Walk-through of long-term utility distribution plans:

Part 2 - Grid modernization plans and plans for high levels of distributed energy resources

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GE Energy Consulting

Distribution Systems and Planning Training for Western States, May 2-3, 2018

GRID
MODERNIZATION
LABORATORY
CONSORTIUM
U.S. Department of Energy

Grid Modernization Planning

With Examples from Unitil's Grid Modernization Plan

Diverse goals for grid modernization

GRID MODERNIZATION LABORATORY CONSORTIUM
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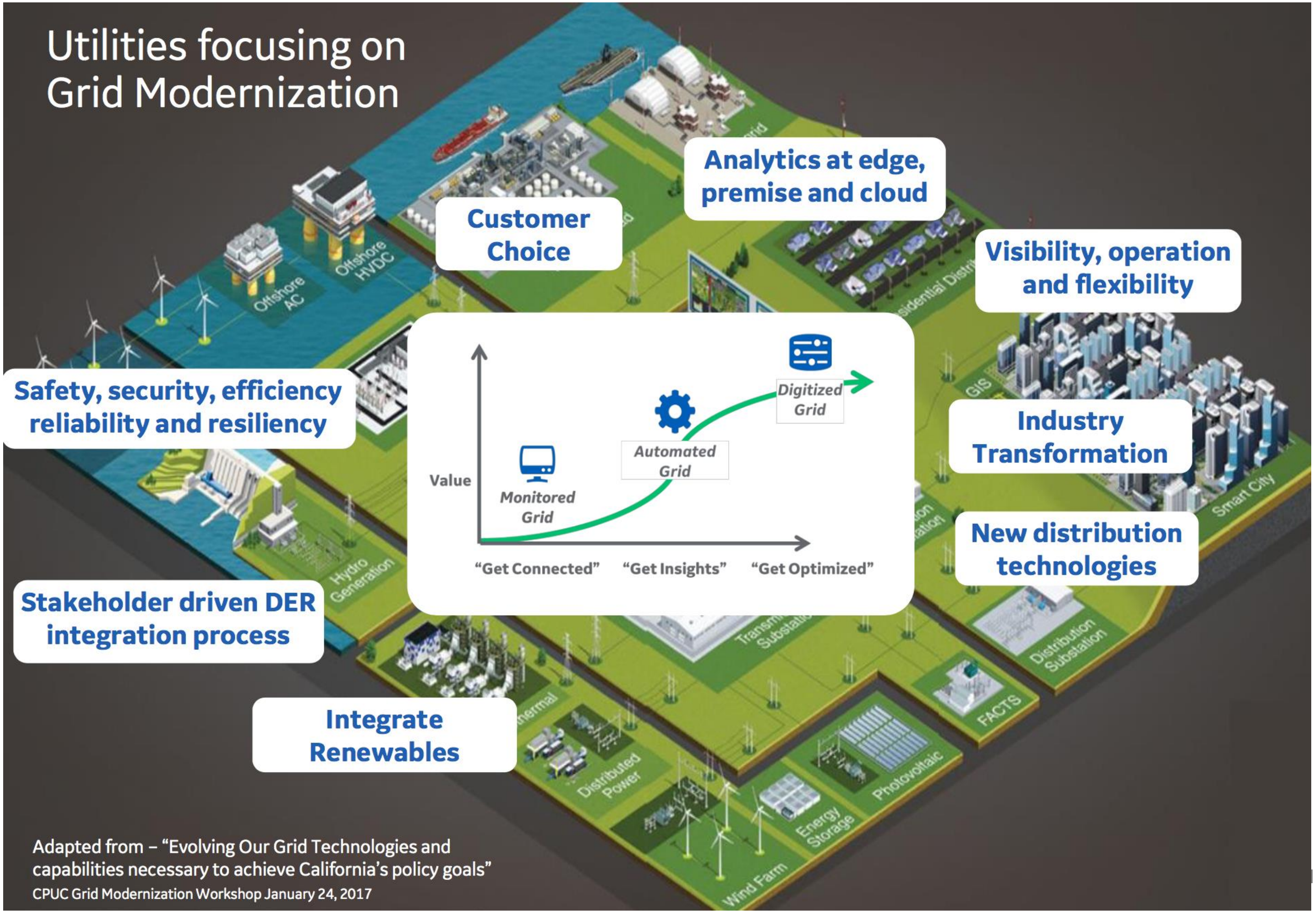


Utilities focusing on Grid Modernization

Customer Choice

Analytics at edge, premise and cloud

Visibility, operation and flexibility

Safety, security, efficiency reliability and resiliency

Industry Transformation

New distribution technologies

Stakeholder driven DER integration process

Integrate Renewables

Adapted from – "Evolving Our Grid Technologies and capabilities necessary to achieve California's policy goals"
CPUC Grid Modernization Workshop January 24, 2017

Byron Flynn, GE

Grid Modernization

- Improve system operations
- Improve system reliability
- Decrease outages and restoration time
- Cybersecurity
- Reduce losses on the distribution system
- Increase workforce efficiency
- Provide better price signals to customers
- Improve DER integration

Advanced Metering Infrastructure

Volt/VAR Optimization

Bi-directional equipment

Advanced Distribution Management System

Fault Location Isolation and Service Restoration

Conservation Voltage Reduction

Time-varying rates

Distributed Energy Resource Management System

Steps of Grid Modernization Plans

1. GOALS	What is the utility's vision for the future? What drives the utility grid mod needs?
2. CURRENT STATE ASSESSMENT	What is the state of existing infrastructure, system operations, and customer needs and desires?
3. PROJECT DEFINITION	What strategic pathways can meet these goals? What technologies, data, communications, etc are needed? Define costs, benefits, timing. Prioritize projects/programs.
4. PUTTING IT ALL TOGETHER	How do the pieces integrate? What is the anticipated performance, risk, and cost of the plan? Prioritization and scheduling; roadmapping.

Goals/Objectives

Massachusetts Dept of Public Utilities (DPU) defined objectives:

1. Reducing the effects of outages
2. Optimizing demand
3. Integrating distributed resources
4. Improving workforce and asset management

Unitil's *practical grid modernization*:

1. Meeting DPU objectives
2. Responding to customer interests (rate sensitivity)
3. Supporting role of third parties and market solutions for customers
4. Capital investment to replace aging infrastructure while modernizing grid
5. Anticipating transformation of electric delivery business model and regulatory considerations

This is a ten-year plan

Overview of Unitil

►Cost-sensitive Customers

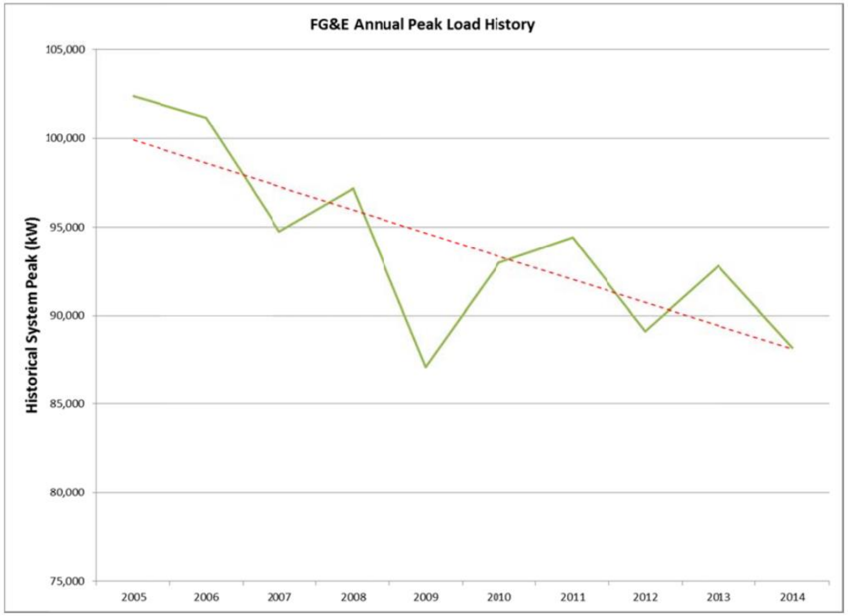
- Economically under-performing region in MA with higher than average % of low-income rate discount customers
- Higher than average unemployment and poverty rate

► Small distribution system

10 substations, 44 circuits, 28,600 customers (90% residential)

► Capital expenditures

- Balance replacement/upgrading of aging infrastructure with grid modernization
- Therefore, highly values investments that provide net benefits for customers and have acceptable rate impacts such as efficiency and reliability



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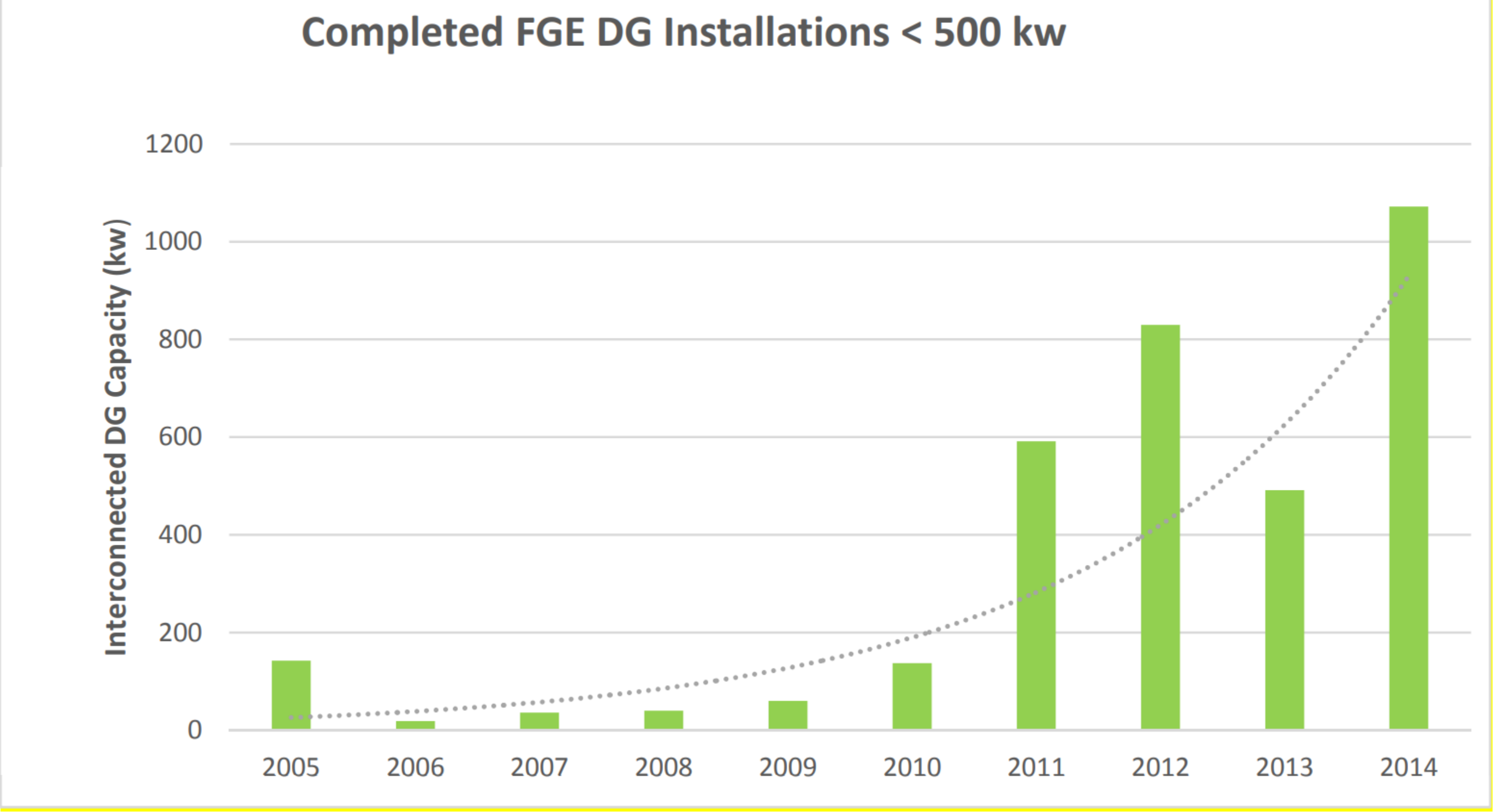
Distributed generation is growing



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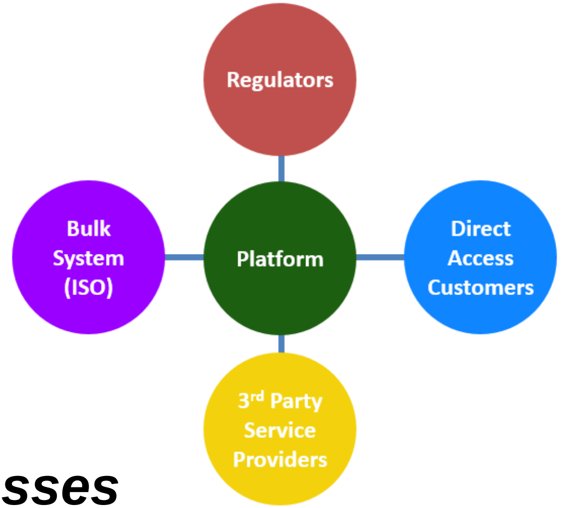
Programs to reach these goals

- ►Unitil convened experts
- ►Defined future vision: ***A Platform for the 21st Century***
  - Unitil's role will evolve
  - Grid operations will be two-way, dynamic and diverse
  - Unitil will enable rather than provide many of these services
- ► What are the gaps?
  Systems; Customer information; Business processes
- ► What projects could fill these gaps?

  Unitil identified projects
  - Description, cost, scope, schedule
  - Rationale, business drivers
  - Benefits and costs (quantifiable and non-quantifiable)



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Project definition and prioritization

- 52 potential projects were mapped to goals, reduced to 16 capital investment projects, and organized into five programs:
  1. DER enablement -encourage DER with flexible grid; DER pricing reflects value
  2. Grid reliability – reduce impact of outages
  3. Distribution automation – automate grid operations
  4. Customer empowerment – provide customers with tools and information to manage energy choices
  5. Workforce and asset management – improve efficiency and effectiveness of field crews and asset management

Recommended projects in each program

DER Enablement	Reliability	Distribution Automation	Customer Empowerment	Workforce & Asset Management
Circuit capacity study	Integrate Enterprise mobile damage assessment tool	Field Area Network	Energy information web portal	Mobility platform for field work
DER analytics and visualization platform	Integrate AMI with Outage Management System (OMS)	SCADA at substations	Gamification pilot	
Zero sequence voltage (3V0) protection at substations		Auto devices for Volt/VAR Optimization (VVO)	Time-varying rates (TVR)	
		Advanced Distribution Management System (ADMS)		

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DER Enablement Program

► Objective

To accommodate high DER penetrations; to create pricing approach that recognizes value of DER without cross subsidies between customers with and without DERs

► Projects:

- Circuit capacity study for DER (hosting capacity)
- DER analytics and visualization platform
- 3V0 relay protection and voltage regulation controls

Photo by NREL, 568

Circuit capacity study for DER

- ► Annual hosting capacity analysis to encourage DER where it is easily hosted.
- ► Identify substations that require upgrades to host more DER.
- ► Post results on website.

