Walk-through of long-term utility distribution plans

Lavelle Freeman, Debbie Lew

GE Energy Consulting

Distribution Systems and Planning Training
for Midwest Public Utility Commissions, Jan. 16-17, 2018

Three elements of distribution planning

Traditional Distribution Plan

- Forecast load growth
- New capacity investments:
  - Overloads
  - Aging infrastructure
- O&M:
  - Vegetation
- SAIDI/SAIFI

Consumers Energy

Grid Modernization Plan

- Advanced functions
  - VVO
  - CVR
  - FLISR
  - Distribution Automation
- Management Systems
  - ADMS
  - OMS
  - DMS
  - DERMS
  - SCADA
- AMI
- Data Analytics

Unitil

Plan for high levels of DERs

- DER Growth Scenarios
- Hosting Capacity Analysis
- Locational net benefit analysis
- Non-wires alternatives projects

PG&E

End goal is investment plan (or solicitation plan)

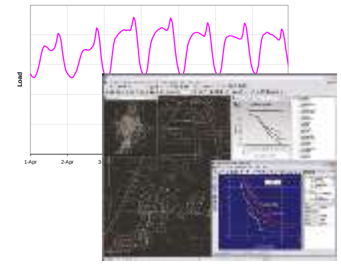
Traditional Distribution Planning

With Examples from Consumers Energy Electric Distribution Infrastructure Investment Plan

Primary mission of distribution systems

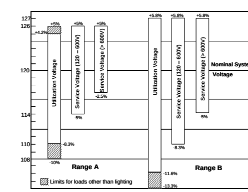
► Deliver power to customers *at their locations* with adequate

- **Capacity**
  - Supply enough power to meet instantaneous kW demand
  - Capacity requirements dictate equipment type, sizing, duty
  - Utilities are experts at designing for capacity (load flow, SC, etc.)

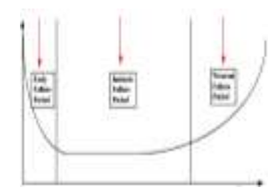


- **Frequency**
  - Not a typical distribution issue – set by generation and bulk system
  - Sometimes considered in under-frequency load-shedding schemes
  - Critical for DER applications

- **Voltage**
  - Regulate voltage at the customer location within ANSI C84.1 limits
  - Drives system design, operation & equipment application (caps, regs)
  - Common cause of voltage issue is overloading or undersized conductor



- **Reliability**
  - Reduce frequency (how often) and duration (how long) of outages
  - Engineering and operation decisions to maintain customer service
  - Typically regulated by state commissions, municipal boards, etc.



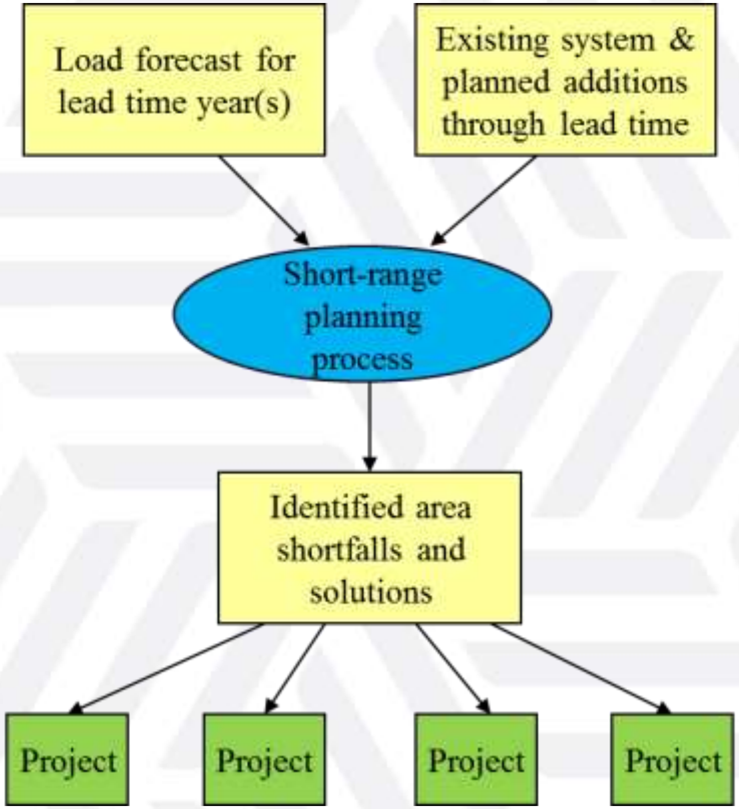
Goal of distribution planning

► Provide orderly, economic expansion of equipment and facilities to meet future demand with acceptable system performance

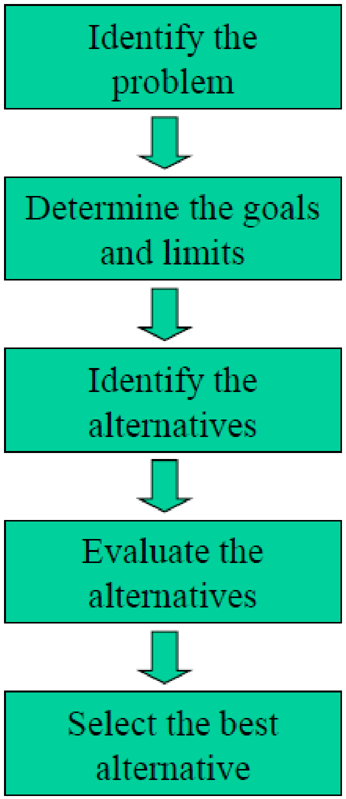
- Deliver power with required frequency (60Hz)
- Satisfy voltage requirements (within ±5%)
- Deliver adequate availability (<2 hours out/yr)
- Have capacity to meet instantaneous demand
- Reach all customers wherever they exist

… and do it all for the lowest possible cost

The Planning Process



H. L. Willis, "*Power Distribution Planning Reference Book*," 1997 Marcel Dekker, Inc., New York, NY



Compare existing capability to future needs and initiate projects to address shortfalls

Typical Minimum Lead Times

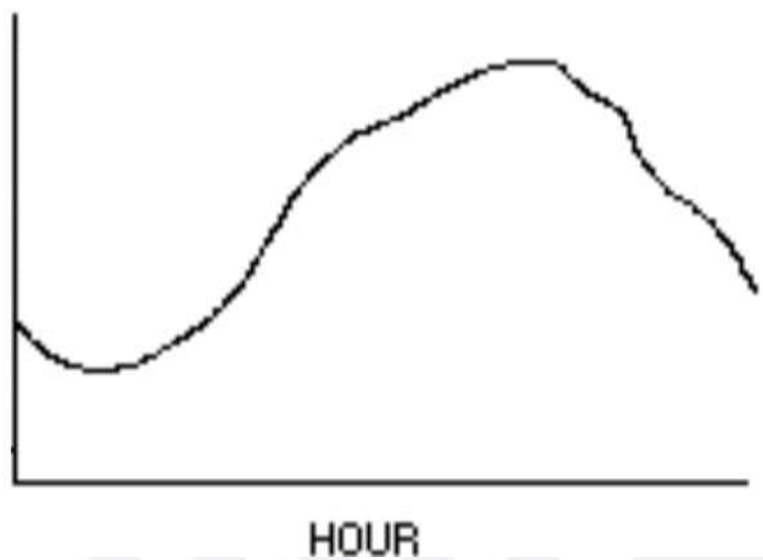
- Effective minimum-cost planning accounts for lead time to deploy T&D assets in developing reasonable alternatives

T&D Level	Lead Time (yrs)
Generation	13
EHV Transmission	9
Transmission	8
Sub-transmission	7
Substation	6
Feeder	3
Lateral	0.5
Service	0.1

Loads and Demand

- Loads vary over time

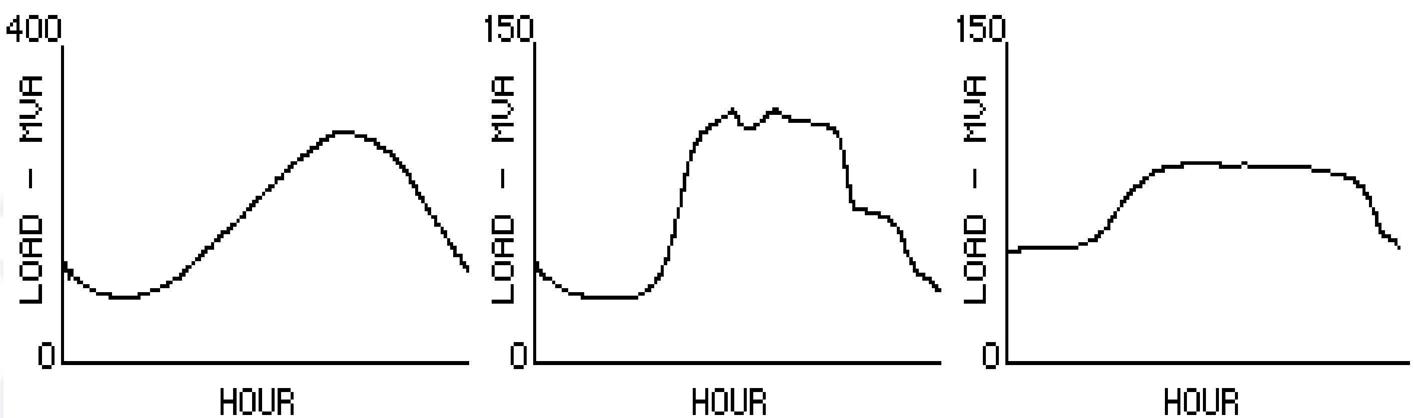
Typical Feeder Load



Typical Customer Load

Perceived variability depends of level of aggregation and resolution

Loads Vary by Customer Class

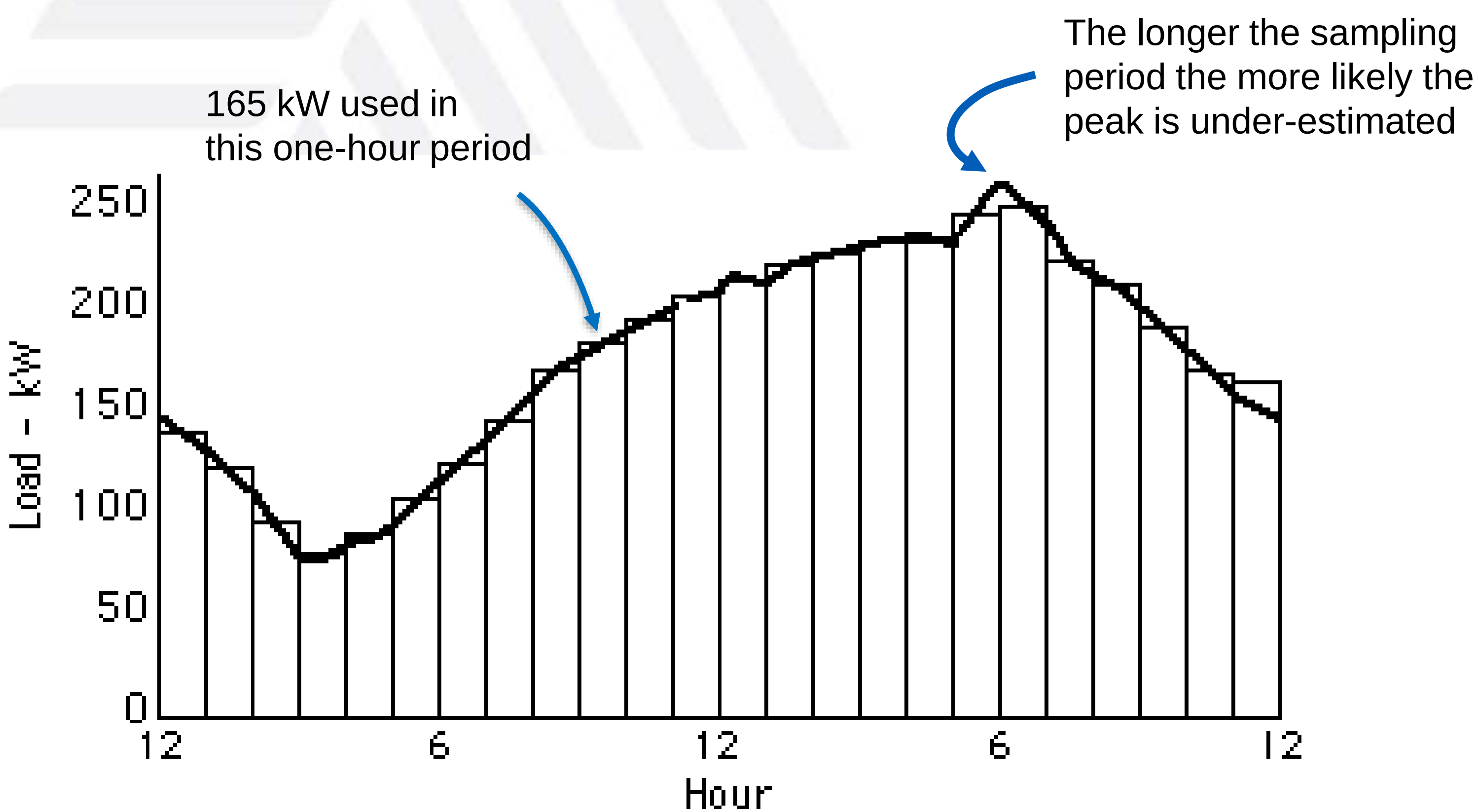


► "Class" is any distinction that is useful for segmentation

- Residential
- Commercial
- Industrial
- Agricultural
- Institutional
- Resort
- Storage

Demand

- **Demand** is average value of load over a period



Most distribution utilities sample demand on a 15-60 minute basis

Other Load-related terms and definitions

- **Peak load** – maximum demand measured
  (Varies with demand period)

- **Load factor** – ratio of average demand to peak demand
  (low LF = “peaky” loads)

- **Diversity** refers to the fact loads vary randomly, i.e. not all loads peak together

- **Coincidence factor** – ratio of observed peak for a group to sum of individual peaks (inverse of diversity)

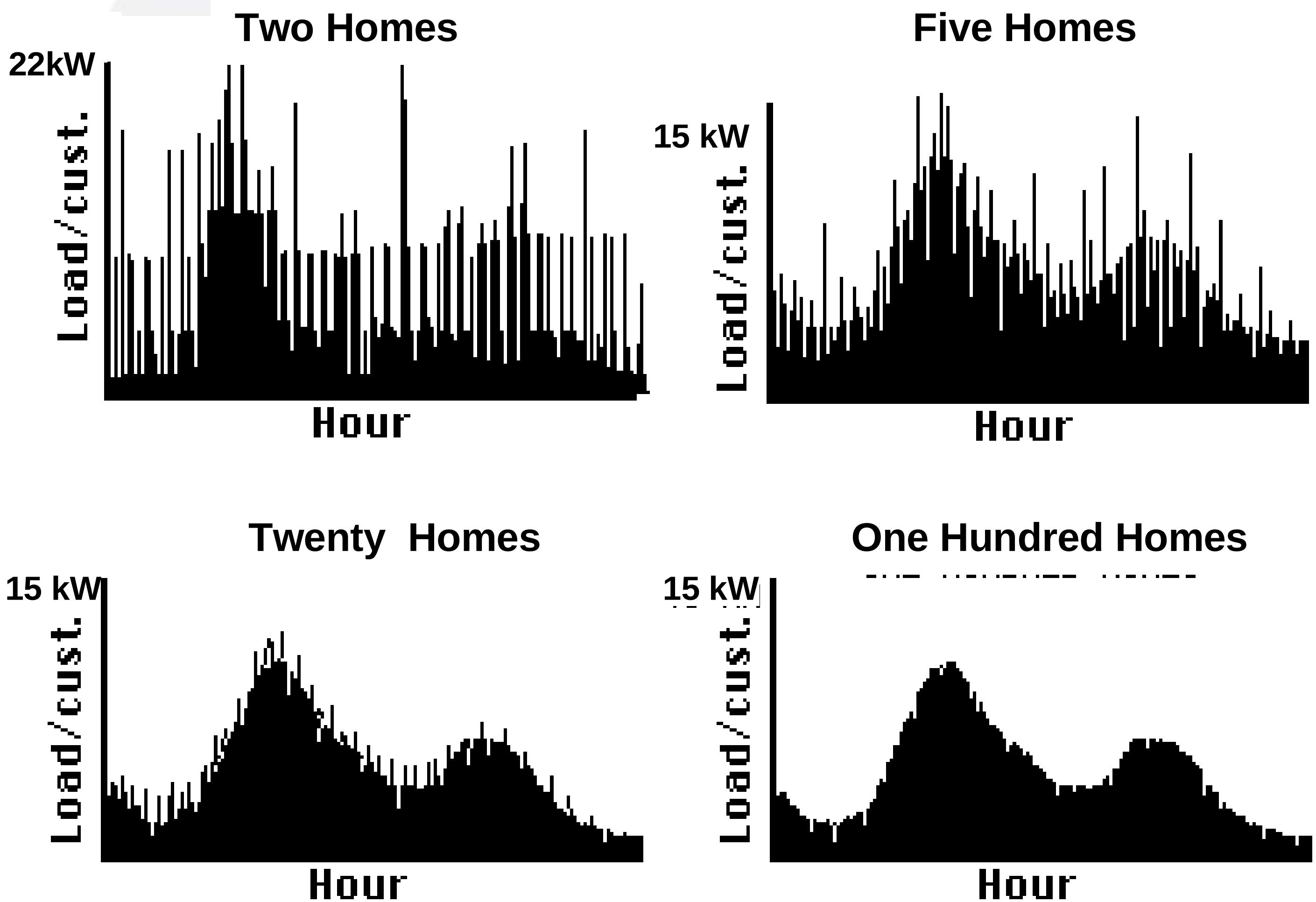
Individual Customer Load

LF = 0.2
CF = 1

- As number of customer loads in group increases:
  - Peak demand per customer drops
  - Load profile curve becomes smoother
  - Load factor (LF) increases
  - Coincidence factor (CF) decreases

H. L. Willis and G. B. Rackliffe, "*Introduction to Integrated Resource T&D Planning*"

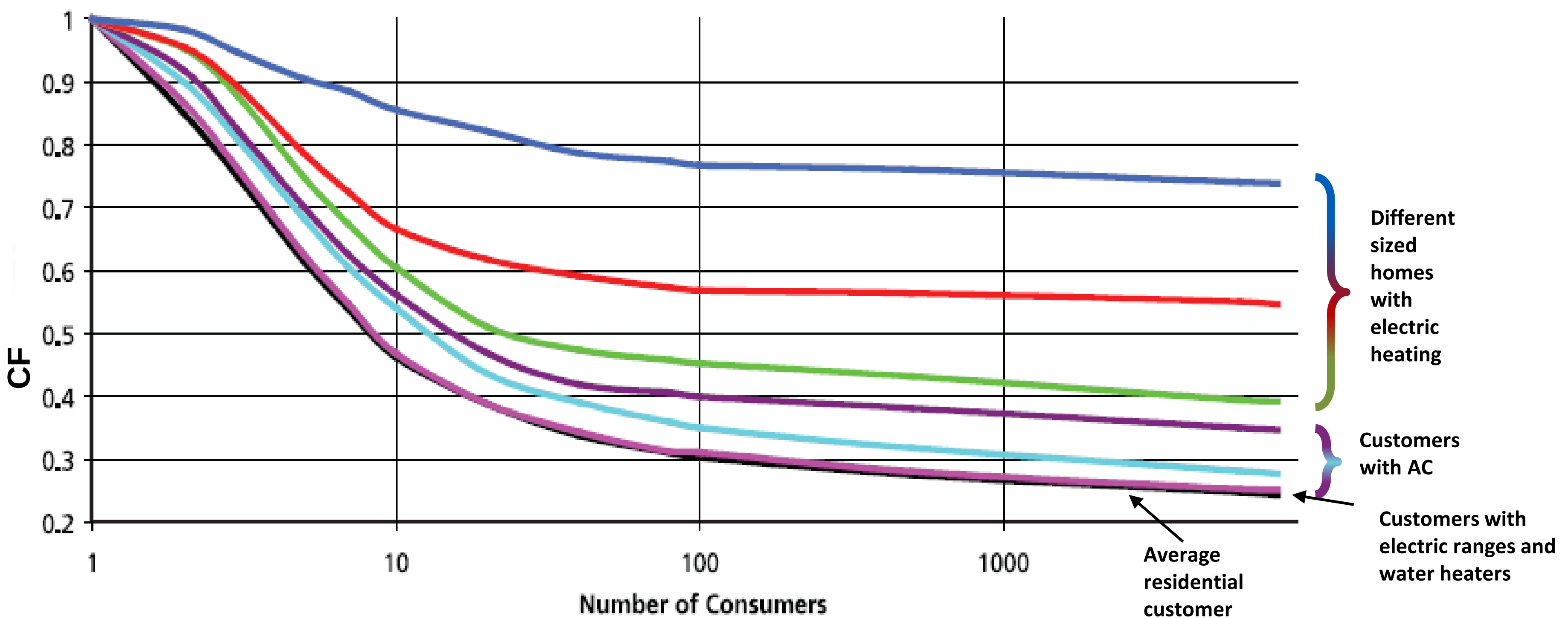
Groups of customer loads



H. L. Willis and G. B. Rackliffe, "*Introduction to Integrated Resource T&D Planning*"

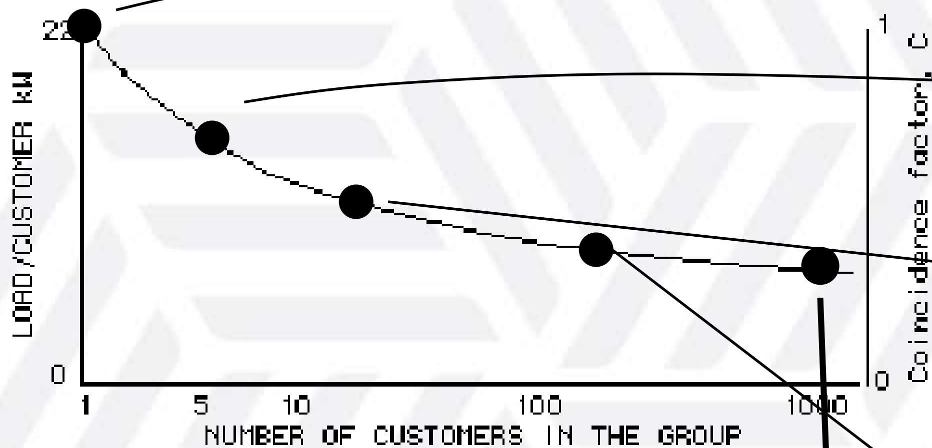
Coincidence curves

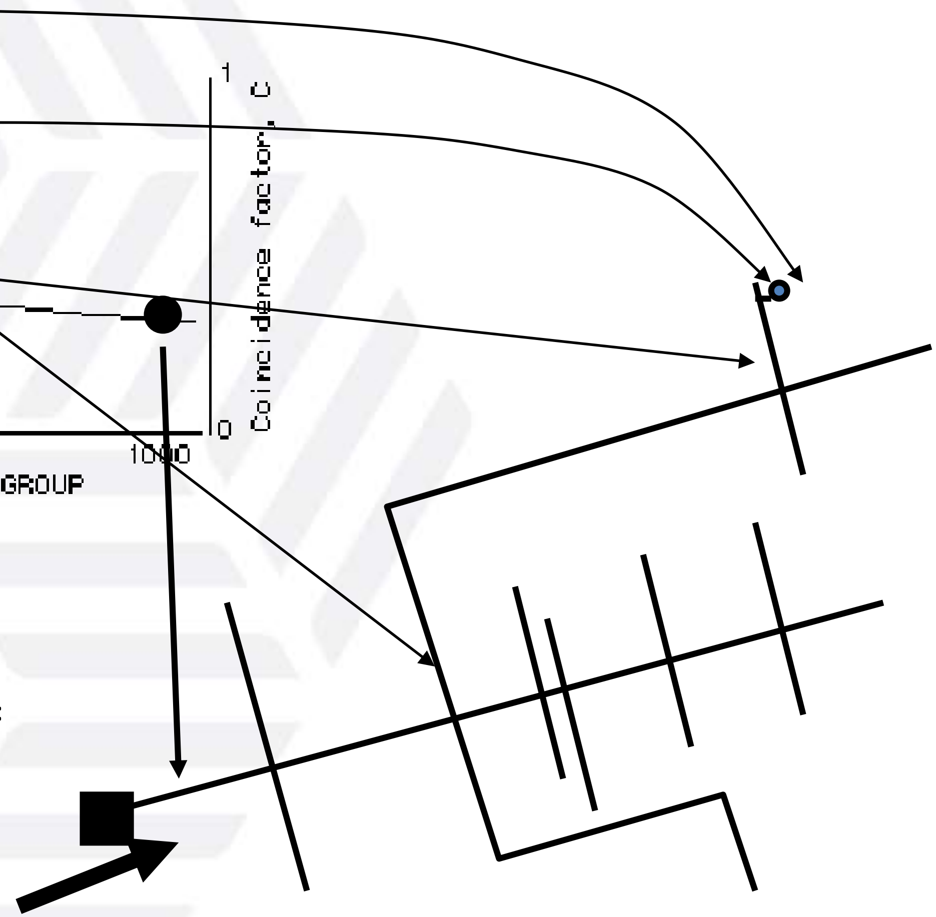
► Planners typically develop coincidence curves for various customer types based on load research data



Example of coincidence data from a utility in the Southeastern U.S.

Coincidence application to capacity planning





Planners use coincidence curves to determine load = coincidence * number of customers downstream

H. L. Willis and G. B. Rackliffe, "*Introduction to Integrated Resource T&D Planning*"

Planning for Reliability

- **Two main methods for reliability assessment**
  - **Historical**: compute reliability indices using archived data on outages and interruptions
    - Can determine the current system performance
    - May (*carefully*) be used to project future performance
    - Cannot be used for multiple-scenario analysis
  - **Predictive**: assess system reliability using a connectivity model with component reliability data
    - Usually calibrated using historical reliability indices
    - Historical interruption data may be used to represent component reliability
    - Excellent for “what-if” scenarios and project justification

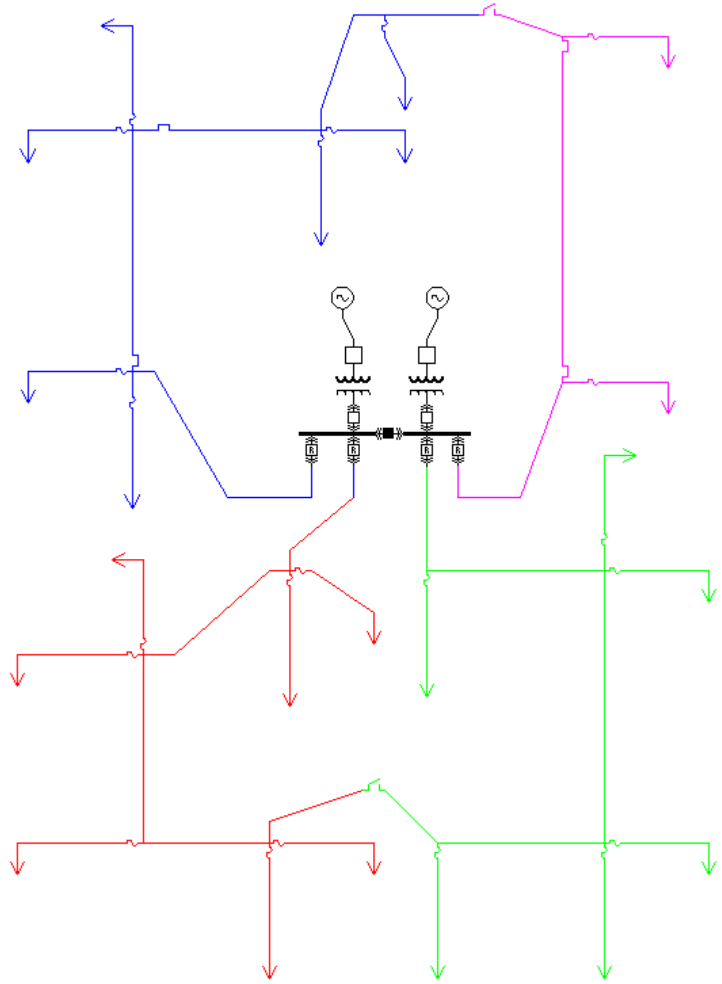
Predictive Reliability Model

► Connectivity is a functionally accurate description of the topographical arrangement capturing diversity of supply, equipment redundancies, remedial actions and mitigating measures.

