements and Objectives, and the Proposal and Timeline."

On October 31, 2025, the Utilities submitted their draft Reports. Attachment A presents SDG&E's Report pursuant to D.24-10-30.

III. CONCLUSION

SDG&E respectfully submits this Report in compliance with D.24-10-030.

Respectfully submitted,

/s/ Roger A. Cerda

Roger A. Cerda
8330 Century Park Court, CP32D
San Diego, CA 92123
Telephone: (858) 654-1781
Email: rcerda@sdge.com

Attorney for:
SAN DIEGO GAS & ELECTRIC COMPANY

January 28, 2026

ATTACHMENT A

SDG&E'S FINAL ELECTRIFICATION IMPACT STUDY PART 2

San Diego Gas & Electric Company's

Final Electrification Impact Study Part 2

January 28, 2026

TABLE OF CONTENTS

Executive Summary 1
Purpose 3
Background 3
Study Approach and Methodologies 4
Assumptions and Scenarios 4
Forecasting Methodology 5
Base Case 5
Equity Scenario 7
Demand Flexibility Scenario 9
Planning and Solutioning Methodologies 16
Secondary System Approach 17
Results 20
Peak Load and DER Allocation 20
Load Shift and Shed in Demand Flexibility Scenario 25
Grid Needs and Upgrades 25
Costs 27
Correlation and Integration with Distribution Planning Process 28
Impacts and Dependencies 30
Supply Chain 30
Workforce Planning Considerations 31
Historical Project Costs 32
Revisions to the Draft Report 32
Clarifications 33
Updates and Additions 33
Conclusion 34
Appendix A. List of Grid Needs & Planning Solutions Identified 35
Appendix B. Primary System Upgrade Component Cost Breakdown 36

LIST OF FIGURES

Figure 1. SDG&E Step-by-Step EIS Part 2 Methodology 4
Figure 2. Base Case Normalized Weekday Load Shape, by Month 12
Figure 3. Demand Flexibility Normalized Weekday Load Shape, by Month 13
Figure 4. Light-Duty Electric Vehicle Load Shape under Unmanaged Charging 14
Figure 5. Light-Duty Electric Vehicle Load Shape under Managed (Passive) Charging 14
Figure 6. Light-Duty Electric Vehicle Load Shape under Managed (Active) Charging 15
Figure 7. Demand Flexibility Scenario Weekday Normalized Light-Duty EV Load Shape, by Month 15
Figure 8. Demand Flexibility Scenario Weekday Normalized Medium- and Heavy-Duty EV Load Shape, by Month 16
Figure 9. System-Level Load Shape, September Weekday 2040 20
Figure 10. Device-Level Load Shape for Sample Circuit in the Base Case 21
Figure 11. Device-Level Load Shape for Sample Circuit in the Demand Flexibility Scenario ... 22
Figure 12. Heat Map of MW Allocation in SDG&E Service Territory for Base Scenario 23
Figure 13. Heat Map of MW Allocation in SDG&E Service Territory for Equity Scenario 23
Figure 14. Heat Map for MW Allocation in SDG&E Service Territory for Demand Flexibility Scenario 24
Figure 15. End-Use Category Contribution to Peak Growth in Each Scenario in 2030 and 2040 24
Figure 16. Forecast Mitigation Solutions and Infrastructure Additions for Primary Distribution 26
Figure 17. Cost Estimate Results for Base Case, Equity, and Demand Flexibility Scenarios in 2030 and 2040 27
Figure 18. EIS Part 2 Study Methodology 29

LIST OF TABLES

Table 1. Peak Load and Estimated Costs for Distribution Upgrades, by Scenario 1
Table 2. Infrastructure Needs for Primary and Secondary Distribution by 2040 1
Table 3. Equity Scenario DER Allocation within DAC Demographic 9
Table 4. End Uses Included in DR Potential for Demand Flexibility Scenario by Customer Type 10
Table 5. Primary System Upgrade Costs by Component Category in 2030 and 2040 17
Table 6. Secondary Distribution System Estimated Average Costs, residential, by Element 19
Table 7. Forecast Annual Peak Load in 2030 and 2040 20
Table 8. Annual Reduction in Demand Flexibility Scenarios in 2030 and 2040 25
Table 9. Number of Forecast Mitigation Solutions and Infrastructure Additions for Primary Distribution 25
Table 10. Projected Average Headroom per New Circuit Solution... 25
Table 11. Projected Average Headroom per New Bank Solution 26
Table 12. Summary of Transformer Needs for the Secondary Distribution System, 2025-2030..... 26
Table 13. Summary of Transformer Needs for the Secondary Distribution System, 2025-2040..... 26
Table 14. Cost Estimate Results for Primary Distribution System and Total Upgrade Costs in 2040 27
Table 15. Historical Annual Capital Spend on Capacity / Expansion and Materials for Distribution 32
Table 16. Circuit Upgrade Costs, by Component 36
Table 17. Bank Upgrade Costs, by Component.. 36
Table 18. Load Transfer Upgrade Costs, by Component 36

LIST OF ACRONYMS

AAEE	Additional Achievable Energy Efficiency
AAFS	Additional Achievable Fuel Substitution
AB	Assembly Bill
ACC	Avoided Cost Calculator
ALJ	Administrative Law Judge
BE	Building Electrification
CARE	California Alternate Rates for Energy
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DAC	Disadvantaged Community
DER	Distributed Energy Resource
DPP	Distribution Planning Process
DR	Demand Response
EIS	Electrification Impact Study
ES	Energy Storage
EV	Electric Vehicle
FERA	Family Electric Rate Assistance
IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility
LD	Light Duty
MB	Medical Baseline
MD/HD	Medium Duty/Heavy Duty
OP	Ordering Paragraph
PV	Photovoltaic
SB	Senate Bill
SDG&E	San Diego Gas & Electric
TOU	Time-of-Use

Executive Summary

In compliance with Ordering Paragraph (OP) 19 of Decision (D.)24-10-030 (Decision), San Diego Gas & Electric Company (SDG&E) conducted a comprehensive analysis of distribution system impacts under three forecast scenarios for years 2030 and 2040:

- **Base Case Scenario** – 2023 Integrated Energy Policy Report (IEPR) system-level load forecast inputs incorporating known loads and pending loads
- **Equity Scenario** – Base Case forecast plus hypothetical load modifiers for equity
- **Demand Flexibility Scenario** – Base Case forecast plus hypothetical load modifiers for load management impacts on forecast load growth

This report documents SDG&E's Electrification Impact Study Part 2 (EIS Part 2). The EIS Part 2 evaluates peak load growth, infrastructure needs, and associated costs, with a particular emphasis on how demand flexibility and equity-driven electrification, programs, and technologies influence system needs.

Table 1. Peak Load and Estimated Costs for Distribution Upgrades, by Scenario

	Peak Load (MW)	Primary Distribution Solutions Cost (Nominal $, Millions)	Secondary Distribution Solutions Costs (Nominal $, Millions)	Total Cost (Nominal $, Millions)
Base Case				
2025-2030	6,204	$592	$321	$913
2025-2040	7,007	$2,450	$752	$3,202
Equity Scenario				
2025-2030	6,245	$609	$304	$914
2025-2040	7,172	$2,770	$799	$3,569
Demand Flexibility Scenario				
2025-2030	6,084	$490	$310	$801
2025-2040	6,814	$1,785	$720	$2,505
**Costs reflect a future escalation rate of 3%.[1] Costs exclude distribution line segments, substation costs, and land acquisition.*				

Table 2. Infrastructure Needs for Primary and Secondary Distribution by 2040

	Base Case	Equity Scenario	Demand Flexibility Scenario
Primary Distribution System – New Circuits	141	162	111
Primary Distribution System – Bulk Transformer Upgrades	32	33	16
Secondary Distribution System – Replacement Transformers	22,469	23,515	21,502
Secondary Distribution System – New Transformers	1,215	1,480	1,165

The Equity Scenario reflects the highest infrastructure needs and costs due to increased Distributed Energy Resource (DER) adoption on circuits that primarily serve disadvantaged communities (DACs). The Demand Flexibility Scenario demonstrates the potential for reduced infrastructure needs through strategic load management. Although the Demand Flexibility Scenario reflects the potential related to load management impacts, SDG&E did not independently undertake an investigation to identify any specific load management programs that could be leveraged to fulfill this potential. Instead, SDG&E relied on Lawrence Berkeley National Laboratory (LBNL) and analysis from SDG&E's consultant

[1] U.S. Bureau of Labor Statistics, Table 1. Consumer Price Index for All Urban Consumers (CPI-U), https://www.bls.gov/news.release/cpi.t01.htm. October 24, 2025.

Energy + Environmental Economics (E3). The costs provided in this study report are limited to distribution infrastructure costs. Implementation costs associated with the demand response (DR) programs modeled in the LBNL and E3 work, including required incentives, are not provided in this study report. However, the influence of DR program costs on DR program adoption rates were included in the LBNL study and are therefore implicit in the results of E3's work.

SDG&E's current planning aligns with the Base Case, but future updates may incorporate elements from the alternative scenarios as policy, market, and customer behaviors and conditions evolve. While the Commission's interest in exploring alternative futures is understandable, SDG&E cautions against adopting any directives that would interfere with the utility's ability to plan for the needs of its customers. It may be that, over time, it becomes apparent that some of the drivers from the Equity and Demand Flexibility Scenarios will be implemented (e.g., increased DER incentives for disadvantaged communities and customers, Time of Use (TOU) rate changes, DR program development with cost-effective incentives, etc.). If this happens, SDG&E will modify the planning inputs for the next DPP cycle and the Base Case will be updated. This is part of the robust, existing planning process, which already allows for such changes to be incorporated.

Purpose

San Diego Gas and Electric Company (SDG&E) hereby submits its draft Electrification Impact Study (EIS) Part 2 report in compliance with Ordering Paragraph (OP) 19 of Decision (D.)24-10-030 (Decision).

Background

In response to feedback received on the Electrification Impact Study Part 1 (EIS Part 1), the California Public Utilities Commission (CPUC) directed the Investor-Owned Utilities (IOUs or Utilities) to lead the development of EIS Part 2 for their respective service territories. The CPUC expects that the utilities' Part 2 studies will reflect their operational knowledge and other considerations that may not have been included in the EIS Part 1 study. This includes examining the effects of policy-based electric load forecasts and factors such as demand flexibility.

On May 9, 2023, EIS Part 1 was released via an Administrative Law Judge (ALJ) ruling in the High Distributed Energy Resources (DER) Future proceeding.[2] The Part 1 study was conducted by a Commission consultant and examined the potential impacts of high adoption of DERs, which includes the forecast electric loads from electric vehicles (EVs) and from converting natural gas technologies to electric technologies. The Part 1 study estimated the scope of distribution upgrades, and the associated costs, assuming no electric load flexibility beyond that which existing rate structures and load control programs provide.

It was determined that the Part 2 study would be conducted by the utilities.[3] The focus of the Part 2 study is to estimate the potential costs of upgrading the primary and secondary distribution systems to meet electrification needs under multiple scenarios. Specifically, the Part 2 study includes the demand flexibility mitigation scenario proposed in the CPUC Staff Proposal[4] and an Equity-driven scenario.

The CPUC Staff Proposal prepared in this proceeding and released on March 13, 2024, recommended that the Commission require the Utilities to prepare a load flexibility Distribution Planning Process (DPP) assessment. The Staff Proposal stated that "the intent of the assessment is to examine how future load shapes resulting from a range of flexible load strategies could impact distribution planning such as controlling distribution upgrade costs. The assessment would also address how the DPP process can incorporate results of flexible load strategies into the planning process." If adopted by the Commission, the Staff Proposal would require utilities to "conduct load shape analysis to determine the distribution system level benefit of demand flexibility, including a quantification of avoided costs" and "publish their load flexibility inputs and assumptions along with justification for their decisions in Q4 2024 for public comment."[5]

Since the timing of the Part 2 study generally aligns with the timing of the Staff Proposal's load flexibility DPP assessment, the Commission eliminated the Staff Proposal's requirement for the Utilities to separately publish their load flexibility inputs and assumptions for party comments. Instead, the

---

[2] *Administrative Law Judges' Ruling Setting a Workshop, Admitting into the Record Part 1 of the Electrification Impacts Study and Research Plan, and Seeking Comments.*
[3] The Part 1 and Part 2 studies were authorized in *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*.
[4] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M527/K221/527221491.PDF.
[5] *Staff Proposal for the High DER Proceeding*, p. 83.

Commission directed the Utilities to prepare the load flexibility DPP assessment within the EIS Part 2 and file a draft report on the Part 2 study in this proceeding. SDG&E's draft EIS Part 2 report has been prepared, served to stakeholders, and filed with the Commission in accordance with requirements set forth in D.24-10-030.[6]

Study Approach and Methodologies

SDG&E developed a step-by-step approach for the EIS Part 2 (Figure 1). Building on existing datasets, an initial validation step was completed prior to the forecast development for each of the three outlined scenarios: Base Case, Equity, and Demand Flexibility. The results were reviewed for accuracy and the outputs requested by the CPUC Energy Division were extracted for reporting purposes.

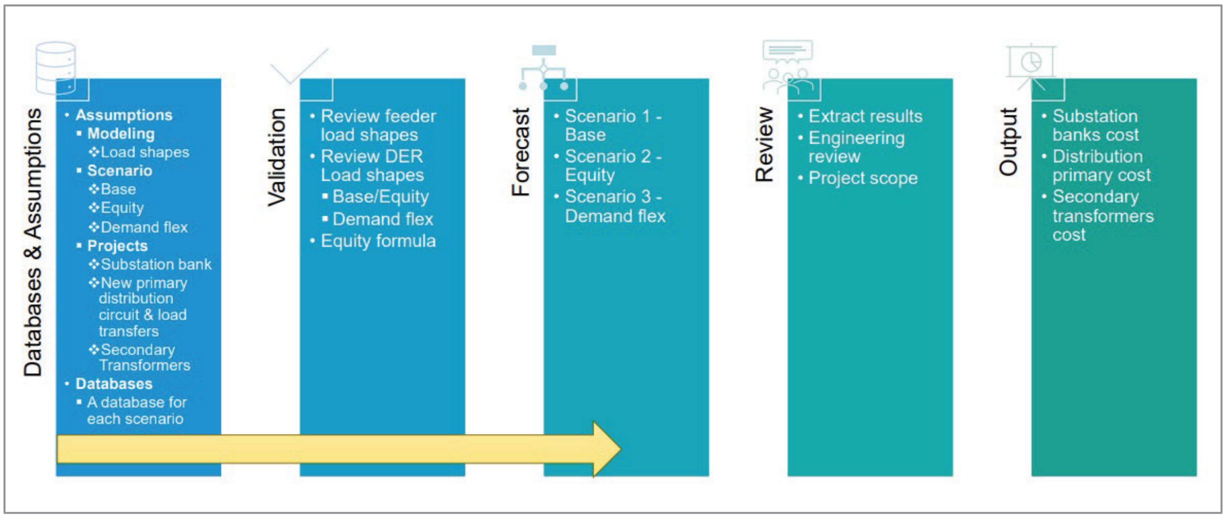


Figure 1. SDG&E Step-by-Step EIS Part 2 Methodology

Assumptions and Scenarios

The EIS Part 2 study is a conceptual analysis designed to estimate distribution infrastructure upgrade costs. It evaluates future distribution system needs under three distinct scenarios, each built upon the 2023 IEPR system-level load forecast. Assumptions include: 1) standardized assumptions for project configurations and unit costs (intentionally excluding certain cost components such as distribution line segment costs), and 2) no requirement to maintain existing levels of operational flexibility. Note that some of the bulk power transformer ("bank") additions may necessitate greenfield substations.

A description of each study scenario and the associated assumptions are provided below:

1. **Base Case Scenario**
   The Base Case incorporates the 2023 IEPR forecast and integrates both known loads and pending loads. It reflects SDG&E's current planning assumptions and includes the results from the 2024-2025 DPP (which covers the 2025-2029 planning horizon) and also includes the years 2030 and 2040. As the Base Case reflects 'business as usual' conditions, it reflects the impact of current regulations and customer program offerings. The Base Case serves as the foundational reference for infrastructure needs in both the Equity and Demand Flexibility Scenarios.

---

[6] D.24-10-030, Ordering Paragraph 19.