Implementation Timeline & Cost	Annual study in 2017 through 2026 for a total cost of $180,000 over ten years									
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs (000s)	$30	$30	$15	$15	$15	$15	$15	$15	$15	$15
Benefits (000s)	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10

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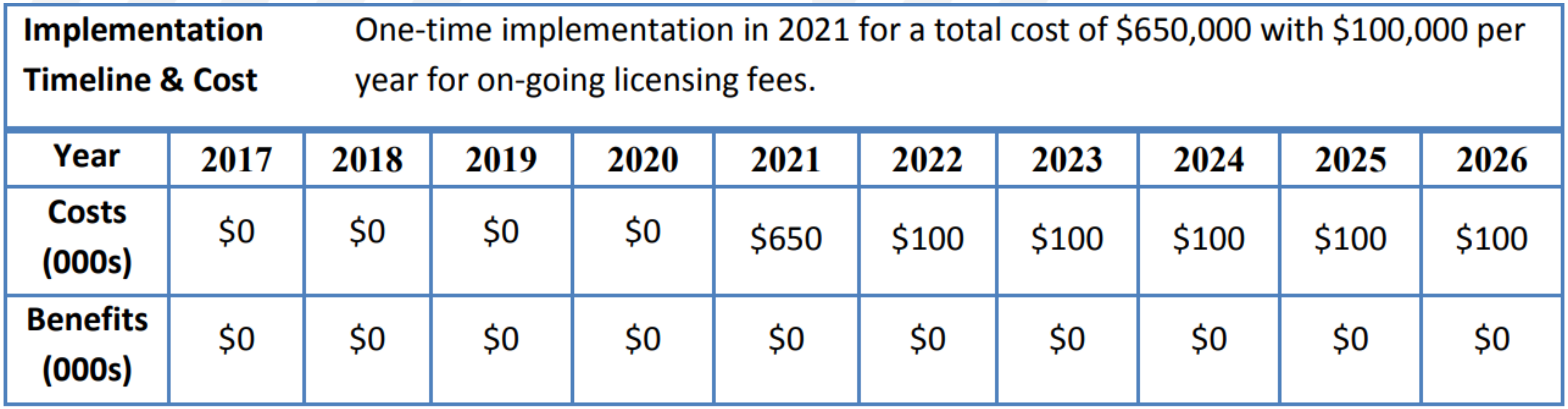
DER analytics and visualization platform

- ► Distributed Energy Resource Management System (DERMS) to monitor, manage and control DERs
- ► Stand-alone DERMS or work with Distribution Management System (DMS)
- ► Provide situational awareness (real time visibility) and operational intelligence
- ► Supports operations and planning



Implementation Timeline & Cost One-time implementation in 2021 for a total cost of $650,000 with $100,000 per year for on-going licensing fees.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$0	$0	$0	$0	$650	$100	$100	$100	$100	$100
Benefits (000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

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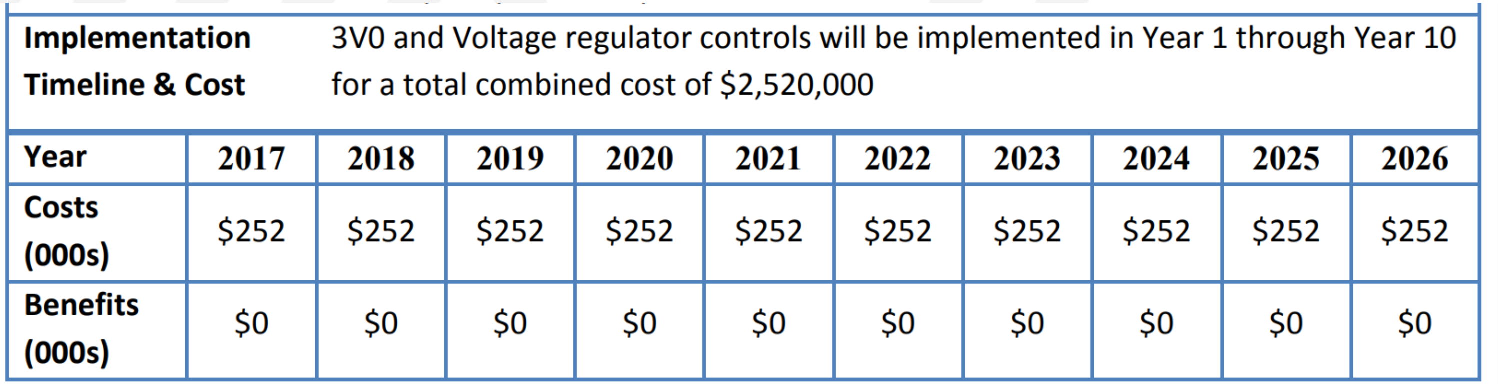
3V0 overvoltage relays & voltage regulation controls

- Install zero sequence voltage relaying and voltage regulator controls at substations to alleviate equipment damage concerns caused by reverse power flow
- This protection will allow power flow from distribution to subtransmission system without jeopardizing substation equipment
- One of ten substations is already experiencing reverse power flow
- Enables higher DER penetration without having to closely study every new installation



Implementation Timeline & Cost	3V0 and Voltage regulator controls will be implemented in Year 1 through Year 10 for a total combined cost of $2,520,000									
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs (000s)	$252	$252	$252	$252	$252	$252	$252	$252	$252	$252
Benefits (000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

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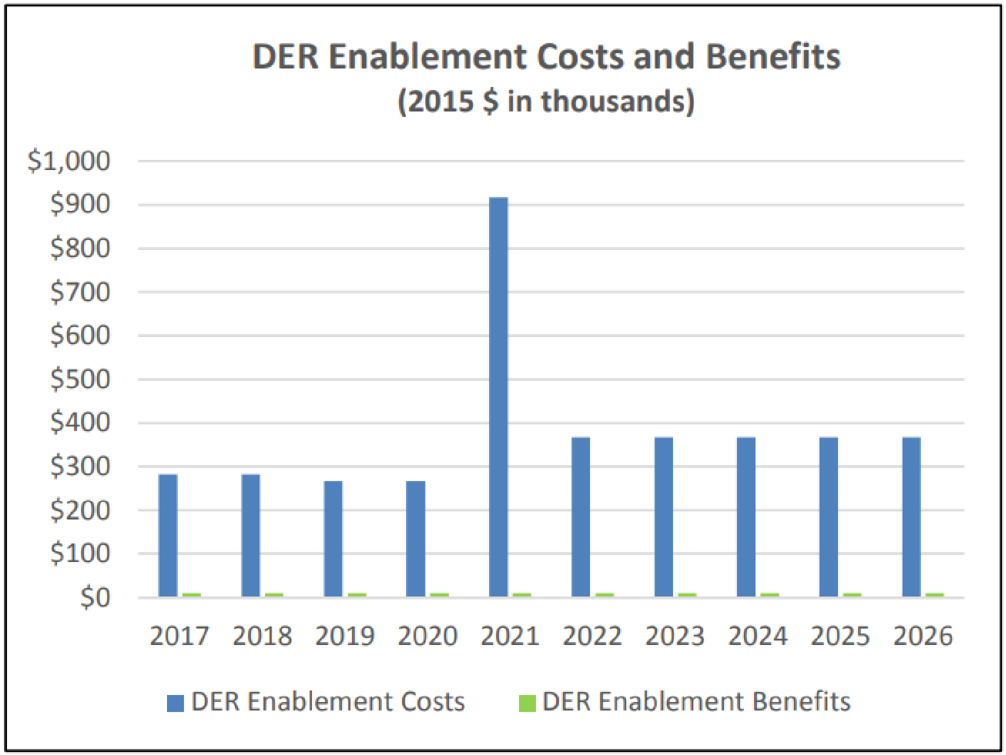
Overall DER enablement program cost/benefit



- Almost $4M over ten years with a DERMS investment in Year 2021
- Early work to upgrade substation protection, develop a tariff for customer-owned DG, and to conduct a capacity study to identify the best locations for DG
- Will produce the qualitative benefits of enabling high penetration of DER
- This is a strategic investment that will help Unitil make the transition to becoming an Enabling Platform

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$282	$282	$267	$267	$917	$367	$367	$367	$367	$367
Benefits (000s)	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10

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Distribution Automation Program

► Objective

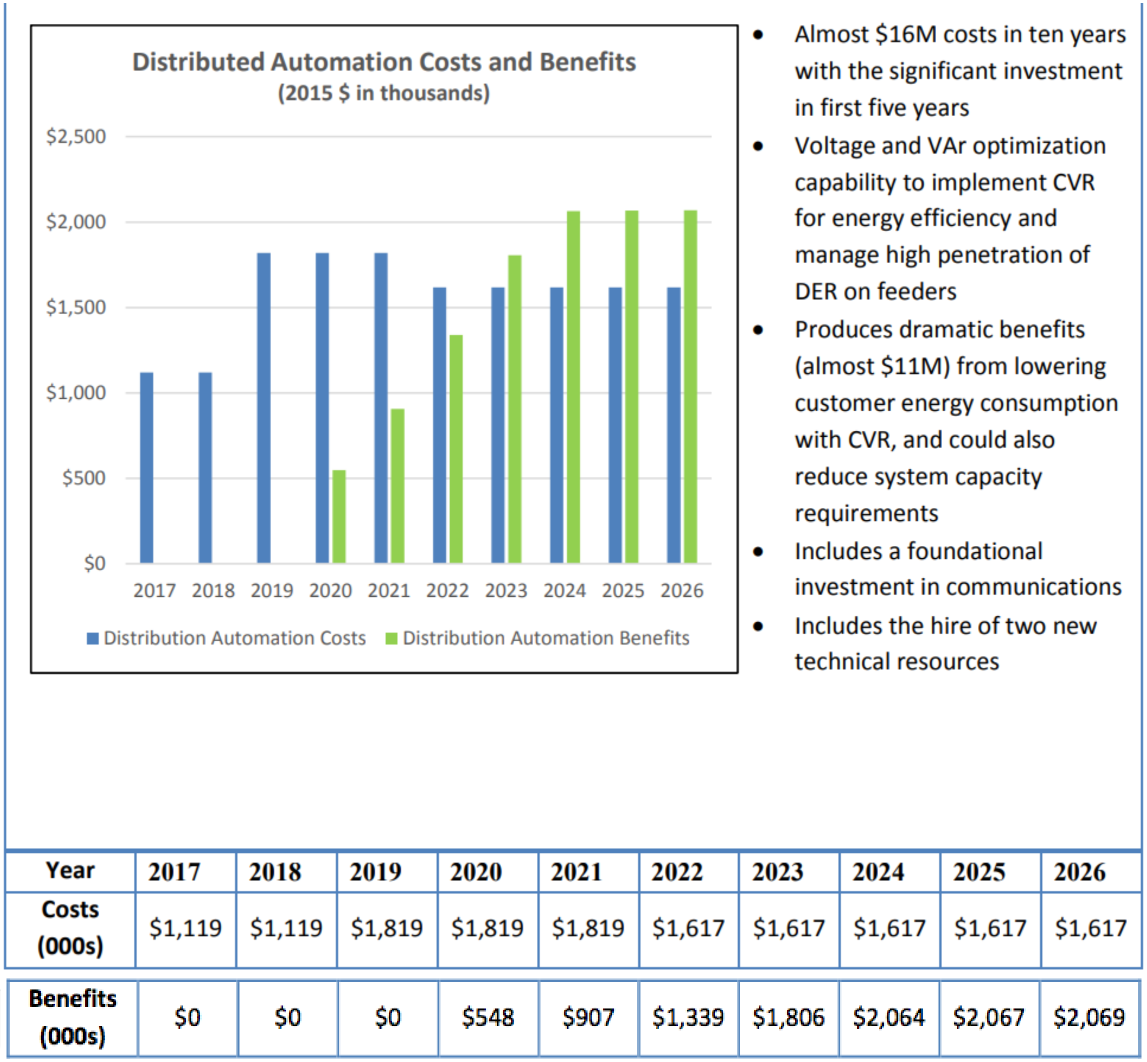
- Create communication layer of the Enabling Platform to support advanced metering functionality and distribution automation
- Automate and optimize voltage and reactive power equipment to implement CVR and respond to changes in DER output

Distribution Automation Program

► Projects

Field Area Network (FAN)	Wireless communication between centralized systems and grid edge devices (meters, distribution devices). Advanced metering, TVR, distribution automation, and DER management will use this FAN. $2.8M
SCADA	Install SCADA communications to all substations so grid operators can monitor and control substation equipment from remote control center, and manage reliability and operational efficiency. $1M
Volt/VAR Optimiz. (VVO)	Install automated controls on voltage and reactive power equipment (capacitor banks, voltage regulators, load tap changers). The operation will be coordinated and optimized by the ADMS. $9.1M
Adv. Dist. Mngmt System (ADMS)	Integrate system with existing GIS, OMS, SCADA and CIS. ADMS supports VVO, CVR, 3 phase unbalanced power flow analysis and distribution system operations. ADMS manages automated distribution switching and FLISR. CVR will reduce customer consumption by 2-3% or more. $2.9M

Overall distribution automation program cost/benefit



Distributed Automation Costs and Benefits
(2015 $ in thousands)

- Almost $16M costs in ten years with the significant investment in first five years
- Voltage and VAr optimization capability to implement CVR for energy efficiency and manage high penetration of DER on feeders
- Produces dramatic benefits (almost $11M) from lowering customer energy consumption with CVR, and could also reduce system capacity requirements
- Includes a foundational investment in communications
- Includes the hire of two new technical resources

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$1,119	$1,119	$1,819	$1,819	$1,819	$1,617	$1,617	$1,617	$1,617	$1,617
Benefits (000s)	$0	$0	$0	$548	$907	$1,339	$1,806	$2,064	$2,067	$2,069

