Pacific Gas and Electric Company

EPIC Final Report

Program	***Electric Program Investment Charge (EPIC)***
Project	***EPIC 2.23 – Integrate demand side approaches into utility planning***
Department	*Distribution Asset Management*
Project Sponsor	Ahmad Ababneh
Business Lead	Richard Aslin
Date	September 9, 2017
Version Type	*Final*
Contact	EPIC_info@pge.com

Table of Contents

1.0 Executive Summary 1
2.0 Introduction 7
3.0 Project Summary 7
3.1 Project Objective 8
3.2 Issue Addressed 8
3.3 Scope of Work 9
3.3.1 Major Milestones, Tasks and Deliverables 10
3.3.2 System and Process Description 11
4.0 Project Results, Findings and Next Steps 14
4.1 Technical Results 14
4.1.1 Customer Class Load Shape Enhancements 14
4.1.2 Load Shape Viewer 16
4.1.3 Load Forecast Viewer 18
4.1.4 Incorporated DER Projection Scenarios 22
4.1.5 Load Forecasting and Power Flow Analysis Integration 23
4.1.6 Streamlined Integration Capacity Analysis 24
4.1.7 Enhanced Data Transfer Capabilities 25
4.2 Findings, Learnings and Next Steps 25
4.3 User Feedback 28
4.4 Data Access 29
4.5 Value Proposition 29
4.5.1 Primary Principles 30
4.5.2 Secondary Principles 30
4.6 Technology Transfer Plan 31
4.6.1 IOU’s Technology Transfer Plans 31
4.6.2 Adaptability to other Utilities/Industry 31
5.0 Metrics 32
6.0 Conclusion 32

List of Figures

Figure 1: Integrated Distribution Planning Framework 9
Figure 2: EPIC 2.23 Integrated Process Flow Diagram 12
Figure 3: Bottom-up Load Growth Projection Process 13
Figure 4: PG&E RAM Program Map 14
Figure 5: Load Shape in Forecast Viewer Before EPIC 2.23 15
Figure 6: Load Shape in Forecast Viewer After EPIC 2.23 15
Figure 7: DER Load Shape Examples 16
Figure 8: Load Shape Catalog 17
Figure 9: Load Shape Viewer 18
Figure 10: Forecast Viewer Before EPIC Project 2.23 19
Figure 11: Forecast Viewer After EPIC Project 2.23 19
Figure 12: Load Forecast without DER Adjustments 20
Figure 13: Load Forecast with Energy Efficiency and PV Adjustments 21
Figure 14: DER Adjustment Contributions 21
Figure 15: Load Shape in Forecast Viewer 22
Figure 16: PG&E DER Growth Scenarios 23
Figure 17: Load Forecasting and Power Flow Analysis Integration 24

List of Acronyms

AAEE – Additional Achievable Energy Efficiency
AB – Assembly Bill
AMI – Advanced Metering Infrastructure
CEC – California Energy Commission
CED – California Energy Demand
DER – Distributed Energy Resources
DR – Demand Response
DPA – Distribution Planning Area
DSM – Demand Side Management
EE –Energy Efficiency
EV – Electric Vehicle
ICA – Integration Capacity Analysis
IDER – Integrated Distrusted Energy Resources
IDPP – Integrated Distribution Planning Process
IEPR – Integrated Energy Policy Report
IOU –Investor Owned Utility
LF – Load Forecasting
LNBA – Locational Net Benefit Analysis
PFA – Power Flow Analysis
PV – Photovoltaic
REM – Renewable Auction Mechanism
SCADA – Supervisory Control and Data Acquisition
UAT – User Acceptance Testing
WECC – Western Area Coordinating Council

1.0 Executive Summary

Pacific Gas and Electric Company's (PG&E) Electric Program Investment Charge (EPIC) Project 2.23 *Integrate Demand Side Approaches Into Utility Planning* successfully developed and demonstrated the integration of a broader range of customer-side technologies and Distributed Energy Resources (DER) approaches into the utility planning process. The project served as a necessary and enabling precursor to the fulfillment of Assembly Bill (AB) 327/ Section 769,[1] which requires transparent, consistent and more accurate methods to cost-effectively integrate DERs into the distribution planning process. AB 327 recognized that achieving this objective requires advancing the analytical methods, tools and mechanisms, which are leveraged throughout the utility planning process. This process, in its most basic form, uses as much relevant and currently available data as possible to predict future loading on one or more components of the electric distribution system.

This project delivered new load shape profiles, enhanced load forecasting tool and overall analytical process that allows PG&E to more accurately and consistently integrate DER impact to the distribution system load profile. With these enhancements, PG&E can evaluate if DER growth could defer or even in some instances eliminate the need for future network upgrades. Furthermore, these enhancements enable the utility not only to shape load by applying DER (load) shape adjustments, but also to determine the right type (mix) of DERs that could be considered as an alternative solution to traditional wired investments.

Leveraging any of the SmartMeter™ data, PG&E created more accurate and granular load shapes that allowed distribution planners to more precisely capture DER impact on the load growth forecast. As a result, PG&E was able to model DER deployment uncertainty at the circuit level in the context of the distribution planning process in a more standardized and transparent way. A new and novel process successfully demonstrated the use of customer energy usage, utility electric operations data and customer care program activities to provide distribution planners, marketers, and supply planners with a more integrative toolset for inclusion of DERs in their respective analysis and decision making processes.

PG&E plans to continue leveraging this tool for future distribution and transmission planning. Additionally, as a result of this demonstration, the vendor is working to incorporate the enhancements into their core product.

Issue Addressed

With the penetration of DERs increasing, the need and opportunity is presented to integrate DER growth forecast into the distribution planning process. Although the prior distribution planning process provided an effective electric delivery system that served in the best interest of safety, affordability and reliability over the many years of existence, it did not account for the impact and uncertainty of increased DER deployment, mainly due to a need for:

1. Accurate customer class load shapes (profiles) at a granular level, such as hourly percentage load reduction due to energy efficiency for agricultural customer on a given circuit.

[1] 769(b) to the California Public Utilities Code was added to the AB 327 of 2014. This section requires each California Investor Owned Utility (IOU) to submit a distribution resources plan proposal "to identify optimal locations for the deployment of distributed resources…" https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

2. An established methodology for modeling DER deployment uncertainty at the circuit level under different DER adoption scenarios.

This project developed tools and processes that address these needs and enable PG&E to meet the Distribution Resources Plan (DRP)[2] goals, specifically evaluation of locational benefits and costs of DERs located on distribution system, and identification of optimal locations, time horizons and quantities of DER deployments so that benefits to the grid are maximized and costs are potentially reduced. This evaluation is based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electric utility. Furthermore, one goal of the DRP is to identify additional utility spending to integrate cost effective DER into Distribution Planning to yield net benefits to ratepayers, as well as to identify barriers to deployment of DER, including, but not limited to, safety standards related to technology or operation of the distribution system in a manner that ensures reliability.

Currently, potential DER solutions are not fully modeled in a least-cost planning framework at the distribution feeder/bank/substation level. This project aimed to more accurately represent both customer class load and DER shapes for the purpose of integrating demand side approaches into utility planning. In addition, the project integrated different DER scenarios as part of load forecasting tool, which is an essential distribution planning tool that informs distribution planners of the existing and expected future capacity of distribution assets. Finally, evaluation of DER scenarios for integration into utility investment planning require these sophisticated distribution planning tools to be part of an integrated and automated process.

Project Objectives

The primary objective of EPIC Project 2.23 was to demonstrate an enhanced and integrated analytical process to help evaluate various Demand Side Management (DSM)[3] and other DER solutions,[4] for integration into utility investment planning. The project evaluated how alternative distributed and/or demand-side solutions can be successfully and cost-effectively integrated into utility capacity and reliability planning.

The integrated process starts with use of customer energy usage and operational data for the purpose of capturing DER impact in the load forecast, and ends with user friendly display of forecast data for the purpose of PG&E planning. The main three enhancements targeted for this process were:

- **Accuracy:** The load profiles and DER adjustments based on actual energy use measurements are more representative than profiles defined based on research data. Therefore, the tool needed to have the ability to leverage the vast amount of customer energy usage and operating data available to more accurately profile present and future hourly loads with DER adjustments at different locations in the distribution systems, from the traditional supply system to the service transformer (customer) level.
- **Transparency & Consistency:** Due to the system's physical size, along with the geographical characteristics and barriers, the PG&E distribution planning process is segmented to several

[2] Pacific Gas And Electric Company - Electric Distribution Resources Plan, July 1, 2015.
[3] Demand Side Management (DSM) refers to Energy Efficiency (EE) and Demand Response (DR)
[4] Other DER solutions refer to Electric Vehicles (EV) and Photovoltaic (PV)

geographical areas, knows as Distribution Planning Areas (DPA). This segmentation requires the overall planning process, incorporating DER needs, to be transparent and consistent across all of PG&E's DPAs when determining the optimal location, timing and need for future distribution infrastructure investment that includes both traditional wired and alternative non-wired solutions.

- **Fast Processing Time:** PG&E has over 3000 distribution feeders. Due to the large system size, the analytical process must be able to quickly perform automated analyses with multiple load forecasting scenarios (e.g. 2 load forecasting scenarios in 48 hours) involving all PG&E distribution feeders.

Key Accomplishments
The project consisted of two phases: Phase 1 (Software Development) and Phase 2 (Application and User Testing). By the end of Phase 1, the project delivered enhanced distribution circuit load forecasting tools and processes that integrate and automate analysis of the impacts of DERs on the distribution system. The enhancements include expanded customer class load shapes, DER load shapes and allocation of DER forecasting down to circuit level. Furthermore, the project developed modules for DER integration capacity analysis and locational benefits analysis, supporting the PG&E DRP process that identified optimal locations for the deployment of DER within PG&E's service area.

The following is a summary of the project's key accomplishments:

- **Enhanced Load and DER Shapes:** PG&E used SmartMeter™ 2012-2014 interval data for all 5 million PG&E electric customers to create over 320,000 new load shapes (comprised of different aspects such as customer class, DER, feeder, bank and DPA). Previously the load shapes catalog contained approximately 1,000 shapes (4 customer class load shapes for each DPA). The new load shapes include feeder load shapes, customer class load shapes, as well as DER adjustments for:
    - Electric Vehicle (EV) charging
    - Photovoltaic (PV) production
    - Energy Efficiency (EE) load reduction, and
    - Demand Response (DR) program responses.

- **Incorporated DER Scenarios:** DER expected (a.k.a. "trajectory"), high and very high growth DER scenario projections were provided for every feeder. These location-specific DER projections were included as adjustments in the 10-year hourly load forecasts, which allow distribution planners to observe load forecasts with various levels of DER adjustments.
- **Developed Integrated Batch Processing**: The project developed an interface between the Load Forecasting (LF) and the Power Flow Analysis (PFA) tools for batch processing in a cloud environment. Also, an advanced parallel computing framework was implemented to automate and speed-up the analyses.

Key Learnings and Next Steps
The project gathered several key learnings from each of these activities:

Improved Distribution Planning
- **Learning – Distribution Planning is Enhanced by Granular DER and Usage Data:** This project successfully demonstrated that an enhanced tool with granular DER and usage data can enable

potential alternative solutions to capacity needs as opposed to traditional wired methods. A specific example to how this enhanced tool can help PG&E is with one of the banks for which the load forecast without DER projected overload at 105% in 2020. Through the application of feeder-specific DER projections, planning engineers can now assess potential for DERs to mitigate to mitigate bank overloading. With DER growth forecast and targeted deployment opportunity, PG&E can assess the least cost option to mitigate the overload in 2020.

Next Step – Continue to Leverage Tool in Future Planning Cycles: PG&E plans to continue leveraging the enhanced tool in future planning cycles, and will continue to make refinements to the tool and processes as its use progresses. Some of these potential refinements identified by this project are discussed below in further learnings.

Use of Customer Energy Use Data

- **Learning – SmartMeter™ Data Improved Load Profiles:** Improved load profiles can lead to more accurate distribution system power flow modeling. PG&E compared load shapes before and after the project. There was a notable difference in load shape profiles after use of customer interval energy reads captured by SmartMeters™. Use of actual SmartMeter™ interval data from all electric customers proved to be more representative of hourly load shapes than those based on load research and sample SmartMeter™ data as done in the past.

  Next Step – Refine Load Shapes with Additional 2 Years of SmartMeter™ Historic Data: Based upon the timeframe of the project, load shapes were defined during the demonstration based on SmartMeter™ interval data from the 2012-2014 periods. Further load shape enhancements can be achieved by using SmartMeter™ recorded interval reads from a longer and most recent time period, providing the utility with the most accurate and up to date load shape forecast for the investment planning process. Therefore, PG&E plans to refine load shapes by using SmartMeter™ data from the 2015-2016 time period and continue to update the load shape profiles used in the distribution planning process on an annual basis.

