Emerging Changes in Electric Distribution Systems in Western States and Provinces

WIEB/SPSC

DRAFT

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1 Introduction

1.1 Report Objective and Organization

The purpose of this report and web-wiki is to assist WIEB stakeholders with engaging utilities in decisions related to distribution system investment, planning, and operations. Electric distribution systems are generally considered to be equipment, facilities and operations that fall below 69kV that directly serve customers. Utility distribution proposals for new facilities may range from a utility's ordinary course of business related to load growth to requests for large investments in areas such as:

1. Distributed Energy Resources (DER): both utility-side and customer-side[1],
2. Reliability and service improvements[2],
3. New customer services e.g., electric vehicle charging, energy efficiency, energy management, backup power, and others.

The primary audiences for this report are state and provincial utility commissions and energy offices, with secondary audiences being utilities, vendors, and customers.

Our report is divided into three sections:

1. Emerging Distribution Issues
2. Regulator Questions and Response to Utility Scenarios
3. Details on distribution changes and technical information

1.2 Executive Summary

Historically, utilities have designed and operated distribution systems to reliably serve load, not to manage distributed generation (DG). With thoughtful integration, DG will serve to improve reliability and power quality while also helping communities meet renewable energy targets and reduce customer power costs.

Utilities, regulators, vendors, and customers are working in an environment with numerous choices of technologies and business model that affect the distribution system. In addition to DG, there are other DERs, e.g., load management (aka demand response) and energy storage; and utility grid modernization, e.g., Volt/VAR Optimization (VVO), and distribution automation. Nonutility vendors and investors are gaining political influence and are anxious for market share related to electricity and energy-related services. With this increased choices and providers comes increased opportunity for

[1] DER in this report includes, but is not limited to renewable generation equipment; energy storage; smart inverters; electric vehicles; demand response technologies; and control systems used to automatically curtail and increase generator output and charge and discharge energy storage via internal or external signals.

[2] 90% of customer reliability issues are on distribution system. "Electric Power Distribution Reliability," Richard Brown, 2009.

customer benefits, but also more complex decision-making related to utility distribution planning and operation. Regulators should begin to pay closer attention to distribution investments, and how they benefit customers, help integrate DERs, and improve reliability and power quality.

Utilities and regulators in a number of jurisdictions are seeking to better understand both the positive and negative impacts of various types and amounts of DER on a system-wide and local basis. The negative impacts of DER systems need to be understood and mitigated – and equally important, the capabilities of "smart" DER systems must also be used to ameliorate these impacts and improve the overall reliability and efficiency of distribution operations.

Distribution and DER planning in many jurisdictions will be seen as an increasingly important part of the overall utility integrated resource planning (IRP) process. As DER technology development continues to provide new capabilities, the need for distribution resources planning (DRP) is becoming clearer.

The challenge for regulators and utilities is how to best understand the positive and negative impacts of these new technologies, how to recognize and address the technical, financial, societal, and regulatory issues as the distribution system evolves, how to partner with key stakeholders to coordinate mutually beneficial activities, and how to make "least regrets" decisions on technologies and processes.

1.3 Summary of Findings

"***In the near future, distribution utilities can no longer just supply electric energy to customers, but must now plan for, coordinate, and manage the flow of electric energy to, from, and between customers.***"

1.3.1 Regulation

1. Regulators have not been closely involved with traditional distribution system planning.

Traditional distribution planning is based on assessing each feeder separately to determine how to meet the maximum forecast customer load plus some level of spare capacity, depending on utility-specific practices such as reconfiguration during emergencies or for maintenance. Regulators are normally not very involved in reviewing these distribution plans in deep technical detail.

2. Utilities and regulators are beginning to take DERs into account.

Some distribution utilities are currently taking DER system impacts and capabilities into account, both for resource planning and during real-time operations. California has started this process through the DRP effort mandated by the California law AB327 and overseen by the California Public Utilities Commission (CPUC). Another California effort is the Smart Inverter Working Group (SIWG) sponsored by the California Energy Commission (CEC) and the CPUC to develop the technical requirements for "smart" DER systems. The MESA Alliance is developing the information exchange requirements for energy storage systems.

3. Many utilities are moving toward new tariffs for DER.
Utilities and regulators are exploring new ways to measure and compensate DER. For example, value of solar tariffs have been proposed that track DER usage separately and pays for the generation based on a commission determined value methodology. (See section **Error! Reference source not found.**).

1.3.2 Planning and Operations

4. "Every distribution circuit is a snowflake."[3]
Distribution engineers and industry researchers commonly say that no two feeders are alike. In the west, utilities have historically planned their distribution systems in unique ways, pursuant to individual priorities for investments and methods of ensuring reliability. In general, common standards or best practices for distribution planning do not exist. For example some utilities have decided to invest in automation while others have not – the analysis framework to determine costs and benefits is utility-specific and often not transparent to regulators or stakeholders.

5. Planning and operational tools need improvement to assess DER.
Distribution planning tools currently in use are not equipped to support the analysis of where and how DER systems can provide alternatives to traditional equipment and sources of supply. The California DRP process is analyzing the various "avoided costs" if DER systems are used in place of traditional solutions. Operationally, few utilities are capable of monitoring what DER systems are producing. DER aggregators have collected large amounts of data, but have not yet determined how best they and the utilities can use this data, particularly in light of privacy concerns.

1.3.3 WECC Distributed Energy Resources

6. DER impacts vary by feeder design.
Because of the feeder "Snowflake" phenomenon, DER impacts may be considerably different based on feeder characteristics, e.g., length, load type, installed equipment, and conductor specification among many other factors.

7. DER penetration will vary by location.
The 2022 DER forecast in WECC is 43GW out of a 178GW peak forecast (23%). In 2014 Germany's Solar PV is at 32 GW with an 80GW peak (40%). The amount and type of regional DER will depend on resource potential, state policies/incentives, vendor push, and customer preference. Throughout WECC In the next 6 years:

- High penetration of solar PV will be a localized phenomenon primarily in California, Arizona, Colorado and New Mexico,
- Combined heat and power development will depend on the availability of low cost natural gas, and may be driven by density developments which also supply space heat and/or domestic hot water,

[3] Clark Gellings, EPRI Fellow

- Demand Response capabilities will improve and provide cost effective flexible capacity to the system, and specific locational value by deferring transmission and distribution investments, and integrating Variable Energy Resources (VER),
- Distribution or customer energy storage will be primarily in California.

8. Low penetrations of DER systems can be considered "negative load", making planning difficult unless DER data is known.

In low penetrations and/or operating strictly "behind the meter", DER systems can be almost invisible and can be considered as "negative load" by distribution grid operators, until growth leads to key thresholds of generation to load ratios being reached on distribution feeders.

9. High penetrations of DER systems require attention by distribution utilities and regulators.

In higher penetrations or in "sensitive" locations, DER systems can impact traditional distribution operations. As an example, in 2003 Italy experienced a major blackout that was caused in part by large numbers of PV systems tripping off due to a short frequency anomaly. Germany and Italy then required very expensive retrofitting of the large numbers of PV systems to avoid this problem in the future. Hawaii recently upgraded about 60% of their PV systems for the same reason – fortunately they were able to push a single button to upgrade them electronically rather than pay for truck rolls. Most jurisdictions do not or will not have this ability without changes in DER deployment rules and regulations.

1.3.4 Technology

10. "Smart Inverters" is an opportunity to improve the value proposition for all inverter based DER.

As a result of European, Hawaii, and other experiences, DER inverter-based systems are being made "smarter" with functions that can provide many different capabilities to transmission and distribution utilities, customers, and society. These DER capabilities range from energy and flexible capacity, to power quality/reliability, to energy efficiency, and to extending capacity of existing transmission and distribution assets. For example, energy storage systems are being used to counter some of the fluctuations caused by PV and wind DER systems, as well as smooth frequency deviations, while PV systems can help maintain steady voltage levels on feeders. The challenge will be to define the methods of coordinating inverter operation and transactions with inverter owners who provide grid services other than energy or capacity.

11. Grid modernization – "smart grid" is addressing important utility and customer objectives.

Grid modernization is addressing important utility objectives, e.g., reliability, resiliency, outage restoration, etc. Some of these measures also improve tools to address future DER, e.g., VVO control, "smart meters", conservation voltage reduction, rapid fault location, isolation, and restoration, and microgrids.

12. Monitoring for reliability

Ensuring reliability with high penetration of customer DER systems involves constant monitoring distribution system, data, smart inverters, and new methods/tools for planning and operating the distribution system. If DER system operation is unknown ("negative load") to a distribution utility, then the utility will have to over-engineer distribution systems for worst-case scenarios. If the distribution utility collects data on DER installations/operations, has full-time grid situational awareness, has appropriate planning/operational tools, and the ability to coordinate DER operation, then reengineering for reliability can be more precise and effective.