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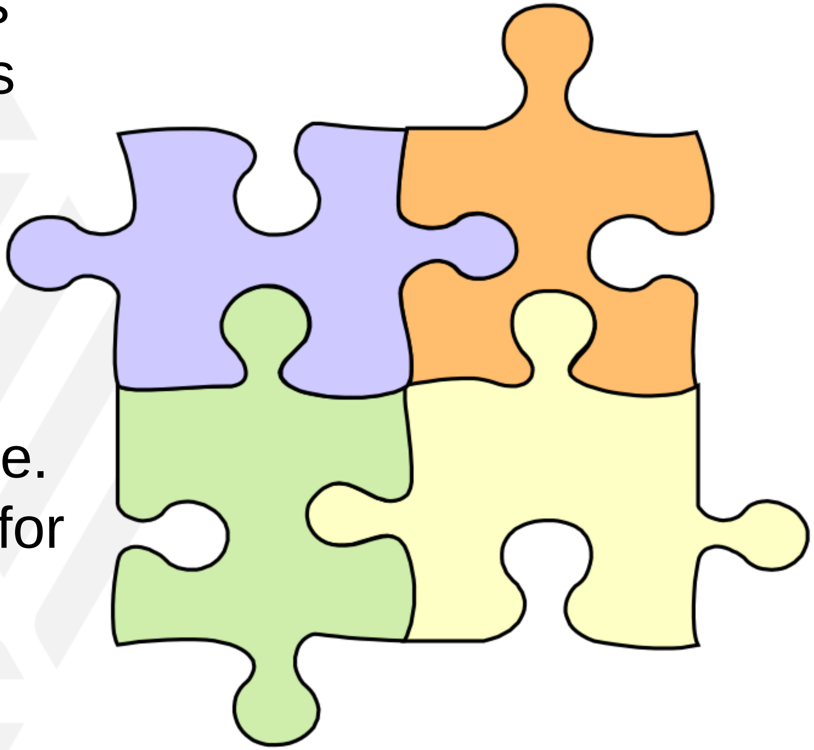
Time-varying rate (TVR) and time-of-use pricing

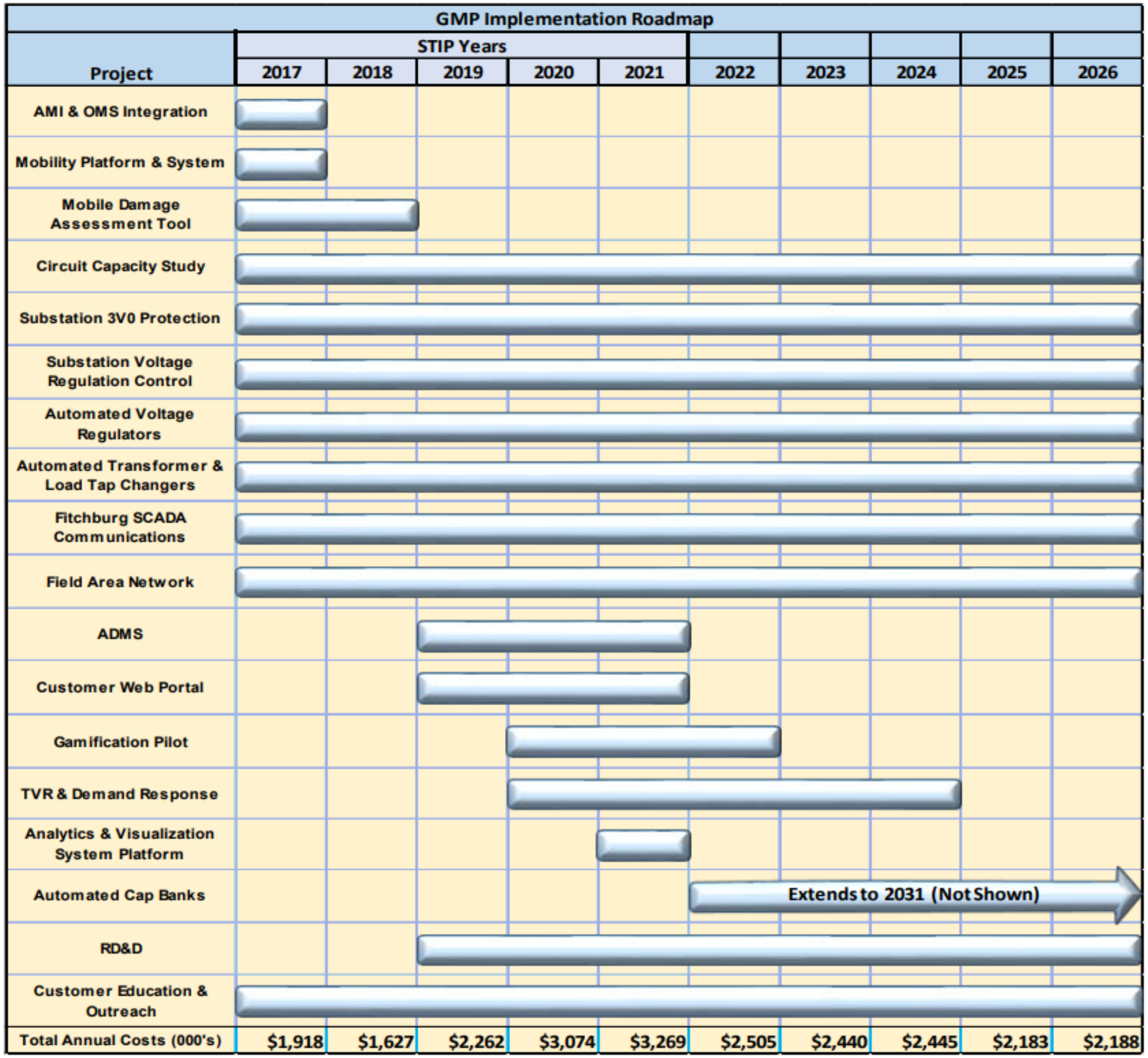
- PUC order requires advanced metering functionality (AMF) and optional TVR
- Upgrading all meters was not a good solution:
  - Cost of $12M with benefits of only $3.3M; existing smart meters have not reached end of useful life; municipal aggregation is competing with TVR for customers
- Build on existing advanced metering infrastructure (AMI) that provides some advanced metering functionality.
- Use new communications network to enable AMF
- Offer optional TVR rate

Integration of the plan

- Implement foundational projects first, along with others that achieve results and benefits quickly: communications network, hosting capacity, grid reliability
- Protection and voltage regulation control projects are annual projects and need to be done at the same time. Start with substations highest at risk for reverse power flow
- SCADA and VVO start in year 1 as well. ADMS in year 3 so that enough equipment is ready for use.



Roadmap



GMP Implementation Roadmap

Project	STIP Years									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
AMI & OMS Integration	▬									
Mobility Platform & System	▬									
Mobile Damage Assessment Tool	▬	▬								
Circuit Capacity Study	▬	▬	▬	▬	▬	▬	▬	▬	▬	▬
Substation 3V0 Protection	▬	▬	▬	▬	▬	▬	▬	▬	▬	▬
Substation Voltage Regulation Control	▬	▬	▬	▬	▬	▬	▬	▬	▬	▬
Automated Voltage Regulators	▬	▬	▬	▬	▬	▬	▬	▬	▬	▬
Automated Transformer & Load Tap Changers	▬	▬	▬	▬	▬	▬	▬	▬	▬	▬
Fitchburg SCADA Communications	▬	▬	▬	▬	▬	▬	▬	▬	▬	▬
Field Area Network	▬	▬	▬	▬	▬	▬	▬	▬	▬	▬
ADMS			▬	▬	▬					
Customer Web Portal			▬	▬	▬					
Gamification Pilot				▬	▬	▬				
TVR & Demand Response				▬	▬	▬	▬	▬		
Analytics & Visualization System Platform					▬					
Automated Cap Banks						▬ Extends to 2031 (Not Shown)	▬	▬	▬	▬
RD&D			▬	▬	▬	▬	▬	▬	▬	▬
Customer Education & Outreach	▬	▬	▬	▬	▬	▬	▬	▬	▬	▬
Total Annual Costs (000's)	$1,918	$1,627	$2,262	$3,074	$3,269	$2,505	$2,440	$2,445	$2,183	$2,188

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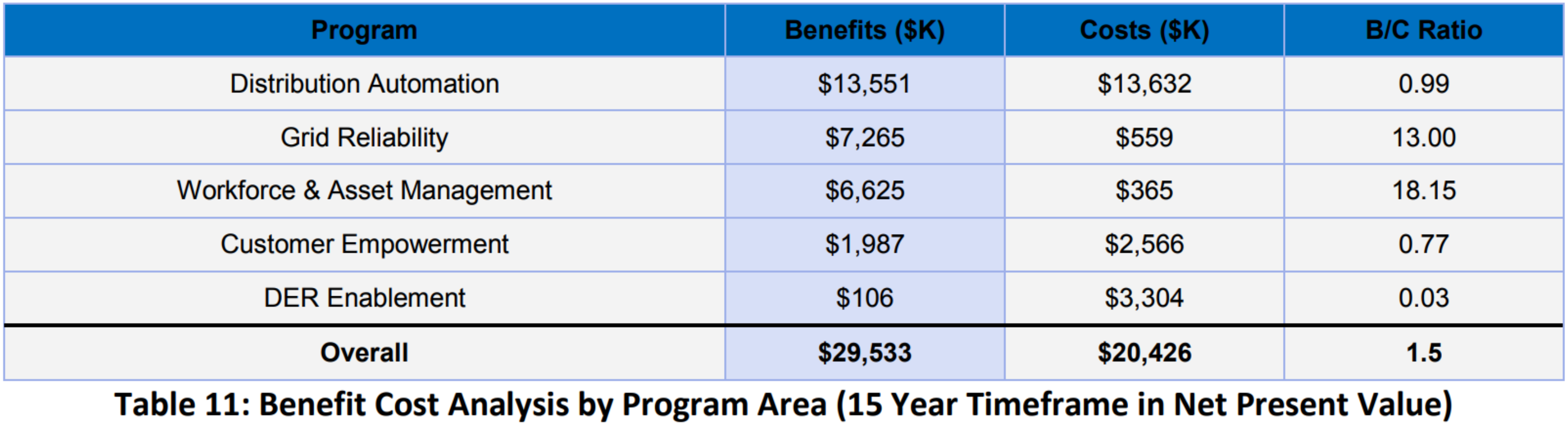
Benefits exceed costs over 15 years



Program	Benefits ($K)	Costs ($K)	B/C Ratio
Distribution Automation	$13,551	$13,632	0.99
Grid Reliability	$7,265	$559	13.00
Workforce & Asset Management	$6,625	$365	18.15
Customer Empowerment	$1,987	$2,566	0.77
DER Enablement	$106	$3,304	0.03
Overall	**$29,533**	**$20,426**	**1.5**

Table 11: Benefit Cost Analysis by Program Area (15 Year Timeframe in Net Present Value)

- ► Investments will not “pay for themselves” through operational efficiency and cost reductions that accrue to utility
- ► Benefits primarily accrue to customers through cost savings or reducing outages
- ► Grid mod investments increase the revenue requirement but this may be offset by lower bills from VVO

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Performance Metrics

- DER Enablement
  - Number of DG facilities, capacity, output, type
- Grid Reliability
  - Number of customers that can benefit from this plan that work to prevent or minimize outages
  - Number of customers compared to automated devices
- Distribution Automation
  - Load reduction by TVR customers during declared critical peak pricing event
  - Number and % of customers on TVR
  - CVR factor and number of customers on CVR feeders
- Customer Empowerment
  - Number of customers using self-service through web and mobile app
  - Average cost per customer contact
- Workforce and Asset Management
  - Traditional reliability metrics

Unitil, EDIIP, 8/1/15

Questions to ask utilities

- What goals and objectives do each of these projects support?
- Which of your projects are foundational? What higher level projects will they enable? How does the timeline and longer term plan reflect this?
- What are the ramifications if this project is not approved? What other options can help address these goals?
- Is there existing infrastructure that you could utilize instead of building new and what functionality would be lost by doing so?
- Who do benefits accrue to? Can project ‘pay for itself’ through efficiency savings back to utility?
- How do these investments impact the utility revenue requirement? What is the impact on customer bills?

Plans for High DER Penetrations:

With Examples from PG&E's Distribution Resources Plan

PG&E's Distribution Resources Plan 2015

- ► PG&E's traditional distribution planning process includes:
  - Forecasting load and peak demand
  - Power flow modeling to simulate performance to determine needs
  - Identifying and developing capacity additions to meet needs
- ► The goal of the DRP is to integrate DERs into the distribution planning process

Modernize distribution system to accommodate expected DER growth through two-way power flow

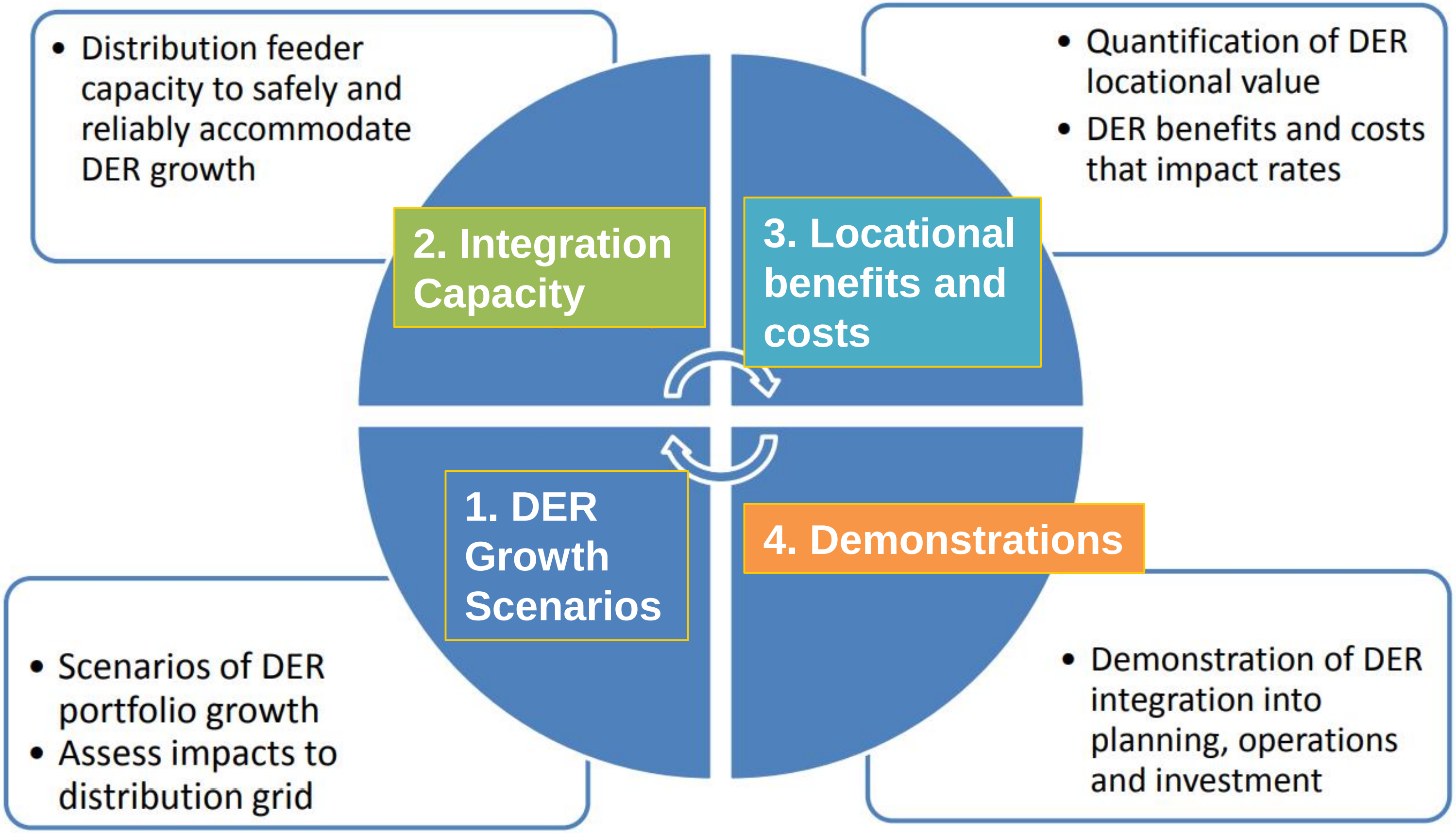
Enable customer choice of new electric DER technologies and services