Sources: system maps and one-line diagrams, GIS databases, drawing files

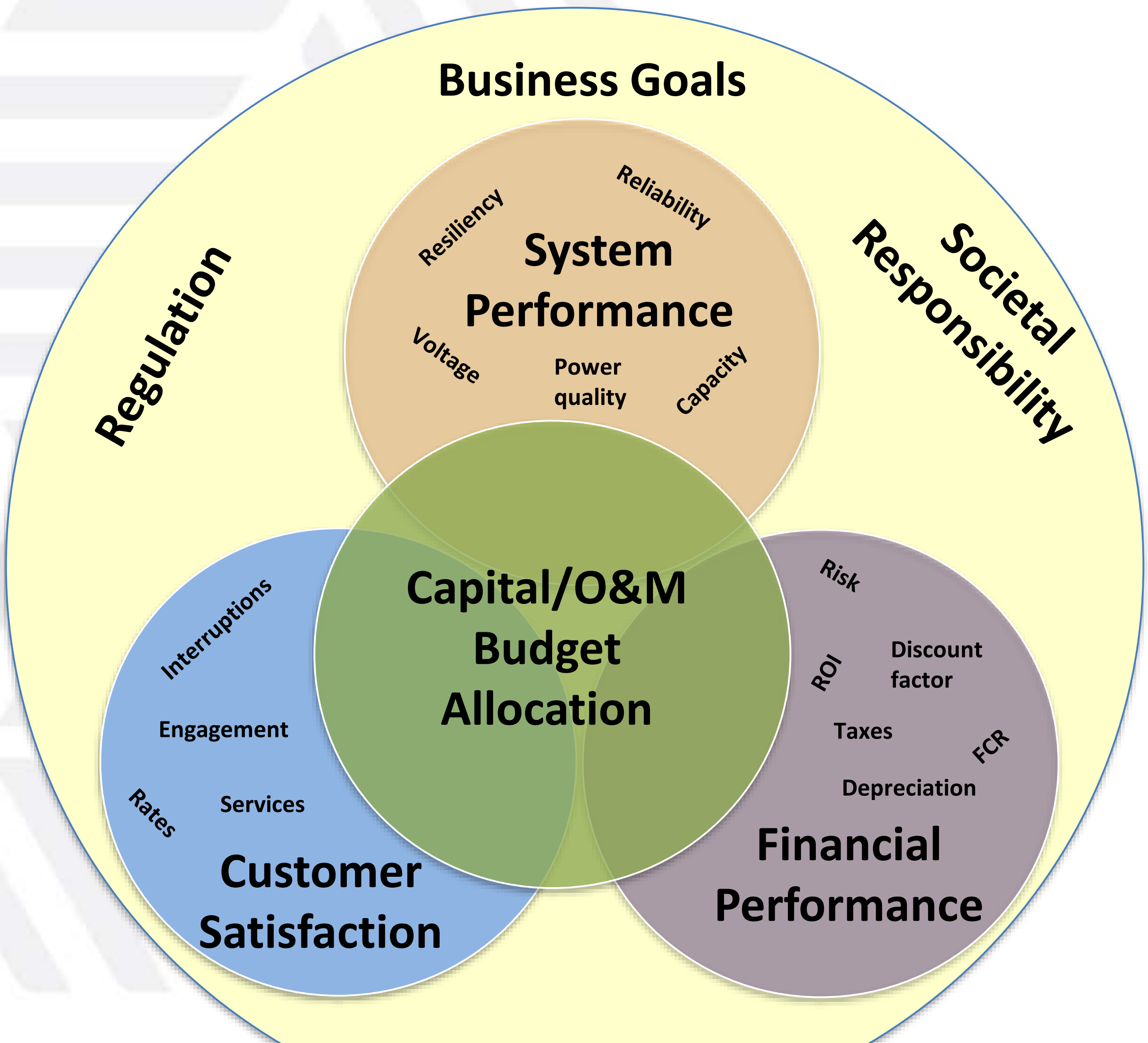
► Component data describes the failure, repair and remedial characteristics of individual system components

- Failure rates, repair times, switching times
- Sources: utility archives, databases, industry sources such as IEEE standards, papers, and publications



Excellent for developing and evaluating reliability improvement strategies

Effective Asset Management



Consumers Energy

Electric Distribution Infrastructure Investment Plan (2018-22)

Michigan Public Service Commission Order for Case No. U-18014

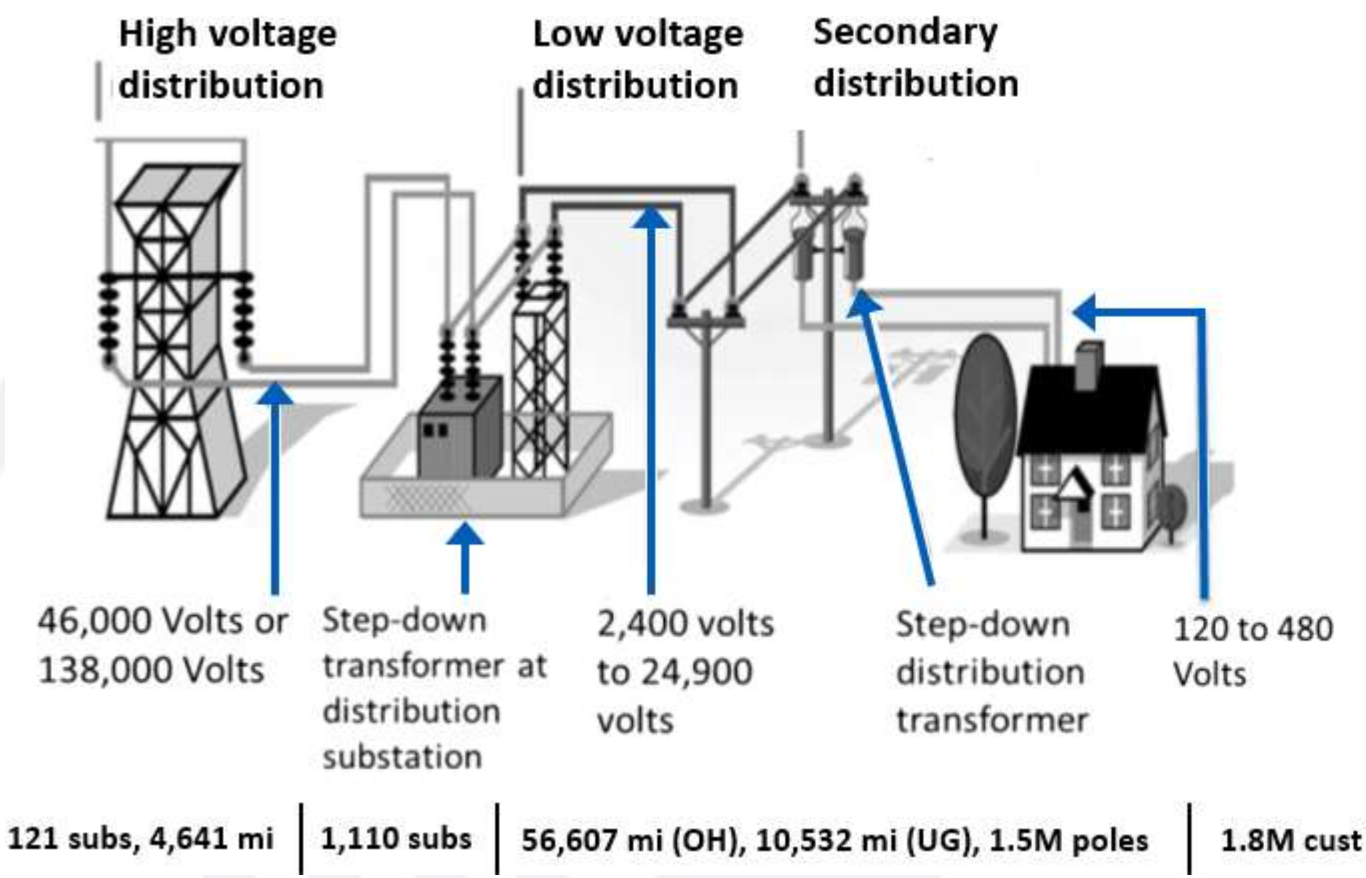
Requires a **<u>five-year distribution investment and maintenance plan</u>** that contains:

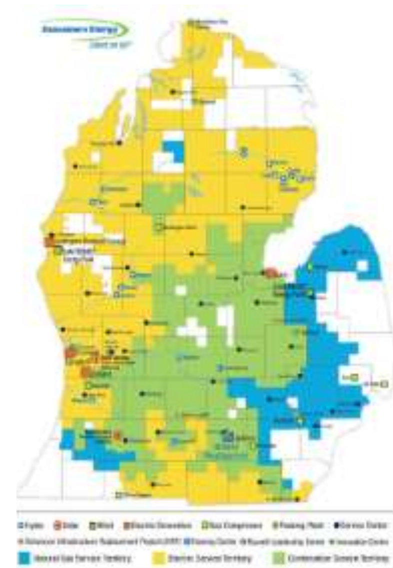
1. **Current state of the electric distribution system:** a detailed description, with supporting data, on distribution system conditions, including age of equipment, useful life, ratings, loadings, and other characteristics
2. **System goals and related reliability metrics**: assessment of performance using industry standards and metrics such as SAIDI, SAIFI, CAIDI
3. **Local system load forecasts**: forecasts of load at the system, area and local levels
4. **Maintenance and upgrade plans**: project categories including drivers, timing, cost estimates, work scope, prioritization and sequencing with other upgrades, analysis of alternatives
5. **Cost / benefit analysis**: analysis considering both capital and O&M costs and benefits

Consumers filed their draft Plan on Aug 1, 2017; Final Plan is expected to be filed on or before Jan 31, 2017

Consumers Energy (CE) Background Information

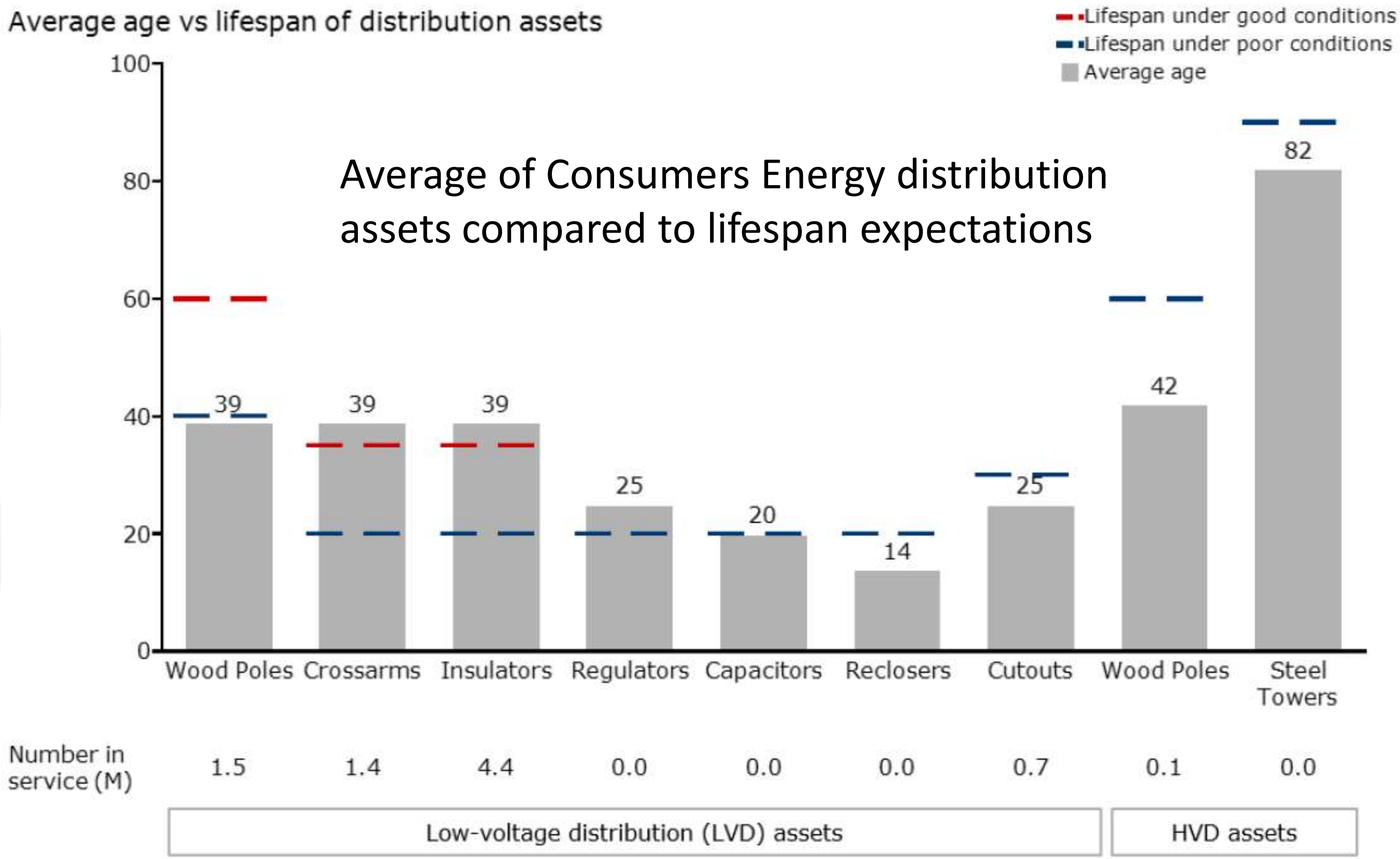
Serves 1.8 million customers in the north, central, and western MI





From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17, https://mi-psc.force.com/s/ Filing U-17990-0416

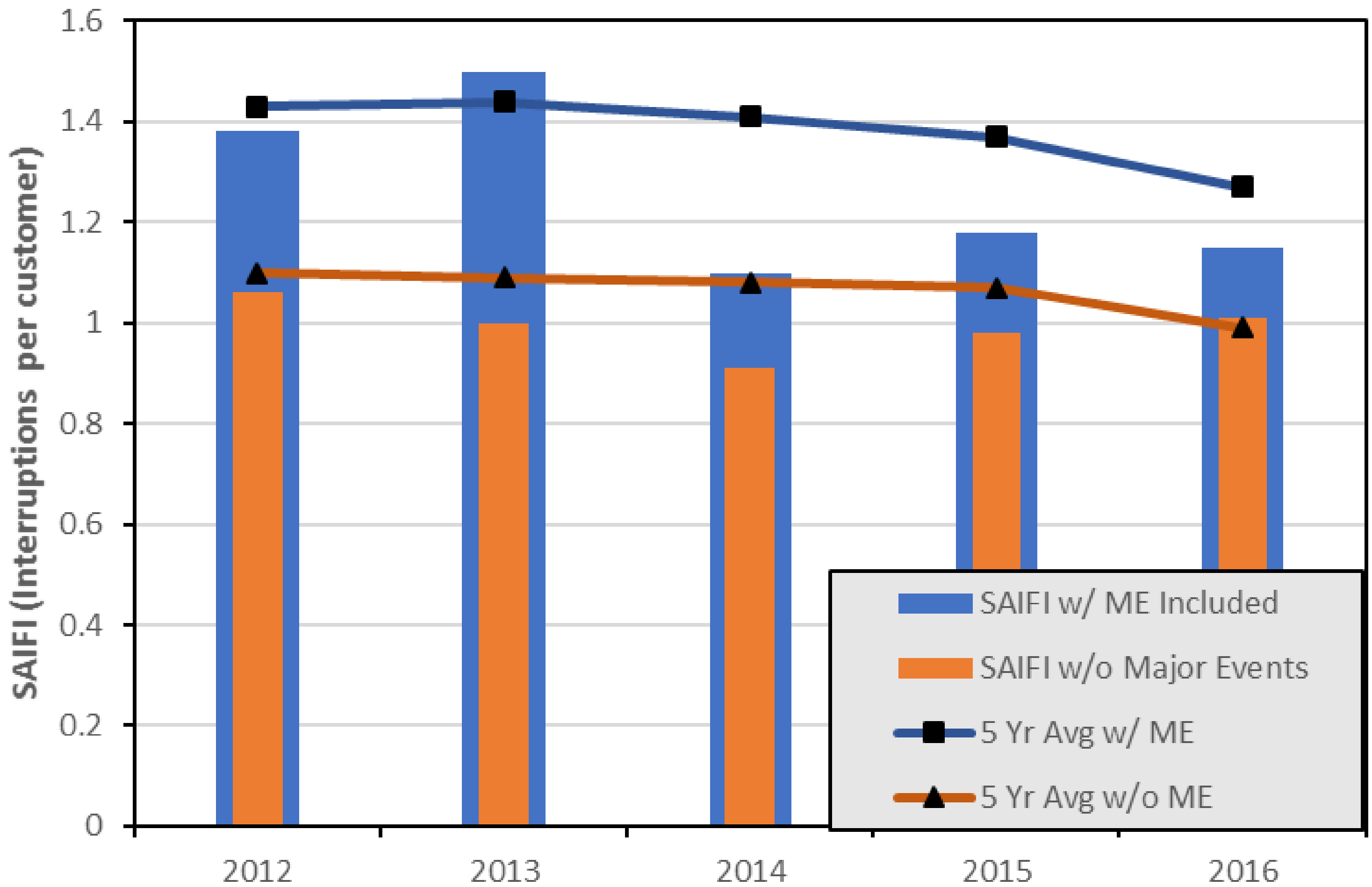
Average age of Consumers Energy distribution assets



Compared to other major U.S. utilities, the age of CE infrastructure is in the third quartile

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17, https://mi-psc.force.com/s/ Filing U-17990-0416

Trend in Consumers Energy SAIFI with and without Major Events



Based on data from *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17, https://mi-psc.force.com/s/ Filing U-17990-0416

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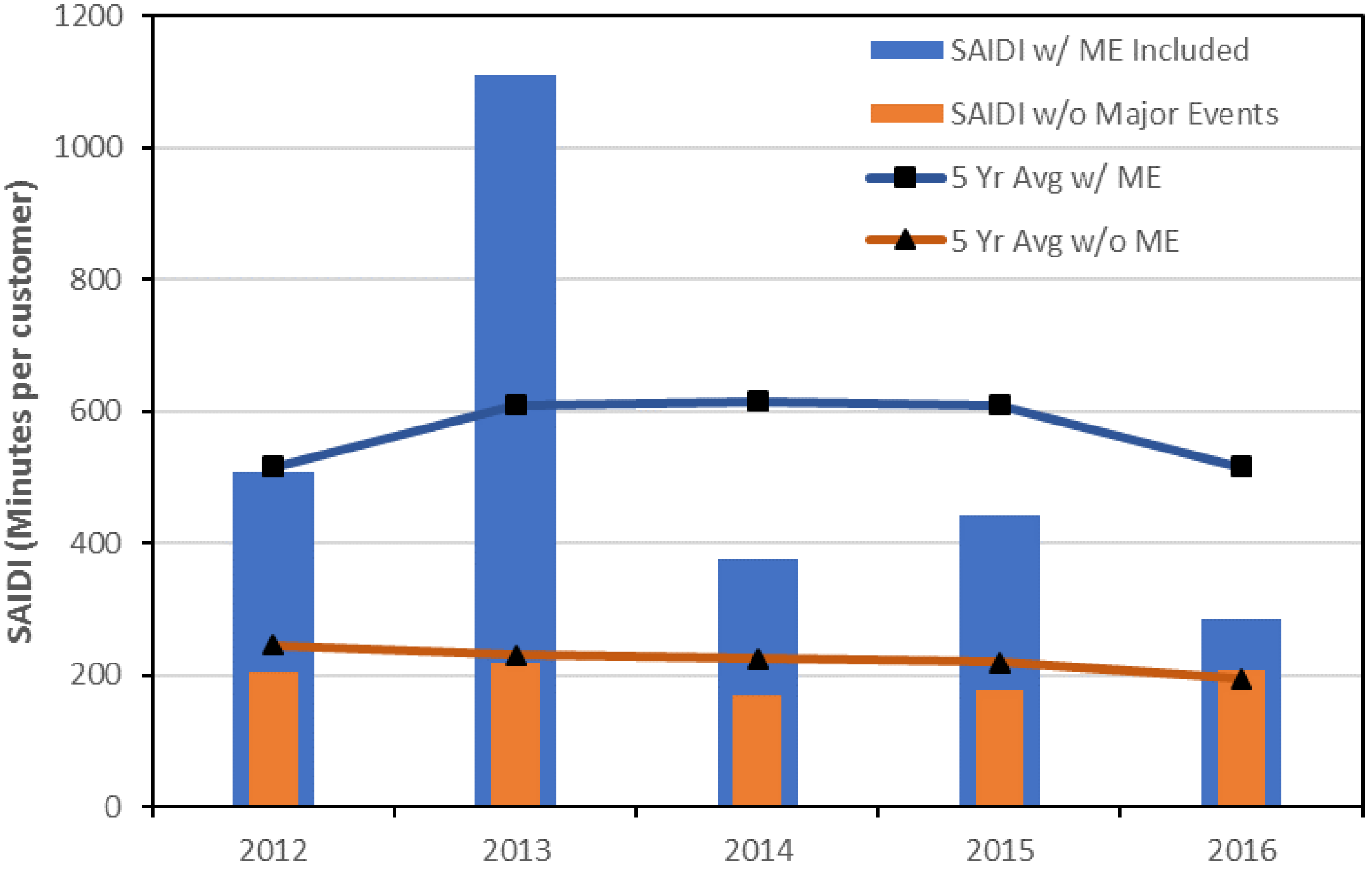
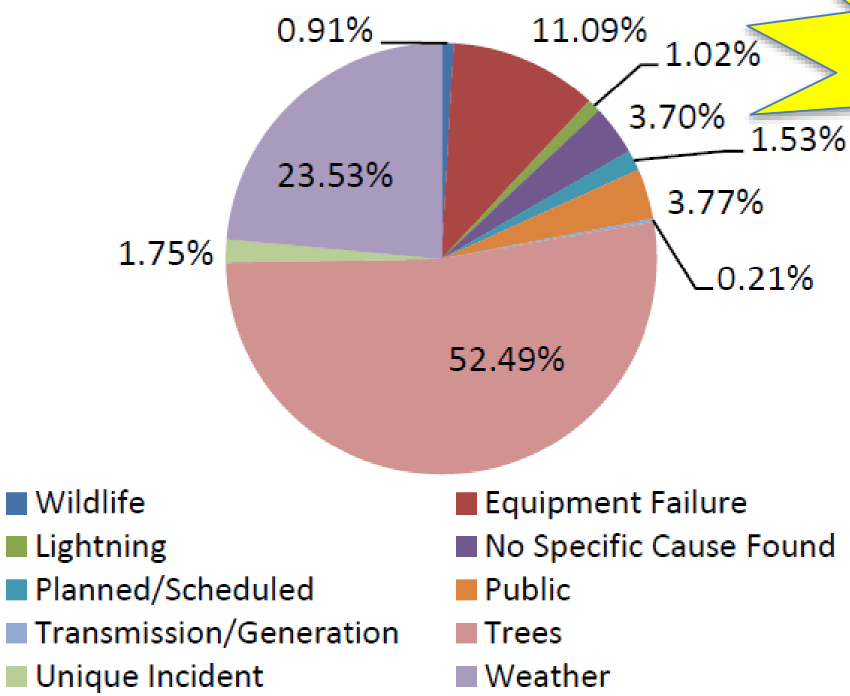
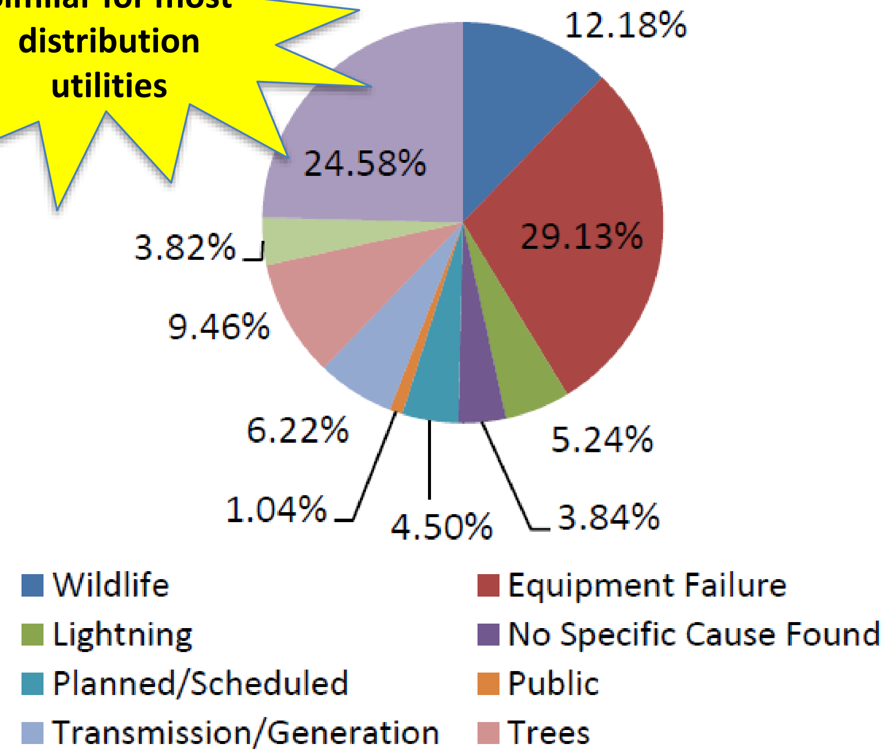


Based on data from *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*,8/1/17, https://mi-psc.force.com/s/ Filing U-17990-0416

Common causes of interruptions for Consumers Energy

Similar for most distribution utilities





Low Voltage Distribution

High Voltage Distribution

- Trees and weather account for 75% of LVD outages
- Equipment failures and weather account for over 50% on HVD

Trends in Consumers Energy customer expectations

- **Reliability and resiliency**

  Customers increasingly focus on reliability and resiliency in assessment of utility service
- **Security**

  Customers, governments, and utility executives are increasingly focusing on security threats, especially cybersecurity
- **Distributed energy resources (DERs)**

  Customers will continue to pursue adoption
- **Renewable generation**

  C&I customers will continue to desire expanded renewable generation
- **Data proliferation**

  Customers have more access to big data and are making more new, real-time decisions

"meaningfully affect … assets and capabilities required to operate [the distribution system] successfully"

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17, https://mi-psc.force.com/s/ Filing U-17990-0416

Consumers Energy primary objectives for distribution infrastructure investment

- **Optimize system cost over the long-term**: cost effective and equitable for entire customer base over the long-term
- **Improve reliability and resiliency**: harden the system; improve visibility; minimize outage occurrences; respond with speed and effectiveness to minimize outage duration; and better manage frequency and voltage
- **Enhance cybersecurity and physical security and safety**: design system to ensure the security and safety of customers
- **Reduce carbon footprint**: explore opportunities to promote lower carbon resources where economical (e.g. non-wires alternatives that integrate distributed generation)
- **Enable greater control**: provide customers with the data, technology, and tools to take greater control over their energy supply and consumption

"We commit to building a more modern electric distribution system that integrates greener, more distributed sources of electric supply with grid enhancements that are engineered for customer value."

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17, https://mi-psc.force.com/s/ Filing U-17990-0416

Consumers Energy Three-Phase, Fifteen-Year Investment Plan

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U.S. Department of Energy

Phase 1 (2018-Early 2020)

1. Complete the foundation
- Address immediate needs
- Develop critical infrastructure (distribution automation loops, AMI)
- Launch early pilots (VVO, FLISR)

Five-Year Plan

Phase 2 (Early 2020-Mid 2020)

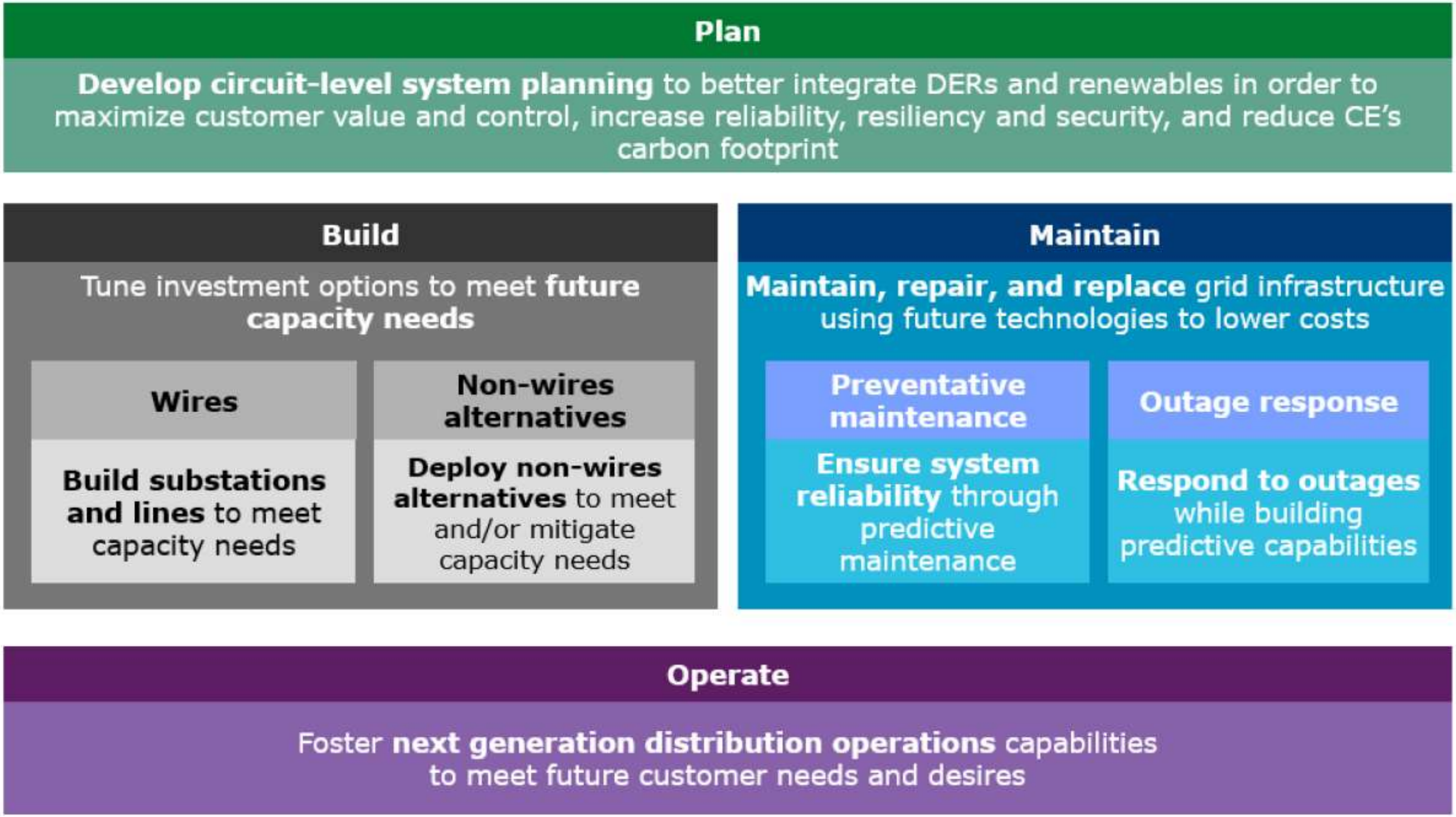
2. Enhance our capabilities
- Enhance communications and critical system planning capabilities
- Expand ADMS platform (VVO, FLISR)
- Launch additional pilots (LiDAR, drones)

Phase 3 (Mid 2020-Late 2020)

3. Optimize the future system
- Fully implement phase 1 and 2 projects
- Improve asset management, grid analytics
- Improve operational efficiency capabilities

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17, https://mi-psc.force.com/s/ Filing U-17990-0416

Consumers Energy Five-Year Electric Distribution Infrastructure Investment Plan (2018-22)



Bridges Phase 1 and phase 2 of Consumers' 15-year plan

First Role: Plan

Plan
Develop circuit-level system planning to better integrate DERs and renewables in order to maximize customer value and control; increase reliability, resiliency and security; and reduce CE's carbon footprint.

