Tools and Methods for Distribution System Planning with Distributed Energy Resources (DERs)

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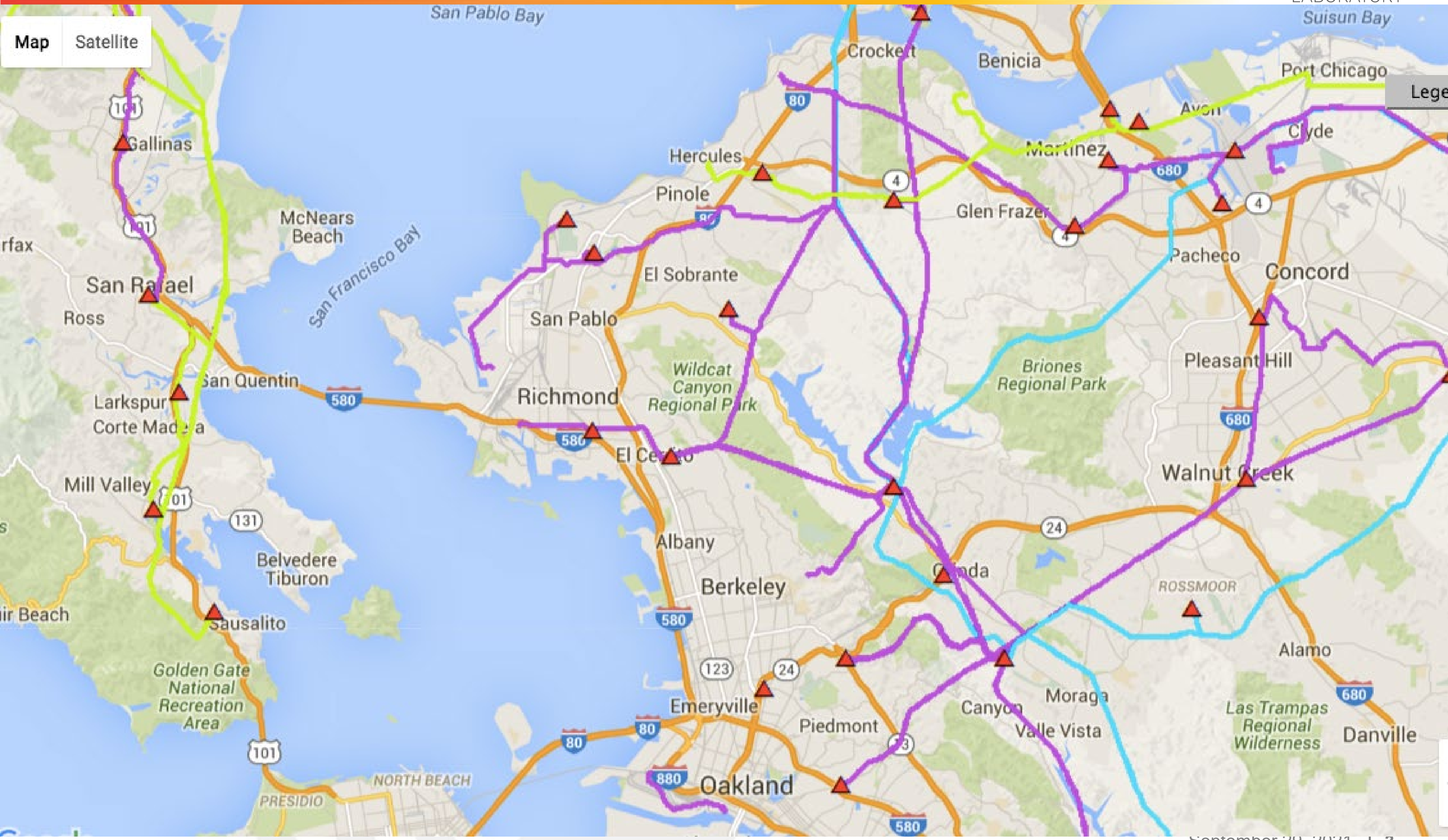
Agenda

- Foundational elements in distribution system planning - Juliet
- Load and DER forecasting - Juliet
- Tools and data integration and holistic planning - Tom
- Standards and planning for smart inverters - Tom
- Bulk system integration and reverse power flow - Tom
- Proactively planning for DERs - Tom
- Locational value assessments - Juliet

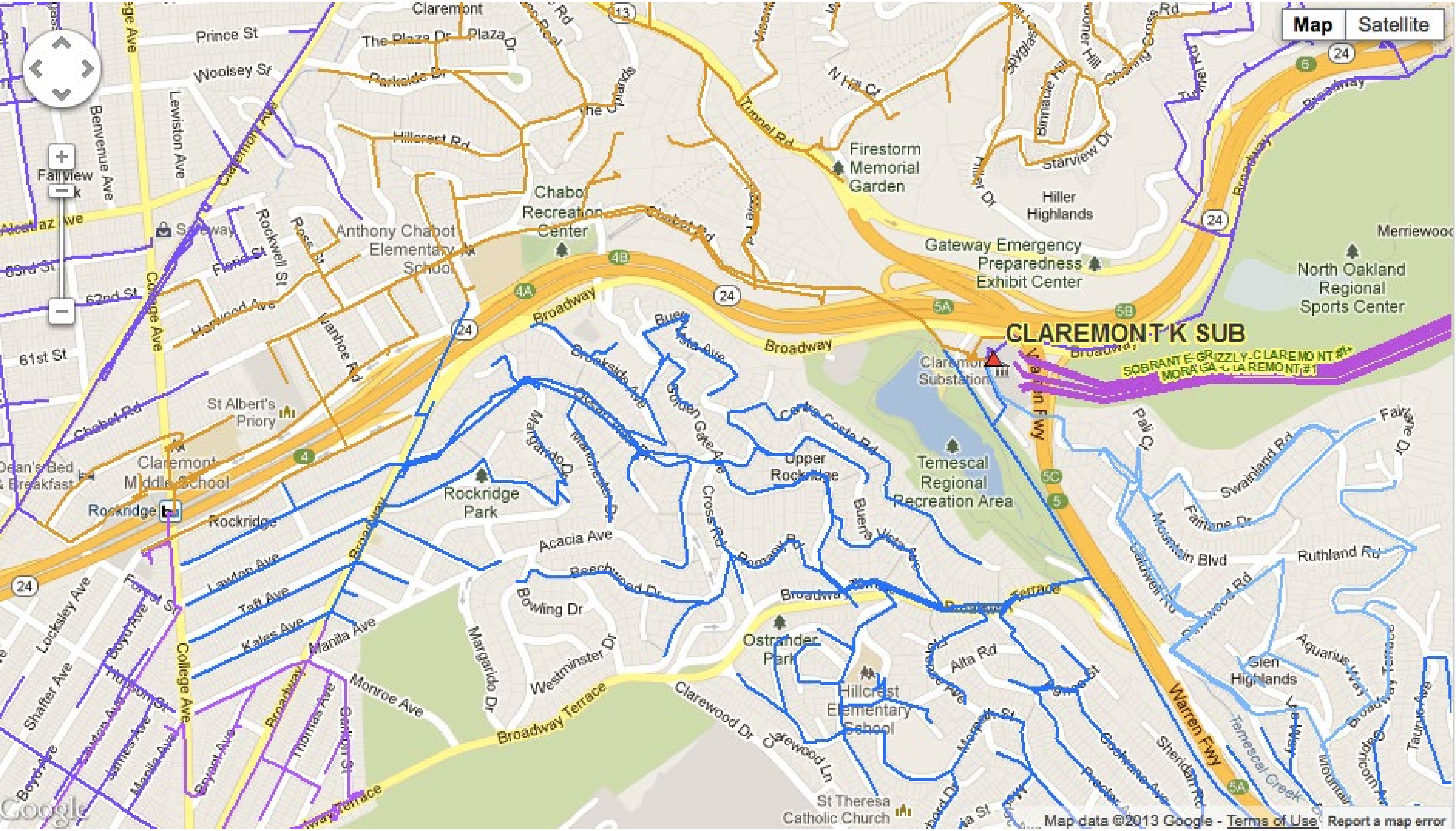
115 kV transmission network

▲ Distribution substations



https://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/PVRAMMap/index.shtml

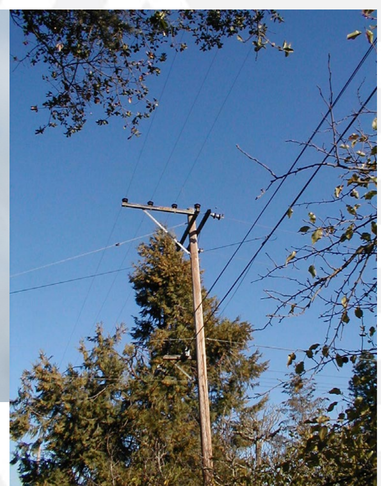
Distribution systems



Foundational elements in distribution system planning with DERs

- Validated and calibrated feeder models
- Accurate and granular data
- Trained staff and right tools for necessary studies

For advanced distribution planning, utilities and commissions need to make **data collection**, **data management**, and **maintaining validated and calibrated feeder models** priorities.



Distribution Operator’s control room, 2003

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DISTRIBUTION SUBSTATION

A distribution substation is where high-voltage electricity from the transmission system or sub-transmission system is converted to lower-voltage electricity for the distribution system.