Identify and develop opportunities for DERs to realize grid benefits

Identify Optimal Locations for deployment of DERs

PG&E, DRP Webinar, 2015

PG&E's Distribution Resources Plan 2015



- Distribution feeder capacity to safely and reliably accommodate DER growth

2. Integration Capacity

- Quantification of DER locational value
- DER benefits and costs that impact rates

3. Locational benefits and costs

1. DER Growth Scenarios

- Scenarios of DER portfolio growth
- Assess impacts to distribution grid

4. Demonstrations

- Demonstration of DER integration into planning, operations and investment

Adapted from PG&E, DRP Webinar, 2015

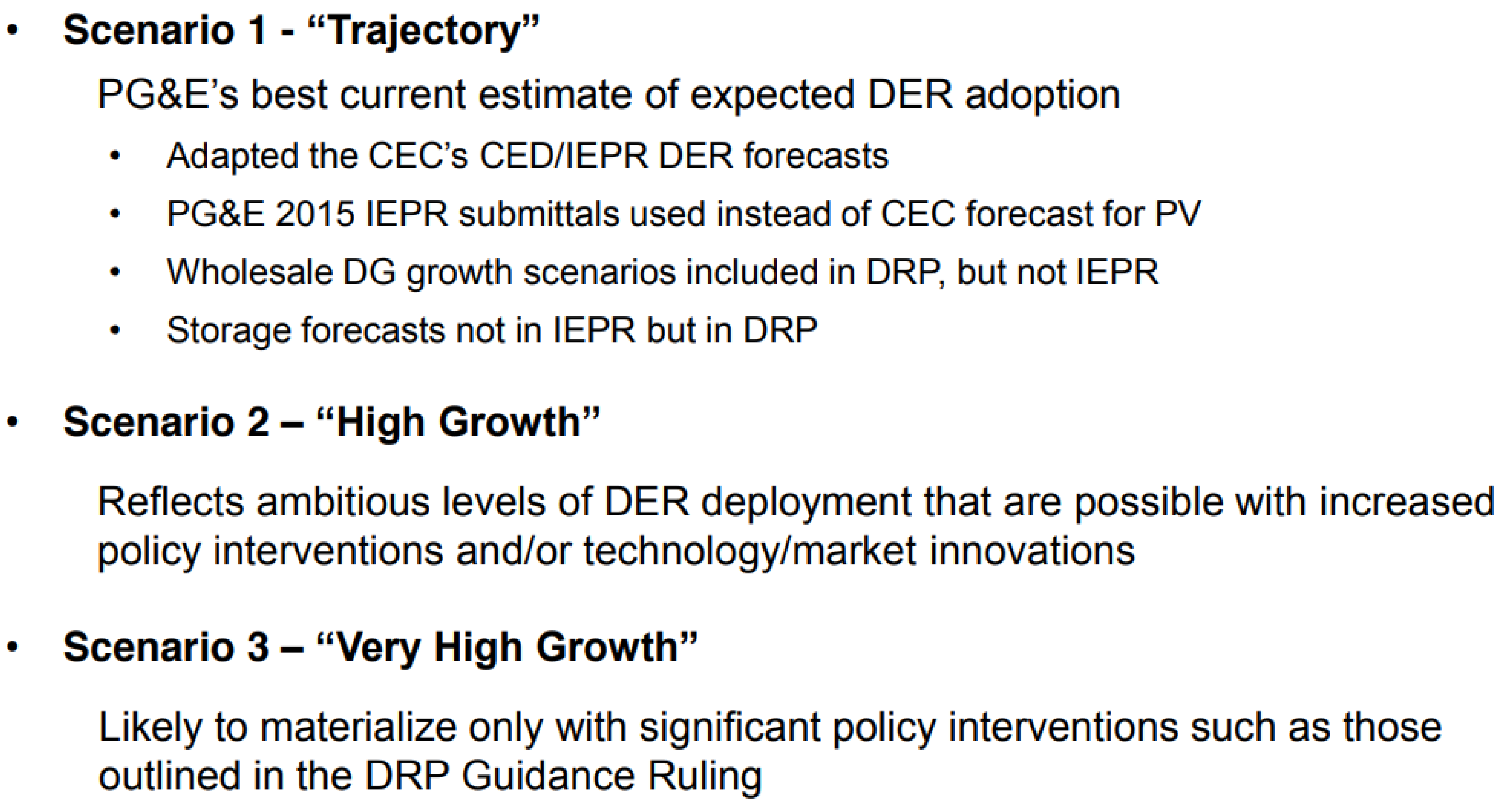
Ten DERs were examined

- Energy Efficiency
- Demand Response
- Retail* Distributed Generation
    - Solar PV
    - Combustion and Heat to Power Technologies
    - Fuel Cells
- Retail* Storage
- Electric Vehicles
- Combined Heat and Power Associated with the CHP Feed in Tariff Program
- Wholesale Distributed Generation** (solar PV, bioenergy and small hydro)
- Wholesale Energy Storage**

*Retail = Behind-the-meter (BTM), or customer side of the meter
**Utility side of the meter < 20 MWs

PG&E, DRP Webinar, 2015

Three scenarios were created



- **Scenario 1 - “Trajectory”**

  PG&E’s best current estimate of expected DER adoption

  - Adapted the CEC’s 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”**

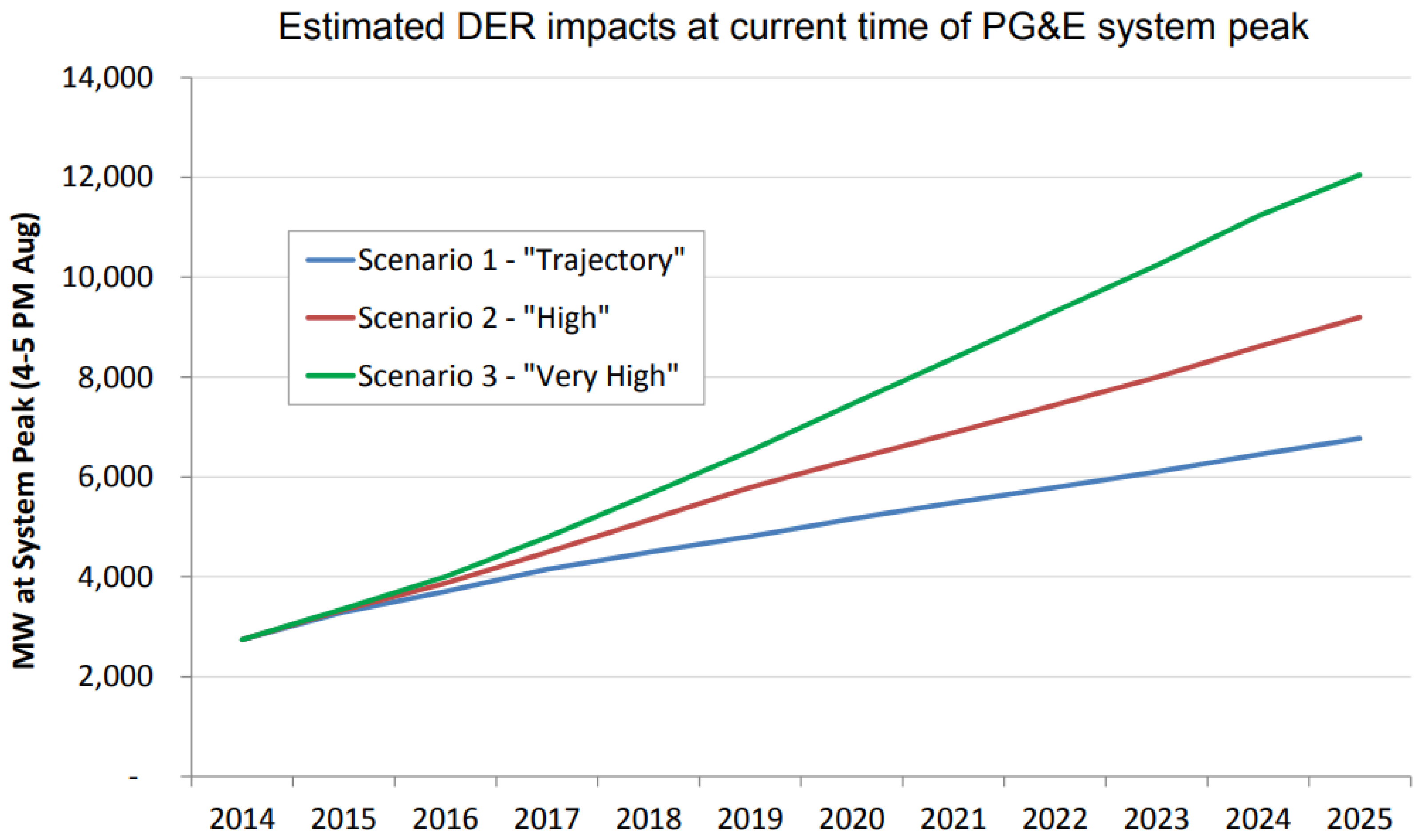
  Reflects ambitious levels of DER deployment that are possible with increased policy interventions and/or technology/market innovations

- **Scenario 3 – “Very High Growth”**

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

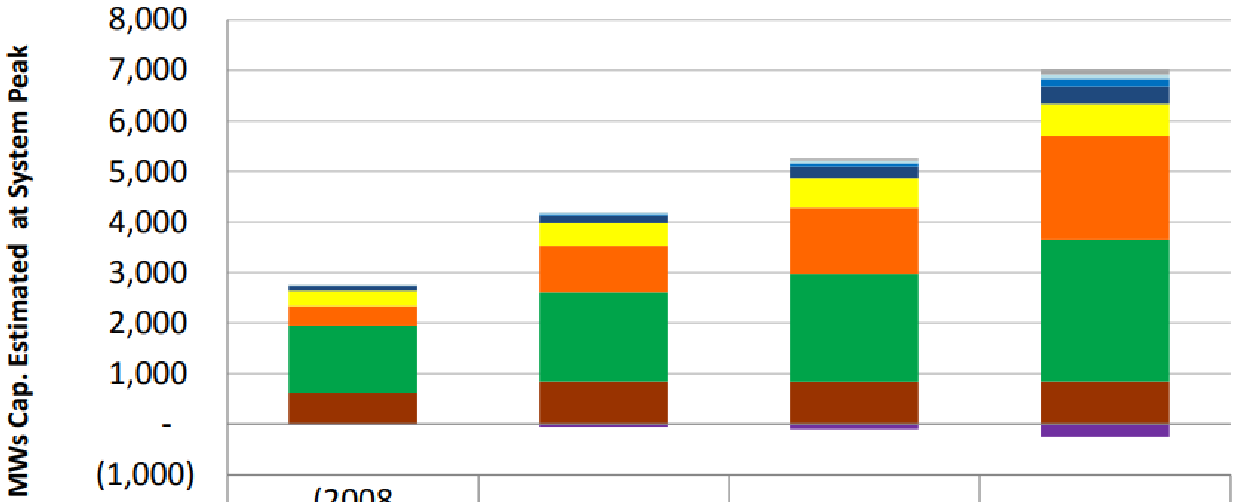
PG&E, DRP Webinar, 2015

DERs may significantly impact peak load



PG&E, DRP Webinar, 2015

Energy efficiency and solar have greatest impact on peak load



	(2008 -2014)	2017	2020	2025
⬜ Distributed Wholesale Energy Storage	6	6	40	97
🟦 CHP from Feed in Tariffs	9.6	30	50	83
🟦 Retail Storage	7.4	34	68	156
🟦 Retail Non-PV DG	92	153	220	347
🟨 Wholesale DG	302	443	590	631
🟧 Retail PV	396	916	1,317	2,052
🟩 Energy Efficiency	1,318	1,770	2,134	2,809
🟫 Demand Response	627	845	834	841
🟪 Electric Vehicles	(16)	(48)	(95)	(248)

PG&E, DRP Webinar, 2015

Impacts depend on DER characteristics and local load profiles

- Variable impact driven by:
  - Coincidence of DER impact with local distribution asset load profile (e.g., evening peaking feeders with high solar deployment)
  - Resource characteristics (e.g., generation profile, associated communications and controls, dispatchability, geographic location, intermittency)
  - Services provided
- Utility currently has limited visibility, operational control and ability to influence geographic location of DER assets
- Deployment is currently optimized on customer economics, not utility cost drivers

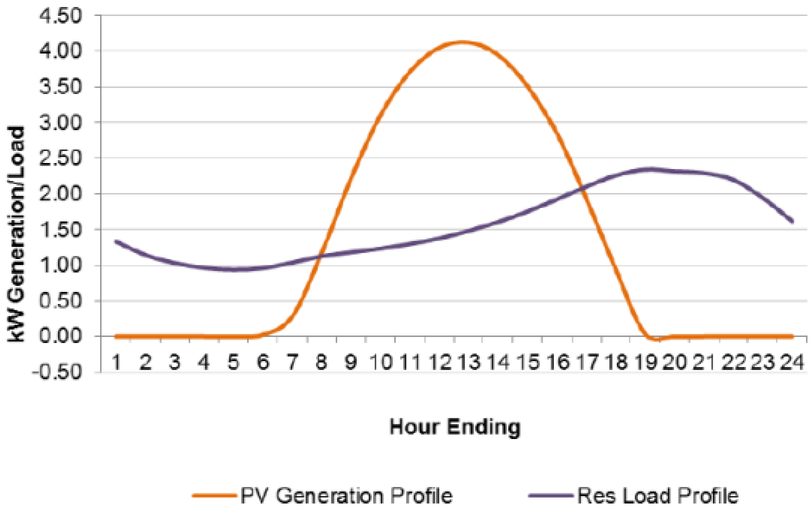
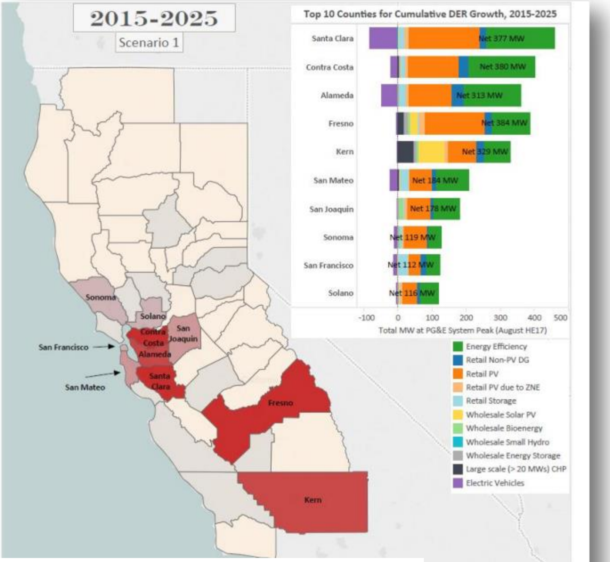