- ► Identify future infrastructure needs to ensure that the system
  - Has adequate distribution capacity
  - Can effectively integrate DERs where most beneficial
  - Can effectively manage frequency and voltage regulation
  - Is able to proactively adapt to ensure reliability, resiliency, and safety
- ► Process relies on load forecasts as primary input

Current Approach to System Planning

- Identify future supply-side and demand-side resource needs based on load forecasts and the acquisition of various resources

Build HVD system peak load forecast

- Using historical data, economic forecasts and weather data
- 65% confidence interval

Allocate forecast to planning areas

- Allocated based on historical growth within each area
- Load flow model developed for HVD system

Build LVD system peak load forecast

- Allocated based on local substation peak*
- Local load flow model developed in CYME

*Real-time data (SCADA or Distribution SCADA -- DSCADA) is used where available. Otherwise, historical data from manual readings is used

Key planning related expenses

► Future investments to improve planning capabilities:

- **System Modeling Tools**: Tools that help perform near-real time distribution power flow studies to help streamline interconnection requests for DERs
- **Data Lake**: Gather disparate data sources (asset, customer, outage, smart meter, DSCADA, etc.) into a single location to be used for advanced data processing and analytical techniques
- **Grid Analytics "Sprints":** Develop analytical capabilities to perform feeder and circuit level analyses quickly
- **External Planning Services:** Offer DER planning services for customers and project developers

Planning related expenses

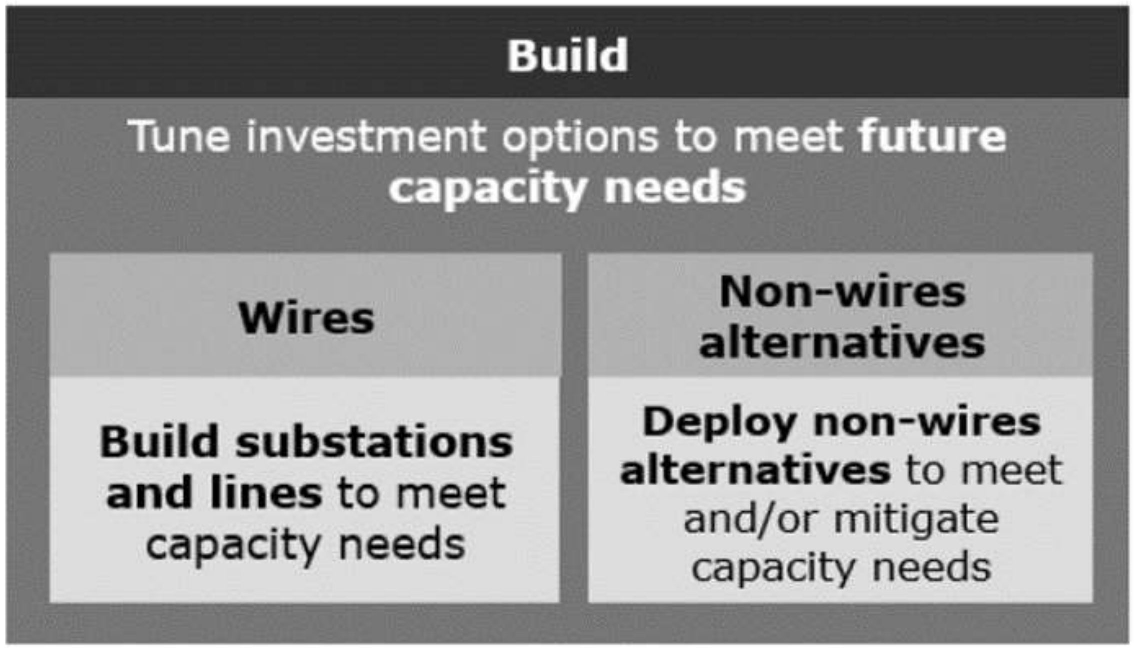
Plan - Capital Expenditures ($K)				
Investment Category	2016 Actuals	2017 YTD (June)	Five Year Estimate (2018-22)	Major investments
Grid Analytics	--	--	*Final Report*	Sprints (Mis-phasing, Customer power quality) and Data Lake
System Modeling	--	--	*Final Report*	System modeling tools, external planning services
Total Plan CapEx	--	--	*Final Report*	N/A

Plan – O&M Expenses ($K)				
Expense category	2016 Actuals	2017 YTD (June)	Five Year Est. (2018-22)	Major expenses
Scheduling and dispatch	$3,605	$2,554	*Final Report*	Long range planning, weekly planning, scheduling, dispatch and office support for field operations to execute their work activities.
Grid infrastructure	$5,067	$3,214	*Final Report*	Capacity and reliability planning, infrastructure inspections, system load analysis, agricultural services, Reliability First dues.
Data management	$536	$388	*Final Report*	Update geographic information system (GIS) records and applications
Distribution and customer operations staffing	$2,711	$950	*Final Report*	Salaries and expenses for management personnel.
Other*	$6,843	$3,686	*Final Report*	Substation and HVD line design and standards.
Total Plan O&M	***$18,763***	***$10,792***	*Final Report*	N/A

**Other includes project management, regulatory and compliance, infrastructure standards, financial management, contract administration, etc.*

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17

Second Role: Build



- Develop solutions to needs identified by system planning
- Incorporate both traditional assets and non-wires alternatives

Current Approach to System Building

- Determine Investment to ensure the entire system meets overall load and peak demand

Determine needs

- Conduct distribution studies
- Power flow analysis
- Reliability assessment
- Planning criteria violations

Identify Solutions

- Load transfer
- Capacity increase
- New LVD substation
- Alternate LVD substation connection
- Non-wires alternatives

Prioritize Projects

- Equipment loading compared to peak capability
- Performance on lines (SAIDI) and projected improvement

System Modeling and Analysis

GIS

Device monitoring & control

Customer information system

Equipment database

Planning model

- Network topology
- Equipment
- Phase

- Equipment status
- Control settings
- Load information
- Conductor type
- Device capacity

- Single-phase unbalanced load flow model
- Reliability model

- ESRI ArcGIS
- Intergraph
- GE Small World
- Milsoft WindMilMap
- Schneider EcoStruxur

- CYMDIST, CYME
- SynerGEE, Advantica-Stoner
- WindMil, Milsoft
- PoweFactory, DIgSILENT
- DEW, EDD
- NEPLAN, Neplan AG

Traditional Substation Expansion

Substation expansion	
Location	Deerfield
Major cause	Customer expansion
Local load	The existing transformer in the substation was loaded to approximately 86% of capability in 2016. The customer's load addition of 1.8MW in late 2017 will place the transformer at 131% of capability in 2018.
Primary options considered	Expand the existing substation Build a new substation Energy efficiency / demand response
Rationale	The existing substation is a small substation that is group regulated. These substations were not built to the current minimum approach distance standards. Working in them without forcing an outage to customers is difficult. The substation expansion project will address the capacity the concerns and ultimately improves reliability to the area. The addition of a new substation was not necessary due to the relatively small nature of the load addition (about 1.5MW of peak load increase), but neither energy efficiency nor demand response were considered viable in this location to achieve sufficient peak load reduction.

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17

Non-Wires Alternatives (NWA)

Two Focus Programs

Demand Response	Energy Efficiency
Since 2010, we have partnered with more than 1,700 Michigan residences and businesses to reduce peak electric demand by approximately 52 MW (majority through our C&I program)	Since 2009, our portfolio of Energy Efficiency programs have saved customers more than $1B in reduced energy bills while reducing peak electric demand by approximately 400 MW

- Ongoing NWA project at the Swartz Creek substation to defer a capacity project
- Demand Response
  - AC cycling pilot with 1,754 customers, 2 MW in 2016
  - Two time of use (TOU) pilots with 37 employees, enrolling 0.0233 MWs in 2016
  - $20M investment to increase C&I demand response portfolio from 50 MW to 150 MW
- Future BESS Pilots
  - WMU Solar Farm (Kalamazoo) - 1MW/1MWhr
  - Circuit West BESS (Grand Rapids) - 0.25 to 0.75 MW
- NWA are now an integral part of the supply planning process and part of the Company’s supply plan.

Swartz Creek NWA Pilot

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U.S. Department of Energy

Non-wires alternative (Pilot)	
Location	Swartz Creek
Major cause	General load growth
Local load	The substation transformer at Swartz Creek has experienced peak loadings of 92%, 94%, 80%, 79%, and 85% from 2012 through 2016. The load appears to be highly dependent upon the weather as no system changes (large transfers or large, new customers) have been observed.
Primary alternative considered	N/A
Rationale	A traditional substation capacity increase would be implemented after an observed overload. Swartz Creek substation was chosen for the NWA (pilot) due to historical loads that have been observed close to capacity, but never over. Piloting an NWA at this location was an opportunity to test an NWA solution's feasibility without risking the equipment or customer reliability due to an observed overload the prior year. The company's NWA pilot at Swartz Creek substation will rely heavily on the existing Energy Efficiency and Demand Response programs in place. The pilot will also make use of the Time of Use and dynamic peak pricing rates that are offered. These programs and rates will be marketed in the community to show off the rebates and long-term cost savings that can be realized. The marketing plan utilized will reach both residential and business customers. The NWA pilot is being run in coordination with the Natural Resources Defense Council (NRDC).

Overall expenditures

Build - Capital Expenditures ($K)				
Investment category	2016	2017 YTD (June)	Five Year Estimate (2018-22)	Major investments
"Wires" investments	$145,010	$67,199	*Final Report*	New business (lines, meters, transformers) and capacity increases (substations, upgrades)
Non-wires alternatives	$1,200	*$2,752*	*Final Report*	Battery storage pilots, demand response and energy efficiency programs
Total Build CapEx	$146,210	$69,952	*Final Report*	N/A

Build – O&M Expenses ($K)				
Expense category	2016	2017 YTD (June)	Five Year Estimate (2018-22)	Major expenses
"Wires" investments	--	--	*Final Report*	New business (lines, meters, transformers) and capacity increases (substations, upgrades)
Non-wires alternatives	$78,836	$49,488	*Final Report*	Battery storage pilots, demand response and energy efficiency programs
Total Build O&M	$78,836	$49,488	*Final Report*	N/A

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17

Third Role: Maintain

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U.S. Department of Energy

Maintain

Maintain, repair, and replace grid infrastructure using future technologies to lower costs

Preventative maintenance	Outage response
Ensure system reliability through predictive maintenance	**Respond to outages** while building predictive capabilities

Consistently maintain distribution assets as they age

Current Approach

▶ Ensure all equipment is operating safely, effectively, and efficiently

Repairing Assets

- Multiple programs covering poles, lines, pole-top equipment, and substation equipment
- Tree trimming and line clearing program
- Programs to reduce customers' average outage duration (SAIDI).

Replacing Assets

- Investments to upgrade deteriorated equipment, to reduce system outages
- Investments for adverse weather
- Investments to build for the future need and demands of our customers.

Outage Restoration

- Restoration management program
- Storm restoration relies on
  - outage management system
  - resource management system
- Continuous feedback loop to improve restoration program

Project Prioritization

- ► Evaluate reliability projects based on estimated avoidance of outage minutes for the customers impacted by the project
- ► Projects are prioritized using
  - Cost-benefit ratio analysis
  - Input by engineers and program managers based on experience and knowledge of the system
  - Availability and location of resources
  - Funding
- ► Reliability Analytics Engine (“RAE”) used to analyze outage data outage data
  - Produces ranked list based on line performance and opportunity for improvement

Repair/Replacement Programs

- ► Pole inspection and replacement
- ► Line inspection and replacement
- ► Tree trimming
- ► System protection
- ► Substation inspection
- ► Substation maintenance and reliability
- ► Demand failures
- ► Storm restoration

Maintain the System – Capital Expenses

Maintain - Capital Expenditures ($K)				
Investment category	2016 Actuals	2017 YTD (June)	Five Year Estimate (2018-22)	Major investments
Reliability	$113,866	$45,517	*Final Report*	Proactive rehabilitation of poor performing LVD lines, pole inspection and replacements, pole-top replacements, sectionalizing, etc.
Demand failures	$116,539	$81,888	*Final Report*	Respond to failures on distribution lines including poles, pole-top equipment, voltage improvement, service restoration, etc.
Cost of removal	$41,618	$36,061	*Final Report*	Retirement only projects and labor costs to remove assets associated with the investments in LVD New Business, Reliability, Capacity, Demand Failures, and Asset Relocations.
Asset relocations	$19,504	$11,804	*Final Report*	Respond to requests (internal or external) to relocate distribution lines.
Technology	$3,533	$941	*Final Report*	Budget for projects that may be required in order to maintain compliance. Incudes control house upgrades to meet National Electric Safety Code (NESC).
Other*	$3,982	$2,160	*Final Report*	Conversion of Mercury Vapor streetlights to the streetlight of the community's choice (e.g. High Pressure Sodium, LED).
Total Maintenance CapEx	$297,254	$177,470	*Final Report*	N/A

**Other includes streetlight maintenance (mercury vapor / LED)*

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17

Maintain the System – O&M Expenses

Maintain – O&M Expenses ($K)				
Expense category	2016	2017 YTD (June)	Five Year Estimate (2018-22)	Major expenses
Reliability	$53,906	$27,829	*Final Report*	Vegetation management along LVD and HVD electric system rights-of-ways.
Repair and restoration	$53,390	$40,256	*Final Report*	Respond and make necessary repairs for no light calls, outages, wire downs, emergency orders, and hazards.
Field operations	$18,606	$11,119	*Final Report*	Supervision and leadership for electric operations.
Meter services	$14,574	$2,637	*Final Report*	Meter maintenance, customer requested work, theft investigation, mixed meter investigation, routine exchanges.
Other*	$8,684	$4,201	*Final Report*	Credits associated with purchase of pre-capitalized assets (e.g. distribution transformers).
Total Maintenance O&M	***$149,159***	***$86,042***	*Final Report*	N/A

**Other includes DCO accruals, joint pole rental, IT projects, unallocated emergency funds, and WMIP*

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17

Fourth Role: Operate

Operate
Foster **next generation distribution operations** capabilities to meet future customer needs and desires

► Actively manage the distribution system at all times to

- Minimize cost
- Ensure safety
- Improve reliability and resiliency
- Allow customers more control over their energy supply and consumption

Current and Future System Operations

Current System Operations

- Power flow analysis tools
- Customer call triangulation
- SCADA
- Four hours of analysis to run CYME report and interpret the results
- Limited capability to perform switching
- Limited interactions with DER

Future system operations

- Operations increasingly complex
- Digital capabilities enable real-time system view
- integrated ADMS allows enhanced operations, better tools to assess, monitor, analyze and control
- Sensors and AMI increase situational awareness and system control

"*Increase situational awareness and automate manual processes, shifting operations from being reactive to proactive*"

Key operations investments

- **Grid Communication**: Reliable, high-speed, high-capacity, wired and wireless communications platform based on internet protocol to connect all substations and distribution grid devices
- **Substation and Line Automation**: DSCADA, distribution automation, device controllers, and line sensors to optimize power flow and performance and avoid outages
- **Unified System Control Center**: Consolidating System Control Center (SCC) personnel and developing a Distribution Control Center (DCC). consolidating operations support functions such as Operating Technologies, Data Center, Security, Real-Time Engineering, Applications Support
- **Advanced Distribution Management System**: Consolidated grid management applications including Volt-VAR optimization; conservation voltage reduction; and fault location, isolation, and service restoration
- **Communications Device Management System**: Operational platform to enable system-wide communications by collecting information from multiple grid device technologies
- **Data Management**: Accurate system model and processes to maintain the integrity of model data provides the foundation for ADMS and other distribution applications

Distribution Line Automation – Benefit

DA Loop Benefits		
	Customer minutes saved	Cumulative customer minutes saved
2015 and earlier years	2.861M	2.861M
2016	1.871M	4.732M
2017 (as of 6/30/17)	3.385M	8.117M

Reliability assessment using Cyme, and historical data to project benefits

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17

Distribution Line Automation – Deployment Cost

DA Loop 5 Year Deployment Summary						
	Based on current LTFP			If more funding ...		
	Number of loops	% of circuits looped (cum)	Cost (k)	Number of loops	% of circuits looped (cum)	Cost (k)
2016 Actual	19 (include previous years)	1.5%	$1,430			
2017 Actual (Q1-Q2)	6	2.0%	$309			
2017 Plan (Q3-Q4)	12	3.0%	$3,953			
2018 Plan	10	3.8%	$8,933	20	4.6%	$17,866
2019 Plan	17	5.2%	$16,422	30	7.1%	$28,980
2020 Plan	20	6.8%	$17,520	40	10.3%	$35,040
2021 Plan	22	8.6%	$19,932	45	14.0%	$40,770
2022 Plan	28	10.9%	$25,368	45	17.7%	$40,770

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17

Operate the system – capital expenses

Operate - Capital Expenditures ($K)

	Investment category	2016	2017 YTD (June)	Five Year Estimate (2018-22)	Major investments
Grid Modernization	Total Grid Modernization	$18,518*	$8,253*	*Final Report*	Various – see below
Grid Modernization	Grid Analytics - Sprints	*Final Report*	*Final Report*	*Final Report*	Outage analysis
Grid Modernization	Grid Communications Modernization	*Final Report*	*Final Report*	*Final Report*	Modernizing the communications technology through standards based communication and replacement of frame relay and analog multi-drop technologies
Grid Modernization	Grid Modernization Applications	*Final Report*	*Final Report*	*Final Report*	Implementation of Advance Distribution Management System (ADMS) for Grid Management, data readiness of the electric system model, and Communication Device Management Software
Grid Modernization	Lines Automation, Monitoring & Control	*Final Report*	*Final Report*	*Final Report*	Implementation of distribution automation loops, reclosers, line regulators, and line sensors
Grid Modernization	Substation Automation, Monitoring & Control - LVD	*Final Report*	*Final Report*	*Final Report*	Implementation of Distribution SCADA and Distribution SCADA upgrades
SCADA		$407	$348	*Final Report*	Capital repair/replacement of systems necessary to support HVD & Distribution SCADA, including Substation RTU's, Servers, and Test Equipment
System control		$2	$6	*Final Report*	System control room upgrades and projects to mitigate System Operating Limitations (SOL's).
Total Operations CapEx		**$18,927**	**$8,607**	*Final Report*	N/A

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17

Operate the system – O&M Expenses

Operate – O&M Expenses ($K)				
Expense category	2016	2017 YTD (June)	Five Year Estimate (2018-22)	Major expenses
Smart Energy MTC	$0	$3,522	*Final Report*	Smart meter software maintenance and backhaul costs
System control	$3,754	$2,478	*Final Report*	Real time operation and monitoring of the electric system
Meter services	$1,133	$485	*Final Report*	New technology evaluation, meter upgrades, and verification of meter accuracies for all customer classes (residential, commercial, industrial)
Total Operations O&M	**$4,887**	**$6,485**	*Final Report*	N/A

From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17

Key Take-Aways

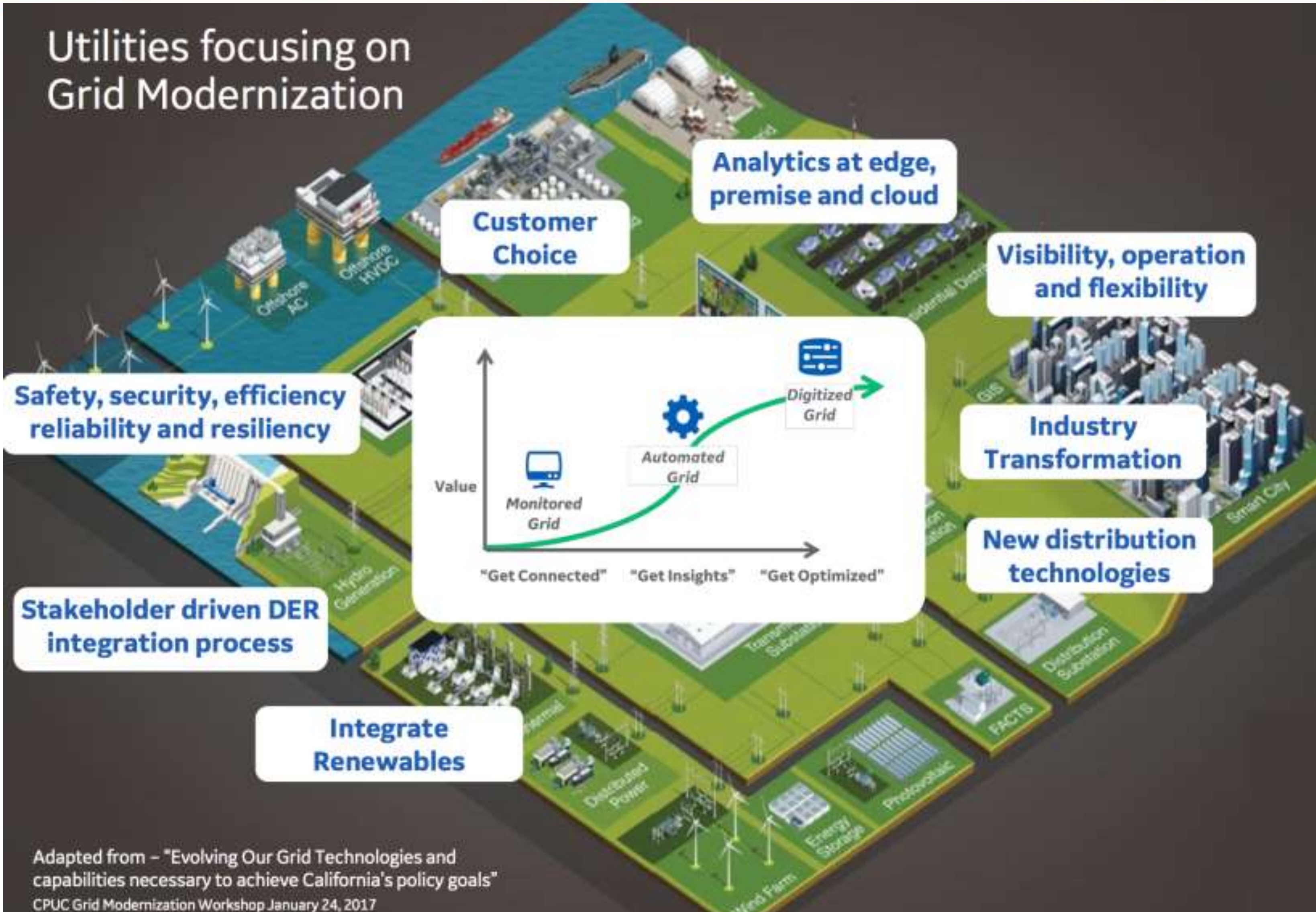
- ► Almost $5 billion invested in electric distribution over past decade by Consumers Energy
- ► Initial steps toward grid modernization through
  - Automation loops
  - AMI rollout
- ► Five-year distribution investment plan focuses more on “near-term” tactical approaches to
  - Improve reliability and resiliency
  - Provide capacity and voltage
  - Ensure protection and safety
- ► 15-year plan is roadmap for “longer term” grid modernization strategy to provide
  - Advanced devices and capabilities (VVO, FLISR)
  - Enhanced data integration and analytics
  - Real time asset control
  - DER integration and optimization

Grid Modernization Planning

With Examples from Unitil's Grid Modernization Plan

GRID MODERNIZATION LABORATORY CONSORTIUM
U.S. Department of Energy

Diverse goals for grid modernization



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 prosumers
- 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

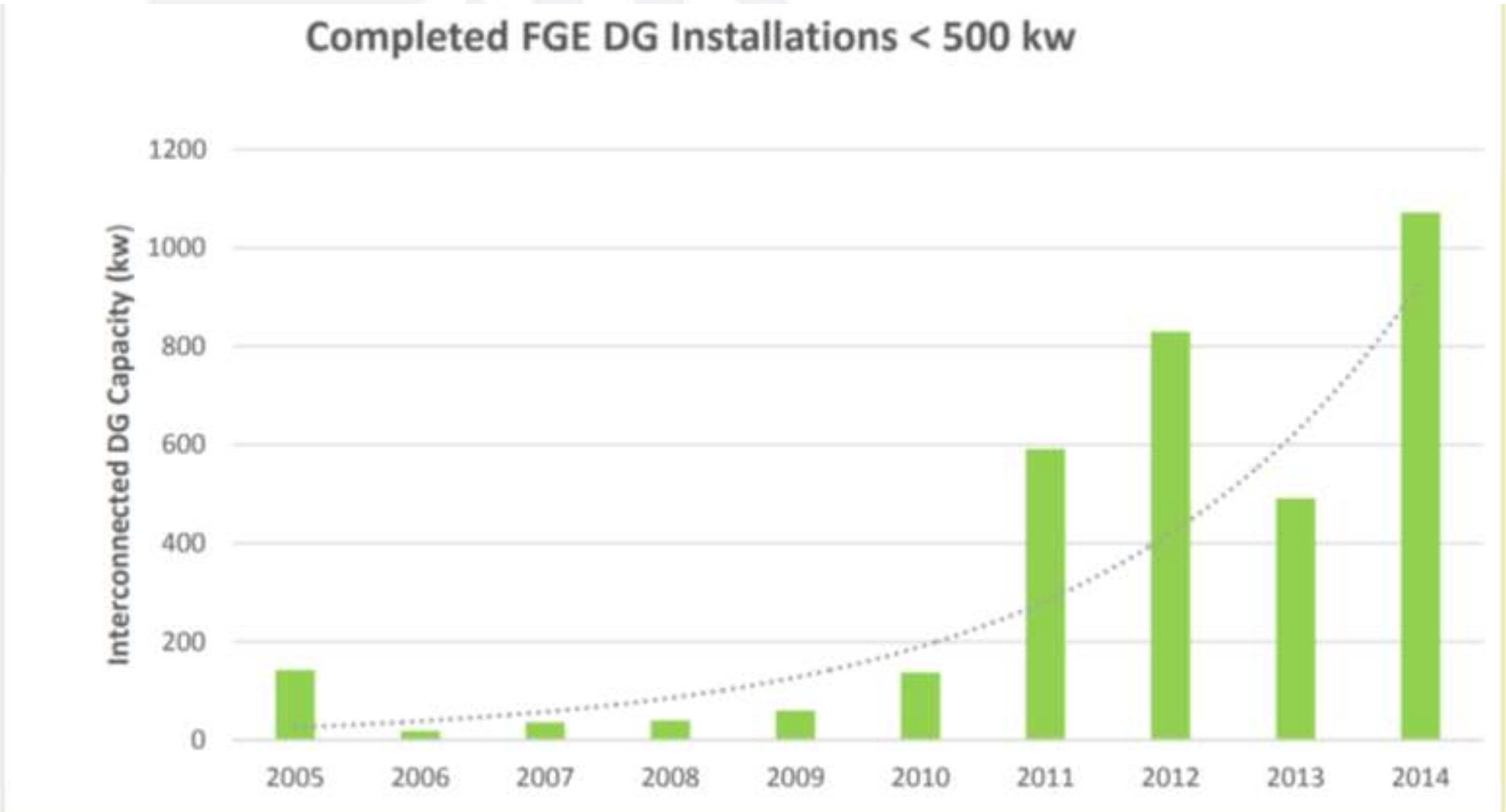
10 substations, 44 circuits, 28,600 customers (90% residential)

