Emerging distribution planning analyses

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Distribution Systems and Planning Training
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Outline

- ► Introduction
- ► Multiple scenario forecasts
- ► Hosting capacity
- ► Locational net benefits analysis
- ► Key questions to ask

Introduction

Passive DER planning

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Autonomous DER deployment with little information/guidance

- ► Customer decides what kind of DER to install, how big, where, and how to operate it
  - Utilities must manage integration of the DER
  - Location may be unfavorable leading to expensive interconnection and no one is happy
- ► If the next DER requires upgrade/mitigation, that next customer is responsible, even though it might enable many more customers to install DERs
- ► Utility compensates customer (e.g., net metering, fixed tariff)
  - Compensation may not reflect actual net value that DER brings

Consequences of passive planning

- 7,900 MW of uncontrolled distributed PV (DPV), resulting in negative prices, overgeneration events, difficulty in forecasting load (California)
- Uncontrolled DPV that increases curtailment of wind plants (Maui)
- Projects in difficult locations that require challenging mitigation (National Grid)
- Inability to recover cost of service from DPV customers (multiple utilities)
- Unhappy customers who want to install DER but whose feeder can't accommodate additional DER (Hawaii)

Photos by NREL, 7400 and 14697

Smart, proactive planning

Give customers information about where the grid needs help. Incentivize them.

- Hosting capacity shows how much more DER can be managed on a given feeder easily, or where interconnection costs will be low/high
- Locational net benefits analysis helps determine the benefits of specific services at a specific location to guide developers
- Proactive upgrades of circuits that are likely to see DER growth
- Defer some traditional infrastructure investments through cost-effective non-wires alternatives that provide specific services at specific locations
- Help prioritize solicitations
- Inform rates and tariffs
- Leverage customer and third-party capital investments

Multiple Scenario Forecasts

Types of scenarios

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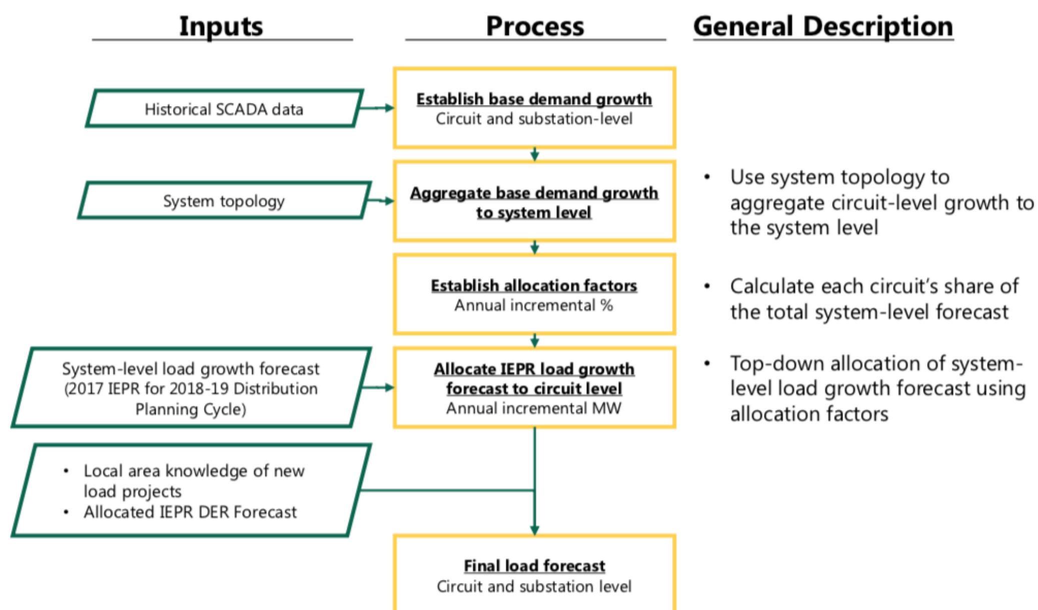
- Business-as-usual (e.g., California's Trajectory case)
- High penetrations of DERs
- Costs decrease for certain DERs
- Policy-driven
- Carbon/sustainability
- High community choice aggregation scenario

What are the main drivers in your region?

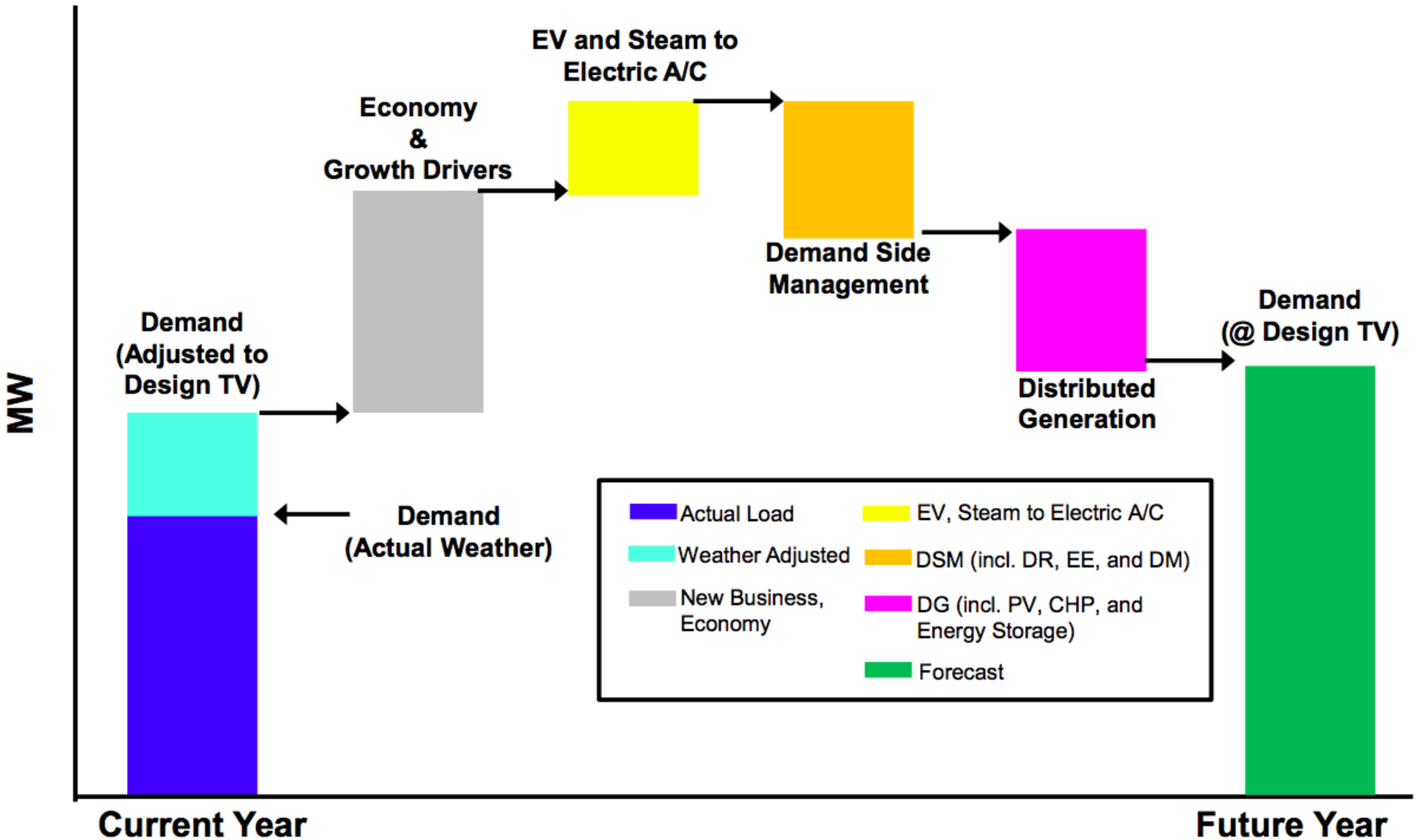
Making load forecasts more granular in time and space

- State level: California
  - California Energy Commission Integrated Energy Policy Report
  - Annual peak load forecast
  - Annual energy
  - By climate zone
- Utility system level: Southern California Edison (SCE)
  - Annual hourly load forecast by customer class, accounting for DERs
- Utility distribution level: SCE
  - Annual peak hour by substation (subtransmission and below) with limited accounting for DERs at present
  - Goal: Annual hourly load forecast by feeder, accounting for all DERs



SCE, Distribution Forecasting Working Group Meeting, May 30, 2018

Example of load forecasting with DER



Con Edison, *Distributed System Implementation Plan*, June 30, 2016

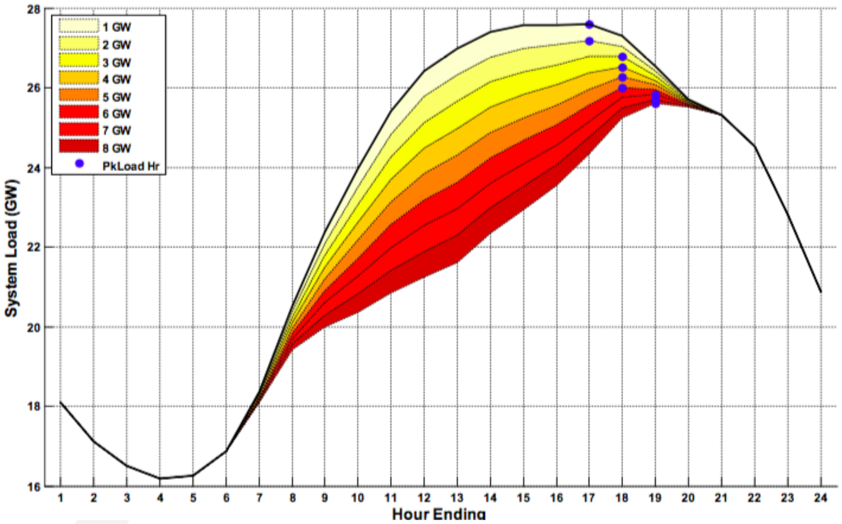
Where does the data come from?

PV Data source	Source	Resolution
Demographic and socio-economic (customer characteristics)	US Census Bureau	Census tract/zip code
Demographic and socio-economic (customer characteristics)	Experian	Customer (res. only)
PV adoption history (historical PV adoption)	CA DGStats Database	zip code
IEPR forecast of solar PV (system level PV forecast)	CEC	System
GIS and parcel data (GIS info showing new development)	Integral Analytics	Zip code and/or parcel
PV adoption history and metered output where available	IOUs	Customer
Energy usage (historical energy usage)	IOUs	Customer
Service accounts and rate structure	IOUs	Customer
System topology (electrical topology showing customer, circuit, substation, IOU system)	IOUs	Electrical hierarchy
PV Technical potential and profile (technical potential; typical solar shapes)	NREL	Zip code
Building stock growth forecast (Moody's forecast)	New Solar Homes Partnership	System

Itron, Distribution Forecasting Working Group Final report June 28, 2018

Load profiles/shapes are important

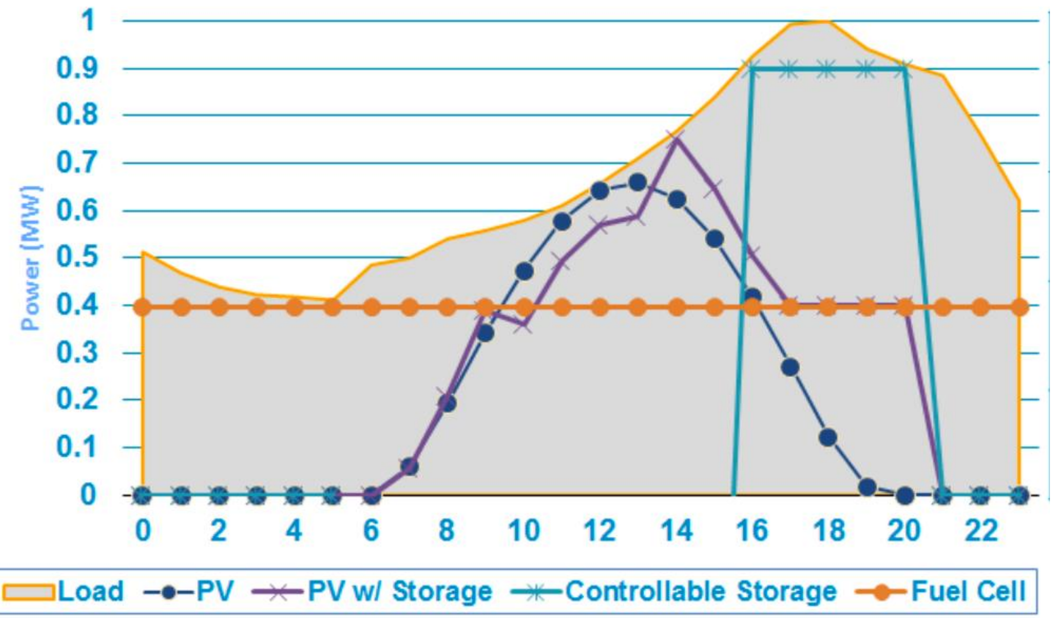
- ► Traditional generation offered fixed capability at all times
  - Resource adequacy could be determined by peak
- ► However, DERs may offer variable output
  - Resource adequacy needs to be based on hourly profile for peak day
- ► “Peak” is moving because of a changing grid
  - As we move to time-varying rates, as solar penetrations increase, as EVs proliferate, it becomes harder to predict when peak will be
- ► System peak is different from circuit peak



Graphic: W. Henson, ISONE, 2016

Distributed generation (DG)

- ► How much, where, when?
- ► How much does it contribute to peak demand?
- ► How much does it reduce energy demand?
- ► How is it operated?