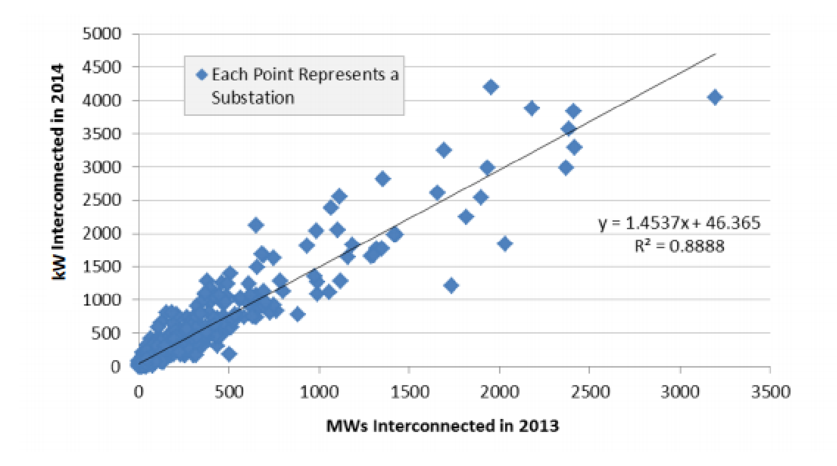
FIGURE 2-28: TYPICAL RESIDENTIAL LOAD PROFILE AND SOLAR GENERATION PROFILE ON AN AUGUST DAY

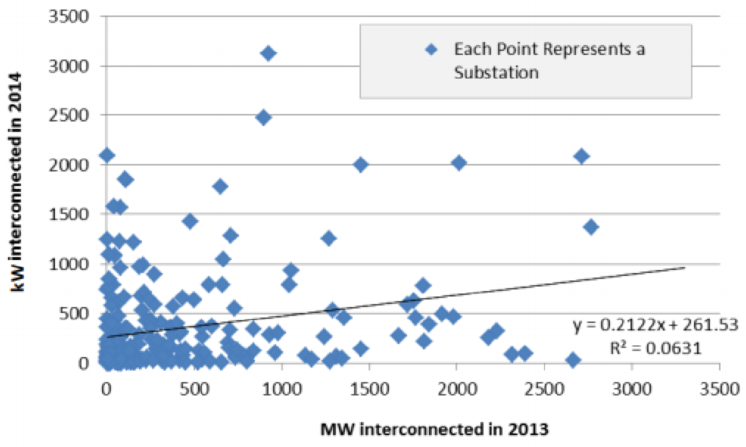
PG&E, DRP Webinar, 2015

Other findings from growth scenarios

- DERs likely to cluster
- To estimate DERs, we need to understand load and adoption patterns
- Past behavior may not be indicative of future behavior

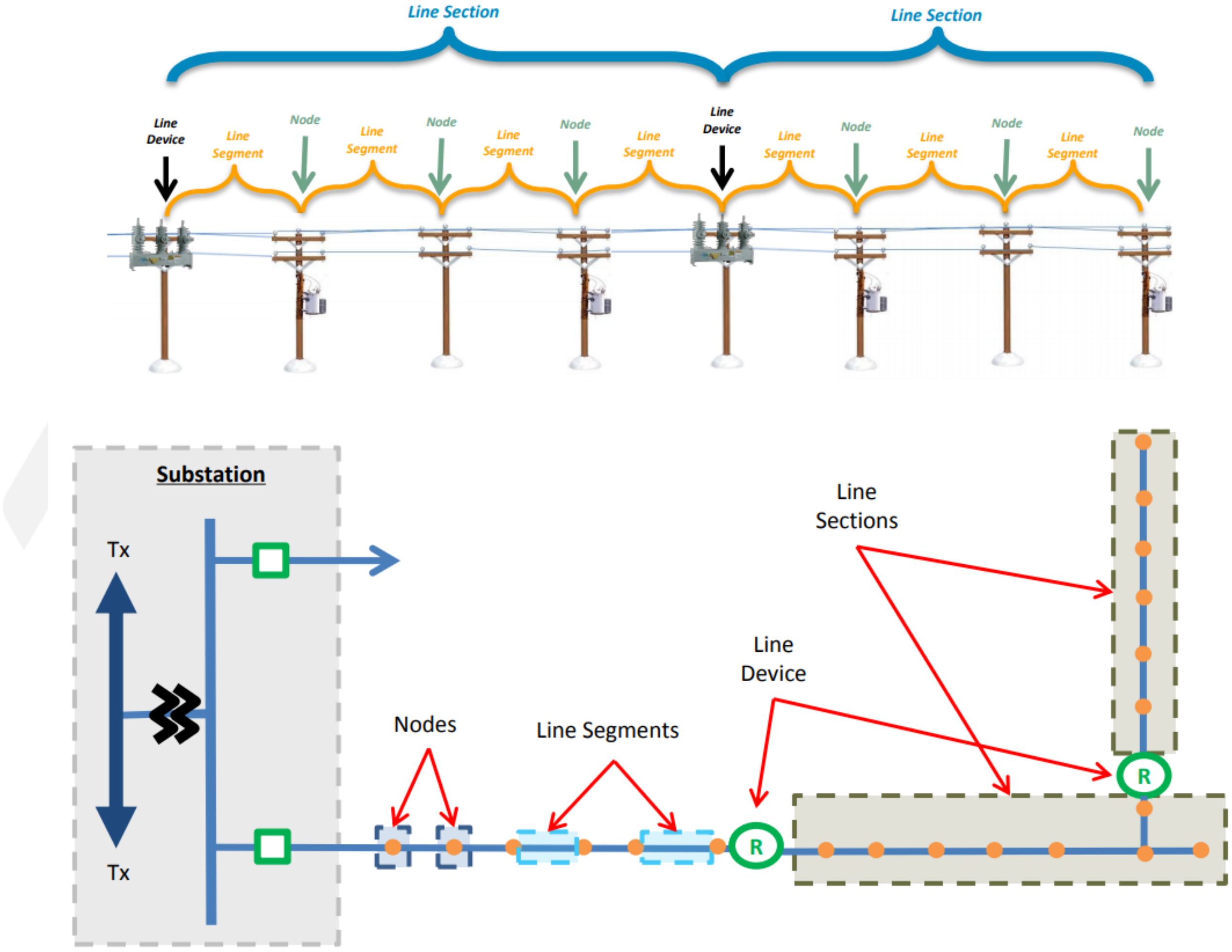






PG&E, DRP Webinar, 2015

Hosting capacity analysis - granularity



Analysis was granular down to line sections within each feeder

- PG&E was able to perform the analysis down a very granular level on specific line sections within each distribution feeder
- This is very important to be able to capture the limiting aspects of the tapered radial distribution system design
- Industry studies and analyses typically only consider or have the ability to do this analysis at the substation level

PG&E, DRP Webinar, 2015

What tools did PG&E use?

Advanced Planning Tools Capabilities

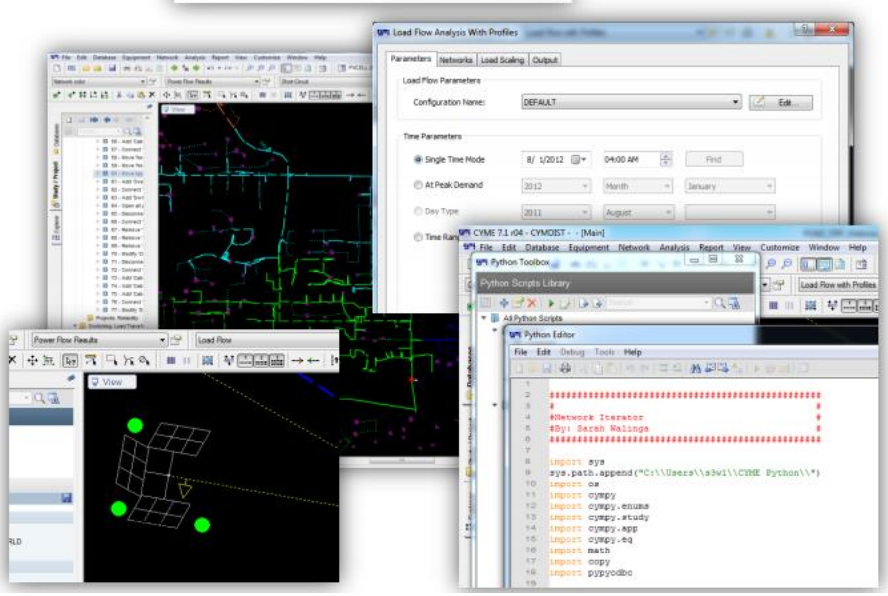
Utilizes Advanced Planning Tools and Datasets to help perform analysis

- PG&E upgraded its planning tools 3 years ago to enhance the planning process and accuracy
- Load and Generation Hourly Profiles
  - Utilize PG&E's Load Forecast Analysis tool to get representative load profiles for every distribution feeder
  - Compares these profiles against representative DER hourly profiles to determine hourly impact to capacity
  - Tool is LoadSEER developed by Integral Analytics
- Geospatial Distribution Feeder Models
  - Utilizes PG&E's Power Flow Analysis tool to understand the power flow effects on the distribution lines granular down to customer service transformers
  - Utilizes advanced automation scripting features capable with Python
  - Tool is CYMDIST by CYME International

Year: 2014

Customer Class	Count
Domestic	6,194
Commercial	384
Industrial	65
Agriculture	5
Total:	6,648

Shape peak (summer): September, 5 PM
Shape at system peak: 93% of summer peak



Load Flow Analysis With Profiles

Parameters | Networks | Load Scaling | Output

Load Flow Parameters

Configuration Name: DEFAULT — Edit...

Time Parameters

● Single Time Mode: 8/ 1/2012 — 04:00 AM — Find
○ At Peak Demand: 2012 — Month — January
○ Day Type: 2011 — August
○ Time Rang

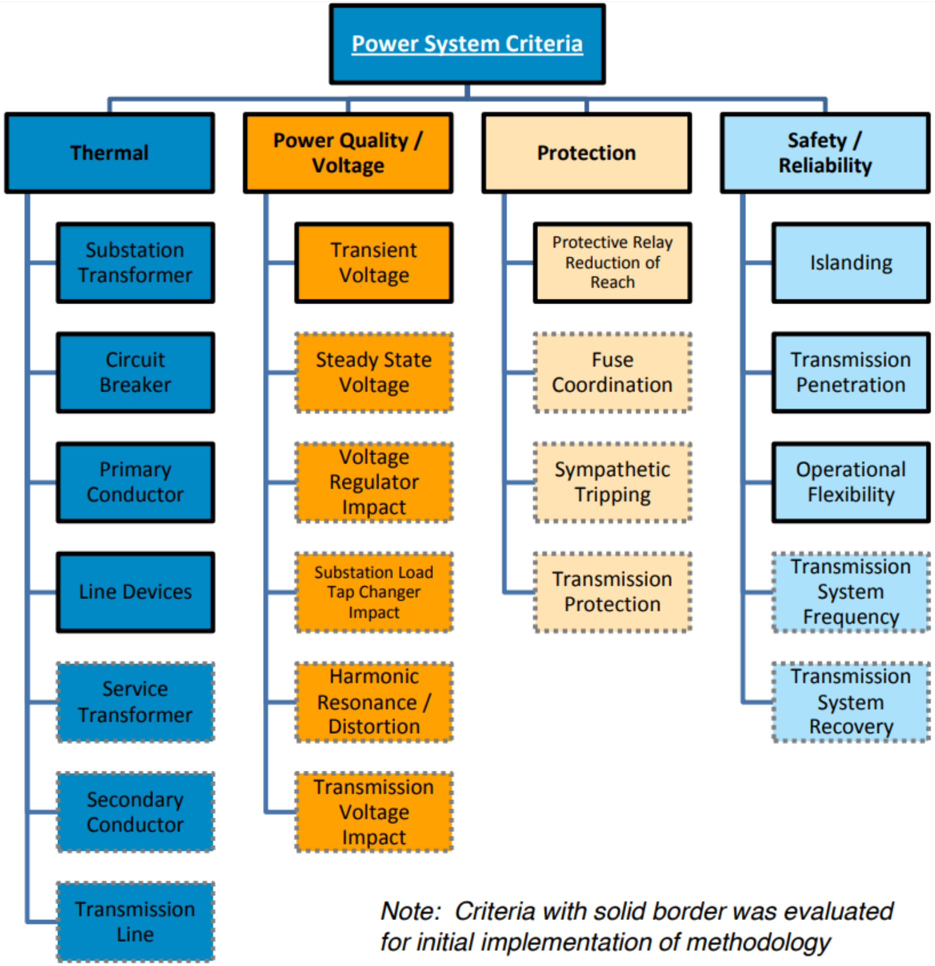
```

##############################################
#                                            #
#Network Iterator                            #
#By: Sarah Walinga                           #
##############################################

import sys
sys.path.append("C:\\Users\\s3w1\\CYME Python\\")
import os
import cympy
import cympy.enums
import cympy.study
import cympy.app
import cympy.eq
import math
import copy
import pypyodbc
```

PG&E, DRP Webinar, 2015

Which power system criteria did PG&E evaluate?