Unitil, EDIIP, 8/1/15

► 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

Distributed generation is growing



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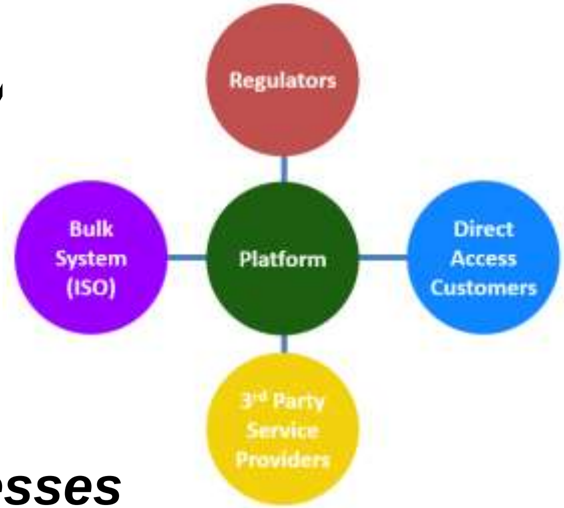
Programs to reach these goals

- ►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)

Unitil, EDIIP, 8/1/15

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)		

Unitil, EDIIP, 8/1/15

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 cause 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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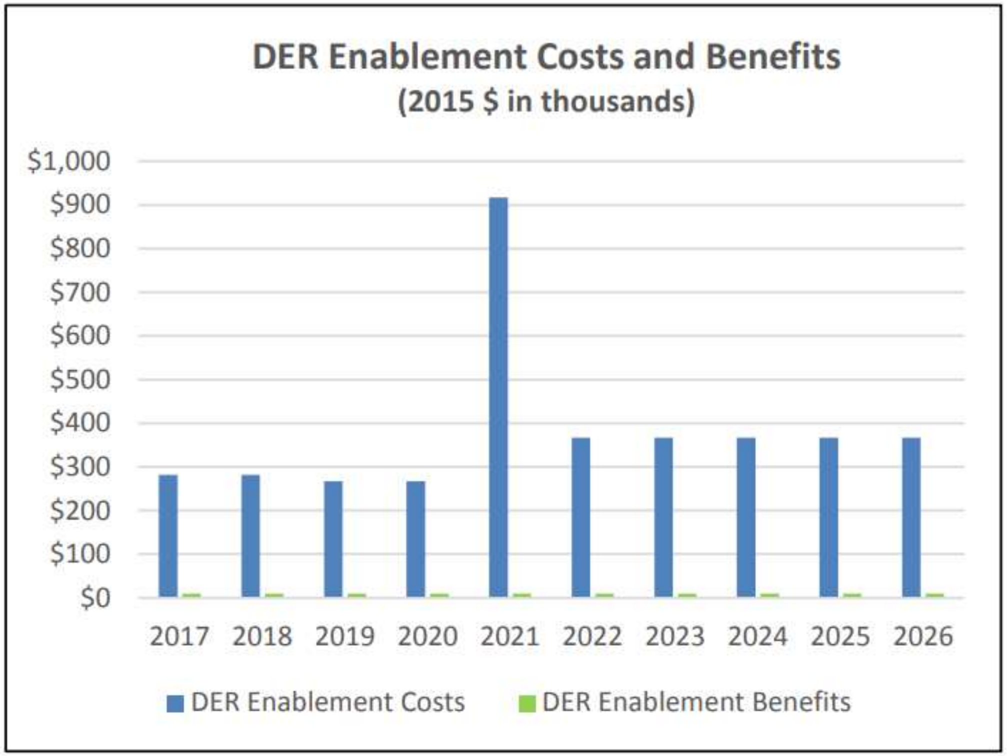
Overall DER enablement program cost/benefit



- 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

Unitil, EDIIP, 8/1/15

Distribution Automation Program

► Objective

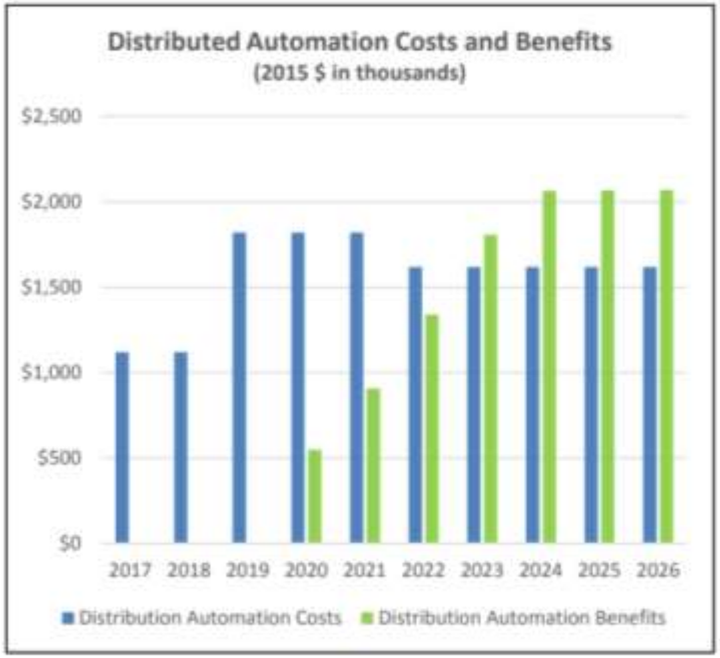
- Create communication layer of the Enabling Platform to support advanced metering functionality and distribution automation
- Automate and optimize voltage and reactive power equipment to implement CVR and respond to changes in DER output

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



- 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

Unitil, EDIIP, 8/1/15

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

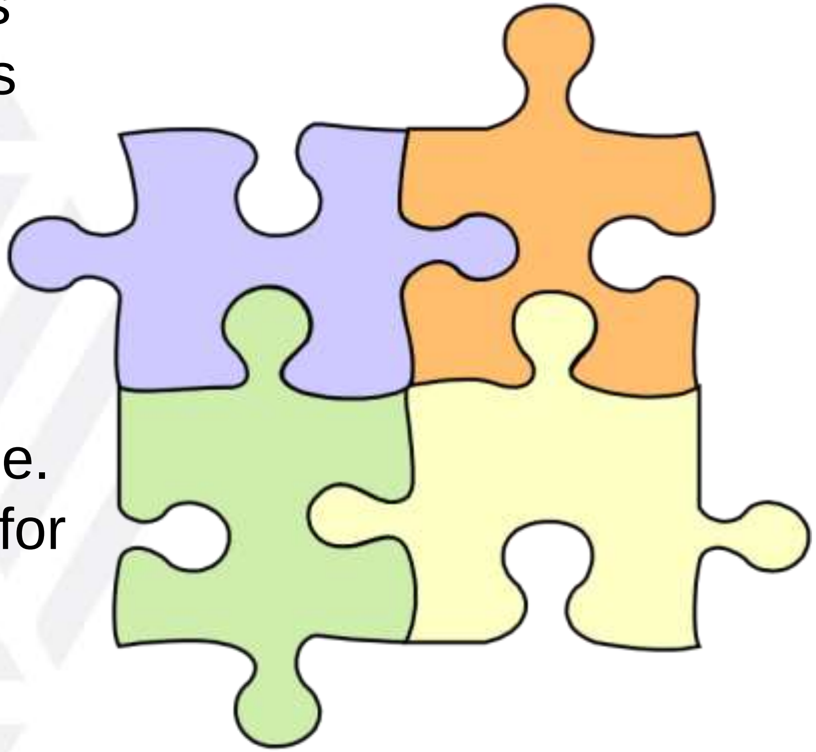
- PUC order requires advanced metering functionality (AMF) and optional TVR
- Upgrading all meters was not a good solution:

  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

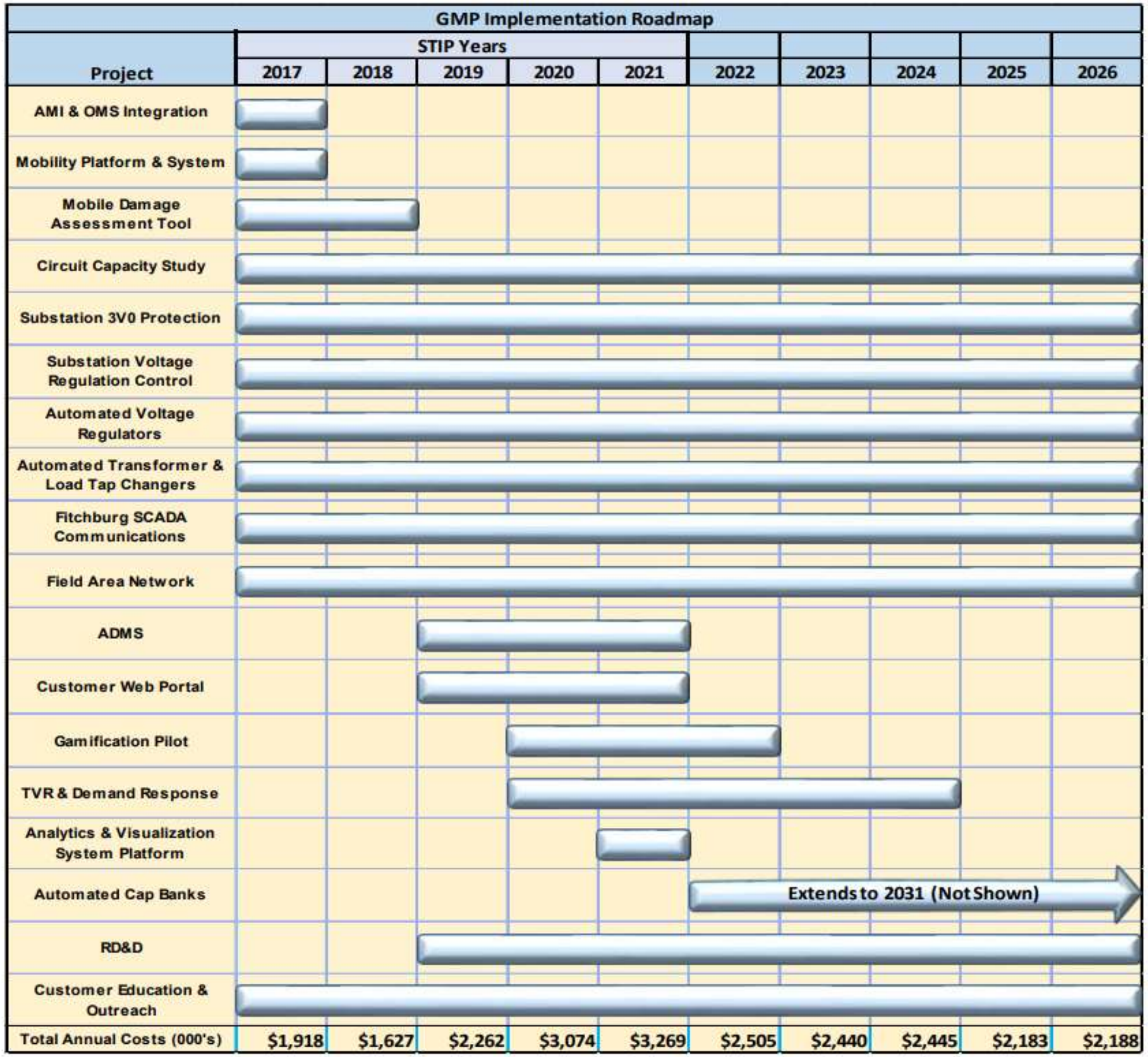
- Build on existing advanced metering infrastructure (AMI) that provides some advanced metering functionality.
- Use new communications network to enable AMF
- Offer optional TVR rate

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



Unitil, EDIIP, 8/1/15

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

Unitil, EDIIP, 8/1/15

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

Plans for High DER Penetrations:

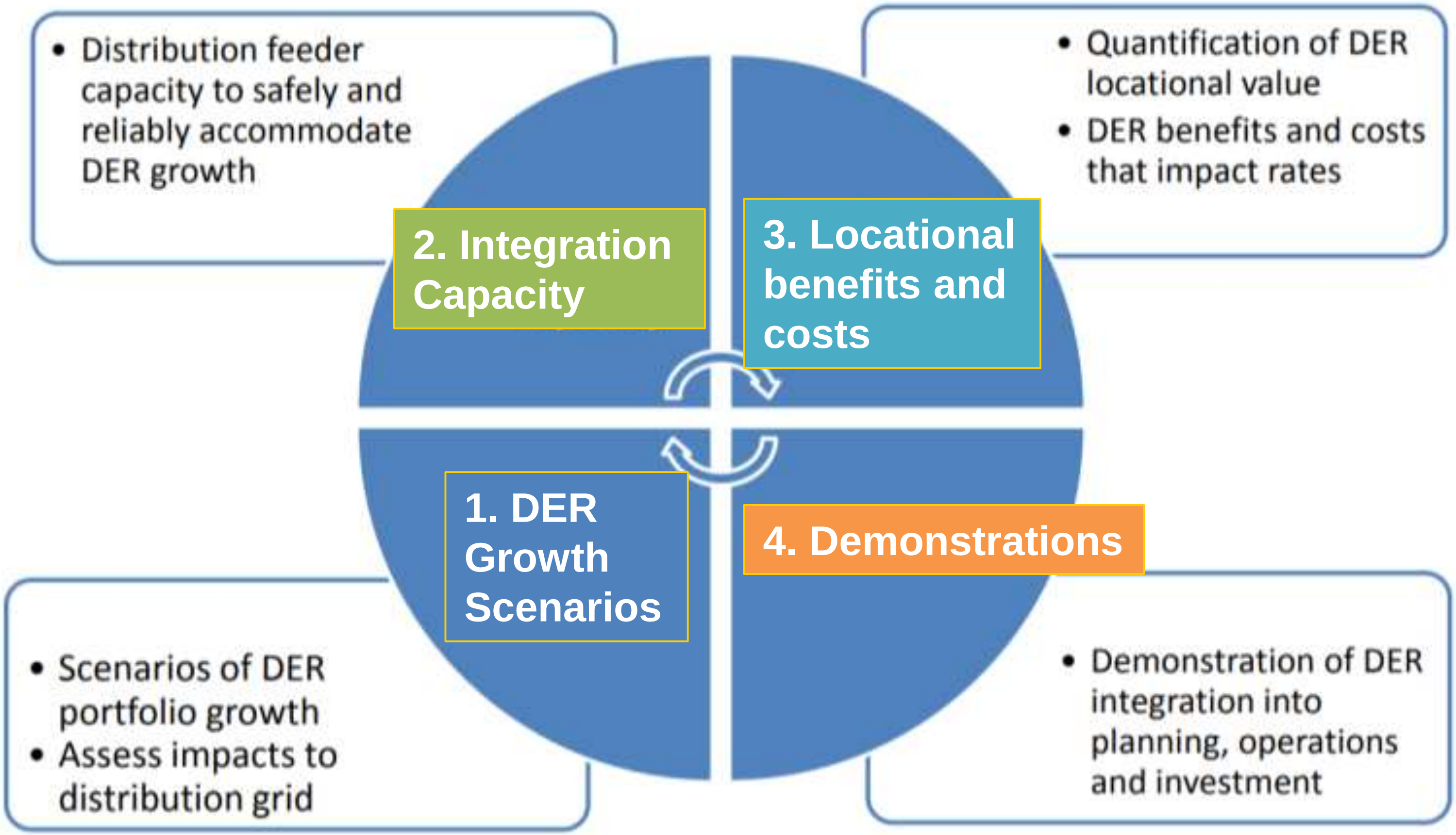
With Examples from PG&E's Distribution Resources Plan

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

PG&E, DRP Webinar, 2015

PG&E's Distribution Resources Plan 2015



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”**

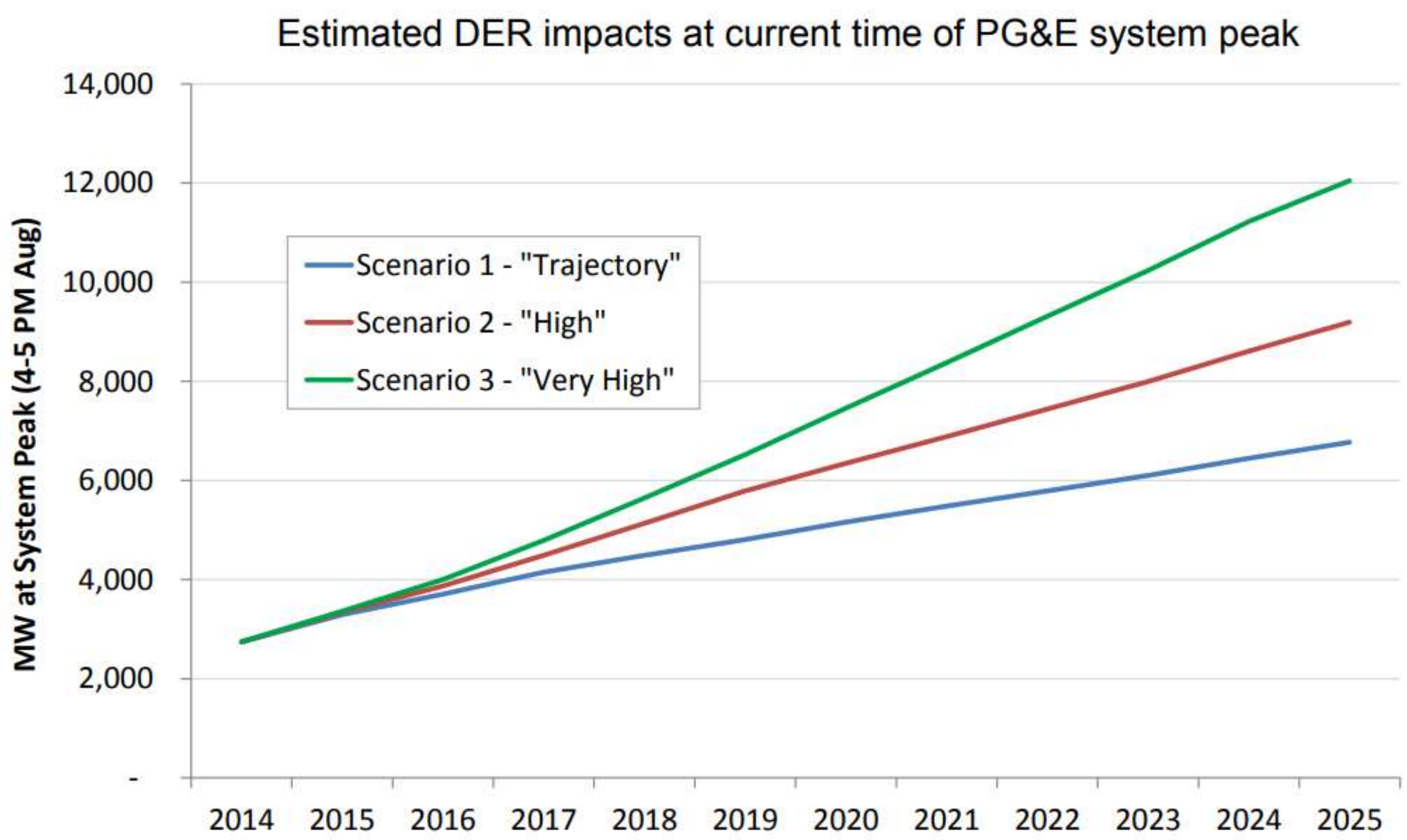
  Reflects ambitious levels of DER deployment that are possible with increased policy interventions and/or technology/market innovations

- **Scenario 3 – “Very High Growth”**

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

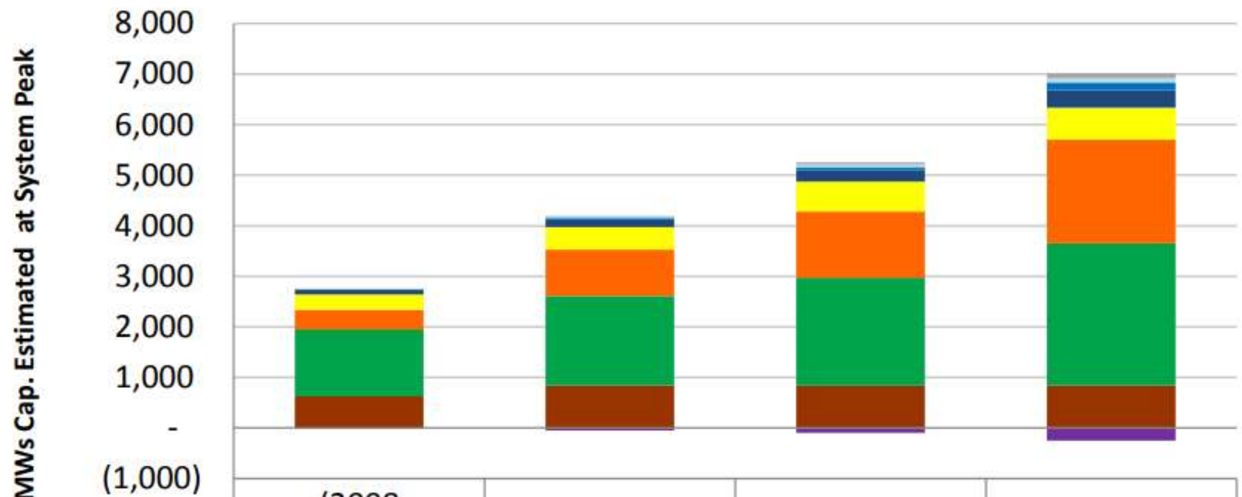
PG&E, DRP Webinar, 2015

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

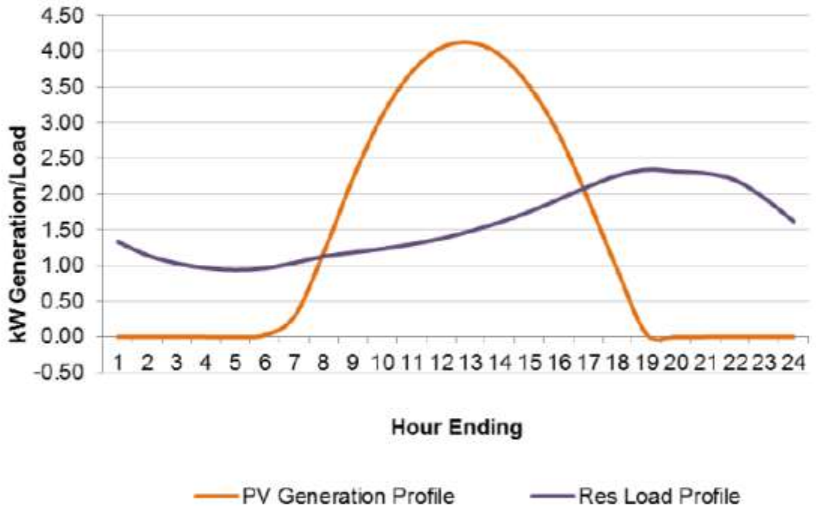


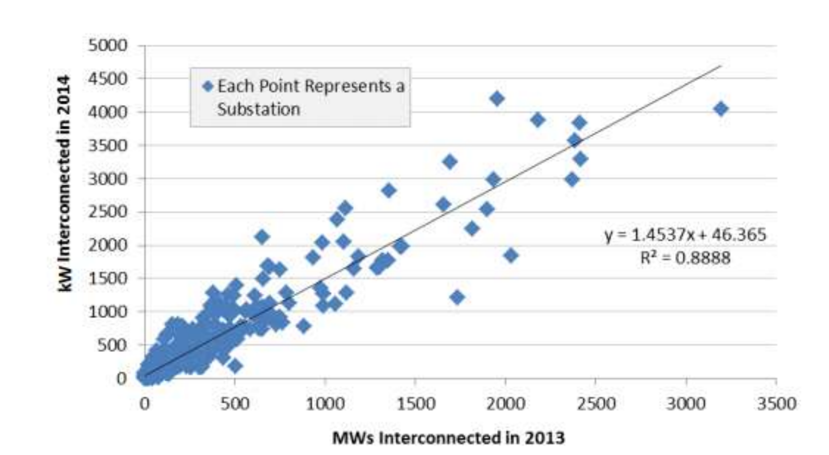
FIGURE 2-28: TYPICAL RESIDENTIAL LOAD PROFILE AND SOLAR GENERATION PROFILE ON AN AUGUST DAY

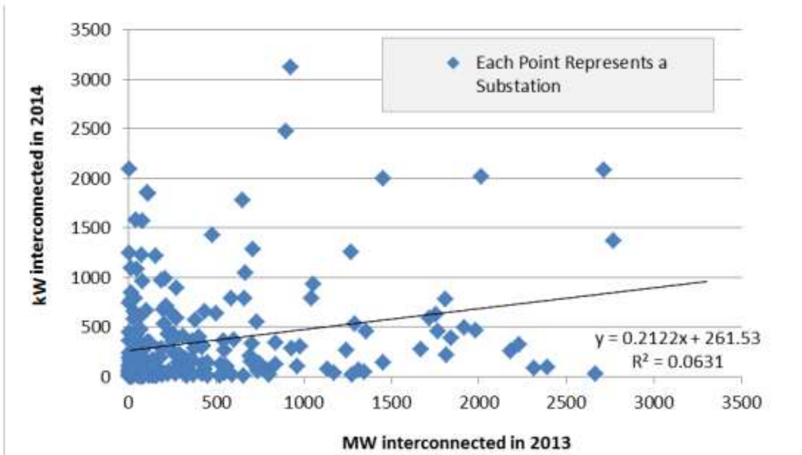
- Deployment is currently optimized on customer economics, not utility cost drivers

PG&E, DRP Webinar, 2015

Other findings from growth scenarios

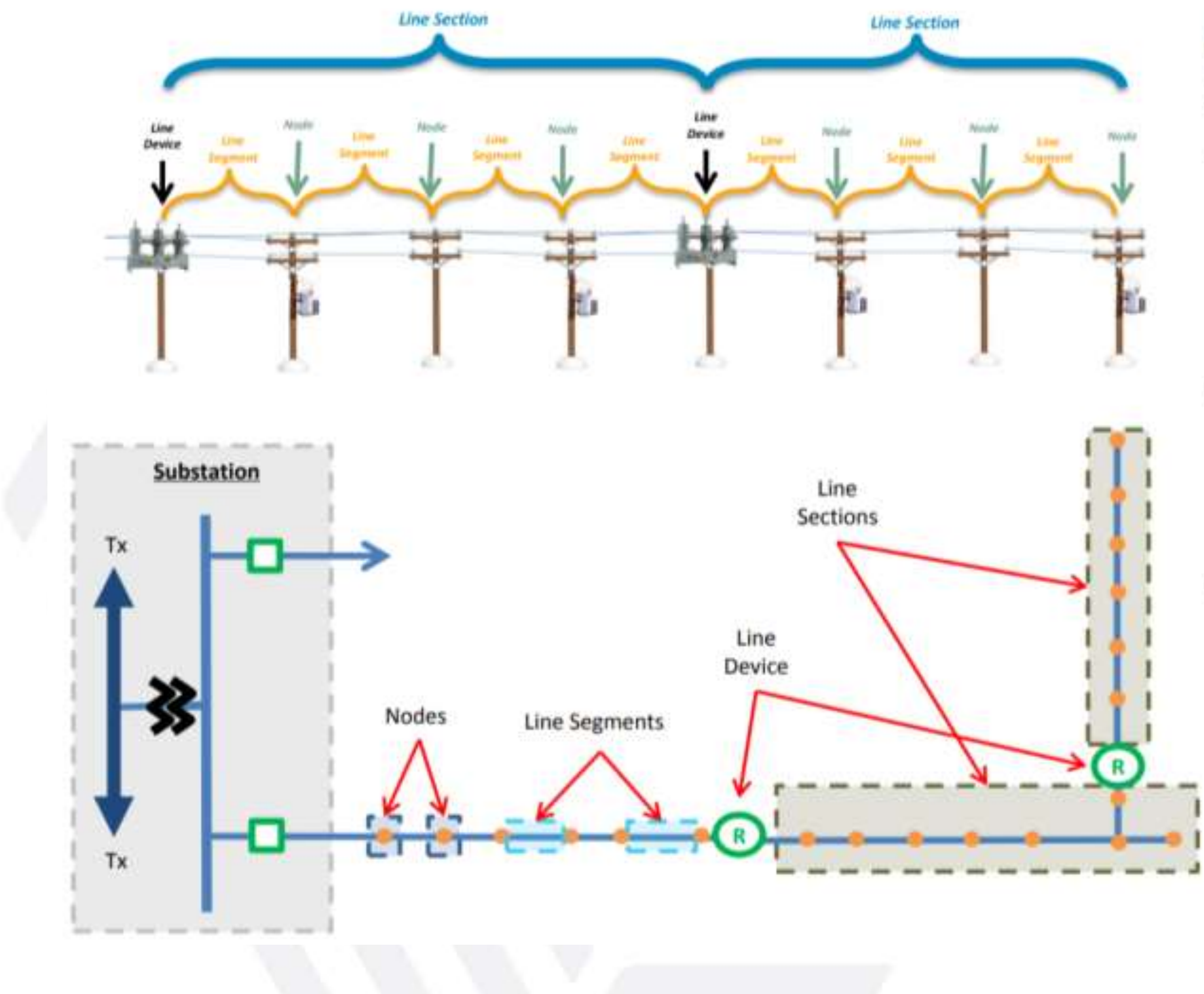
- ► DERs likely to cluster
- ► To estimate DERs, we need to understand load and adoption patterns
- ► Past behavior may not be indicative of future behavior





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?