Source: PG&E, Distribution Resources Plan, 2015

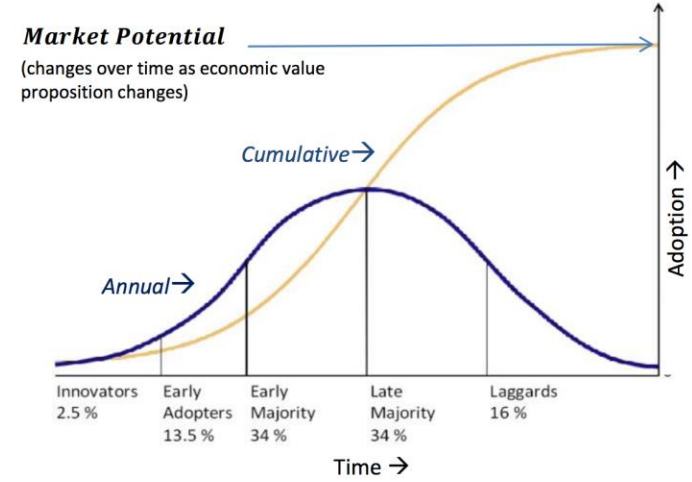
Disaggregation methods

- Proportional Allocation
  - Based on utility data (load, energy, # customers)
  - Examples:
    - Total energy on certain circuit compared to all circuits
    - PV adoption patterns to drive EV forecasts
- Propensity Models
  - Based on customer characteristics (location, high energy user, etc.)
  - Regression analysis (or other statistical method) to link characteristic with propensity weighting
  - Calculate propensity score for each customer
- Adoption model
  - Bottom-up adoption forecast time-series model
  - S-curve models (Bass Diffusion Models, etc.) model early adopters, adoption rates over time

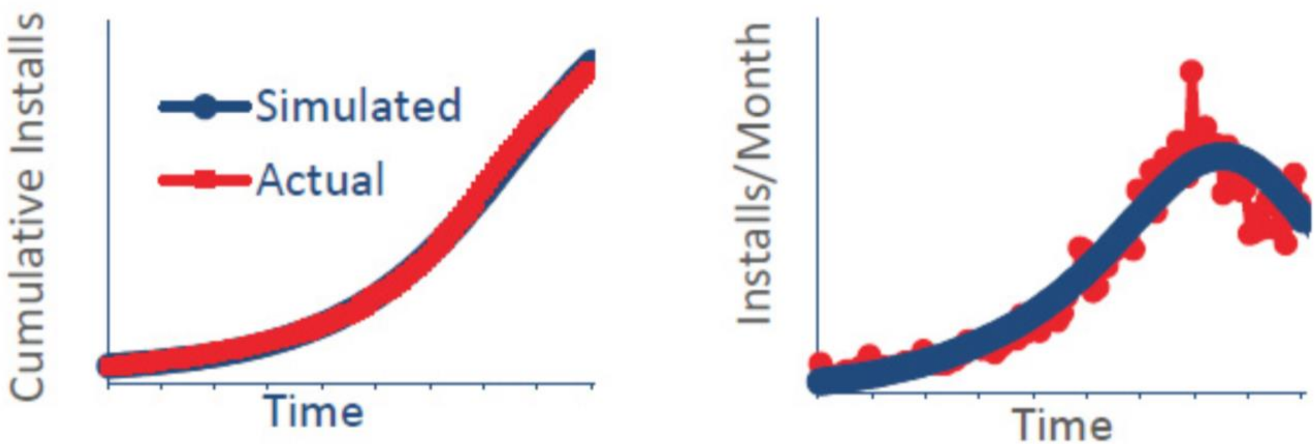
Itron, Distribution Forecasting Working Group Final report June 28, 2018

Best practice method for PV

1. Identify adoption characteristics
2. Develop S-curve model based on adoption characteristics (e.g., by zip code)
3. Forecast adoption by zip code
4. Allocate DPV to zip codes proportional to zip code adoption forecast
5. Allocate DPV to circuits proportional to load or proportional to number of customers



SDG&E example of PV adoption model

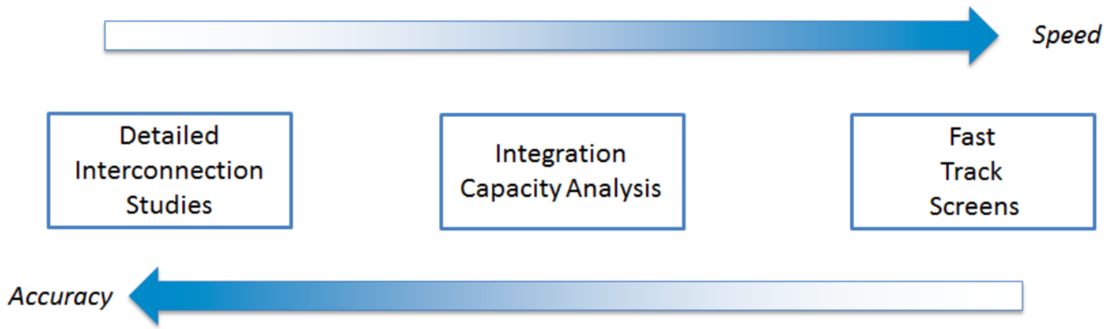


Top: PG&E, DRP DER Growth Scenarios Workshop Distributed Generation, May 3, 2017
Bottom: Itron, Distribution Forecasting Working Group Final report June 28, 2018

Integration Capacity Analysis/ Hosting Capacity

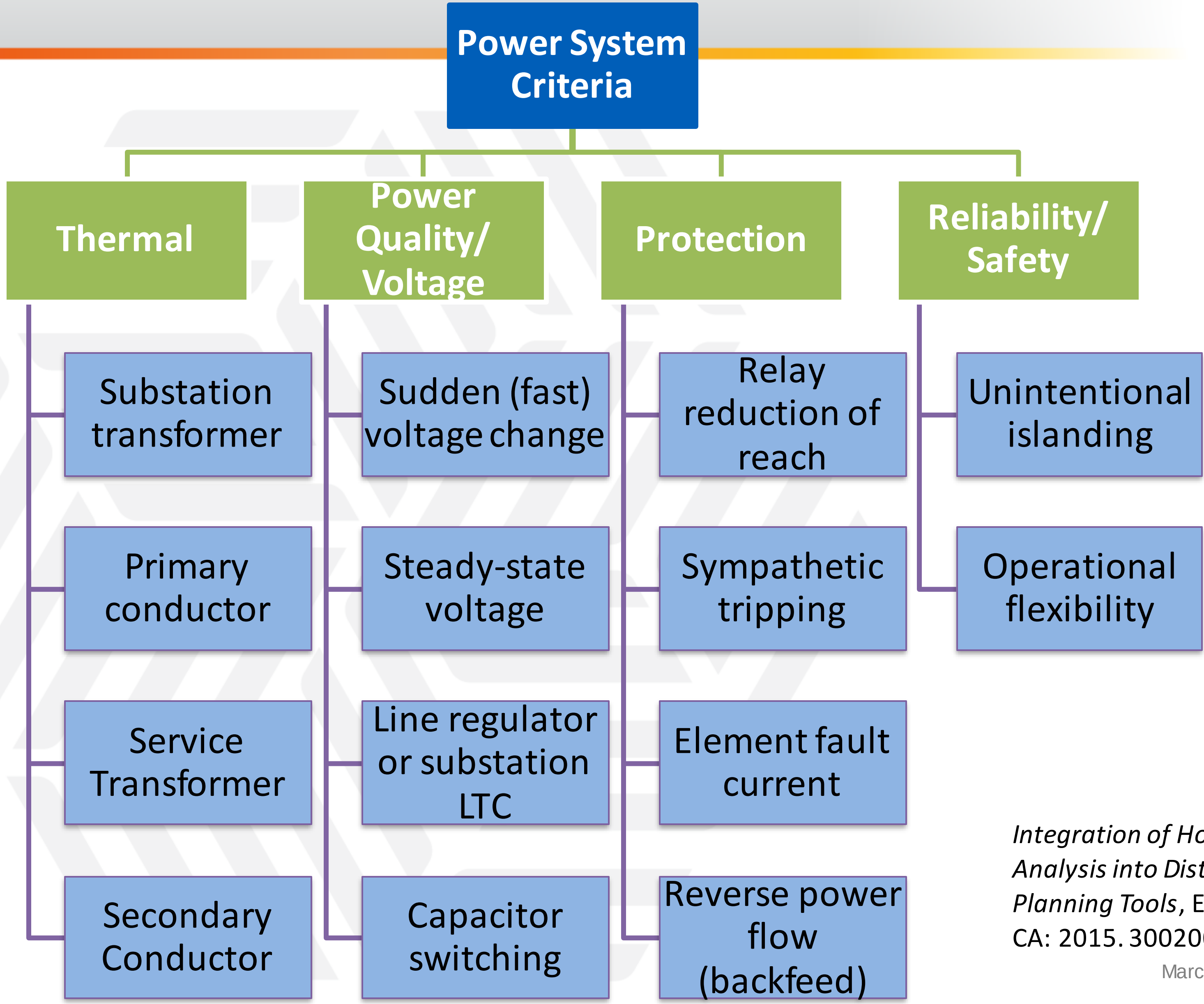
Why?

- ► Inform customers and developers where DER can interconnect without system upgrades
- ► Streamline and potentially automate the interconnection process
- ► Inform distribution planning, such as where to proactively upgrade the grid to accommodate autonomous DER growth



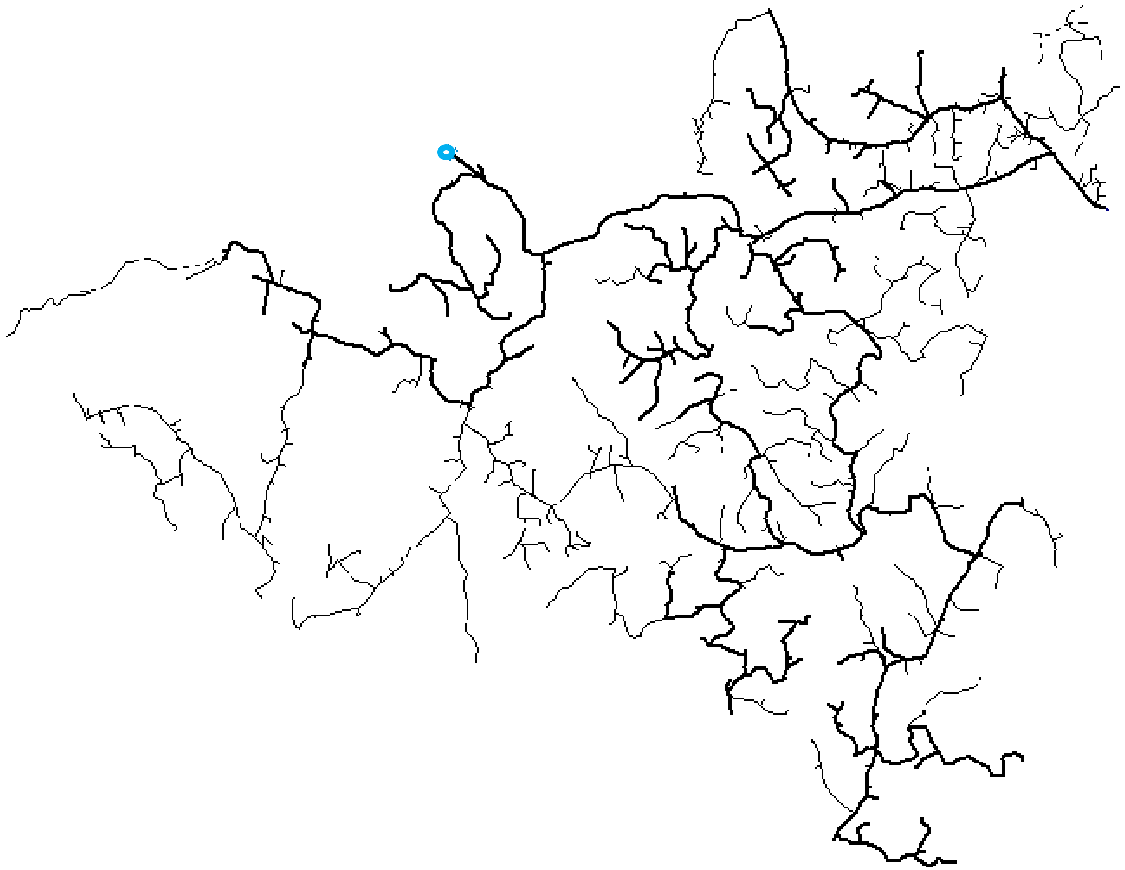
PG&E, Distribution Resources Plan Webinar, Aug. 3, 2015

Power system criteria for hosting capacity



Integration of Hosting Capacity Analysis into Distribution Planning Tools, EPRI, Palo Alto, CA: 2015. 3002005793