2. **Equity Scenario**
   The Equity Scenario would be potentially applicable only if an equity assessment identifies disparities in Distributed Energy Resource (DER) adoption between Disadvantaged Communities (DACs) and non-DACs within the SDG&E service territory. This scenario builds on the Base Case by applying hypothetical load modifiers that are intended to reflect targeted electrification efforts in underserved areas. The California Air Resources Board (CARB) California Climate Investments Priority Populations Mapping Tool (June 2024)[7] was used to identify underserved areas.

3. **Demand Flexibility Scenario**
   The Demand Flexibility Scenario builds on the Base Case but introduces hypothetical load modifiers to simulate the impact of load management strategies on forecast load growth, such as shifting EV charging based on changed TOU rates or developing new demand response programs for Building Electrification (BE) loads. It explores how customer response to hypothetical TOU rate structures and load management programs could reduce peak demand and defer infrastructure upgrades.

   Certain load shed and load shift assumptions were adopted by Energy + Environmental Economics (E3)[8] from the Lawrence Berkeley National Laboratory (LBNL) California Demand Response Potential Study[9] to determine the impact of load management on the Additional Achievable Fuel Substitution (AAFS) load component.

   E3 also developed updates of EV load profiles using its EV Load Shape Tool to estimate the impact of revised TOU rates on forecast charging loads for Light-Duty Electric Vehicles (LDEV), Medium-Duty Electric Vehicles (MDEV), and Heavy-Duty Electric Vehicles (HDEV). These updated AAFS and EV load profiles, then modified to reflect the impact of revised TOU rates, were incorporated in the Demand Flexibility Scenario. The revised TOU rates result in a hypothetical EV charging load reduction compared to the Base Case. The reduced EV charging loads contribute to a reduction in distribution infrastructure upgrades in the Demand Flexibility Scenario as compared to the Base Case.

Forecasting Methodology

Base Case

The Base Case models a "business as usual" approach and was designed to be consistent with the current annual DPP.[10] As it was built from historical load shapes, the influence of existing customer-facing programs for building and transportation electrification, energy efficiency, etc. are built-in to the resulting

[7] California Climate Investments Priority Populations https://gis.carb.arb.ca.gov/portal/apps/experiencebuilder/experience/?id=5dc1218631fa46bc8d340b8e82548a6a&page=Priority-Populations-4_0. June 2024.
[8] SDG&E contracted E3 to develop the load profiles used in the Demand Flexibility scenario.
[9] Gerke, B.F., et. al., 2024. Lawrence Berkeley National Laboratory, The California Demand Response Potential Study, Phase 4: Report on Shed and Shift Resources through 2050. phase_4_dr_potential_study_final_2024-05-21.pdf.
[10] See SDG&E's August 15, 2025 Grid Needs Assessment (GNA) report for a detailed description of the load forecasting process used in the 2024-2025 DPP to determine circuit- and substation loads for the 2025 through 2029 planning horizon. The 2025-2029 planning horizon constitutes the initial years of the Base Scenario. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M576/K179/576179691.PDF.

demand forecast. Loads at the primary system level for the Base Case were forecast via a phased process. The initial phase involved creating hourly profiles at the feeder level using SCADA data. This profile creation process began with an analysis of three years' worth of SCADA data, where recorded power flows were examined for temporary transfer, faults, metering errors, outliers, and other abnormalities. Once the data was cleaned, it was modeled and projected in relation to assumed weather conditions to generate typical and extreme peak day load profiles for each month. These profiles were subsequently imported into the forecasting software LoadSEER developed by Integral Analytics to initiate the forecasting of future load. LoadSEER has been in use by California utilities since the early 2010s and is a well-established and accepted software tool.

The forecasting process for the primary system began with the use of the California Energy Commission's (CEC) IEPR forecast, a valuable resource that provides insight into anticipated energy consumption. The initial step in creating the Base Case load forecast was to derive the Annual Base Growth from the 2023 IEPR forecast. This served as the foundation, setting the stage for the forecast. Next, known load growth was considered, including the specific load shape for each known load. "Known loads" are for specific customers that have signaled a service need. By systematically deducting this growth from the overall IEPR forecast, the remaining base growth was identified. This base growth was then allocated to individual circuits.

To distribute this remaining forecasted load growth, SDG&E uses LoadSEER as a mapping and simulation tool. This tool helps estimate where future load demand will occur by looking at how communities grow and how customers adopt new technologies. LoadSEER works by creating "agents," which represent customers and undeveloped land. Each agent is linked to locations using maps, parcel data, transportation networks, and satellite imagery. The system uses information such as past development patterns, zoning rules, and utility customer types to predict how neighborhoods may develop or change in the future. It also models how customers might start using new types of electric equipment over time.

By analyzing all these factors, LoadSEER identifies specific places where electricity use is likely to increase. SDG&E then uses these growth points to help allocate load growth across the entire service area. Finally, SDG&E engineers reviewed the results to make sure they were reasonable and aligned with actual growth trends in the region. This review helped confirm the findings and make any needed adjustments.

The culmination of this process was circuit-level load growth estimates which were used in the planning process to identify new distribution grid needs. Determining solutions for these needs ensures the preparedness of the distribution infrastructure to provide delivery capability for customers' energy requirements.

For DER shapes in the Base Case, various inputs were used, including the CEC IEPR forecast and local energy consumption data. Other inputs for DERs included historical adoption trends, economic payback considerations, and geospatial factors. This data played a crucial role in disaggregating, to the circuit level, the IEPR's system-level forecast of rooftop solar photovoltaic (PV) output, Behind-The-Meter (BTM) energy storage (ES) charging/discharging, and EV charging.

The IEPR's system-level Additional Achievable Energy Efficiency (AAEE) load component was disaggregated to the circuit level by assessing localized consumption and scaling to align with the system-wide forecasts.

Disaggregation of IEPR's AAFS load component was based on natural gas consumption. Like AAEE, it was scored by natural gas usage (where usage was aggregated at circuit level). This approach ensured the findings were reflective of localized natural gas consumption. Once again, the localized analysis results were scaled to align with IEPR's system-wide forecasts.

For the PV, ES, and EV components,[11] anticipated growth was disaggregated by utilizing a non-linear optimization of a diffusion model. A local forecast was generated and applied at the zip code level. This detailed approach captures the projected adoption in different neighborhoods, which was then scaled to fit the overall system-wide forecast.

Through this analytical process, several key outputs were derived. Circuit-specific load growth forecasts and a 576-hour MW shape were developed which served as critical inputs for the LoadSEER application to produce the distribution system load forecast.

Equity Scenario

The aim of the Equity Scenario was to assess how, compared to the Base Case, increasing the amount of DERs in DACs would impact the distribution system's peak loads, grid needs, and costs. Future equity-focused legislation, regulatory requirements, and customer incentive programs would likely be the primary drivers for such an increase. As the details of these hypothetical future drivers are unknown at this time, the details and implementation costs of such programs (if any) are not included within this scenario.

Before developing revised forecasts for the Equity Scenario, and in accordance with guidance provided by the Energy Division staff, SDG&E engineers followed a structured process to assess whether DER allocations in the Base Case differ between DAC and non-DAC areas. This preliminary analysis was to determine whether an Equity Scenario was necessary. If a meaningful difference in DER allocation was identified, a hypothetical equity-driven forecast was then developed to reduce the differences. The analysis consisted of the following steps:

1. **Circuit Allocation to ZIP Code Allocation**
   The circuit level forecast was combined using specific addresses of the customers in those circuits. If the entire circuit is within one zip code, then 100% of circuit allocation gets added to that ZIP code. When a circuit is between two ZIP codes, a proportional method based on customers in each ZIP code is used. The sum of all circuit-level allocations within a ZIP code gives the total allocation for that ZIP code.

   For example, if a circuit is divided into two ZIP codes and each ZIP code has 50 customers, then each zip code will get 50% of the allocation.

2. **Zip Code Allocation to Census Tract Allocation**
   ZIP Codes and Census Tracts were overlayed to determine the population of each ZIP-Census Tract overlapping area. These overlapping areas were necessary because DAC designation is determined by Census Tract and DER allocation is determined by ZIP Code. A ratio of these overlapping areas' populations to the population of the whole ZIP Code was taken to determine the amount of DER allocated to that ZIP-Census Tract overlapping area.

   For example, if a ZIP-Census Tract overlapping area has 2,000 people in a ZIP Code with 10,000 people, then that overlapping area represents 20% of the total ZIP Code allocation.

[11] Consistent with the 2024–2025 DPP cycle, the MD/HD component reflects SDG&E's own bottom-up forecasting results, rather than being disaggregated from the CEC's IEPR forecast. For full details on the methodology, refer to SDG&E's 2025 Grid Needs Assessment Report.

3. **DER Allocation in DAC Areas**
The Census Tracts that are inside DAC areas, as defined in the CARB Priority Populations Map, were flagged. Then the corresponding ZIP-Census Tract overlapping areas were flagged as DAC. The DER MW allocation[12] for the overlapping areas that were flagged were added for all of the SDG&E service territory. The total amount of DER MWs allocated to CARE, FERA, and MB customers that were not already included in the DAC overlapping areas defined above were then added for all of the SDG&E service territory. This was also approximated by applying a ratio of the number of CARE, FERA, and MB customers in each ZIP-Census Tract overlapping area to the total number of customers and applying that to the DER MW allocated. After adding all of these DAC DER MW allocations together, the total represents the allocation of system level DER MWs to DAC areas.

   For example, if Census Tract A and Census Tract B are both in DAC areas, but Census Tract C is not in a DAC area, only the DER allocation from Census Tracts A and B are added to find the DAC DER allocation.

4. **Total System DER MW Allocation**
The allocation for all the overlapping areas was added to get the total system level allocation for each DER component.

5. **Percentage of DER Allocation to DAC Areas**
The total DER DAC MW allocation was taken from step 3 above and divided by the total system DER MW allocation taken from step 4. DER MW adoption with DAC demographic characteristics comprises 55.4% of all DER growth at the system level by the year 2040.

   For example, if the DER MW for a certain DER load component is a total of 100 MW at the system level, and if 50 MW of that was allocated to DAC areas, then 50% will be the portion allocated to the DAC areas.

6. **Percentage of Customers in DAC Areas**
The population of all customers across all ZIP-Census Tract overlapping areas was calculated for SDG&E's service territory. The population of Census Tracts flagged as having DAC demographic characteristics, as defined in the CARB Priority Populations Map, plus all CARE, FERA, and MB customers not already included in DAC overlapping areas, were added and compared to the total population as a percentage. 59.3% of the total SDG&E population was flagged as having DAC demographic characteristics in that specification. The percentage of the population flagged as having DAC demographic characteristics was used as a proxy for the percentage of customers in DAC areas.

7. **Perform the Analysis**
The percentage of DER MW allocation to DAC areas is considered "equitable" if equal to or greater than the percentage of customers in DAC areas. Because the percentage of DER MW allocation to DAC areas was found to be less than the percentage of customers in DAC areas, SDG&E undertook an equity-driven forecasting scenario. In this Equity Scenario, the DER MW allocation is increased on circuits serving at least 50% DAC populations until the percentage of DER MW allocation to the DAC areas equals the percentage of customers in the DAC areas.

---

[12] MD/HD growth was excluded from this analysis due to MD/HD load belonging primarily to commercial and industrial customers that cannot be simply classified as DAC.

The Equity Scenario analysis shows that in the Base Case 59.3% of SDG&E's customer base is identified as having DAC demographic characteristics, while 55.4% of DER allocation (by MW) is disaggregated within DAC areas (Table 3). To address this 3.9% gap, a hypothetical Equity Scenario was created which increased DER allocation until the gap was functionally eliminated. About 1,000 MW of DER was added to circuits that included at least 50% DAC populations in the Equity Scenario.

Table 3. Equity Scenario DER Allocation within DAC Demographic

DER Allocation in the Base Case						
Customers w/DAC Demographic (Population)	887,774	59.3%	>	55.4%	2,607 MW	DER MW Allocated to Areas w/DAC Characteristics
All Customers (Population)	1,496,436[13]				4,708 MW	Total DER MW

While the equity calculation produces a "gap," the 3.9% difference (3.9% = 59.3% - 55.4%) indicates only that DER uptake in DACs is slightly lower than in other areas of the SDG&E distribution service area. The existence of a gap does not indicate that SDG&E's delivery of distribution services to DACs is intentionally, or unintentionally, different than in other areas.

Demand Flexibility Scenario

The Demand Flexibility Scenario explores the possible impacts of hypothetical load management programs, such as Demand Response (DR) for building electrification (BE) and modified TOU rates for EVs, on forecast electric load growth. While the use of hypothetical programs is necessary for modeling, and while the LBNL study does include estimates for the costs of implementation and required incentives to achieve the necessary participation rates, the scenario does not specifically investigate or address important nuances and challenges with effective load management implementation. These issues include securing adequate customer participation rates, determining and setting cost-effective incentive levels, required communications across a range of DR-enabled technologies, the ability to count on customer response to the dispatch of load flexible resources (to ensure reliable distribution operations), and the overall administrative management of load management programs. Known and pending loads in the Base Case are included in the Demand Flexibility Scenario as well.

Note that the Industrial and Agriculture sectors are not currently a significant driver of load growth within SDG&E's service territory and so were not considered in the Demand Flexibility Scenario. Understanding these limitations, SDG&E took the approach described below to develop and forecast the impacts of a Demand Flexibility-focused Scenario.

Because load flexibility modifiers from the CEC were not available in time for this study, SDG&E contracted E3 to develop modified load profiles for this scenario. These profiles were derived from the Base Case and reflect assumptions about DR and TOU impacts. The load profiles were developed by E3 using their own modeling assumptions.

SDG&E's role in the Demand Flexibility Scenario was to incorporate the E3-developed load profiles in SDG&E's internal forecasting and planning tools. Specifically, the profiles were input into LoadSEER to generate circuit-level forecasts. These forecasts were then used in the planning and solutioning process to identify potential system upgrade needs and associated costs, enabling a comparison between the Demand Flexibility and Base Case scenarios.

[13] SDG&E customer population as of April 2025.

Building Electrification

For BE, E3 applied DR adjustments utilizing both load shed and shift strategies from the LBNL study. The Base Case uses the AAFS load shape from the CEC's IEPR, modeled as a 576-hour shape over 12 months, accounting for variations between weekends and weekdays. In the Demand Flexibility Scenario, E3 simulated peak load reductions using DR events: shed DR reduces load during peak hours, while shift DR reallocates load to off-peak periods.

For the EIS Part 2, shift DR was modeled as shed, simplifying analysis by excluding reallocation of load to off-peak hours since the focus is on identifying the need for distribution upgrades caused by thermal overloads which occur during on-peak hours. Distinct methodologies for shed and shift DR to the Base Case load shape were applied, with shed DR concentrated during peak hours from 4 to 8 PM in September and shift DR based on the top 200 CAISO net load hours, ensuring that shift potential remains a fraction of end-use loads. Overall, E3 used DR potential from the previously referenced LBNL California Demand Response Potential Study Phase 4 ("LBNL study"), along with selected end-use load shapes categorized by customer type to form the basis for the study's ultimate DR shift and shed potential.[14,15]

The LBNL study assesses the DR potential across various end uses and customer types, considering both existing and future electrification potential, while providing DR estimates at different levelized costs for a variety of DR technologies through 2050. LBNL accounts for program costs including DR program administration and marketing, equipment and installation costs, incentives, and the ongoing operating costs associated with each of the BE DR technologies. In this way, the influence of program costs is accounted for in the Demand Flexibility Scenario.

The LBNL study includes a range of incentives that could be paid to customers to encourage adoption of BE DR technology. Higher incentive cost tranches increase the number of enrolled customers thereby increasing the amount of DR that can be realized. Projected customer enrollment is based on historical DR program enrollment data provided by SCE and a regression model that predicts enrollment as a function of the sector, income level (CARE vs. non-CARE), building type, site size, climate region, and the per-kW incentive level.[16]

The table below shows, by customer type, the end uses E3 assessed for purposes of estimating BE DR impacts.

Table 4. End Uses Included in DR Potential for Demand Flexibility Scenario by Customer Type

End Use	Residential	Commercial
Cooling	X	X
Dishwasher	X	
Dryer	X	
Freezer	X	
Space Heating	X	X

---

[14] Gerke, B.F., et. al., 2024. Lawrence Berkeley National Laboratory, The California Demand Response Potential Study, Phase 4: Report on Shed and Shift Resources through 2050. phase_4_dr_potential_study_final_2024-05-21.pdf.