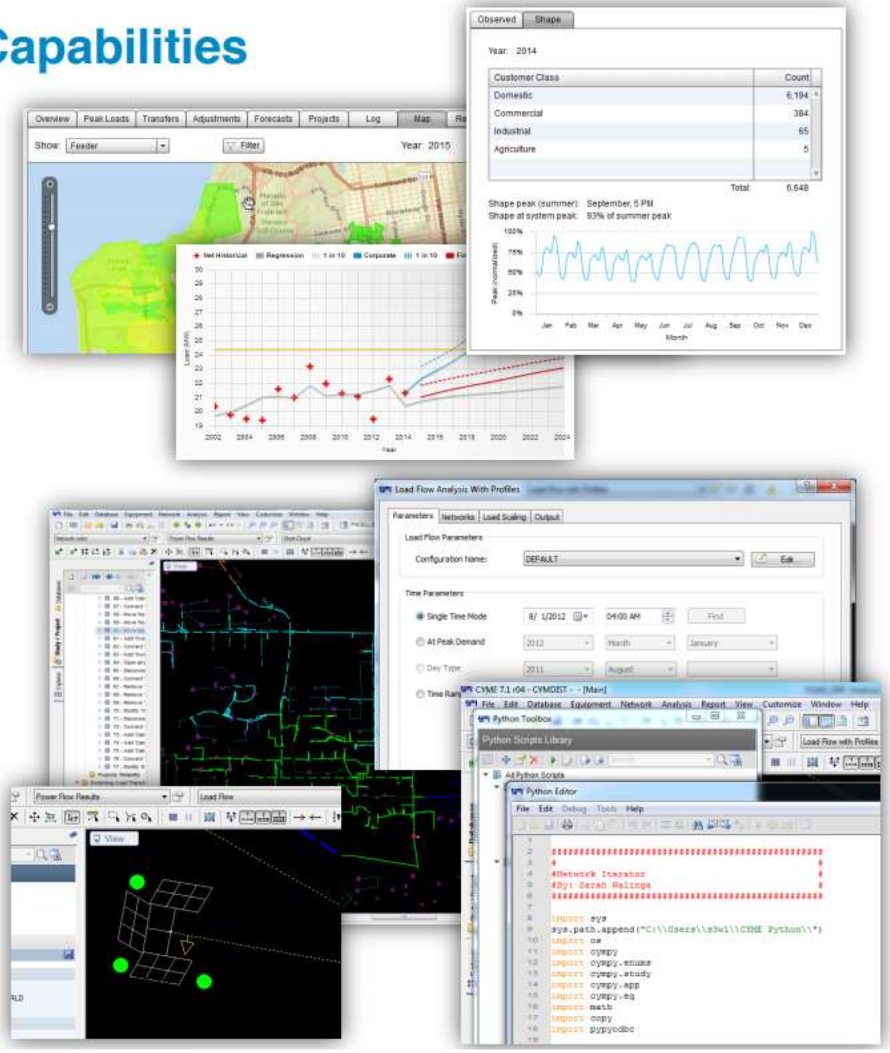
Advanced Planning Tools Capabilities

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

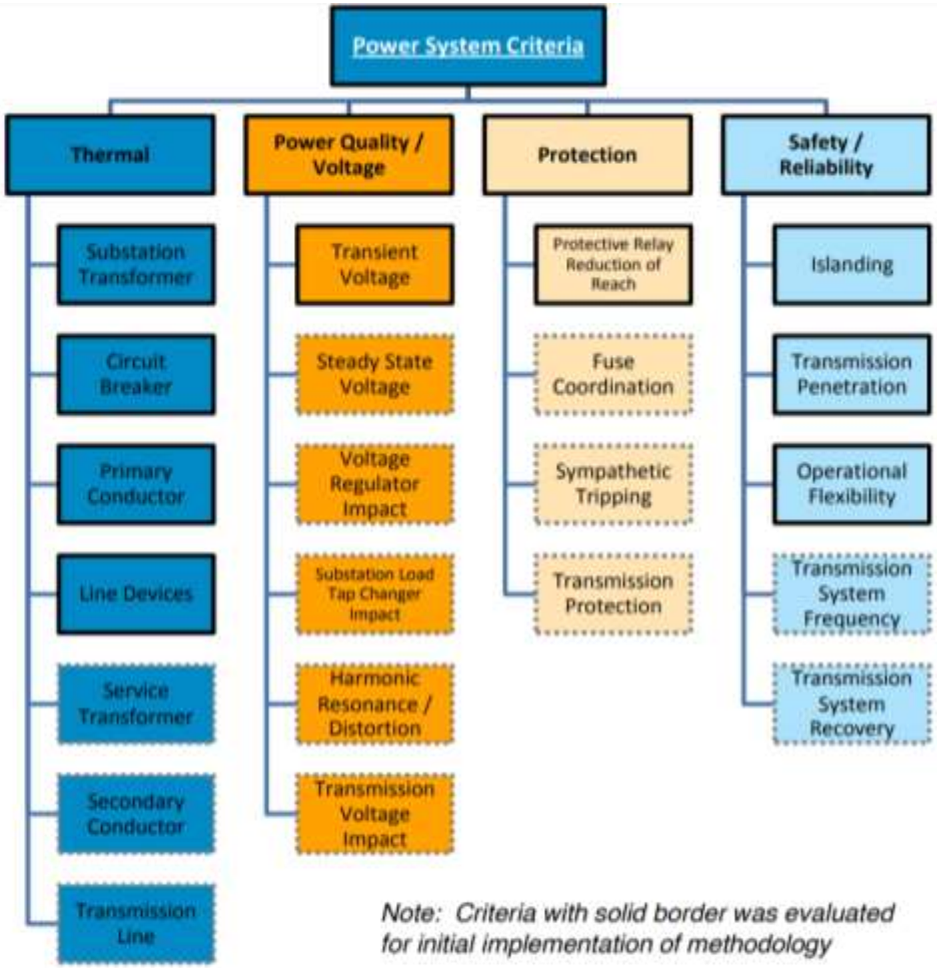


PG&E, DRP Webinar, 2015

Which power system criteria did PG&E evaluate?

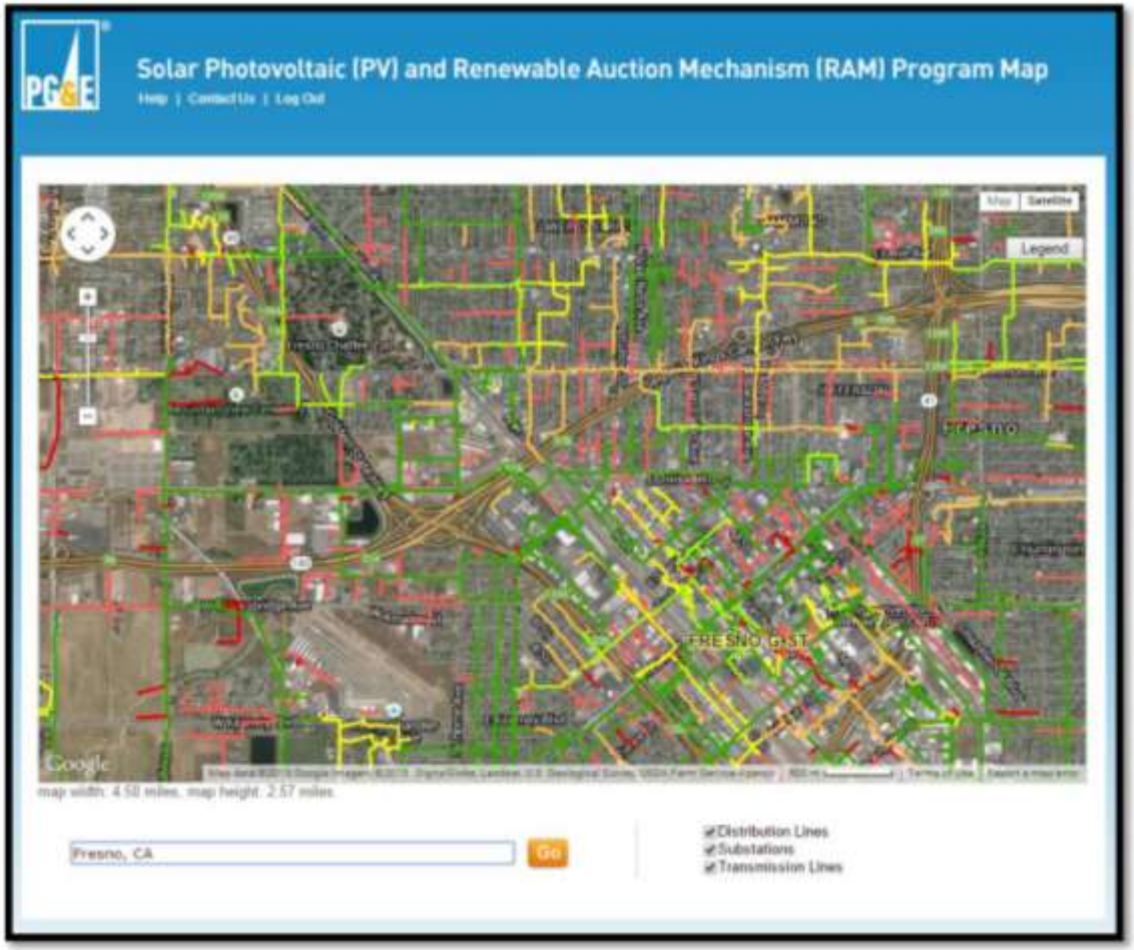
Various aspects of the power system must be analyzed to determine possible impacts

- 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



PG&E, DRP Webinar, 2015

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

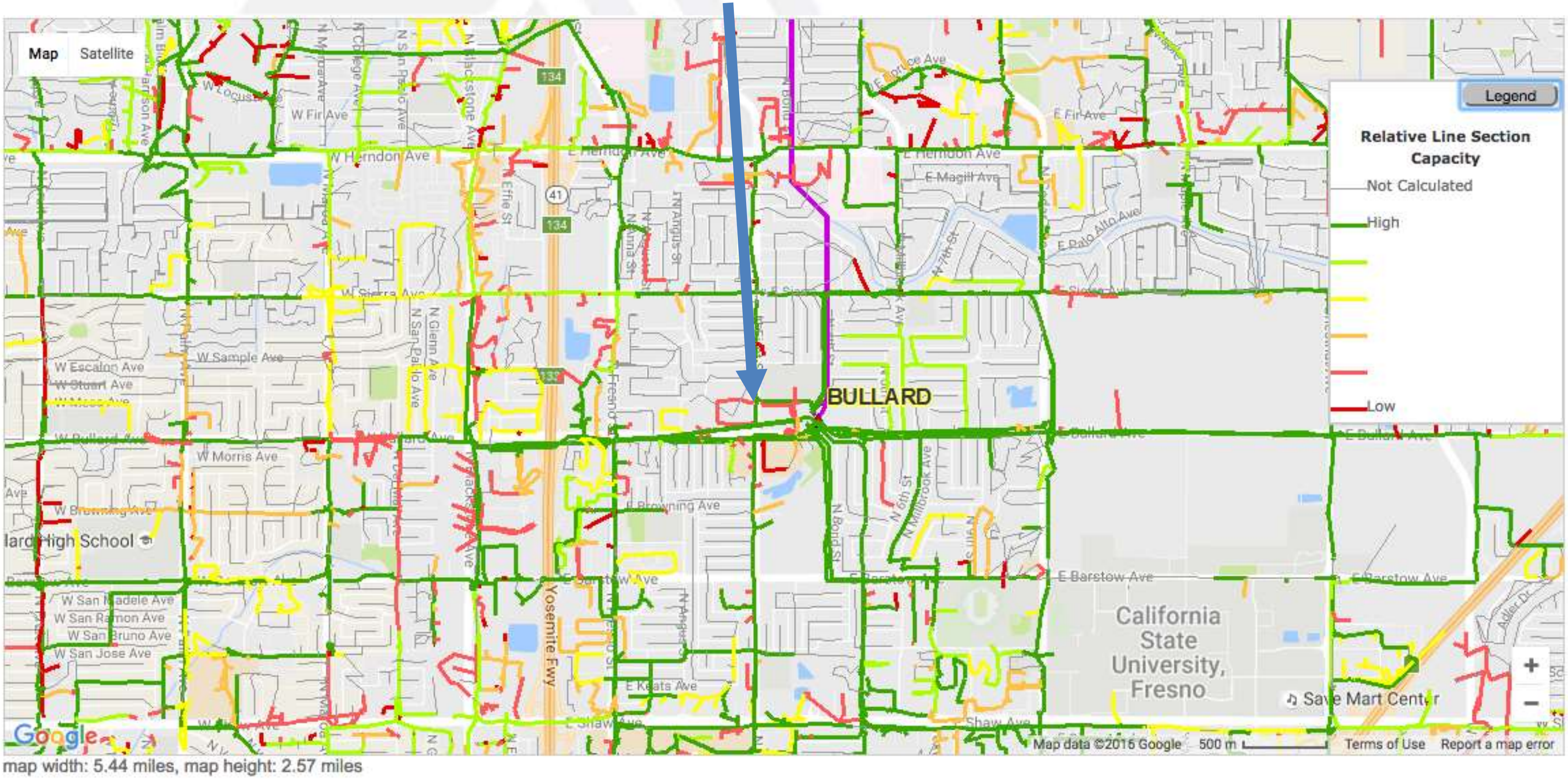


PG&E analyzed all three phase line sections for all the 3,000+ distribution circuits

- 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*

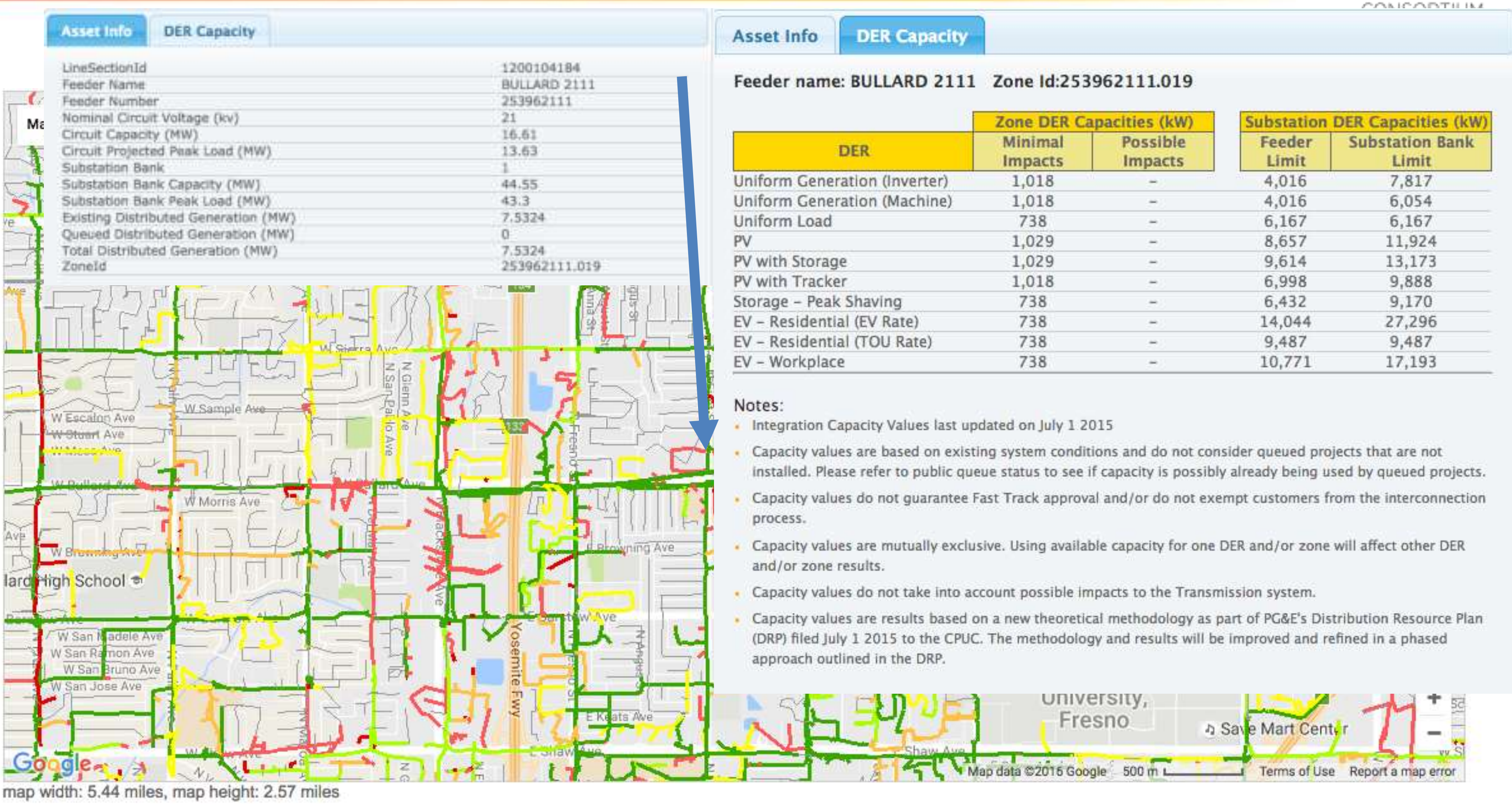
PG&E, DRP Webinar, 2015

PG&E map of hosting capacity



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

DER	Zone DER Capacities (kW)		Substation DER Capacities (kW)	
	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:

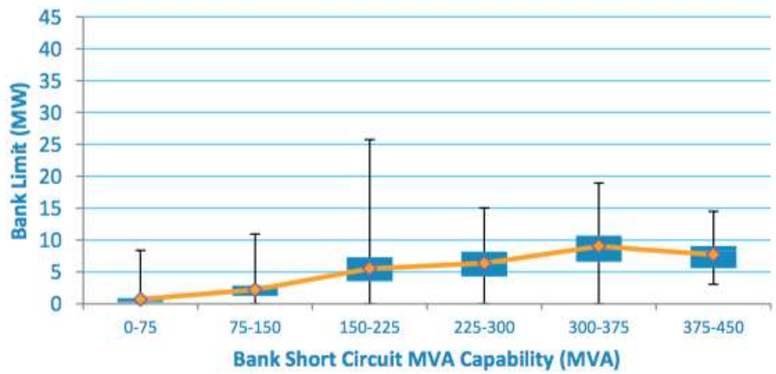
- Integration Capacity Values last updated on July 1 2015
- Capacity values are based on existing system conditions and do not consider queued projects that are not installed. Please refer to public queue status to see if capacity is possibly already being used by queued projects.
- Capacity values do 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.

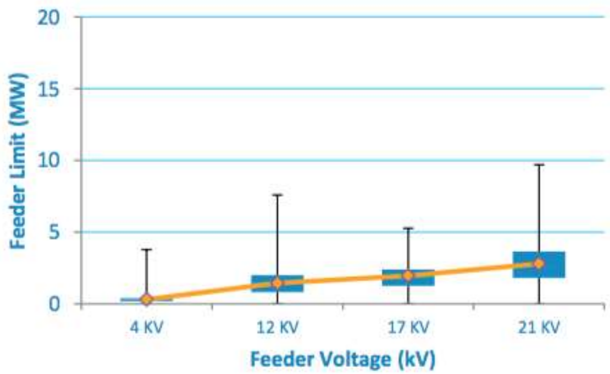
map width: 5.44 miles, map height: 2.57 miles

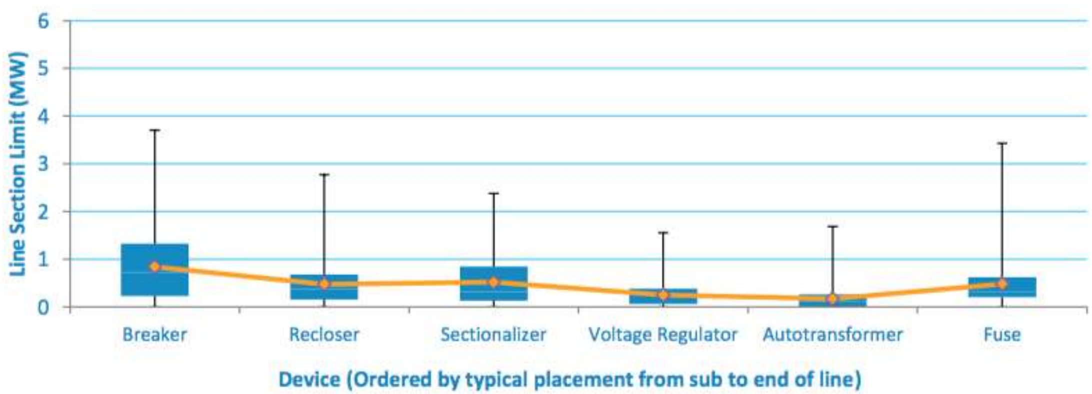
From PG&E DRP Web Tool, 2016

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





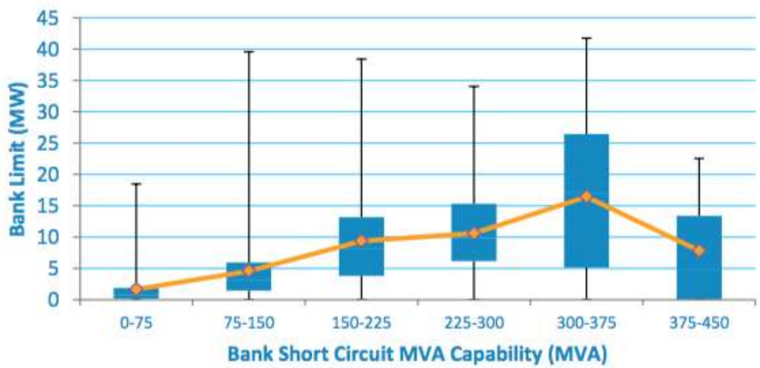


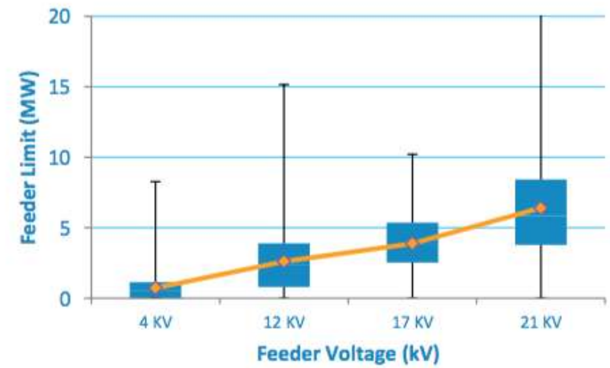
NOTE: Results based on July 1 2015 ICA data

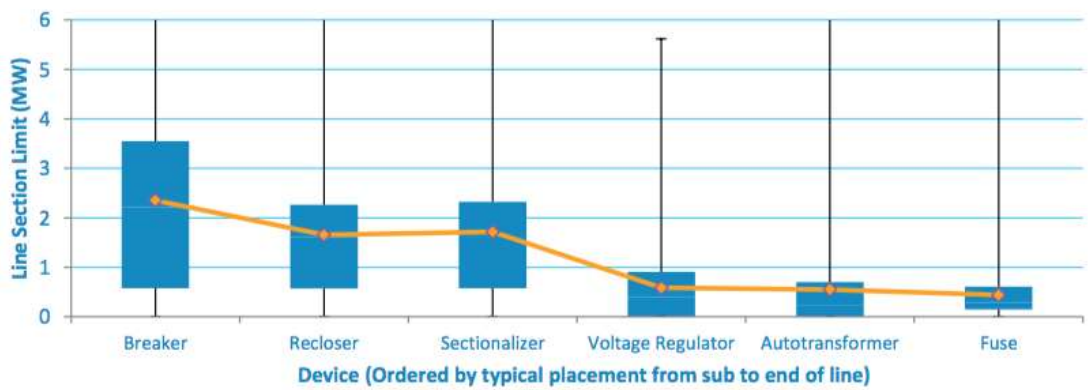
PG&E, DRP Webinar, 2015

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

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U.S. Department of Energy

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)

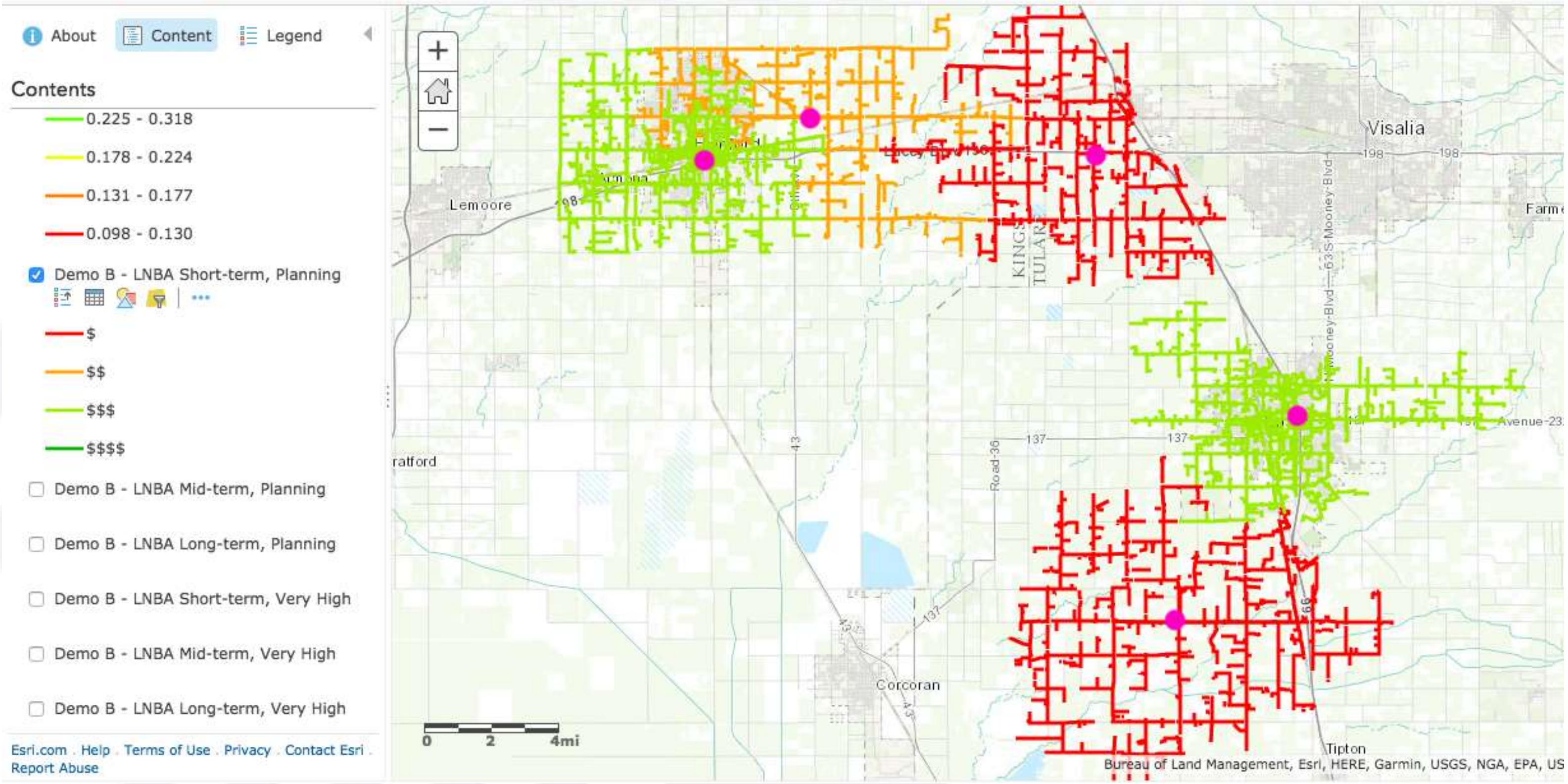
Determining DERs' Impact: Distribution engineering tools are used to determine DERs' ability to meet criteria for
- Right Time (Coincides with a deficiency that requires investments)
- Right Availability (Performs in hours that coincide with deficiency)
- Right Location (Can be connected at a location 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