- **Learning – For Forecast Accuracy, It is Important to Ensure All Customer Data in an Area Is Incorporated:** Some large customers who are metered using a legacy meter system were not initially included in the EPIC demonstration feeder load shapes. As part of the Legacy data User Acceptance Test (UAT) to validate load shape accuracy in the LF tool, PG&E compared the feeder load shape profile created with and without use of legacy meters data on two feeders that each had a large legacy account with loads between 3 and 7 MW. On both of these two test feeders; there was a large difference between load forecasts representing the 50^{th} and 10^{th} percentile probability when legacy meter data was not used in the load shape profile. After including the legacy meter data in the load profile, the 50^{th} and 10^{th} percentile volatility was reduced to a normally expected range (from approximately 200% to between approximately 0-30%).

  Next Step – Incorporate All Legacy Meter Data in Load Shapes: In order to further improve load shape accuracy, legacy meter systems energy use data will be fully incorporated in the next annual revision of feeder load shapes.

DER Scenarios Projections

- **Learnings – Large PV Projects Can Overallocate the DER Scenario Projections On Individual Feeders**: Eight feeders had Agricultural PV adoption forecasts that depended on single, large (1-4 MW) PV systems to be installed in specific years, causing forecasted loads on these eight feeders to drop based upon that single large PV project installation. This forecasted load drop on eight agricultural feeders, if relied upon in the planning process, could delay required infrastructure expansion work, or overload mitigation measures such as transfers.

Next Step – Introduce New Methodology for Large PV Adoption Forecast: After analyzing the impact of these specific eight Agricultural PV adoption forecasts, PG&E excluded large PV projects from the load forecast. Next year, PG&E plans to introduce a methodology to allocate the agricultural PV forecast adoption over multiple feeders in multiple years, as opposed to projecting the adoption to specific feeders in specific years.

- **Learning – The Time of Peak Shifts in High DER Adoption Areas:** Knowing the magnitude and time of the system peak is crucial for an effective distribution system planning process, especially in the presence of PV. PV adoption in recent years has decreased the daytime feeder peak, causing it to shift later in the day. For example, in one DPA area, the summer peak shifted from 4 PM to 7 PM, based on AMI data from 2012-2014 and SCADA data from 2016. This timing change for the maximum load on feeders can have a significant impact on the possible solutions to load expansion or power quality problems.

  Next Step – Annual Update of Load Shapes: Although a peak time shift is likely to occur in areas where DER adoption is more expansive, the project established monthly data collection from all PG&E electric SmartMetersTM, and the annual load profile update process, to capture feeder peak time shifts in a timely manner. Any impacts of the peak time shifts will be evaluated as part of the annual distribution planning process. Consequently, network upgrade plans may be adjusted if required due to load shape peak magnitude and time forecast changes.

- **Learning: Temporal Granularity Is a Key Contributor to Forecast Accuracy** – During the demonstration, load shapes were created at a monthly level for feeders, banks, customer classes, and each DER technology. The impact of adjustments can now be properly modeled, not as the sum of peak values that may occur at different times, but as the sum of shapes that have complex interactions over time. In other words, PV adjustments applied to a feeder peak that occurs at 6pm should be less than the same PV adjustments applied to a feeder that peaks at 1pm. The application of feeder, bank, customer classes, and DER shapes now allows for this more accurate modeling.

  Next Step: Explore the Use of Even More Granular Data – PG&E plans to explore creating daily load shapes as opposed to monthly as a means to even further refine forecast projections and grid needs assessments. With regards to the timing and duration of grid needs, it would be an improvement to describe the hours and days of a grid requirement rather than the hours and months of a grid requirement. Presently, given the limitation of monthly shapes, it cannot be determined how many days out of that month the grid need is present.

- **Learning – Change Management is Key to Successful DER Scenario Implementation:** Training on proper use of DER adjustments within the load forecasting tool, combined with feedback based process improvement, is essential to tool acceptance and improvement.

  Next Steps – Incorporate Load Forecasting Enhancements into Planning Processes: PG&E plans to continue to refine and enhance planning use cases, processes and criteria. The enhanced load forecasting tool with DER adjustments is expected to be fully incorporated into the distribution planning process for future planning cycles and train relevant stakeholders for effective charge management.

Integrated and Automated Process

- **Learning – Integrated and Automated Process Requires a Large Amount of Data Storage** Capacity **and Computational Capability:** A large amount of computational capability is required to both run the integrated analysis and leverage for post-processing the raw outputs. This process generated significant amount of data (e.g. analysis of 6 million rows for each feeder) and required advanced data storage techniques, creating an opportunity for PG&E to gain learnings on large scale data processing that is expected to be leveraged in the future.

  Next Steps – Integrated and Automated Process Transition to Production: Although the project successfully demonstrated a use of cloud computing and storage techniques, PG&E will assess what solution architecture (e.g. cloud or internal/on-site hosting) best serves needs based upon enterprise strategy in the years to come. This assessment will take into account not only the needs of the load shape profile update process, but also the needs of other PG&E large scale processes and analyses such as DER Integration Capacity Analysis5 (ICA) and Locational Net Benefit Analysis6 (LNBA).

Conclusion

As a result of EPIC Project 2.23, the historic loading information is now explainable with newly created DER load shapes. Thus, distribution planning engineers can better understand attributes that led to a particular feeder/bank load profile and more accurately model DER in their planning process. With increasing amounts of DERs coming online, this tool provided an efficient way to model them. Without such a tool, finding optimal locations for DERs at the feeder level may have been a manual effort.

Furthermore, this project provided tool enhancements that can also help explain station/regional load shapes, specifically maximum and minimum load levels used in the transmission planning analytical process. Currently, transmission planners have to determine what banks are fed from what busbar prior to running planning studies. With this enhanced tool including the Western Area Coordinating Council (WECC) busbar in the hierarchy as the lowest level of granularity needed for this studies, this may potential reduce the time it takes to run transmission planning studies.

In addition to enhancements in load shape definitions, an integrated analysis process enabled faster analysis processing time, greater system and granular level load modeling accuracy, and inclusive DER forecast scenarios. These improvements allow more efficient, accurate, flexible, yet standardized process to analyze various DER scenarios with minimal user intervention in order to maintain the planning process consistency across the DPAs.

The EPIC Project 2.23 created a solid demonstration as a foundation from which electric utilities, regulators, adjacent industries, policy makers and prospective vendors can broadly leverage for the ultimate benefit of utility customers. Beyond this demonstration, the enhanced tools will be further leveraged and refined in future planning cycles at PG&E. Feedback from engineers will inform process changes and training needed to continue to successfully leverage the tools. In parallel, the enhanced

[5] ICA will be used to help streamline the DER interconnection process and potentially identify areas where grid modernization investment is needed to support future DER deployments.

[6] LNBA may be used to signal where future DER investment (either IOU or third party) will provide highest value to the grid.

tool will support IDER/DRP proceedings, including Integration Capacity Analysis and Locational Net Benefit Analysis, Distribution Infrastructure Deferral Framework, Competitive Solicitation Framework and Grid Modernization Filings.

2.0 Introduction

This report documents the achievements of EPIC Project 2.23 *Integrate Demand Side Approaches Into Utility Planning,"*, highlights key learnings from the project that have industry-wide value, and identifies future opportunities for PG&E and other utilities to leverage this project.

The California Public Utilities Commission (CPUC) passed two decisions that established the basis for this pilot program. The CPUC initially issued D. 11-12-035, *Decision Establishing Interim Research, Development and Demonstrations and Renewables Program Funding Level,*[7] which established the Electric Program Investment Charge (EPIC) on December 15, 2011. Subsequently, on May 24, 2012, the CPUC issued D. 12-05-037, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020,*[8] which authorized funding in the areas of applied research and development, technology demonstration and deployment (TD&D), and market facilitation. In this later decision, CPUC defined TD&D as "the installation and operation of pre-commercial technologies or strategies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks associated with a given technology."[9]

The decision also required the EPIC Program Administrators[10] to submit Triennial Investment Plans to cover three-year funding cycles for 2012-2014, 2015-2017, and 2018-2020. On November 1, 2012, in A.12-11-003, PG&E filed its first triennial Electric Program Investment Charge (EPIC) Application at the CPUC, requesting $49,328,000 including funding for 26 Technology Demonstration and Deployment Projects. On November 14, 2013, in D.13-11-025, the CPUC approved PG&E's EPIC plan, including $49,328,000 for this program category. Pursuant to PG&E's approved EPIC triennial plan, PG&E initiated, planned and implemented the following project: Project 2.23 *Integrate Demand Side Approaches into Utility Planning.* Through the annual reporting process, PG&E kept CPUC staff and stakeholder informed on the progress of the project. The following is PG&E's final report on this project.

3.0 Project Summary

EPIC project 2.23 aimed to enhance PG&E's ability to incorporate the growing usage of DER by developing:

- **I.** New customer class load shapes based on actual historic customer energy usage hourly measurements;
- **II.** A methodology for modeling DER deployment uncertainty at the circuit level in the context of distribution planning tools; and
- **III.** An integrated and automated process to effectively perform periodic customer class load shape updates and DER forecast related analysis on a large scale.

---

[7] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/156050.PDF
[8] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/167664.PDF
[9] Decision 12-05-037 pg. 37
[10] Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and the California Energy Commission (CEC)

3.1 Project Objective

The primary objective of EPIC Project 2.23 was to demonstrate an enhanced and integrated analytical process to help evaluate various Demand Side Management (DSM[11]) and other DER solutions,[12] for integration into utility investment planning, which ultimately may enable deferral (or delay) of traditional investment upgrades. The project evaluated how alternative distributed and/or demand-side solutions can be successfully and cost-effectively integrated into utility capacity and reliability planning.

Therefore, the ultimate goal was to build capability to annually refresh customer class load shapes and efficiently execute cost/benefit analysis for DER deployments/impacts on a circuit level, in an automated fashion. Following the successful demonstration of the enhanced tools and process within the testing and PG&E's distribution planning process, the demonstrated solution would be fully incorporated into PG&E's distribution planning process for future planning cycles.

3.2 Issue Addressed

Utilities have been forecasting circuit-level load without DER growth for many years, and performed distribution planning process in the best interest of safety, reliability and affordability for our customers. With higher penetration of DERs, the need and opportunity is presented to integrate DER growth forecast into the distribution planning process.

The distribution planning process uses as much relevant data as possible to predict future loading on one or more components of the electric distribution system. It involves the collection of data, such as historic loading, customer counts, weather data, economic variables, known customer load increases, and geospatial growth information to assign yearly load increases to components being studied, such as banks and feeders. Prior to EPIC Project 2.23, the impact of DERs was only seen in reduced historic loads which, in turn, reduced the starting point of the load forecasts.

EPIC Project 2.23 added DER forecasts to the relevant data used by the distribution planning process. The DER forecasts were added as adjustments to the future bank and feeder loading. In most cases, inclusion of the DER forecasts resulted in a reduction from the previous, non-DER-informed, load forecast.

This project addresses issues as identified in the Distribution Resource Plan (DRP) Ruling (R.) 14-08-13[13] and AB 327 Section 769 proceedings, which require transparent and consistent methods to integrate cost-effective DER mitigations into the distribution planning process. Accordingly, the planning process is required to adjust the load forecasts for DER growth and assess the feasibility of DERs as alternatives that support Transmission and Distribution reliability.

The significance of this project can be best understood by observing the Integrated Distribution Planning framework that consists of three streamlined stages, as shown in Figure 1. The overall outcome of the Integrated Distribution Planning Process (IDPP) is dependent upon accurate load forecast that takes into account DER growth scenarios in the Integrated Energy Policy Report (IEPR) stage – the approach demonstrated by EPIC Project 2.23. Because IDPP will be an annual process to identify distribution

[11] Demand Side Management (DSM) refers to Energy Efficiency (EE) and Demand Response (DR).
[12] Other DER solutions refer to Electric Vehicles (EV) and Photovoltaic (PV).
[13] Distribution Resources Plan (R.14-08-013).

deficiencies that can be addressed with cost effective DER alternatives, there is a need for efficient periodic update of load forecasts.