Various aspects of the power system must be analyzed to determine possible impacts

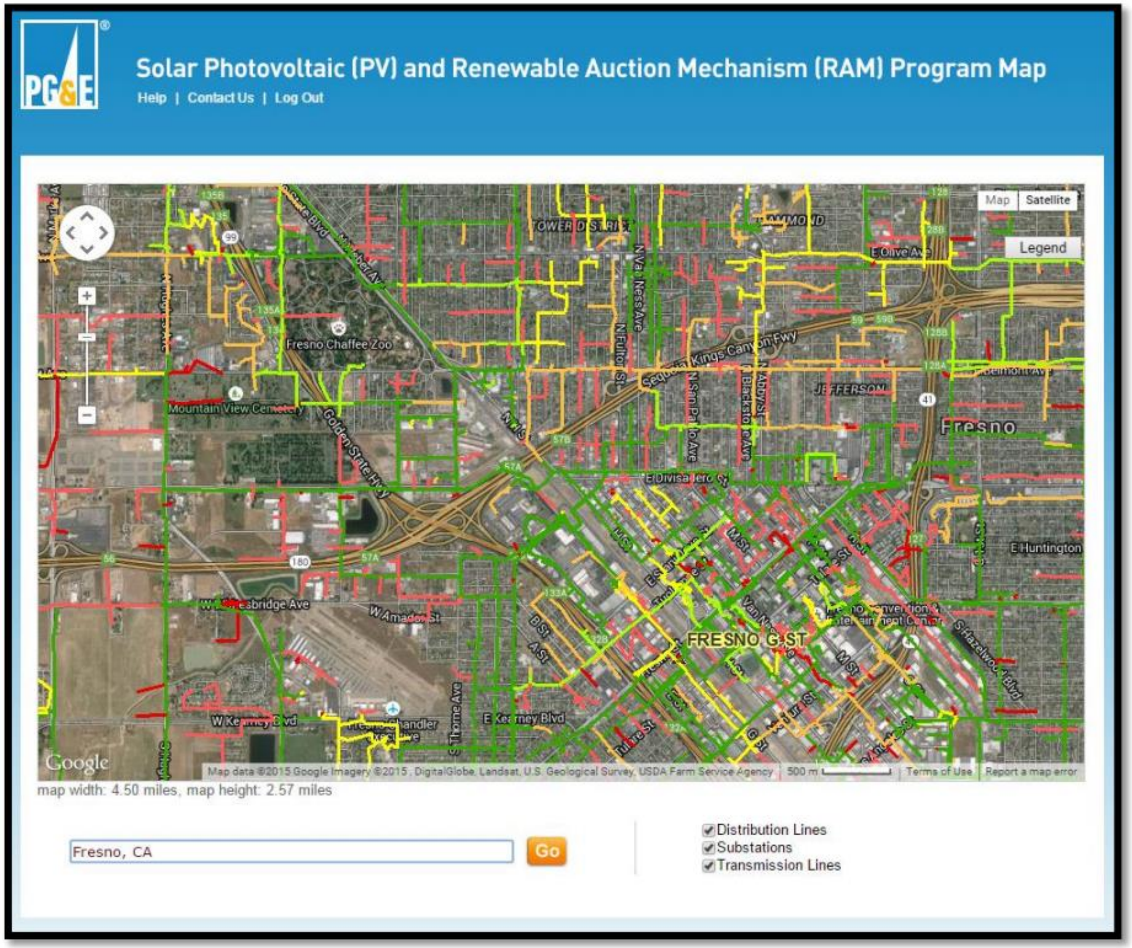
- Thermal
  - Determines limits based on equipment thermal ratings
- Power Quality / Voltage
  - Determines limits that do not create power quality to operate outside prescribed thresholds
- Protection
  - Determines limits that ensure protection equipment can still operate as designed
- Safety / Reliability
  - Determines limits that reduce impacts to safe and reliable operation of the grid during abnormal conditions



Note: Criteria with solid border was evaluated for initial implementation of methodology

PG&E, DRP Webinar, 2015

PG&E analyzed 102,000 line sections within >3000 circuits



Solar Photovoltaic (PV) and Renewable Auction Mechanism (RAM) Program Map

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map width: 4.50 miles, map height: 2.57 miles

Fresno, CA

Go

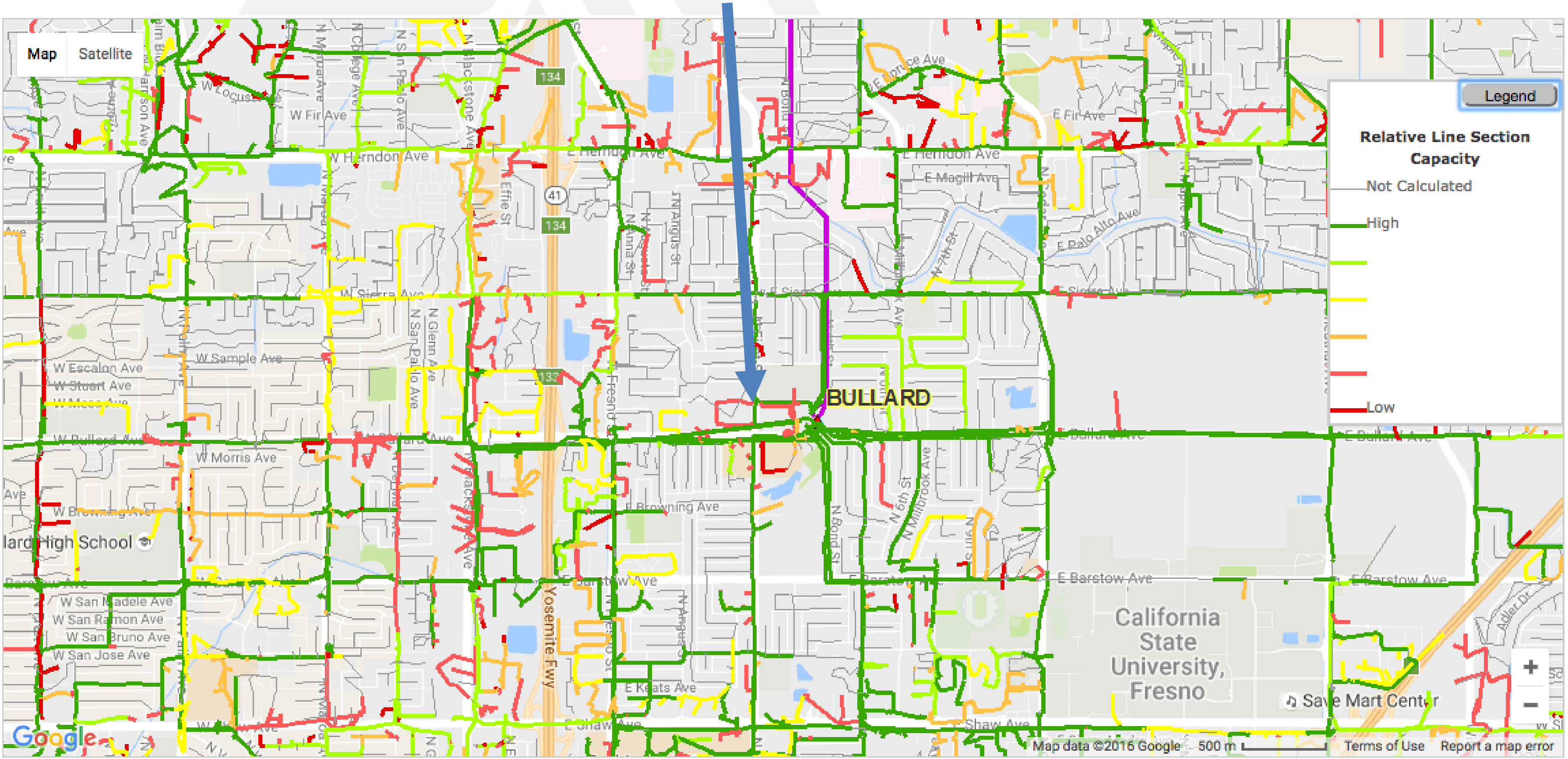
☑ Distribution Lines
☑ Substations
☑ Transmission Lines

PG&E analyzed all three phase line sections for all the 3,000+ distribution circuits

- Results for approx. 102,000 line sections
  - *Average of 34 line sections per feeder*
  - *Largest number of line sections for one feeder was found to be 310*
- Locational results published by each DER type
- Granular down to fuse devices
- Initially colored by PV Results
  - *Line Section IC / Feeder IC*
  - *Red, Amber, Green color scheme with green being higher capacities*

PG&E, DRP Webinar, 2015

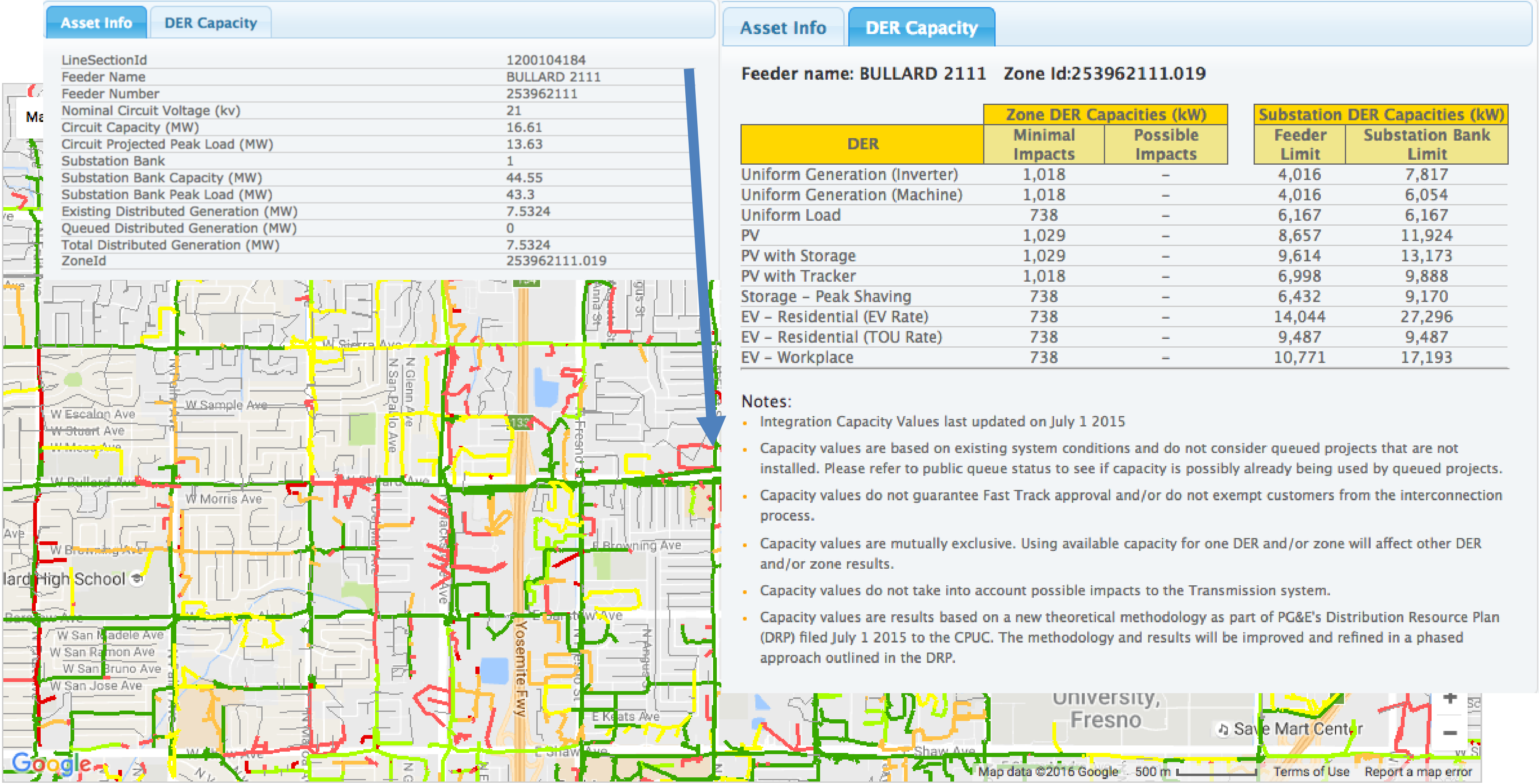
PG&E map of hosting capacity



map width: 5.44 miles, map height: 2.57 miles

From PG&E DRP Web Tool, 2016

PG&E map of hosting capacity



Asset Info | DER Capacity

LineSectionId	1200104184
Feeder Name	BULLARD 2111
Feeder Number	253962111
Nominal Circuit Voltage (kv)	21
Circuit Capacity (MW)	16.61
Circuit Projected Peak Load (MW)	13.63
Substation Bank	1
Substation Bank Capacity (MW)	44.55
Substation Bank Peak Load (MW)	43.3
Existing Distributed Generation (MW)	7.5324
Queued Distributed Generation (MW)	0
Total Distributed Generation (MW)	7.5324
ZoneId	253962111.019

Asset Info | **DER Capacity**

Feeder name: BULLARD 2111 Zone Id:253962111.019

	Zone DER Capacities (kW)		Substation DER Capacities (kW)	
DER	Minimal Impacts	Possible Impacts	Feeder Limit	Substation Bank Limit
Uniform Generation (Inverter)	1,018	–	4,016	7,817
Uniform Generation (Machine)	1,018	–	4,016	6,054
Uniform Load	738	–	6,167	6,167
PV	1,029	–	8,657	11,924
PV with Storage	1,029	–	9,614	13,173
PV with Tracker	1,018	–	6,998	9,888
Storage – Peak Shaving	738	–	6,432	9,170
EV – Residential (EV Rate)	738	–	14,044	27,296
EV – Residential (TOU Rate)	738	–	9,487	9,487
EV – Workplace	738	–	10,771	17,193

Notes:

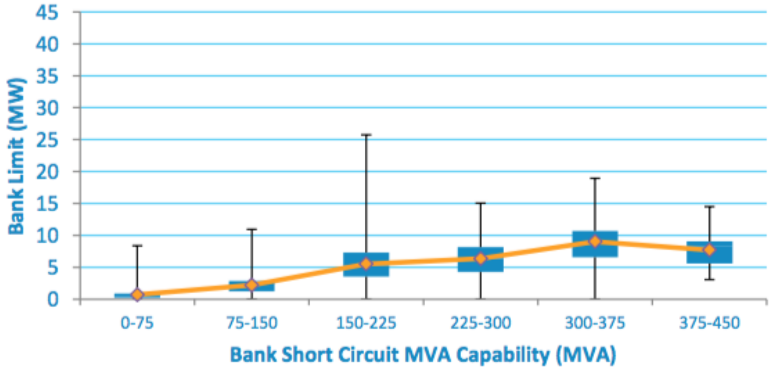
- Integration Capacity Values last updated on July 1 2015
- Capacity values are based on existing system conditions and do not consider queued projects that are not installed. Please refer to public queue status to see if capacity is possibly already being used by queued projects.
- Capacity values do not guarantee Fast Track approval and/or do not exempt customers from the interconnection process.
- Capacity values are mutually exclusive. Using available capacity for one DER and/or zone will affect other DER and/or zone results.
- Capacity values do not take into account possible impacts to the Transmission system.
- Capacity values are results based on a new theoretical methodology as part of PG&E's Distribution Resource Plan (DRP) filed July 1 2015 to the CPUC. The methodology and results will be improved and refined in a phased approach outlined in the DRP.