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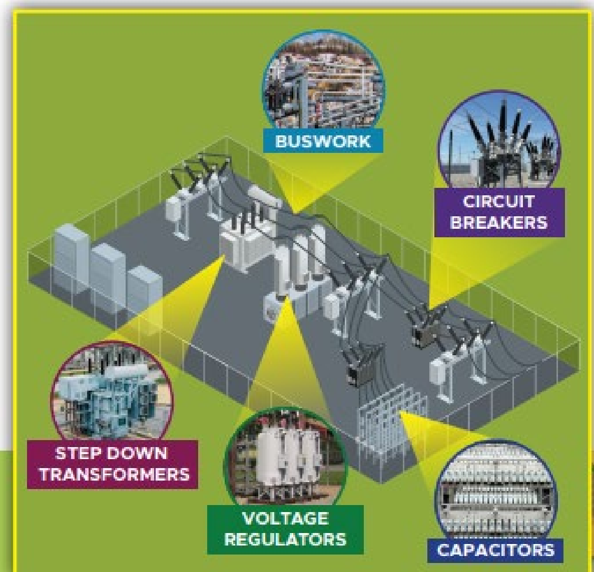
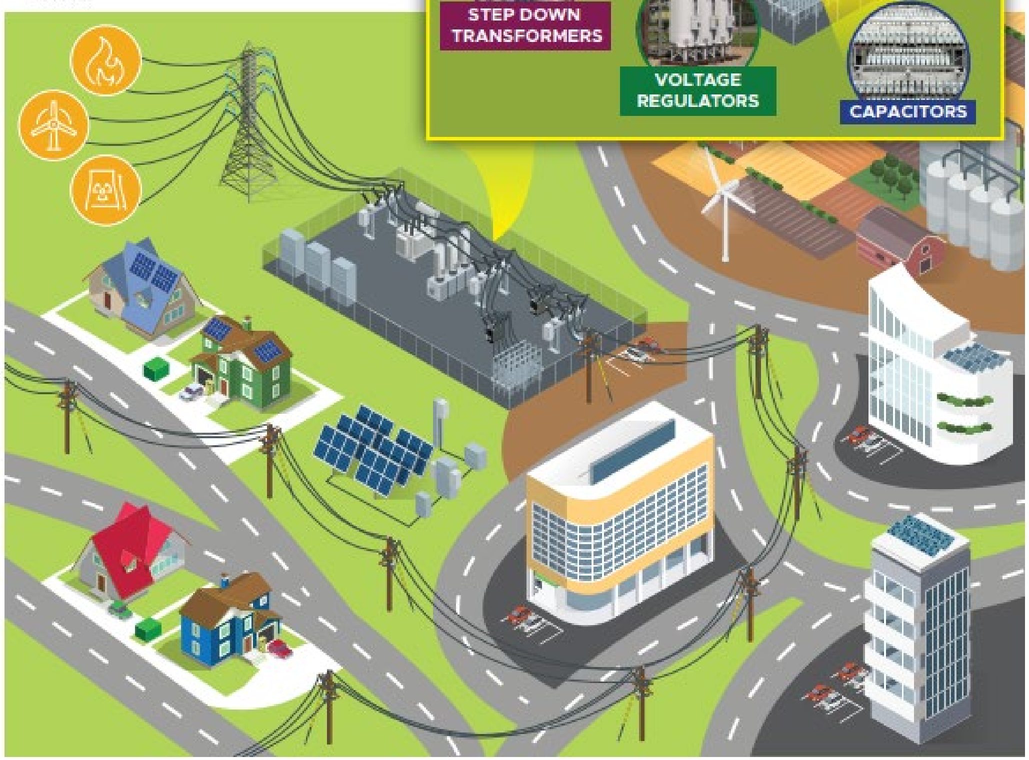
Substation components

- **BUSWORK** consists of electrical conductors that interconnect electrical equipment.
- **CIRCUIT BREAKERS** protect a transformer from damage by interrupting the current when a fault in the line is detected.
- **VOLTAGE REGULATORS** adjust output voltage within a specified range regardless of changes in input voltage or load conditions.
- **STEP DOWN TRANSFORMERS** convert voltage from transmission or sub-transmission levels down to levels appropriate for local distribution.
- **CAPACITORS** maintain or increase voltage in power lines and improve efficiency of the system by compensating for inductive losses.





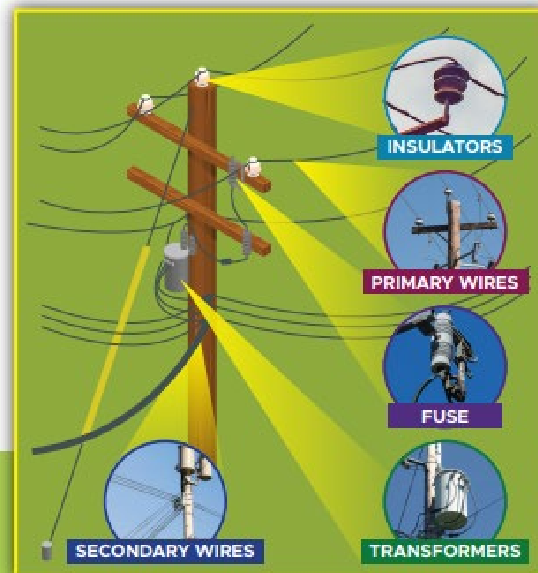
https://epe.pnnl.gov/pdfs/Distribution_system_infographic.pdf

DISTRIBUTION SYSTEM

The distribution system refers to the medium voltage system (typically up to 35 kV) which distributes electricity to and from customer houses and businesses. This system includes physical equipment as well as information, communications, and operational technologies.

Utility pole components

- **INSULATORS** are non-conducting supports which prevent energized wires from coming in contact with or arcing to the utility pole.
- **PRIMARY WIRES**, also called conductors, are on top of the pole and carry medium voltage electricity from a substation to the transformer.
- A **FUSE** is housed in a cutout and interrupts power flow when there is an overcurrent in the line.
- Service or secondary **TRANSFORMERS** step voltage down from primary distribution levels to lower voltage secondary levels for customer use. Transformers can also be housed in a steel box on the ground if the electric wires are underground.
- **SECONDARY WIRES** carry lower voltage electricity from the transformer to the home or business where electricity is used.



https://epe.pnnl.gov/pdfs/Distribution_system_infographic.pdf

Eyes and ears in the field

Key challenges around data and feeder models

Challenges and Gaps – Data and Feeder Models

- Developing required data sets to conduct detailed analyses
- Managing the sheer amount of data and daily configuration changes
- Breaking down data silos at utilities
- Standardizing data formats between applications
- Making sure validated and calibrated feeder models are kept up to date

Questions states can ask utilities

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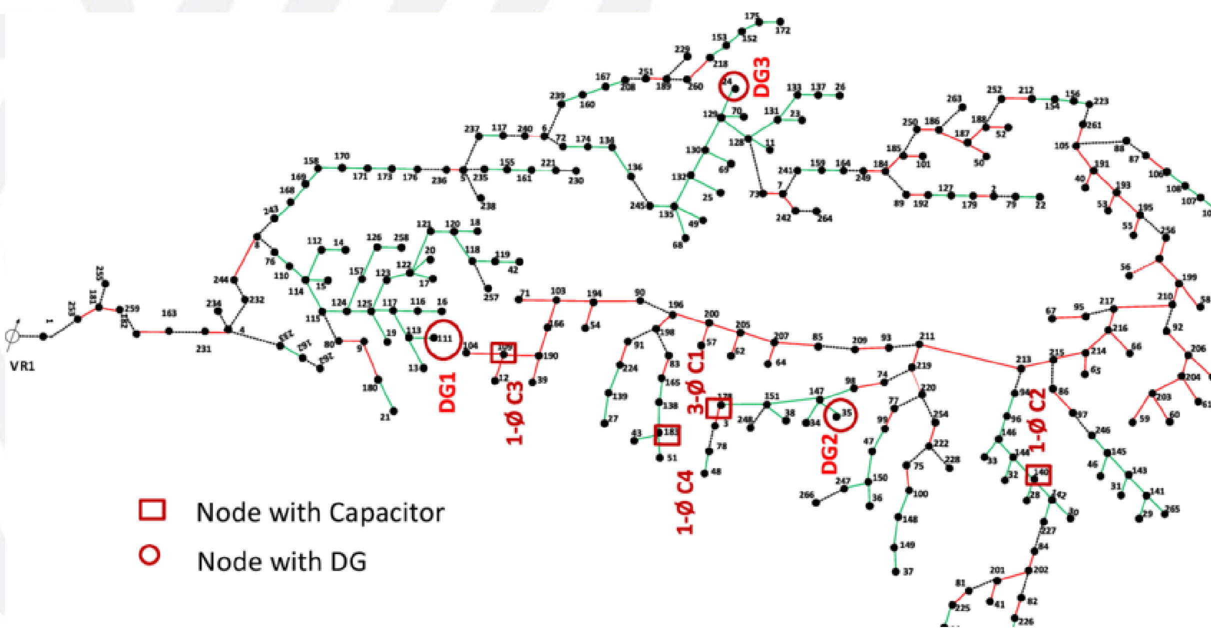
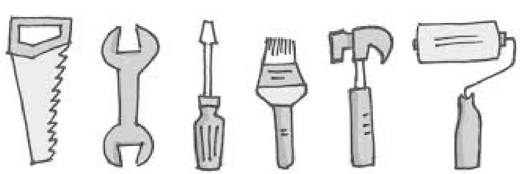
- What is your source data for your models?
- How accurate do you think your models are?
- Do you have a way to check the accuracy of your models
- What are your mechanisms for updating your models?
- How often are they updated and how are you updating your models?
- Do you have visibility into customer EVs and solar? How do you take that into account?