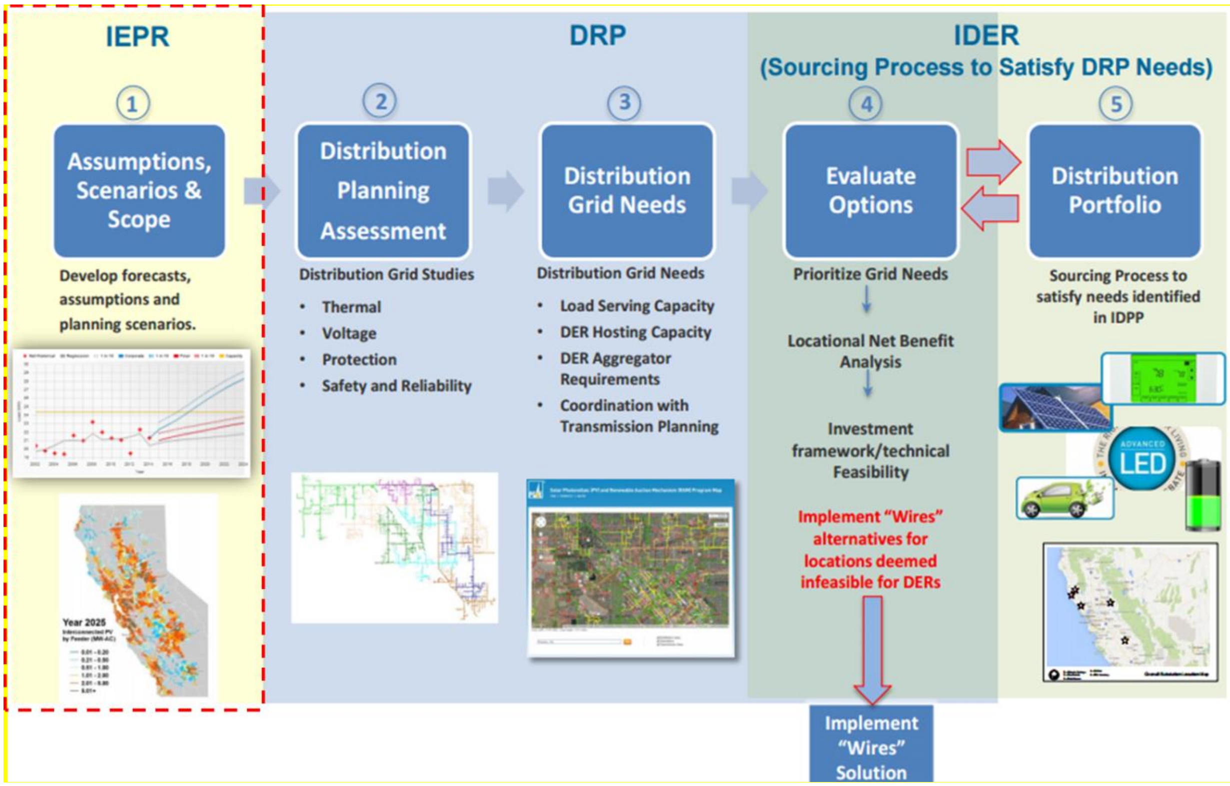

Figure 1: Integrated Distribution Planning Framework

In order to establish the least-cost IDPP framework, it is crucial for the IEPR stage to:

1. Create accurate customer load shapes based on the usage of DERs.
2. Implement a process that integrates a broad range of customer-side technologies and DER approaches into grid planning and operations.
3. Enhance the capability to model and analyze the uncertainty of DER deployment at the circuit level in an automated fashion.

This project aimed at addressing all three critical aspects that enable the least-cost planning framework. With these enhancements, distribution planners will be able to effectively evaluate if DER growth could defer or even eliminate the need for future network upgrades. Also, these enhancements provide distribution planners with a mechanism to shape load by applying DER (load) shape adjustments that could be considered as an alternative solution.

3.3 Scope of Work

The scope of this project was to integrate a broader range of customer-side technologies and DER approaches into the grid planning process by enhancing distribution load forecasting tools. These include the ability to develop new customer load shapes based on the SmartMeter™ recorded interval data reads, model the uncertainty of DER deployment at the different distribution system levels, and improve the large scale analysis process by integrating distribution tools and databases. The project was divided into software development and application/user testing phases to gain insight in potential operational use and user preferences.

The main goal of the project was to generate more accurate customer class, substation transformer bank and feeder load shapes by leveraging 3 years of recorded interval reads for over 5 million SmartMeters™. Due to the volume of data, one key work requirement of this project was the ability to utilize large scale data storage and cloud computing. The volume of the data used in this project is exponentially greater than that in the prior versions of the load forecasting tool. Therefore, it required integration between the distribution planning load forecasting and power flow simulation tools, as well as between the distribution planning load forecasting tool and PG&E databases.

3.3.1 Major Milestones, Tasks and Deliverables

Throughout the demonstration project, PG&E and technology providers worked collaboratively on the following main milestones with associated tasks and deliverables. Further detail on each task and associated results can be found in Section 4.0: Project Results, Findings and Next Steps.

Key Milestone 1: Tool development and User Acceptance Testing (UAT). The following tasks enabled the development and initial testing of the enhanced load forecast tool:

- **Customer class, bank and feeder hourly load shapes enhancements** – PG&E used recorded electric energy usage interval reads from all PG&E SmartMeters™ to more accurately determine customer class (residential, commercial, industrial and agricultural) load profiles, as well as bank and feeder load profiles. This task deliverable was an enhanced catalog of customer class, bank, feeder and DER load shapes in the LF tool.
- **Reconciliation of customer class load shapes based on SCADA data** – This task developed the LF tool capability to generate a standalone load forecast viewer application that can be leveraged to assess customer class impact on the overall load shape.
- **Develop DER scenario projections and incorporate into the LF tool** – This task delivered a Forecast Viewer application to support the forecasted load analysis, including the DER scenario impact on forecasted load.
- **Develop interface between the LF and PFA tools for batch processing integration** – This task objective was to streamline the Integration Capacity Analysis (ICA) in order to enable PG&E to produce the ICA results within a short time period (48 hours).
- **Integrate LF tool with PG&E databases** – This task objective was to integrate the LF tool database with PG&E databases containing customer energy usage data in order to automate the process of passing this data on a scheduled basis (monthly) to the LF tool for further processing. Specifically, the task deliverable was the integration of PG&E PI, Teradata, Media (Legacy Meter) data, and the Integrated Data and Analytics (IDA) platform interface to the LF tool in the cloud environment.
- **User Acceptance Testing (UAT)** – UAT, performed by PG&E Distribution Engineers, was focused on functional performance testing. The objective was to review the end-to-end process and results, and approve the tool/process progression to the next phase. Testing included running automated scripts to verify the functionality of the software, such as ensuring that the tool was able to import shapes and make adjustments.

Key Milestone 2: User testing and feedback. The following tasks enabled the demonstration to ensure the tool could be leveraged successfully by distribution planners and to drive next steps for continuous improvement:

- **Distribution planning operational testing** – This task focused on operational testing with multiple (cross-functional) users, who were trained in several sessions. This test included evaluating how the new tool interacts with users to produce a distribution needs assessment during a planning cycle.
- **User training and feedback** - During and after operational training sessions, users provided useful suggestions how to further improve and standardize the new analytical process. These findings and learnings are captured in Section 4 below.

One of the main project achievements was to integrate the analytical process by establishing the interface between the load forecasting tool and PG&E databases, and by enhancing existing interface between the load forecasting and power flow analysis tools. This achievement directly supported the ICA and LNBA by streamlining the analyses process, and contributed to development of DRP Demos C, D, and IDER Incentive Pilots by supporting identification of projects and development of solicitation materials.

Another major project achievement was the development of an automated process for inclusion of SmartMeter™ data to more accurately represent the customer class, bank, feeder and nodal[14] load shapes at various levels of the distribution system. In addition, PG&E or enhanced distribution planning tools to enable a more efficient process for the evaluation of DER impact.

3.3.2 System and Process Description

Due to the complexity of the project tasks and dependency on the task deliverables, PG&E separated and staged the Integrated Distribution Planning process for assessing needs on distribution feeders and banks for loads, and needs for generation. Figure 2 presents the project end-to-end process workflow. Essentially, the process was broken into two parts:

a) Load Growth Assessment – a grid needs assessment that began at the substation bank and feeder, which was based on a DER-informed load growth forecast. These bank and feeder forecasts were then used to model and analyze the entire feeder at peak loading for a feeder needs assessment.

b) Generation Growth Assessment (ICA or Hosting Capacity) – the modeling and analysis of the entire feeder at minimum loading to produce grid needs analysis for distribution generation hosting. One output of this process was made public via the Renewable Auction Mechanism (RAM) map on PG&E's website[15] that customers and distributed generation providers can use to assess the impacts of generation at a specific geographic location.

[14] Some analyses use load shapes at particular locations on the distribution circuit. An example of a nodal load shape can be a load shape at the recloser location on the distribution feeder.
[15] https://www.pge.com/en_US/for-our-business-partners/energy-supply/solar-photovoltaic-and-renewable-auction-mechanism-program-map/solar-photovoltaic-and-renewable-auction-mechanism-program-map.page.

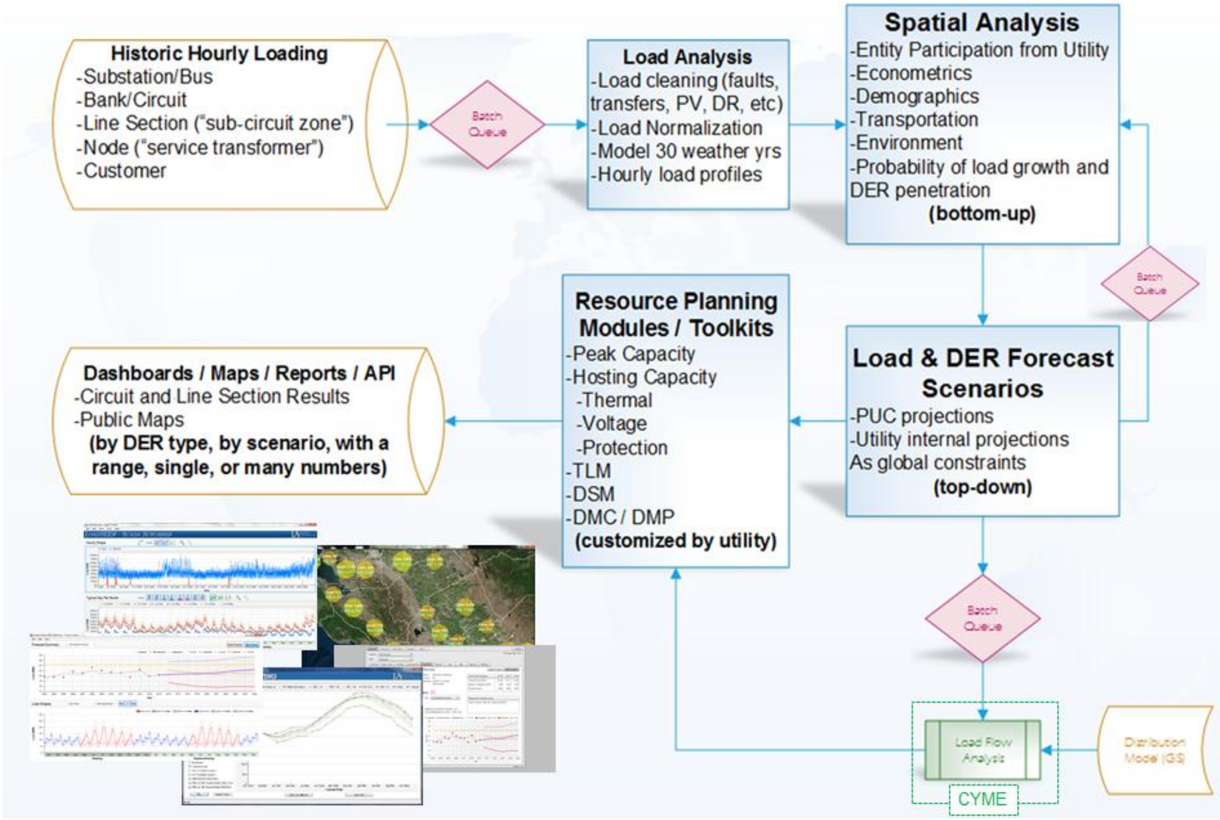

Figure 2: EPIC 2.23 Integrated Process Flow Diagram

Throughout the process, the project progressed through the following steps:

1. **Historic Hourly Loading:** Acquisition and cleansing of field measurements (SCADA and SmartMeter™). The SCADA data recorded the peak load for the banks and feeders while the AMI data was scaled to this bank or feeder peak to provide a bank or feeder shape across 24 hours for each month of the year. This data was cleaned for errors and switching peaks before being loaded into the forecasting tool.
2. **Load Analysis:** The feeder and bank shapes were weather-adjusted. 30 years of historic weather data was used combination with customer composition and known customer weather sensitivities to produce percentile shapes for the feeders, banks, and customer classes.
3. **Spatial Analysis:** A geospatial (bottom-up) aggregation was performed by customer class. This process is a proven[16] methodology that analyzes energy usage data from small geographical areas and uses statistical analysis to project small area load growth based on various attributes (e.g. econometrics, demographics, transportation and environment). The statistical analysis was combined with historic satellite imagery to include areas of recent growth where growth was likely to continue.