We don't know where the PV will be interconnected



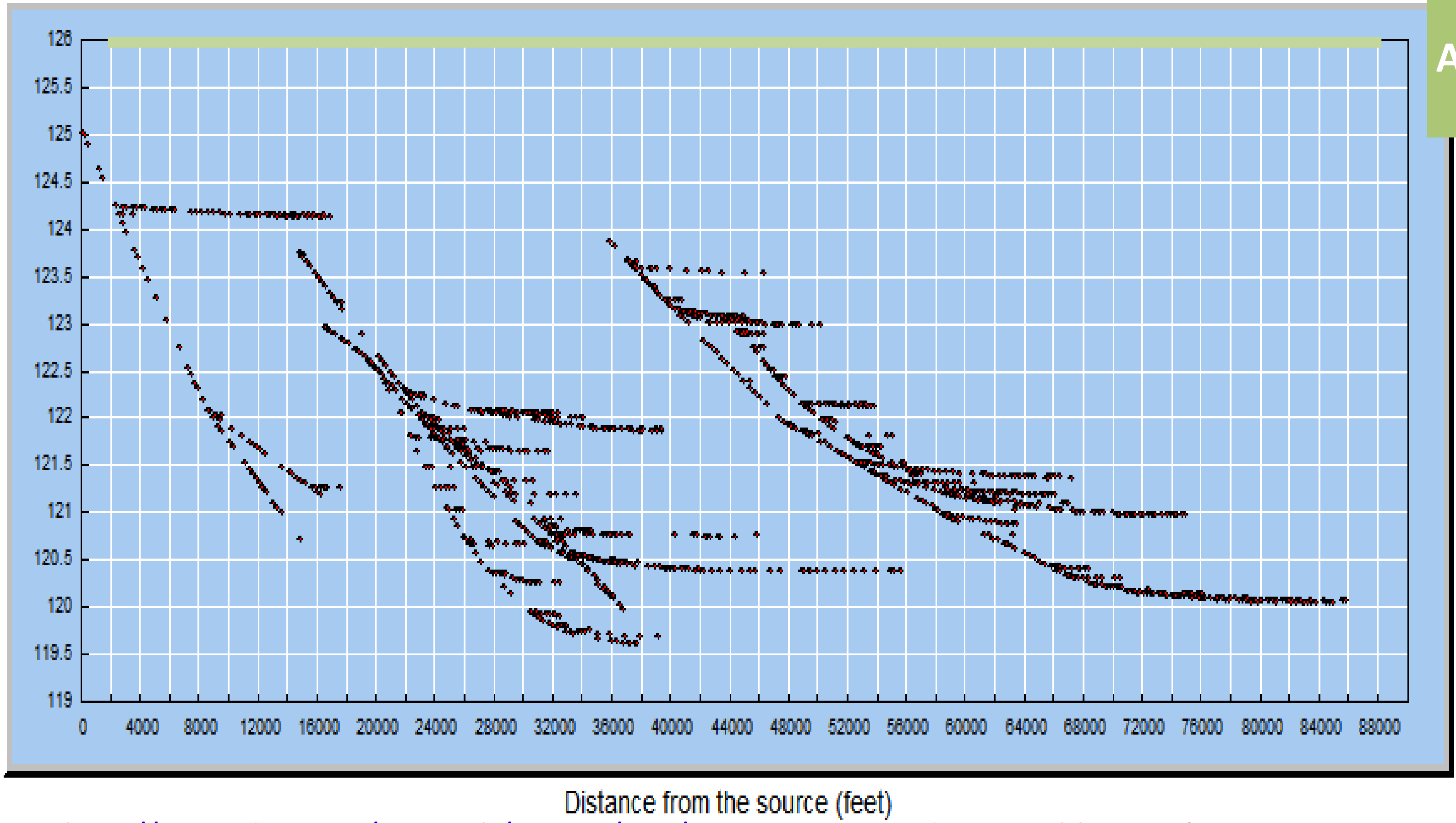
There are 4,000-5,000 nodes on this feeder where PV could be interconnected.

PV location makes a huge difference

Feeder voltage profile

PV = 0%

ANSI limit

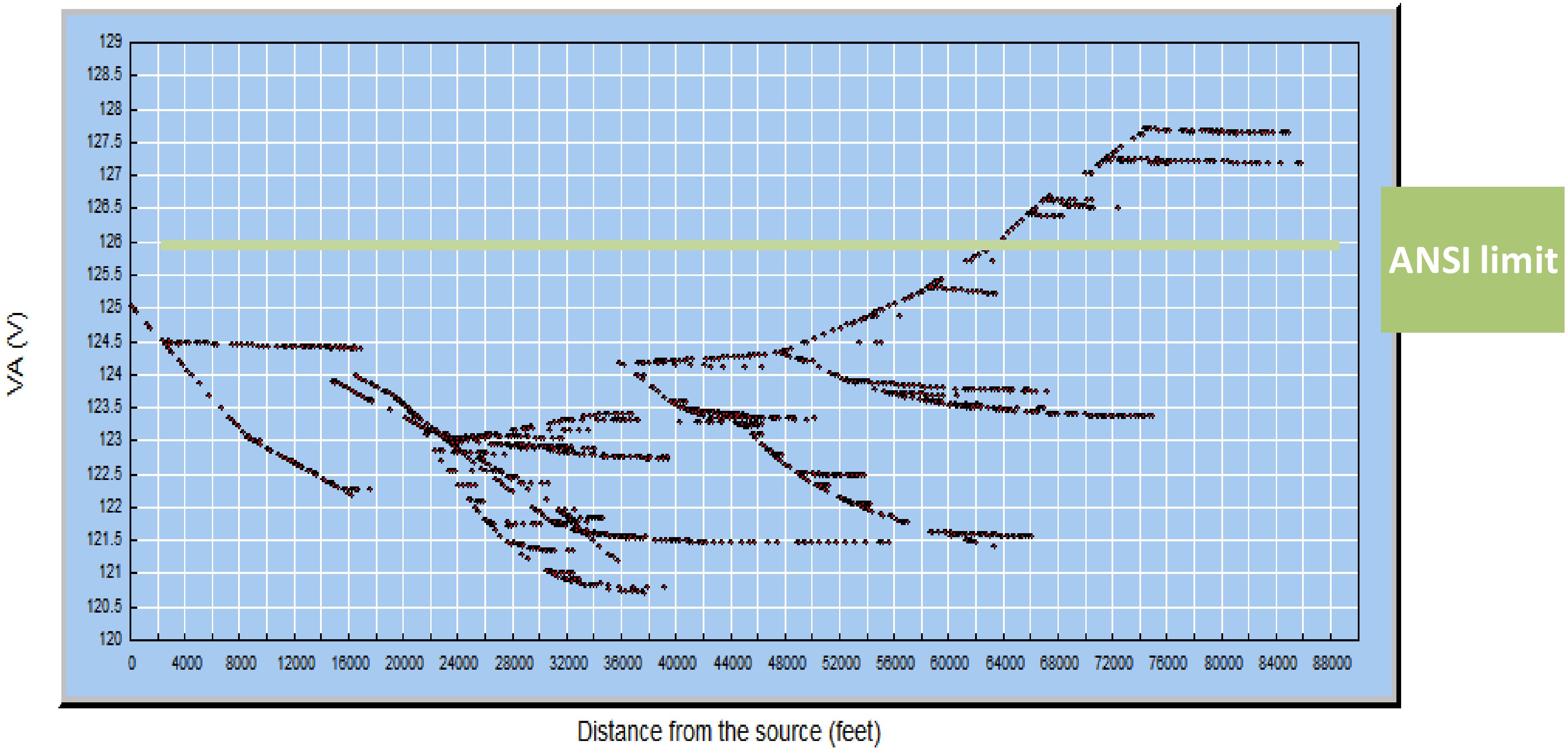


DSTAR, http://www.dstar.org/research/project/103/P15-6-impact-and-practical-limits-of-pv-penetration-on-distribution-feeders

PV location makes a huge difference

Feeder voltage profile

Single PV = 20%



DSTAR, http://www.dstar.org/research/project/103/P15-6-impact-and-practical-limits-of-pv-penetration-on-distribution-feeders

PV location makes a huge difference

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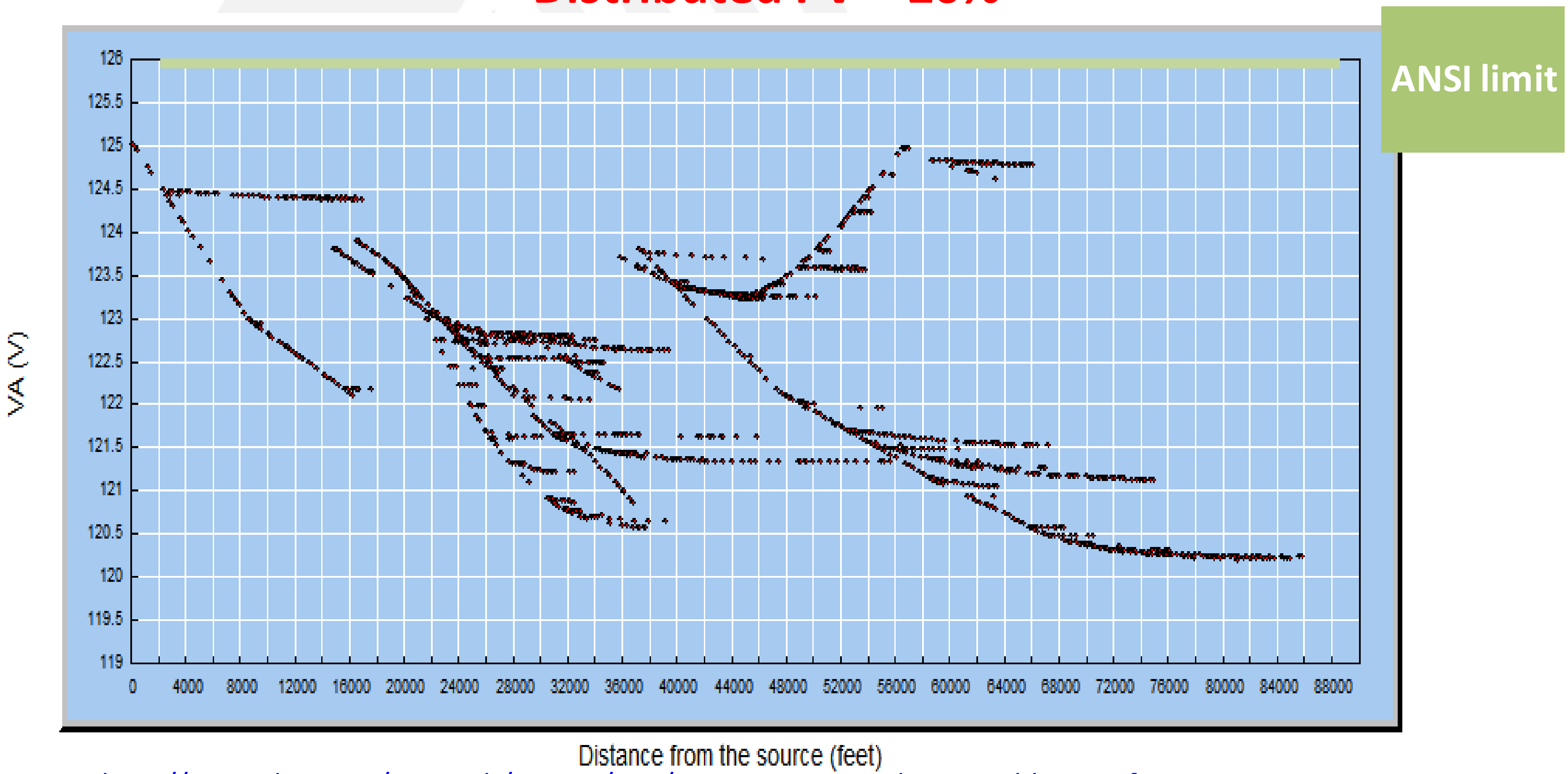
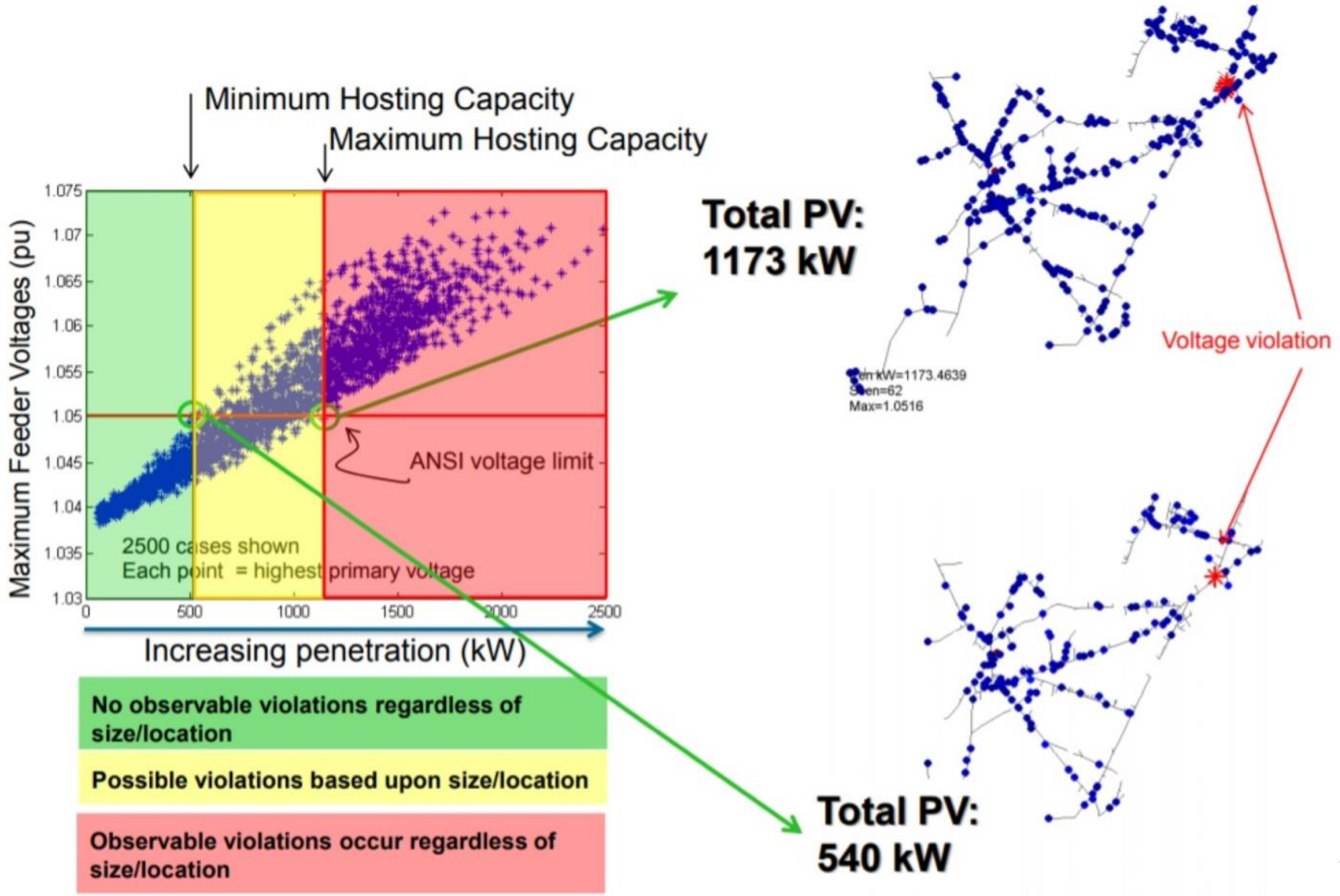
Feeder voltage profile