[15] The LBNL study includes an assessment of the amount of load shed and load shift that could be realized from dynamic pricing similar to the CPUC Staff's CalFUSE concept. SDG&E's EIS Part 2 load flexibility study does not attempt to incorporate the potential impacts of dynamic pricing.

[16] LBNL study, p. 51.

End Use	Residential	Commercial
Indoor Lighting	X	X
IT Equipment		X
Office Equipment		X
PC	X	
Pool Pump	X	
Refrigeration	X	X
Spa Heater & Pump	X	
TV	X	
Ventilation		X
Washer	X	
Water Heating	X	X

For each BE DR technology and incentive level, the LBNL study produces an estimate of the DR impact. To determine the amount of BE shed and shift DR that can realistically be achieved given historical information on customer participation rates (the "achievable potential"), the LBNL study 1) estimates the $/kW per year costs the utility would avoid by employing shed BE DR and the $/kWh per year costs the utility would avoid by employing shift BE DR, and 2) applies customer enrollment estimates as described above.

The avoided costs are derived from the CPUC Avoided Cost Calculator (ACC) and dispatch probability calculations based on 2021 load forecasts and grid modeling aligned with Integrated Resource Planning (IRP) standards. The avoided costs include estimates of the marginal distribution and transmission infrastructure costs (measured at the system-level) that would be avoided by an incremental reduction in load that results from operation of a DR program. These avoided costs are key to determining the maximum amount of incentives that can be paid to program participants while maintaining overall cost-effectiveness of the programs. Note that these avoided costs may not be relevant at the individual circuit level since any particular distribution or transmission upgrade may be more or less costly than the system-level avoided cost. At the circuit level, DR programs are, in most circumstances, unlikely to be a viable non-wires alternative (NWA). The Commission tested this concept through its now discontinued Distribution Investment Deferral Framework (DIDF). The results of the DIDF demonstrated that the compensation that can be offered to DER developers to cost-effectively defer planned distribution upgrades does not support commercially viable DER additions (where DERs include DR in this case). Given these results, SDG&E's EIS Part 2 solutioning process did not undertake an assessment of NWAs, including DR.

Figures 24 and 28 in the LBNL study show, for all three IOUs, the points on the DR achievable potential supply curve at which the various amounts of shed and shift DR potential would be both economic (i.e., cost-effective) and realistic given historical enrollment in traditional DR programs.[17] The LBNL study also forecasts aspirational future adoption rates of DR-enabled technologies, as evidenced in Figure 33 from the study, which shows how the relative efficacy of shed DR for different end uses changes over time. These amounts were used by E3 to estimate the amount of load reduction that could be achieved within the SDG&E service area given the forecast load growth in the Base Case. The LBNL study results specific to SDG&E's customer base were used for this analysis.

[17] The DR supply curves in the LBNL study include both BE and EV DR technologies. For purposes of SDG&E's load flexibility study, SDG&E used LBNL's BE DR results and performed a separate analysis for EV DR as described in the next section.

Note that based on LBNL's historically based customer enrollment model, the amount of economic DR potential that is likely to be realized is a small fraction of the total economic potential. The LBNL study states that for shed DR "[a]t the avoided-cost threshold, the achievable resource amounts to less than one-quarter of the economic potential."[18] For shift DR the LBNL study observes that "the values are considerably smaller than…the economic potential, owing to the large reduction arising from modeled customer enrollment at low costs. Given the low avoided costs for shift DR calculated from the ACC, there is not enough value available to incentivize widespread shift enrollment."[19]

The following figure shows a normalized weekday profile for each month in the Base Case.

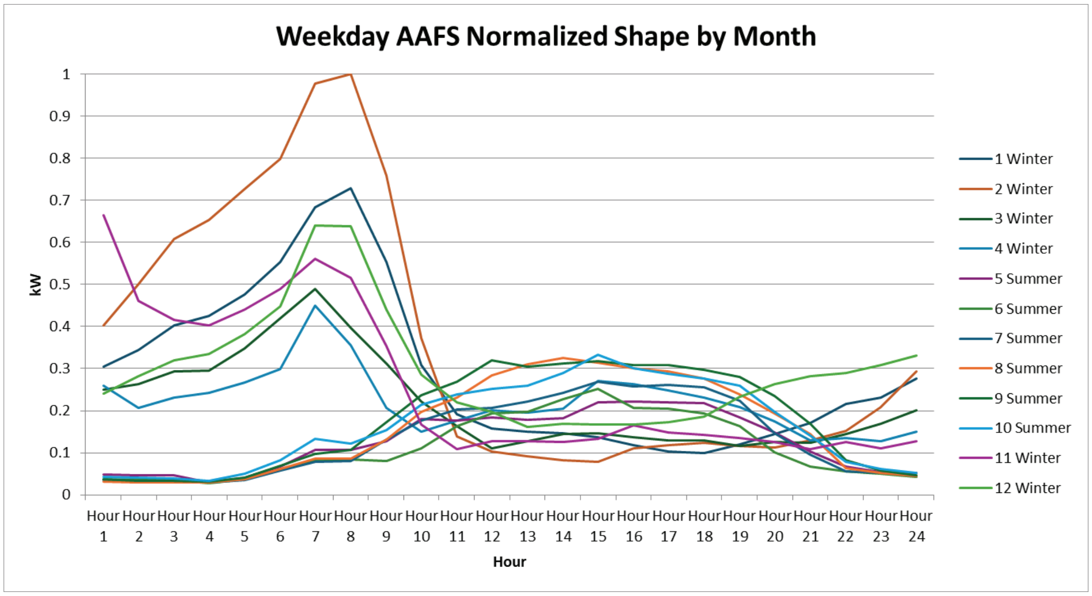


Figure 2. Base Case Normalized Weekday Load Shape, by Month

As discussed, shed was applied to the peak hours between 4PM and 8PM during September, and shift was applied to the top 200 CAISO net load hours. The resulting Demand Flexibility BE normalized profile is shown in the following figure.

[18] LBNL study, p. 72.
[19] LBNL study, p. 82.

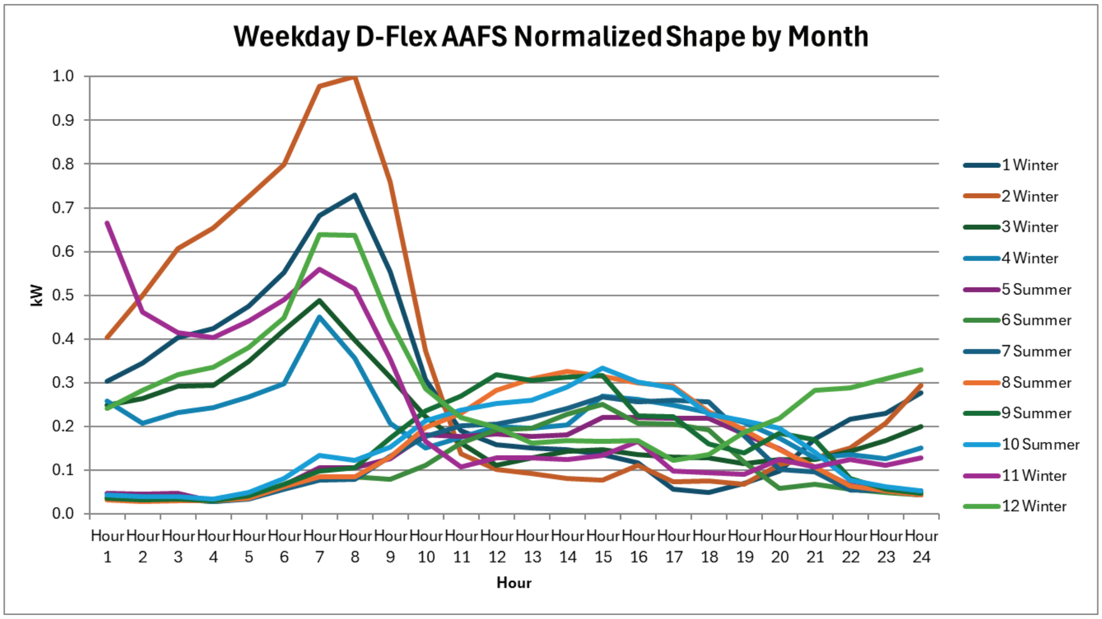


Figure 3. Demand Flexibility Normalized Weekday Load Shape, by Month

<u>Transportation Electrification</u>
As previously discussed, for the Base Case in EIS Part 2, SDG&E used LD and MD/HD EV load shapes from the CEC's IEPR, modeled over 576 hours across 12 months with weekday/weekend differentiation.

To support the Demand Flexibility Scenario, E3 developed modified EV load profiles using its EV Load Shape Tool. The LBNL study was not used for this analysis. The tool creates load shapes based on various charger types (Home L1, Home L2, work, public, depot) but, for this study, aggregates them into two shapes – one for LD vehicles and one for MD/HD vehicles. This facilitates comparison with corresponding shapes in the Base Case.

Additionally, E3 modeled in their EV Load Shape Tool representative charger efficiencies and power output specifications for each charger category and application scenario as sourced from the CEC's Assembly Bill (AB) 2127 report.[20] This data was supplemented with industry-standard data. Vehicle Miles Traveled estimates were obtained from the U.S. Department of Energy's Alternative Fuels Data Center.[21]

The EV Load Shape Tool generates diverse EV charging load shapes by analyzing driving patterns of thousands of drivers and considering various factors including charger access, vehicle types, and charging costs across different locations. The tool models managed charging scenarios, optimizing load response to staggered TOU price signals, where active managed charging incorporates strategies to smooth charging demand during price fluctuations to prevent rebound peaks. This can be achieved through various methods, like staggered off-peak charging periods or participation in aggregator programs.

The tool distinguishes between three types of charging: Unmanaged Charging, where drivers respond to the availability and convenience of charging locations without reacting to time-sensitive price changes;

---

[20] Assembly Bill 2127 Second Electric Vehicle Charging Infrastructure Assessment: Assessing Charging Needs to Support Zero-Emission Vehicles in 2030 and 2035 https://www.energy.ca.gov/publications/2024/assembly-bill-2127-second-electric-vehicle-charging-infrastructure-assessment. March 2024.
[21] U.S. Department of Energy Alternative Fuels Data Center, Average Annual Vehicle Miles Traveled by Major Vehicle Category https://afdc.energy.gov/data/10309.

Managed (Passive) Charging, where drivers adapt their charging based on TOU rates at specific locations; and Active Managed Charging, wherein drivers smooth out their charging schedules to mitigate demand peaks. The final load shapes are a composite of these charging types, weighted according to their prevalence among representative customer types, accounting for factors such as vehicle specifications, charger capabilities, and simulated competition among charging points. For LD and MD EVs, the modeled charging prices are based on simplified SDG&E's EV-TOU-5 and AL-TOU rate structures, with load smoothing strategies, that encourage off-peak charging to leverage stored solar energy, positioning these rates as potential designs for future demand responses.

The following figures show the resultant LD EV load shapes for each charging type and use case per vehicle. All three graphs are weighted based on the hypothetical future adoption of actively and passively managed charging, combined and then scaled to the system level to create the final load shape.

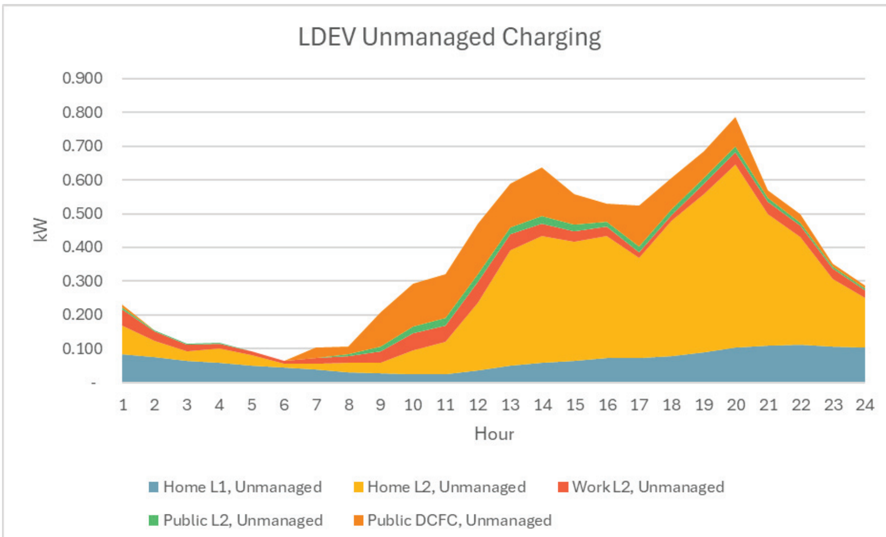


Figure 4. Light-Duty Electric Vehicle Load Shape under Unmanaged Charging

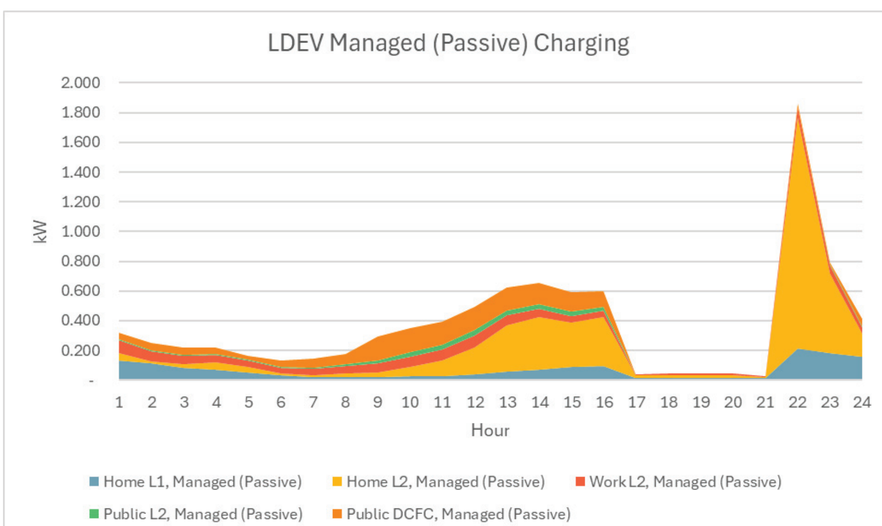


Figure 5. Light-Duty Electric Vehicle Load Shape under Managed (Passive) Charging

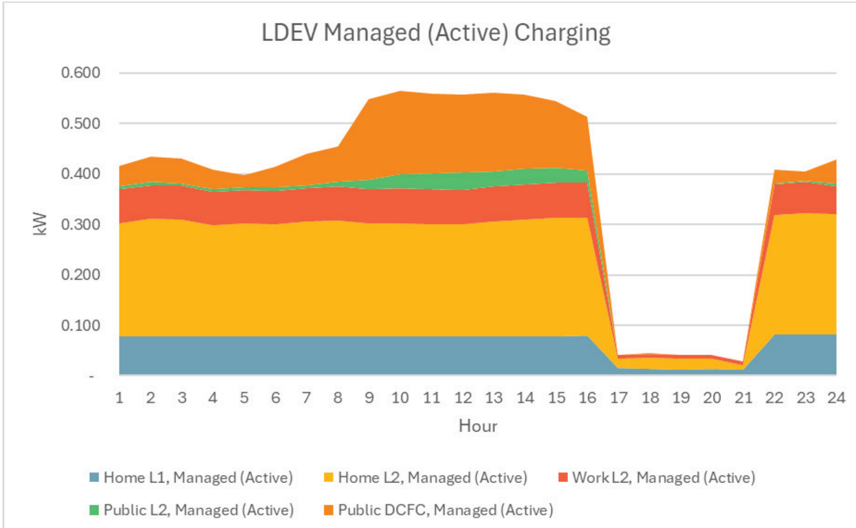


Figure 6. Light-Duty Electric Vehicle Load Shape under Managed (Active) Charging

Below is the weekday final normalized LD EV load shape used in the Demand Flexibility Scenario analysis.