[16] This method was first commercialized by Carrington (CARR-EL) in 1988, although it was used prior to that in a set of load forecasting "shareware" developed in South America in the mid-1980s, known as INSITE.

The process aggregated smaller area growth until the system/regional level was reached, as demonstrated in Figure 3. At the system level, the bottom-up process generated a system level load growth forecast.

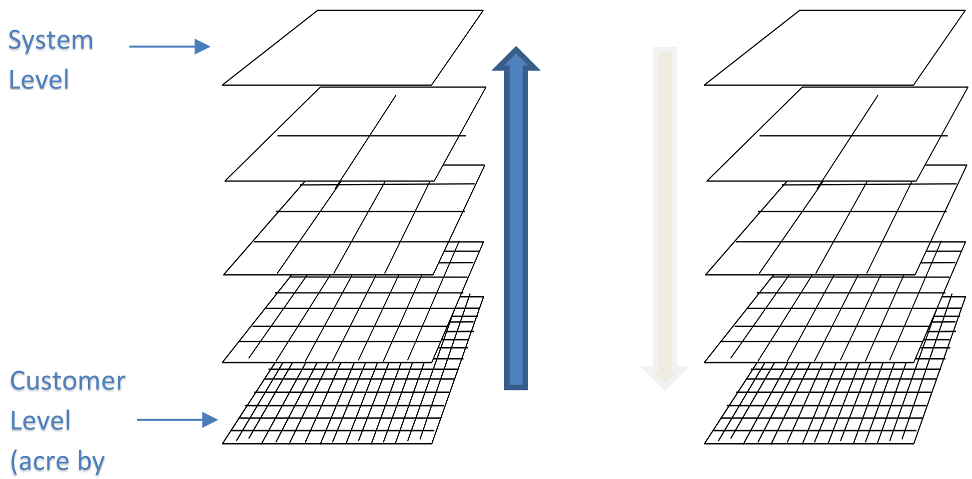

Figure 3: Bottom-up Load Growth Projection Process

4. **Load and DER Forecast Scenarios:** This geospatial forecast was then reconciled to an adjusted CEC system level forecast.[17] This CEC forecast was adjusted to remove known growth adjustments (large loads that have applied for electric service) that were already present in the load forecasting tool. This step avoided the double counting of known load growth. The reconciled geospatial forecast was then allocated back to all distribution feeders. DER adjustments, load adjustments, planned transfers, and future projects were then applied to the feeder forecasts.

5. **Resource Planning:** Final 10 year load forecasts for banks and feeders were created and analyzed for errors and discrepancies. Modifications were made based on those findings. LNBA and grid needs assessments were made based on the DER-informed growth forecasts. These forecasts were used to determine both the magnitude and the duration/timing of the need based on the new bank and feeder load shapes.

6. **ICA Development:** The ICA was run for all feeders and the results were made available for public use via the RAM program map that is shown in Figure 4. The map shows selected electric transmission lines, distribution lines and substations in PG&E's service area. The figure below features a snapshot of Fresno, CA. Customers and distributed generation providers can use this map to assess the impacts of generation at specific grid locations. LNBA analysis was not performed on the ICA results, but may be considered as a potential future enhancement to the Integrated Distribution Planning process.

[17] The California Energy Demand Updated Forecast provides 10-year projections for electricity consumption, sales and peak demand for electricity planning areas and the state as a whole. http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN214635_20161205T142341_California_Energy_Demand_Updated_Forecast.pdf.

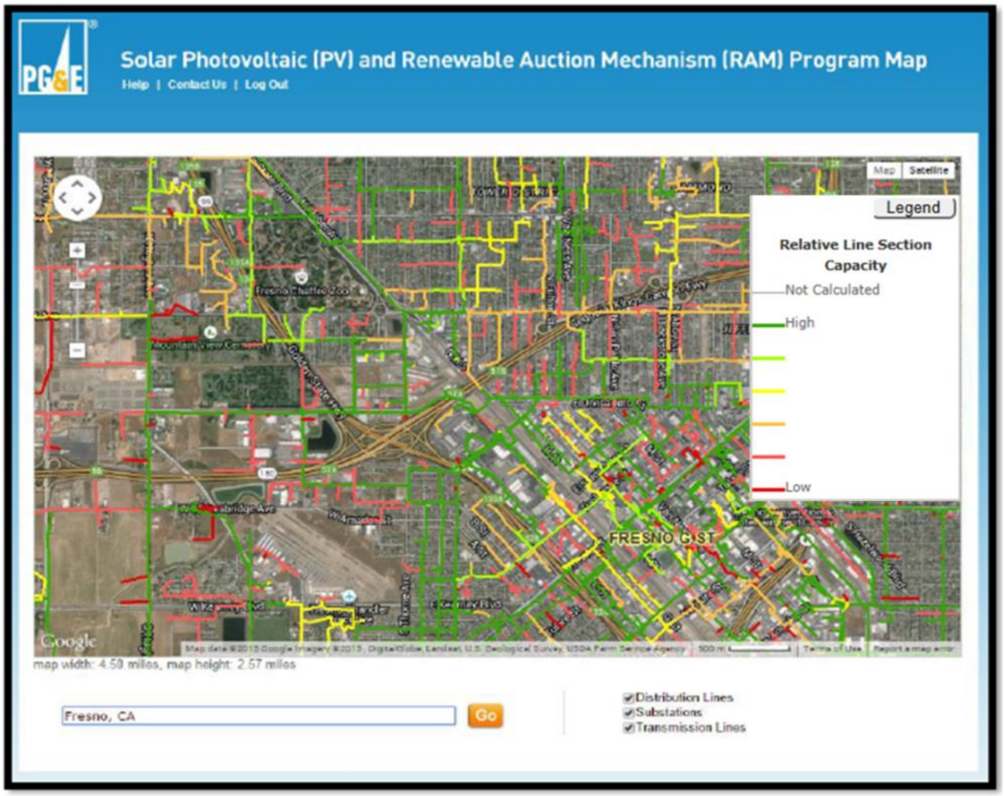

Figure 4: PG&E RAM Program Map

4.0 Project Results, Findings and Next Steps

4.1 Technical Results

4.1.1 Customer Class Load Shape Enhancements

Before EPIC Project 2.23, the load forecasting tool relied on load research and stratified random samples of SmartMeter™ data to create bank, feeder and customer class load shapes, due to the fact that full year data SmartMeter™ data across all circuits was not readily available in the load forecasting tool. These past sample sizes are, in some cases, not fully representative of each circuit's unique blend of customers.

As part of this project, PG&E leveraged recorded SmartMeter™ interval data for the period of 3 years (2012 – 2014) for over 5 million residential and commercial electric customers. The SmartMeter™ data was analyzed by customer classes, rates and program participation in order to generate more precise hourly load shapes. By the end of the project, PG&E created over 320,000 load shapes for all feeders, banks and DPAs. Per feeder, there are over 100 customer class load shapes, such as cattle ranch & farm, fruit & tree nut farm, hog & pig farm, oil & grain farm, elementary & secondary school, university, miscellaneous store retailers, etc. Each load shape was assigned a specific recurrence probability (e.g. 50th, 75th, 90th, and 95th percentile likelihood of a load shape occurring in a given year). The probability is based on 30+ years of weather observations and the known volatility of the customer energy use with respect to weather conditions. In addition, there is an established process for the annual addition of new customers, DER and/or load transfers.

Figure 5 and Figure 7**: DER Load Shape Examples**

present the load shape for one PG&E transformer bank before and after the project. Before the project, the load shape was generated based on the customer class research data. The bank peak time changed from July to December after the use of SmartMeter™ data in the geospatial forecasting process.

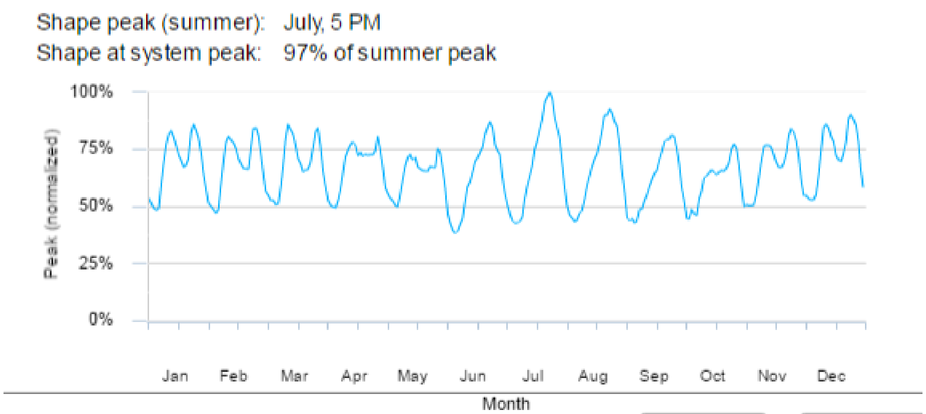

Figure 5: Load Shape in Forecast Viewer Before EPIC 2.23

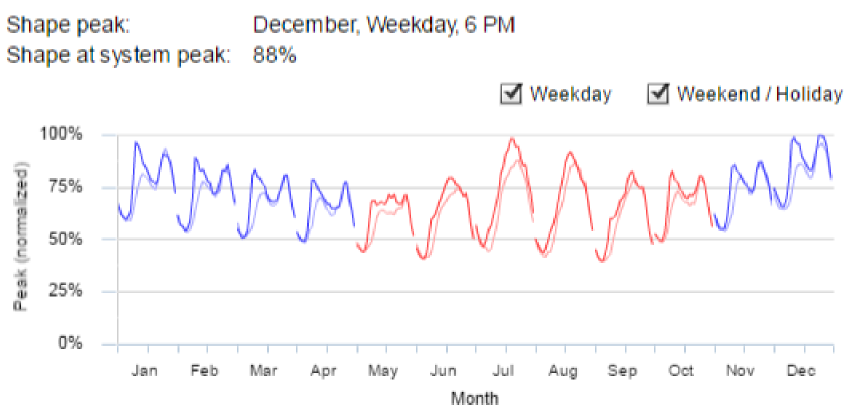

Figure 6: Load Shape in Forecast Viewer After EPIC 2.23

Figure 7 shows the probability of occurring once in 2 years (a 50th percentile probability, referred to as 1-in-2) load shape examples for each DER group. The DER load shapes are normalized based on their full capacity/rated value, and can be location specific (e.g. PV, EE) or identical system-wide (e.g. EV).

The industrial EE load shape follows the industrial customer class load shape, and energy efficiency forecasts scales down the load. The industrial EE load shape example shows two lines: thin and thick. The thin line shows the load reduction on the weekend/holiday. The thicker line shows the load reduction during the weekday.

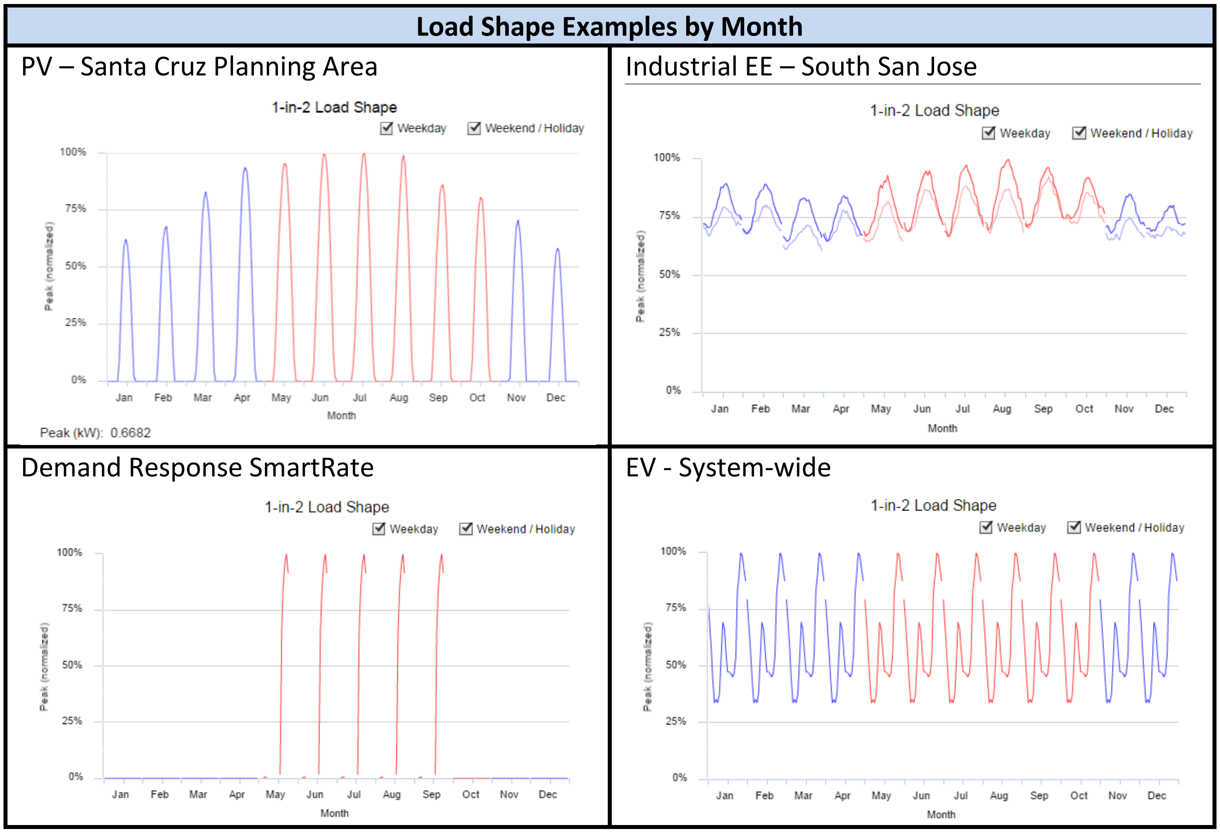

Figure 7: DER Load Shape Examples

With new load shapes being more precise than those used in the past, the next step is to further refine them with even longer time periods of SmartMeter™ interval data. PG&E believes these additional data could further enhance the accuracy of the load shape profiles.