Distributed PV = 20%



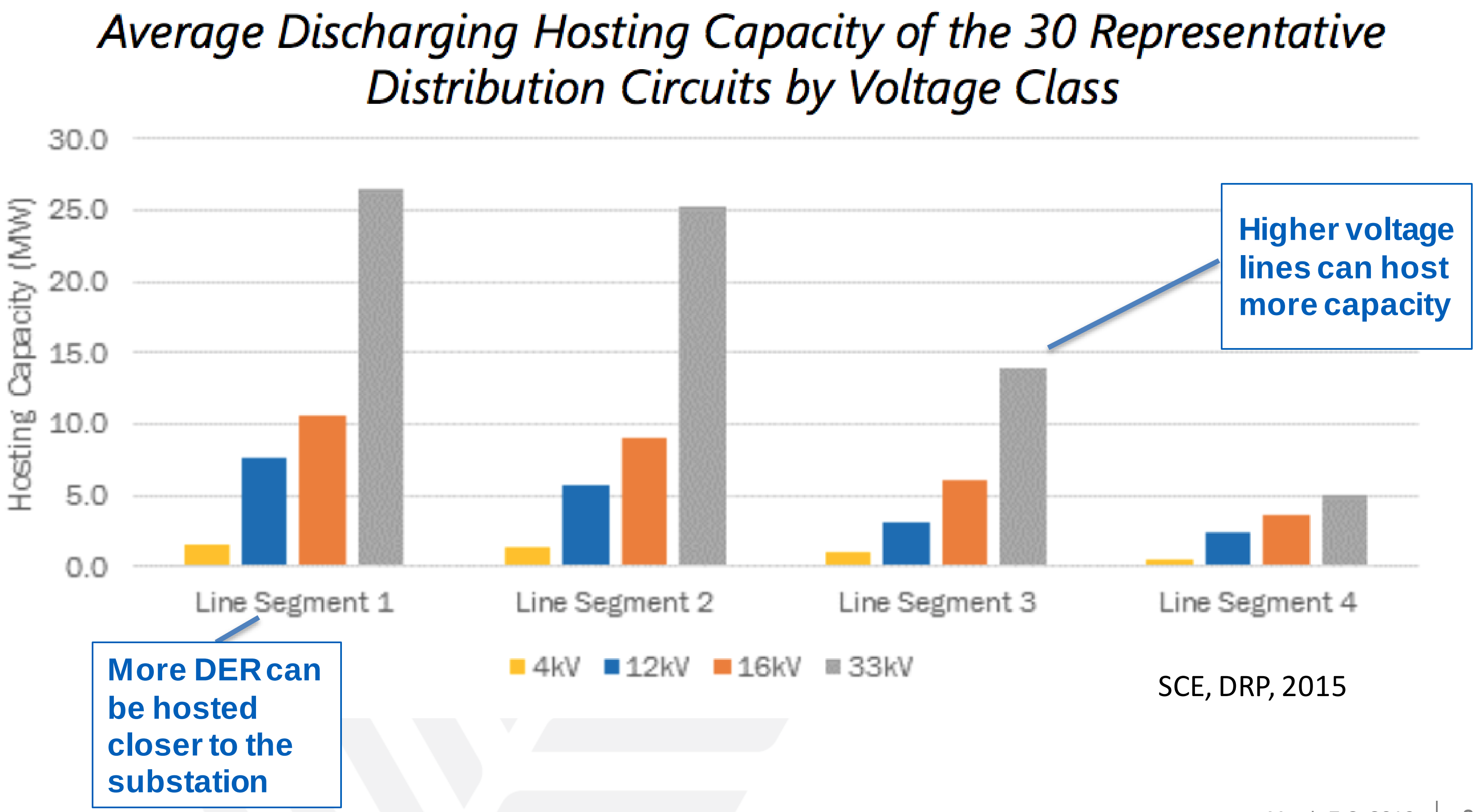
DSTAR, http://www.dstar.org/research/project/103/P15-6-impact-and-practical-limits-of-pv-penetration-on-distribution-feeders

Hosting capacity range for overvoltage violation



EPRI, *Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV, Palo Alto, CA 2012.*

Hosting Capacity in SCE for energy producing DERs



SCE, DRP, 2015

Summary of Hosting Capacity Methodologies

- **Streamlined**

Calculates one power-flow simulation for each hour in the analysis (accuracy depends on the distribution system complexity; can yield sub-optimal results)

- **Iterative** [SCE, SDG&E, PG&E]

Performs multiple power-flow simulations with varying levels of DER connected to each node (parallels typical interconnection studies)

  - Hosting capacity calculations are performed over 12-month period using one day per month of both typical high- and low-load conditions ($12 \times 24 \times 2 = 576$ hours)

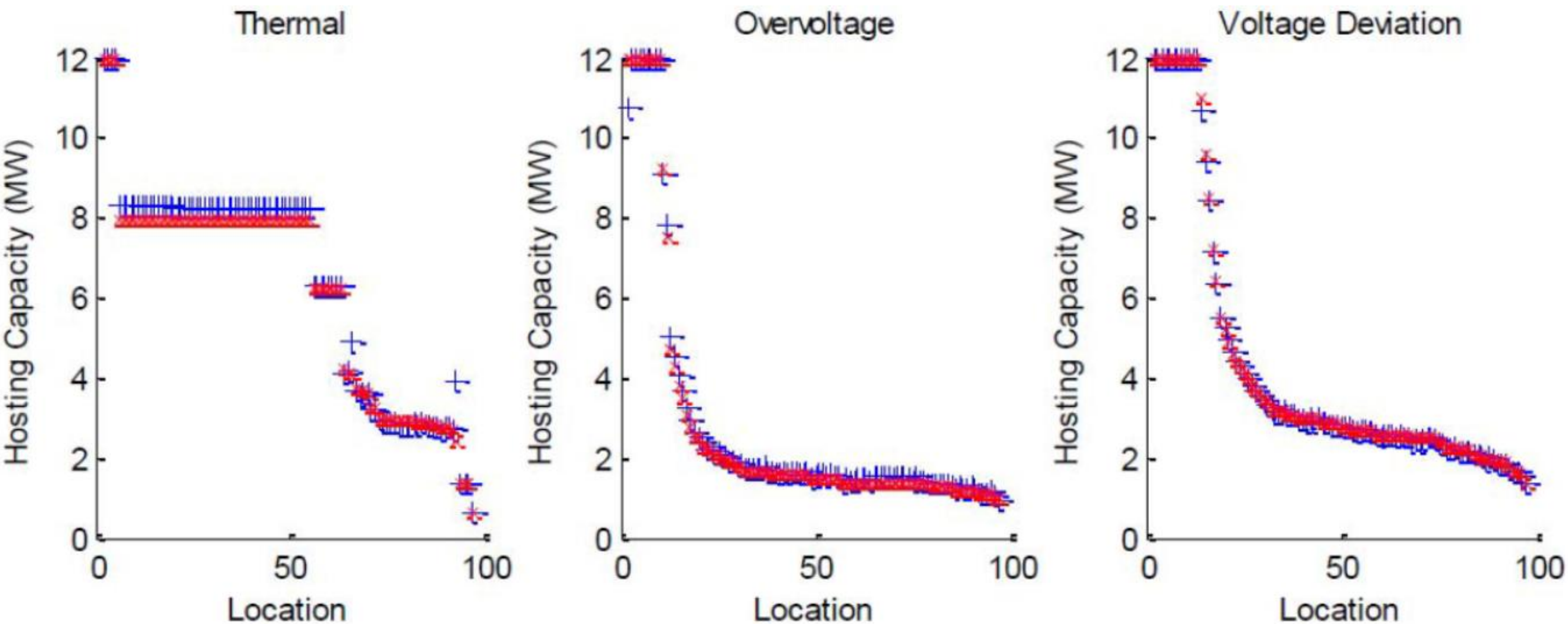
- **Stochastic** [Pepco, ComEd]

Increases DER penetration throughout the feeder using randomly chosen DER sizes and locations to simulate 1000's of scenarios (Monte Carlo simulation)

- **EPRI DRIVE** [Xcel, NY, MA National Grid, TVA, SouthernCo]

Applies statistical distributions to equations to account for dispersion of DER on a given circuit and for breadth of the distribution network (can be described as hybrid stochastic-streamlined; proprietary method with implementations for many distribution system analysis tools)

ITERATIVE vs EPRI DRIVE method comparison



ITERATIVE

EPRI DRIVE

- San Diego Gas and Electric's EPIC Final Report (12/2017, pg. iv)

  Conclusion: DRIVE hybrid method produces comparable results

  https://www.sdge.com/sites/default/files/EPIC-1%20Project%204_Module%203_Final%20Report_0.pdf

Xcel Energy hosting capacity analysis (HCA)

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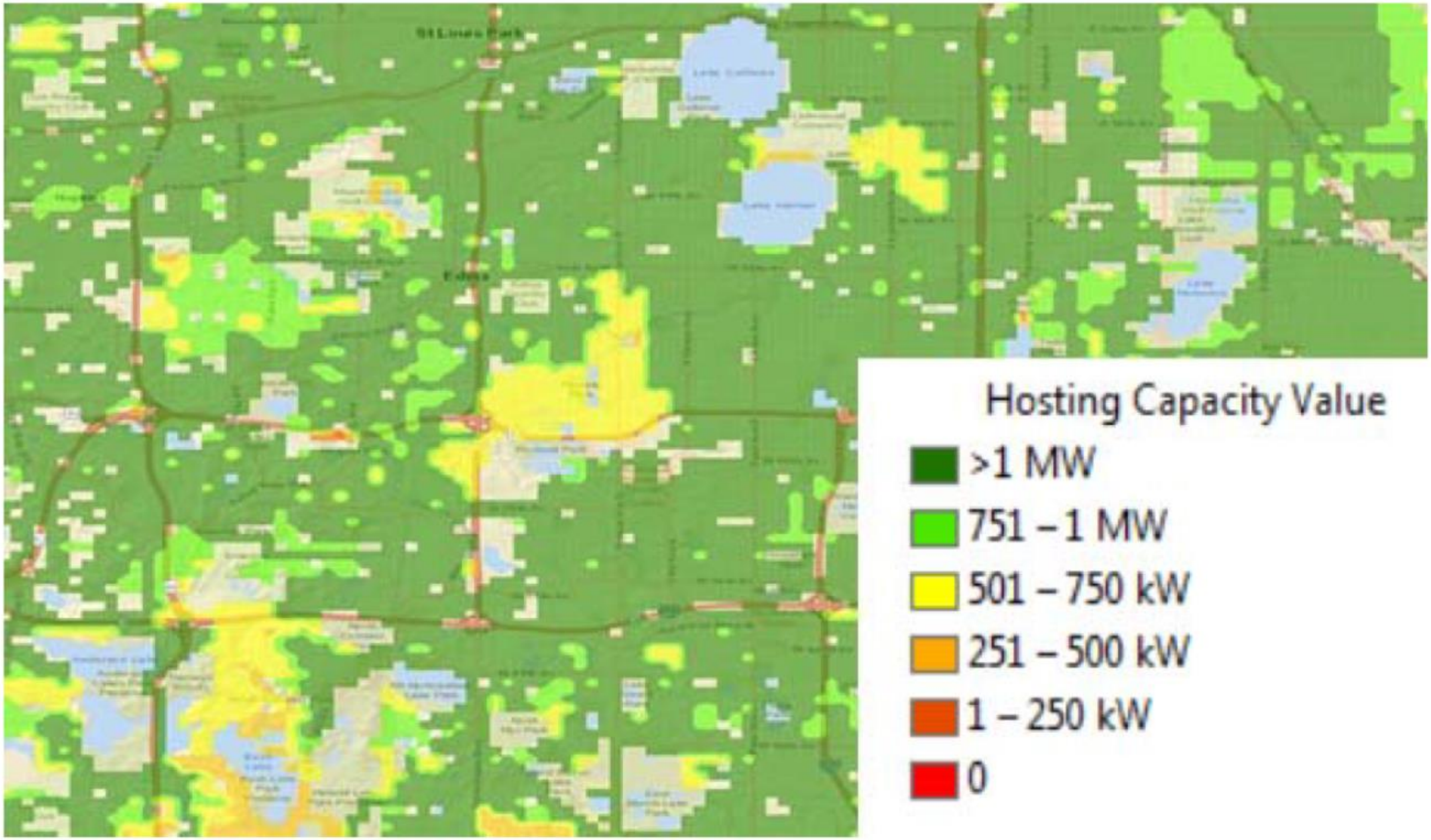
- July 2018: Minnesota PUC ordered hosting capacity analysis be one of the distribution plan filing requirements:
  - HC of **each feeder** on the Xcel distribution system for small-scale distributed-generation resources (1 MW or less)
  - Xcel must file a HCA Report on an **annual** basis
- November 2018: Xcel filed a color-coded map-based representation of the available HC down to the feeder level
  - Used **EPRI DRIVE** methodology
  - Provided also tabular HCA results for each feeder: Minimum HC MW, Minimum Limiting Criteria, Maximum HC MW, Maximum Limiting Criteria
- Xcel considered only DERs that act as generation sources. Future DRIVE releases will improve HCA for load sources (e.g., EVs and storage)
- HCA maps provided “a starting point prior to an interconnection application.” It produced discrete hosting capacity of individual feeders without analysis of the cumulative effects of DER additions.