Tools utilities currently have and what they can do

- <u>Operational tools</u> – Used for day-to-day system operation
  - Include supervisory control and data acquisition (SCADA) and distribution management systems (DMS)
  - Developed by companies such as GE, Siemens, ABB, and Survalent
- <u>Planning models</u> – Developed from operational models
  - Power flow models – make sure all loads are served and voltage standards met
  - Most common software: CYME, Synergi, and Milsoft
  - Relatively static steady-state power flow models; updated every year or two
- For detailed <u>hosting capacity and interconnection studies</u>, need more than traditional power flow planning models operated in traditional way
  - Need to use existing tools in a new way through add-on modules; conduct analyses with more granularity in space and time, or
  - Need new models (such as those that consider dynamic electromagnetics)
  - Requires **capabilities, skill sets, and data many utilities currently don’t have**



Utility staffing implications of planning for DERs

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- Utilities are staffed up to do traditional distribution planning studies
- DER interconnections, hosting capacity, and locational value studies require different models and skill sets
  - This is one reason interconnection queues can be very long, up to two years in some cases!
  - DER studies are often performed by consultants and expensed by utilities rather than bringing capabilities in house and increasing FTE
- If utility staff aren’t knowledgeable in DER interconnection studies and models aren’t finely tuned, results may be “No” or result in overly conservative interconnection requirements and costs
- For detailed analysis, time and effort are needed to evaluate and maintain model quality, exercise the model, and conduct the detailed studies
- Regulators and utilities can work together to understand needs and develop an approach. Approach may include approving additional or higher salaried FTE in rate case

Utilities and regulators can work together to match expectations to resources

- Think through the long-term need
- Consider state policies, what regulators are asking from the utility, and what customers are asking for
- Be clear about the expectations and make sure utilities have the data and resources needed to meet those expectations
- Weigh pros and cons of outsourcing vs. in-house

Policies Expectations Requests

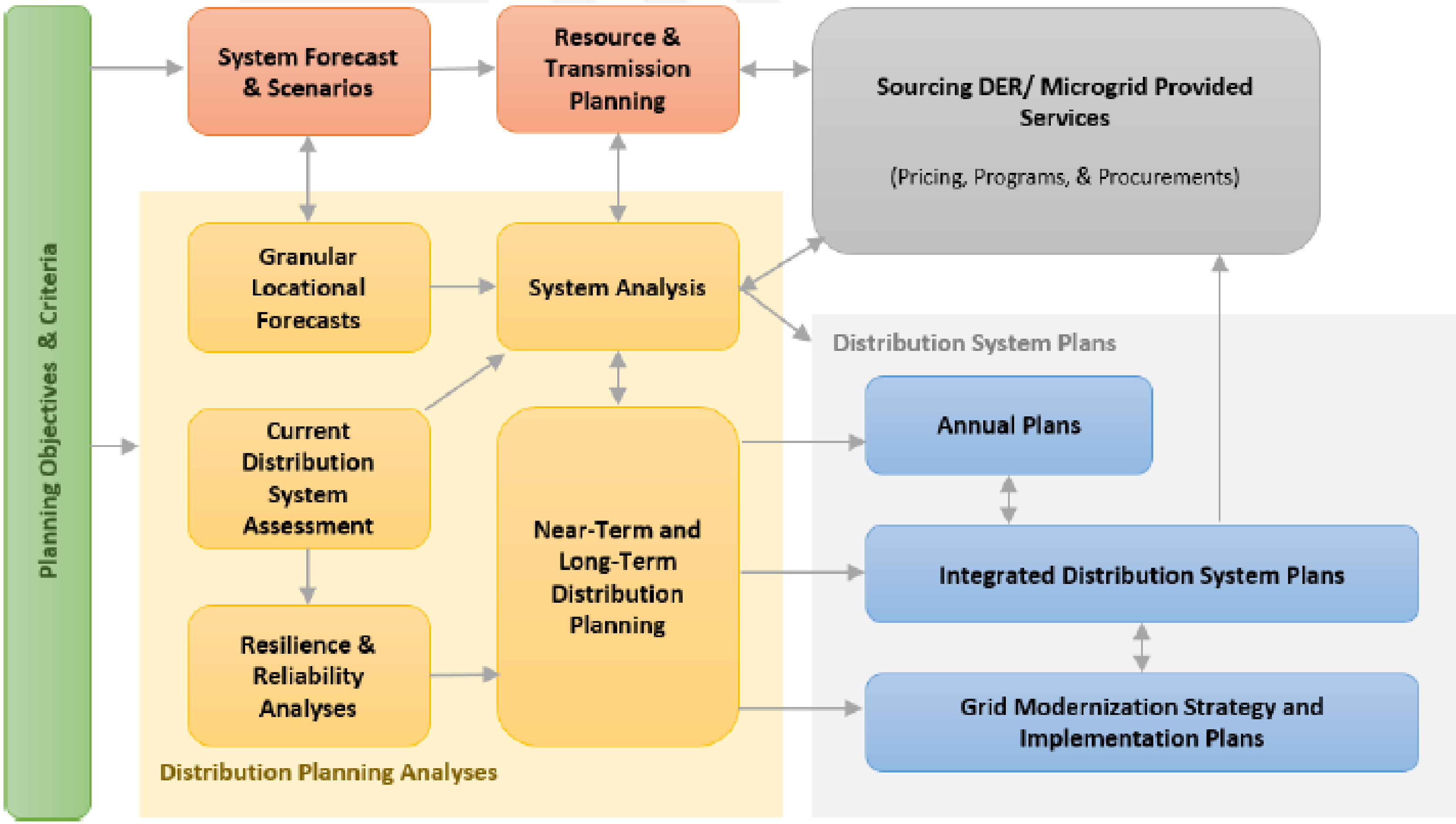
Data
- Data on existing systems and power flow
- DER data

Modeling
- Power flow models
- Operational & Planning models

Studies
- Operations studies
- Hosting capacity/ interconnection studies
- Forecasts

Decisions
- Yes or no to interconnections
- Operational decisions
- Resource decisions

Integrated Distribution System Planning



https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_IV_v1_0_draft.pdf

Traditional load forecasting

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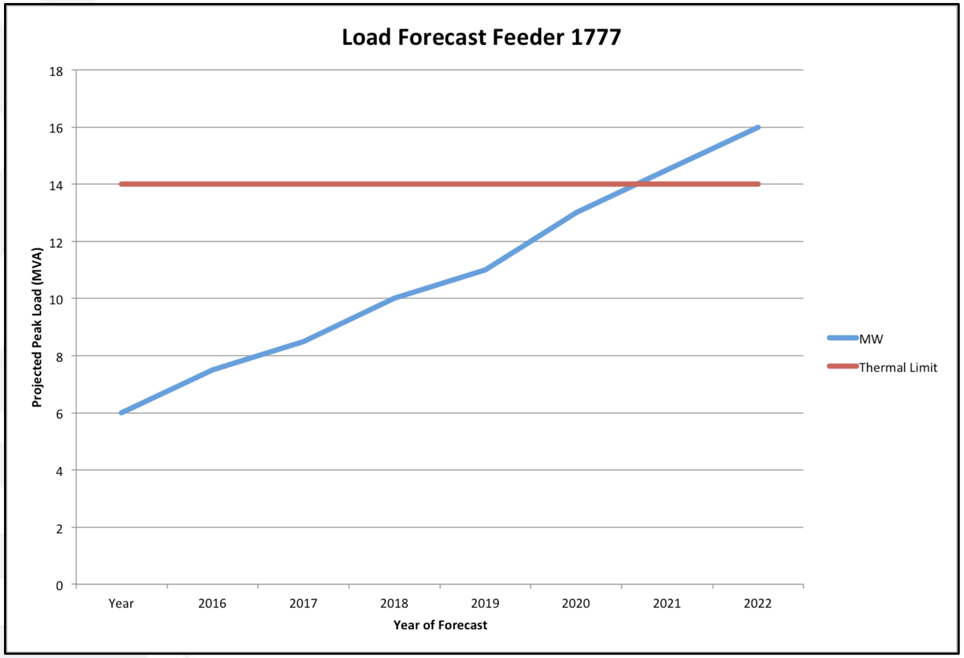
- Track peak loads (using SCADA data)
- Evaluate each distribution feeder for annual growth and new loads
- Feeder load forecasts aggregated to show substation status, need for expansion
- Substations may require upgraded transformers, new transformer banks, transmission, distribution equipment
- Traditional load growth projections are commonly included in utility tools (e.g., Cyme, Synergi, Milsoft)

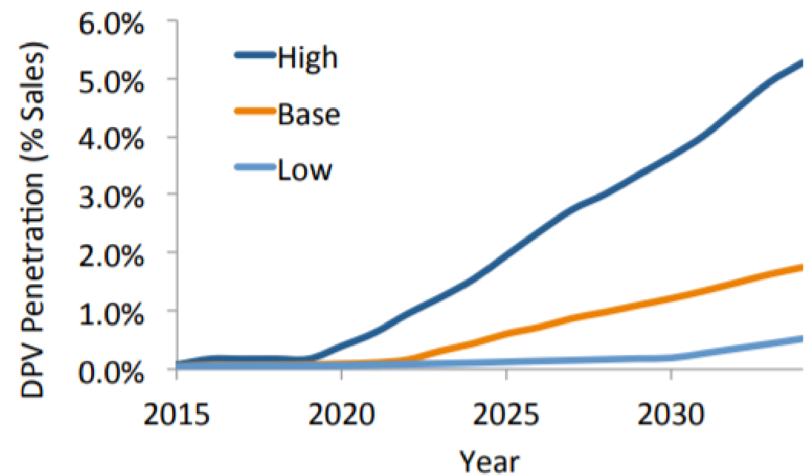


Traditional DER forecasting

- Even understanding baseline or current DER energy production is difficult – utilities don't have visibility or data on customer-owned systems
- Traditional DER forecasting has been based on:
  - Historical trends
  - Specific targets set by policy or program goals
  - Regression-based approaches applied at the service area level
  - Planners' judgement
- These rely on few or no quantifiable predictive factors and may not be sufficiently robust for planning purposes going forward.
- Forecasting load and DER often happens in a "top-down" way, separately forecasting load and quantity of DER at the system level, and then allocating that system forecast down to more granular levels.