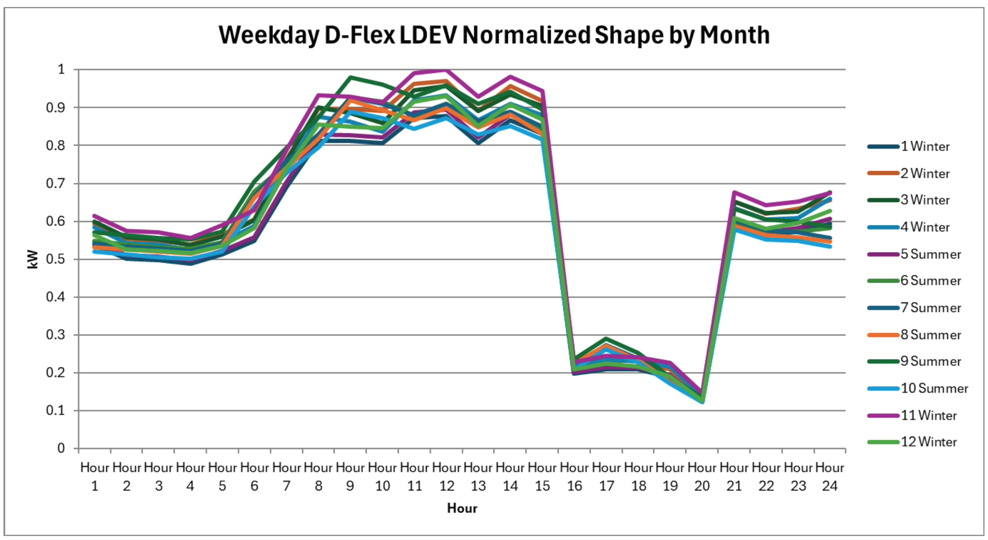


Figure 7. Demand Flexibility Scenario Weekday Normalized Light-Duty EV Load Shape, by Month

The MD/HD EV load shape was created more directly because all charging was assumed to be done at the depot. Therefore, multiple load shapes for different use-cases were not needed. The following graph shows the weekday final MD/HD EV normalized load shape used in the Demand Flexibility Scenario analysis. Multiple TOU structures were tested to find which would result in the most reduction in capacity needs. A TOU structure that encourages charging between 7AM and noon proved to be the most effective at reducing capacity needs and was chosen for this study. This can be seen in the increased load around this time in the normalized load shape.

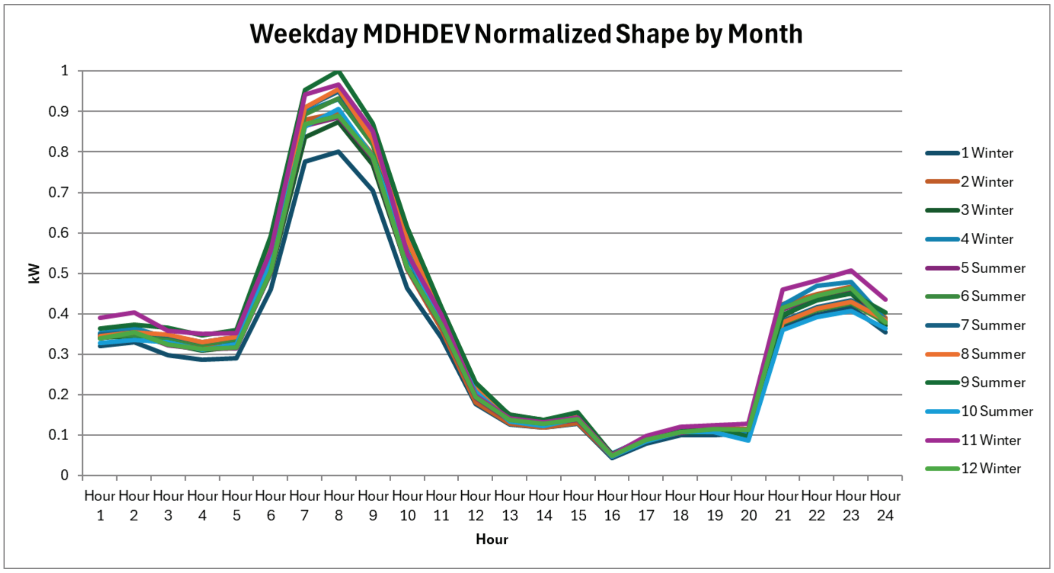


Figure 8. Demand Flexibility Scenario Weekday Normalized Medium- and Heavy-Duty EV Load Shape, by Month

Planning and Solutioning Methodologies

SDG&E's solutioning at the primary distribution system level was based on circuit and bulk power transformer needs identified through the year 2030, as well as additional needs identified through the year 2040. To determine whether capacity upgrades are needed for existing circuits, adjacent tying circuits were evaluated for their ability to carry additional load. If the tying circuits were less than 90% loaded, the tying circuit was deemed to have sufficient capacity to accommodate a load transfer from the adjacent circuit. Load transfers were assumed to require an installation of one new switch between the adjacent circuits. When the tying circuit did not have sufficient capacity to accommodate a load transfer, a new circuit was assumed to be necessary to mitigate the identified need. New circuits are assumed to consist of one new switch, one mile of new cable with trenching,[22] and one new circuit breaker.

Capacity upgrades of existing bulk power transformers ("substation banks") were determined based on available bank positions within the substation. If the substation had space for additional banks, then a new bank installation, along with one quarter switchgear, was assumed as the solution to mitigate capacity needs. If there was no additional space for bank installation within the substation, a new circuit from an adjacent substation was assumed as the capacity solution.

The solutioning and cost estimating approach described above are simplified and intended solely to support the timeline and scope of this study. They do not reflect SDG&E's actual planning, engineering, scoping, and design processes, which involve more detailed technical assessments, field surveys, and stakeholder coordination. As previously noted, greenfield substation projects often require significant design, permitting, and construction efforts, as well as land acquisition to accommodate new facilities. Land acquisition costs are excluded from this study. Likewise, new circuit projects and substation expansion projects may involve additional complexities and costs beyond the installation of the new facilities. The upgrade solutions and associated cost estimates presented here are generalized and do not capture the full range of project-specific requirements or implementation challenges that would be

---

[22] The length of cable required for a new circuit can vary widely depending on the location of the tie-in with existing infrastructure. For this study, SDG&E used rough averages from several recently completed new circuit projects as a baseline to support the assumption of a one-mile cable length for general cost estimation purposes.

addressed through SDG&E's formal project development processes. Further details around these costing assumptions are outlined in the Costs section.

To ensure that 2030 and 2040 mitigations do not overlap, circuit and bank solutioning consider the following assumptions.

For circuits:

- If an overload exists in 2030 and is less than 110% overloaded in 2040, then the mitigation in 2030 will mitigate the overload in 2040.
- If an overload exists in 2030 and is less than 110% overloaded but more than 110% overloaded in 2040, then a load transfer would be considered as the mitigation in 2030 and the overload in 2040 would be addressed by a new circuit.
- If an overload exists in 2030 and is more than 110%, then a new circuit would be identified as the solution in 2030 and clear the overload in 2040.

Substation bank overloads were addressed as a case-by-case situation based on:

- Percentage of overload
- Ultimate substation capacity

The costs for load transfers, new circuits, and new banks were derived from the SDG&E 2025 Rule 21 Unit Cost Guide with an escalation of 3% per year.[23,24] The total costs for these mitigations are in the table below. The equipment assumptions for each mitigation option are listed below:

- For a load transfer, 1 new switch is assumed to transfer load.[25]
- For new circuits, 1 new switch, 1 mile of new cable with trenching, and 1 circuit breaker is assumed.
- For a new substation bank, 1 substation transformer, and 1 quarter section switchgear are assumed.

Table 5. Primary System Upgrade Costs by Component Category in 2030 and 2040

Primary Upgrade	2030 Cost $	2040 Cost $
New Circuit	$11,027,780	$14,820,414
New Bank	$11,058,315	$14,861,451
Load Transfer	$622,066	$836,005

A cost breakdown utilizing SDG&E's 2025 Rule 21 Unit Cost Guide can be found in Appendix B.

Secondary System Approach

The secondary distribution system forecast was developed using a bottom-up approach based on SDG&E's 2024 transformer loading report,[26] which captured peak loading data during the system peak

[23] San Diego Gas & Electric, Unit Cost Guide, https://www.sdge.com/sites/default/files/documents/2025-03/SDGE%20Updated%20Rule21%20Unit%20Cost%20guide%20-%202025.pdf. March 31, 2025.
[24] U.S. Bureau of Labor Statistics, Table 1. Consumer Price Index for All Urban Consumers (CPI-U), https://www.bls.gov/news.release/cpi.t01.htm. October 24, 2025.
[25] 10% was added to account for construction costs.
[26] Considers all of SDG&E's service transformers. Note: outliers with inaccurate telemetry data were removed. A total of 163,890 residential and commercial service transformers were included.

period in early September 2024 (September 5–10). This dataset provided the baseline peak demand for each service transformer, accounting for day-to-day variations in customer behavior.

To project future transformer loading for 2030 and 2040, SDG&E applied scenario-specific scaling factors to the 2024 transformer peak values to project electrification-driven load growth. This approach balances technical complexity and accuracy, providing sufficient approximation for the purpose of this study. A description of each scenario and associated assumptions for the secondary distribution system is outlined below:

1. **Base Case**
   The Secondary Base Case takes the Primary Base Case "business as usual" forecasted peak values for 2030 and 2040 and develops a scaling factor by comparing the forecasted system peak to the summation of all the service transformer peaks. Those scaling factors are then applied to the service transformer historical peak values for that date range to determine their electrification-driven forecasted peaks for 2030 and 2040 in the Secondary Base Case. For all modeled scenarios, this study is separate from typical DPP procedures. SDG&E's secondary system upgrades are independent of the DPP and are driven by specific customer requirements and operational needs.

2. **Equity Scenario**
   This scenario takes the hypothetical circuit equity load additions developed in the primary equity scenario analysis and develops a scaling factor by comparing these values to each service transformer historical peak. These scaling factors are called Equity Load Modifiers and are proportional to the circuit increases established in the primary Equity Scenario. Due to the additional load modifiers applied in this scenario, the resulting increase in load drives a greater need for new service transformers compared to the Base Case. Transformers with no equity adjustment identified in the primary equity scenario analysis are scaled by the Base Case Forecast Scaling Factor instead.

3. **Demand Flexibility Scenario**
   This scenario explores potential changes in Base Case consumption based on customer response to hypothetical load management programs for BE and changes to existing TOU rate structures for EVs. The resulting load reductions translate into a lower need for new service transformers than in the Base Case.

Based on the forecast peak system loads in 2030 and 2040 for each scenario, and the resulting estimate of loading on existing transformers, SDG&E compared the predicted transformer loading to the service transformer emergency loading threshold, defined as 120% of the transformer's nameplate rating per IEEE Std C57.91-1981. SDG&E elected to assume an 8-hour continuous loading for the purpose of the EIS Part 2 as it more accurately reflects the expected loading on transformers due to increasing electrification and EV adoption. Circuits with high electrification penetration are already encountering the emergence of nearly dual peaks, reducing the traditional transformer cooling time and accelerating thermal degradation. Transformers forecast to peak above this 120% threshold were flagged for replacement.

$$\begin{gathered}\textit{Overload Condition}: \\ \textit{Transformer Load}\ 2024 * \textit{Forecast Scaling Factor} > 120\% * \textit{Transformer Nameplate}\end{gathered}$$

$$\begin{gathered}\textit{Equity Overload Condition}: \\ \textit{Transformer Load}\ 2024 * \textit{Equity Load Modifier} > 120\% * \textit{Transformer Nameplate}\end{gathered}$$

In addition to the number of transformer replacements, the need for additional service transformers was evaluated. Transformers identified for upsizing were further assessed to determine whether if, when upgraded to the maximum transformer size, the upgraded unit would still exceed the 120% threshold. Those transformers that continued to exceed the loading threshold were identified as requiring additional new transformers. These new additional service transformers (i.e., energization-related transformer upgrades) were analyzed in the same way as transformer replacements (i.e., overloaded transformers).

For example:

If a transformer with 100 kVA nameplate rating is loaded to 150 kW which exceeds the 120% threshold (120 kW)

Mitigation: Split the load between two service transformers: 100 kVA (existing) + 50 kVA (new)

$$100\ kVA\ namplate\ rating\ loaded\ to\ 170\ kW, exceeds\ the\ Loading\ Threshold\ of\ 120\%$$

Following the forecasting of secondary distribution system requirements using the above methodology, SDG&E established a set of cost assumptions for service transformer upgrades and associated service wire installations. These assumptions were derived by quantifying the number of transformer replacements and new installations required and applying the average unit cost for transformers inclusive of service upgrades.

The transformer cost for the residential units reflects a weighted average across SDG&E's single-phase overhead and underground units, encompassing various standard capacities (25 kVA, 50 kVA, 75 kVA, and 100 kVA). The service upgrade cost includes trenching, installation of a 3-inch conduit, and approximately 500 feet of wire. All transformer cost estimates for both residential and commercial units were calculated in alignment with the methodology used under the Rule 21 Unit Cost Guide and a 3% escalation rate was applied for future year costs.[27,28]

Table 6. Secondary Distribution System Estimated Average Costs, Residential, by Element

Secondary System Element	Estimated Average Cost (2025$)
Transformer	$14,796
Service	$5,014
Total	$19,810

The transformer cost for the commercial units encompasses SDG&E's Rule 21 Unit Cost Guide, with a 3% escalation rate applied for future year costs.

The secondary system analysis was conducted using the best available data with several notable limitations:

- Transformer-to-meter mapping is not yet fully validated across SDG&E's service territory. As a result, the analysis was performed using available transformer-level data without detailed customer-level attribution or validation.
- No model cleaning or manual validation of transformer data was performed as part of this study.

[27] Unit Cost Guide is not binding for actual facility costs and is provided only for additional cost transparency and developer reference. For reference, Ft = Per Foot

[28] U.S. Bureau of Labor Statistics, Table 1. Consumer Price Index for All Urban Consumers (CPI-U), https://www.bls.gov/news.release/cpi.t01.htm. October 24, 2025.

The analysis includes only the costs associated with service transformer replacements and estimated service wire upgrades.

- EV clustering was not modeled; localized adoption impacts on secondary loading or upgrade needs were not quantified. EV charging load was included within the total forecast and allocated to secondary transformers proportionally to existing loading.
- As such, actual costs to accommodate new customer load energization may vary from the estimates presented here.

Results

The EIS 2 analysis results are summarized in Table 1 of the Executive Summary. Utilizing the forecasting, planning, and solutioning methodologies outlined in the previous sections of this report, the overall results are discussed further in the following tables and figures.

Peak Load and DER Allocation

Table 7 shows the forecast annual peak load for each of the three scenarios, reflecting data that represent 1-in-10 September peaks. Significant growth is seen between 2030 and 2040, with the differences between scenarios becoming larger in later years. However, the relative trends of the results across the scenarios remain similar from 2030 to 2040, with the Equity Scenario reflecting the highest peak while the Demand Flexibility (as would be expected) reflects the lowest annual peak (Figure 9).