Customer-owned DER systems are often operated for the benefit of the customer, and may be unknown to utility. Contracts with customer-owned DER systems are typically net metering of energy with minimal emphasis on providing a grid support service or capacity utilities can count on for planning purposes.

1.4 Recommendations

1.4.1 Essential

1. Develop long term distribution planning roadmaps.
Utilities should develop long term roadmaps that describe steps toward grid modernization and integration of DER systems, making sure different territories are identified (urban, suburban, rural, commercial, industrial, etc.). Topics these roadmaps should address include:

a. Forecast the expected customer and DER development over the next 10-20 years.

b. Take into account possible regulatory, financial, and technical changes.

c. Include risk metrics regarding when and where more comprehensive Distribution Resource Plans could be required that include the use of DER systems to be balanced against avoided transmission and distribution and generation costs. (See beneficial recommendation 8)

d. Identify key milestones for the different efforts needed to meet the forecast requirements. It is critical that development of these roadmaps be an inclusive process. ISOs, transmission utilities, distribution utilities, DER integrators, and other stakeholders should be included in roadmap creation efforts in order to achieve the most comprehensive and intelligent result as well as bolster public support.

2. Address DER integration benefits, costs, and interconnection tariffs now.
Examples include value of solar tariffs, net metering, or feed in tariffs. Since solar and DER is expected to only increase, it is recommended utilities and regulators address customer costs of owning DER before stakeholders become vested in inappropriate tariffs and rate structures. Steps in these efforts include:

a. Cost estimation of DER integration, such as enhanced substation relays, phasor measurement units, smart inverter communication systems, transfer-trip communications and static var compensation equipment.

b. Avoided cost determination methods that include benefits from DER (e.g., deferral of T&D upgrades, flexibility, lower line losses, operating reserves, and ancillary services etc.).

c. Exploration of new utility business models related to DER that allow for the interconnection and coordination of DERs and related services that may exist behind the customer meter, provided by 3rd parties or utilities.

Addressing these early will support utility customer desires for new services and provide the economic and political justification for utility distribution related upgrades and associated expenditure.

3. Major utility transmission or distribution investments should be supported by:

a. Utility DER and distribution roadmapping processes, which include pilots, demonstrations, and planned smooth and equitable roll-out of services and programs based on documented results of pilot and demonstration projects.

b. DER potential and forecast studies to defer or support investments.

c. Open and inclusive stakeholder processes.

d. Subsequent incremental steps to reduce the chance of large investment technological obsolescence or supplier bankruptcies and product failures.

4. DER Planning

DER forecasting should be included in utility integrated resource planning and considered by States for all distribution utilities. Forecasts of DER penetration by feeders should be developed, and jurisdictions should consider assessing costs and benefits of DER participation.

5. Meter DER systems separately from energy usage

Utilities and regulators should consider metering technology that tracks DER performance separately from customer usage. Benefits of this are for planning, modeling, operations, and customer pricing programs not available with net meters. (See 4.3.2)

6. Interoperability and Standards should be encouraged and supported.

a. Join existing technology and communication standard efforts. For instance, the SIWG has developed some basic “smart DER” requirements that are being implemented by most DER vendors and are being used as the basis for updates to the DER interconnection standard, IEEE 1547.

b. Regulators should provide support for utilities to provide staff, training, funding and participation for standards organizations and groups. (This will reduce the often hidden costs of typical “one-off” installations used for meter data management systems, utility to DER communications or behind the meter equipment and services)

c. Regulators should consider requiring utilities to specify interoperability standards when purchasing equipment or deploying programs that involve communications technology. Refuse vendors who refuse standards. (See section 4.7 on interoperability)

d.

1.4.2 Beneficial

Recommendations that could be beneficial for utilities and regulators at different stages in the changes to their distribution systems include:

1. Hold workshops on key topics

Hold and/or participate in workshops on relevant topics to help inform stakeholders on ideas and results from work underway locally or in other jurisdictions.

2. Undertake demonstration projects with clear objectives

Undertake or participate in pilot projects and demonstrations that can help flesh out the technology requirements and validate the value propositions. These projects can be in conjunction with stakeholder groups, such as DER manufacturers, DER integrators, communities, aggregators, and specific types of customers.

3. Determine communication and cybersecurity requirements

Determine different communication alternatives for information exchanges with aggregators and facilities that are participating in any grid-management or market activities. Do not forget to include cyber security.

4. Specify and improve distribution planning/operational tools

Help specify new tools that could be used to analyze distribution systems, both for planning and for operations. For instance, distribution planning tools do not yet have the capability to assess locational values for DER, while distribution management systems (DMS) do not have the power flow or state estimation applications that could be used for improving the reliability and efficiency of distribution operations.

5. Participate in standards and specification efforts

Participate in standards and regional planning processes. For instance, participating in the SIWG effort can provide insights into different smart DER capabilities. Following the DRP process can provide information on avoided costs and DER benefits during planning processes. Participation in interconnection standards efforts, such as IEEE 1547 revision, or distribution planning working groups can allow participants to influence standard and plan development and distinguish elements that need region-specific attention.

6. Address financial and technology risk through roadmapping and distribution planning process with regulator and stakeholders

Explore new pilot or new product introduction cost recovery methods for utilities that reduce the risks. Remove current incentives for maintaining status quo or doing no development. For example, allow a guaranteed or certified cost recovery of 20% to 30% for a new service introduction or technology trial pilot project. This will reduce the risk of failure and allow utilities to try new equipment, products and service offerings.

7. Bring together all stakeholders to resolve DER issues
In the technical areas, joint efforts at resolving issues have proven effective. This has been illustrated in California's Smart Inverter Working Group (SIWG), California DRP Guidance Proceeding, and More Than Smart working group. Heated discussions can still occur over whether 0.2 seconds or 0.3 seconds is appropriate for a particular situation, but the participants still have a common interest in reaching solutions.

8. Distribution Resources Planning
Regulators should consider, through roadmapping or other means, the costs and benefits of requiring utilities to conduct enhanced distribution level planning processes that compare the increasing number of options for meeting essential needs, including DERs in a process transparent to stakeholders and regulators. The timing and detail will depend on utility jurisdiction, DER forecasts, or other distribution upgrades penetrations. Useful milestones to help regulators and utilities decide when to undertake a DRP include:

a. Utility proposing major investment for new or upgraded transmission and distribution,
b. DER or EV penetration is forecasted to increase beyond specified percentage of peak load for any feeders in the next 5 years,
c. Distribution management or automation systems proposed,
d. Value of Solar of other charges proposed for customer DER integration.

9. Distribution planning process and best practices
Regulators should consider adopting distribution planning process standards to ensure the procedures used by their utilities are representative of industry best practices. Achieving the best possible reliability at an acceptable cost will in some cases require regulators to get more involved in their utilities distribution planning processes to ensure all options are considered, including the increasing number of utility-side technologies, a broad range of system configuration possibilities and customer-side DER capabilities.

2 Emerging Distribution Issues

2.1 Forces Changing Distribution System Planning and Operation

Utility distribution system planning has traditionally been managed by estimating new or increased loads that need to be served in each area generally over a 3 to 5 year timeframe. Utilities build and maintain distribution systems to reliably serve load, which includes calculating the maximum demand during peak periods for each service area, plus spare capacity, and then designing and building distribution substations and feeders to meet those maximum demand requirements. If capital distribution costs do not fall under a utility's ordinary course of business, these capital costs may be presented to regulators in utility rate cases for approval for cost recovery. This will be changing based on several forces at play on both the utility-side and customer-side, as summarized in Figure 1 below.