More advanced load and DER forecasting

- There is a move to more granular load forecasts in time and space, such as annual hourly load forecasts by feeder and/or by customer class.
- Multi-scenario forecasts of DER penetration and gross load can support understanding *potential* effects of DERs on a distribution system.
- Scenarios may include:
  - a business-as-usual case
  - varying DER growth projections (EE, DR, CHP, DG, EV and storage)
  - cost decreases for certain DERs
  - specific policies, including carbon/ sustainability scenarios
  - exploring different energy service provider landscapes, such as a high community choice aggregation scenario



- Market analysis reports, potential studies, procurement requirements, and internal company analysis can be used to develop different DER growth scenarios.

Load and DER forecasting tools

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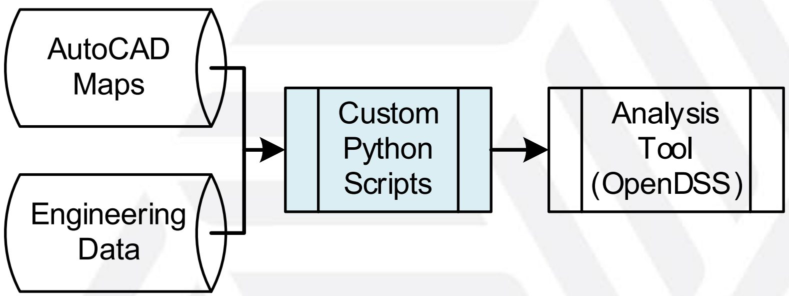
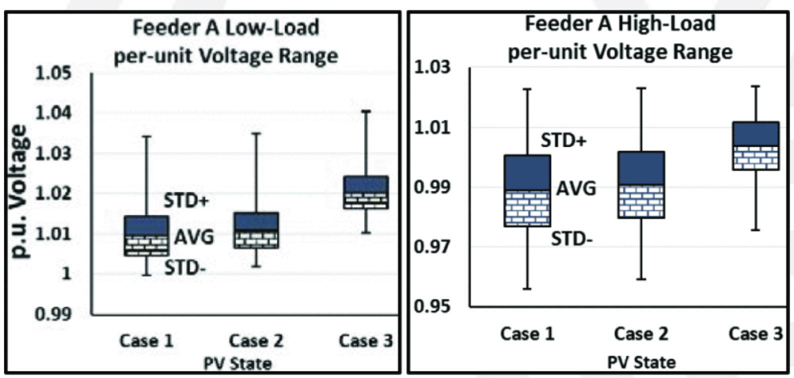
- Load forecasts*
  - LoadSEER - Integrates geospatial and advanced metering infrastructure data along with historical and forecasted weather information, economic and societal factors to develop regularly updated multi-scenario load forecasts
  - CYME, Snergi, Milsoft – Add-on modules can develop multiple-scenario forecasts
  - NREL’s dsgrid - Creates detailed electricity load data sets
- DER adoption forecasts
  - dGen forecasts technical and economic potential but does not project customer adoption in the short term
  - Utility specific tools based on Bass Diffusion Models
  - WattPlan® Grid - Piloting advanced modeling and machine learning methods to project customer adoption (Clean Power Research and SMUD)

**Note:* Not all tools work together. For example, a CYME model cannot be run on Milsoft, and the NREL tool may not export a format for use in all other tools. This is due to different software companies and a lack of standards.

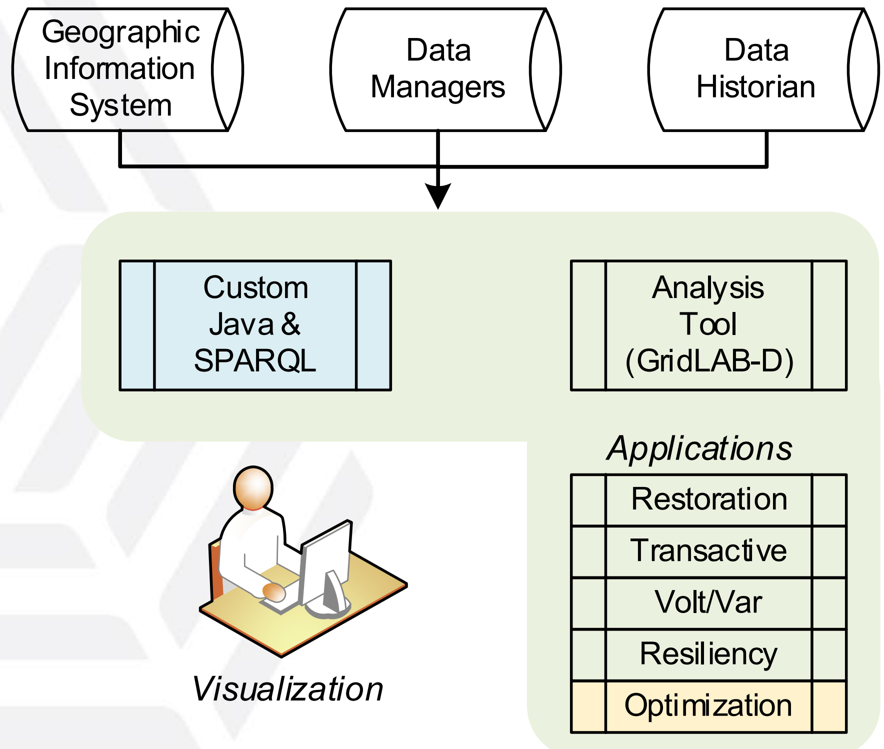
Tool and data integration speeds up planning and interconnection, also enforces best practice

Duquesne Light Example





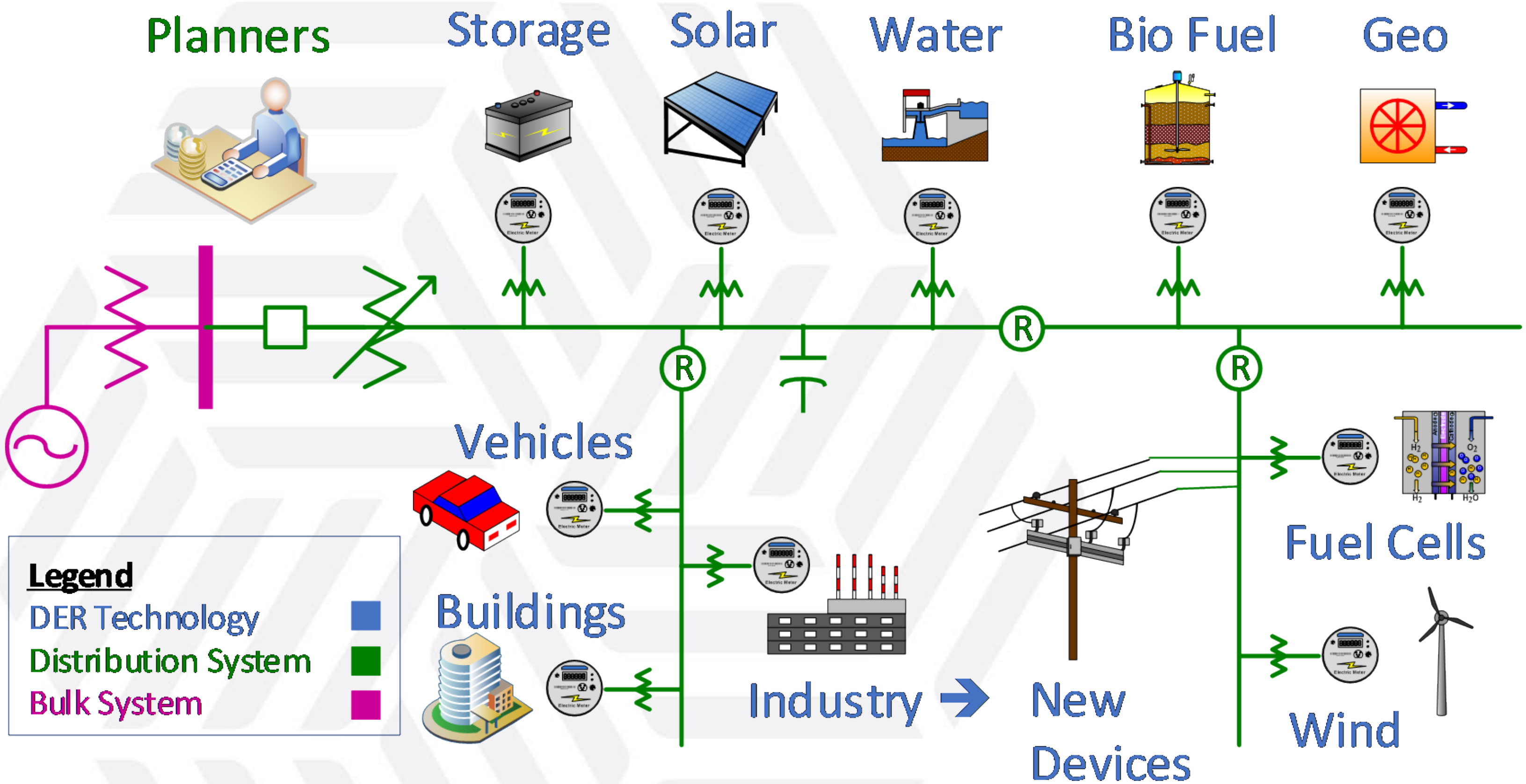
Avista Example



Questions: How long do your planning and interconnection processes take? Do they always produce consistent results? What would it take to improve them? Have you, or can you, automate your modeling and analysis?