Table 7. Forecast Annual Peak Load in 2030 and 2040

Scenario	**Annual Peak Load (MW) (1-in-10 weather condition)**	
	2030	**2040**
Base Case	6,204	7,007
Equity	6,245	7,172
Demand Flexibility	6,086	6,814

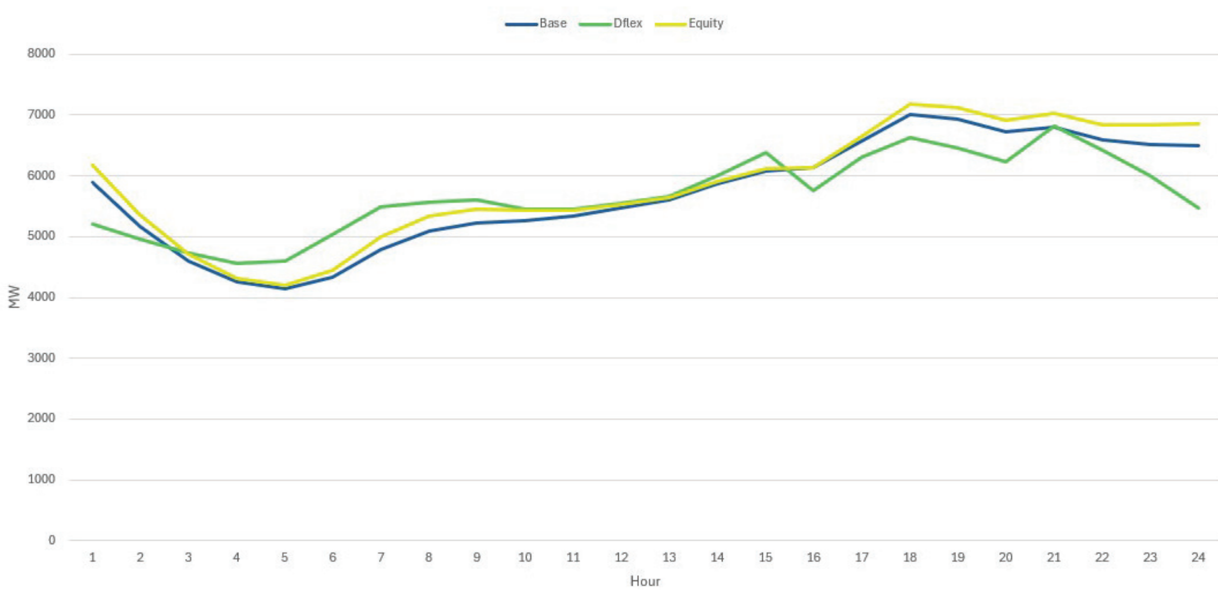


Figure 9. System-Level Load Shape, September Weekday 2040

The following figures show device-level load shapes for example circuits in the Base Case and Demand Flexibility Scenario. The influence of load management programs and DR technologies can be seen in the differences between the two shapes, primarily driven by changes in EV charging behavior. Given the significant similarity between the Base Case and Equity Scenario system-level load shapes, a device-level example is not included. Additional load shape data was provided to the Commission's Energy Division in March and August 2025 as part of requested data transfers.[29]

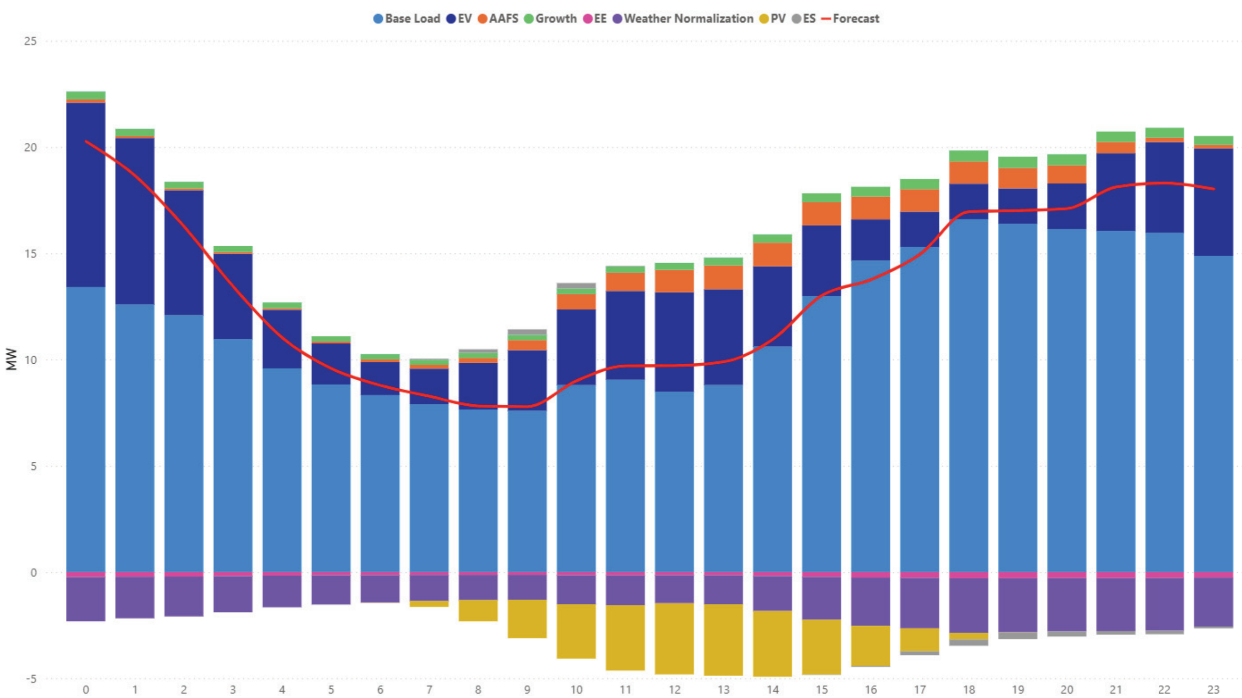


Figure 10. Device-Level Load Shape for Sample Circuit in the Base Case

[29] Further details on the weather normalization process used by SDG&E can be obtained through the submission of a data request by the interested party.

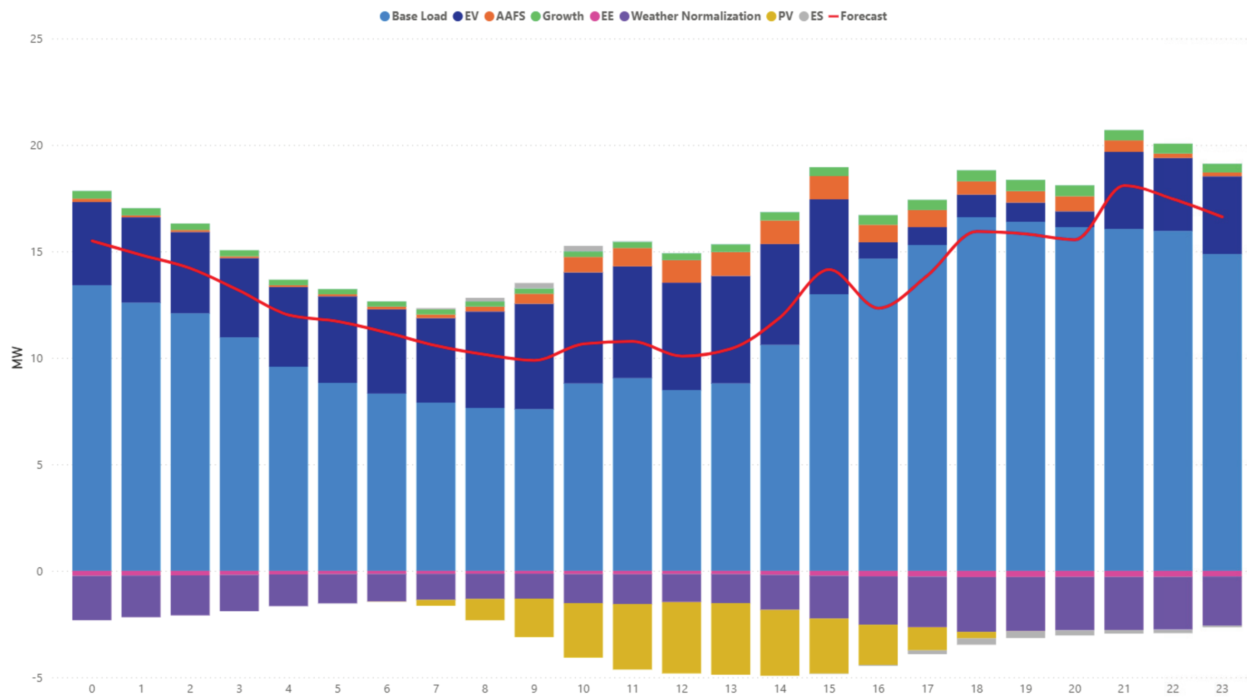


Figure 11. Device-Level Load Shape for Sample Circuit in the Demand Flexibility Scenario

To display the geographic allocation of load growth, SDG&E created the following three maps that display the distribution of DER allocations in megawatts (MW) across ZIP codes within the SDG&E service territory. Darker shades indicate higher MW allocations. Figure 12 includes only DER components used in the SDG&E Base Case, Figure 13 includes only those components within the Equity Scenario, and Figure 14 captures only those components within the Demand Flexibility Scenario. Variation across ZIP codes can be seen between the three displayed scenarios, with Demand Flexibility showing greater differences in allocation compared to the Base Case.

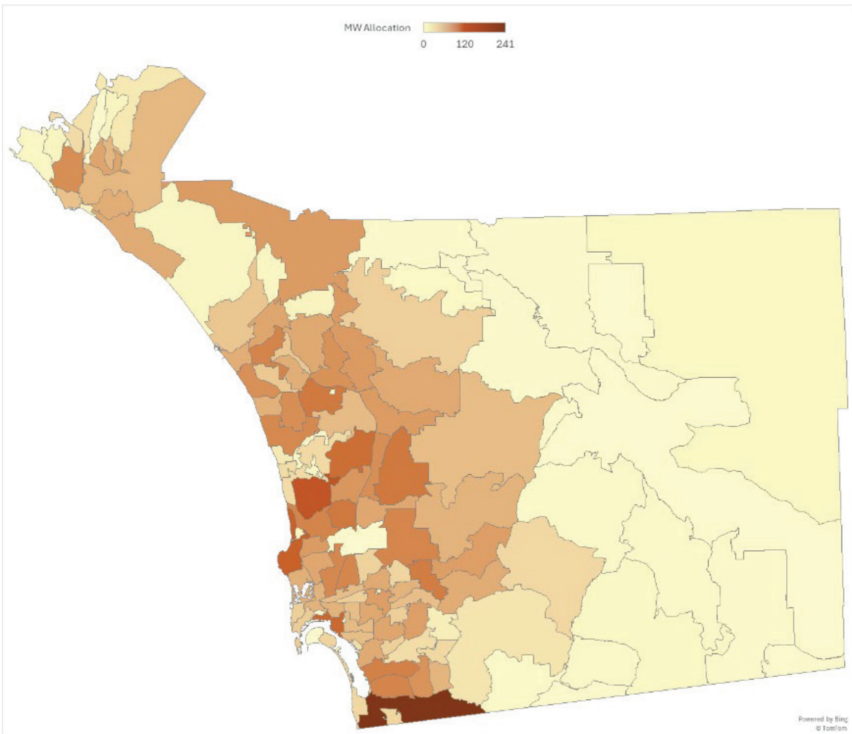


Figure 12. Heat Map of MW Allocation in SDG&E Service Territory for Base Scenario

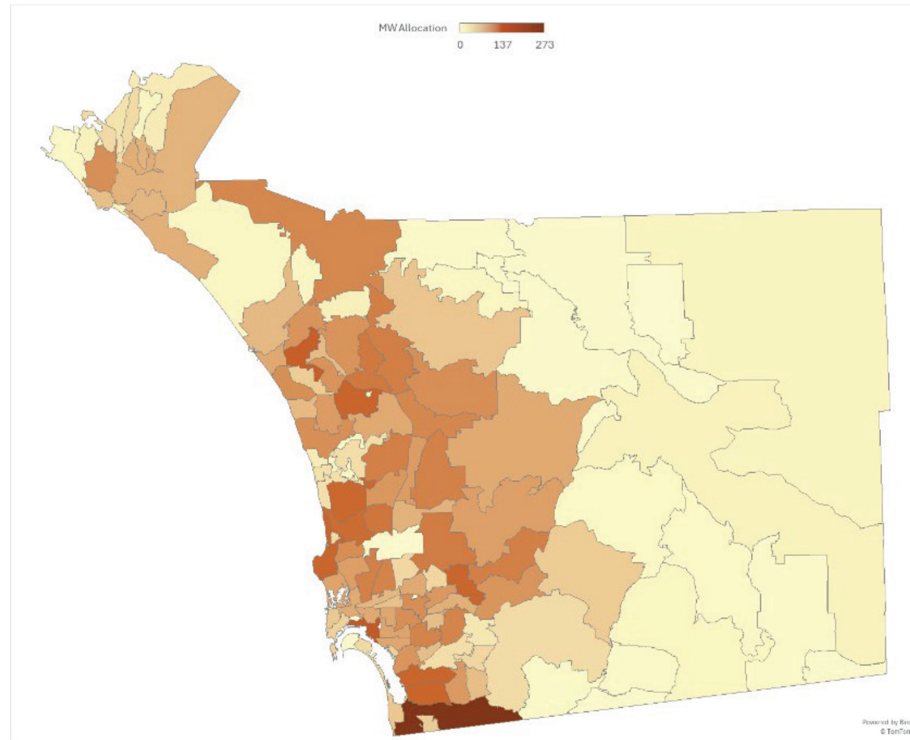


Figure 13. Heat Map of MW Allocation in SDG&E Service Territory for Equity Scenario

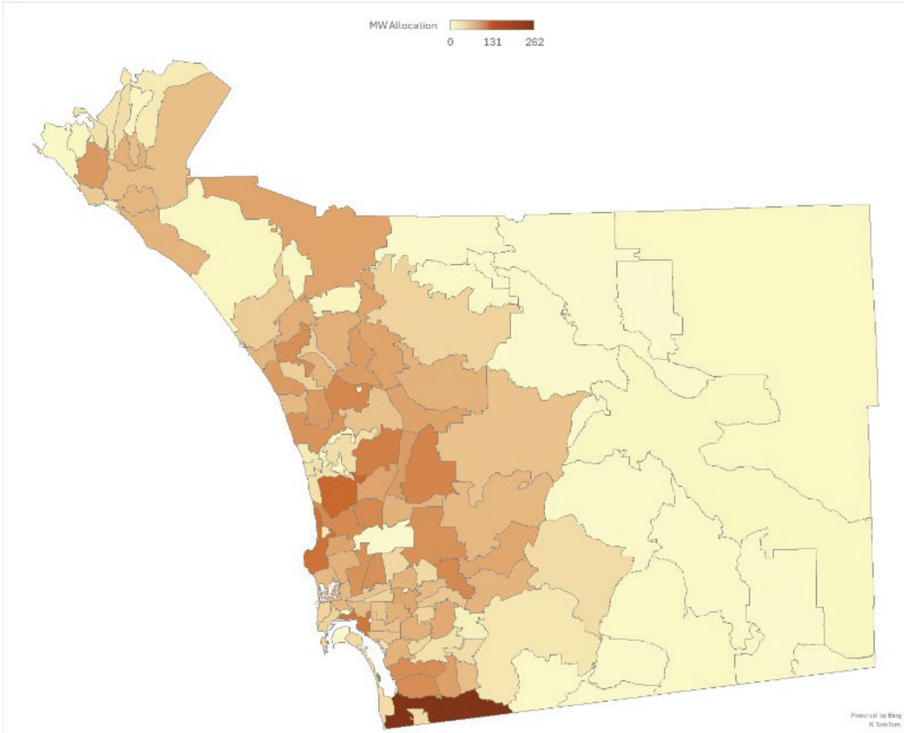
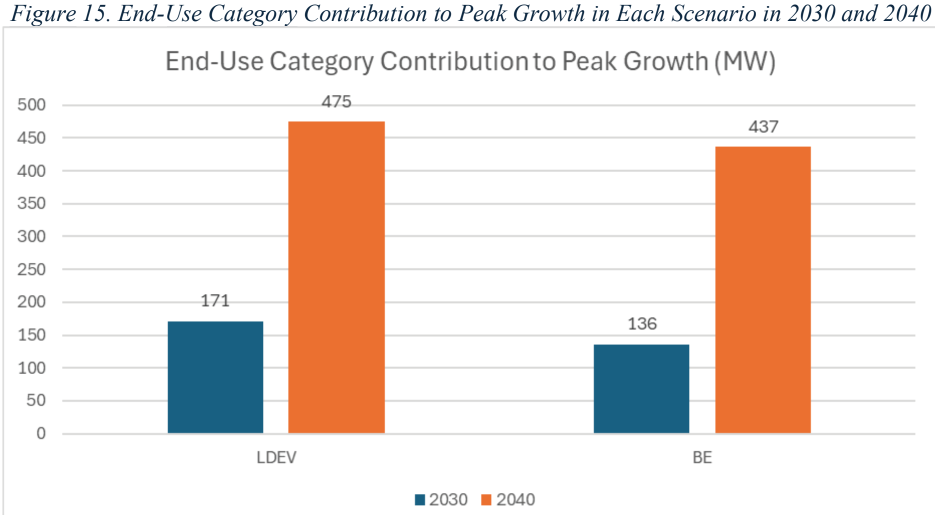


Figure 14. Heat Map for MW Allocation in SDG&E Service Territory for Demand Flexibility Scenario

The future of TE charging behavior comes with uncertainties. All scenarios largely assume that LDEVs will charge where they are domiciled and MD/HD EVs where their depots are located. This is based on currently observed trends and industry practices.

The largest drivers of peak load growth across all scenarios are LD EVs and BE. The below figure shows how much each end-use category contributes to peak load growth in the base scenario.

Figure 15. End-Use Category Contribution to Peak Growth in Each Scenario in 2030 and 2040



As can be seen, LD EVs contribute most significantly to peak load growth. The geographical distribution of LD EVs changes in each of the scenarios from 2030 to 2040 based on non-linear optimization of diffusion modeling. The geographical distribution of BE remains the same year-by-year in all scenarios.