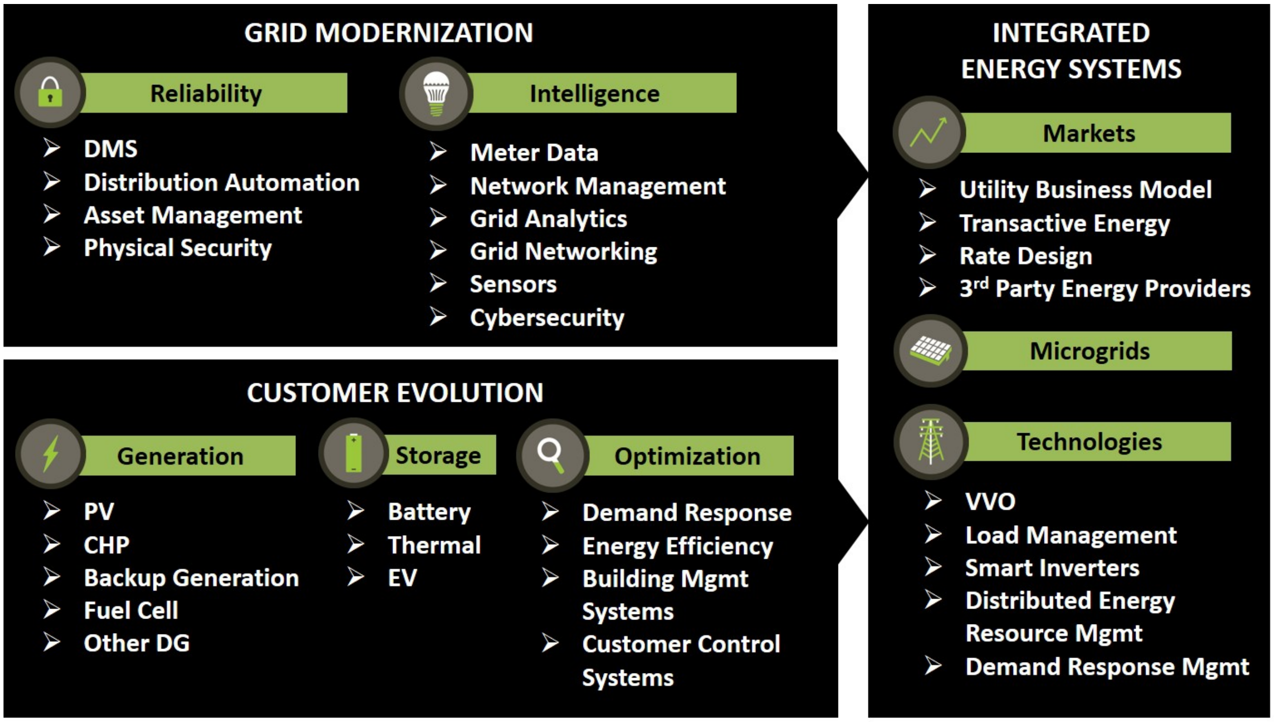

Figure 1: Forces affecting utility distribution systems[4]

Technology

Technology related to grid modernization and customer/utility distribution level DER are causing more attention to be placed on the planning and operation of the utility distribution system. These changes may have great benefits, but depending on the situation, could create relatively higher rates, shorten the useful life of some equipment, generate unexpected utility integration costs, and create other unforeseen impacts.

Utilities will find themselves with more factors to consider around distribution investments due to the increasing number of options available to meet a given need. This refers to both utility-side investment possibilities and customer-side activities - both are driven by rapidly advancing technology. The role of customer-side activities is commonly viewed as driving the need for the new utility-side investments, but new technologies such as smart inverters are in many cases able to aid rather than detract from reliable utility operations.

There is also greater technology risk associated with distribution equipment than in the past. When most of the prior work was replacing worn out distribution equipment with newer versions, risk was minimized. Now, with increased communications and software replacing hardware, there may be greater risk of technology obsolescence or other unforeseen consequences and outcomes.

Policy

Federal and state policies are also driving the pace of DER adoption and distribution changes. State policies, e.g., tax credits, financial incentives, utility mandates like

[4] Source: Greentech Media / EQL

Renewable Portfolio Standards (RPS), restricting out of state renewables to satisfy RPS, or energy storage are contributing to the pace of DER adoption. RPS policies range from 15% by 2025 (Arizona) to 33% (California) by 2020, to Hawaii's 40% by 2030, to California's recently announced goal of 50% renewable energy by 2030[5]. In 2014 the U.S. installed 6,201 MW of solar photovoltaics (PV) at the distribution level, and 767 MW of concentrating solar power at the transmission level.[6] Over half of these installations were in California where the state currently limits out-of-state renewables to satisfy their RPS, and hence limits the ability of wind and transmission level renewables to compete with in-state resources.

Economics

As DER economics improve relative to other energy resources, they will be used by customers and become a higher percentage in utility resource portfolio. Like other resources, the cost to integrate will need to be considered and allocated, just like utilities are doing with VER integration (see WIEB report January 2015, Variable Energy Resource Integration Charges)[7]. DERs have additional values to utility system other than system-wide capacity, such as reserves, flexibility, Var support, and T&D capital project deferral. VER integration can be assisted with DERs, e.g., demand response, energy storage, and generation. The Western Interstate Energy Board report on demand response for VER Integration estimated 2.6GW of load following load reduction potential throughout the WECC.[8] Distribution planning will need to consider the DER role, and could become more closely aligned with traditional IRP (see section 4.6.4).

Integrating DER

The integration of DER capacity in an electric distribution system will require a change in traditional distribution operations, maintenance and design, in part to accommodate two-way power flows across distribution facilities, a capability that was not originally intended. Further, in order to accurately determine the capability of distribution feeders to accommodate DER interconnection, enhanced use of distribution models will be needed to assess not only impacts on single feeders at single points in time, as is commonly the case today, but also to evaluate system-wide impacts over time and with operational control to modify DER output in real-time. Other values to be analyzed include: locational value, capital deferment possibilities and alignment with utility planning procedures.

Power generated by renewable DERs can be unpredictable and intermittent. The integration of high penetrations of intermittent resources at many dispersed sites on the distribution system could result in bi-directional power flows and have other impacts. These situations may necessitate a rethinking of distribution grid design, planning procedures, grid operation, and maintenance.

In states that experience a high percentage of DER integration, whether to meet RPS requirements or for other reasons, the impact of DER on the distribution system will

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[5] US Department of Energy, Database of State Incentives for Renewables and Efficiency (DSIRE) **http://www.dsireusa.org/**

[6] Solar Energy Industry Association (SEIA) , "U.S. Solar Market Insight New Report Shows U.S. Solar Industry Reaches 20 GW of Installed Capacity", **http://www.seia.org/research-resources/us-solar-market-insight**

[7] 2015, http://wiebver.org/wp-content/uploads/2015/03/01-15Report-on-Review-of-VER-Integration-Charges.pdf

[8] 2013, http://wiebver.org/wp-content/uploads/2015/03/12-20-13SPSC_EnerNOC.pdf

need to be addressed. The challenge for regulators and utilities is to gain the best understanding of impacts and ramifications of new electric distribution technologies, and to recognize and address the technical, financial, societal and regulatory issues as the grid evolves.

Distribution Reliability and Efficiency

While a large part of the funding for smart grid projects since 2009 went to advanced metering infrastructure projects, the pace has also accelerated for other distribution investments such as distribution automation. A recent survey by Newton-Evans found one-third of the utilities had one or more feeders equipped with FLISR (Fault Location, Isolation, Service Restoration) , with 6% of feeders configured to provide FLISR functionality.[9] With more attention to increasing distribution reliability (particularly those in the Northeast United States), utilities are continually exposed to new options developed by vendors to leverage technology for greater reliability and operational efficiency.

Because automation and communications is not generally present on many utilities distribution systems, there will be wide opportunities for investments that address specific issues that are determined to be worth the cost relative to enhanced reliability. Reliability is important to the broader utility business model as tariffs could be designed to reflect different levels of reliability to end-use customers.

Examples of automation to promote reliability include:

1. FLISR systems that responds rapidly to faults to minimize the number of customers experiencing and outage. (See 4.2.9)
2. IEC 61850 Substations, providing enhanced communications, goose messaging for better fault detection and restoration and reduced wiring costs and complexity. However, the steep learning curve for IEC 61850 designs have limited adoption in the US. Currently few electrical engineering schools teach IEC 61850 methods.(see 4.7.4)

Aside from distribution modernization investments that need reliability-based justification, there are opportunities based upon reducing operational cost and distribution energy losses. Examples include:

1. Distribution management systems that could streamline multiple utility operations, among other benefits.[10] (See Section 4.2.8)
2. Volt-Var optimization. Utility investments in equipment, software and other systems that reduces voltage while staying above minimum levels thereby reducing demand and energy use. (See Section 4.2)

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[9] 2015, http://www.newton-evans.com/new-utility-insights-on-adoption-of-advanced-distribution-automation-applications/

[10] EPRI DMS Systems Planning Guide http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001024385

2.2 DER Issues for Regulators

2.2.1 Distributed Energy Resources Defined

It may sound easy, but there are several ways to define DER. Operationally DER are devices that operate on a utility distribution system at provide grid or customer services (energy, capacity, Volt/Var, etc.), and includes generators, energy storage, and controllable load. For planning purposes DER is anything a regulator or utility chooses that has an impact on distribution system operation.

The California PUC's DRP guidance document lists resources defined as DERs, as shown in Figure 2 below. Some advocacy groups argued to include energy efficiency in utility DRPs – if energy efficiency is part of DRP, then it begins to make sense to include all programs that have an impact on load shape. Some DERs will produce variable energy, while others have controllable or dispatchable energy qualities. Figure 2 shows an example of DER categorized by variable and controllable attributes.