References: https://ieeexplore.ieee.org/document/8585960, https://ieeexplore.ieee.org/document/9281658, https://gridapps-d.org/

The potential massive adoption of DER calls for a holistic planning approach

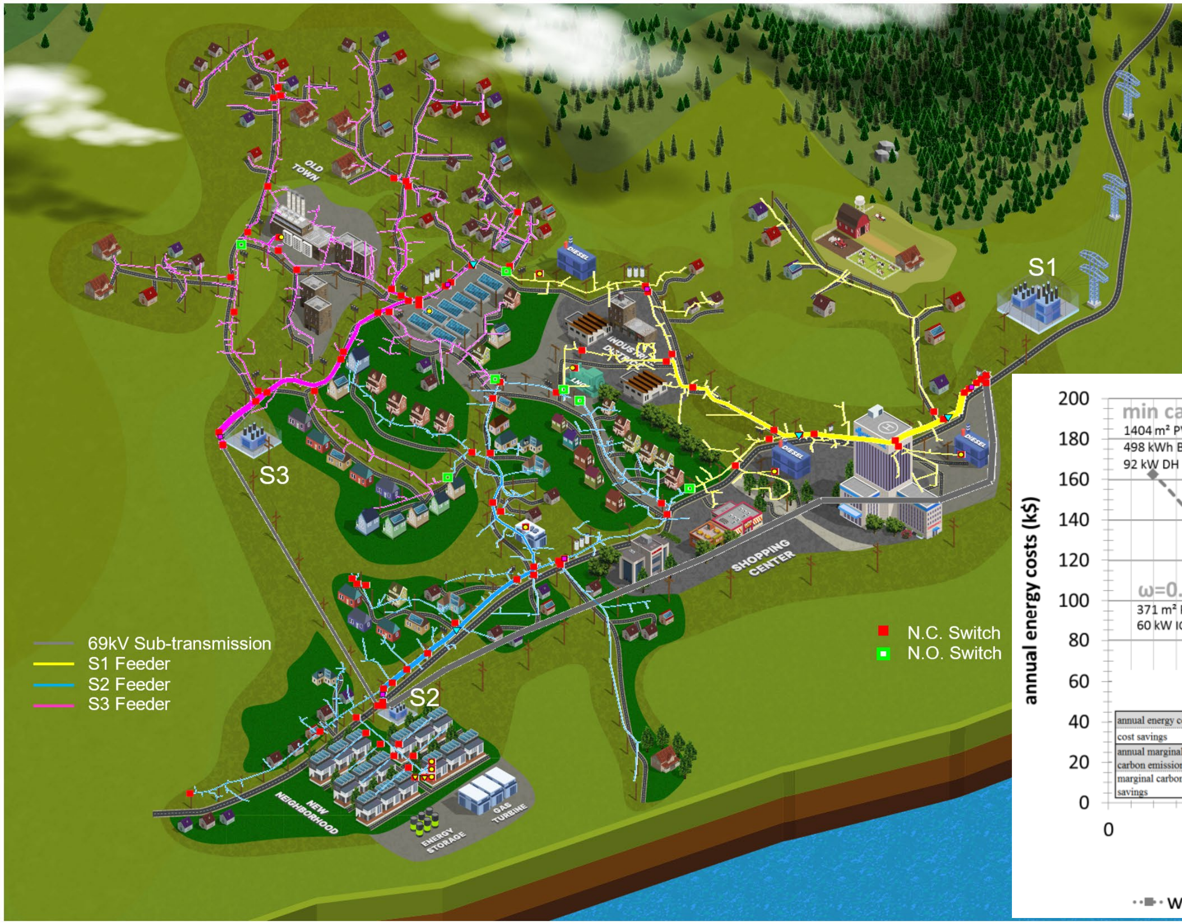


Questions: How does the utility plan for a mixture of DER — e.g., solar, wind, water, fuel cells, geothermal, responsive loads, vehicles, batteries, etc.?

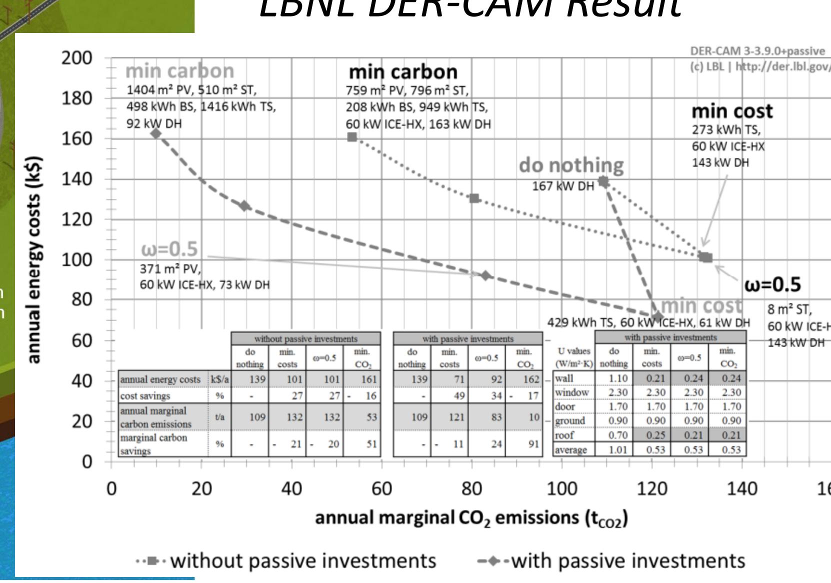
References: http://hdl.handle.net/10222/71377, https://www.nature.com/articles/s41893-019-0271-9

DER planning and operation can be optimized, given enough granularity of influence

GridAPPS-D 9500-Node Feeder



LBNL DER-CAM Result



		without passive investments				with passive investments			
		do nothing	min. costs	ω=0.5	min. CO_2	do nothing	min. costs	ω=0.5	min. CO_2
annual energy costs	k$/a	139	101	101	161	139	71	92	162
cost savings	%	-	27	27	- 16	-	49	34	- 17
annual marginal carbon emissions	t/a	109	132	132	53	109	121	83	10
marginal carbon savings	%	-	- 21	- 20	51	-	- 11	24	91

U values (W/m²·K)	with passive investments: do nothing	min. costs	ω=0.5	min. CO_2
wall	1.10	0.21	0.24	0.24
window	2.30	2.30	2.30	2.30
door	1.70	1.70	1.70	1.70
ground	0.90	0.90	0.90	0.90
roof	0.70	0.25	0.21	0.21
average	1.01	0.53	0.53	0.53

Questions: How does the utility manage or influence DER location and sizing to provide system benefits? Is the utility planning at the substation or feeder level?

References: https://www.osti.gov/servlets/purl/1163652, https://www.tdworld.com/overhead-distribution/article/21175388/simulating-the-distribution-system-of-the-future

A plethora of standards for DER, communication, and cyber security calls for choices to be made

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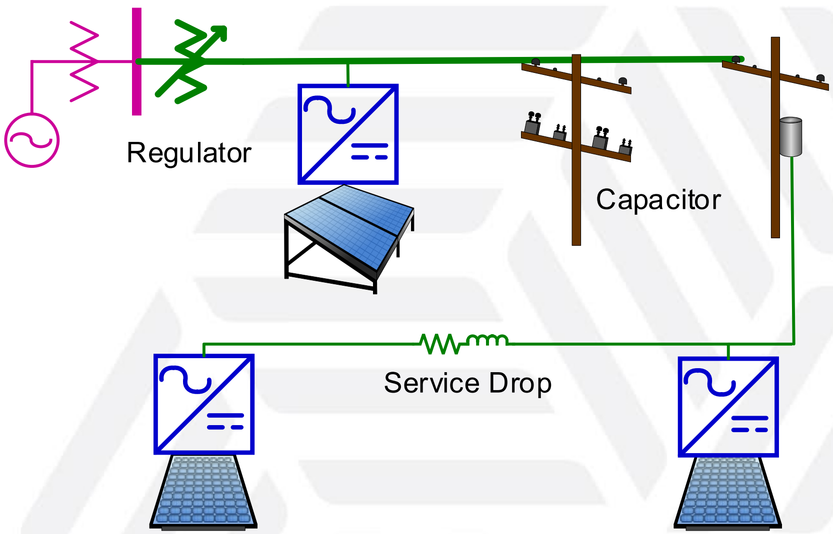
- IEEE 1547, with possible state-level exceptions — e.g., CA, HI
  - 1547-2018; (normative) smart inverter functions, ride-through, interoperability
  - 1547.1-2020; (normative) test procedures, parameter names
  - P1547.2; application guide for DER, to ballot in a few months
  - P1547.9; application guide specific to storage DER, moved to ballot
- DER Protocols
  - IEEE 1815 (DNP3), widely used by utilities, 1st of 3 options in 1547
  - Sunspec Modbus, widely used by vendors, 2nd of 3 options in 1547
  - IEEE 2030.5, close to IEC 61850 but not identical, 3rd of 3 options in 1547
  - IEC 61850 (object model), 61968-5 (DERMS messaging)
  - OpenFMB; relies on distributed adapters to support other protocols
- Cybersecurity (of course, NIST Cyber Security Framework applies)
  - P1547.3; application guide to cyber security, to ballot in a few months

Questions: Which standards (and features) will be used for DER interconnection and communications? Which ones for cyber security? How are cyber risks assessed?