Xcel visual hosting capacity result example



https://www.xcelenergy.com/working_with_us/how_to_interconnect

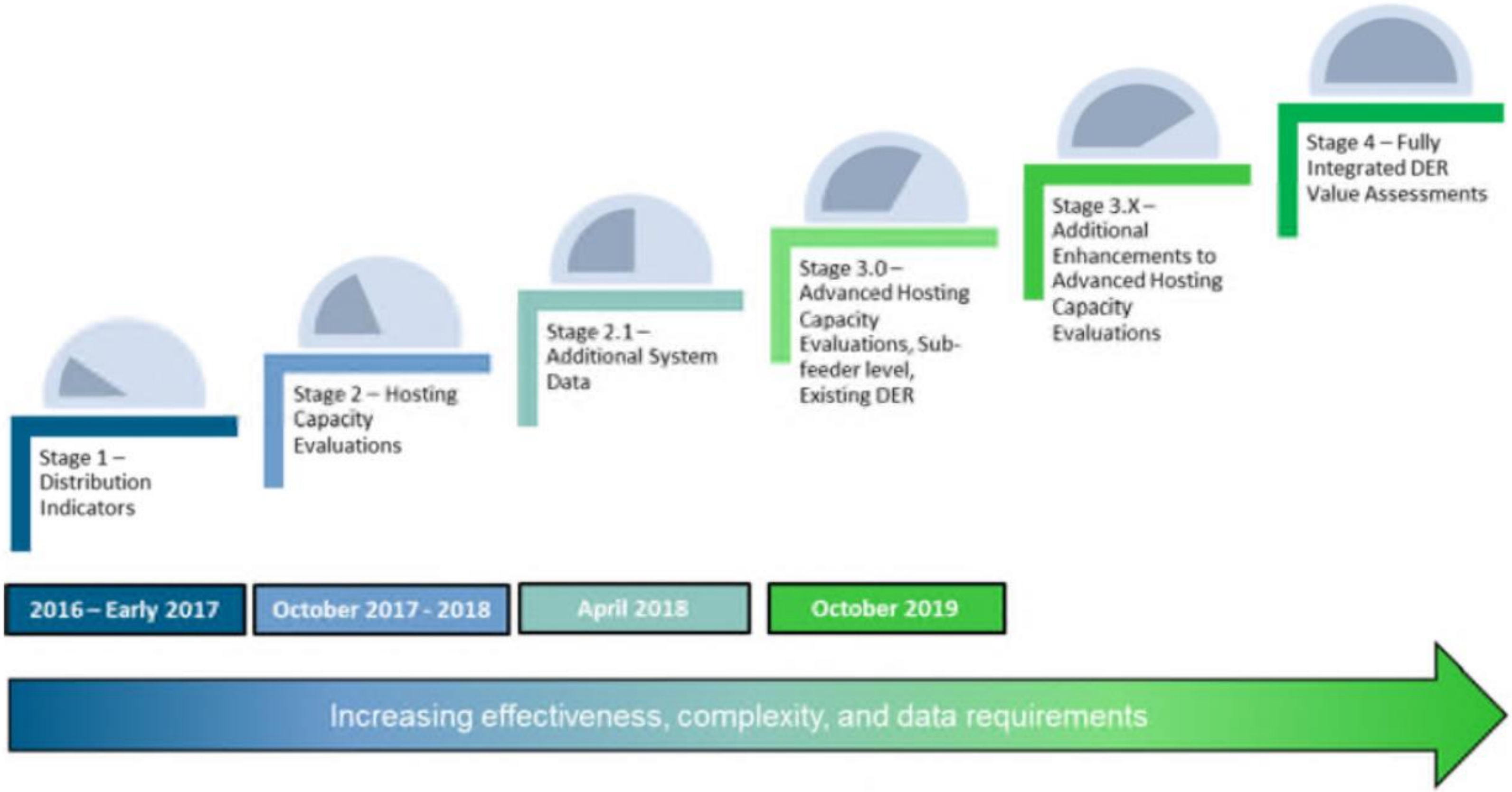
Xcel lessons learned

- Due to the large amount of community solar gardens deployed in Minnesota, Xcel used only the *Large Centralized* option of the DRIVE tool that considers DER separately at each location. Using *Small Distributed* option for roof-top secondary system installations thought to be complex and inaccurate.
- HCA conducted on ~1,000 feeder models using Synergi Electric tool
  - 2018 HCA results show 95 feeders with zero maximum hosting capacity (83 of which already have 1 MW or more)
- Used 7 of 11 violation criteria available in DRIVE (3 voltage, 1 thermal, 3 protection)
- Removed certain feeders from the heat map to protect confidential customer data, and/or critical distribution infrastructure information
- Recent DRIVE tool enhancements included
  - Reverse Power Flow based on feeder head threshold violation
  - Unintentional Islanding dependent on switch locations
  - Inclusion of fuses for thermal violations

New York State HCA

- March 2017: New York PUC ordered hosting capacity analysis be a part of the Distributed System Implementation Plan filings:
  - HC of **each radial distribution** circuit operating at or above 12 kV
  - HCA results must be published on annual basis
- Since October 2017: Joint Utilities of NY filed color-coded map-based representation of the available HC
  - Used **EPRI DRIVE** methodology
  - Updating hosting capacity data on a **monthly** basis
  - HC displays use pop-up boxes to provide system data, including minimum and maximum total three-phase feeder hosting capacity, peak load, and installed and queued DG values (available in Stage 2.1)
- Future Stage 3 releases could include sub-feeder level hosting capacity, increased analysis frequency or forecasted hosting capacity evaluations
- April 2018: Joint Utilities of NY recognized the need to balance the value of increasing the granularity of the analysis against the additional computational time and its subsequent impact on refresh frequency

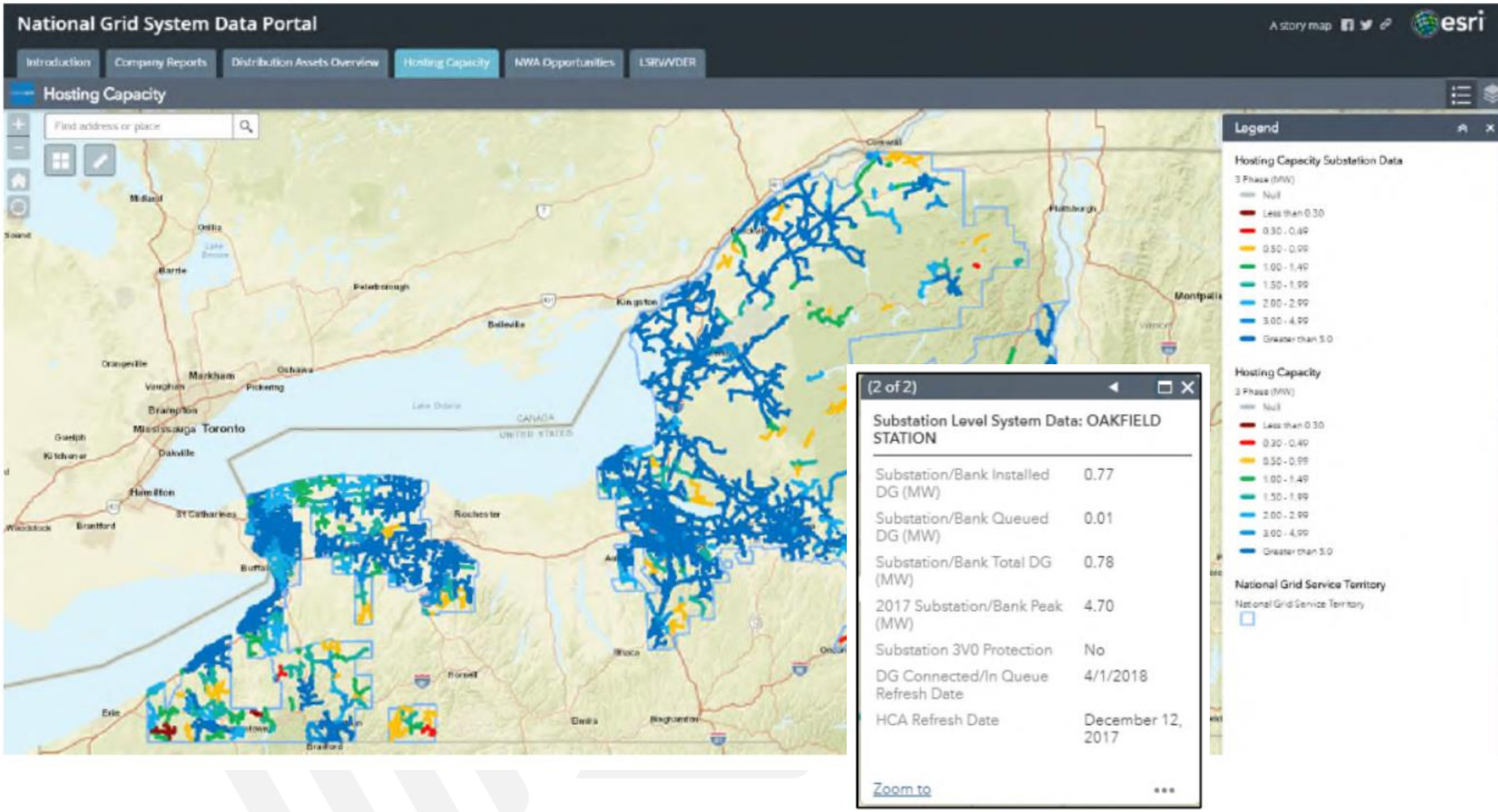
NY Joint Utilities Roadmap for HCA



► Follows EPRI Roadmap "Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State," June 2016.

http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008848

National Grid hosting capacity portal



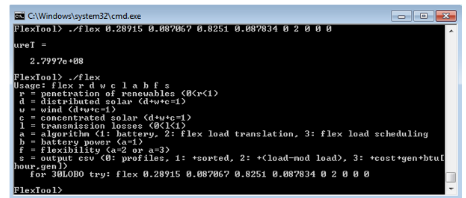
https://ngrid.apps.esri.com/NGSysDataPortal/NY/index.html

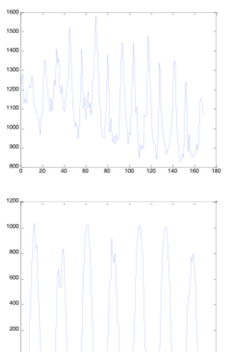
NY HCA lessons learned

- National Grid
  - Biggest challenge in completing the Stage 2 HCA: the quality of the data used for individual feeders. Need automation of HCA data processing.
  - Performed HCA on all 910 15 kV class feeder models as well as 1,009 5 kV class feeders using CYMDIST distribution power flow software
- CHGE
  - Had to work with distribution software (DEW) vendor to extract DRIVE input data
  - CHGE was approved for additional engineering resources to support HCA tasks
  - Stage 3 release (10/2019) will provide sub-feeder level hosting capacity incorporating existing installed DERs into the modeling
- O&RU
  - Creating, cleaning, and maintaining GIS mapping information expedites the HCA process
  - The experience from previous distribution network modeling projects allowed O&R to create the modelling files for DRIVE that permit an accurate analysis to be run in a shorter amount of time