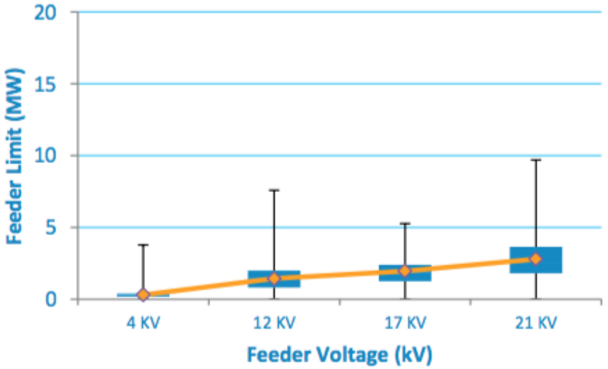
map width: 5.44 miles, map height: 2.57 miles

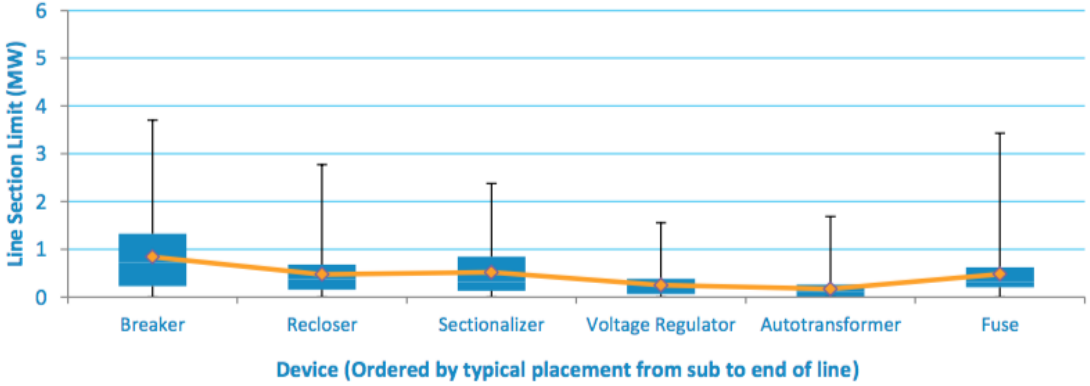
From PG&E DRP Web Tool, 2016

Hosting capacity analysis for Hydro/Biogas in PG&E

Typical DER Use Case: Hydro, Bio-Gas, and other DER with constant full output using machinery





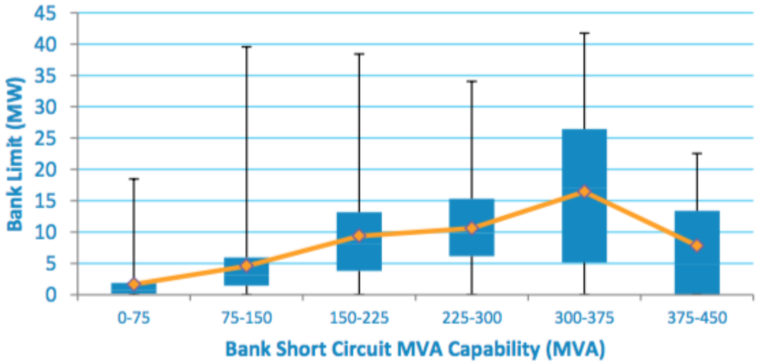


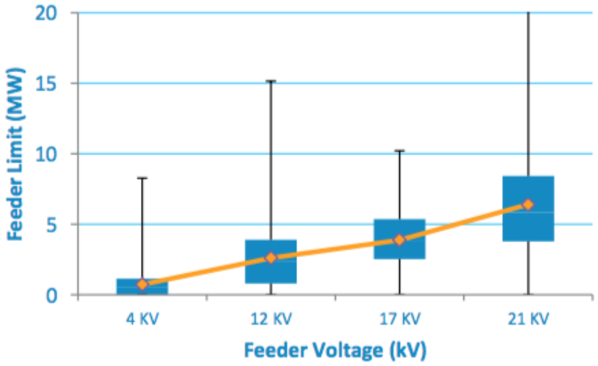
NOTE: Results based on July 1 2015 ICA data

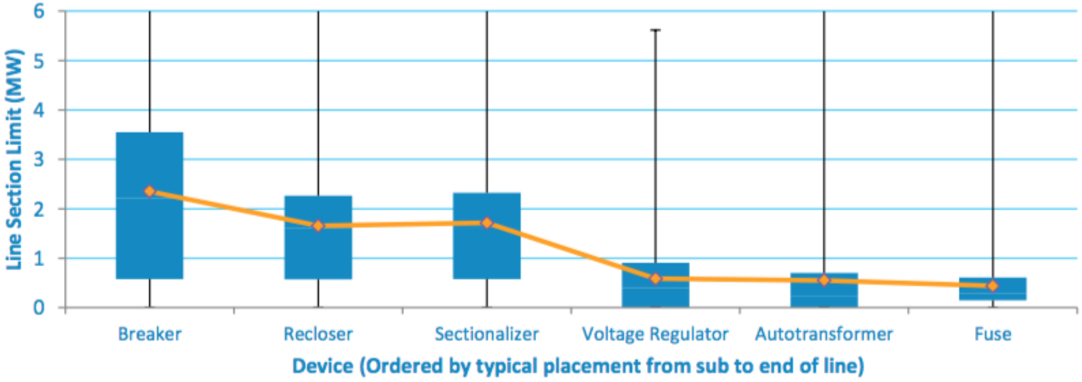
PG&E, DRP Webinar, 2015

Hosting capacity analysis for Storage in PG&E

Typical DER Use Case: Storage Charging Capability without Time Constraints



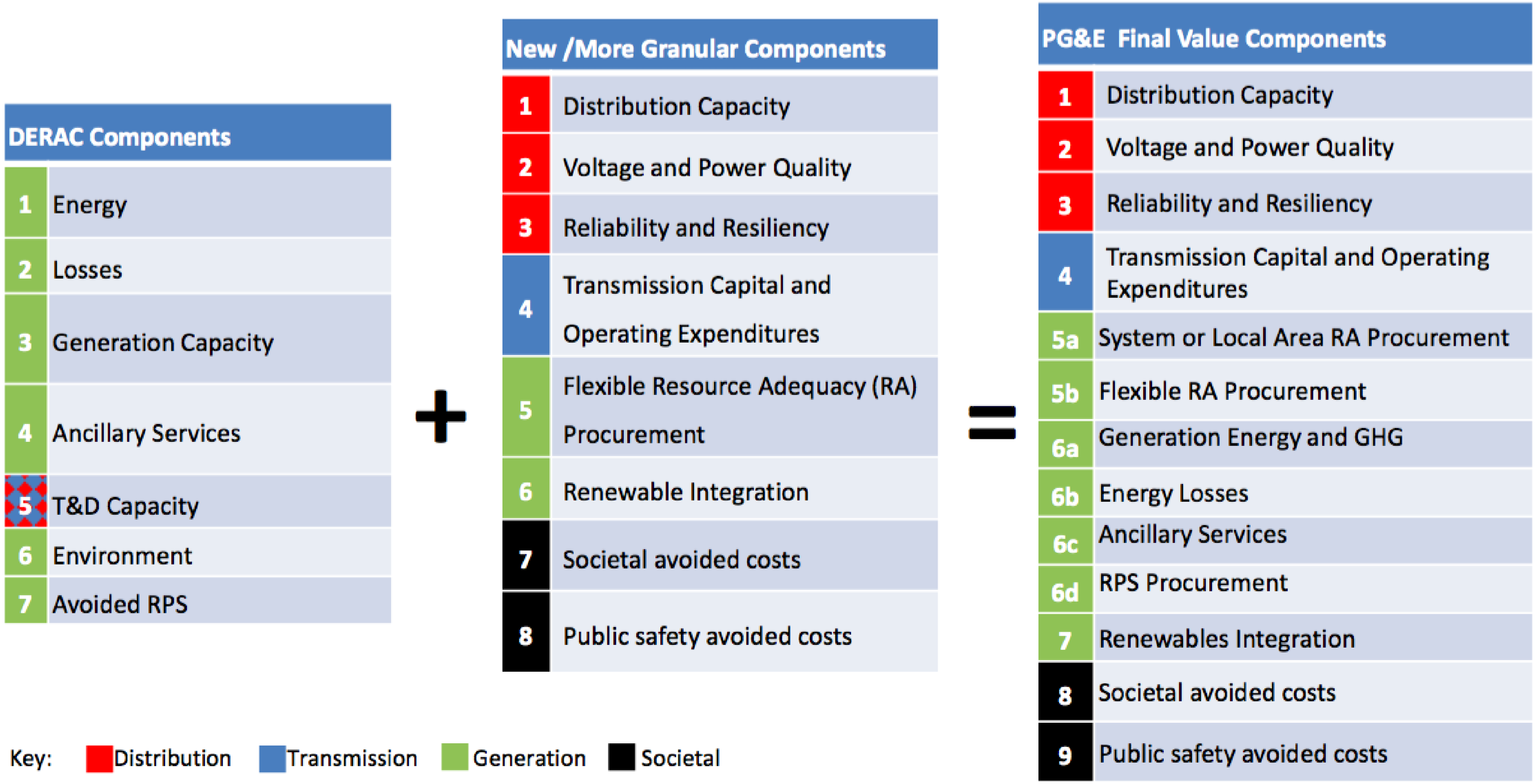




NOTE: Results based on July 1 2015 ICA data

PG&E, DRP Webinar, 2015

Start with existing tools and add granularity



DERAC Components	
1	Energy
2	Losses
3	Generation Capacity
4	Ancillary Services
5	T&D Capacity
6	Environment
7	Avoided RPS

+

New /More Granular Components	
1	Distribution Capacity
2	Voltage and Power Quality
3	Reliability and Resiliency
4	Transmission Capital and Operating Expenditures
5	Flexible Resource Adequacy (RA) Procurement
6	Renewable Integration
7	Societal avoided costs
8	Public safety avoided costs

=

PG&E Final Value Components	
1	Distribution Capacity
2	Voltage and Power Quality
3	Reliability and Resiliency
4	Transmission Capital and Operating Expenditures
5a	System or Local Area RA Procurement
5b	Flexible RA Procurement
6a	Generation Energy and GHG
6b	Energy Losses
6c	Ancillary Services
6d	RPS Procurement
7	Renewables Integration
8	Societal avoided costs
9	Public safety avoided costs

Key: 🟥 Distribution 🟦 Transmission 🟩 Generation ⬛ Societal

* E3's Distributed Energy Resources Avoided Cost Calculator (DERAC) estimates avoided costs uniformly across the ISO system

PG&E, DRP Webinar, 2015

Locational value

Example: Distribution Components (1- 3)

Value Component Definition: Avoided or increased cost associated with:

1) Distribution Capacity (accommodates forecasted loads)
2) Voltage & Power Quality (ensures power is delivered within specifications)
3) Reliability & Resiliency (ability to prevent / respond to routine / major outages)

Determining DERs' Impact: Distribution engineering tools are used to determine DERs' ability to meet criteria for

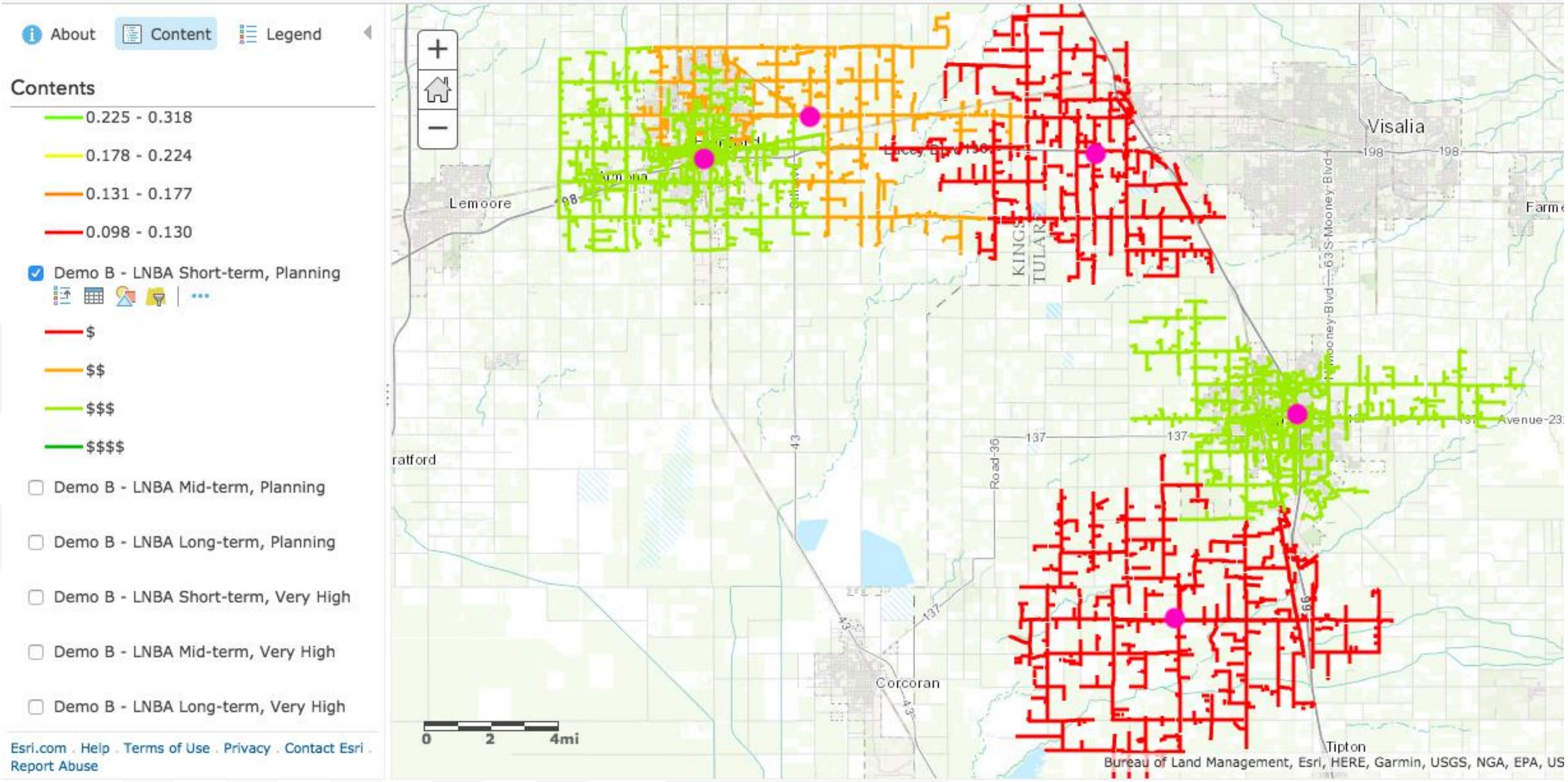
- Right Time (Coincides with a deficiency that requires investments)
- Right Availability (Performs in hours that coincide with deficiency)
- Right Location (Can be connected at a location that mitigates deficiency)
- Right Size (Can assure magnitude of impact is sufficient to mitigate deficiency)

Translating DER Impact Into Avoided or Increased Cost:
Present value of investment deferral (or acceleration) due to DER

Granularity of Locational Variation:
Anticipated to vary from feeder to feeder within PG&E service territory