Medium cost project

About | Content | Legend

Contents

2025 DER Coincident Peak (MW)

- 0.319 - 0.590
- 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

- $
- $$

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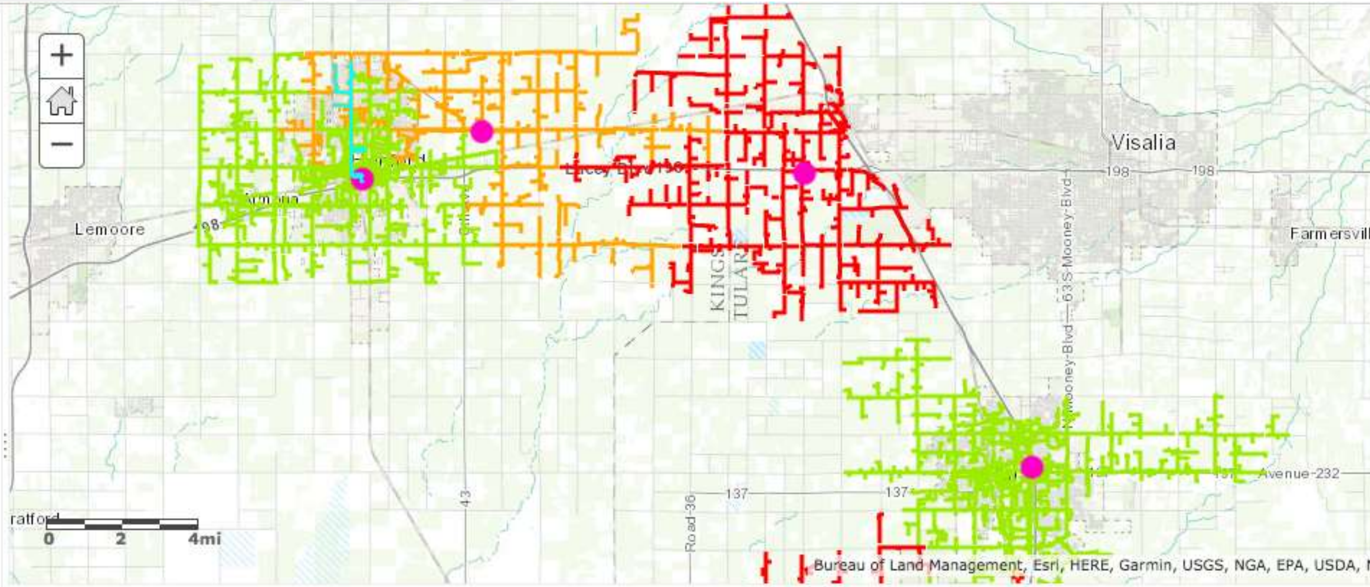


Demo B - LNBA Short-term, Planning (Features: 90, Selected: 1)

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.			
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)

A, B, C: **Central Fresno DPA**

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

D: **Gates DPA**

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

E: **Angel Island**

Analysis and Methodology Demonstration

Deployment of DERs Field Demonstration

Example demonstration pilot projects

Demonstration Pilots A, B and C

Proposed Area of Demonstration: Central Fresno DPA

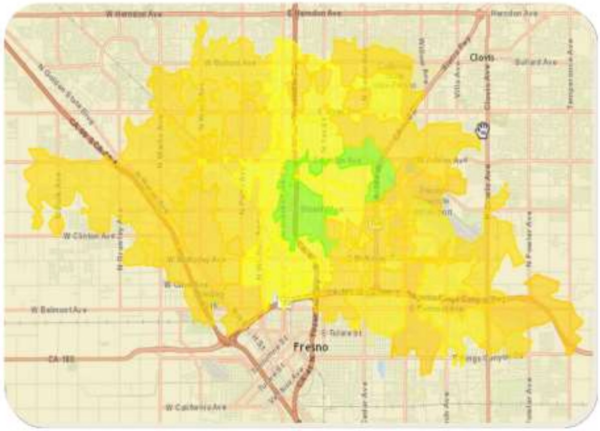
Scope of Pilots:

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

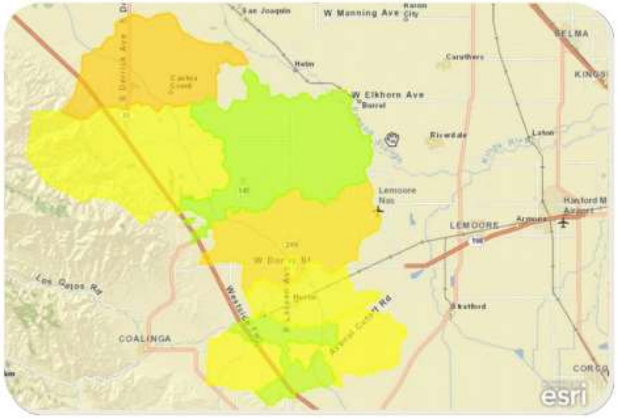
Proposed Area of Demonstration: Gates DPA

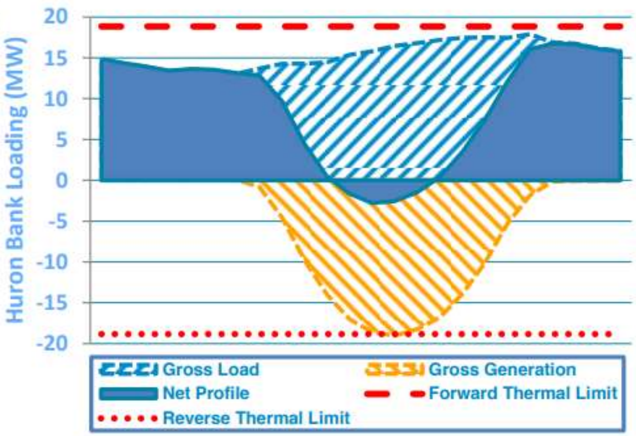
Scope of Pilot:

- 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.





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 Lavelle Freeman at
518-385-3335
Lavelle.freeman@ge.com
and Debbie Lew at
debra.lew@ge.com
303-819-3470

Additional Slides

Challenges to the Distribution Mission

- ► Increased performance pressures
  - Customer satisfaction, reliability, resiliency, sustainability, power quality, consumer engagement, energy efficiency, asset utilization

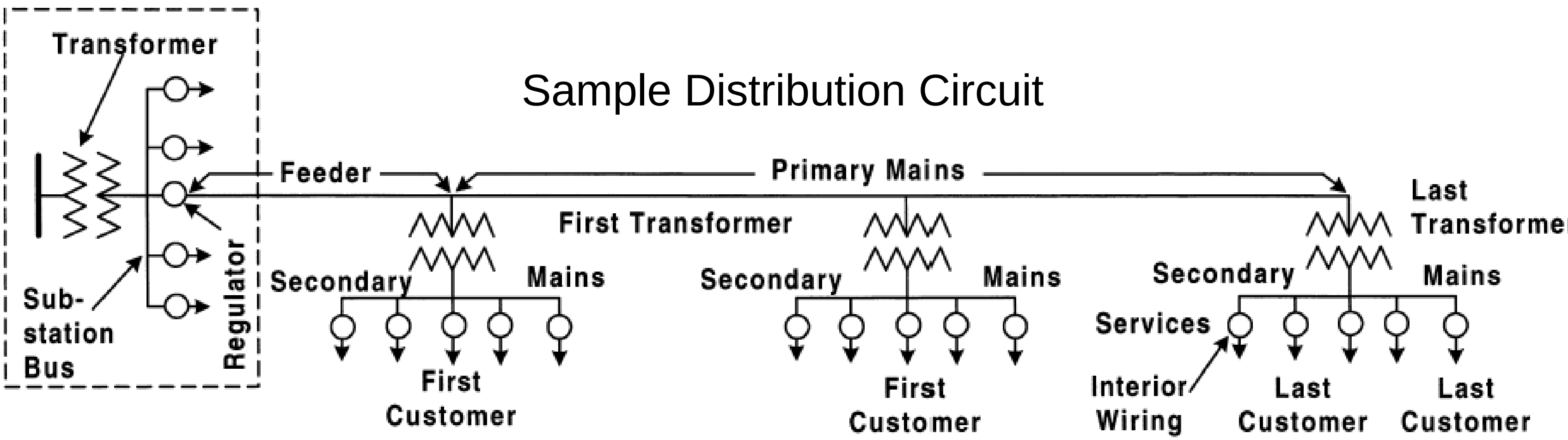
- ► Cost escalation and regulatory uncertainty
  - Cost recovery, rate freeze, risk of bypass, stranded assets, market fluctuations, mergers & acquisitions, new business models, disruptive technologies

- ► Aging infrastructure
  - Majority of T&D assets approaching end of useful life
  - Lack of visibility for UG/Network assets

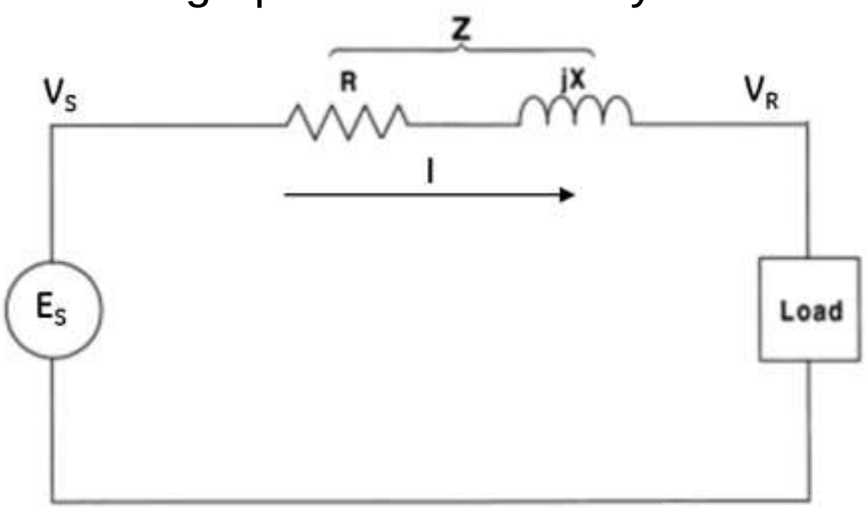
- ► Aging workforce and shrinking talent pool
  - 50% of engineers eligible for retirement in 5 years
  - 99% drop in power engineer graduation rate over last 20 years

Voltage Regulation

Sample Distribution Circuit



Singe-phase circuit Analysis



$$\overline{V}_S = \overline{V}_R + \overline{I}\,\overline{Z}$$

$$\text{Voltage Drop (VD)} \equiv |\overline{V}_s| - |\overline{V}_r|$$

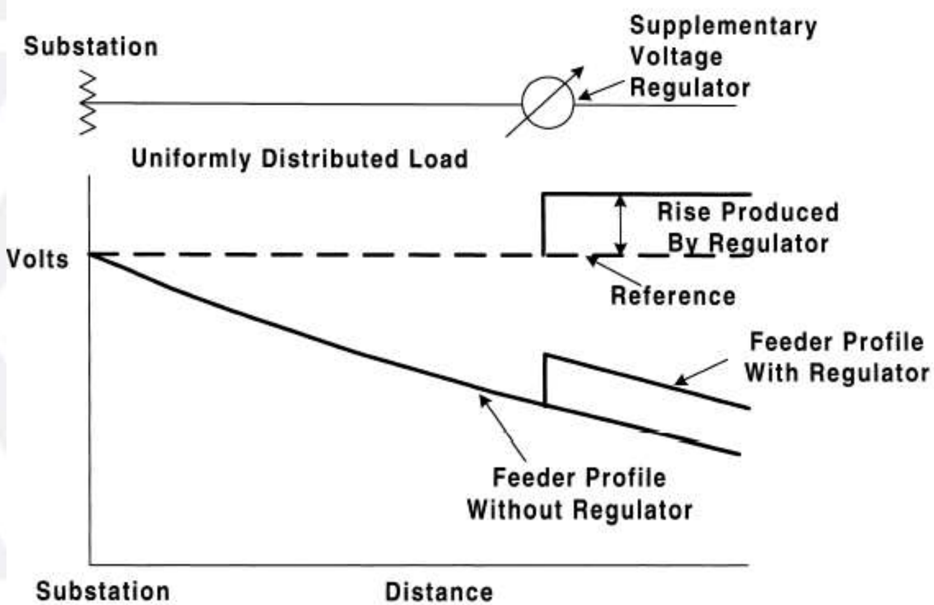
% Voltage Regulation

$$= \frac{\text{Voltage Drop, Line - Neutral}}{\text{Voltage at Receiving End, Line - Neutral}} \times 100\%$$

Improving Voltage Regulation

- **Voltage regulators**
- **Capacitors**
- Substation load tap changer (LTC)
- Substation capacitors
- Load balancing
- Reconductoring
- Re-phasing (single-phase to multi-phase)
- Load transfers
- Voltage upgrades
- New substations and feeders

General Application of line voltage regulators



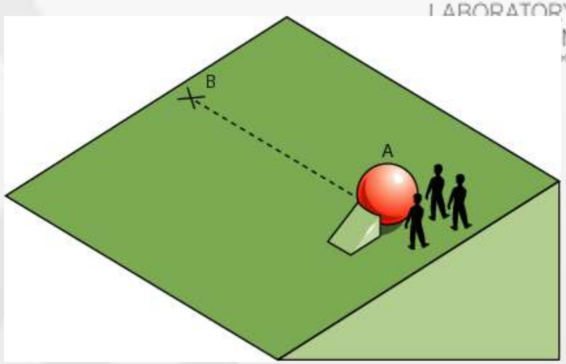
Real and Reactive Power - Inclined Plane Analogy

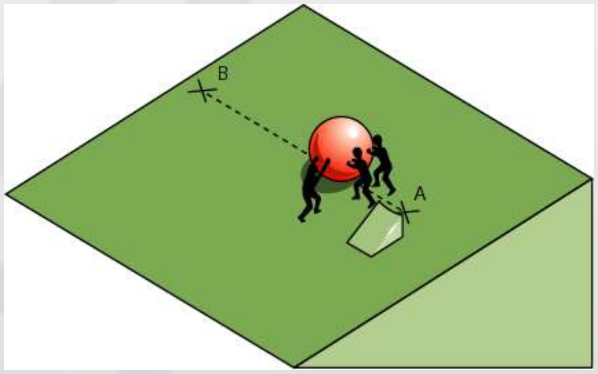
- Suppose men have to push a large ball from one side of an inclined plane to another (A to B)

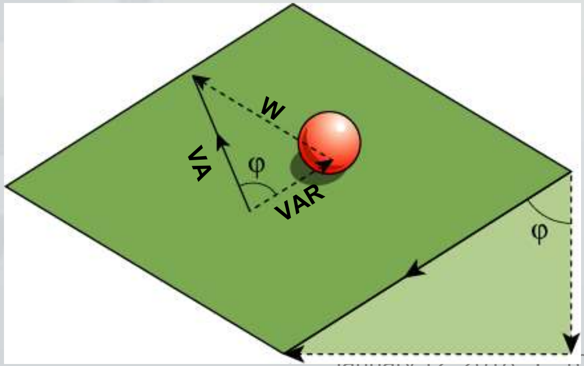
- The active power needed is the same as if the plane
  were flat, i.e. 2 men, but an extra man is needed to keep the ball up on its path.

- Consequences:
  - A loss of capacity (3rd man cannot be used for pushing)
  - Extra friction losses (since this man will have to touch the ball)

- Vector representation of ball movement:
  - The real power (W) to move the ball from A to B, requires a finite amount of reactive power (VAR) to accomplish the task.







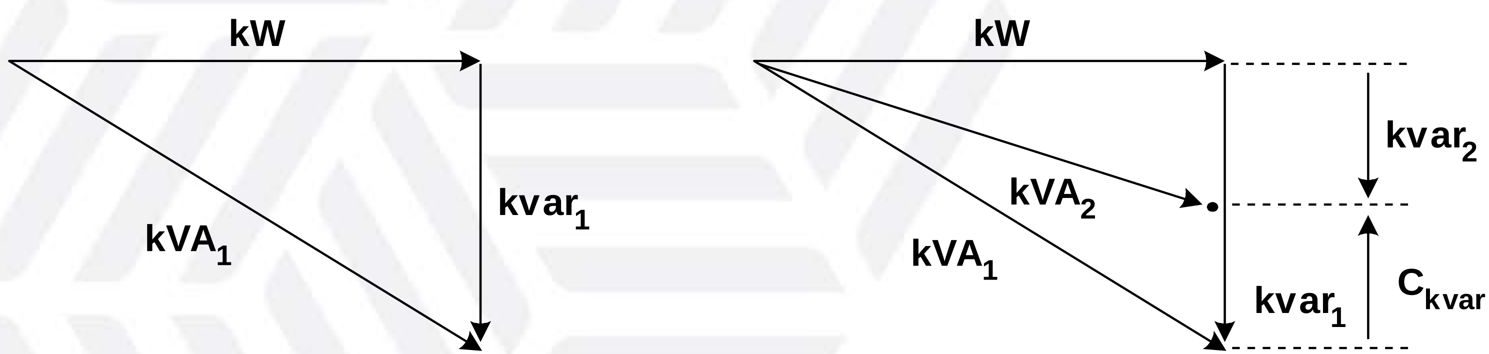
P Sauer, What is Reactive Power, PSERC, Sep 2003

General Application of Capacitors

- Power system loads Require kW and kVAr
  - kW supplied by generation.
  - kVAr can be supplied by generation, but this is not cost-effective
  - Capacitors can be used to supply kVAr

kVA line flows are phasor sum of kW, kVAr

Adding capacitors reduces net kVAr, kVA



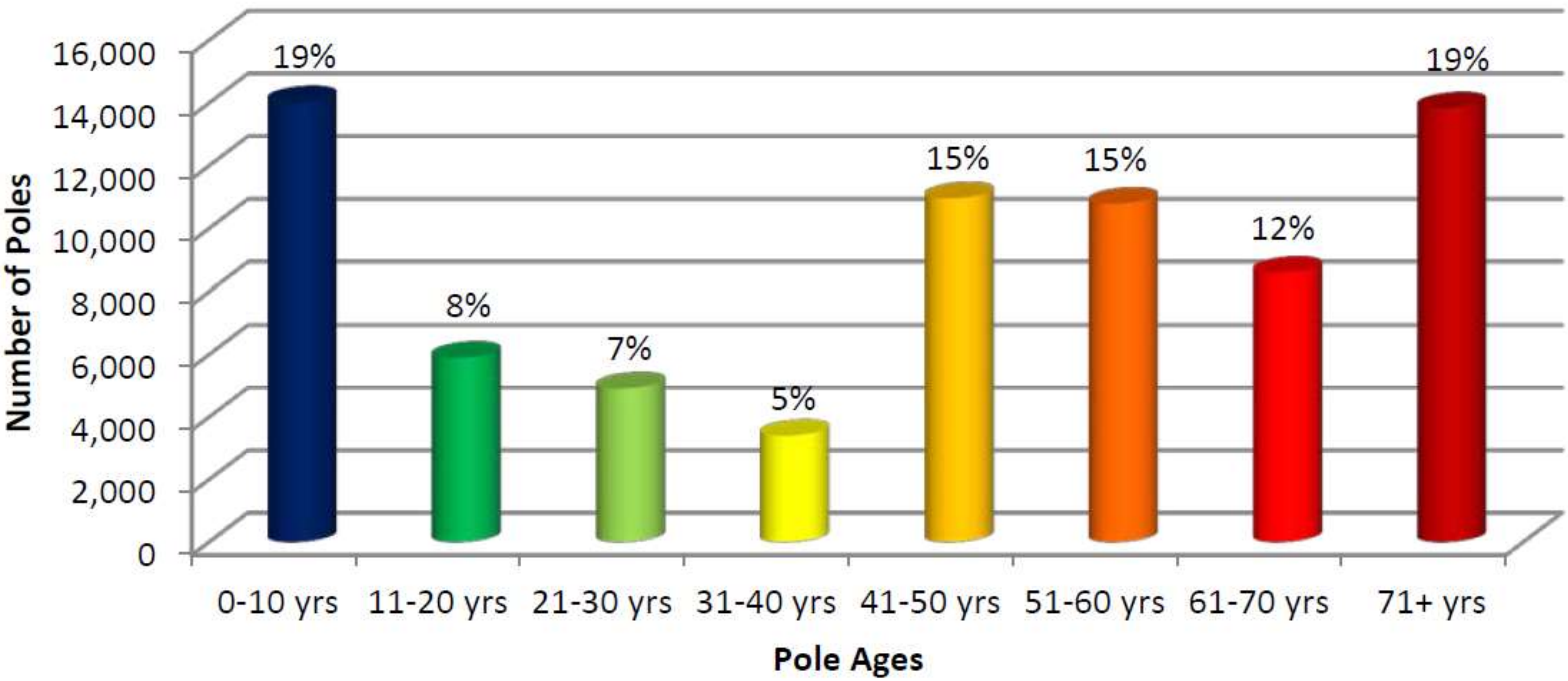
Reduced kVA flow => reduced magnitude of current flow on feeder

Benefits of Capacitor Application

- ► Why Use Feeder Capacitors?
  1. Improve voltage profile
  2. Demand reduction
  3. Loss reduction

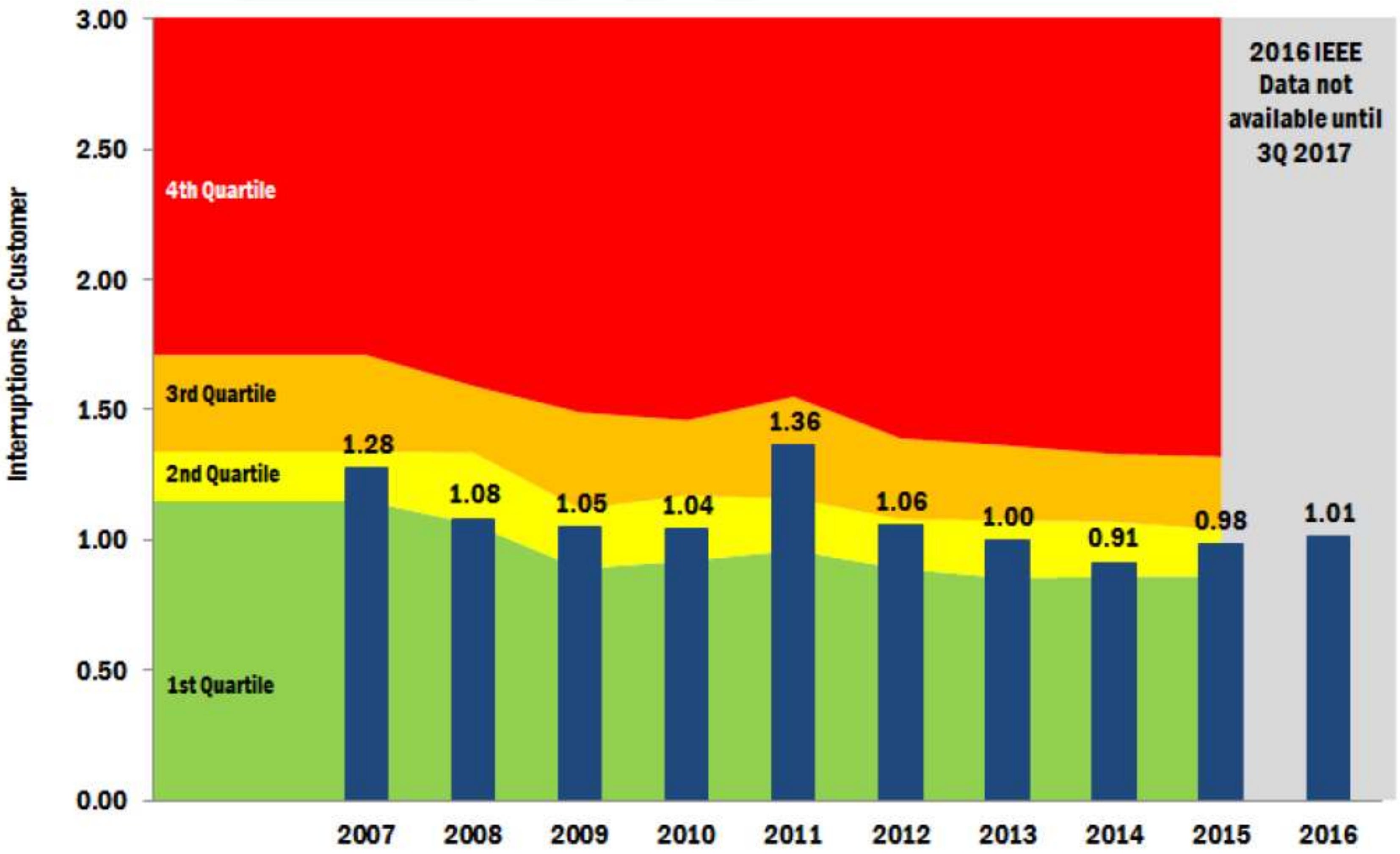
- ► Impact on upstream system
  - Released capacity
  - Increase power factor of generators
  - Reduced MVA where power is supplied
  - Possible deferment of G,T, and/or D
  - Reduced system investment per MW of load supplied

HVD wood pole ages



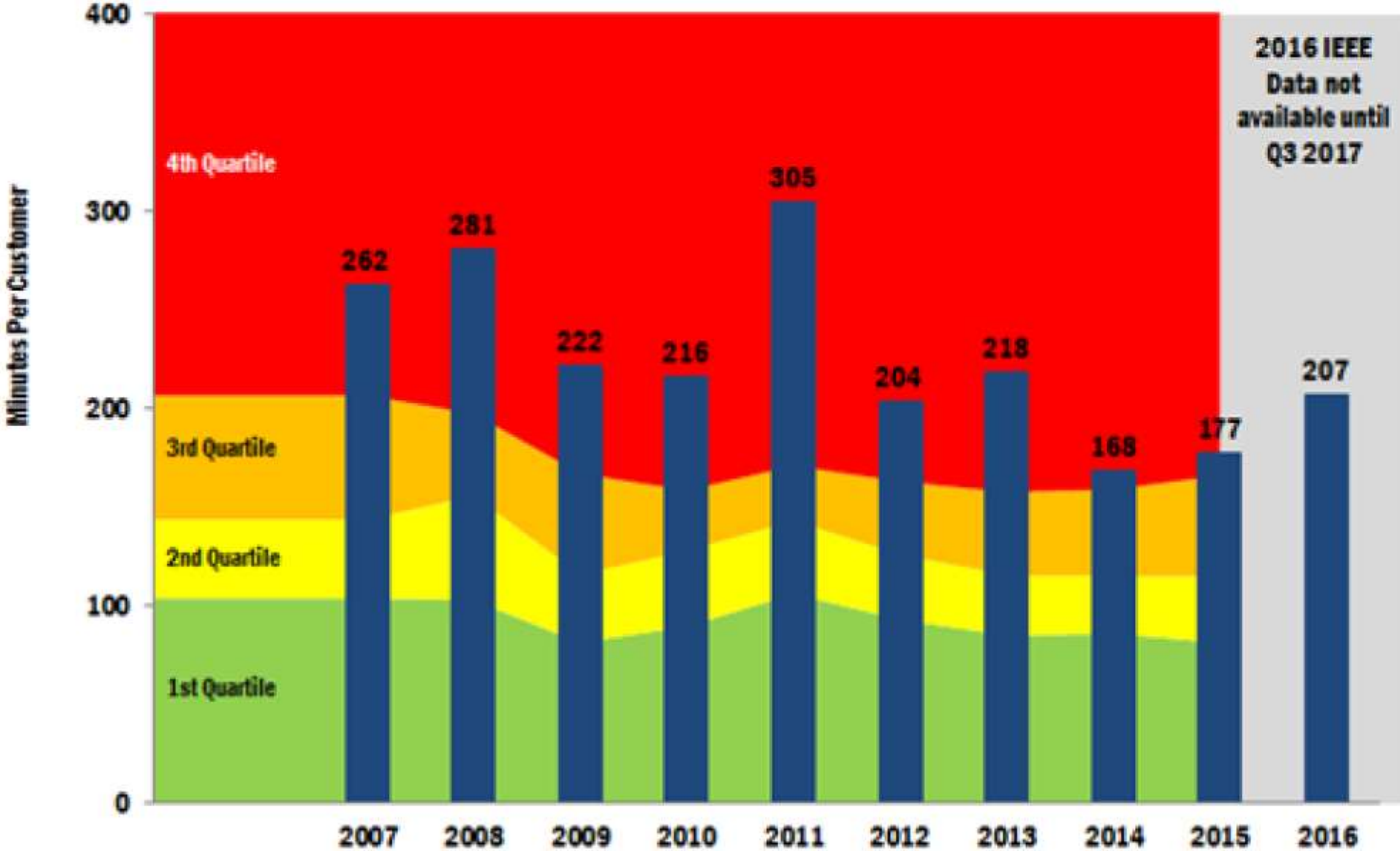
More than 70,000 HVD wood poles, approximately 30%, are older than the expected life of sixty years