Detailed analysis

PV Scenario Scripts

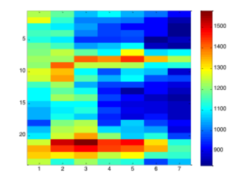


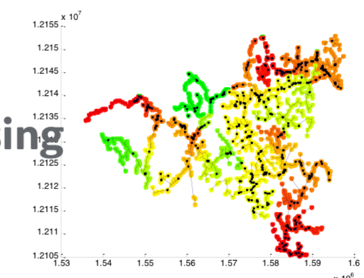


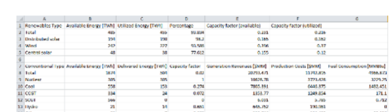
Data Filtering Scripts

Time Series Load-Flow Simulations

Post-processing Scripts

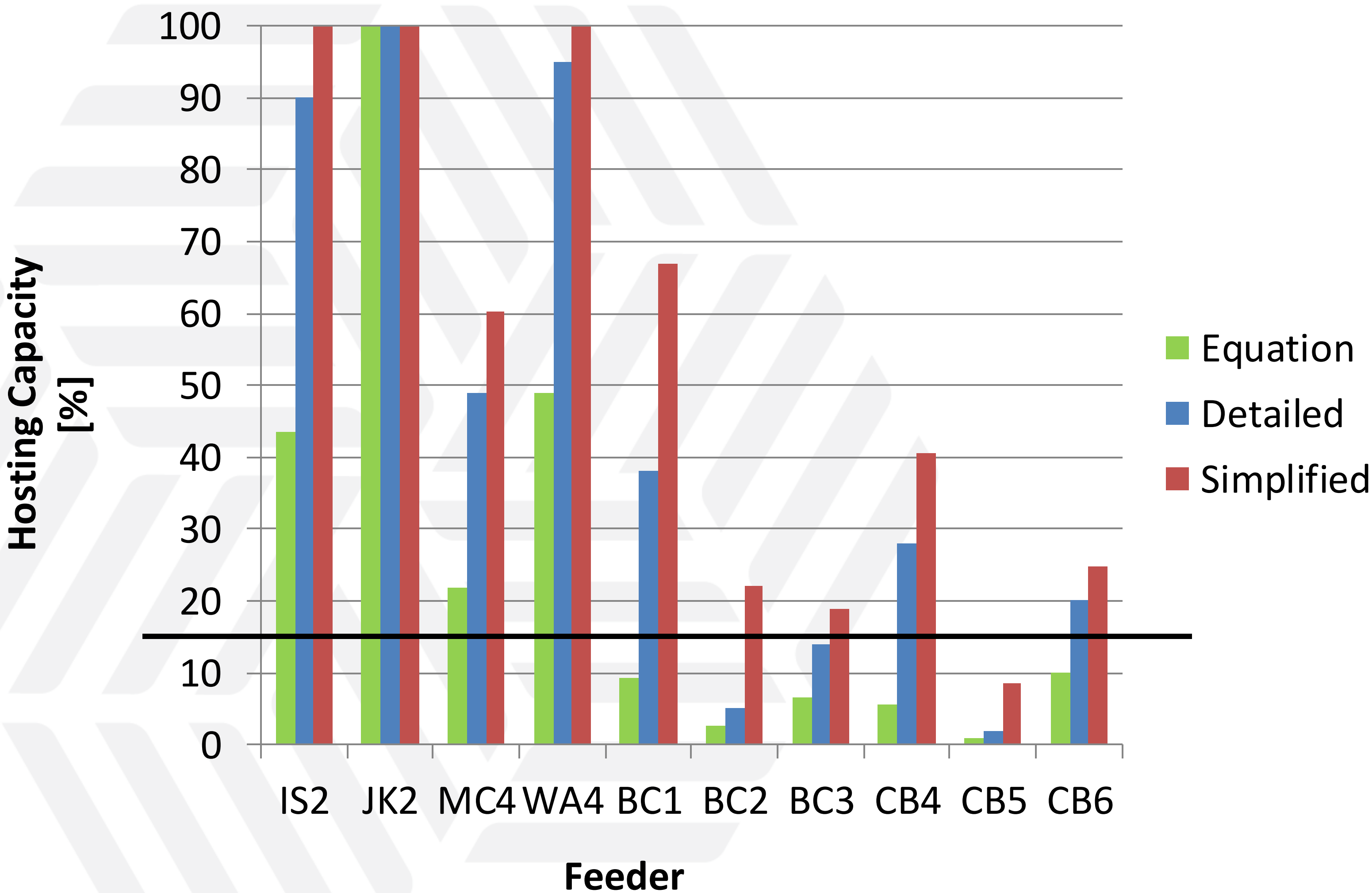






DSTAR, http://www.dstar.org/research/project/103/P15-6-impact-and-practical-limits-of-pv-penetration-on-distribution-feeders

Method comparison - hosting capacity



Locational Net Benefits

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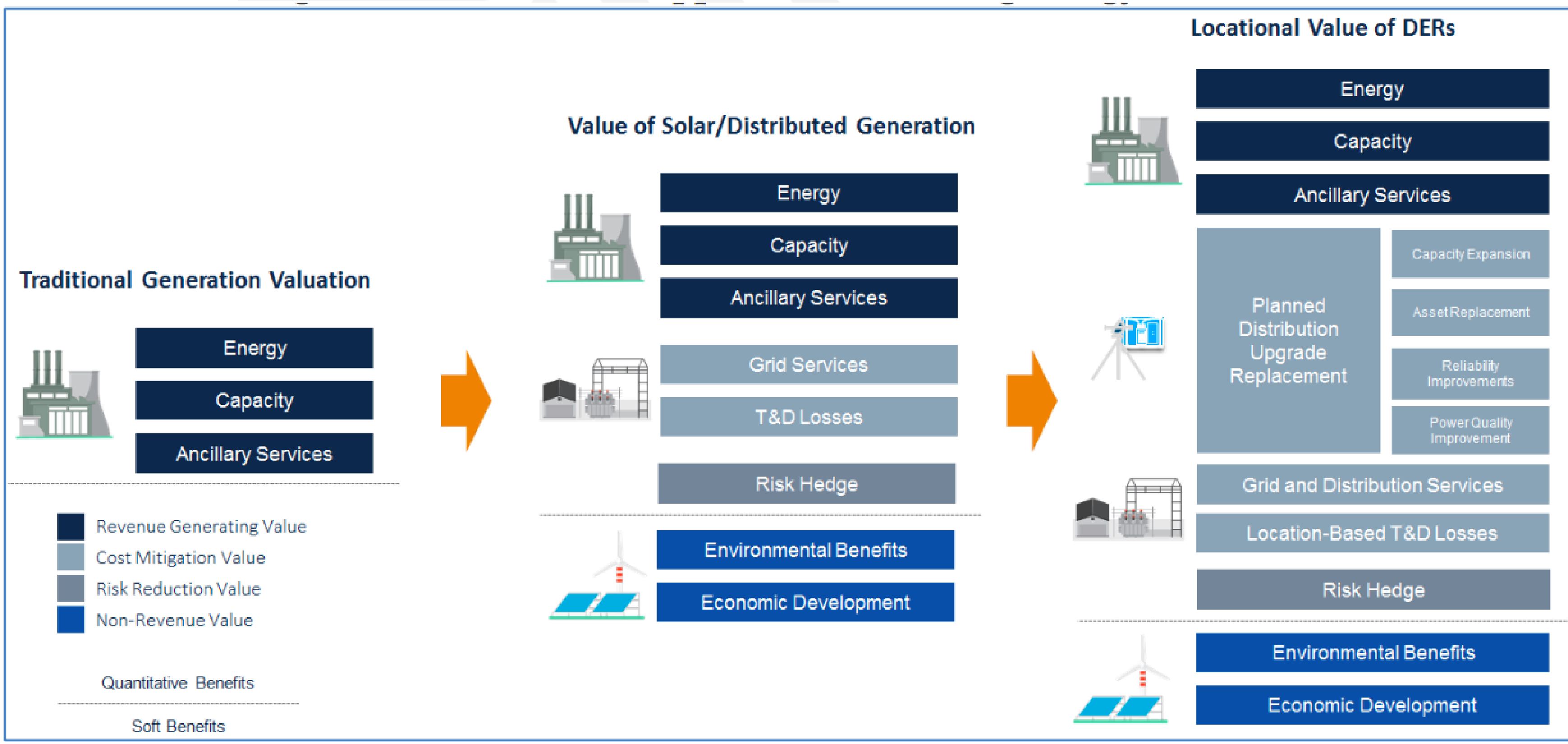
Why LNBA?

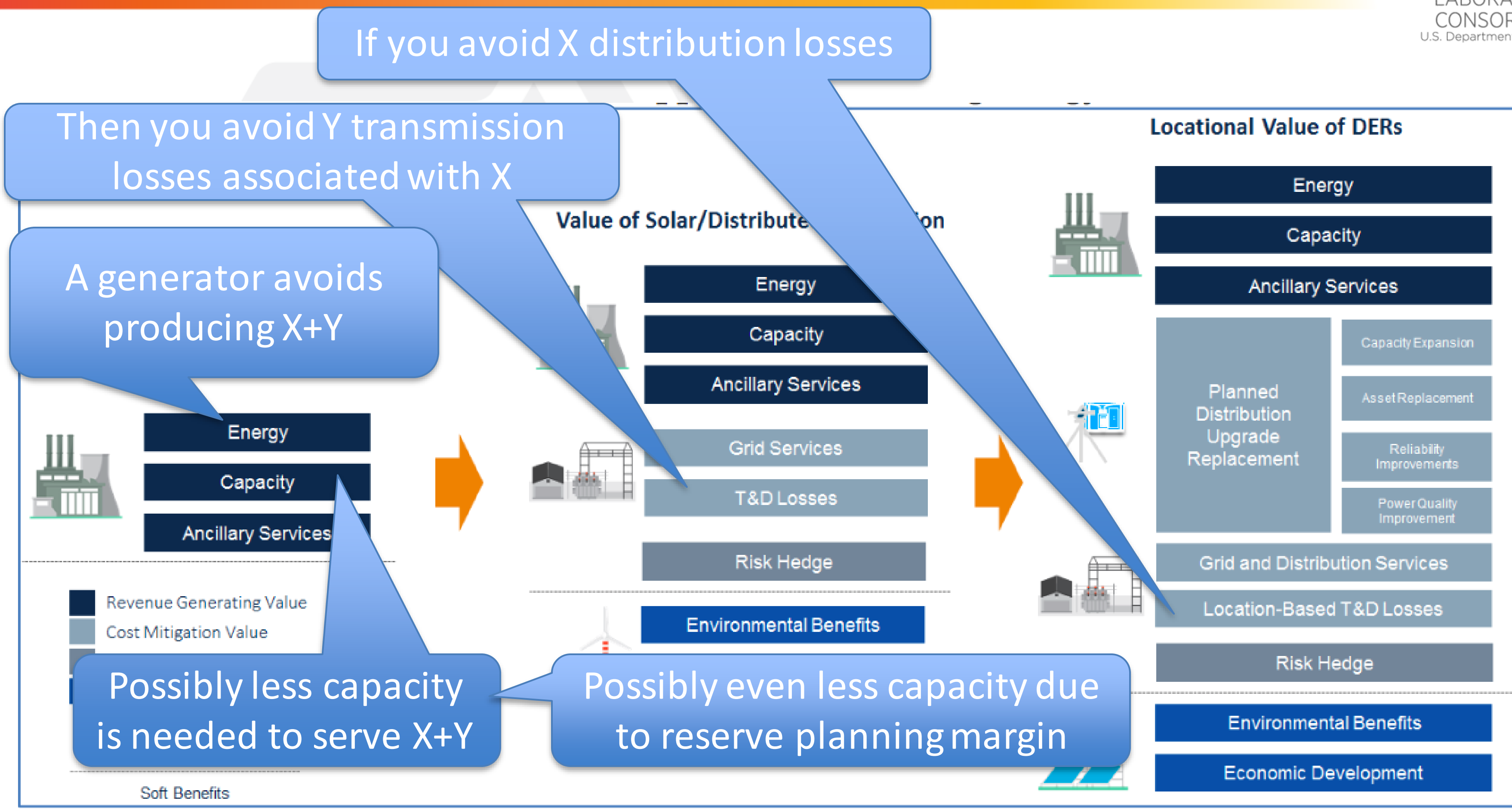
- Public tool and heat map
- Prioritization of candidate distribution deferral opportunities
- Determine cost-effectiveness, compare projects
- Inform compensation or incentives

Benefits of DERs



Ben Kellison, "Unlocking the Locational Value of DER 2016: Technology Strategies, Opportunities, and Markets," January 2016,

These value streams have ripple effects



Ben Kellison, "Unlocking the Locational Value of DER 2016: Technology Strategies, Opportunities, and Markets," January 2016,

Calculate the localized impacts first

Beware: Pitfalls of calculating locational net benefits

- ► Benefits vary
  - By technology
  - By time (of day, season, etc.)
  - By location (LMP node, feeder, location on feeder)
- ► The value of PV declines with increasing penetration (can be mitigated with storage)
- ► DER may provide many services/benefits – be careful to avoid double-counting
- ► What are you avoiding? What is the business-as-usual path?
- ► Average avoided cost estimates are easy and transparent but lack rigor of modeling actual hourly, location-based operations. Get the large value streams correct.