The ability to control a DER provides an added benefit of assisting a utility to manage load or integrate VER. For instance, a feeder with high amounts of solar can use demand response or energy storage to move load away from hours when there is no solar contribution. These controllable loads can also take action to address bulk system needs. EV Charging, or Combined Heat & Power could be variable or controllable depending on how a utility engages these technologies for grid services.

<table>
<tr><th>Controllable (Capacity/Ancillary)</th><th>Variable (Energy)</th></tr>
<tr><td>Load Control (aka Demand Response)</td><td>Energy Efficiency</td></tr>
<tr><td>Energy Storage (Customer, Utility)</td><td>Solar</td></tr>
<tr><td>Dispatched Generation</td><td>Small Wind</td></tr>
<tr><td colspan="2">Electric Vehicle Charging</td></tr>
<tr><td colspan="2">Combined Heat & Power (renewable fuels)</td></tr>
<tr><td colspan="2">Smart Inverter services (e.g., VAR Support)</td></tr>
</table>

Figure 2: List of Distributed Energy Resources (based on CPUC DRP Guidance)[11]

California's Energy Plan II states that, "The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation. Concurrently, the bulk electricity transmission grid and distribution facility infrastructure must be improved to support growing demand centers and the interconnection of new generation, both on the utility and customer side of the meter."

Where is the DER: Utility-Side or Customer-Side?

[11] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF

Utilities traditionally plan for expansions and upgrades to their distribution systems based on the simple philosophy of building to reliably meet the maximum expected load over the next 3 to 5 years (see 4.2.1). Often, these distribution upgrades are part of the utility's normal course of business, as is the case in Colorado where distribution expansion and maintenance falls under the ordinary course of business which means utilities generally do not have to request permission to build or recover cost.

Recently however, new possibilities for reliably and safely meeting customer electricity needs have emerged, such as demand response (see 4.9.3), renewable energy resources, FLISR (see 4.2.9), and conservation voltage reduction (CVR) (see 4.2.9). These approaches could potentially reduce customer bills or lower the impact of rate increases, and therefore may be attractive to regulators in their role of protecting the public interest. But these programs may not benefit utilities because they reduce energy sales and in turn reduce customer bills, impacting a utility's revenue stream between rate cases. They may also require the utilities to perform additional studies, implement new types of systems, and install equipment to support the programs.

At the same time, utilities are being pressured by their customers and by third parties to permit increasing numbers of DER systems to be interconnected. Concerned that these DER systems could lead to safety and reliability problems, utilities have been slow in approving them, particularly the larger DER installations. As long as DER systems were just a few in number and size, utilities could treat them as "negative load". But as their numbers are starting to increase, utilities are recognizing that they are not only a challenge but also could become an opportunity.

Exactly how and what regulatory changes might be necessary are not yet clear. But possible options could be to provide some of the DER services to communities and to incentivize customers to install DER systems where they might be most beneficial to utilities for reliability and power quality reasons.

Figure 3 below is an example of where different technologies and solutions to DER can reside with utility, customer, or in between, which is an interactive position. Regulators will be placed right in the middle of the decision making process on where to direct investment to meet utility and ratepayer objectives.

System Operator Solutions	Interactive Solutions	DER Owner Solutions
Network reinforcement	Price-based demand response	Local storage
Centralized voltage control	Direct load control	Self-consumption
Static VAR compensators	On-demand reactive power	Power factor control
Central storage	On-demand curtailment	Direct voltage control
Network reconfiguration	Wide-area voltage control	Frequency-based curtailment
Utility owned DER	Community DER	Customer DER

Figure 3: Technology Choices for Integrating PV and DER (2013)[12]

2.2.2 Utility Business Models

Utilities that experience financial pressure in relation to low levels of load growth or competitive pressure from 3rd parties may wish to seek new investment opportunities in non-traditional areas for a utility such as in DER.

A media survey shown in Figure 4 included over 400 utility executives, who ranked DER as the biggest growth opportunity over the next five years. Though the same survey found 63% of respondents who see DER as an opportunity are not sure how to build a business around it.

[12] M.Vandenbergh et.al., "Technical Solutions Supporting the Large Scale Integration of Photovoltaic Systems in the Future Distribution Grids," in *22nd International Conference on Electricity Distribution (CIRED)*, 2013. "Prioritisation of Technical Solutions Available for the Integration of PV into the Distribution Grid," PV Grid, 2013.

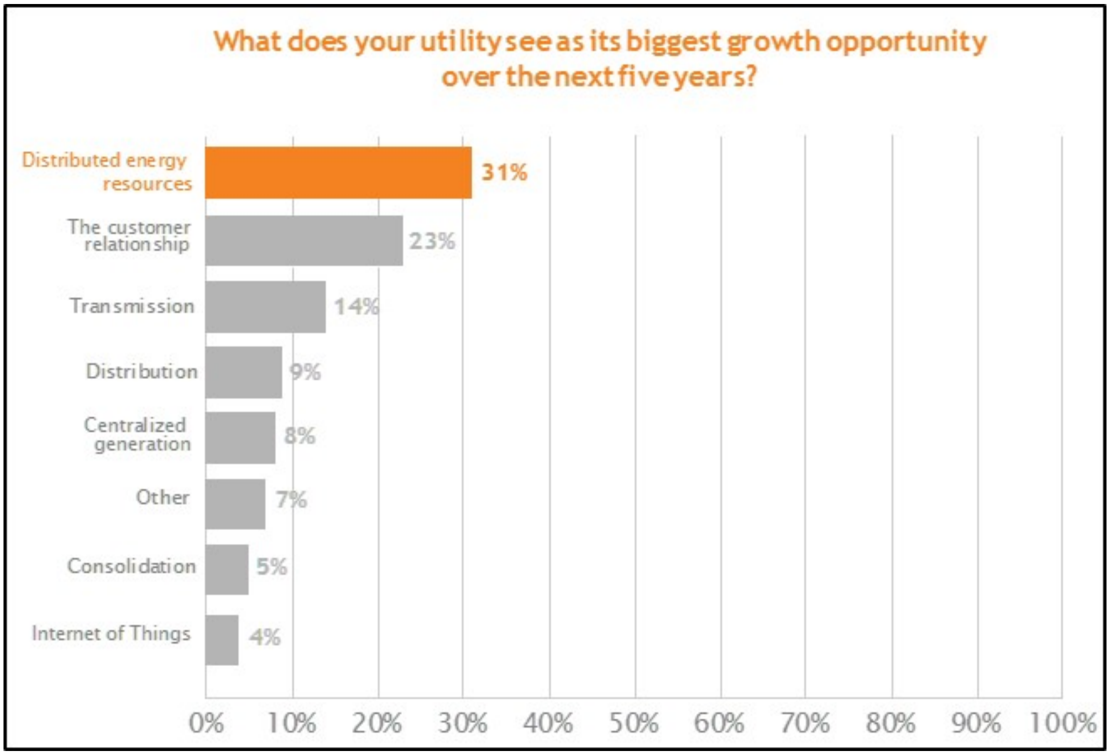

Figure 4: Utility Dive Survey 2015, http://app.assetdl.com/landingpage/utility-survey-2015/

Additional examples of the changing utility business model include:

A Western Interstate Energy Board paper titled "New Regulatory Models" highlights some potential solutions for utility business models.[13]

A recent discussion in the Edison Electric Institute (EEI) identified the need for utilities to develop new business models:[14]

- In order to participate in the DER industry, utilities need to have the barriers removed from owning, partnering, or operating DER facilities
- Utilities need to be able to partner with other stakeholders to pursue these interests
- Utilities need to have the allocation of costs of providing power more fairly divided between customers who have DER systems and those that do not.
- Utilities need regulators to support investments in grid upgrades that are needed for high penetrations of DER systems.

[13] http://westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf
[14] EEI presentation, particularly slides 14 & 15: https://www.documentcloud.org/documents/1374670-2012-eei-board-and-chief-executives-meeting.html#document/p48/a191712

2.2.3 Managing Technological Obsolescence

Distribution system utilities are seeing a wide variety of new technology offerings, from smart meters to customer generation. In deploying emerging technologies, there will never be a perfect understanding ahead of time as to the "most optimal" path forward. There could be obsolescence of equipment and systems as technologies and market forces may require decisions be made with imperfect knowledge and with less-than-mature devices and software. Waiting for more perfect knowledge or more mature technology is also risky since certain challenges may become overwhelming and costly, and many opportunities for realizing benefits may be lost.

Managing new technology investments requires taking small incremental steps, placing off-ramps and go-forward decision points on plans, and implementing modular technologies. For instance, laboratory pilot projects can test and evaluate new technologies, while field pilot projects can determine whether and where the technology may benefit operations. Modular technologies can allow portions of a system to be replaced or the software updated without requiring entire systems to be scrapped.