References: https://www.nist.gov/cyberframework, https://doi.org/10.6028/NIST.TN.2042

Smart inverter functions in IEEE 1547-2018 enable voltage control, grid support, and ride-through



Category A & B Voltage Control Functions:

- Constant Power Factor (no response)
- Constant Reactive Power (like a capacitor)
- Volt-Var (may use "autonomously adjusting reference voltage" with this)

Category B Voltage Control Functions:

- Volt-Watt (for steady-state voltage rise)
- Watt-Var (like a constant power factor)

Frequency Response Function:

- Frequency ("droop," 1-sided or 2-sided)

Ride-through Categories (mandatory operation):

- I (minimal); 70% voltage for 0.7 seconds
- II (coordinates with NERC PRC-024-2); 65% voltage for 3 seconds
- III (high DER); 50% voltage for 10 seconds
- All; 57.0 – 61.8 Hz for 299 seconds

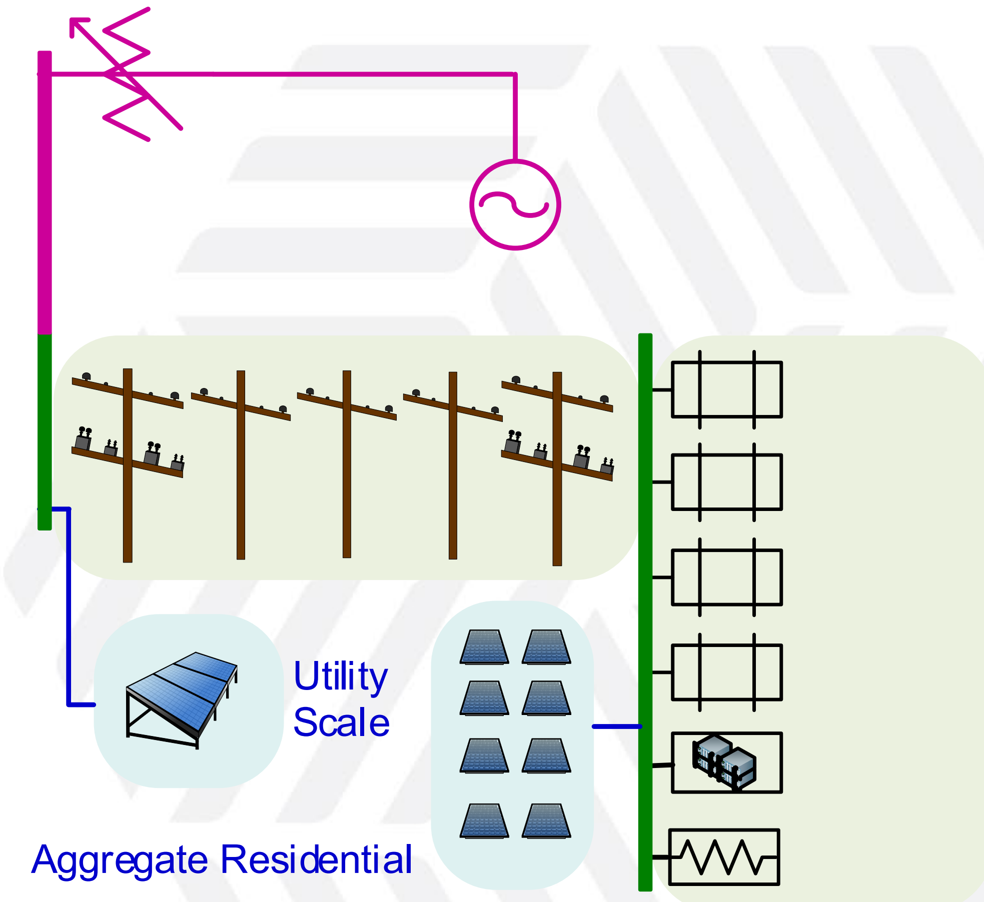
Utility Concerns:

- Will smart inverters fight the grid or each other?
- What if communication is lost?
- Engineering and commissioning

Questions: What reservations does the utility have about smart inverter functions? What would it take to resolve any concerns?

Reference: https://www.osti.gov/servlets/purl/1468187

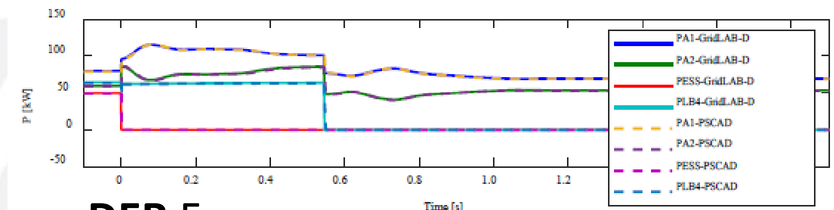
Bulk system planners need increasingly detailed and accurate models and forecasting for DER



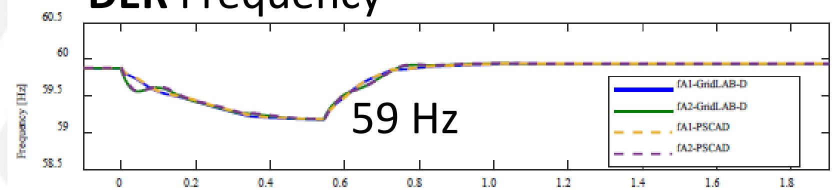
DER Transient Models:

- Three-phase, high-frequency
- Vendor-proprietary details

DER Power



DER Frequency



0 to 2 seconds

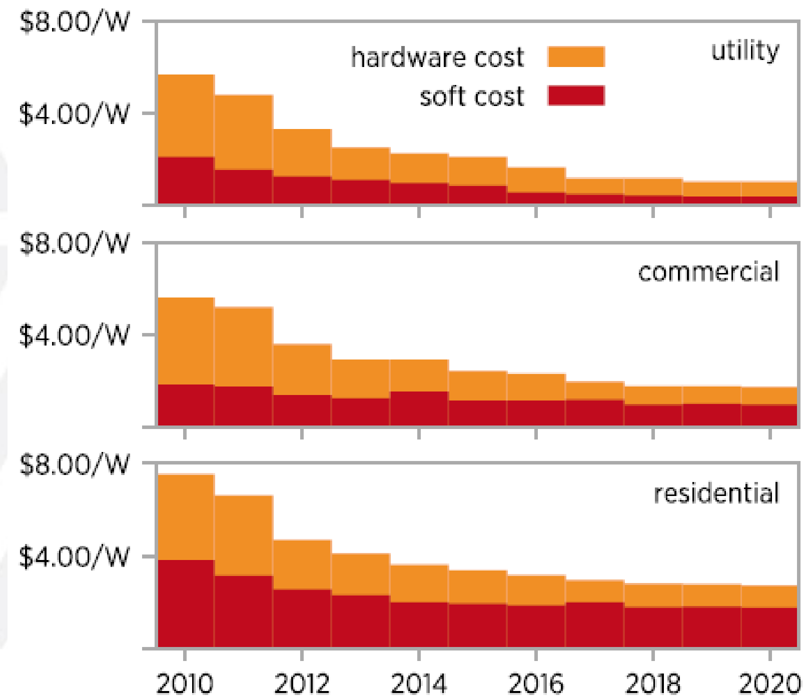
Source: Wei Du, 2021 IEEE PES GM Panel Session

Questions: Are you able to get DER models from applicants? How do you aggregate DER models for the bulk system planners? Are you ready for transient/dynamic modeling?

References: NERC Reliability Guideline, DER Data Collection for Modeling in Transmission Planning Studies, September 2020, NERC Technical Report: BPS-Connected Inverter-Based Resource Modeling and Studies, May 2020

Stubborn "soft costs" account for more than 50% of total residential and commercial-scale PV costs

- Soft costs include permitting, studies, inspections, financing, installing, marketing, overhead, supply chain, taxes, etc.
- DOE Solar Energy Technologies Office (SETO) organized two 2021 workshops on "Reimagining Interconnection for Solar Energy (RISE)"
- Business and jurisdictional processes are not in the scope of IEEE 1547
- Can we learn from the building codes?

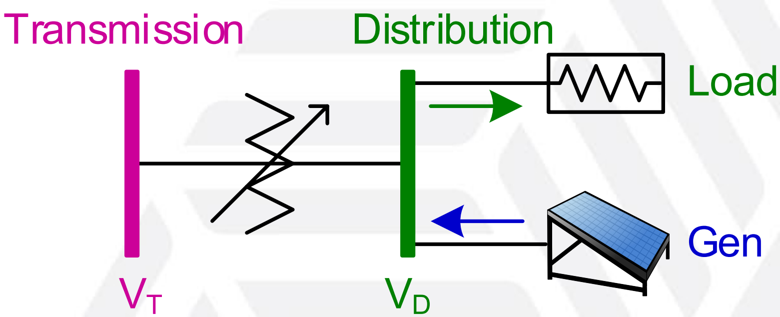


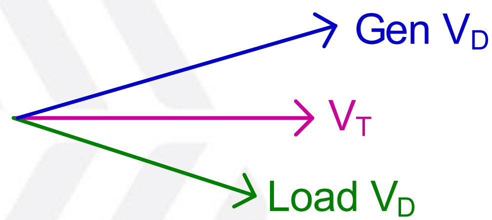
Source: 2021 SETO MYPP

Question: How can utilities, regulators, and local authorities support the normalization of DER interconnection processes, with only essential variances?