Historical reliability performance - SAIFI



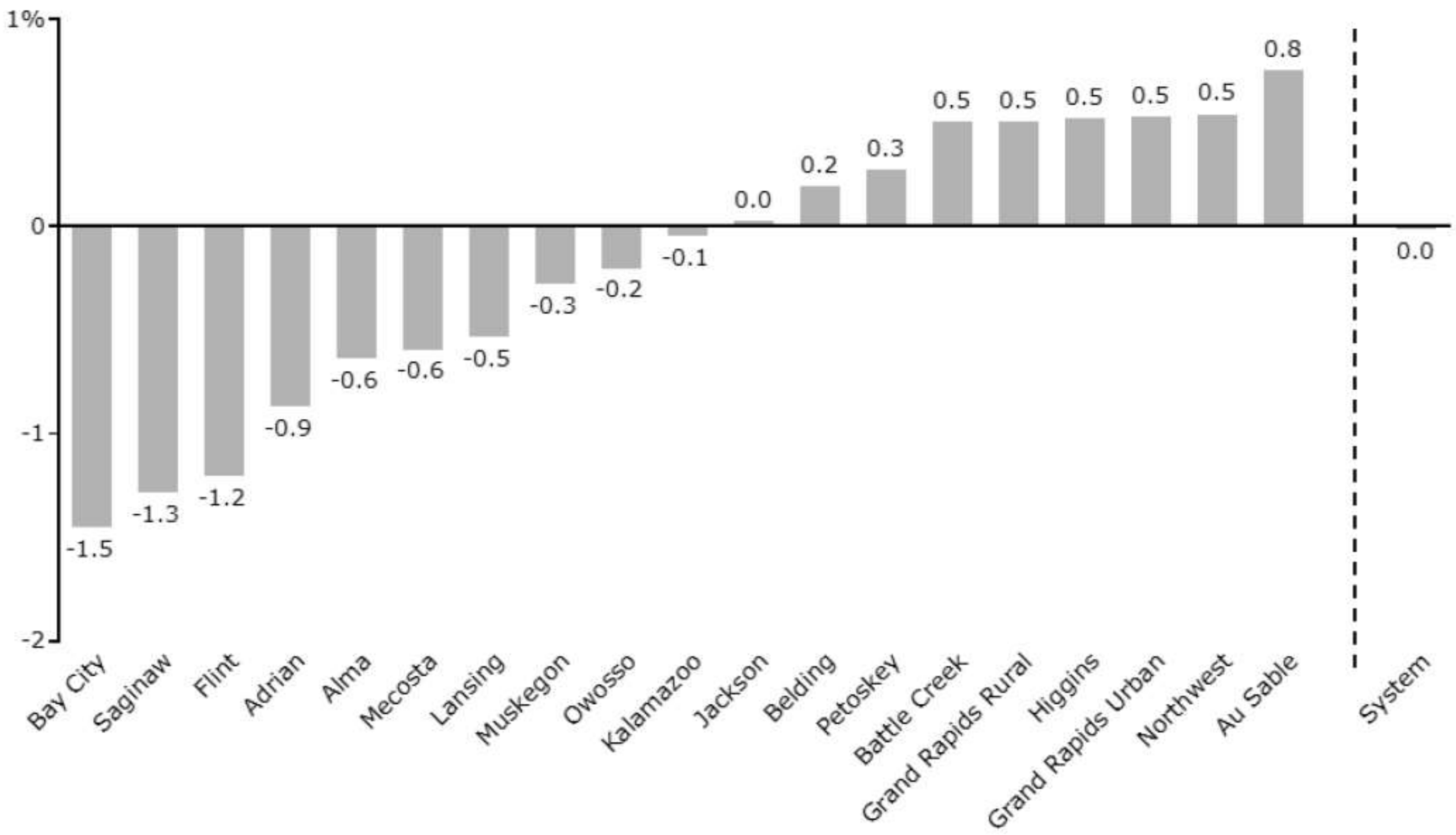
SAIFI: COMPARISON OF CONSUMERS ENERGY TO IEEE RELIABILITY SURVEY (2007 - 2016)

Historical reliability performance - SAIDI



SAIDI: COMPARISON OF CONSUMERS ENERGY TO IEEE RELIABILITY SURVEY (2007 - 2016)

Projected Load Forecast by HVD Planning Area



Note: Does not include Midland

Analysis Tools and Data

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U.S. Department of Energy

- Voltage drop analysis
- Short circuit analysis
- Harmonic analysis
- Load growth analysis
- Motor start analysis

Dynamic analysis

Dynamic data for DGs
Control settings for equipment
Dynamic data for load

Reliability analysis

Failure rate
Repair time
System connectivity

Protection coordination analysis

Network model
Device configuration

Load flow analysis

Basis for most distribution planning analysis

Network topology
Conductor geometry
Electrical parameters
Equipment capacity
Equipment settings
Load data

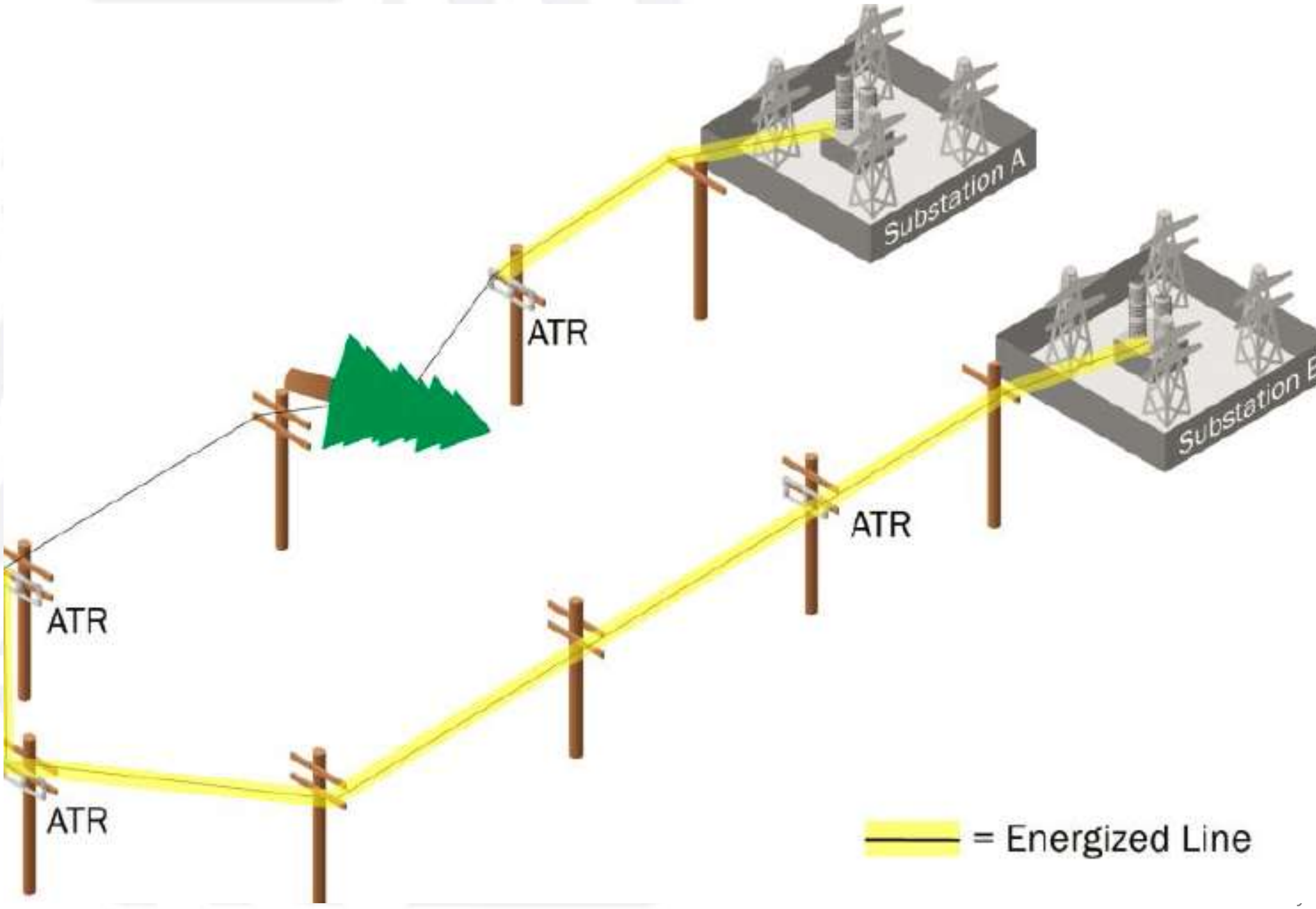
Build the System – Traditional Wires Expenditures

Traditional "Wires" – Capital Expenditures ($K)				
Investment category	2016	2017 YTD (June)	Five Year Estimate (2018-22)	Major investments
New Business	$60,401	$35,898	Final Report	Equipment needed to serve new customers, including lines, transformers, and meters
Capacity – HVD	$20,965	$10,668	Final Report	High voltage lines and substations needed for increased load
Capacity – LVD	$35,780	$17,788	Final Report	Low voltage lines, substations, and transformers needed to meet increased load
Strategic Customers – HVD (Lines)	$27,864	$2,846	Final Report	HVD project to support new business needs for large industrial customers or increased load requirements for these customers.
Total "Wires" CapEx	$145,010	$67,199	Final Report	N/A

"76 areas with capacity or reliability challenges identified that require new investments between 2018 and 2022"

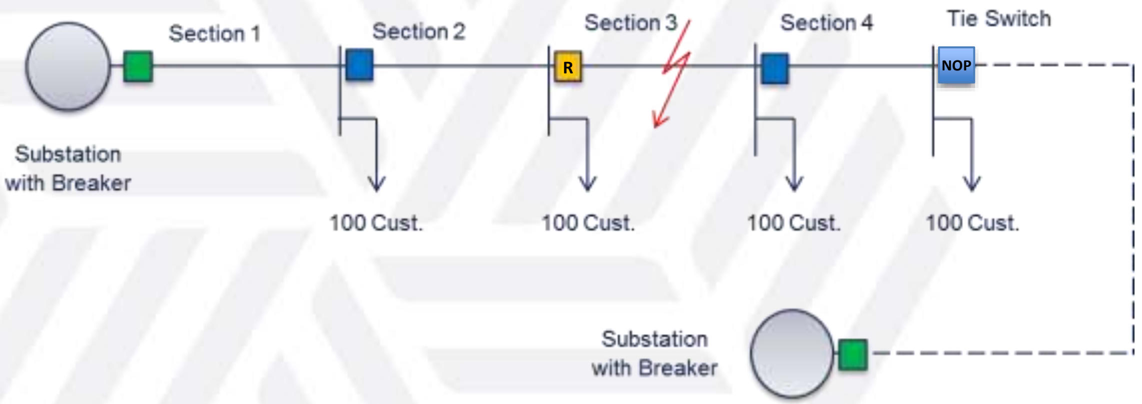
From *Consumers Energy's Electric Distribution Infrastructure Investment Plan (2018-22)*, 8/1/17

Distribution Line Automation - Example



Analytical Simulation Approach

- Develop reliability model capturing system connectivity, failure and response characteristics
  - Simulate faults at various points, and isolation and restoration procedures
  - Aggregate interruptions and outage duration for customers



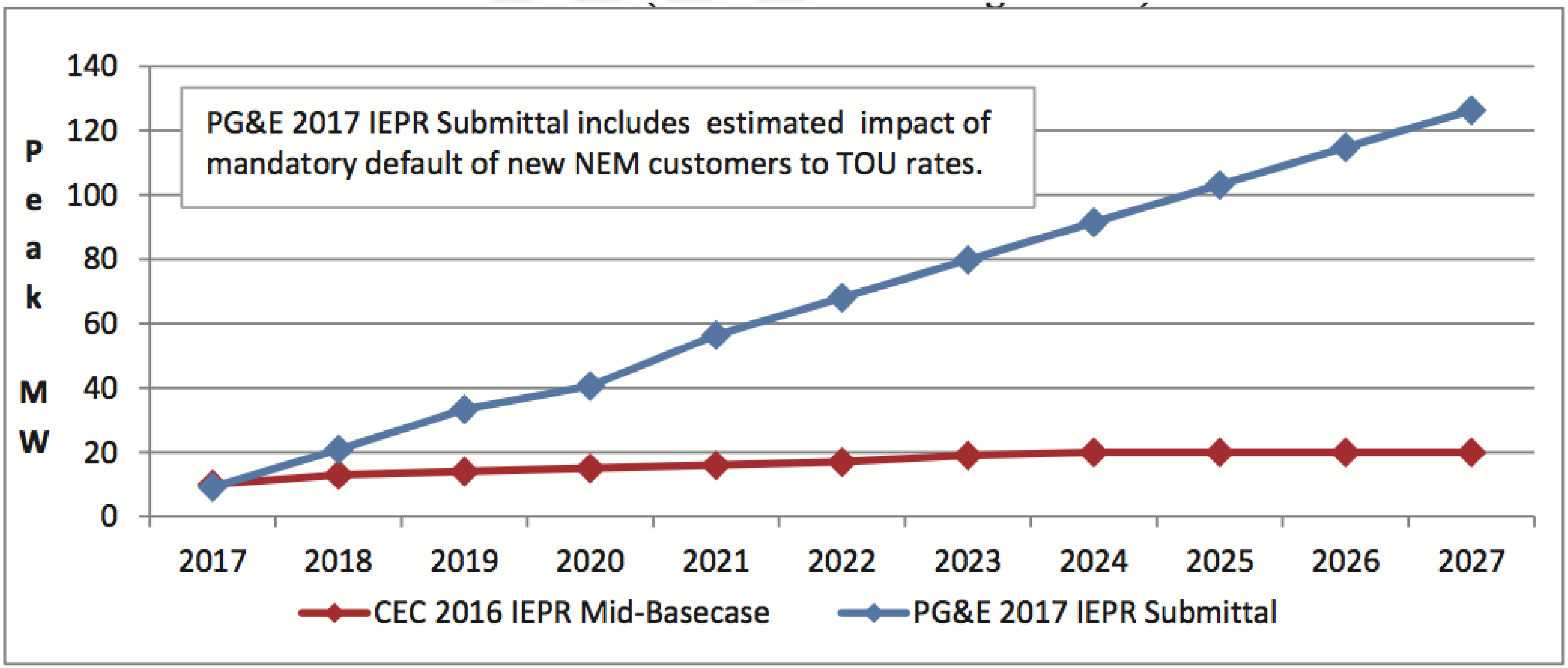
Typical sequence of event:

1. Recloser at mid-point operates to clear the fault
2. Switch in section 4 opens to isolate downstream
3. Tie-switch closes to restore customers in section 4
4. Crew dispatched to repair fault, and initiate restoration
5. Tie-switch opens and switch in section 4 closes back
6. Recloser closes and normal supply is restored

Impact on Customers:

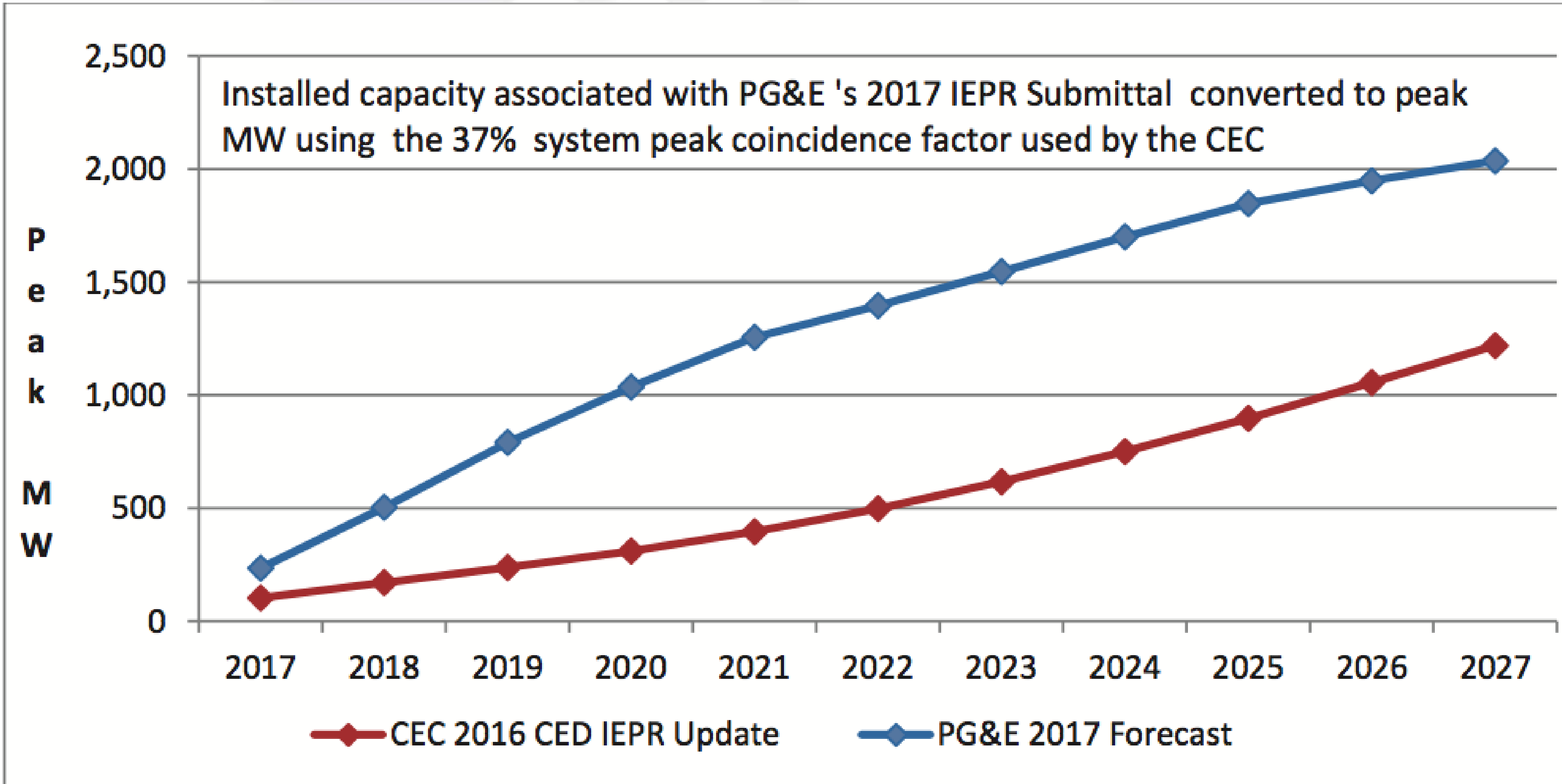
1. Upstream customers in section 1 and 2 do not see any interruptions
2. Downstream customers in Section 4 see 2 momentary interruptions
3. Customers on faulted section (3) see a sustained interruption for until fault is repaired

Example: PG&E Load Modifying Demand Response



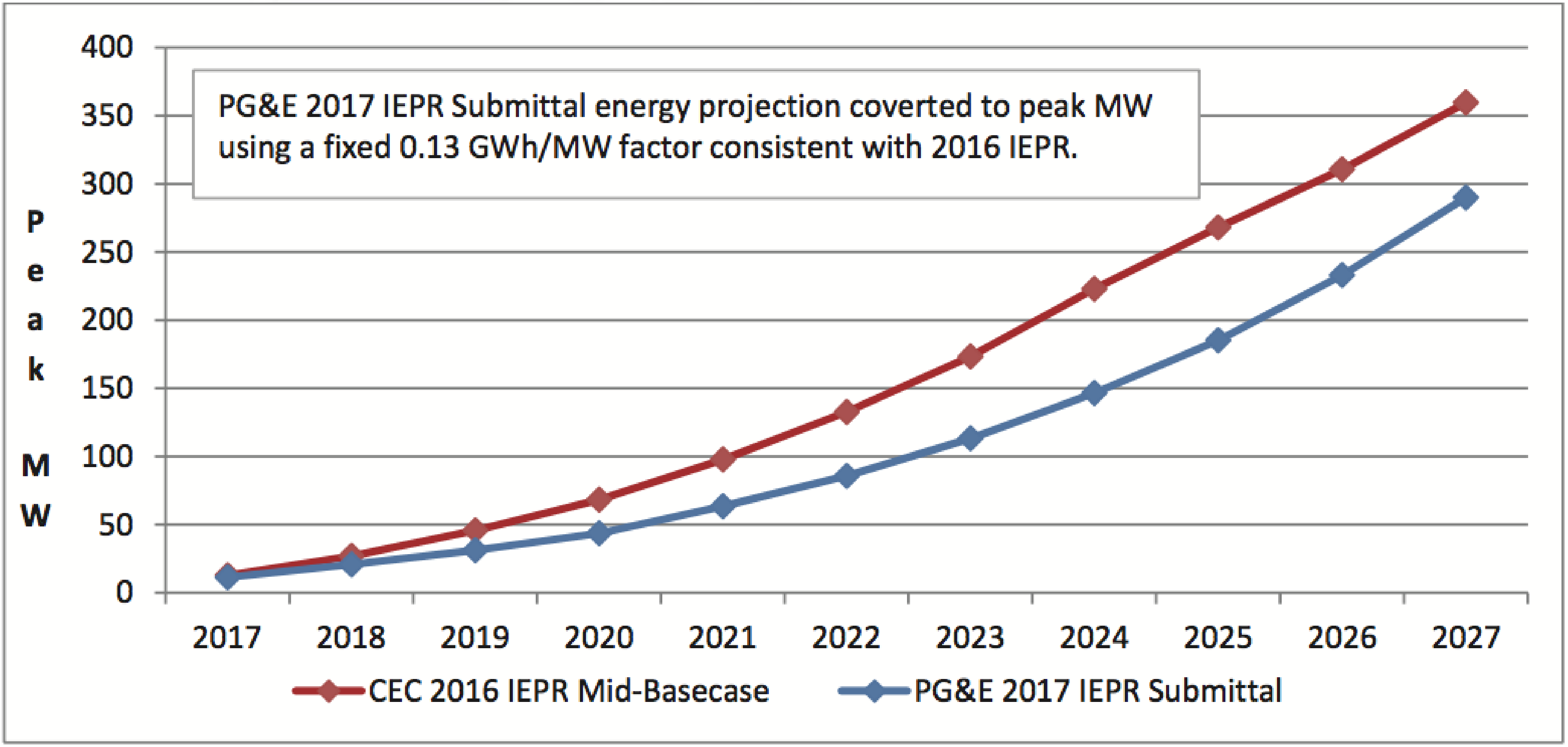
http://drpwg.org/wp-content/uploads/2017/04/R-14-08-013-Revised-Distributed-Energy-Resource-Assumptions-Framework-....pdf

Example: PG&E's BTM DPV



http://drpwg.org/wp-content/uploads/2017/04/R-14-08-013-Revised-Distributed-Energy-Resource-Assumptions-Framework-....pdf

Example: PG&E’s EVs



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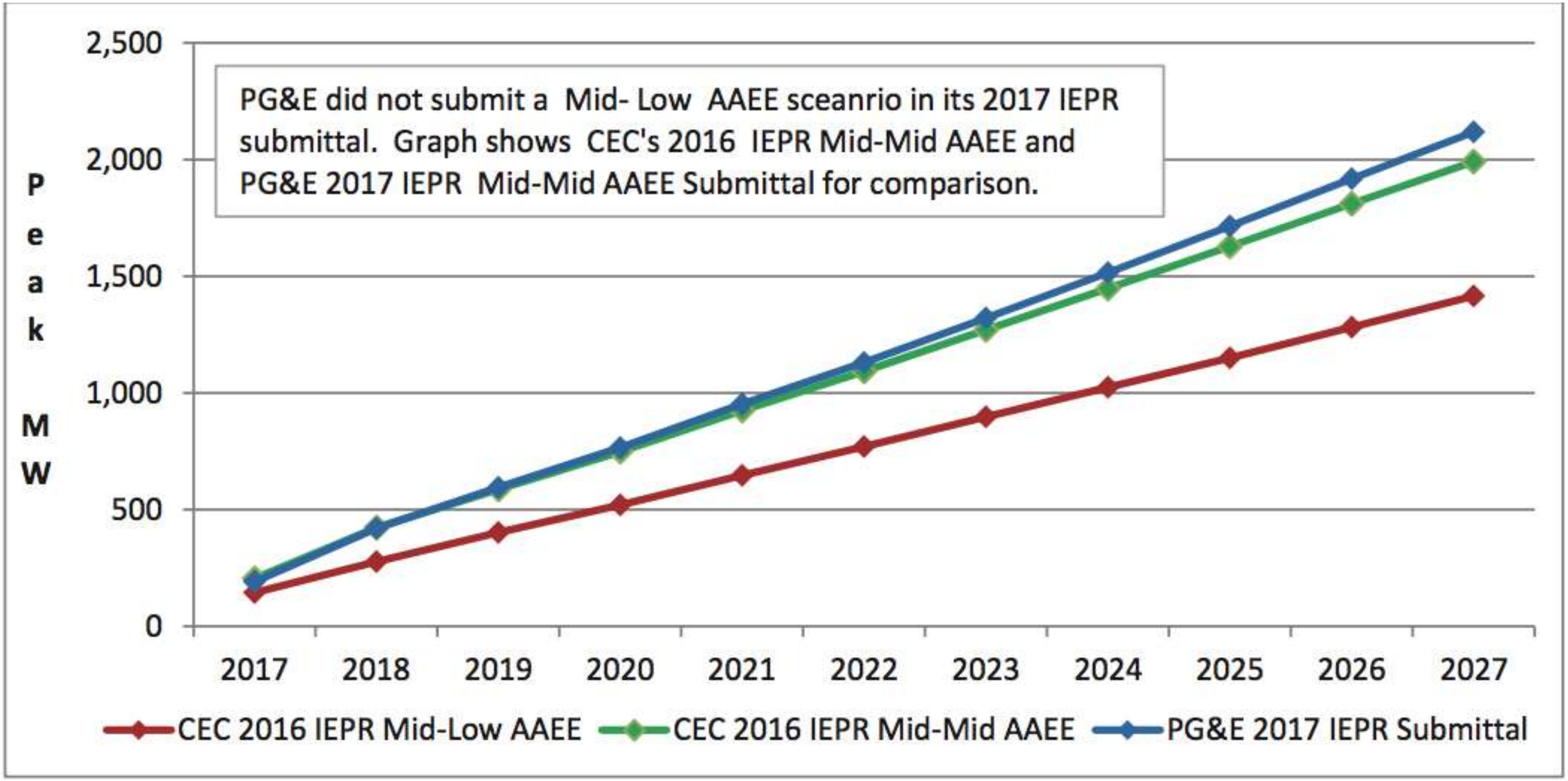
Example: PG&E's Energy Efficiency



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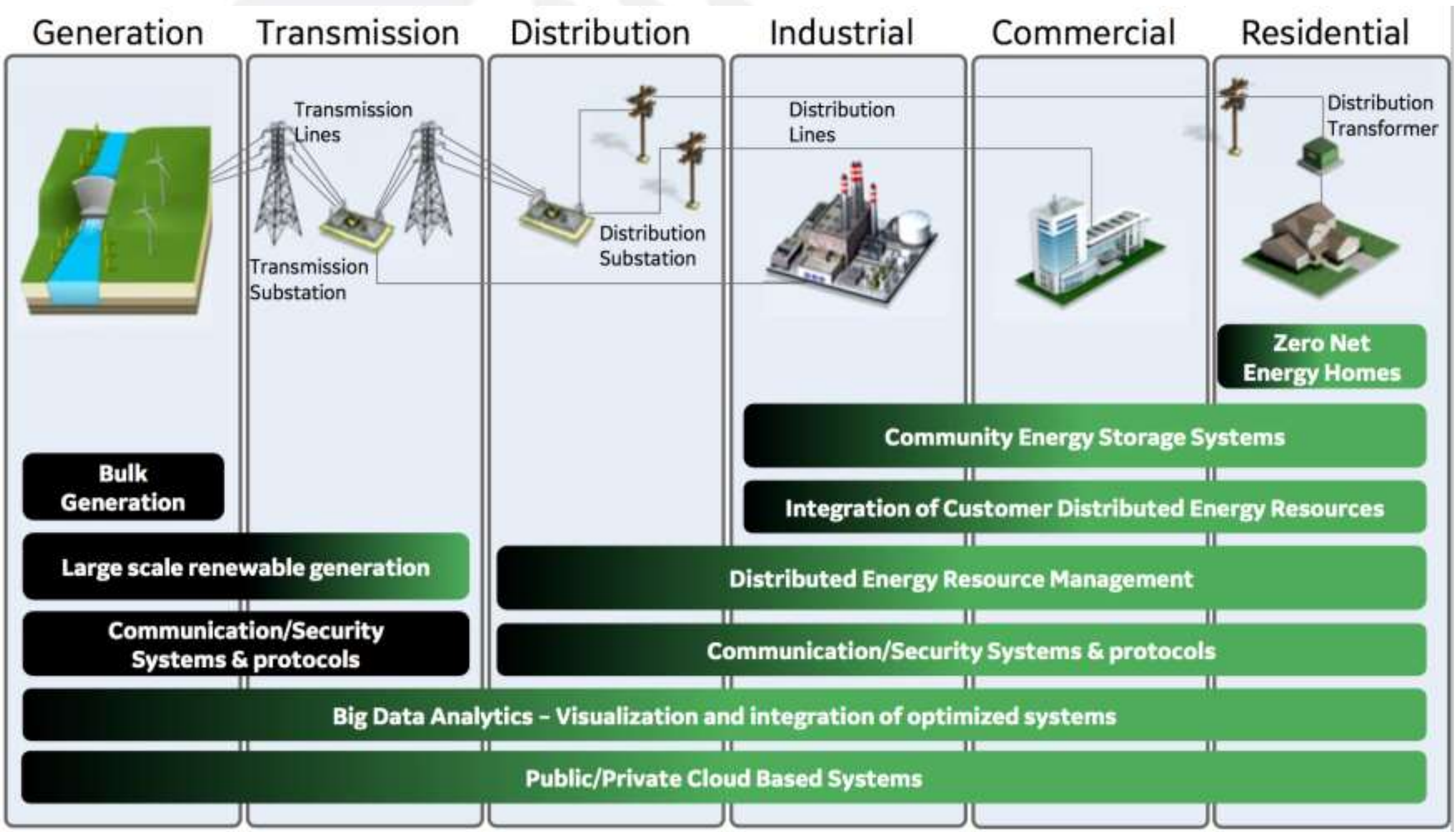
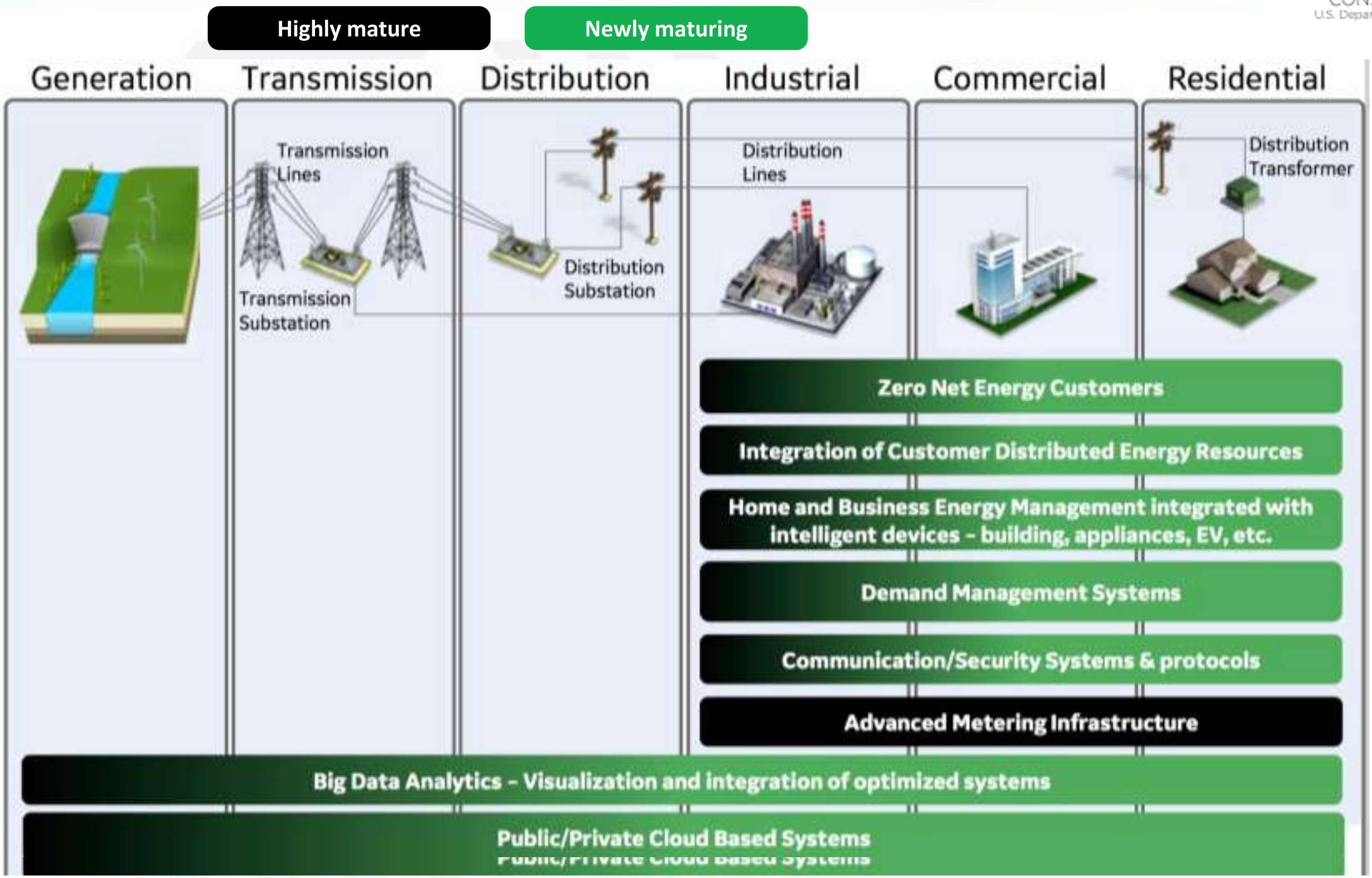
DER Enablement