Load Shift and Shed in Demand Flexibility Scenario

Within the Demand Flexibility Scenario, as noted above, shift DR was modeled as shed which simplified the analysis by excluding reallocation of load to off-peak hours. The total amount of DR load shed in the Demand Flexibility Scenario is modest given the combined effects of program implementation costs including incentives, forecast avoided costs, and expected customer participation rates (Table 8).

Table 8. Annual Reduction in Demand Flexibility Scenarios in 2030 and 2040

	Annual Demand Reduction (MWh) Compared to Base Scenario	
Scenario	**2030**	**2040**
Reduction (MWh)	59,710	109,854
Reduction (%)	0.20%	0.30%

Grid Needs and Upgrades

For each scenario, the study identified the mitigation actions and infrastructure upgrades across the 2025-2030 and 2031-2040 time periods. The forecast number of these actions and additions are summarized in Table 9. As would be expected given these respective peaks, the number of solutions is most significant in the Equity Scenario. The estimated distribution costs in the Demand Flexibility Scenario are the lowest, which is as expected given the implementation of DR programs and technologies as the central focus of this scenario.

Table 9. Number of Forecast Mitigation Solutions and Infrastructure Additions for Primary Distribution

	Base Scenario			**Equity Scenario**			**Demand Flexibility Scenario**		
	2025-2030	**2031-2040**	**Total**	**2025-2030**	**2031-2040**	**Total**	**2025-2030**	**2031-2040**	**Total**
Load Transfers	29	58	87	39	67	106	25	60	85
New Circuits	41	100	141	42	120	162	30	81	111
New Bulk Transformers	11	21	32	11	22	33	13	3	16

In response to Energy Division's request, SDG&E provides below an estimate of the average headroom (in MW) created by each new circuit and new bank. While this metric is relatively straightforward for newly constructed circuits, it is more complex for load transfer projects, where the added capacity can vary significantly depending on the specific system configuration and operational needs. The average headroom was calculated by taking the average percentage of overloads multiplied by the capacity increase. New circuits were assumed to provide 12 MW of capacity and banks 28 MW of capacity.

Table 10. Projected Average Headroom per New Circuit Solution

Added MW Capacity	**Avg Overload**	**Avg Headroom per New Circuit**
12 MW	28%	8.64 MW

Table 11. Projected Average Headroom per New Bank Solution

Added MW Capacity	Avg Overload	Avg Headroom per New Bank
28 MW	19%	22.68 MW

For the secondary distribution system, the below tables summarize the number of required transformer replacements and new transformers for each scenario and timeframe.

Table 12. Summary of Transformer Needs for the Secondary Distribution System, 2025-2030

2025-2030	Replacement Transformers	New Transformers Required
Base	13,067	644
Equity	12,318	660
Demand Flexibility	12,625	624

Table 13. Summary of Transformer Needs for the Secondary Distribution System, 2025-2040

2025-2040	Replacement Transformers	New Transformers Required
Base	22,469	1,215
Equity	23,515	1,480
Demand Flexibility	21,502	1,165

Figure 16 below summarizes the total number of upgrades and additions identified in each scenario, providing a comparative view of how infrastructure needs vary under different planning assumptions.

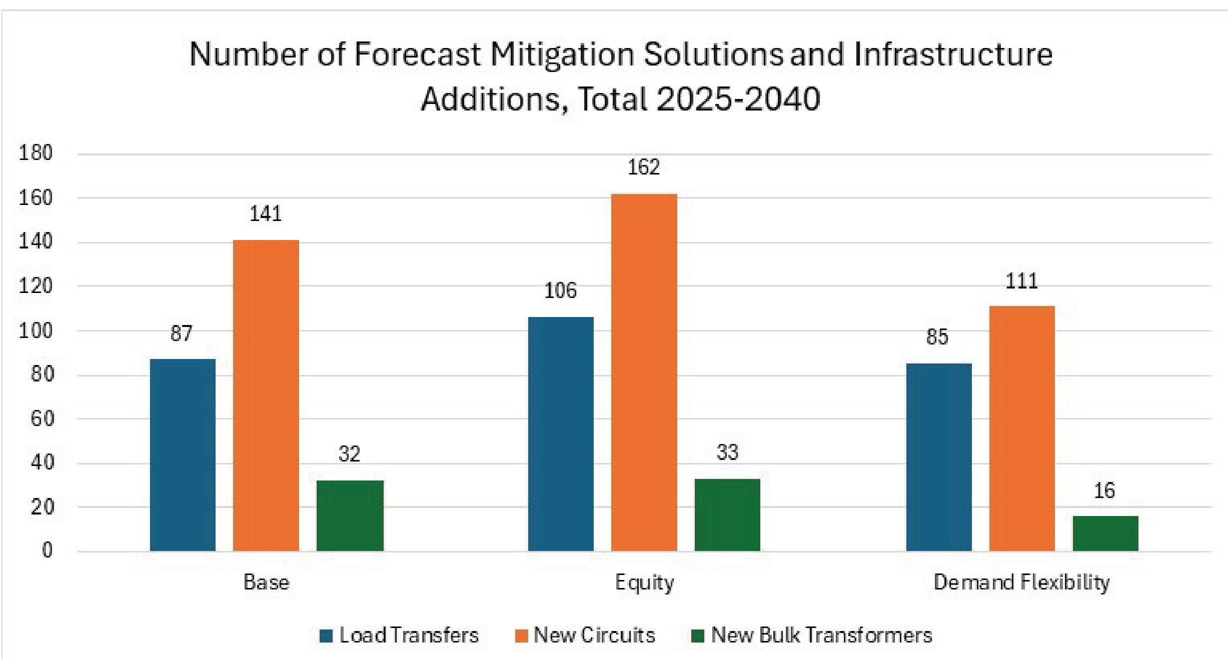


Figure 16. Forecast Mitigation Solutions and Infrastructure Additions for Primary Distribution

Costs

Cost estimates were developed for each scenario and results are presented in fully-loaded nominal dollars. An annual inflation rate of 3% was used to estimate future costs (Table 14). The inflation rate reflects the September 2025 Consumer Price Index (CPI).[30] No economic discounting factor was applied to future costs in EIS 2 since there was no consideration of solution alternatives having different in-service dates or different economic lives; i.e., there was no reason to apply a discount rate.

Table 14. Cost Estimate Results for Primary Distribution System and Total Upgrade Costs in 2040

Scenario	Costs of Load Transfers and New Circuits and Bulk Transformers[31] (nominal $, millions)		Secondary System Upgrade Costs (nominal $, millions)	Total Costs for Primary and Secondary Systems (nominal $, millions)
	2025-2030	**2031-2040**	**2025-2040**	**2025-2040**
Base Case	$592	$1,858	$752	$3,202
Equity	$609	$2,102	$799	$3,569
Demand Flexibility	$490	$1,295	$720	$2,505

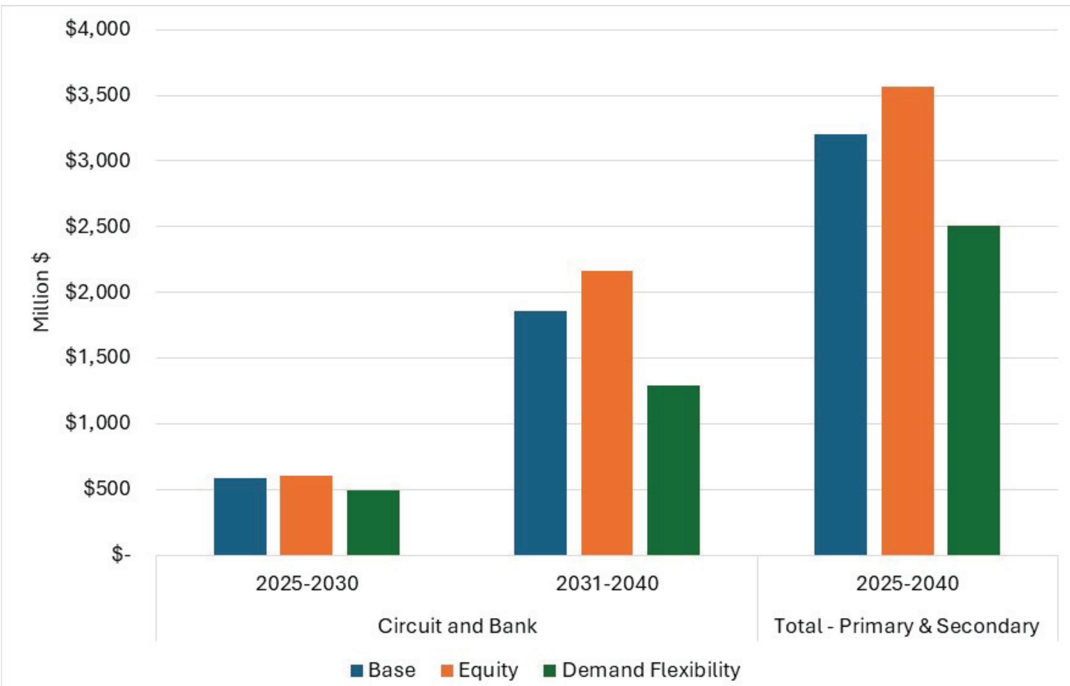


Figure 17. Cost Estimate Results for Base Case, Equity, and Demand Flexibility Scenarios in 2030 and 2040

It is important to note that the following cost categories are excluded and may affect the overall costs of implementing any of these scenarios:

- Distribution line segment costs
- Land acquisition costs, such as when a greenfield substation may be necessary

[30] U.S. Bureau of Labor Statistics, Table 1. Consumer Price Index for All Urban Consumers (CPI-U), https://www.bls.gov/news.release/cpi.t01.htm. October 24, 2025.
[31] Bulk transformer costs include both FERC- and CPUC-jurisdictional costs.

- Any equity or demand flexibility-focused implementation costs (i.e., program costs, technology costs, or customer incentives)[32]

The relative impact of these excluded costs is not expected to vary widely between scenarios, apart from the equity-focused and demand-flexibility implementation costs each of which would naturally only apply to their respective scenarios. It is unlikely that any of the built-in assumptions of the Equity and Demand Flexibility Scenarios would significantly enhance the line segment or greenfield substation costs beyond what is seen in the Base Case.

SDG&E decided to exclude these costs due to their high degree of uncertainty and because including them could result in highly misleading conclusions. Greenfield substation projects not only require extensive design, permitting, and construction efforts but also involve land acquisition to accommodate the new facilities. These costs may vary significantly depending on physical location and system needs. Land acquisition in a dense, coastal, urban portion of the SDG&E service territory could be magnitudes more expensive than in the more rural back country. Given these uncertainties, the land acquisition costs of any new substations are not included in this study. Similarly, many substation expansion projects may incur additional costs beyond simply upsizing or adding a transformer bank. Distribution line segment costs are typically only forecast in the relative near-term (i.e., for implementation in years 1-3 of the planning horizon). Identifying line segment needs beyond this time is highly speculative given their sensitivity to very localized conditions which can change markedly over time. Moreover, there is limited value in identifying line segment needs beyond year 3 since the lead times for mitigation of line segment needs tend to be very short; e.g., load transfers.

Uncertainty in cost projections is an inherent characteristic of long-term forecasting, particularly for complex distribution infrastructure development. SDG&E's development of the EIS Part 2 analysis inevitably involves economic, technological, and regulatory assumptions about the future – factors that naturally become less accurate the further out in time the assumptions are pushed. These assumptions and exclusions are not mistakes but rather fundamental considerations in any long-term forecasting exercise. SDG&E acknowledges that should one or more load drivers (e.g., transportation electrification infrastructure needs) change in the future, it may impact the overall cost and could influence excluded costs to a material agree. This is an inherent trait of any future-facing analysis.

Correlation and Integration with Distribution Planning Process

At a high level, the EIS Part 2 study follows the same general steps as the Distribution Planning Process (DPP). It begins with forecast development. Then a determination is made regarding grid need requirements. This leads to an evaluation of mitigation and solutioning options, and final outputs that may include distribution upgrades and costs. The EIS Part 2 load forecast for the primary distribution system begins with the 2024 - 2025 DPP forecast which is disaggregated to the circuit level. The DPP does not include grid need assessments for the secondary distribution system, so a methodology using 2024 service transformer peak loading levels was developed for the EIS Part 2 study. The approach and assumptions used in EIS Part 2 aligned with DPP where possible, but the EIS Part 2 process was modified where necessary to produce the results and analytical granularity required by the Decision and Energy Division staff guidance.

[32] Program costs, technology costs, and customer incentive costs are not included in Table 14 or in Figure 16 as the table and figure are showing only distribution infrastructure costs. However, program costs, technology costs, and customer incentive costs were included in the LBNL study that determined the economic DR program potential for each of the hypothetical DR programs.

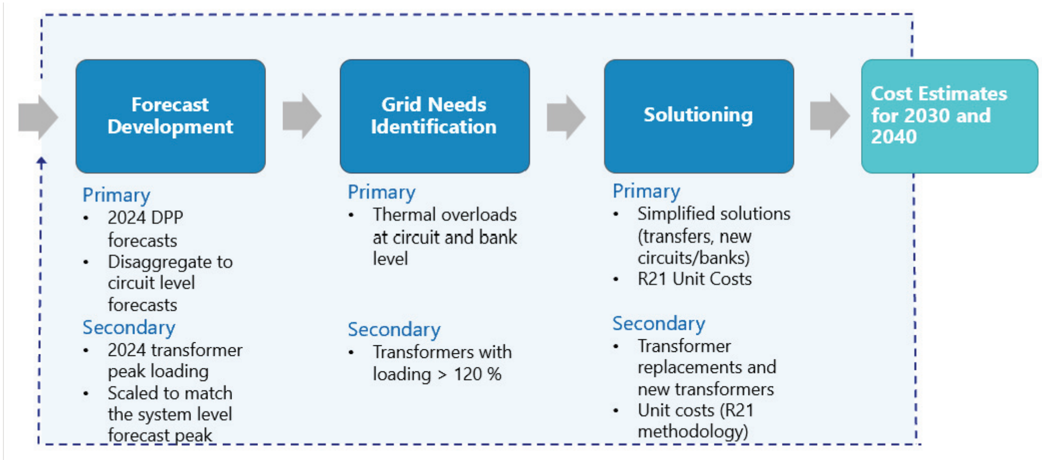


Figure 18. EIS Part 2 Study Methodology

In accordance with R.21-06-017 OP 20, SDG&E's Final EIS Part 2 Report meets the objective of the Load Flexibility Distribution Planning Process assessment as outlined in the *Staff Proposal to Improve the Distribution Planning and Execution Process* dated April 5, 2024. The objective of this assessment was to quantify the potential for flexible load strategies to reduce future distribution costs at the primary and secondary system levels. The Commission emphasized that the assessment was not intended to be a detailed set of load flexibility strategies, rates, policies, and programs but should examine how future load shapes resulting from a range of flexible load strategies could impact distribution planning, potentially impacting distribution upgrade costs. As part of the EIS Part 2 analysis, SDG&E conducted load shape analysis to explore the benefit of demand flexibility, including an examination of potential distribution system cost reductions, thereby meeting this requirement.

OP 20 directs SDG&E to address how the Demand Flexibility and Equity Scenarios may be integrated into the DPEP to inform distribution planning and execution in the future.[33] SDG&E maintains that the load and infrastructure needs identified in the Equity Scenario are hypothetical and exploratory in nature. There currently exists no programmatic basis upon which the DER additions necessary to close any DER gap in disadvantaged communities could be realized. Further the modeling limitation that required circuit-wide additions of DERs to those circuits with 50% or greater levels of DAC-qualifying customers (not just to those portions of the circuit that serve the DAC), means the amount of load added in the Equity Scenario is somewhat overstated.

The Equity Scenario is not a reasonable predictor of real-world load growth and SDG&E does not intend to adopt any of its components into DPEP. Fundamentally, SDG&E treats all its customers and communities equitably and all customers and communities have equitable access to SDG&E's services. SDG&E's distribution planning is solely focused on ensuring safe and reliable electric service for everyone. Accordingly, for distribution planning purposes, SDG&E intends not to adopt existing equity metrics nor to create new equity metrics. However, SDG&E will continue with the activities outlined in the annual Community Engagement Plan, including coordination and collaboration with disadvantaged, rural, and tribal communities to ensure their input is considered in SDG&E's planning processes. In the future, if actionable measures are adopted under which more DERs are added in disadvantaged communities, SDG&E's distribution planning will take those measures into account in forecasting circuit-level loads.