Distribution utilities are discovering ways to accommodate high penetrations of DER systems while trying to determine how to make good use of the smart DER system capabilities. Third parties, whether they are DER aggregators, independent power producers, or retail energy providers, are also wending their ways through the many potential business strategies and the rapidly proliferating technologies. Customers are slowly becoming more aware of possible ways of reducing their energy costs. Regulators are struggling to enable utilities to meet the increasingly demanding renewable energy standards or goals, while balancing the allocation of costs and benefits among ratepayers and stakeholders.

Given this complex web of stakeholders, challenges, and opportunities, there is no time to analyze what the best solution to a particular problem, even if enough information were available to permit this. ***So the best advice is for stakeholders to follow a "Policy of Least Regrets"***.

- **For utilities**, which are naturally conservative in implementing new technologies since their overarching purpose is to support a reliable and safe power grid, this policy of least regrets means that they may have to explore new ideas through distribution planning roadmaps, pilot projects and in-depth studies, but fairly quickly come to resolutions regarding which of these new ideas they bring to the field and to the customers.
- **For third parties**, which are typically the opposite of utilities in wanting to quickly deploy new technologies and can become very impatient with the utilities' careful approaches, this policy of least regrets means that they take the time to understand the utility concerns related to reliability and safety, and work with them to resolve problems. All too often it is easy to fall into adversarial relationships which end up causing even more problems with associated costs.
- **For customers**, who are mostly concerned about electricity prices but also occasionally with the impact of new technologies on their privacy and life styles, the policy of least regrets means that they should look at longer term solutions as well as immediate solutions to reducing those energy costs and understanding the privacy and life style impacts of their decisions. They should

be willing to spend the time exploring different avenues for working with both third parties and the utilities to arrive at mutually acceptable programs, but also be willing to make some decisions.

- **Regulators**, whose purpose is to balance utility needs with customer needs, the policy of least regrets needs to include gaining enough understanding of the opportunities provided by new technologies and stakeholder ideas, and balance these against the challenges that these might pose to utility planning and operations. Possible actions include:
  a. Add DER forecasts to IRP processes, include new avoided costs/benefits for DER,
  b. Request detailed distribution (e.g., smart grid) roadmaps be developed that include stakeholder process,
  c. Provide assured cost recovery for targeted demonstrations and pilots.

For all of these stakeholders, the policy of least regrets entails being willing to explore the new ideas without jumping too quickly, while nonetheless making active decisions even if all the information is not available. There will be some decisions which will be regretted – but not making decisions could be a cause for even more regrets.

2.2.4 New Stakeholders in Distribution and DER Management

Although utilities must still be in charge of managing distribution systems for reasons of safety and reliability, they are no longer the only stakeholders that must be involved. The new stakeholders include:

- **DER owners**, often customers of the utility, who are installing DER systems primarily to offset their loads, but can provide energy and possibly ancillary services to the utility as well
- **Third party DER aggregators**, who are selling or leasing DER systems to customers, and are acting on their behalf with utilities.
- **Retail energy providers**, who do not directly manage DER systems, but provide attractive tariffs and billing services to customers.
- **DER operators**, who may be facility managers or may be aggregators with permission to manage the DER systems
- **DER manufacturers**, who are updating their DER systems, possibly with more advanced functionalities.
- **Distribution planning**, who must plan for increased amounts of DER generation, who must undertake studies to ensure that DER installations meet the power system requirements for reliability and safety, and who must approve which DER advanced functions may or must be implemented.
- **Distribution operations**, who must operate their distribution system with high penetrations of DER systems even though they may have imperfect knowledge of generation, reliability, storage, and load patterns.
- **Distribution maintenance personnel**, who must safely maintain the distribution system even though DER units could potentially cause harm.
- **DER maintenance personnel**, who must ensure that the DER systems remain in compliance with the utility interconnection requirements.

An overview of these stakeholders is shown in Figure 5.

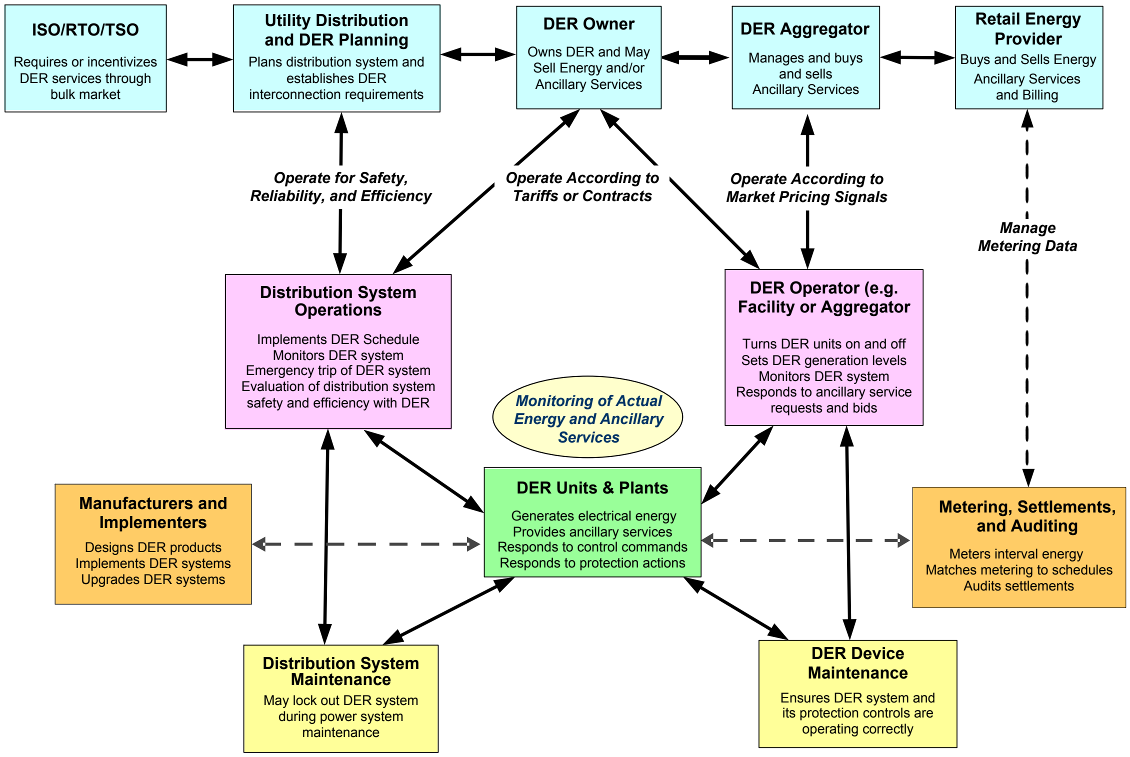

Figure 5: Stakeholders in DER Management[15]

Distribution system planning and operations are experiencing a paradigm shift as new technologies and declining costs of these technologies provide the opportunities for customers and many different third parties to actively participate in using and managing energy. The distribution system of the future will not just be supplying power out to the customers, but will transfer power to and from customers (see 4.6 and 4.4). Third parties will help to manage generation, storage, and controllable loads (see 4.7). Customers will actively participate rather than passively receive power (See 4.9).

2.3 Financial and Market Pressures for Regulators

2.3.1 Why is Cost Allocation Becoming an Even Larger Issue?

The means by which utilities allocate costs to customers has come under increasing question. As regulators balance utility needs and customer rates, there are an increasing number of parties questioning whether utilities are charging fair rates, and whether some customers benefit more than others from these rates.

Some of the issues that are causing financial mismatches are:

- **Customers have been mostly passive in energy management** since they typically receive bills and pay without understanding the actual utility costs, such as the time-based cost of energy, any load-based impacts on distribution transformers and feeders, or the impacts of different types of DER systems.

[15] Xanthus Consulting International, 2015

- **Customers have no incentive to change their load patterns** since they are typically billed by the month at a set rate or tier of rates that are just load-based, not cost-to-utility-based.
- **Utilities have no incentives for improving energy efficiency or supporting renewable energy**, since they are regulated only to provide electricity reliably and safely to customers. They have no incentive to spend more than they are regulated to for other purposes, such as efficiency, use of renewable energy, or allowing more DER systems to interconnect than mandated by the regulations.
- **Third party implementers of DER systems are driven by selling energy**, and have no financial interest in providing other services, such as reactive power or frequency smoothing, unless there are incentives to do so.
- **Customers with DER systems do not pay for utility "backup power" or other services**, since they only pay a typically-small distribution connection fee, but no longer pay for generation. Although this may seem reasonable in one sense (they are providing their own generation), this shifts the burden of the uncovered utility costs to those customers who do not have DER systems.