Avoided energy

DER may avoid fuel and O&M costs from the marginal generator

- ► DER may avoid the energy it produces plus the T&D losses associated with that production
- ► Options for calculation:
  - Assume marginal generator(s), heat rate(s)
  - Historical Locational Marginal Prices (LMPs), forward prices
  - Nodal LMP – production cost modeling simulates unit commitment and economic dispatch for each hour of the year

Avoided capacity

DER may avoid the need for additional generation capacity

- ► DER may avoid capacity equivalent to its capacity value plus some amount due to avoided T&D losses. It may also avoid additional capacity that would be needed for the planning reserve margin (e.g., 12-15%).
- ► Options for calculation:
  - Average capacity factor of DER during peak net-load hours
  - Approximations to effective load-carrying capability without iterations
  - Effective load-carrying capability analysis with iterative loss-of-load probability calculation

Transmission losses

DER may avoid transmission losses

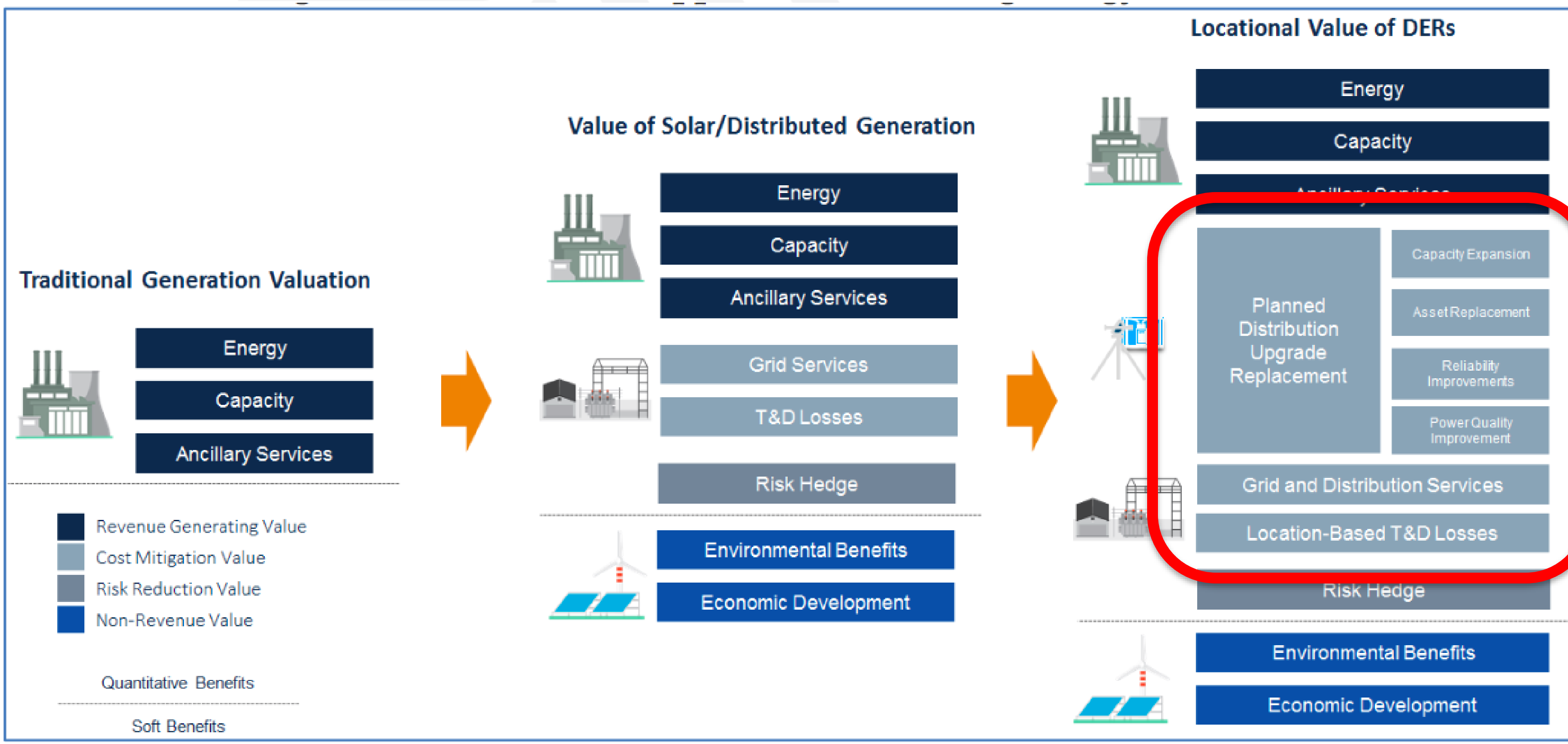
- ► DER may avoid transmission losses associated with the energy production of the DER plus avoided distribution losses
- ► Options for calculation:
  - Average loss rate – overestimates losses
  - Marginal loss rates with diurnal and monthly profiles – losses are higher during peak flows
  - Power flow modeling – production cost models may estimate transmission losses

Avoided emissions

DERs may avoid CO_2, NO_x, SO_2 and other emissions

- DERs may avoid emissions associated with avoided energy use. It may also avoid or incur emissions based on generator cycling (starts, ramps, part loading)
- Options for calculation in order of simplicity:
  - Assume marginal generator(s), emissions rate(s)
  - Correlation of historical LMPs to generator type and associated emissions rate
  - Production cost modeling simulates unit commitment and economic dispatch for each hour of the year. It can also capture cycling impacts.

Benefits of DERs



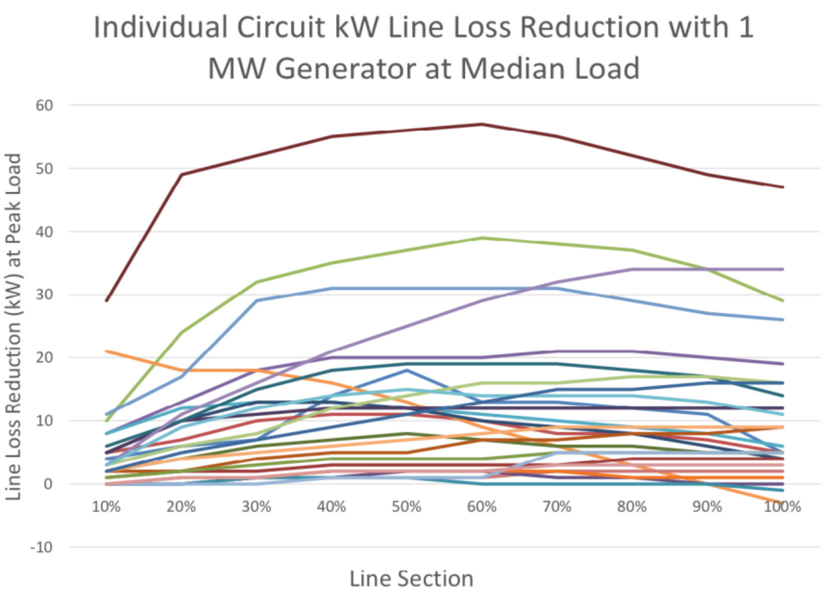
Ben Kellison, "Unlocking the Locational Value of DER 2016: Technology Strategies, Opportunities, and Markets," January 2016,

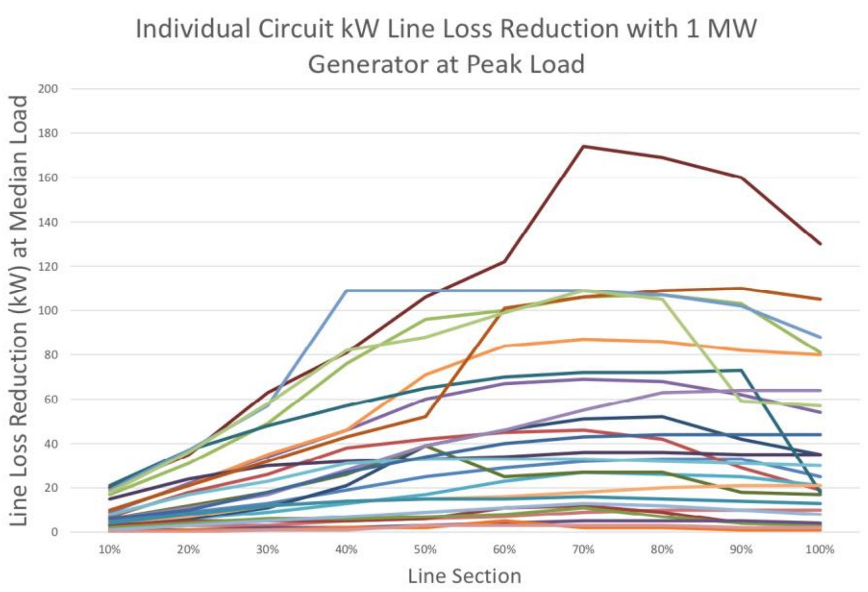
Distribution losses

DER may avoid distribution losses since energy is generated at the point of consumption.

- Issues
  - High penetrations of DER could lead to reverse power flow and increased distribution losses.
  - Different types of feeders result in different sensitivities.
  - We don’t know where DER will be and location matters.
  - Size of DER compared to feeder loading matters.
  - Timing of DER peak to feeder loading peak matters.
- Options for calculation:
  - Average loss rate – overestimates losses
  - Marginal loss rates with diurnal and monthly profiles – losses are higher during peak
  - Power flow modeling of feeder for selected (peak load, peak PV, etc.) periods or time-series simulations. Computationally challenging: where and how big are the DERs; should all feeders or representative feeders be modeled?

SDG&E distribution losses vary widely



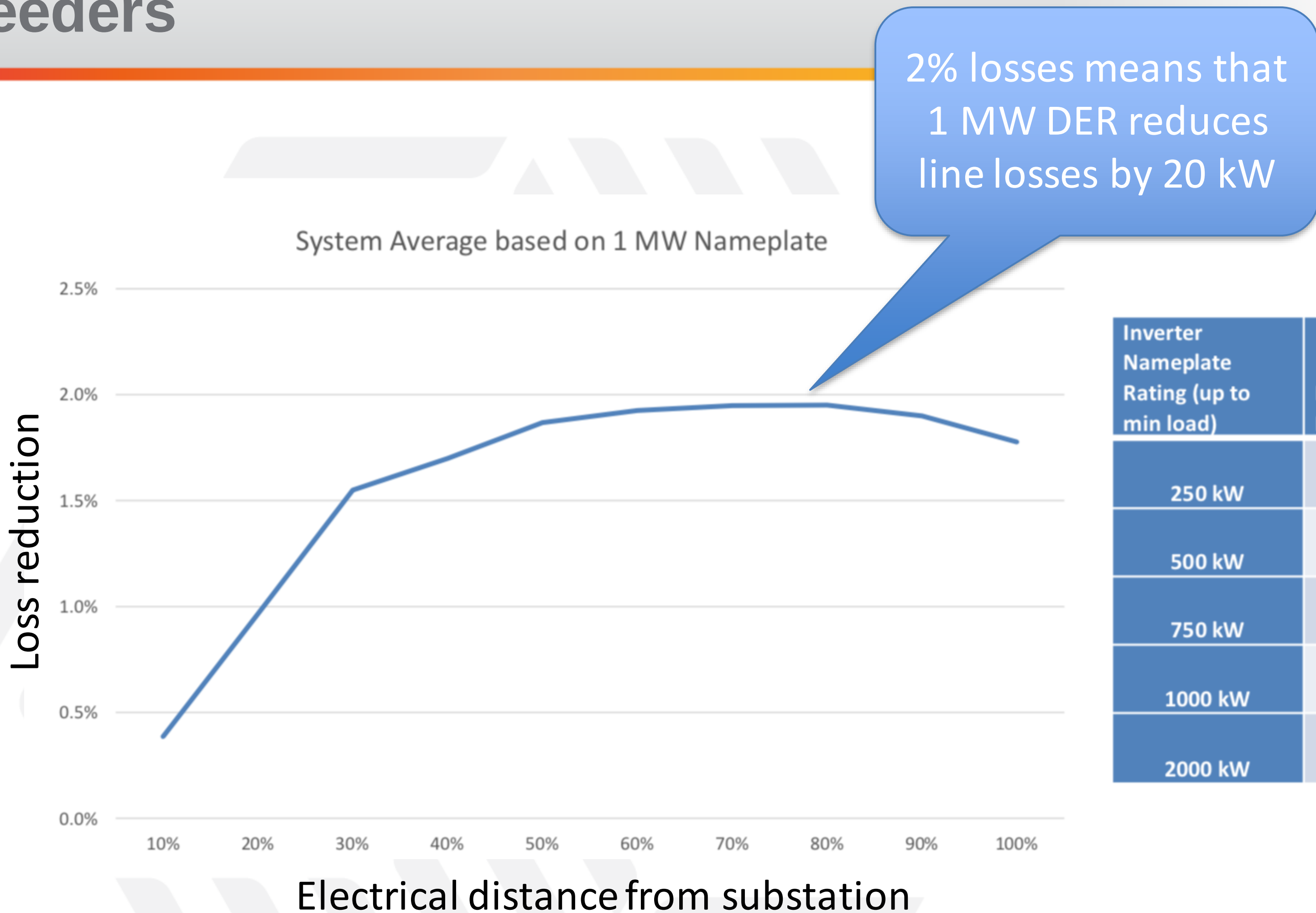


Every feeder is different

Peak loading times show much more variance in location and loss reduction

Source: SDG&E Nov 13, 2017

SCE finds 2% loss reduction in 12kV/16kV feeders



Inverter Nameplate Rating (up to min load)	Percent Reduction
250 kW	0.5%
500 kW	1%
750 kW	1.5%
1000 kW	2%
2000 kW	4%

SCE found *no* reduction in average line losses for any location of 1 MW DER for 4kV circuits because it resulted in reverse power flow

Source: SCE Nov 13, 2017

Avoided distribution capacity, deferrals of upgrades, distribution impacts

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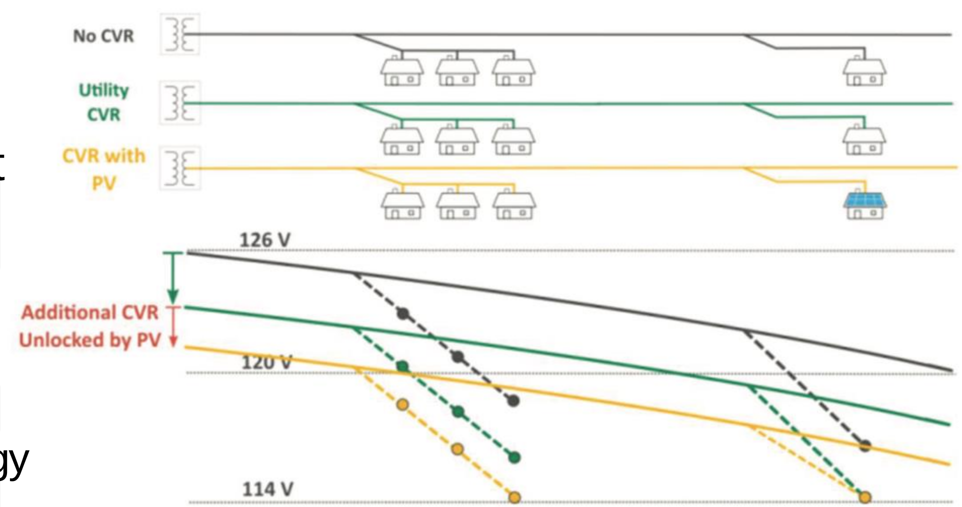
DER may avoid the need for additional T&D capacity or defer the need for upgrades. DER may also incur costs.