[33] OP 20 directs the IOUs to file "a detailed proposal and timeline of how the…equity scenario assessment will be integrated into the Distribution Planning and Execution Process to inform distribution planning and execution in the future."

The Demand Flexibility Scenario reflects a more plausible and potentially impactful set of drivers. The best way for the future impacts of DR to be included in the DPP is through the CEC's IEPR load forecast. DR could constitute another load modifier, similar to AAEE. The timeline for such activities would be dependent upon CEC priorities and availability but may be possible within the 2026 or 2027 IEPR process. SDG&E notes that the CEC has already made progress in developing DR models.

While the Demand Flexibility Scenario is helpful in understanding the complexities of explicitly incorporating DR program impacts in the DPP, the underlying DR program design has not progressed to the point that it can be relied upon to make decisions on individual distribution upgrades or to support grid modernization elements targeted at mitigating the need for such upgrades.[34] As indicated above, the Equity Scenario does not provide information that is useful for addressing the needs of Disadvantaged Communities. SDG&E will continue with its current DPP practices, including incorporation of the Commission's Pending Loads Resolution as well as ongoing consideration of other potential process improvements.

Impacts and Dependencies

Supply Chain

The tables summarizing forecast distribution needs and solutions provide some indication of the amount of material and labor that will be required to provide the distribution infrastructure necessary to meet the forecast loads in each of the three scenarios.[35] By 2040, the Base Case results in the need for 141 new circuits (the majority being in the 2025-2030 period) and 32 new bulk transformers and 1,215 new service transformers. The Equity Scenario requires the largest number of new circuits and service transformers. The new circuits are concentrated in the 2031-2040 period. The larger number of new circuits in the Equity Scenario is a product of the modeling limitations that required incremental DERs to be added at a circuit-wide level (rather than only in the DACs served by the circuit), and the assumption that programs and incentives will be developed to stimulate increased adoption of DERs (such as EVs) within DACs and for disadvantaged people.

The Demand Flexibility Scenario requires the lowest number of new circuits, new bulk power transformers, and new service transformers. This is the unsurprising result of an assumed introduction of load shed and load shift demand response for customers that convert natural gas uses to electric uses (building electrification), and for small and large customers that are projected to own EVs (LD and MD/HD EV charging, respectively). As described above, load shed and shift demand response impacts are determined as a function of customers' reactions to assumed changes in existing TOU rates as well as an increase in financial incentives to engage in demand response beyond what is included in the Base Case.

SDG&E's current distribution infrastructure planning is based on the results of the Base Case. The objective of the DPP is to make sure the right materials and the right people are in the right place at the right time. This planning allows SDG&E to address any supply chain issues as well as to efficiently manage workforce requirements. At this time, SDG&E expects that it will be able to timely source the

[34] SDG&E is currently exploring the possibility of developing pilots to test the efficacy of using an Advanced Distribution Management System (ADMS)/Distributed Energy Resource Management System (DERMS) to manage/mitigate abnormal real-time and near-real-time circuit conditions.
[35] The identified infrastructure additions include some FERC-jurisdictional transmission in as much as bulk power transformers include both CPUC-jurisdictional distribution and FERC-jurisdictional transmission elements.

materials necessary to build the infrastructure that will serve forecast loads safely and reliably. This expectation is based on many years of successfully meeting customer's energization needs despite fluctuating load growth and significant economic turmoil (e.g., the "dot-com" boom, the financial crisis and ensuing "great recession", COVID, tariffs, an aging population, extreme weather).

New distribution circuits can typically be constructed with lead times under three years and bulk power transformers well under five years. These relatively short lead times provide flexibility in the event the Base Case's forecast of loads through year 2040 trends lower or higher.

While supply chain issues can arise, the burden to the supply chain that SDG&E's projected need for materials in all three scenarios imposes is insignificant when viewed from the context of the entire electric utility industry. All utilities compete for material from the same set of suppliers. SDG&E is a very small player in the overall picture.[36] Effective efforts to manage supply chain issues would require a coordinated national approach. At this time, it is not evident that such efforts are needed or would be practical to develop and implement.

Workforce Planning Considerations

As with material sourcing, SDG&E's distribution planning allows for efficient workforce planning. The infrastructure upgrades identified in the Base Case will enter the regulatory and environmental permitting processes (where required) and be designed with successive levels of technical and construction detail. The detailed facility design and construction timeline will determine workforce requirements. Workforce requirements include assigning individuals with specific skill sets, identifying the number and sources of workers, and staging those workers across the permitting, design and construction periods. Currently, SDG&E expects it will be able to deploy a workforce that is able to timely implement the infrastructure upgrades identified in the Base Case. This expectation is based on many years of successfully navigating the challenges of maintaining a qualified, appropriately sized, employee base while being responsive to changing workforce needs. Examples of changing needs with significant staffing implications include new load types such as electric vehicle and battering charging, wildfire mitigation demands, technology advancements such as Automated Metering Infrastructure (AMI), and evolving climate policies that have eliminated significant amounts of gas-fired generation.

Compared to the Base Case, the Equity Scenario has a larger number of new circuits and, across the 2025-2040, would therefore require more labor hours to implement. The Demand Flexibility Scenario would require fewer labor hours to implement. At the same time, the development, implementation, and administration of programs and technologies needed to drive the changes in load growth under the Equity and Demand Flexibility Scenarios (compared to the Base Case) would likely require an increase in the workforce. Estimating the specific workforce requirements for any of these scenarios across the complete time horizon of this study is an exercise in speculation. There are simply too many unknowns.

Further, the infrastructure additions identified during the 2031-2040 period are generic in nature. The scope and complexity of the actual upgrades that will be constructed will vary greatly. For example, some new circuits may be long and constructed underground in urban areas while others may be short and constructed overhead in relatively unpopulated areas. The workforce requirements for these two types of circuit upgrades would likely be vastly different. Second, SDG&E's workforce at any point in time is the result of numerous inputs, considerations, and tradeoffs. Company priorities can change, and existing staff can be reassigned when and where most needed. Contract personnel can be used to manage short-

[36] For example, SDG&E's current electric load is less than 3% of the electric load in the interconnected western electric grid, and a far smaller fraction of the combined United States electric load.

term needs. Third, it is possible that construction of different infrastructure upgrades can be staged in a manner that minimizes the need for new hires as well as making efficient use of existing personnel.

Finally, the need for and specific timing of distribution infrastructure additions beyond 2030 are increasingly uncertain given the variability in projected organic load growth, DER adoption, and DER impacts on load growth. SDG&E does not see a benefit in speculating how the different scenarios might affect SDG&E's future workforce needs.

Historical Project Costs

The EIS Part 2 provides estimates for future primary and secondary distribution system upgrade costs. As a point of comparison, it was requested by the Energy Division that historical upgrade costs also be provided. While this data has been presented in previous cost recovery proceedings and applications, it is provided here for convenience. The figures are based on information submitted in SDG&E's Application for Authority to Establish a Ratemaking Mechanism for Energization Projects Pursuant to Senate Bill 410 (A.25-04-015)[37] and reflect direct costs only.

Because SDG&E's internal cost tracking processes and procedures do not perfectly mirror EIS Part 2 cost forecast methodologies, the historical costs provided in A.25-04-015 are not directly comparable to the costs reported in this study. Instead, the historical costs provided in A.25-04-015 provide a general sense of how the costs reported in this study compare in terms of magnitude and historical trends.

It is important to note several key caveats regarding the historical cost data:

- Historical spending reflects aggregated actual expenditures for a range of projects and may include costs beyond those associated with electrification-related upgrades.
- Transformer material costs are not tracked by business unit or use case, making it infeasible to isolate costs specifically attributable to electrification-driven needs.
- Additionally, the transformer costs submitted in A.25-04-015 reflect material-only expenses and do not include installation or labor, making them not directly comparable to the unit costs used in this study, which typically include both material and installation components.

Table 15. Historical Annual Capital Spend on Capacity / Expansion and Materials for Distribution

	Annual Capital Spend ($000)			
GRC Cost Category	**2021**	**2022**	**2023**	**2024**
Capacity / Expansion	$10,265	$13,420	$6,188	$17,961
Materials (Transformers)	$5,288	$8,142	$11,989	$17,302

Revisions to the Draft Report

SDG&E filed the Draft EIS 2 Report on October 31, 2025. A stakeholder workshop was held November 19-20, 2025, where IOUs presented their respective EIS 2 methodologies, analysis, and results. Parties' comments were received on December 15, 2025, and feedback from Energy Division staff was received on December 23, 2025. There were several comments received on SDG&E's EIS Part 2 methodology. While SDG&E appreciates the feedback provided by all stakeholders, the analysis has been many months in the making and at this stage significant methodological changes have not been practicable. SDG&E focused these final revisions and feedback incorporation on the major comments and themes. In

[37] See p. B-2: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M573/K513/573513353.PDF

preparation of the Final EIS 2 Report, SDG&E made revisions related to report clarity and comprehensiveness, as well as finalization of data inputs and results.

Clarifications

After review of feedback received, SDG&E incorporated a variety of changes into the Final EIS 2 Report. Where minor clarification or additional details were needed, they were provided within the applicable sections of the report. For example, the presentation of some of the figures and tables were adjusted to make interpretations more intuitive and clearer. These types of clarifying changes are intended to be minor. Areas where SDG&E provided clarified content in this Final EIS Report include:

- The Draft EIS Report used the term "economic potential" to describe the magnitude of demand flexibility modeled in SDG&E's Demand Flexibility Scenario. To be consistent with the terminology used within the LBNL Demand Response Potential Study, which served as a foundational input to the Demand Flexibility Scenario, the Final EIS Report uses the term "achievable potential". The "achievable potential" factors in a historically based measure of the subset of customers likely to participate in economically beneficial DR programs. The methods, data, and results related to this portion of the EIS Phase 2 analysis are unchanged. These revisions are in the Demand Flexibility Scenario section beginning on page 10.

- Several stakeholders provided comments on how program implementation costs, including incentives, were (or were not) included in the analysis. The final report clarifies how and which if these costs are accounted for in the analysis. This clarification is provided in the Study Approach and Methodologies section beginning on page 5.

- A stakeholder comment was received expressing a desire for information regarding SDG&E's weather normalization process. As this process includes confidential information, any interested party seeking further details can submit a data request to SDG&E. A footnote indicating as such was added on page 22.

Updates and Additions

In certain cases, data was updated and the Final EIS 2 Report reflects the finalized results. Such updates include:

- Updated Equity Scenario primary system solutions and costs to reflect solutioning similar to that performed for the Base Case.

- Updated Base Case and Demand Flexibility project counts to reflect consistent counting methods across scenarios.

- Updated secondary system costs across all three scenarios now reflect assumed inflation for the full 15-year study period.

In accordance with D.24-10-030 OP 20,[38] additional content was included in the Final EIS Part 2 to address the Commission's requirement to meet the objectives and requirements of the Load Flexibility

[38] OP 20 directs the IOUs to file "a description of how the Study's final report meets the requirements and objectives of the Load Flexibility Distribution Planning Process assessment proposed in the *Staff Proposal to Improve the Distribution Planning and Execution Process* and other Commission requirements" and "a detailed proposal and

Distribution Planning Process assessment as provided in the *Staff Proposal to Improve the Distribution Planning and Execution Process [DPEP]* dated April 5, 2024. The Staff Proposal contemplates the IOUs submitting "a Flexible Load DPP Assessment that quantifies the potential for flexible load strategies to reduce future distribution costs at the primary and secondary distribution level."[39] According to the Staff Proposal the "goal of the assessment is to better enable utilities to strategically incorporate load management and load flexibility techniques into their distribution planning."[40] The Final EIS Part 2 contains this additional content in the Correlation and Integration with Distribution Planning Process section beginning on page 29.

SDG&E also addressed how the Demand Flexibility and Equity Scenarios will be considered in the DPEP. This content is found in the Correlation and Integration with Distribution Planning Process section beginning on page 29.

Finally, the Final EIS Part 2 Conclusion section addresses a comment regarding SDG&E's recommendation that the Commission avoid directives that could compromise SDG&E's ability to efficiently plan for the needs of its customers.

Conclusion

While the Commission's interest in exploring alternative futures is understandable, SDG&E cautions against adopting any directives that would interfere with the utility's ability to plan for the needs of its customers. Commission directives that specify prescriptive scenario requirements could result in planning outcomes that are reflective of the defined scenario, but poorly correlated with expected conditions. Measures of effective planning performance, while not necessarily reduceable to metrics, are whether customers are being timely energized and whether customers are receiving reliable service. To date, SDG&E's distribution planning performance has been effective in both regards.

SDG&E interprets the Equity and Demand Flexibility Scenarios as hypothetical "what if" situations that carry little weight in terms of anticipating the infrastructure that will be needed to meet future, real world needs. These scenarios are designed to take a limited set of drivers and extrapolate their impacts across the full system, and it is unlikely that any one of these scenarios would exclusively come to pass. Rather, it is more likely that, over time, it becomes apparent that some of the necessary underpinnings from these two scenarios will be implemented (e.g., increased DER incentives for disadvantaged communities, TOU rate changes, and DR program development with cost-effective incentives). In this way, the most needed and cost-effective solutions will rise to implementation, and when that happens, the planning inputs for the next DPP cycle will be modified and the Base Case updated as per the current standard planning process. The DPP cycle itself serves as a responsive and flexible framework for the incorporation of data that reflects ongoing updates to transportation and building electrification adoption, enabling technologies, and/or flexible load capabilities.

timeline of how the Load Flexibility Distribution Planning Process assessment and equity scenario assessment will be integrated into the Distribution Planning and Execution Process to inform distribution planning and execution in the future."

[39] Staff Proposal, p. 82.

[40] Staff Proposal, p. 83.

Appendix A. List of Grid Needs & Planning Solutions Identified

See Excel file titled "App A_EIS List of Grid Needs and Solutions SDGE-v2.xlsx"

Base Case Grid Needs & Solutions by Year				
Circuit/Substation	**Year**	**Bank**	**Circuit**	**Load Transfer/Switch**
1	2030		1	
2	2030		1	
3	2030		1	
4	2030		1	
5	2030			1
6	2030			1
7	2030		1	
8	2030		1	
9	2030			1
10	2030			1
11	2030		1	
12	2030			1
13	2030			1
14	2030		1	
15	2030			1
16	2030		1	
17	2030			1
18	2030		1	
19	2030		1	
20	2030		1	
21	2030		1	
22	2030		1	
23	2030			1
24	2030		1	
25	2030			1
26	2030			1
27	2030			1
28	2030		1	
29	2030			1
30	2030			1
31	2030			1
32	2030		1	
33	2030		1	
34	2030			1
35	2030		1	
36	2030		1	
37	2030		1	
38	2030			1
39	2030		1	
40	2030			1
41	2030		1	
42	2030		1	
43	2030		1	
44	2030			1
45	2030		1	
46	2030			1
47	2030		1	
48	2030			1
49	2030			1
50	2030			1
51	2030			1
52	2030		1	
53	2030		1	
54	2030		1	
55	2030		1	
56	2030			1
57	2030		1	
58	2030		1	
59	2030			1
60	2030			1
61	2030			1
62	2030			1
63	2030		1	
64	2040			1

Rows shown in Bold do not have solutions for the listed year because the need was addressed by a solution in a previous year.