This often leads to confrontational situations, where customers may complain if rate structures change or rates increase, while utilities are concerned about operating the distribution system safely and reliably with all the third party implementers requesting to interconnect DER systems. Utilities are also reluctant to undertake the sometimes expensive studies and power system upgrades that would be necessary for some DER installations.

It would be helpful if customers could become more of a partner with utilities in understanding the challenges and the opportunities of efficiently and safely utilizing and generating electricity. Currently most customers are treated as passive users of energy who are just expected to pay their monthly bills. However, they could become active partners through participating in energy generation and storage as well as benefitting from new tariffs and technologies.

Some of the customer incentives can be provided by new tariffs and market incentives (see 4.9) if customers are also installing DER systems, (see 4.4). Utilities are facing additional challenges as customers implement these DER systems (see 4.3) but utilities and customers can also mutually benefit each other over the long term if utility distribution planning can incorporate new approaches (see 4.6).

2.3.2 What are the Key Differences between the Bulk Power Market and the Possible Retail Power Markets?

Sometimes it has been suggested that the retail market could just be a scaled down version of the bulk power market, buying and selling kW rather MW. However, there are some major differences. First of all, most agreements between utilities and DER owners (i.e. customers) are simply based on tariffs such as time-of-use (TOU) **(see 4.9.1)**, net metering **(see 4.9.4)**, or feed-in contracts (see 4.9.5). For these tariffs it is up to the customers to decide when to use energy to meet their loads, and whether they wish to modify their energy needs.

Retail energy markets can be established in some States. In addition to the policy-related differences of different States described in section 4.9.6, there are a number of other types of differences between bulk and retail energy markets. These include:

- Unlike the owners of bulk power plants, most owners of DER systems have little interest or time to "bid" into a market. Their purpose is to run their businesses or live in their homes, not to buy and sell energy.
- Most DER systems can provide only a limited amount of generation in excess of what is used to support the local facility's load.
- Renewable DER systems produce energy when the sun is shining, when the wind is blowing, or when the water is flowing, and therefore are not easily "managed" to produce energy according to a market schedule.
- Given the small amounts of available DER energy and the large number of sites, the cost of developing a market infrastructure that directly reaches all of these sites would be daunting.

Therefore the retail markets need to be developed with different expectations and structures than the bulk power market. The most likely stakeholders would be:

- Customers selecting among different retail-level energy management and DER programs that incentivize customers to modify their use of energy and generate their own energy.
- Aggregators could enter into contracts with DER owners to "manage" their DER systems for different purposes, such as "maximum revenue", or "make sure my energy storage systems are charged by 5 pm", or "allow reactive power to be provided only if the price is greater than any losses of energy revenues".
- Commercial or industrial facilities could program their energy management systems with "rules" for maximizing their energy usage profile for their own business purposes, with only any extra energy or ancillary services provided to the utility.

Although there is no single market structure, some of the different structures could include:

- Demand response (DR) (see 4.9.3),which provides customers with energy pricing information for different times or incentive payments, thus permitting them to decide whether to reduce their loads, by how much and for how long.
- Transactive energy (see 4.9.7), which refers to the use of a combination of economic and control techniques to improve grid reliability and efficiency.

2.3.3 What Tariff-Related Questions Are Raised by Different States?

Under the Section 1251 of the Energy Policy Act of 2005, net metering is defined as a service to an electric consumer where electric energy generated by a customer DER system is used to off-set the electric energy provided by the utility to the customer at the customer's rate during the equivalent billing period (see 4.9.4).

In response to the growing concerns regarding cost allocation associated with net metering pricing with respect to DER owners and non-DER owners, several states are starting to review different policies and rules that might be used to address these concerns. Some examples include:

- The Arizona Corporation Commission imposed a $0.70 per kilowatt fee for future customers using net metering.[16] According to Business Wire[17], this means an average increase of $4.90 per month for a typical customer using solar to supplement their services.
- California's AB327 that allows the CPUC to consider a monthly fixed charge of up to $10 on all residential customers (whether or not they have DER systems) and permits the Commission to flatten the tiered pricing scheme so that there is less distinction between high and low energy usage. This helps to level the pricing differences between DER owners and non-DER owners. However, until the Commission accepts a rate, it is unclear to what extent it may impact customer-owned DER systems.
- Minnesota PUC developed a Value of Solar[18] (VOS) tariff that would allow utilities to take into account certain aspects of solar energy that are not found in traditional generation sources including delivery, capacity, line losses, and its environmental value. As of October 2014, no utilities had applied to the Minnesota PUC for a VOS tariff but Xcel Energy's Community Solar Garden has been identified as a good application of the VOS tariff[19]. In the Minnesota department of Commerce developed a VOS methodology which describes the need to meter solar separately from load.[20]
- Hawaiian Electric Companies (HECO) is investigating ending the net metering program and replacing it with a different type of tariff. HECO says the change is needed to prevent distributed solar from overwhelming grid stability, burdening non-solar customers with extra costs, and crowding out other, less expensive forms of renewable energy. In particular, it will permit more customers to benefit from installing solar systems. This tariff would be replaced within a couple of years by a new distributed generation program "DG 2.0." that would allow customers to make money from self-generated power that also supports the grid, by including smart inverters, energy storage, demand response and other advanced DER functions.
- West Virginia, who recently became the first state to repeal its renewable portfolio standard, is reviewing a legislative bill that would require their PUC to set new rules for net metering that would prohibit cross-subsidization, defined as "the practice of charging costs directly incurred by the electric utility in accommodating a net metering system to electric retail customers to electric

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[16] A comprehensive database of renewable and efficiency incentives and regulations can be found at www.dsireusa.org (sponsored by the U.S. Department of Energy and the North Carolina Solar Center)
[17] Arizona Corporation Commission sets new direction for net metering policy, Business Wire, November 14, 2013, http://www.marketwatch.com/story/arizona-corporation-commission-sets-new-direction-for-net-metering-policy-2013-11-14
18 https://mn.gov/commerce/energy/businesses/energy-leg-initiatives/value-of-solar-tariff-methodology%20.jsp
19 http://www.solarindustrymag.com/e107_plugins/content/content.php?content.14600
20 https://mn.gov/commerce/energy/images/MN-VOS-Methodology-FINAL.pdf

retails customers who are not customer generators." This would mean that utilities could charge customers who are installing DER systems for any upgrades needed to accommodate the DER, but might also be used to charge them for any routine grid maintenance.

- Oregon initiated a Volumetric Incentive Rate (feed in tariff) pilot in 2010 that is reviewed every 2 years. Generation is tracked and paid at an established rate. Included in the incentive value are: avoided energy, avoided investments in capacity, and avoided transmission line losses. Oregon PUC chose not to include avoided transmission and distribution investments, firming and shaping costs, fuel price hedging, or carbon costs, stating that a certain threshold level of solar penetration in Oregon is needed before these additional costs and benefits become measurable and need to be considered.[21]

2.4 DER Technologies Affecting Regulations

2.4.1 Why Are Utilities Concerned About DER?

Utilities can manage small numbers and sizes of DER systems using their normal planning and operational procedures. This is currently the situation in most States and jurisdictions.

The issues arise when there starts to be higher penetrations of DER systems, both from a technical aspect and a financial aspect, due primarily to customers seeking to reduce their energy costs, but also in response to environmental regulations and incentives.

Technically utilities must plan for and operate their distribution system that no longer match the traditional patterns of load and generation (see 4.3.2). This causes many concerns about safety, reliability, and costs. Although some efforts are underway to incentivize customers to locate DER systems at sites that can benefit distribution operations (see 4.6), the technical and financial issues still require significant studies.

The installation of generation at customer sites also may decrease utility revenues (depending upon rate structures), both by reducing the revenues from serving loads and by needing to compensate customers for excess generation through net metering and other tariffs. At the same time, the need to provide and maintain the infrastructure to serve all customers remains the same or may even grow more costly (see 4.3.4). Some utilities are looking at ways to restructure their business models (see 4.1.4) as they may view aggregators and 3rd parties injecting an element of competition into the industry.

2.4.2 How May Utility Mandates to "Serve" Be Affected by the Reliability of DER Systems?

In the bulk power system, utilities, including ISOs and RTOs, directly control bulk generators according to contracts and market agreements. Protective relays in substations react within a couple of cycles to faults, sophisticated equipment respond to

21 http://www.puc.state.or.us/docs/2015%20Solar%20Report.pdf

transient stability anomalies, and the networked design of the transmission system provide the necessary redundancy to support very high levels of reliability. SCADA systems collect real-time data with a latency of a second and operators can issue control commands within a few seconds. Load forecasts, contingency analysis, and other energy management system applications provide short-term planning support and insight.