4.1.2 Load Shape Viewer

The Load Shape Viewer developed by this project is an HTML5 web-based application that pulls data from the LF Cloud Services. It allows users to search the transmission and distribution hierarchy and compare load shapes across any combination of node type and hierarchy levels. Further, it allows assessment of what types of customers may be large contributors to the peak load. By identifying those customers, PG&E can target appropriate DER adoption programs that can potentially avoid investments in assets, saving customer dollars. Using this tool will allow PG&E to focus on those coincidences and use its efforts to potentially relieve capacity constraints or move the inhibitors onto other feeders/banks that may not have the same coincidence factor, thus saving customer funds on large investment projects.

Quick and Easy Navigation

The load shape catalog uses Sundial architecture for quick access, as shown in Figure 8. The catalog was enhanced to archive more than *5 million* load shapes for potential use by planning engineers. Previously, the load shapes catalog contained approximately 1,000 shapes (4 customer shapes for each DPA).

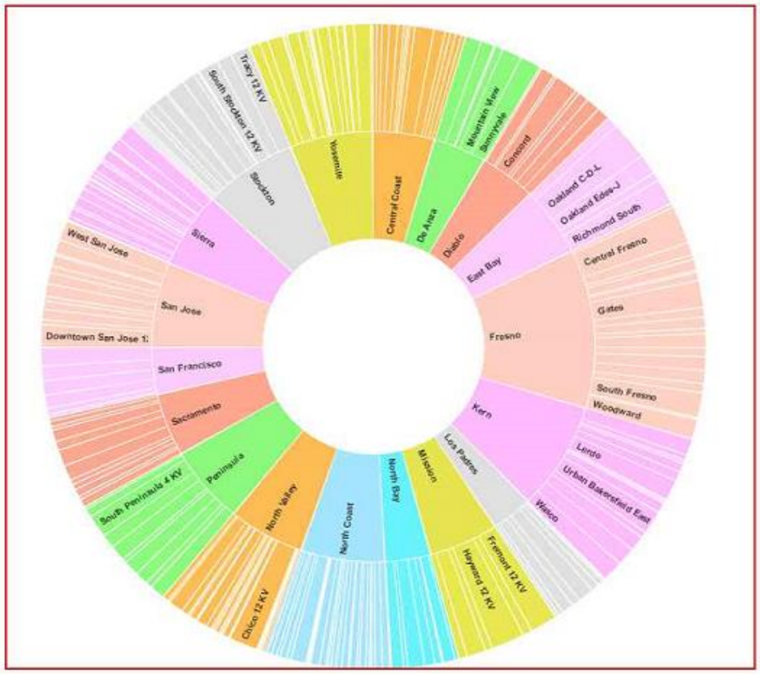

Figure 8: Load Shape Catalog

User Friendly Display

As presented in Figure 9, the load shape viewer allows engineers to observe load shapes at different system levels (e.g. DPA, bank, and feeder) and by customer class for different weather scenarios.

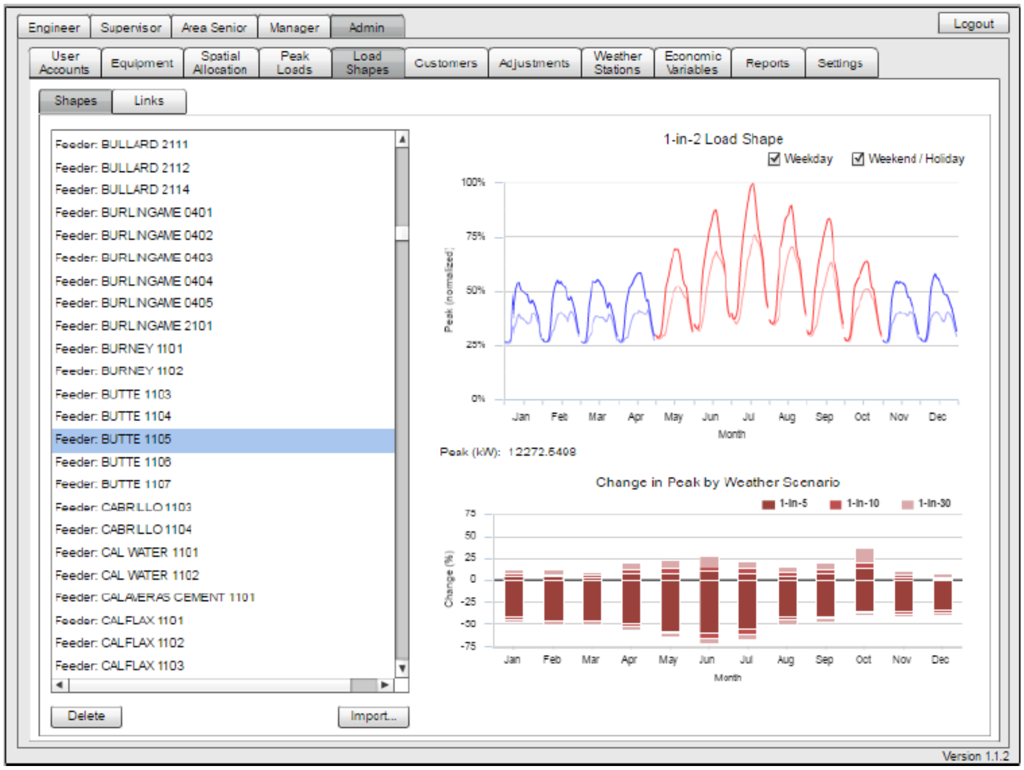

Figure 9: Load Shape Viewer

4.1.3 Load Forecast Viewer

The load forecast viewer enables better understanding of the frequency, timing and duration of projected circuit loading and the impact that DERs are having on either increasing or reducing the loading. The forecast viewer is a standalone application that can be used for such diverse functions as long-term infrastructure additions planning and very short-term local area operations.

Prior to this project, the load forecast process did not account for DERs, as Figure 10 presents for one of the PG&E distribution banks. The graph shows a regression forecast (solid grey line), a CEC forecast (solid blue line), and a final forecast (solid red line). The final forecast includes load, but there are no DER adjustments and the CEC forecast and final forecast are the same.

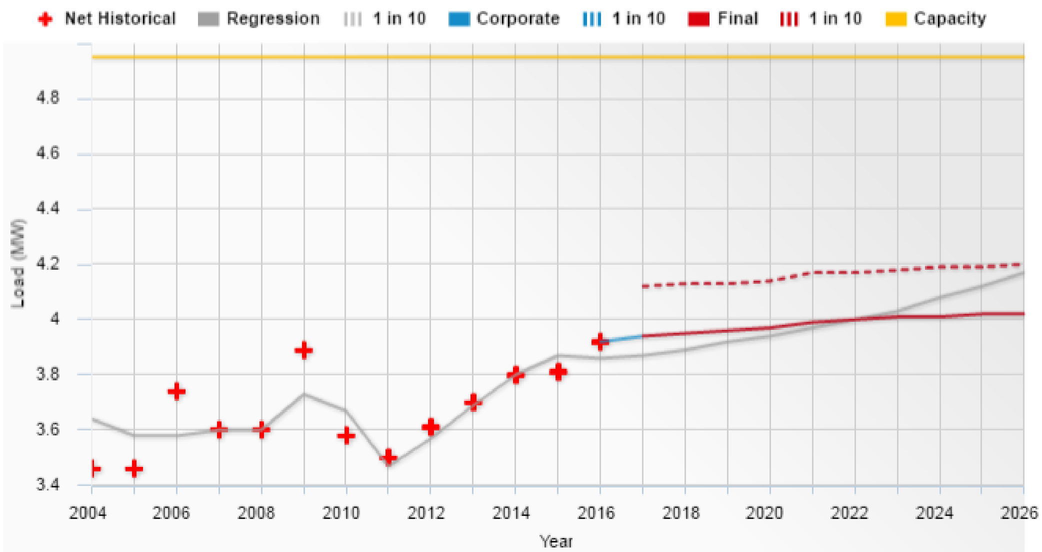

Figure 10: Forecast Viewer Before EPIC Project 2.23

As a result of EPIC Project 2.23, a load forecast now incorporates DER impact. For the same bank mentioned above, Figure 11 shows a regression forecast (solid grey line), a CEC forecast (solid purple line) and final forecast that includes DER adjustments (solid red line). Note that DER applied to the forecast as adjustments cause the difference between the CEC and the final forecast.

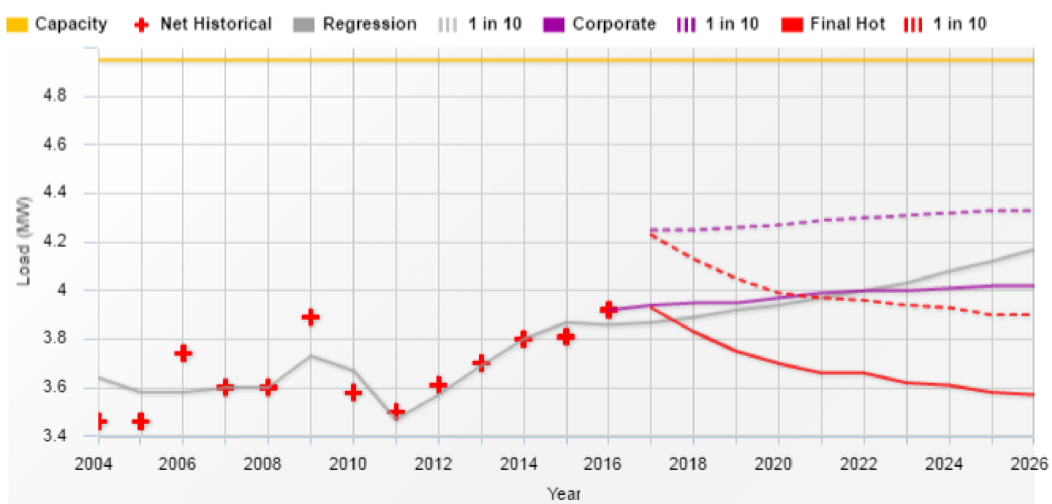

Figure 11: Forecast Viewer After EPIC Project 2.23

Dashed and solid lines on the graphs above correspond to the 10% and 50% probability load forecasts, respectively. The visual aspect of the load forecasts scenario helps distribution planners to better assess and plan the timing of distribution system needs, as well as to evaluate the potential use of DER to defer distribution investment needs.

Figure 12 presents an example of load exceeding the distribution bank capacity by 2022 when DER adjustments are not applied. Figure 13 shows that with Additional Achievable Energy Efficiency (AAEE)[18] and PV adjustments, that bank capacity will not be exceeded in next 10 years, even under extreme (1-in-10) hot weather conditions. This example demonstrates how the enhanced load forecasting tool could help PG&E evaluate if DER growth could defer or even eliminate the need for future network upgrades. Bank replacement or addition of a new bank can be very costly (e.g. up to a few million dollars depending on the work required). This enhanced tool will allow PG&E to better assess cost-effective load transfer options, taking into account load and DER growth on load transfer bank candidates. Furthermore, the enhanced load forecasting tool allows PG&E to determine the right type (mix) and volume of targeted DER deployments to mitigate the overload problem.