65	**2040**			
66	**2040**			
67	2040		1	
68	2040		1	
69	2040			1
70	2040			1
71	2040			1
72	2040			1
73	**2040**			
74	2040			1
75	2040			1
76	2040		1	
77	2040		1	
78	2040			1
79	2040		1	
80	2040			1
81	2040		1	
82	2040			1
83	**2040**			
84	2040		1	
85	2040		1	
86	2040		1	
87	**2040**			
88	2040		1	
89	**2040**			
90	2040		1	
91	2040		1	
92	2040		1	
93	2040		1	
94	**2040**			
95	2040			1
96	2040			1
97	2040			1
98	2040		1	
99	2040		1	
100	2040			1
101	2040		1	
102	2040		1	
103	2040		1	
104	**2040**			
105	**2040**			
106	**2040**			
107	2040		1	
108	**2040**			
109	**2040**			
110	2040		1	
111	**2040**			
112	2040			1
113	2040			1
114	2040		1	
115	2040		1	
116	2040		1	
117	2040		1	
118	2040		1	
119	2040			1
120	2040		1	
121	2040		1	
122	2040			1
123	2040			1
124	**2040**			
125	2040		1	
126	2040			1
127	**2040**			
128	2040		1	
129	2040			1
130	2040		1	

131	2040		1	
132	2040		1	
133	2040		1	
134	2040		1	
135	2040			1
136	2040			1
137	2040			1
138	**2040**			
139	**2040**			
140	2040		1	
141	2040		1	
142	2040			1
143	2040		1	
144	2040		1	
145	2040		1	
146	2040		1	
147	2040		1	
148	2040			1
149	2040		1	
150	2040			1
151	2040		1	
152	2040			1
153	2040		1	
154	2040		1	
155	2040		1	
156	2040			1
157	**2040**			
158	2040		1	
159	2040			1
160	2040		1	
161	2040		1	
162	2040			1
163	2040		1	
164	2040			1
165	2040			1
166	**2040**			
167	**2040**			
168	**2040**			
169	2040		1	
170	2040		1	
171	2040			1
172	2040			1
173	2040			1
174	2040			1
175	2040			1
176	2040		1	
177	2040			1
178	2040		1	
179	2040		1	
180	2040		1	
181	2040		1	
182	**2040**			
183	2040		1	
184	2040			1
185	**2040**			
186	**2040**			
187	**2040**			
188	2040		1	
189	2040		1	
190	2040			1
191	2040		1	
192	2040			1
193	**2040**			
194	2040		1	
195	2040		1	
196	2040		1	

197	2040		1	
198	2040			1
199	2040		1	
200	2040			1
201	2040		1	
202	2040		1	
203	2040			1
204	2040		1	
205	2040			1
206	2040			1
207	**2040**			
208	2040		1	
209	2040			1
210	2040		1	
211	**2040**			
212	2040		1	
213	2040			1
214	2040		1	
215	2040			1
216	2040			1
217	2040		1	
218	2040			1
219	2040			1
220	**2040**			
221	2040		1	
222	2040			1
223	2040			1
224	**2040**			
225	2040			1
226	2040		1	
227	2040		1	
228	2040		1	
229	2040		1	
230	**2040**			
231	2040		1	
232	**2040**			
233	2040		1	
234	2040		1	
235	**2040**			
236	**2040**			
237	2040		1	
238	2040		1	
239	2040		1	
240	2040			1
241	**2040**			
242	2040		1	
243	**2040**			
244	2040			1
245	2030	1		
246	2030	1		
247	2030	1		
248	2030	1		
249	2030	1		
250	2030	1		
251	2030	1		
252	2030	1		
253	2030	1		
254	2030	1		
255	2030		1	
256	2030		1	
257	2030		1	
258	2030	1		
259	**2040**			
260	2040	1		
261	**2040**			
262	**2040**			

263	**2040**			
264	**2040**			
265	**2040**			
266	**2040**			
267	**2040**			
268	2040	1		
269	**2040**			
270	**2040**			
271	2040	1		
272	2040		1	
273	2040		1	
274	**2040**			
275	2040		1	
276	2040	1		
277	**2040**			
278	2040	1		
279	2040	1	1	
280	2040	1		
281	2040	1		
282	2040	1		
283	2040	1		
284	2040	1		
285	2040		1	
286	2040	1		
287	2040	1		
288	2040		1	
289	2040		1	
290	2040	1	1	
291	2040	1		
292	2040		1	
293	2040	1		
294	2040		1	
295	2040	1		
296	2040		1	
297	2040	1		
298	2040		1	
299	2040	1		
300	2040		1	
301	2040	1		
302	2040	1		

Demand Flexibility Scenario Grid Needs & Solutions by Year				
Circuit/Substation	**Year**	**Bank**	**Circuit**	**Load Transfer/Switch**
1	2030		1	
2	2030		1	
3	2030		1	
4	2030		1	
5	2030		1	
6	2030		1	
7	2030		1	
8	2030		1	
9	2030		1	
10	2030		1	
11	2030		1	
12	2030		1	
13	2030		1	
14	2030		1	
15	2030		1	
16	2030		1	
17	2030		1	
18	2030		1	
19	2030		1	
20	2030		1	
21	2030		1	
22	2030		1	
23	2030		1	
24	2030		1	
25	2030			1
26	2030			1
27	2030			1
28	2030			1
29	2030			1
30	2030			1
31	2030			1
32	2030			1
33	2030			1
34	2030			1
35	2030			1
36	2030			1
37	2030			1
38	2030			1
39	2030			1
40	2030			1
41	2030			1
42	2030			1
43	2030			1
44	2030			1
45	2030			1
46	2030			1
47	2030			1
48	2030			1
49	2030			1
50	**2040**			
51	2040			1
52	2040		1	
53	2040		1	
54	2040		1	
55	2040		1	
56	2040			1
57	**2040**			
58	2040			1
59	2040			1
60	2040		1	
61	2040		1	

Rows shown in Bold do not have solutions for the listed year because the need was addressed by a solution in a previous year.

62	2040			1
63	2040			1
64	2040		1	
65	2040		1	
66	2040			1
67	**2040**			
68	2040		1	
69	2040		1	
70	2040		1	
71	2040		1	
72	**2040**			
73	2040		1	
74	2040		1	
75	2040		1	
76	2040		1	
77	2040		1	
78	2040		1	
79	**2040**			
80	2040			1
81	2040			1
82	2040			1
83	2040		1	
84	2040		1	
85	2040			1
86	2040			1
87	2040		1	
88	2040		1	
89	**2040**			
90	2040		1	
91	2040		1	
92	2040			1
93	**2040**			
94	**2040**			
95	2040		1	
96	2040			1
97	2040			1
98	**2040**			
99	2040			1
100	2040		1	
101	2040			1
102	2040		1	
103	2040		1	
104	2040		1	
105	**2040**			
106	2040			1
107	2040			1
108	**2040**			
109	2040		1	
110	2040		1	
111	2040		1	
112	2040		1	
113	2040		1	
114	2040		1	
115	2040			1
116	2040			1
117	2040			1
118	**2040**			
119	**2040**			
120	2040			1
121	2040			1
122	2040		1	
123	2040		1	
124	2040			1

125	2040			1
126	2040			1
127	2040		1	
128	2040		1	
129	2040		1	
130	2040		1	
131	2040		1	
132	2040			1
133	2040			1
134	2040		1	
135	2040			1
136	2040			1
137	2040			1
138	2040		1	
139	2040			1
140	**2040**			
141	**2040**			
142	2040		1	
143	2040			1
144	2040			1
145	2040			1
146	2040			1
147	2040			1
148	2040		1	
149	2040		1	
150	2040		1	
151	2040		1	
152	2040		1	
153	2040			1
154	**2040**			
155	2040			1
156	2040		1	
157	**2040**			
158	2040		1	
159	2040		1	
160	2040			1
161	2040		1	
162	2040			1
163	**2040**			
164	2040		1	
165	2040		1	
166	2040		1	
167	2040		1	
168	2040		1	
169	2040			1
170	2040		1	
171	2040		1	
172	2040		1	
173	2040			1
174	2040			1
175	**2040**			
176	2040			1
177	2040			1
178	2040			1
179	2040			1
180	2040			1
181	2040			1
182	2040		1	
183	2040			1
184	2040			1
185	2040		1	
186	2040			1
187	2040			1

188	2040			1
189	2040		1	
190	2040			1
191	2040		1	
192	2040			1
193	2040		1	
194	2040		1	
195	2040		1	
196	**2040**			
197	**2040**			
198	2040		1	
199	2040		1	
200	**2040**			
201	2040		1	
202	2040		1	
203	**2040**			
204	**2040**			
205	2040		1	
206	2040		1	
207	2040		1	
208	2040			1
209	**2040**			
210	**2040**			
211	**2040**			
212	2040			1
213	2030	1		
214	2040	1		
215	2030	1		
216	2040	1		
217	2030	1		
218	**2040**			
219	**2040**			
220	2030	1		
221	**2040**			
222	2030		1	
223	2040		1	
224	2030	1		
225	2040	1		
226	2030	1		
227	**2040**			
228	2030	1		
229	**2040**			
230	**2040**			
231	2030	1		
232	**2040**			
233	2030		1	
234	2040		1	
235	2030	1		
236	**2040**			
237	2030		1	
238	2040		1	
239	2030	1		
240	**2040**			
241	2030	1		
242	**2040**			
243	2030	1		
244	**2040**			
245	2030	1		
246	**2040**			
247	**2040**			

Equity Scenario Grid Needs & Solutions by Year				
Circuit/Substation	**Year**	**Bank**	**Circuit**	**Load Transfer/Switch**
1	2040			1
2	2030		1	
3	**2040**			
4	2030		1	
5	**2040**			
6	2030			1
7	2040		1	
8	2040		1	
9	2040			1
10	2030			1
11	2040		1	
12	2040			1
13	2040			1
14	2040			1
15	2030		1	
16	**2040**			
17	2040			1
18	2040			1
19	2030			1
20	2040		1	
21	2030			1
22	2040		1	
23	2040		1	
24	2040			1
25	2040		1	
26	2040			1
27	2040		1	
28	2040			1
29	2030		1	
30	**2040**			
31	2030			1
32	2040		1	
33	2030		1	
34	**2040**			
35	2040		1	
36	2040		1	
37	2030		1	
38	**2040**			
39	2040		1	
40	2040		1	
41	2040		1	
42	2040		1	
43	2040			1
44	2040		1	
45	2030			1
46	2040		1	
47	2030			1
48	2040		1	
49	2030		1	
50	**2040**			
51	2040		1	
52	2040			1
53	2030			1
54	2040		1	
55	2040			1
56	2030			1
57	2040		1	
58	2040		1	
59	2040			1
60	2040			1
61	2030			1

Rows shown in Bold do not have solutions for the listed year because the need was addressed by a solution in a previous year.

62	2040		1	
63	2040		1	
64	2030			1
65	2040		1	
66	2030		1	
67	**2040**			
68	2030			1
69	2040		1	
70	2030		1	
71	**2040**			
72	2030			1
73	2040			1
74	2030		1	
75	**2040**			
76	2030		1	
77	**2040**			
78	2040			1
79	2040		1	
80	2030		1	
81	**2040**			
82	2040			1
83	2040			1
84	2040		1	
85	2030		1	
86	**2040**			
87	2040		1	
88	2040		1	
89	2040		1	
90	2040		1	
91	2040		1	
92	2040		1	
93	2040			1
94	2030		1	
95	**2040**			
96	2030			1
97	2040			1
98	2040			1
99	2030		1	
100	**2040**			
101	2030			1
102	2040		1	
103	2040			1
104	2040		1	
105	2030		1	
106	**2040**			
107	2030		1	
108	**2040**			
109	2030		1	
110	**2040**			
111	2030			1
112	2040		1	
113	2040		1	
114	2040			1
115	2040		1	
116	2040			1
117	2040		1	
118	2030			1
119	**2040**			
120	2030		1	
121	**2040**			
122	2030			1
123	2040			1
124	2040		1	

125	2040			1
126	2040		1	
127	2030		1	
128	**2040**			
129	2040		1	
130	2040		1	
131	2040		1	
132	2040		1	
133	2040			1
134	2040		1	
135	2040		1	
136	2040			1
137	2040			1
138	2030			1
139	2040			1
140	2040		1	
141	2040			1
142	2040		1	
143	2040			1
144	2040			1
145	2040		1	
146	2040		1	
147	2040		1	
148	2040		1	
149	2040			1
150	2030			1
151	2040		1	
152	2030		1	
153	**2040**			
154	2040		1	
155	2040		1	
156	2040			1
157	2040		1	
158	2040		1	
159	2040		1	
160	2040		1	
161	2040			1
162	2040		1	
163	2030		1	
164	**2040**			
165	2030			1
166	2040			1
167	2040			1
168	2030		1	
169	**2040**			
170	2030		1	
171	**2040**			
172	2030		1	
173	2040		1	
174	2040		1	
175	2040			1
176	2040			1
177	2040		1	
178	2040			1
179	2040			1
180	2040			1
181	2040			1
182	2030			1
183	2040			1
184	2040			1
185	2040		1	
186	2040		1	
187	2030			1

188	2040		1	
189	2030			1
190	2040		1	
191	2040			1
192	2030		1	
193	**2040**			
194	2040		1	
195	2040		1	
196	2030		1	
197	**2040**			
198	2040		1	
199	2040		1	
200	2040			1
201	2040		1	
202	2040			1
203	2030			1
204	**2040**			
205	2040		1	
206	2030			1
207	2040		1	
208	2040		1	
209	2040		1	
210	2040		1	
211	2040			1
212	2040		1	
213	2040		1	
214	2040			1
215	2040		1	
216	2040			1
217	2040		1	
218	2040			1
219	2030		1	
220	**2040**			
221	2030			1
222	2040		1	
223	2040			1
224	2030			1
225	2040			1
226	2030			1
227	2040			1
228	2040			1
229	2040			1
230	2030			1
231	2040		1	
232	2040			1
233	2030			1
234	2040		1	
235	2030			1
236	**2040**			
237	2030			1
238	2040		1	
239	2040			1
240	2040		1	
241	2030			1
242	2040		1	
243	2040			1
244	2040		1	
245	2040		1	
246	2040		1	
247	2040		1	
248	2030		1	
249	2040		1	
250	2030		1	

251	**2040**			
252	2040		1	
253	2030		1	
254	**2040**			
255	2030			1
256	2040		1	
257	2040		1	
258	2030		1	
259	**2040**			
260	2030			1
261	**2040**			
262	2040			1
263	2030			1
264	2040		1	
265	2040			1
266	2040			1
267	2030			1
268	**2040**			
269	2030			1
270	2040			1
271	2030		1	
272	**2040**			
273	2040			1
274	2040	1		
275	2040	1		
276	2040	1		
277	2040	1		
278	2030	1		
279	2040	1		
280	2040		1	
281	2030		1	
282	**2040**			
283	2030		1	
284	**2040**			
285	2040	1		
286	2040		1	
287	2040		1	
288	2040		1	
289	2030	1		
290	**2040**			
291	2040		1	
292	2030	1		
293	**2040**			
294	2040		1	
295	2040		1	
296	2030		1	
297	**2040**			
298	2030	1		
299	**2040**			
300	2040		1	
301	2040	1		
302	2030	1		
303	**2040**			
304	2040		1	
305	2040		1	
306	2040		1	
307	2030	1		
308	**2040**			
309	2030	1		
310	2040	1		
311	2030		1	
312	2040		1	
313	2030	1		

314	**2040**			
315	2040	1		
316	2040	1		
317	2040	1		
318	2040		1	
319	2040		1	
320	2030		1	
321	2040		1	
322	2040	1	1	
323	2030	1		
324	**2040**			
325	2040		1	
326	2040		1	
327	2040		1	
328	2040	1		
329	2030		1	
330	**2040**			
331	2040		1	
332	2030	1		
333	**2040**			
334	2040		1	
335	2040		1	
336	2040	1		
337	2040	1		
338	2030	1		
339	**2040**			

Appendix B. Primary System Upgrade Component Cost Breakdown

The following cost details rely on the Rule 21 Unit Cost Guide.

Table 16. Circuit Upgrade Costs, by Component

Circuits					
Construction	**Unit Cost (2025$)**	**No.**	**Total**	**2030 (Nominal $)**	**2040 (Nominal $)**
New primary trench and conduit if IOU installs	$1,357/ft	5,280 ft	$7,164,960	-	-
New 1000 KCMIL AL cable and connections	$165/ft	5,280 ft	$871,200	-	-
New Padmount SCADA Switch	$486,600	1	$486,600	-	-
New Substation Circuit Breaker	$989,900	1	$989,900	-	-
Grand Total			**$9,512,660**	**$11,027,780**	**$14,820,414**

Table 17. Bank Upgrade Costs, by Component

Banks					
Construction	**Unit Cost (2025$)**	**No.**	**Total**	**2030 (Nominal $)**	**2040 (Nominal $)**
New 28MVA 69/12kV Transformer	$4,381,000	1	$4,381,000	-	-
Quarter Section Switchgear	$5,158,000	1	$5,158,000	-	-
Grand Total			**$9,539,000**	**$11,058,315**	**$14,861,451**

Table 18. Load Transfer Upgrade Costs, by Component

Load Transfers					
	Unit Cost (2025$)	**No.**	**Total**	**2030 (Nominal $)**	**2040 (Nominal $)**
Load Transfer Labor	N/A		$50,000	-	-
New Padmount SCADA Switch	$486,600	1	$486,600	-	-
Grand Total			**$536,600**	**$622,066**	**$836,005**