In the past, distribution operations have relied on these transmission-level services to provide reliable energy to the substation, and have focused primarily on maintaining reliable “wires” between the substations and customers.

However, that scenario changes when distribution operations have to treat DER systems as additional sources of energy. Initially, transmission-supplied energy could compensate for any reduced reliability of DER systems. But as more generation is supplied locally, utilities may benefit from relying on that local supply through avoidance or deferral of transmission and distribution infrastructure.

Customer-owned DER systems (as opposed to utility-owned or IPP-owned) are generally less reliable for providing energy and any ancillary services to utilities, simply because their primary purpose is to serve their owners, not the grid. Although contracts and market forces can pressure these DER owners to support grid reliability, ultimately these owners may make decisions to further their own needs over those forces. Distribution utilities can partially off-set this lower reliability of specific DER systems by having large numbers of DER systems available to provide these services. Thus the lower reliability of one DER can be compensated statistically by having many other sources.

However, careful planning will need to ensure those alternate sources are able to compensate for the specific location and services required. Thus Distribution Resource Planning (see 4.6.1) will need to include statistical analysis of the “reliability” of customer-owned DER systems, in addition to the inherent reliability of renewable energy sources.

2.4.3 What Are “Smart” DER Capabilities, and What Are Their Benefits?

In some cases, regulators have limited information about the engineering details of DER technologies and what have been termed “smart inverter” functionalities (see 4.4.1). This makes decision-making more difficult because the issues of interconnecting DER systems have become even more complex. Not only are customers reducing their loads and thus reducing utility revenues, but DER systems can cause planning and operational issues for utilities (see 4.3.4). At the same time DER systems are being marketed as being able to benefit utility operations (see 4.3.3) and Table (see 1.2).

Utilities are reluctant to embrace some of these smart inverter functionalities without further studies on exactly how they can be coordinated with their existing equipment (4.3.4), what the interconnection requirements might be (see 4.7.2 and 4.7.3), and what DER communications requirements (see 4.7.5 and 4.7.6) might be needed to take advantage of some of these advanced DER capabilities. And yet utilities are increasingly aware of the problems associated with high penetrations of “less-smart” DER systems in Europe (see 4.5.1) and Hawaii (see 4.5.3), and recognize that these advanced DER functions must be embraced at one level or another.

Customers, aggregators, and other implementers of DER systems also have concerns which they bring to regulators. The foremost of these is usually why utilities take so long to approve an interconnection – or why they might actually reject an interconnection (see 4.4.3). Additional concerns include whether “non-exporting” energy storage (see 4.4.4) should just be considered as negative load and not have to go through the interconnection process. Newer concerns relate to which advanced DER functions must or could be provided, what communications requirements will be necessary (see 4.7.5 and 4.7.6), whether these communication requirements can be “standardized” across different utilities and jurisdictions to provide interoperability (see 4.7.1) (DER vendors do not want to support large numbers of different communication protocols), and what cyber security protections need to be implemented (see 4.8).

2.4.4 What Can Regulators Do to Incentivize Win-Win DER Implementations?

In the big picture, it is clear that the implementation of DER systems could be a win-win for both utilities and customers, including those customers who do not own DER systems. DER systems can support environmental requirements including Renewable Portfolio Standards (see 4.1.3). Customer loads can be reduced and more efficiently spread out over time through different tariffs (see 4.9.1 and 4.9.4) and market incentives (see 4.9.2, 4.9.3, and 4.9.7). Utilities can defer upgrade and maintenance costs (see 4.3.3). Even customers without DER systems may be able to benefit from the increased efficiency of energy production and transport, thus paying lower rates for their electricity. But how can this win-win situation be achieved?

No single answer or set of regulations can solve this complex set of scenarios. However, one task could be to require all DER systems to have a minimum set of advanced DER functions (see 4.4.1), including communications capabilities (see 4.7.6). Another task could be to ask utilities to develop “Distribution Resource Plans” (see 4.6) that plan for high penetrations of DER and that include incentives for siting different types, sizes, and capabilities of DER systems at specific locations. A third task could be to address cost allocation issues with different types of tariffs.

2.4.5 What Are DER Regulations in Different Jurisdictions?

European DER Grid Codes

Since Europe (3.5.1) has implemented far high numbers of DER systems, those countries were the first to recognize both the technical and the financial challenges of installing such high penetrations of DER systems. ENTSO-E (European Network of Transmission System Operators for Electricity), which is responsible for the overall security of the European grid, has taken the lead in addressing DER requirements. They have mandated increased “ride-through” voltage and frequency ranges to ensure that momentary spikes and sags do not cause DER systems to trip off unnecessarily. This requirement was recently extended requirements to upgrade additional DER systems that have already been installed.

Hawaii Grid Codes

Hawaii (3.5.3), because it consists of small islands in a location with lots of solar energy, has experienced high PV penetration. On the island of Oahu, many of HECO's feeders have exceeded acceptable levels, which were initially set at 75% of daytime minimum load for projects under 10 kW. This level has since been raised to 120% of daytime minimum load, and HECO is studying the measures required to increase this level and has released a proposal to increase it to 250% of daytime minimum load.

California New 50% Renewables Goal

California Governor Jerry Brown had called for 12,000 MW of "localized electricity generation", or DER, to help the State procure 33 percent of its energy from renewable resources by 2020, and has recently increased that goal to 50% by 2030.

California is expecting to extend the current goal of 33% renewables by 2020 to 50% renewables by 2030. PG&E's Anthony Earley, president and CEO, and Kent Harvey, senior vice president, said that Pacific Gas and Electric is planning $5.5 billion in capital expenditures in 2015, including about $1.1 billion for electric transmission and around $2 billion for electric distribution[22].

Through updates to Rule 21, the California utilities are also requiring all new DER installations to include certain advanced DER functionalities and be capable of communications (see Section 3.5.2)

2.5 What is California Doing?

2.5.1 What Can Be Learned from California's Smart Inverter Working Group Process?

On December 18, 2014, the California Public Utilities Commission approved the Smart Inverter Working Group (SIWG) recommendations that all new DER systems must support seven autonomous functions and must be capable of communications if deemed necessary by the utility (see 4.5.2).

However, when the SIWG process first started, the utilities, the DER manufacturers, and the DER implementers and aggregators filled the weekly discussions with their concerns. The utilities expressed concern about possible additional utility costs for managing "smart inverters". DER manufacturers were concerned about any mandates that could increase their costs by forcing them to certify their products with any new requirements. DER implementers and aggregators were concerned that this would slow down their implementations and would impact their revenues from selling energy.

However, amazingly through weekly discussions and a workshop during the first few months, all of the stakeholders began to see the benefits of smart inverters. Utilities saw that the DERs could benefit voltage management and emergency handling on their

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[22] Electric Light & Power interview: http://www.elp.com/articles/2015/02/pg-e-invests-in-power-grid-that-flows-in-multiple-directions.html?cmpid=Enl_ELP_Feb-13-2015

distribution systems. DER manufacturers began to see that by providing smart inverters, they would be able to sell more products since utilities could handle more DER installations. In fact, since European utilities were already requiring many of these advanced functions, some of their products already included the functions but were disabled in the US. DER implementers and aggregators realized that they could not only sell energy but also be compensated for ancillary services. So these discussions changed from nervous and confrontational interactions to "***How fast can we get this accomplished?***"! Although it took a little longer than originally planned, the time between the start of the SIWG in January 2013 and the approval of the Phase 1 functions by the CPUC in December 2014 was only 2 years.

2.5.2 Why are California Utilities Changing Their Distribution Planning Procedures?

The California Legislature passed AB327 in 2013 which amended public utilities code to require utilities to file "Distribution Resources Plans," (DRP). These plans will focus on integrating and valuing DERs. At the same time, broader discussions are beginning to highlight typical distribution planning processes as an opportunity for improvement, not only to integrate DER, but also to determine the optimal set of distribution investments for utilities that are seeing increasing complexity at the distribution level.

California utilities were beginning to look more closely at decades-old distribution planning procedures prior to AB327, and the DRPs will likely accelerate such actions. The plans will also change the interaction between the utilities and regulators with regard to distribution system analysis. Today the word "black box" is used by some to describe the transparency of utility distribution planning. While the extent to which this box will be opened up by the DRP process is not known, more information will be exchanged between utilities and regulators, certainly pursuant to public utilities code requirements, and additionally as the CPUC determines is appropriate. See Section 4.6 on DRP.

2.5.3 Why Distribution Resource Plans?

Another effort is also underway that was triggered by legislation, AB 327: the requirement that the California utilities under the CPUC regulations must file Distribution Resource Plans (DRP) (see 4.6.1) with the CPUC which take into account the impacts and the benefits of DER systems. These DRP requirements were based on the principles outlined in a Resnick Institute White Paper "More Than Smart" (see 4.6.2).