PG&E, DRP Webinar, 2015

Locational net benefits analysis for Demo B in Southern California Edison



Contents

🟩 0.225 - 0.318

🟨 0.178 - 0.224

🟧 0.131 - 0.177

🟥 0.098 - 0.130

☑ Demo B - LNBA Short-term, Planning

🟥 $

🟧 $$

🟩 $$$

🟩 $$$$

☐ Demo B - LNBA Mid-term, Planning

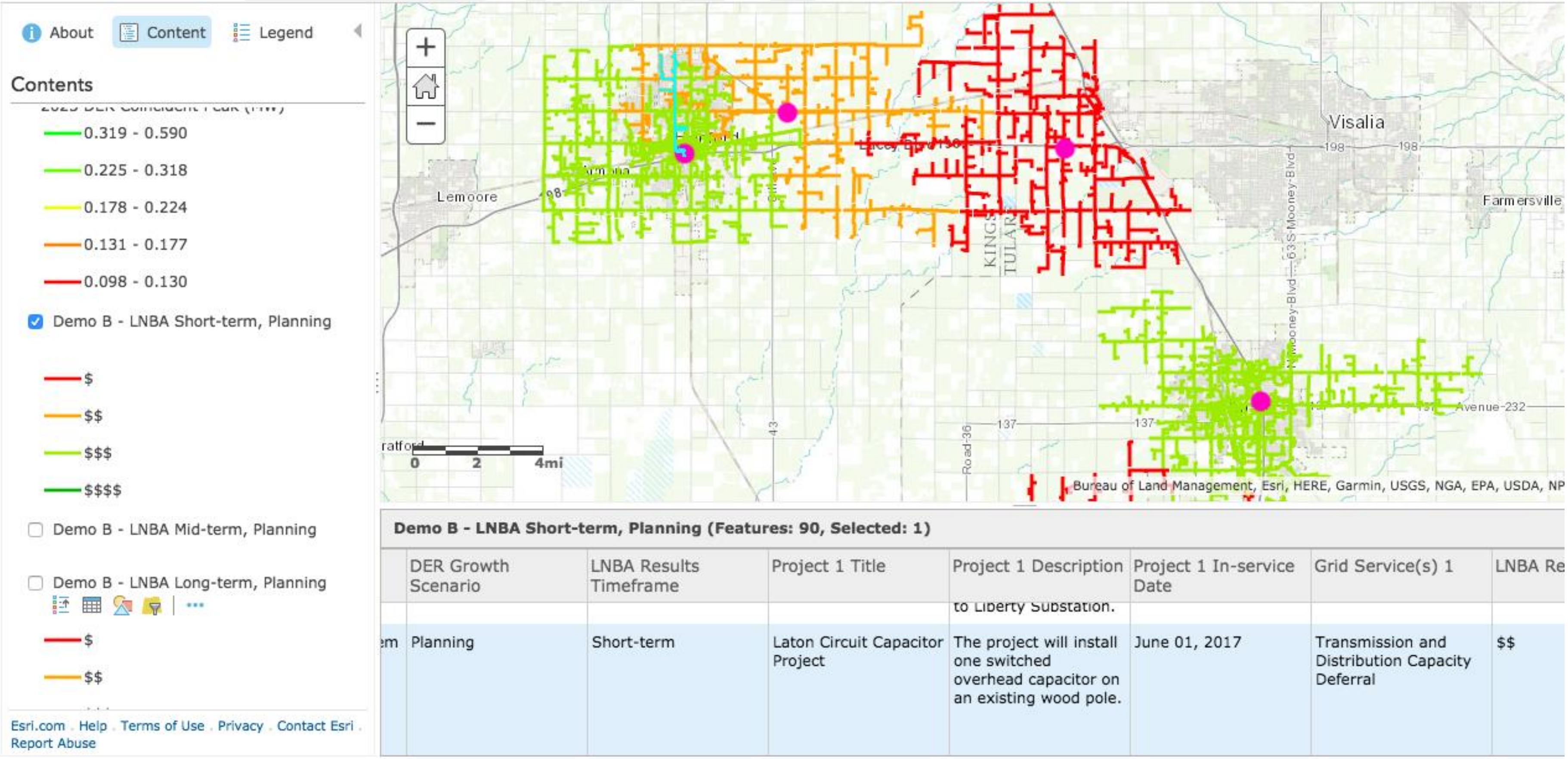
☐ Demo B - LNBA Long-term, Planning

☐ Demo B - LNBA Short-term, Very High

☐ Demo B - LNBA Mid-term, Very High

☐ Demo B - LNBA Long-term, Very High

Medium cost project



Bureau of Land Management, Esri, HERE, Garmin, USGS, NGA, EPA, USDA, NP

Contents

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🟩 0.225 - 0.318
🟨 0.178 - 0.224
🟧 0.131 - 0.177
🟥 0.098 - 0.130

☑ Demo B - LNBA Short-term, Planning

🟥 $
🟧 $$
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🟩 $$$$

☐ Demo B - LNBA Mid-term, Planning

☐ Demo B - LNBA Long-term, Planning

🟥 $
🟧 $$

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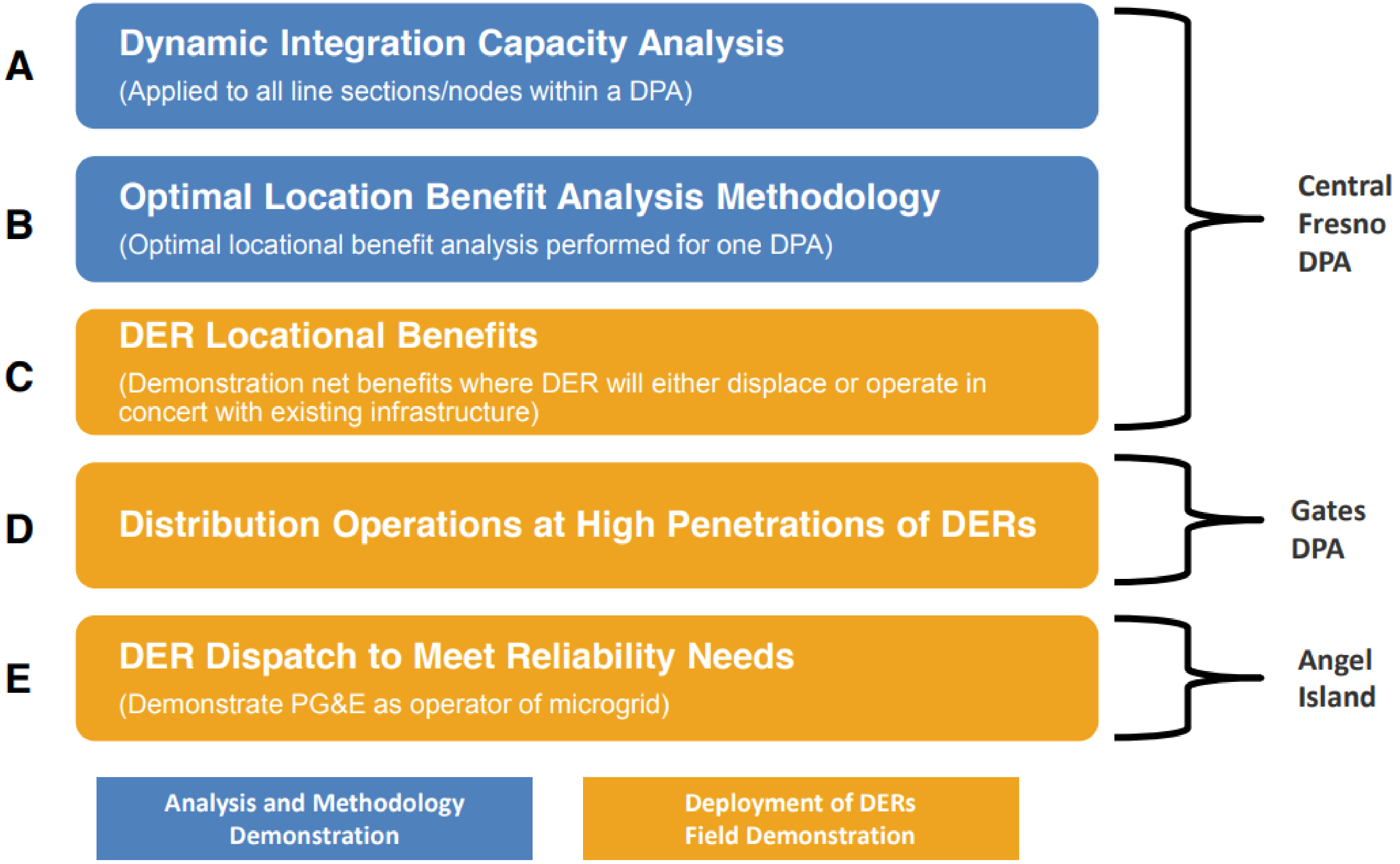
Demo B - LNBA Short-term, Planning (Features: 90, Selected: 1)

	DER Growth Scenario	LNBA Results Timeframe	Project 1 Title	Project 1 Description	Project 1 In-service Date	Grid Service(s) 1	LNBA Re
				to Liberty Substation.			
em	Planning	Short-term	Laton Circuit Capacitor Project	The project will install one switched overhead capacitor on an existing wood pole.	June 01, 2017	Transmission and Distribution Capacity Deferral	$$

Five demonstration pilots were identified



A **Dynamic Integration Capacity Analysis**
(Applied to all line sections/nodes within a DPA)

B **Optimal Location Benefit Analysis Methodology**
(Optimal locational benefit analysis performed for one DPA)

C **DER Locational Benefits**
(Demonstration net benefits where DER will either displace or operate in concert with existing infrastructure)

D **Distribution Operations at High Penetrations of DERs**

E **DER Dispatch to Meet Reliability Needs**
(Demonstrate PG&E as operator of microgrid)

Example demonstration pilot projects

Demonstration Pilots A, B and C

Proposed Area of Demonstration: Central Fresno DPA

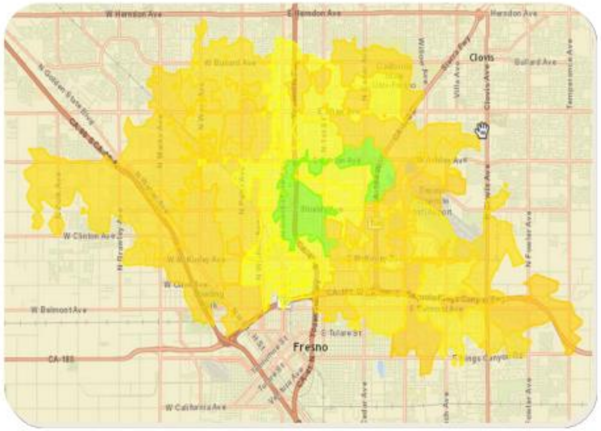
Scope of Pilots:

a) Dynamic Integrated Capacity Analysis

b) Optimal Location Benefit Analysis

c) Near term (0-3 years) and longer term (3 or more years) distribution infrastructure project deferral:

- **Phase 1 (Near Term)** – Build off of on-going Targeted Demand Side Management (TDSM) pilot (SMART AC technology on targeted distribution feeders from Barton Substation) in Central Fresno DPA that deferred substation transformer replacement
- **Phase 2 (Longer Term)** – Develop targeted aggregated DER portfolio (EE, DR, DG, storage) for deferring longer term capacity needs for Central Fresno DPA.



Schedules:

Pilot A: Within 6 months of Commission approval of DRP

Pilot B: Within 12 months of Commission approval of DRP

Pilot C: Phase 1 – Implemented

Phase 2 – Detailed scope within 12 months of Commission approval.

Example demonstration pilot project

Demonstration Pilot D

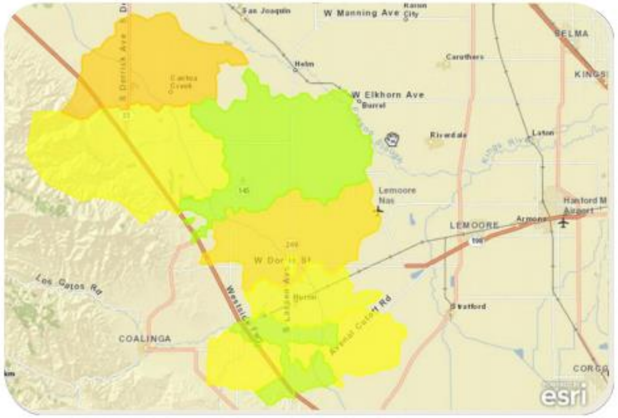
Proposed Area of Demonstration: Gates DPA

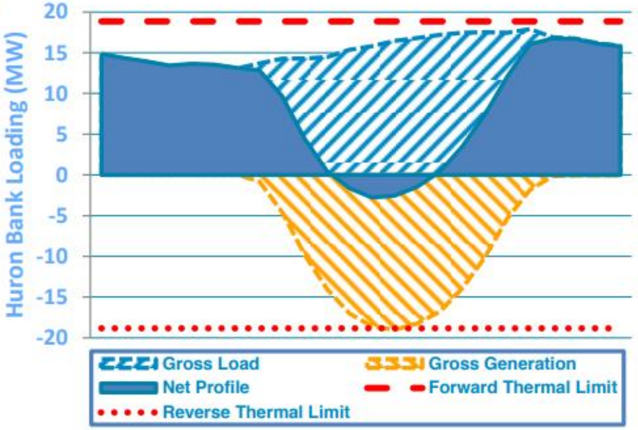
Scope of Pilot:

- Integrate high DER penetrations that integrate into PG&E's distribution system operations, planning and investment for implementation.
  - Huron Substation projected to experience higher demand loading conditions in evening hours, lightly loading conditions during "daytime hours" due to peak solar production and seasonal loads.
  - Explore DER technologies (EE, DR, DG, EV and storage) coupled with existing rates to manage electric loading and reliability.

Schedule

- Detailed scope within 12 months of Commission approval.





Questions to ask utilities

- In addition to the questions from the *Emerging Planning Analyses* presentation, there may be questions you will want to ask regarding the demonstration projects:
  - Is this project representative of other needs across your system and would it be replicable in other regions of your system?
  - Are there potential ways to expand on this project if its original objectives are fulfilled?
  - Is there an urgent need for this project?
  - If this is a competitive solicitation for a non-wires solution to deferring a distribution upgrade, what are the costs of a traditional ‘wires’ solution and how do they compare to estimates of non-wires solutions?

Resources

- Consumers Energy's Electric Distribution Infrastructure Investment Plan, 8/1/17, https://mi-psc.force.com/s/ Filing U-17990-0416
- Unitil's Grid Modernization Plan, 8/19/15, http://web1.env.state.ma.us/DPU/Fileroom/dockets/byindustry under Docket 15-121
- PG&E Distributed Resources Plan, 2015, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5141

Acronym definition

- ADMS Advanced Distribution Management System
- AMF Advanced Metering Functionality
- AMI Advanced Metering Infrastructure
- CVR Conservation Voltage Reduction
- DERMS Distributed Energy Resource Management System
- FAN Field Area Network
- FLISR Fault Location, Isolation, and Service Restoration
- IEPR Integrated Energy Policy Report
- NWA Non-wires Alternatives
- OMS Outage Management System
- SAIDI/SAIFI System Average interruption Duration/Frequency Index
- SCADA Supervisory Control and Data Acquisition
- TVR Time-varying Rates
- VVO Volt VAR Optimization

Any Questions?

Contact Debbie Lew at
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303-819-3470