Highly mature

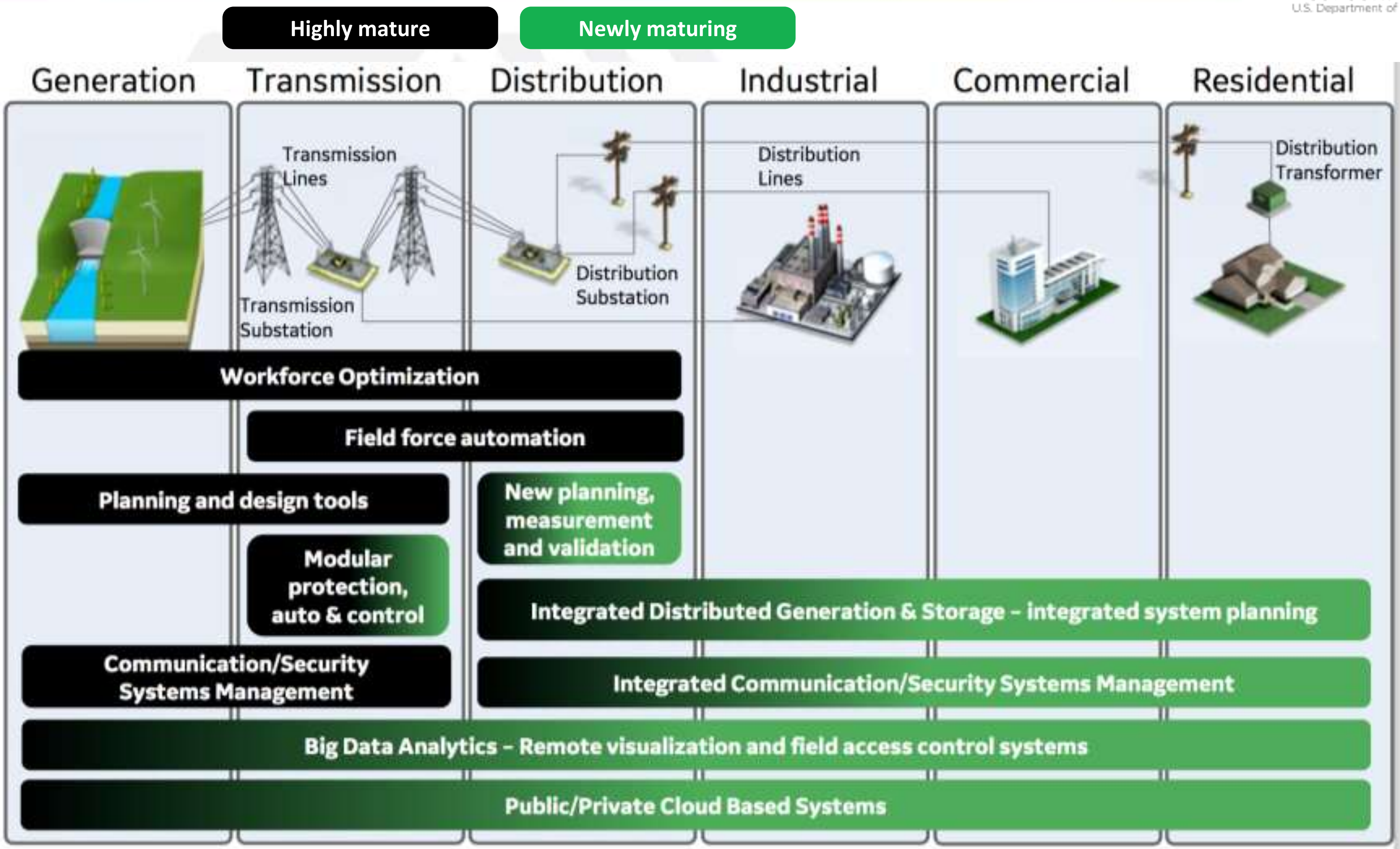
Newly maturing



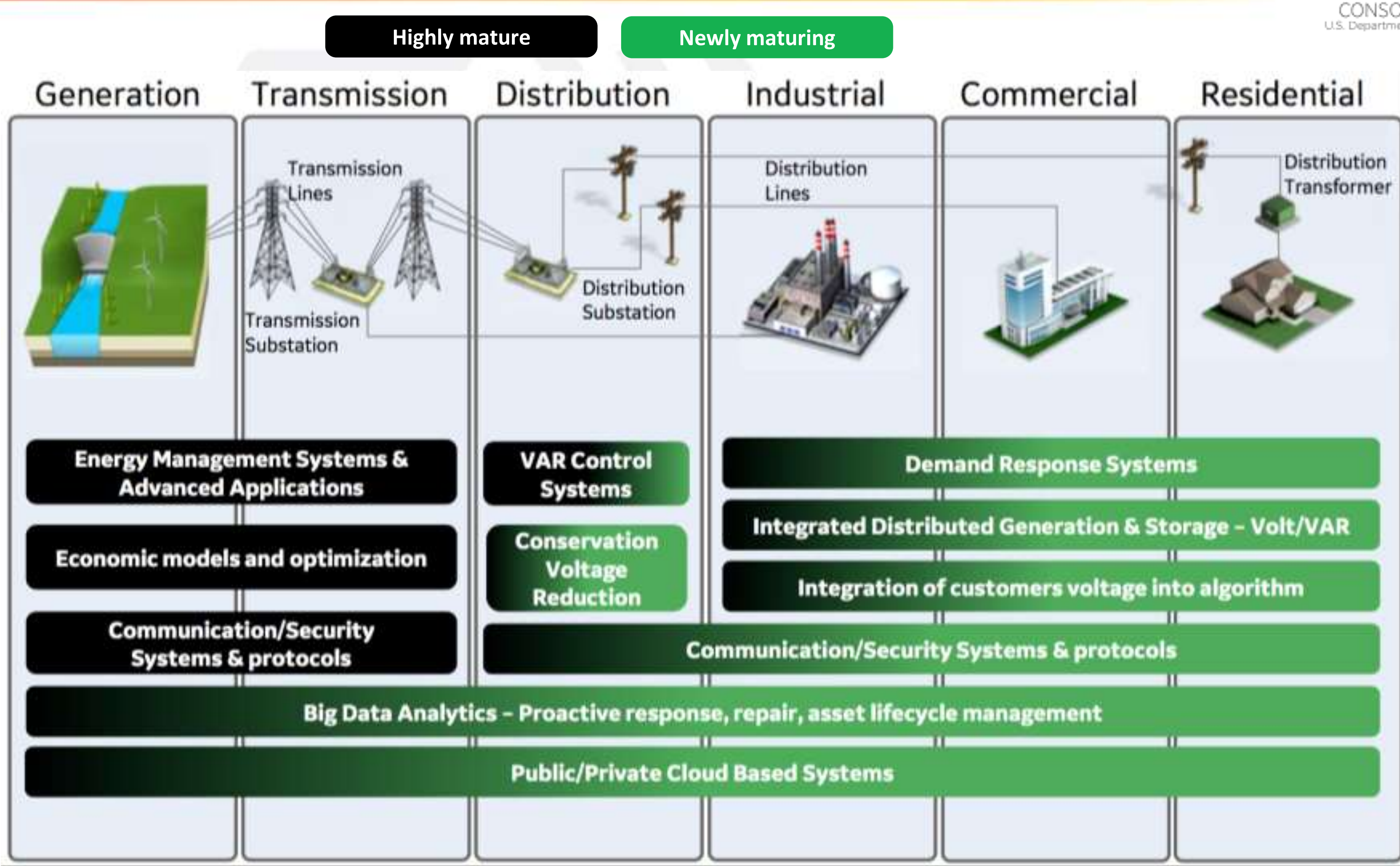
Customer Empowerment



Productive Workforce



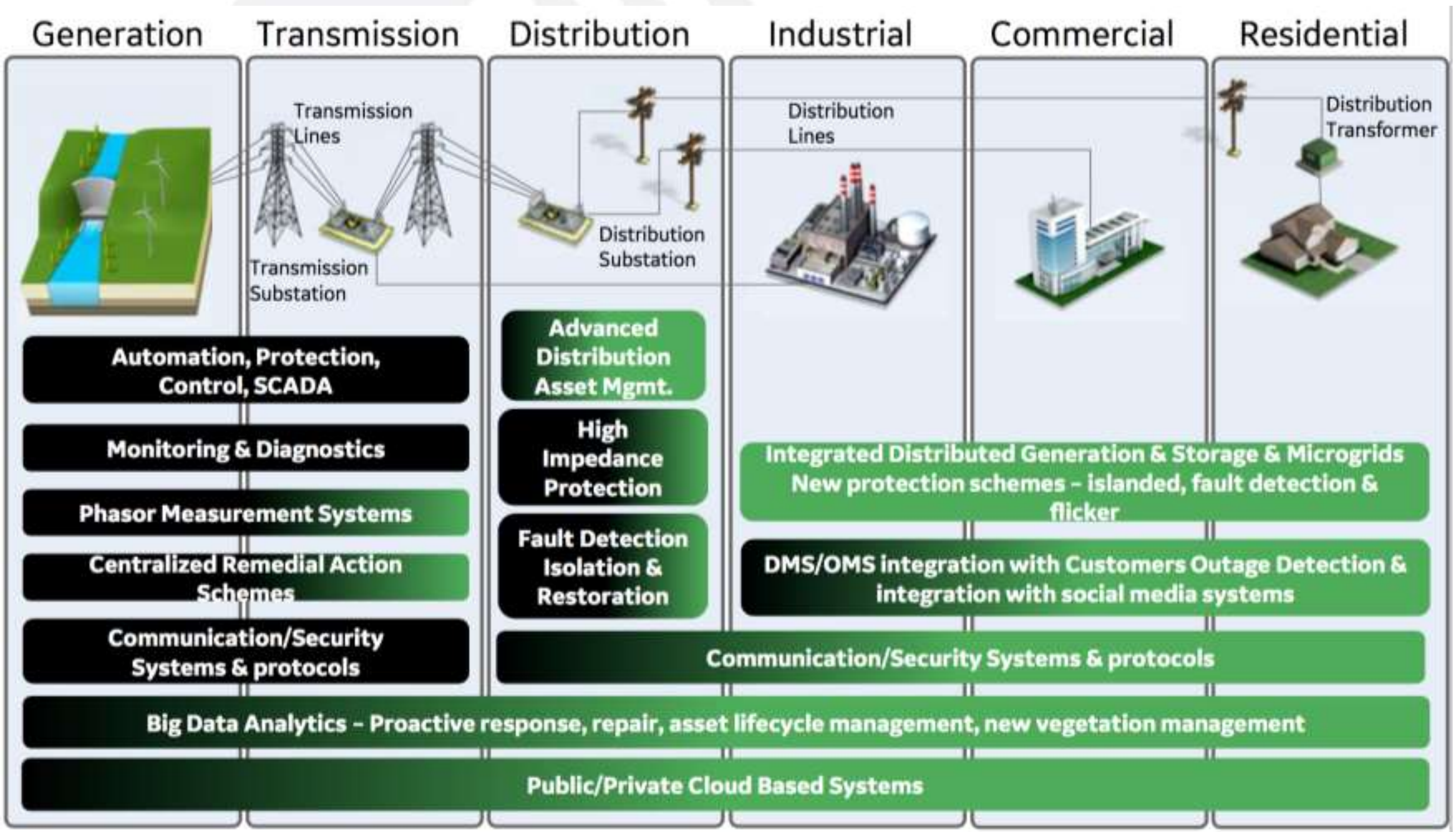
Efficient Grid



Resilient Grid

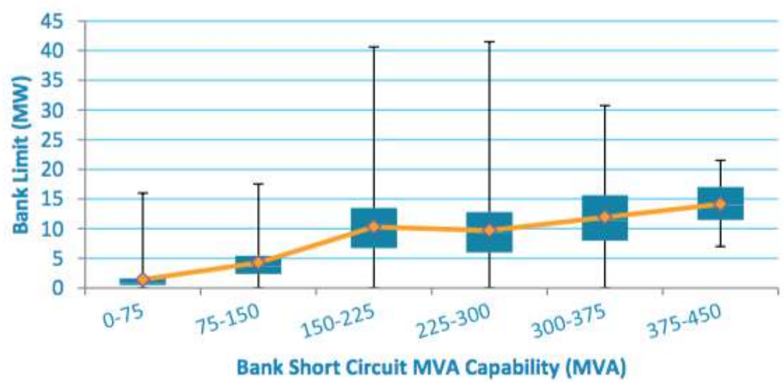
Highly mature

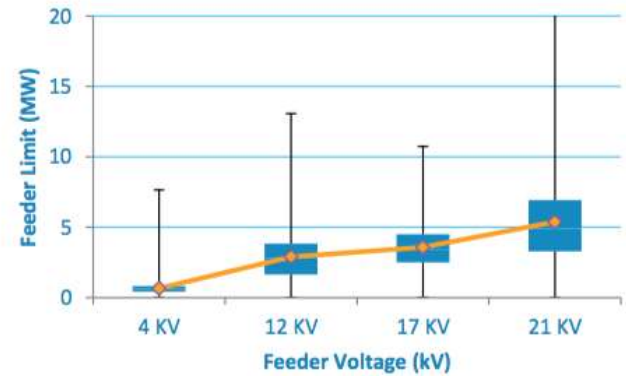
Newly maturing

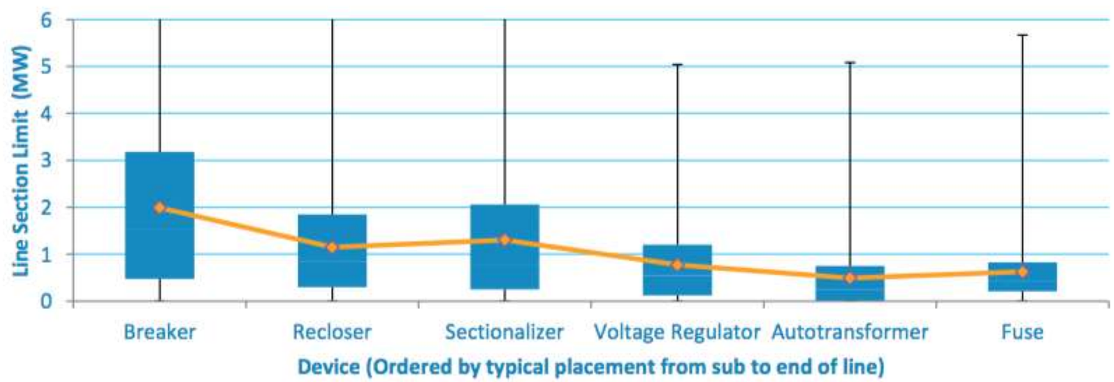


Hosting capacity analysis for PV in PG&E

Typical DER Use Case: Standalone Fixed-Axis PV







NOTE: Results based on July 1 2015 ICA data

PG&E, DRP Webinar, 2015

High Cost project

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Contents

2025 DER Coincident Peak (MW)

- 0.319 - 0.590
- 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

- $
- $$

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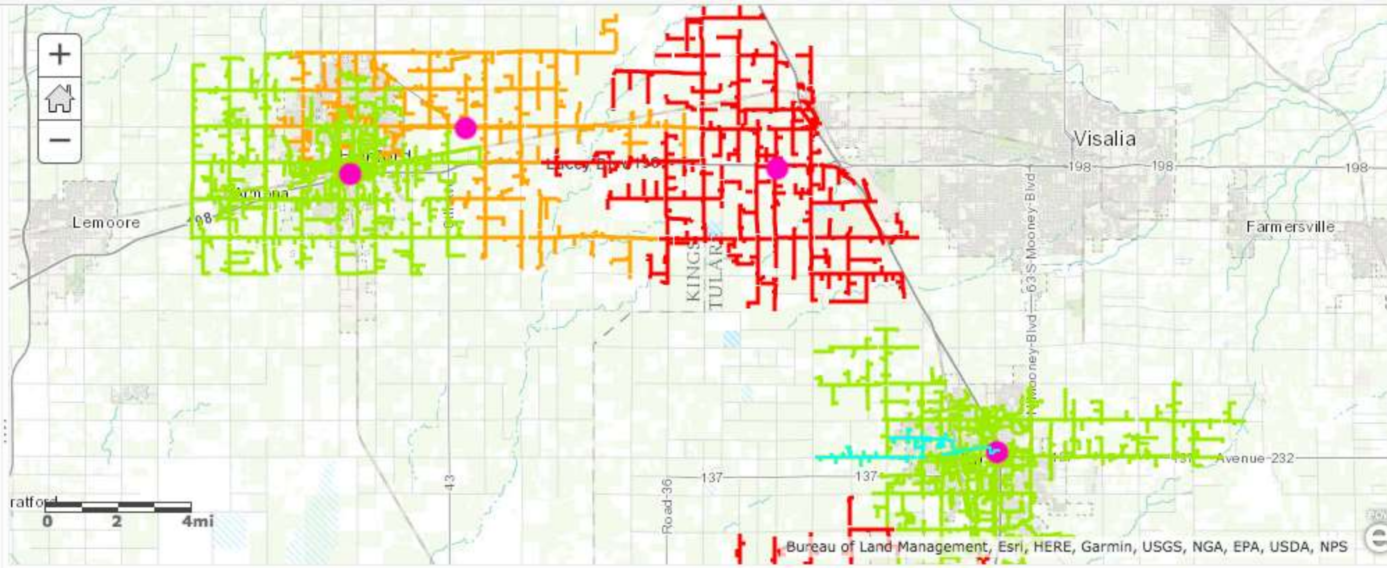
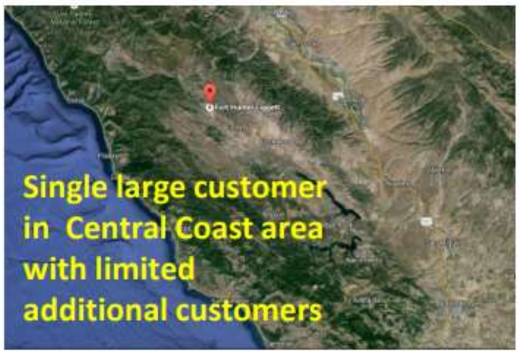


Demo B - LNBA Short-term, Planning (Features: 90, Selected: 1)

DER Growth Scenario	LNBA Results Timeframe	Project 1 Title	Project 1 Description	Project 1 In-service Date	Grid Service(s) 1	LNBA Results 1
Planning	Short-term	New Rector-Goshen-Liberty 66kV Subtransmission Line	The project will construct one 66 kV underground subtransmission line tapped off of the existing Goshen-Liberty 66 kV Subtransmission Line	June 01, 2018	Transmission and Distribution Capacity Deferral	$$$

To estimate DERs, we need to understand load and adoption patterns



		PV as % of Feeder Load			
Feeder (Circuit)	PV kW installed 2014	2014	2016	2020	2024
CENTRAL COAST	2,283	35%	35%	35%	35%
SUNNYVALE	2,008	30%	94%	123%	125%

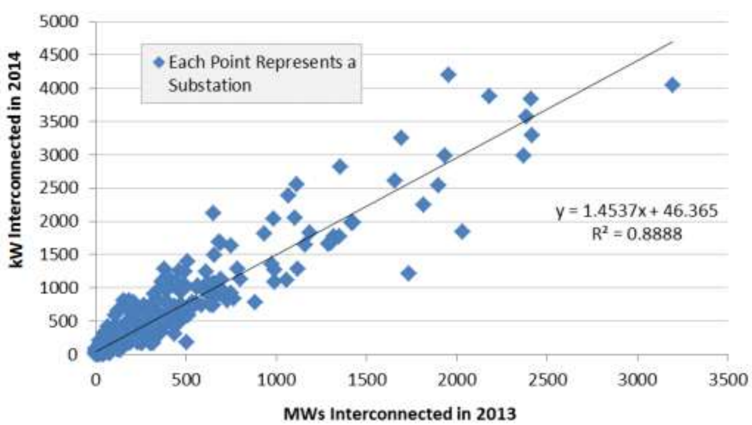
PG&E, DRP Webinar, 2015

Past behavior may not be indicative of future behavior

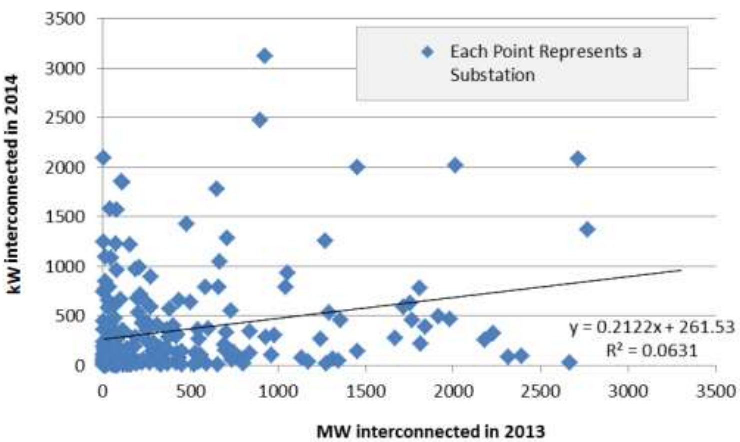
GRID MODERNIZATION LABORATORY CONSORTIUM
U.S. Department of Energy

- DER adoption is heavily determined by uncertain future policy developments
- Limited sample size for some technologies constrains PG&E's ability to elicit general trends that can be applied across our service area
- Larger-scale on residential DER is installed in "chunks" rather than in more predictable incremental additions that might be seen on a distribution asset that serves primarily residential load

PV interconnected by residential customers to a given substation, scatterplot of 2013 vs. 2014 annual additions.

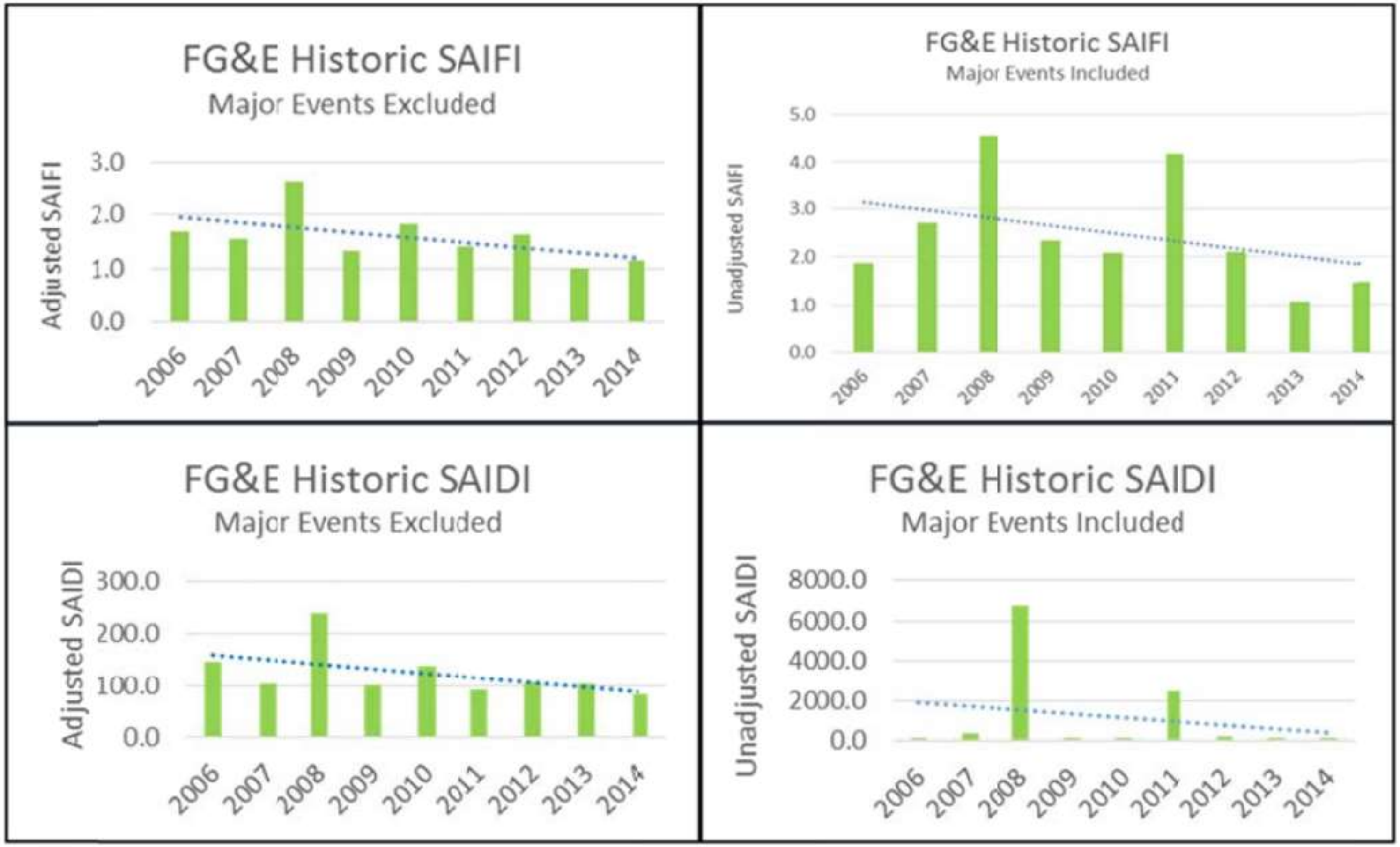


PV interconnected by non-residential customers to a given substation, scatterplot of 2013 vs. 2014 annual additions.



PG&E, DRP Webinar, 2015

Reliability



Unitil, EDIIP, 8/1/15