- ► There are many impacts to consider: Equipment may not be capable of bi-directional power flow; DPV may lessen life of load-tap-changers; smart inverters can regulate voltage, etc.
- ► Options for calculating benefits:
  - Value DER contribution at peak hours at average distribution investment costs
  - Power flow modeling – load growth triggers upgrade that can be deferred by DER
- ► Options for calculating costs:
  - Assume zero – assume DERs limited to hosting capacity
  - Detailed interconnection study for a DER project would cost out a handful of workable mitigation options

Conservation voltage reduction

- Save energy by flattening distribution voltage profile
- DPV and smart inverters can increase end of line service voltage to enable CVR
- DPV and smart inverters along circuit give granular control to CVR
- Options for calculation:
  - For locations on circuits with low voltages, CVR benefit could be a locational value, avoiding some energy and capacity needs
  - CVR benefit is contingent on the details: load and feeder characteristics; smart inverter locations; utility device capability, control and settings; and system communication capabilities. Attribution of savings is tricky because feeder customers receive the benefit.

Figure 1 – Image from SEIA Smart inverter Presentation



Source: LNBA WG Final report Jan 9, 2018

Beware: Not easy to defer distribution capacity

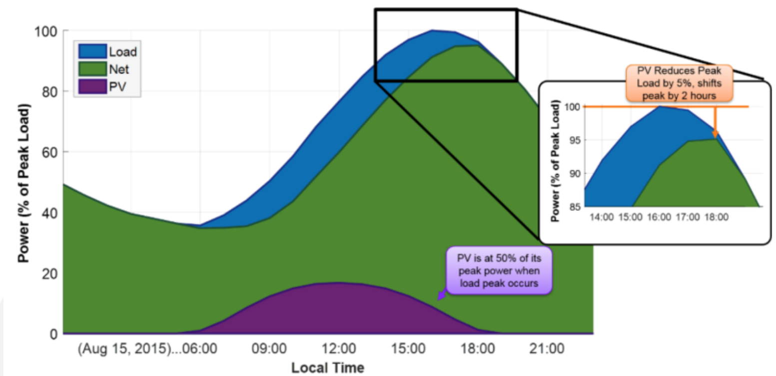
Avoided, deferred or incurred costs on distribution feeders/substation to accommodate load growth

- Is there a need for upgrades or new capacity?
  How much available capacity is there now and in the planning horizon?
- Does the output of the DER match the stressed hours/seasons of the capacity need?
- Is the DER location able to defer that capacity?
- Can the DER consistently/reliably provide power at that time? What happens if it's cloudy (for DPV)?

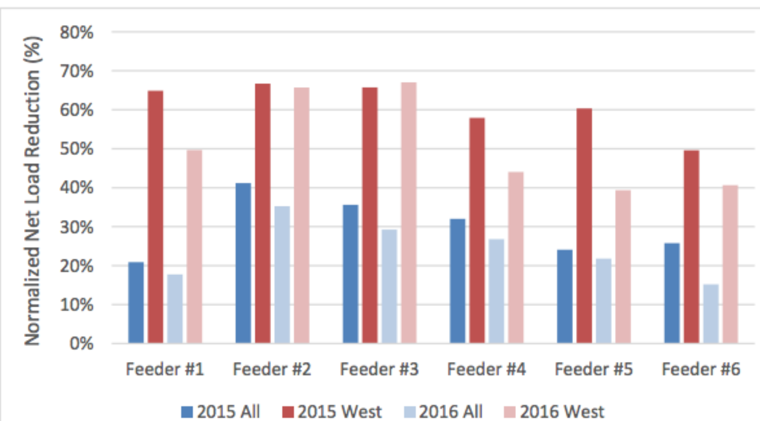
- Will the DER be available throughout the deferral period?
- Can the utility monitor/control the DER to meet distribution system needs?
- Calculation is feeder-dependent

Simulations and experience in distribution deferrals

- APS' Solar Partner Program results:
  - Adding PV did not reliably reduce peak load at house or secondary transformer, but did at the feeder level. ¼ of houses produced less than 5% at time of peak load.
  - Aggregated PV reduced peak net load by 15-41% of PV capacity
  - West-facing PV produced 2-3x the power at peak than the south-facing
  - Correlation between high feeder loading and high PV output



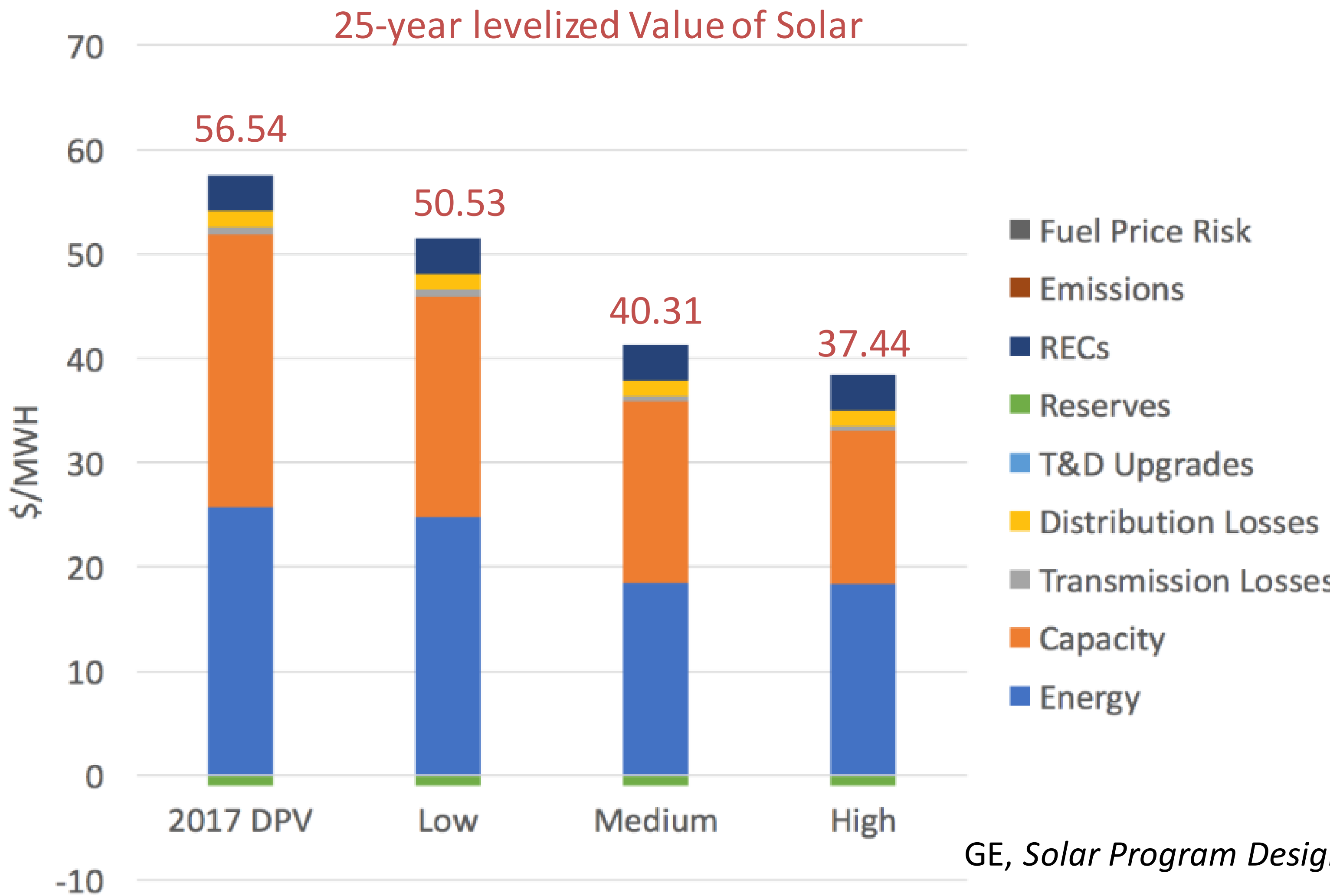
- Cohen, et al., analysis of PG&E feeder upgrades shows:
  - 90% of feeders receive no deferral benefit
  - Remaining feeders receive $10/kW-yr to over $60/kW-yr at very low penetrations
  - Benefits decline as PV increases: at 50% penetration, value is halved



https://www.epri.com/?_sm_byp=iVVwLTjLRHSkw6RL#/pages/product/000000003002011316/

Cohen, et al, "Effects of distributed PV generation on California's distribution system, part 2: Economic analysis", Feb 2016.

Stacking the value stream for DPV



GE, *Solar Program Design Study*, 2017

DPV	7.1MW	20MW	50MW	100MW
UPV	19MW	89MW	89MW	89MW

Questions to ask utilities

- Scenarios
  - How did you select the scenarios? What factors will have the biggest impact on outcomes? How did you take stakeholder input into account?
  - Where did the input data for load, energy efficiency, demand response, DPV, storage, and other DERs come from and are those reliable, recent studies?
- Hosting capacity
  - How do you plan to use these results?
  - What method was used and is that method appropriate for the application?
  - Which power system criteria did you evaluate?
  - At what level of granularity did you analyze the criteria?
- LNBA
  - Which components are included or excluded and are these appropriate for the application?
  - What methods were used to quantify each component? Do you think results are optimistic? Conservative?

Resources

- California DRPs http://www.cpuc.ca.gov/General.aspx?id=5071
- California DRP working group page http://drpwg.org
- New York REV DSIPs http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101&submit=Search+by+Case+Number
- NREL on DPV benefits and costs https://www.nrel.gov/docs/fy14osti/62447.pdf
- DSTAR on hosting capacity http://www.dstar.org/research/project/103/P15-6-impact-and-practical-limits-of-pv-penetration-on-distribution-feeders
- EPRI on hosting capacity https://www.epri.com/#/pages/product/1026640/
- EPRI on shorthand equations https://www.epri.com/#/pages/product/3002006594/

Any Questions?

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Uncertainty and risk in each input/assumption

- Uncertainty – rated DER types for high, medium or low range of possible outcomes
- Impact – rated DER types for large, medium and small impacts on grid
- Risk – function of both uncertainty and impact. Risk is asymmetrical.

Area	Rating	Description
Uncertainty: IEPR	**High**	The IEPR PV system-level forecast captures the volume of PV growth allocated to circuits. Variance and uncertainty in the top-line forecast will proportionally impact the allocation to circuits.
Uncertainty: Method	**Medium**	The S-Curve models are used to allocate total PV adoption to the circuit level. The models are estimated with good quality geographic data providing a strong basis for allocation. All IOUs are in the process of testing, evaluating, and refining their models by exploring input variables and measuring their methods against prior year outcomes.
Uncertainty: Shapes	**Low**	While PV generation data for customers within the IOUs service territory is limited, hourly solar generation profile data are available from national and state level studies. These data may be applied to the IOU service territory, if appropriate.
Uncertainty: Near-Term Lumpiness	**Low**	Near term adoption for large projects is managed on a case-by-case basis with known projects in the interconnection queue.
Uncertainty: Long-Term Lumpiness	**High**	Timing and location of large projects in the long term are difficult to forecast accurately creating significant uncertainty.
Impact	**Large**	Due to the size of the PV market relative to other DERs, the expected impact on distribution planning is large.
Risk	**High**	Time series locational adoption data are well developed due to the requirement for interconnection agreements. These data support direct adoption modeling at the Zip code level, and adoption forecasts are used to allocate system totals. However, the impacts of PV are expected to be large and the location and timing of large projects is unknown in the long run. As a result, risk is judged to be high.

Itron, Distribution Forecasting Working Group Final report June 28, 2018

Hosting capacity

- Amount of DER that can be accommodated without adversely **impacting** power reliability or quality under **current** configurations, without requiring mitigation or infrastructure **upgrades**

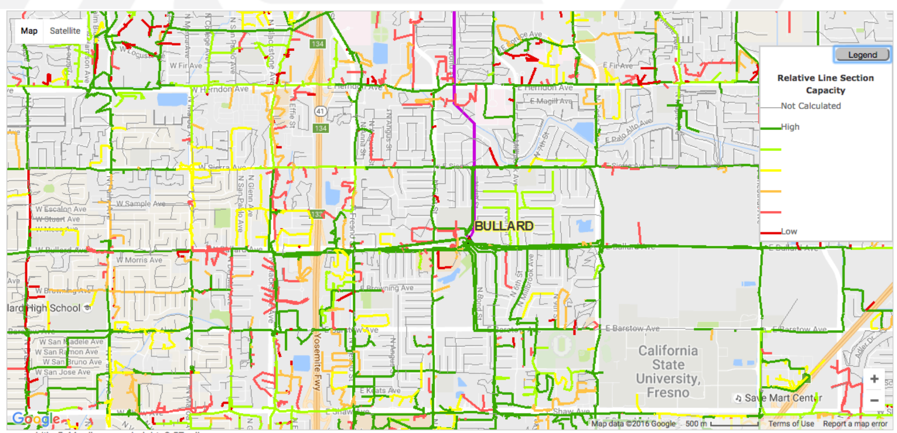
$$\max P_{DER}$$

$$0.6\ \mathrm{MW}$$

$$\frac{\max P_{DER}}{\max P_{LOAD}}$$

$$15\ \%$$

$$0.6 - 1.5\ \mathrm{MW}$$



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