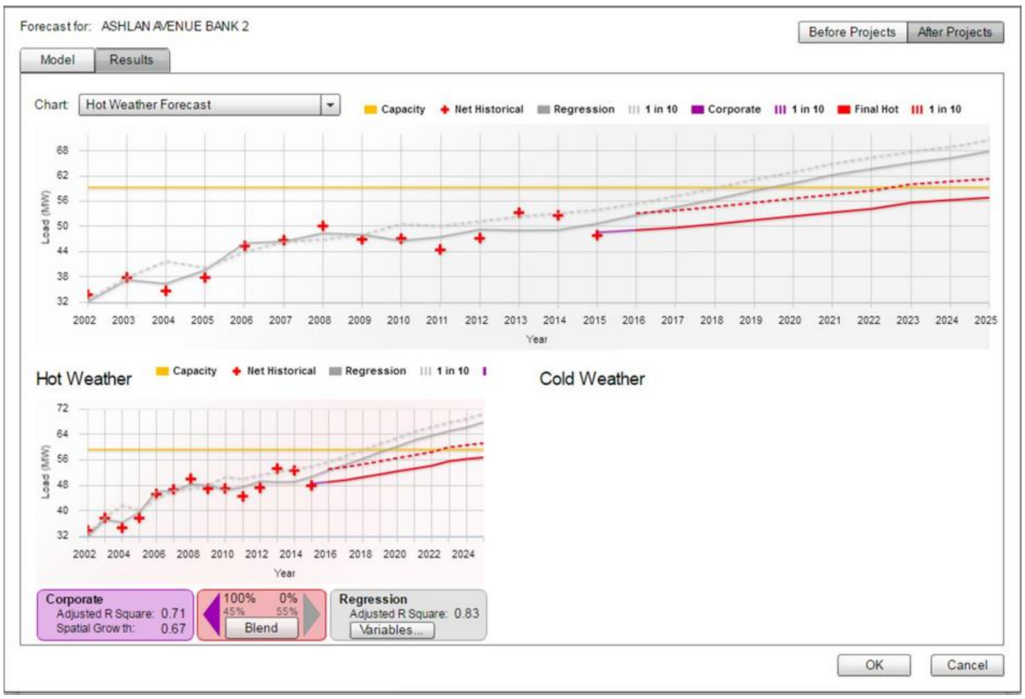

Figure 12: Load Forecast without DER Adjustments

[18] For more information on Additional Achievable Energy Efficiency (AAEE) please see http://www.energy.ca.gov/2013publications/CEC-200-2013-005/CEC-200-2013-005-SD.pdf.

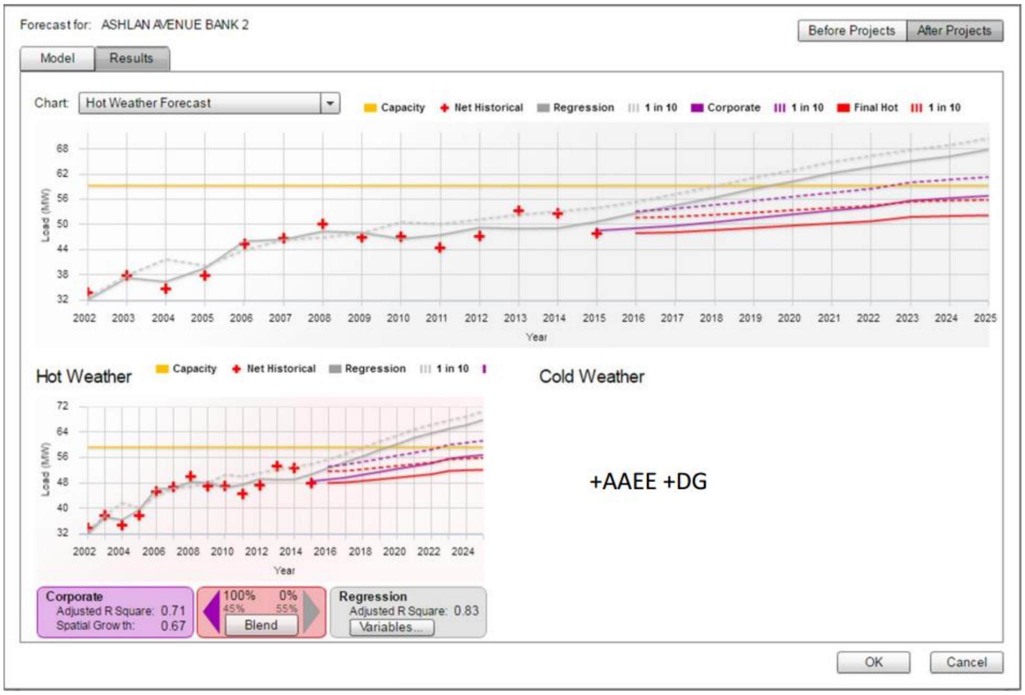

Figure 13: Load Forecast with Energy Efficiency and PV Adjustments

A specific example to how this enhanced tool can help reduce or defer costs is with one of the banks for which the load forecast without DER projected an overload at 105% in 2020. A capital project alternative to resolve this bank overload could be to increase the bank capacity by replacing the current transformer with a larger transformer. By using the forecast viewer to apply DER adjustments, the bank loading could potentially be reduced to 95% in 2020. With DER growth forecast and targeted deployment opportunity, PG&E can assess the least cost option to mitigate the overload in 2020.

Distribution planners are able to determine what DER adjustments have the strongest impact on the forecast by analyzing the DER adjustments contributions by DER type, as shown in Figure 14. This figure shows that the forecasted Energy Efficiency (AAEE) in 2017 for commercial customers (highlighted) is ninety times larger than residential Energy Efficiency forecast and thirty four times larger than industrial Energy Efficiency forecast. The figure also depicts each year's adjustment for Commercial Energy Efficiency (2017-2020) and how each year compares to other years.

Adjustments   Filter

Change Horizon	Adjustment Type	Description	Start Year	MW per Unit	Units	Total MW
✓	EE	AAEE-Mid-Mid-Commercial-LG1	2017	0.47424	1	-0.47
✓	EE	AAEE-Mid-Mid-Domestic-LG1	2017	0.00525	1	-0.01
✓	EE	AAEE-Mid-Mid-Industrial-LG1	2017	0.01408	1	-0.01
✓	EE	AAEE-Mid-Mid-Commercial-LG1	2018	0.61786	1	-0.62
✓	EE	AAEE-Mid-Mid-Domestic-LG1	2018	0.00684	1	-0.01
✓	EE	AAEE-Mid-Mid-Industrial-LG1	2018	0.01835	1	-0.02
✓	EE	AAEE-Mid-Mid-Commercial-LG1	2019	0.46576	1	-0.47
✓	EE	AAEE-Mid-Mid-Domestic-LG1	2019	0.00515	1	-0.01
✓	EE	AAEE-Mid-Mid-Industrial-LG1	2019	0.01383	1	-0.01
✓	EE	AAEE-Mid-Mid-Commercial-LG1	2020	0.45895	1	-0.46

Figure 14: DER Adjustment Contributions

As presented in Figure 15, the load forecast viewer displays the hourly load forecasts with DER adjustments for both weekday and weekend/holiday days throughout the entire year and different weather conditions. For example: Hot 1-in-2 and Cold 1-in-10 correspond to the load forecast during the hot weather conditions that have the probability of occurring once in 2 years (50% chance) and once every10 years (10% chance), respectively. DER adjustments can be applied and removed from the load shape, presenting the viewer with a visual representation of how certain DER technologies could affect the overall feeder forecast under different weather conditions across multiple years. This enhancement is very useful when planners assess what kind of DER deployment might overcome system deficiencies. For example, PV can be applied to a bank or feeder to determine how new solar generation affects peak loading and affects the bank or feeder load shape over time.

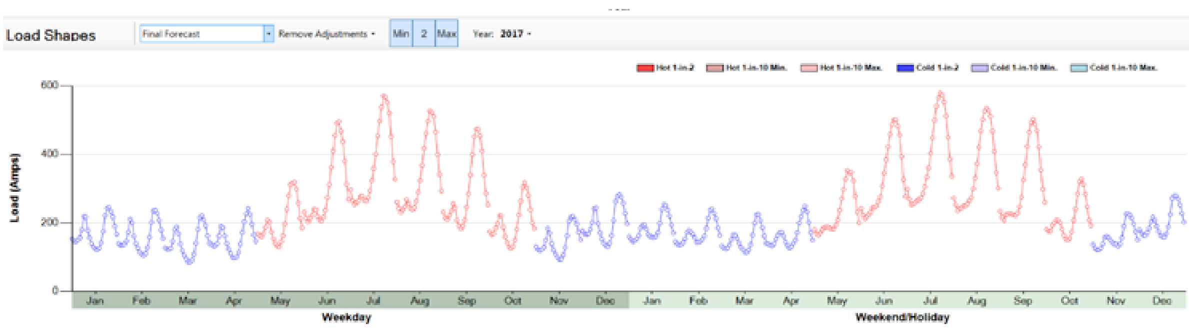

Figure 15: Load Shape in Forecast Viewer

The LF tool contains a hierarchy of distribution feeders, distribution banks, distribution planning areas and Western Area Coordinating Council (WECC) busbars, which is where the distributed and transmission systems interface. This allows PG&E to consistently aggregate the feeder load forecasts up through banks and DPAs to the transmission planning areas via the WECC busbars. Therefore, more accurate aggregated load forecasts with and without DER adjustment can be leveraged in the transmission planning process.

4.1.4 Incorporated DER Projection Scenarios

As discussed in PG&E's 2015 DRP Application,[19] PG&E developed 10-year growth scenarios for each of the technologies for the three scenarios outlined in the Guidance Ruling, listed below

- **Scenario 1 – "Trajectory"**

  This reflects PG&E's best current estimate of expected DER adoption, incorporating the following forecasts:
  - Adapted the CEC's California Energy Demand (CED)/IEPR DER forecasts
  - PG&E 2015 IEPR submittals used instead of CEC forecast for PV
  - Wholesale DG growth scenarios included in DRP, but not IEPR
  - Storage forecasts not in IEPR but in DRP

- **Scenario 2 – "High Growth"**

  This reflects "high" levels of DER deployment that are possible with increased policy interventions and/or technology/market innovations

[19] http://www.cpuc.ca.gov/General.aspx?id=5071.

- **Scenario 3 – "Very High Growth"**

  This is likely to materialize only with significant policy interventions such as those outlined in the DRP Guidance Ruling

These growth scenarios on a system level were driven by the market analyst reports, CPUC potential studies, existing procurement requirements, and internal PG&E analysis. The geographic allocation on a circuit level varied by DER based on adoption drivers, such as economical models and customer composition. Figure 16, shows the three DER growth scenarios implemented in the LF tool.

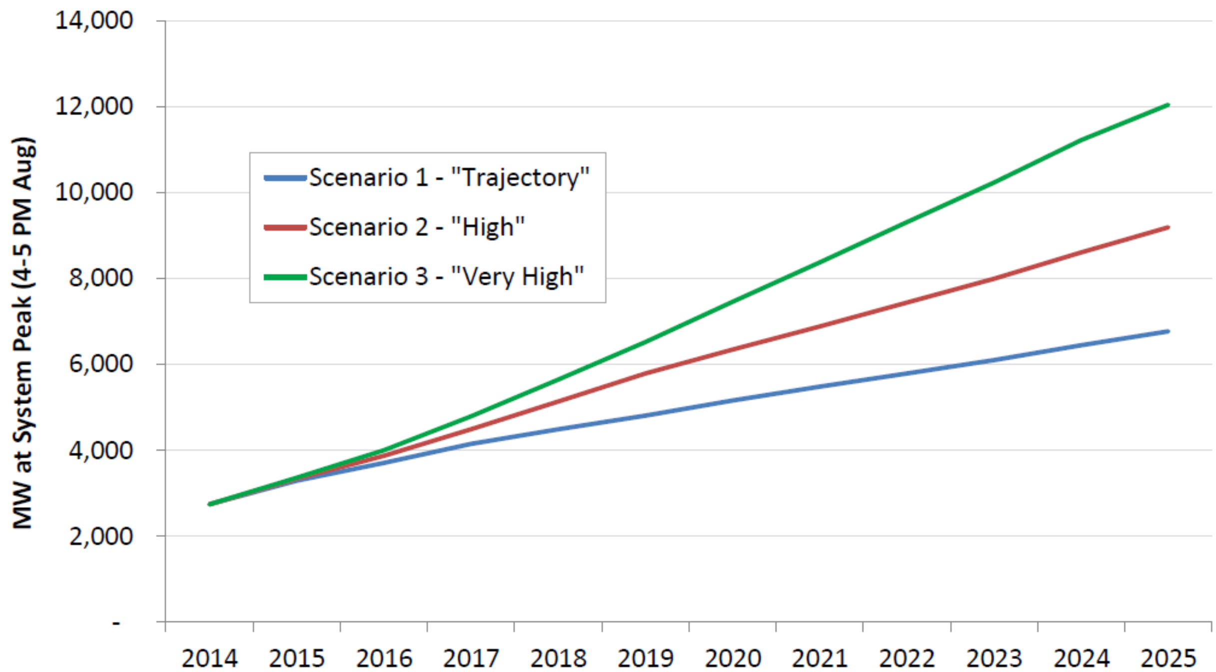

Figure 16: PG&E DER Growth Scenarios

4.1.5 Load Forecasting and Power Flow Analysis Integration

The LF – PFA tool integration was required to enable the analyses batch processing. For this purpose, the project leveraged and enhanced existing Python scripting, such that PFA tool direct integration with the LF tool is automated. Also, the LF tool database was updated with functionality that allows load forecast to be pulled directly from the PG&E PFA software or database, such that minimal or no modifications to the existing PFA Gateway was required.