Reference: https://www.energy.gov/eere/solar/workshop-reimagining-interconnection-solar-energy

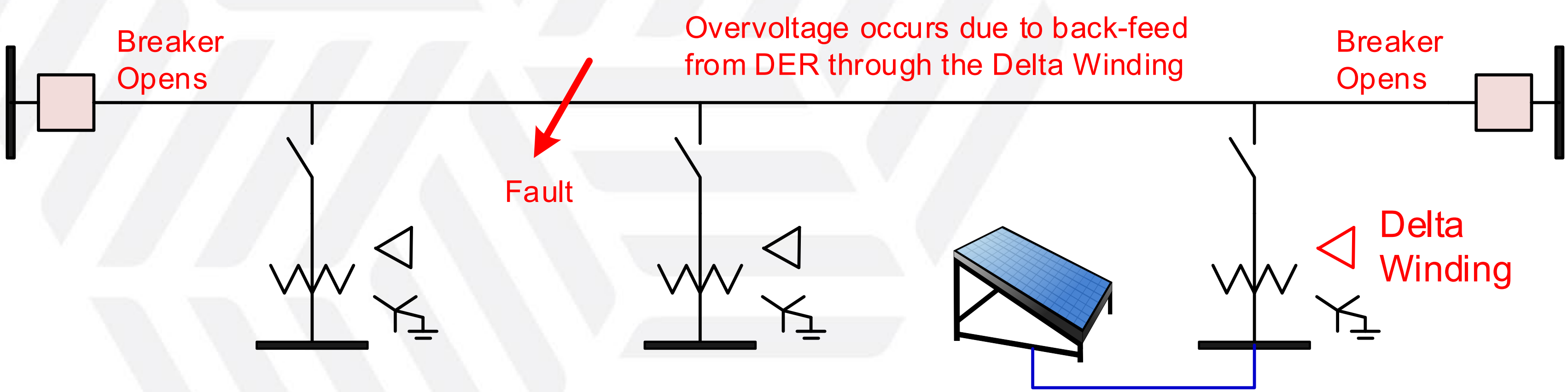
Distribution substations that carry reverse power flow may need customizations or adjustments





Reverse flow may cause transformer to:

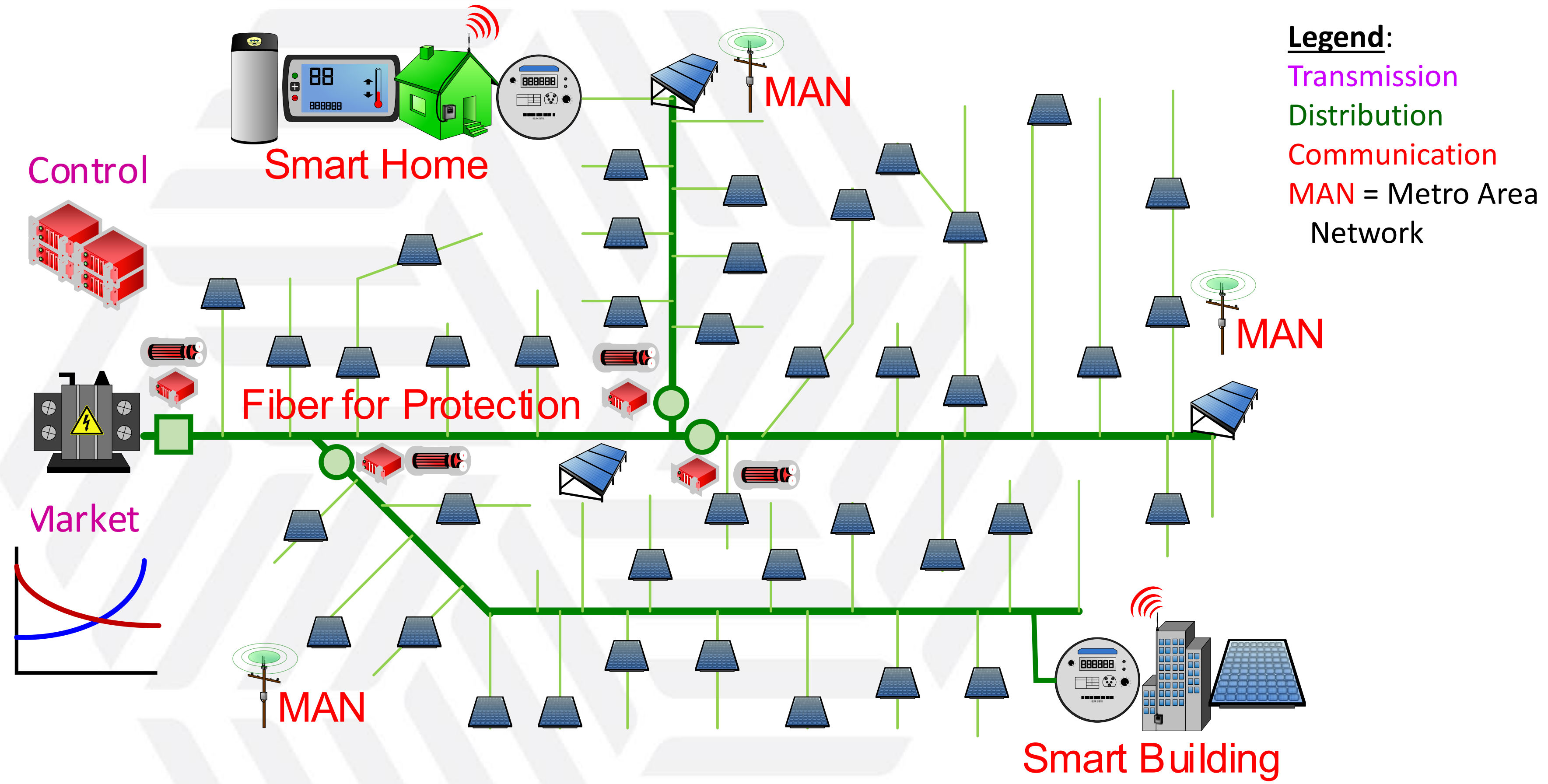
- Increase losses and harmonics
- Try to control V_T instead of V_D



Question: How will you operationally support DER export onto the bulk system?

References: https://energycentral.com/system/files/ece/nodes/463672/der_reverse_power_flow_impacts.pdf, https://doi.org/10.1109/TPWRD.2007.909115, https://www.nrel.gov/docs/fy18osti/70517.pdf

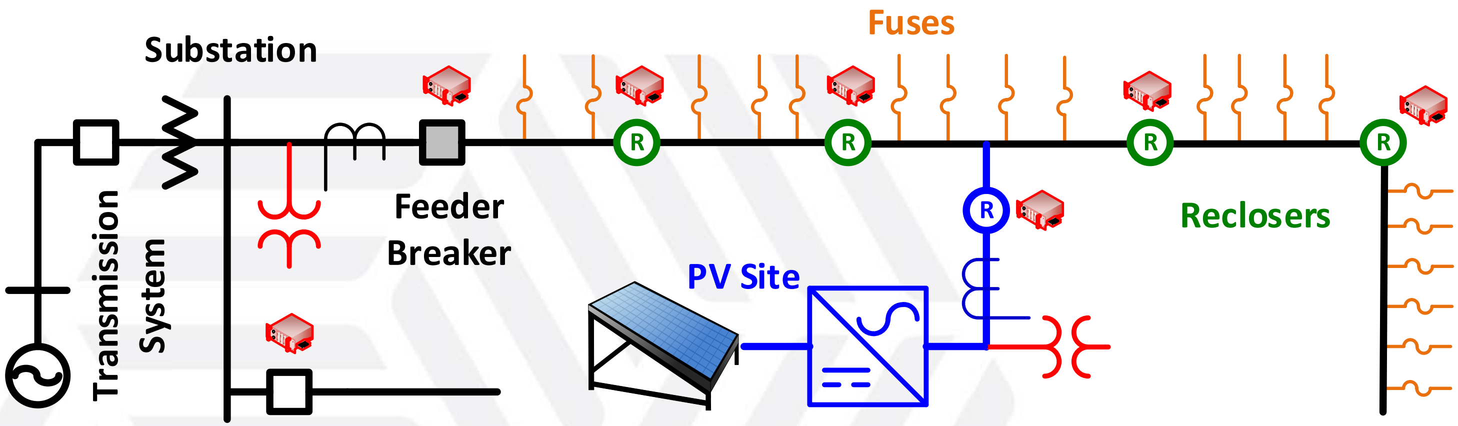
Communications infrastructure can offer shared benefits: protection, control, sensing, transactions