This integration allowed a seamless import of feeder shape forecast results from the LF into PFA tool, which allocated feeder shape to individual service transformer locations in the power flow model before running the power flow simulation. Then, the PFA tool power flow results were transferred to the LF tool for further processing, such as for use in DRP Demonstration pilot work.[20]

Currently, the PFA tool takes feeder load forecast from the LF tool and allocates it to all service transformers on that feeder by scaling up or down the individual service transformer peak loads

[20] DRP Demo A – Integration Capacity Analysis (ICA); DRP Demo B – Locational Net Benefit Analysis (LNBA).

modeled in the PFA tool to match the feeder forecast. PG&E may explore the testing of the load allocation process by assigning each service transformer or customer with the load forecast on the individual customer level. This new allocation process could potentially allow more representative power flow modeling of all circuit segments because it is based on actual SmartMeter™ recorded electric energy usage measurements in a given hour.

4.1.6 Streamlined Integration Capacity Analysis

Integration Capacity Analysis (ICA) is an analytical process that is designed to evaluate the electric system integration capacity (IC), also known as "hosting capacity", to integrate DER in a safe and reliable manner while promoting customer choice, optimal resource placement, and reduction in greenhouse gas emissions. Built upon PG&E's existing ICA methodology, PG&E enhanced existing Python[21] and SQL[22] programming scripts to integrate the LF and PFA tool within the ICA process. As shown in Figure 17, this integration was established in the cloud environment, without integration with PG&E IT infrastructure, to demonstrate the advanced parallel computing capabilities to improve ICA processing time.

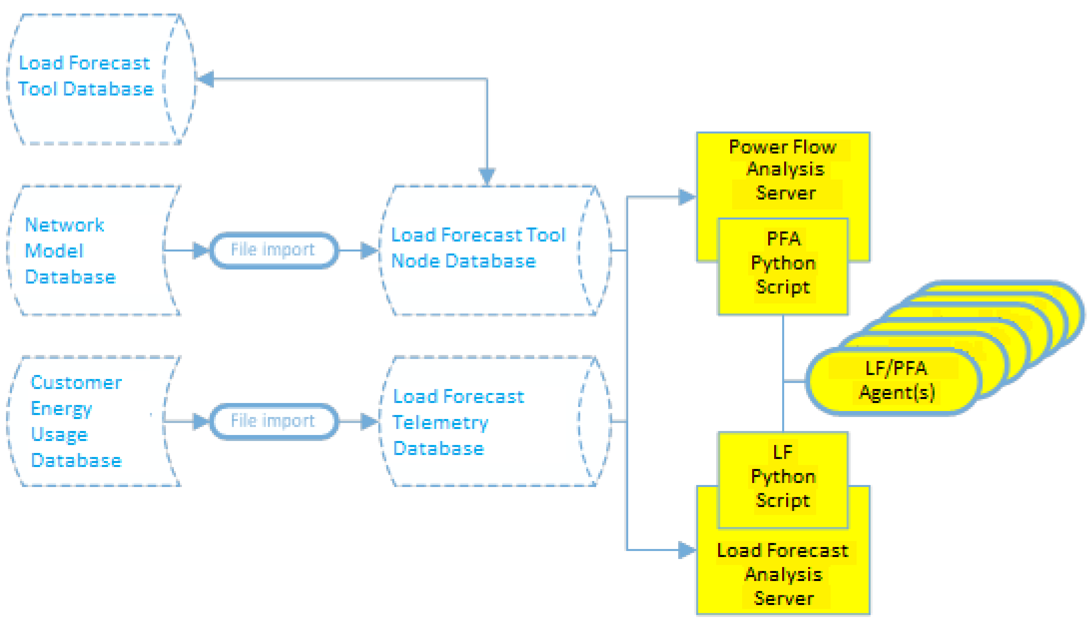

Figure 17: Load Forecasting and Power Flow Analysis Integration

In general, ICA requires batch processing of power flow analyses with load profile inputs based on the load forecast scenarios. Each simulation includes power flow and short circuit calculations, and returns the results for all primary voltage level conductors/nodes. For each circuit section/node, the DER adjustment is scaled up and power flow/short circuit calculation repeated until a violation occurs.

Based upon the EPRI streamlined ICA approach,[23] the PG&E streamlined ICA process starts by obtaining a baseline power flow solution (only once) to determine the initial conditions of the circuit that will be used in the calculations. The streamlined method then applies a set of equations and algorithms to

[21] Python is the dynamic object-oriented programming tool used to automate the streamlined ICA method as well as perform data analysis within the CYMDIST software.
[22] SQL is the informational management tool used for ICA results repository and post-simulation analysis.
[23] EPRI, January 2016, Integration of Hosting Capacity Analysis Into Distribution Planning Tools

evaluate power systems criteria at each node on the distribution system. The iterative method performs an iterative power flow simulation at each node on the distribution system, by solving for thermal and voltage conditions simultaneously using power flow simulations.

As described in the PG&E Demonstration Project A – Enhanced Integration Capacity Analysis,[24] the Demonstration Project A leveraged two sets of 288 hourly load profiles generated as part of EPIC 2.23. Those two sets represent high and low load scenarios at the 90th and 10th percentile load profile, respectively.

For comparison purposes, it takes 12,000 hours of computation time (3 to 4 hours per feeder ~3,200 feeders) to process the ICA analysis for:

- 576 hourly intervals (representing load profile for one year)
- 2 load scenarios (at the 90th and 10th percentile load profile)
- 2 DER scenarios
- 3 study years

With 100 power flow simulation software licensees and 400 dedicated processors in place, the computation time is reduced to approximately 30 hours. This time can be further reduced by creating more computing instances.

4.1.7 Enhanced Data Transfer Capabilities

The project integrated and automated legacy meter data and Integrated Data and Analytics (IDA) platform interface to the LF tool. This integration allows monthly transfer of customer energy usage data for the updating of load shapes in the cloud environment. Note that the load shapes used in the distribution planning process will be updated on an annual basis.

4.2 Findings, Learnings and Next Steps

The project gathered several key learnings, which are summarized below:

Improved Distribution Planning

- **Learning – Distribution Planning is Enhanced by Granular DER and Usage Data:** This project successfully demonstrated that an enhanced tool with granular DER and usage data can enable potential alternative solutions to capacity needs as opposed to traditional wired methods. A specific example to how this enhanced tool can help PG&E is with one of the banks for which the load forecast without DER projected overload at 105% in 2020. Through the application of feeder-specific DER projections, planning engineers can now assess potential for DERs to mitigate to mitigate bank overloading. With DER growth forecast and targeted deployment opportunity, PG&E can assess the least cost option to mitigate the overload in 2020.

  Next Step – Continue to Leverage Tool in Future Planning Cycles: PG&E plans to continue leveraging the enhanced tool in future planning cycles, and will continue to make refinements

[24] http://drpwg.org/wp-content/uploads/2016/07/R1408013-PGE-Demo-Projects-A-B-Final-Reports.pdf

to the tool and processes as its use progresses. Some of these potential refinements identified by this project are discussed below in further learnings.

Use of Customer Energy Use Data

- **Learning – SmartMeter™ Data Improved Load Profiles:** Improved load profiles can lead to more accurate distribution system power flow modeling. PG&E compared load shapes before and after the project. There was a notable difference in load shape profiles after use of customer interval energy reads captured by SmartMeters™. Use of actual SmartMeter™ interval data from all electric customers proved to be more representative of hourly load shapes than those based on load research and sample SmartMeter™ data as done in the past.

  Next Step – Refine Load Shapes with Additional 2 Years of SmartMeter™ Historic Data: Based upon the timeframe of the project, load shapes were defined during the demonstration based on SmartMeter™ interval data from the 2012-2014 period. Further load shape enhancements can be achieved by using SmartMeter™ recorded interval reads from a longer and most recent time period, providing the utility with the most accurate and up to date load shape forecast for the investment planning process. Therefore, PG&E plans to refine load shapes by using SmartMeter™ data from the 2015-2016 time period and continue to update the load shape profiles used in the distribution planning process on an annual basis.

- **Learning – For Forecast Accuracy, It is Important to Ensure All Customer Data in an Area Is Incorporated:** Some large customers who are metered using a legacy meter system were not initially included in the EPIC demonstration feeder load shapes. As part of the Legacy data User Acceptance Test (UAT) to validate load shape accuracy in the LF tool, PG&E compared the feeder load shape profile created with and without use of legacy meters data on two feeders that each had a large legacy account with loads between 3 and 7 MW. On both of these two test feeders, there was a large difference between load forecasts representing the 50th and 10th percentile probability when legacy meter data was not used in the load shape profile. After including the legacy meter data in the load profile, the 50th and 10th percentile volatility was reduced to a normally expected range (from approximately 200% to between approximately 0-30%).

  Next Step – Incorporate Legacy Meter Data in Load Shapes: In order to further improve load shape accuracy, legacy meter systems energy use data will be incorporated in the next annual revision of feeder load shapes.

DER Scenarios Projections

- **Learnings – Large PV Projects Can Overallocate the DER Scenario Projections On Individual Feeders**: Eight feeders had Agricultural PV adoption forecasts that depended on single, large (1-4 MW) PV systems to be installed in specific years, causing forecasted loads on these eight feeders to drop based upon that single large PV project installation. This forecasted load drop on eight agricultural feeders, if relied upon in the planning process, could delay required infrastructure expansion work, or overload mitigation measures such as transfers.

  Next Step – Introduce New Methodology for Large PV Adoption Forecast: After analyzing the impact of these specific eight Agricultural PV adoption forecasts, PG&E excluded large PV projects from the load forecast. Next year, PG&E plans to introduce a methodology to allocate the agricultural PV forecast adoption over multiple feeders in multiple years, as opposed to projecting the adoption to specific feeders in specific years.

- **Learning – The Time of Peak Shifts in High DER Adoption Areas:** Knowing the magnitude and time of the system peak is crucial for an effective distribution system planning process, especially in the presence of PV. PV adoption in recent years has decreased the daytime feeder peak, causing it to shift later in the day. For example, in one DPA area, the summer peak shifted from 4 PM to 7 PM, based on AMI data from 2012-2014 and SCADA data from 2016. This timing change for the maximum load on feeders can have a significant impact on the possible solutions to load expansion or power quality problems.

  Next Step – Annual Update of Load Shapes: Although a peak time shift is likely to occur in areas where DER adoption is more expansive, the project established monthly data collection from all PG&E electric SmartMeters™, and the annual load profile update process, to capture feeder peak time shifts in a timely manner. Any impacts of the peak time shifts will be evaluated as part of the annual distribution planning process. Consequently, network upgrade plans will be adjusted if required due to load shape peak magnitude and time forecast changes.

- **Learning: Temporal Granularity Is a Key Contributor to Forecast Accuracy** - During the demonstration, load shapes were created at a monthly level for feeders, banks, customer classes, and each DER technology. The impact of adjustments can now be properly modeled, not as the sum of peak values that may occur at different times, but as the sum of shapes that have complex interactions over time. In other words, PV adjustments applied to a feeder peak that occurs at 6pm should be less than the same PV adjustments applied to a feeder that peaks at 1pm. The application of feeder, bank, customer classes, and DER shapes now allows for this more accurate modeling.

  Next Step: Explore the Use of Even More Granular Data - PG&E plans to explore creating daily load shapes as opposed to monthly as a means to even further refine forecast projections and grid needs assessments. With regards to the timing and duration of grid needs, it would be an improvement to describe the hours and days of a grid requirement rather than the hours and months of a grid requirement. Presently, given the limitation of monthly shapes, it cannot be determined how many days out of that month the grid need is present.

- **Learning – Change Management is Key to Successful DER Scenario Implementation:** Training on proper use of DER adjustments within the load forecasting tool, combined with feedback based process improvement, is essential to tool acceptance and improvement.

  Next Steps – Incorporate Load Forecasting Enhancements into Planning Processes: PG&E plans to continue to refine and enhance planning use cases, processes and criteria. The enhanced load forecasting tool with DER adjustments is expected to be fully incorporated into the distribution planning process for future planning cycles and train relevant stakeholders for effective charge management.

Integrated and Automated Process

- **Learning – Integrated and Automated Process Requires a Large Amount of Data Storage Capacity and Computational Capability:** A large amount of computational capability is required to both run the integrated analysis and leverage for post-processing the raw outputs. This process generated significant amount of data (e.g. analysis of 6 million rows for each feeder) and required advanced data storage techniques, creating an opportunity for PG&E to gain learnings on large scale data processing that is expected to be leveraged in the future.

Next Steps – Integrated and Automated Process Transition to Production: Although the project successfully demonstrated a use of cloud computing and storage techniques, PG&E will assess what solution architecture (e.g. cloud or internal/on-site hosting) best serves needs based upon enterprise strategy in the years to come. This assessment will take into account not only the needs of the load shape profile update process, but also the needs of other PG&E large scale processes and analyses such as DER Integration Capacity Analysis[25] (ICA) and Locational Net Benefit Analysis[26] (LNBA).

4.3 User Feedback

Overall, the distribution planners provided positive feedback regarding the new DER load shape inclusion in the load shape forecasting process. However, planners identified some feeders where the DER adjustments seemed aggressive based on the planner's local knowledge of the area and the customers in that area. Accordingly, PG&E will establish an annual DER forecast validity process that compares actual and forecasted loads. Any DER forecast projection corrections, if needed, would be revised by the PG&E data analytics group and re-applied by (Distribution Planning Department) Senior Area Engineers for the next forecasting period (e.g. September through December).

Senior Area Engineer Feedback:
"EPIC Project 2.23 enabled distribution planning to produce truly integrated load forecasts for the first time. The forecasting tool now reflects the diversity of customer choices. By inference, it also allows planning to understand how DERs may have influenced historic loading. These additional variables have both enhanced our tools and broadened our perspective. Going forward, we envision the continuous improvement of our forecasting tools to meet the needs of our customers."

ICA Analysis User Feedback:
"EPIC Project 2.23 enhanced the ICA process by improving customer class load shape accuracy and incorporating DER scenarios. Ultimately this is necessary in order to perform a more robust hosting capacity analysis that considers high penetration scenarios. As a result of EPIC Project 2.23, the ICA analysis processing time was greatly improved due to integration of load forecast tool and power flow analysis tool, and use of cloud computing.

The key components focused on were scenario analysis, better accuracy, and speed of analysis. Scenario analysis is needed to ensure various sensitivities are understood for better consideration of more complex high penetration DER circuit operations and behaviors. Accuracy was important using the geospatial circuit models and hourly AMI shapes in order to get a better accounting of the granular issues and where they occur. Speed was a critical factor in which analysis had to graduate from single desktop computers to servers in order to analyze the hundreds of thousands of simulations with all the hours and scenarios."

LNBA Analysis User Feedback:
"The feeder level DER forecast information, created by EPIC Project 2.23, was central to our LNBA demonstration project. It provided us with the feeder level DER forecast for the base (trajectory) and high DER scenario from our 2015 DRP planning in order to determine the list of projects that are deferrable by

[25] ICA will be used to help streamline the DER interconnection process and potentially identify areas where grid modernization investment is needed to support future DER deployments.
[26] LNBA may be used to signal where future DER investment (either IOU or third party) will provide highest value to the grid.

DER, as well as requirements and value of the project deferral. EPIC Project 2.23 allowed us to use a DPA specific PV profile. For any given project that was deferrable, we were able to produce an extensive hourly load reduction profile requirements for multiple years."

Management Feedback:
"This project allows us not only to better forecast loads, but also to better forecast DER impact on future load forecast. Because of the changes in the load forecasting tool, we had to make sure that we properly train our distribution planning engineers who are working with the load forecasting tool. Our load forecasting Subject Matter Expert started holding bi-weekly one hour online training sessions at the end of Phase 1. This training sessions really helped us throughout the change management process."

An Additional Use for Forecasting Tool
One potential new use for the integrated load forecasting tool has arisen due to the potential electrification of natural gas appliances in the state of California to meet clean air requirements. In order to assess the effects of electrification of different technologies, PG&E developed forecast portfolios and load shapes for the following technologies:

- Electric space heating
- Electric water heating
- Electric dryers
- Electric stoves
- Electric pool heaters
- Electric spa heaters

With the enhancements developed from this demonstration, PG&E was able to upload the shapes and growth forecasts for each technology into the load forecasting tool. PG&E may explore applying these technology-specific shapes and technology-specific growth forecasts to each bank and feeder to allow the determination of incremental upgrades that will be required for each type of appliance that is electrified. This may provide useful data in the analysis of grid and customer impacts.

4.4 Data Access

Upon request, PG&E will provide access to data collected that is consistent with the CPUC's data access requirements for EPIC data and results.

4.5 Value Proposition

The purpose of EPIC funding is to support investments in technology demonstration and deployment projects that benefit the electricity customers of three large in California Investor Owned Utilities (IOUs): PG&E, San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE). EPIC Project 2.23 Integrate Demand Side Approaches into Utility Planning has demonstrated incorporation of DSM as well as traditional supply side mitigations as part of more truly integrated least-cost planning at the transmission and distribution level.

4.5.1 Primary Principles

The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. This EPIC project contributes to these primary principles in the following ways:

- **Greater reliability:** The project leveraged SmartMeter™ data to generate more accurate load shapes and DER adjustment forecasts at the system and granular (customer) level. With more accurate representation of load and DER adoption, distribution engineers can better model current and future grid conditions. Consequently, the system simulation results will more accurately represent the direction and magnitude of power flows. Recommended infrastructure modifications, and equipment specifications and settings can therefore better match the actual conditions, improving the reliability of the system. This enhancement supports the ability to decrease overloads, of which wear on the system components inherently increases risk of outages.
- **Lower costs:** The ability to include DER adjustment forecast in an integrated least-cost planning framework will potentially result in lower system costs, by avoiding system upgrades where load growth will be offset with DER adoption. By having the ability to analyze the DER profile impact on the overall load shape, PG&E will be able to potentially target certain DER programs that have the shape and magnitude appropriate to defer or eliminate network upgrades.

  A specific example to how this enhanced tool can potentially help reduce or defer costs is with one of the banks for which the load forecast without DER projected an overload at 105% in 2020. A capital project alternative to resolve this bank overload could be to increase the bank capacity by replacing the current transformer with a larger transformer. By using the forecast viewer to apply DER adjustments, the bank loading could potentially be reduced to 95% in 2020. With DER growth forecast and targeted deployment opportunity, PG&E can assess the least cost option to mitigate the overload in 2020.

  Additionally, with increasing amounts of DERs coming online, this tool provided an efficient way to model them. Without such a tool, finding optimal locations for DERs at the feeder level may have been a manual effort.

- **Increased safety:** By hierarchically aggregating load shapes, PG&E engineers can leverage load forecasts to project the timeframe when power flow could reverse at certain distribution system components (e.g. voltage regulators, protective devices) that are not presently designed to operate under such conditions. The reverse power flow could create a safety concern, as equipment may be more likely to fail. With prior knowledge of such a condition possibly existing, PG&E planners could potentially address the problem and eliminate the safety concern.

4.5.2 Secondary Principles

This technology demonstration project advances the following secondary EPIC principles:

- **Efficient use of ratepayer funds:** A standalone forecast viewer application will provide improved and more granular load and DER adjustment forecasts to be used across PG&E. This will allow companywide analysis of forecasted loads and DER adjustment forecasts, as well as analysis of potential targeted DER programs without affecting the load forecast database performance. Infrastructure additions to the system will be optimized, reducing the overall cost of electric delivery. Furthermore, this project provided tool enhancements that can also help explain station/regional load shapes, specifically maximum and minimum load levels used in the transmission planning analytical process. Currently, transmission planners have to determine what banks are fed from what busbar prior to running planning studies. With this enhanced tool including the Western Area Coordinating Council (WECC) busbar in the hierarchy as the lowest level of granularity needed for this studies, this may potential reduce the time it takes to run transmission planning studies.

- **GHG Emissions Reductions:** ICA could potentially reduce GHGs by providing additional opportunities for distribution connected renewable generation.

4.6 Technology Transfer Plan

4.6.1 IOU's Technology Transfer Plans

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within PG&E, and across the other IOUs, the CEC and the industry. In order to facilitate this knowledge sharing, PG&E plans to share the results of this project in industry workshops and through public reports published on the PG&E website. Below are some key information sharing forums where the results and lessons learned from this EPIC project were presented:

Information Sharing Forums Held

- **The Utility Energy Forum Conference**

  Lake Tahoe, CA | May 2016
- **LF Tool Users Group Conference**

  Cincinnati, OH | April 27-28, 2017
- **Joint IOU Meetings**

  The enhanced functionality of the load forecasting/power flow analysis tool has been discussed in the context of numerous Joint IOU meetings as well as in meetings with non-IOU stakeholders in the context of the Distribution Resources Plan Order Instituting Rulemaking.

PG&E plans to continue exploring industry outreach in order to share project learnings and discuss future potential opportunities.

4.6.2 Adaptability to other Utilities/Industry

Beyond the specific load and DER adjustments shapes that correspond to the PG&E customer base, the overall integrated load shape profile definition and update process can be applied to any other utility that targets to more accurately evaluate DER growth impact on the load shape profile forecast regardless of the preference to host the integrated process in the cloud environment or on their premises. Overall, the demonstrated tool benefits the entire electric power industry and can be applied to any geographical location in the country.

PG&E plans to continue leveraging this tool for future distribution and transmission planning. Additionally, as a result of this demonstration, the vendor is working to incorporate the enhancements into their core product.

5.0 Metrics

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation)	See Section
3. Economic benefits	
Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management	4.1.3
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
Forecast accuracy improvement	4.1.1
Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360)	4.1.6

6.0 Conclusion

The EPIC Project 2.23 delivered an integrated planning process that provides not only the forecasted load growth of new and established customers, but also provides the forecasted load reduction due to expected DER additions. Location specific DER load shapes created as part of this project allows PG&E to perform distribution planning in an integrated, least-cost fashion. Newly created DER load shapes and forecasts will be a key component in assessing DER efficacy to mitigate forecasted network capacity deficiency. This may allow for the better use of non-infrastructure solutions to meet the future system delivery requirements, for example, plan targeted Demand Response (DR) or new rates to shift peak loads earlier or later can now be evaluated as to their effect on the future loading of the distribution feeders. Once DER effected solutions are identified, PG&E can compare the cost-efficiency of both traditional wired and alternative non-wired solutions as part of the Integrated Distributed Energy Resources (IDER) process.

As part of this project, PG&E continued to leverage investments that further enable the modernization of the grid. Use of SmartMeter™ data enabled PG&E to create more accurate and granular load shapes. The enriched catalog with over 320,000 new load shapes allows PG&E to more accurately capture DER impact in the load growth forecasts and incorporate DER in the distribution planning process, especially in the areas with high DER adoption rates.

Some feeders/banks that have had strong DER adoption experienced drastic changes in load shapes, posing challenges to the distribution planning process. Because of EPIC 2.23, the historic loading information is now explainable with newly created DER load shapes. Thus, distribution planning engineers can better understand attributes that led to a particular feeder/bank load profile and more accurately model DER in their planning process. Furthermore, this project provided tool enhancements that can help explain station/regional load shapes, specifically maximum and minimum load levels used in the transmission planning process.

In addition to enhancements in load shape definitions, an integrated analysis process enabled faster analysis processing time, greater system and granular level load modeling accuracy, and inclusive DER forecast scenarios. These improvements allow more efficient, accurate, flexible, yet standardized process to analyze various DER scenarios with minimal user intervention in order to maintain the planning process consistency across the DPAs.

The EPIC Project 2.23 created a solid demonstration as a foundation from which electric utilities, regulators, adjacent industries, policy makers and prospective vendors can advance to a broadly leveraged process to the ultimate benefit of utility customers. Beyond this demonstration, the enhanced tools will be further tested in future planning cycles. Feedback from engineers will inform process changes and training needed to continue to successfully leverage the tools. In parallel, the enhanced tool will support IDER/DRP proceedings, including Integration Capacity Analysis and Locational Net Benefit Analysis, Distribution Infrastructure Deferral Framework, Competitive Solicitation Framework and Grid Modernization Filings.