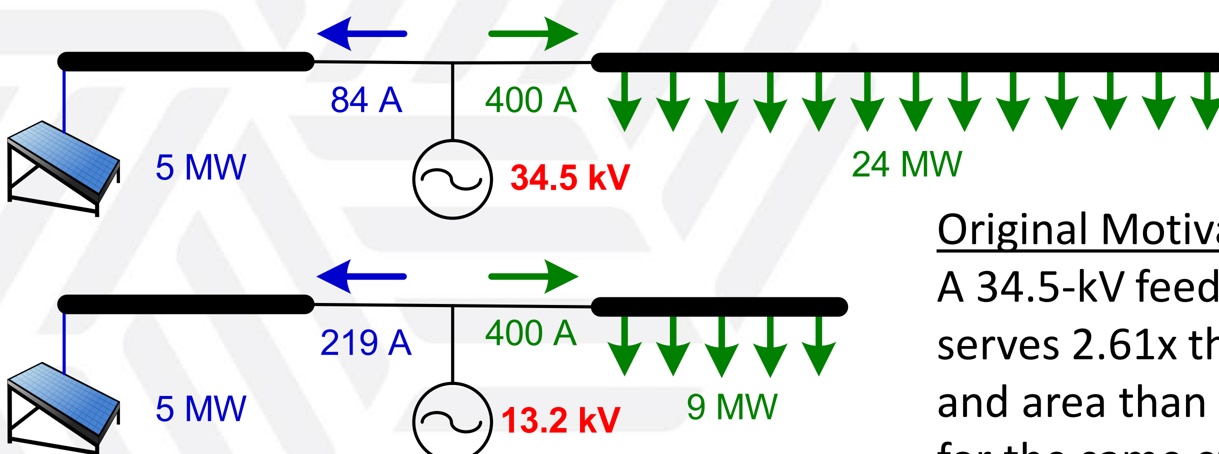
Questions: Does the existing communication infrastructure support advanced applications? What improvements could be made? How would they be paid for?

Reference: https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-24643.pdf

Proactive circuit upgrades, e.g., voltage level, comms, protection, can improve hosting capacity



Upgraded Sensors and Time-Domain or Machine Learning Relays



Voltage drop is 0.24 kV or 0.7%
20 MW is "easy"

Voltage drop is 0.66 kV or 5.0%
3 MW is "easy"

Original Motivation: A 34.5-kV feeder serves 2.61x the load and area than 13.2 kV, for the same current.

Question: How can the utility and prosumers pay for and benefit from proactive upgrades?

References: https://doi.org/10.2172/1574999, https://doi.org/10.1109/61.127081

Locational value analysis

- Locational value analysis helps utility planners understand the benefits and costs of DERs at a specific location on the distribution system.
- There are two parts to locational value assessments:
  1. **understanding the physical implications** of DERs on the grid — most commercial and research tools for distribution system analysis can be used to understand physical impacts of DERs on the grid
  2. **understanding the value** - an emerging area of study and application because the value does not depend solely on where the technology is located on the system; value depends on several variables and can vary depending on the time of day and/or year
- Specific distribution system investments that can be avoided often drive locational value
- DERs may <u>avoid</u> the need for energy and associated fuel, operations and maintenance costs, additional generating capacity, deferred distribution capacity upgrades, and emissions
- DERs may cause <u>additional costs</u> if equipment is not capable of bi-directional power flow, requiring upgrades to different types of equipment on the distribution system. DERs may lessen the life of load tap changers and may adversely impact protection schemes.

Locational Value in New York

- DER compensation tariffs based on locational benefit
  - New York Value Stack tariff compensates DER based on location, in addition to energy, capacity, environmental and demand reduction
  - Locational specific relief value (LSRV) zones are identified by each utility based on utility-defined criteria
  - Response to event calls in LSRV zones results in additional DER compensation

Source: Con Edison LSRV Zone Map

What goes into calculating locational value of DER in CA?

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#1 General system-level avoided costs

Component	Description
Generation Energy	Estimate of hourly wholesale value of energy
Generation Capacity	The costs of building new generation capacity to meet system peak loads
Ancillary Services	The marginal costs of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads
Environment	The cost of carbon dioxide emissions associated with the marginal generating resource
Avoided RPS	The reduced purchases of renewable generation at above-market prices required to meet an RPS standard due to a reduction in retail loads

#2 Info on avoidable poles and wires project

#3 Info on DER project replacing traditional investment

Universal inputs	Discount rate
	Revenue Requirement Multiplier
	Equipment inflation rate
	O&M inflation rate
Project-specific inputs	Book life
	O&M factor
	Project identifiers
	Equipment type
	Project cost
	Project install/commitment year
	Project flow factors
	Loss factors
	Load profile/need profile
	Overloading threshold magnitude and hours
DER inputs	DER type and location
	DER useful life
	DER install year
	Defer T&D to this year
	Hourly DER profile
	Dependability in local area

DER Avoided Cost Tool - DERAC

Non-wires alternatives – a subset of locational value

- Non-wires alternatives (NWA) are investments in energy efficiency, demand response, distributed generation, and storage that provide particular services at given locations as a way to defer, mitigate, or eliminate the need for traditional distribution infrastructure investments
- Example approaches – currently apply to <u>load relief</u>, <u>reliability</u>, and <u>resilience</u> projects:
  - New York: NWA "suitability criteria" – 1) project type; 2) timeline; and 3) cost suitability
  - California: Utilities must file "Grid Needs Assessment" and "Distribution Deferral Opportunity Reports" each year as part of a combined report

Challenges and Gaps – Non-wires Alternatives

- Additional functionality needed for planning tools to automatically identify a set of appropriate NWA for a particular application given system needs and constraints
- Better understanding of NWA ability to address power quality, voltage optimization, resilience, new business and service upgrades
- Contracting challenges – utility remains responsible even when third party is providing NWA; lack of precedence and standard contracting clauses re: liquidated damages, etc.

Example PG&E distribution investment deferral locations

2019 DIDF Project Locations

	Candidate Deferral	In-Service Date	Deficiency (MW)
★ (blue)	**New Lammers Feeder**	6/1/2021	1.5
★ (green)	**Huron Bank 1**	4/1/2021	3.7
★ (orange)	**Santa Nella Bank 1 and New Feeder**	5/1/2022	5.4
	Subtotal		***10.6***

Figure: PG&E presentation on 2019 RFO for support of local distribution capacity relief in three 3 areas in central Calif.

Locational value

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- Tools
  - Utilities are developing spreadsheet calculators to track potentially avoidable projects and costs (e.g., DERAC developed by E3 for the California utilities)
  - New York utilities are using marginal cost of service studies as basis for locational value determinations in the value stack tariff
  - In California, LNBA Tool (E3) was developed as an addition to DERAC to identify locational benefits of DERs
  - Other tools that support the determination of locational value: Kevala Network Assessor, HOMER Grid, GridLAB-D; OpenDSS; FINDER; DER-CAM; IESM; and SAM
- Challenges and Gaps
  - Granular data needed to understand potentially avoidable costs
  - Characterization of impact of DERs on resilience, reliability, power quality, and the transmission system
  - Characterization of impacts of multiple smart inverters and/or storage systems operating on a circuit

Questions states can ask (1)

- Validated and calibrated distribution system models
  - What is your source data for your models?
  - How accurate do you think your models are?
  - Do you have a way to check the accuracy of your models
  - What are your mechanisms for updating your models?
  - How often are they updated?
  - Do you have visibility into customer EVs and solar? How do you take that into account?
- Hosting capacity and interconnection analysis
  - Do you perform hosting capacity and interconnection analyses in house, or do you contract out?
  - How long do your planning and interconnection processes take?
  - Do they always produce consistent results?
  - What would it take to improve them?
  - Have you, or can you, automate your modeling and analysis?

Questions states can ask (2)

- Planning for DERs
  - How do you plan for a mixture of DER — e.g., solar, wind, water, fuel cells, geothermal, responsive loads, vehicles, batteries, etc.?
  - How do you manage or influence DER location and sizing to provide system benefits?
  - Are you planning at the substation or feeder level?
- DER standards and smart inverter functions
  - Which standards (and features) will be used for DER interconnection and communications? Which ones for cyber security? How are cyber risks assessed?
  - What reservations does the utility have about smart inverter functions? What would it take to resolve any concerns?
- DERs and bulk system planning
  - Are you able to get DER models from applicants? How do you aggregate DER models for the bulk system planners? Are you ready for transient/dynamic modeling?
  - How will you operationally support DER export onto the bulk system?

Questions states can ask (3)

- Communications
  - Does the existing communication infrastructure support advanced applications?
  - What improvements could be made? How would they be paid for?
- Proactive system upgrades to accommodate DERs
  - How can the utility and prosumers pay for and benefit from proactive upgrades?
- Locational value and non-wires alternatives
  - Has the utility identified criteria to use to identify when a potential capital project is a god candidate for a non-wires alternative? If yes, what are the criteria?
  - Does the utility have a process to solicit, review, and select potential non-wires alternatives from non-utility parties? What is the process?
  - Has the utility considered varying compensation for DERs based on locational value provided? If so, what are the criteria for identifying locations of interest?

Resources and more information

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- ► PNNL Report – High-level Overview of Distribution System Planning Tools and Methods with DERs
- ► PNNL Report - Summary of Electric Distribution System Analysis with a Focus on DERs
- ► LBNL Report - Locational Value of DERs
- ► U.S. Department of Energy's (DOE) Modern Distribution Grid guides
- ► NREL Report - An Overview of Distributed Energy Resource Interconnection: Current Practices and Emerging Solutions
- ► NREL Report - High-Penetration PV Integration Handbook for Distribution Engineers
- ► NREL Report - Sequential Mitigation Solutions to Enable Distributed PV Grid Integration
- ► NREL Report - New Approaches to Distributed PV Interconnection: Implementing Considerations for Addressing Emerging Issues

Thank you & Questions

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