These DRPs could also identify locations where DER systems could be particularly beneficial, and would identify "locational incentives" for implementing DER systems with the appropriate advanced functionalities at those locations. These DRPs would thus support utilities in exploring and making the most beneficial use of DER system capabilities. However, the challenges and questions that need to be resolved are both technical and financial.

From a financial perspective, a number of questions would need to be answered in any regulatory jurisdiction that is requesting utilities to develop distribution plans that take into account DER systems, such as[23]:

- **Bulk power**. What are the financial impacts and potential benefits for the bulk power systems?

1. Wholesale energy reductions, due to the reduced quantity of energy produced based on net load
2. Reductions in the marginal wholesale price of energy (Locational Marginal Prices) if DER systems are located in strategic sites
3. Reductions in the requirements for resource adequacy, such as the reductions in total generation capacity and operational reserves
4. Reductions in flexible capacity, due to the reduced need of resources for system balancing
5. Reduced need for other bulk power ancillary services, such as frequency management
6. Reduced RPS energy prices and integration costs
7. Reduced transmission capacity required for system and local area transmission
8. Increased ability for DER systems to be bid into the wholesale market for energy and other services
9. Avoided transmission local congestion and losses as determined by the difference between system marginal price and LMP nodal prices
10. Reduces charges to Load Serving Entities (LSEs) for wholesale market and transmission access charges

- **Distribution**. What are the financial impacts and potential benefits for the distribution system?

1. Reduced or deferred subtransmission, substation and feeder capacity upgrades, due to the reduced need for local distribution system upgrades
2. Reduced distribution losses, due to losses between wholesale transactions and distribution points of delivery
3. Improved distribution steady-state voltage, including voltage limit violation relief, reduced voltage variability, and the use of compensating reactive power
4. Improved distribution power quality, including minimizing transient voltage spikes and sags, avoiding or minimizing momentary outages, and providing harmonic compensation.
5. Extended life for distribution equipment, by minimizing the number of switching and level changing actions
6. Improved distribution reliability, resiliency, and security, by reducing the frequency and duration of outages along with the ability to withstand and recover from external natural, physical and cyber threats
7. Increased distribution safety, with improved public safety and the reduced potential for property damage

- **Customers and Society**. What are the financial impacts and potential benefits for customers and society in general?

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[23] Extracted from E3 presentation to the CPUC, "*Overview of Public Tool to Evaluate Successor Tariff/Contract Options*", Dec. 16, 2014 at http://www.cpuc.ca.gov/NR/rdonlyres/1FCC2996-1232-4D97-8B4A-0A194A003ACA/0/16Dec2014PublicToolWorkshopFinal_12_15_14.pdf

1. Increased customer choice, which could provide customer and societal value from robust markets for customer alternatives
2. Reduced CO_2 emissions, reflecting federal and/or state emissions cap-and-trade allowance revenues, cost savings, or compliance costs
3. Reduced health costs caused by other pollutants, due to use of renewable sources
4. Increased energy security, due to the reduced risks derived from greater supply diversity and less “lumpiness” of supply
5. Coordinated with water use, where synergies can be found between DER and water management (electric-water nexus)
6. Fewer impacts on land use, with environmental benefits and avoided property value decreases from DER deployment instead of large generation projects
7. Economic benefits for State and/or local entities (e.g., increased jobs, investment, GDP, tax income)

In addition to these specific questions, many tariff and incentive issues need to be answered:

1. What form should locational regulations and incentives take?
2. How can double counting of benefits be avoided if locational and temporal incentives are used for multiple purposes?
3. How should tariffs be structured to permit utility requests/commands for voltage management by DER systems?
4. What financial aspects should be tariff-based and which should be left to the retail energy market?

2.6 What is the WECC forecast for DER?

By 2022 WECC may see 43GW of DER with a peak load of 178GW. EQL compiled various forecasts of DER in WECC from several independent sources, see Figure 6. In comparison, Germany currently has 32GW of solar PV out of a peak capacity of 80GW (40%). Because of state and provincial differences in resource potential, alternative energy resources deployed or removed (e.g., coal/nuclear), policies, incentives, vendor push, customer preference, and utility business models, etc. the relative amount of DER by region will be very different, See Location Heat Map, section 4.10.

DER	2022 DER WECC Estimate (GW)	Source
Solar	25	2013 E3 TEPPC study on High DG (reference) (1)
CHP	9	2013 E3 TEPPC study on High DG (reference) (1)
DR Load Following	2.6	2013 WIEB VER Integration (2)
DR Other	4.7	2013 LBNL 6381, Incorporating Demand Response into Western Interconnection Transmission Planning (3)
Storage	1.8	AB2514 California 2020 mandate , plus 500 MW
Total	**43**	178GW WECC peak forecast (23%)

Figure 6: WECC DER Forecast 2022

Sources:

- https://www.wecc.biz/Administrative/141010_E3_TEPPC_HighDG_20-Year.pptx
- http://wiebver.org/wp-content/uploads/2015/03/12-20-13SPSC_EnerNOC.pdf
- http://emp.lbl.gov/sites/all/files/lbnl-6381e_0.pdf

3 Utility Scenarios and Regulatory Response

Not all utilities have regulatory, policy, and resource environments like California, or Hawaii. Other utilities are nonetheless considering changes to distribution planning and managing DER on their systems. These are separated into three categories based on the expected impact of DER in the future. For each scenario we provide on: 1) utility examples, 2) regulator questions/response to utilities, and 3) other actions to be considered. In some cases, the regulator questions are accompanied by an explanation or a link. The questions are meant to be answered by utilities.

3.1. Utility is Planning Investments to address load growth or generation retirements

DER solutions in integrated resource planning and procurement processes are reasonable and becoming more common. Utilities and system operators planning new investments in the bulk power system are increasingly being asked to include DER alternatives. While DER has historically been treated simply as reductions in load forecasts, certain factors could shift perspectives toward using DER for reliability purposes as penetration increases and DER management experience broadens. Below are some examples of utility situations and regulatory questions and responses related to DER and Distribution Resource Planning.

Examples

3.1.1 Generation

California utilities, at the direction of the CPUC and the state legislature, have made acquiring DER a priority in procurement decisions, but determining the appropriate level of DER investment compared with traditional infrastructure options is proving to be challenging. Of many ongoing procurement proceedings before the CPUC, an application filed by SDG&E in July 2014 with the CPUC illustrates tensions between DER and traditional natural gas power plants with respect to local reliability challenges.

In California, utilities regulated by the CPUC generally request pre-approval for large investments such as generating plants, as is the case here. SDG&E asked[24] for

24 Docket: A14-07-009, Application dated 07.21.2014

permission to enter an agreement with a new 600 MW natural gas simple cycle power plant in Carlsbad, along with 200 MW of DER, pursuant to a prior CPUC decision[25] authorizing 500 to 800 MW of local capacity, with DER supplying a minimum of 200MW.

On March 6, 2015, the CPUC issued a proposed decision[26] in the proceeding that would deny the application and place the proposed plant in a backup role to be called upon in the event SDG&E could not procure sufficient DER to meet reliability needs.

On April 6, 2015, an alternate proposed decision[27] was issued that approves a smaller 500 MW plant and increases DER procurement requirements to 300 MW. The California ISO submitted comments on both proposals describing a need for dependable generation, and SDG&E argued DER options are not yet mature enough to be counted on for reliability purposes. The commission may vote on the matter during its May 21 business meeting.

Regulator Questions to Generation Sponsor

1. What services are being provided by proposed Generation? E.g., peak capacity, energy, ancillary services, etc.?

2. Has the ability for DER to provide these services been evaluated?

DER is increasingly identified as an alternative to offset the need for generation or meeting RPS objectives. Incentivizing and integrating DER may be more cost effective and meet multiple utility requirements. The timing to implement DER may be different than that of conventional generation and must be planned ahead of need.

3. If energy storage is considered, what analysis or procedures is required to ensure these resources can be interconnected and their generation will be available when needed?

In California, the ISO, utilities and the PUC are currently grappling with questions of how to interconnect and credit energy storage with peak, local and flexible capacity attributes. Because storage consumes energy, the interconnection process may become more complex and questions are raised about how to treat system upgrades that may be necessary for charging and discharging.[28]

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http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M098/K406/98406519.PDF
25 D14-03-004
26 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M148/K259/148259638.PDF
27 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M150/K379/150379054.PDF
28 CAISO Energy Storage Interconnection Proposal:
http://www.caiso.com/Documents/DraftFinalProposal_EnergyStorageInterconnection.pdf

3.1.2 Transmission

Transmission projects are proposed to support load growth, economic price differences between regions, and reliability. DER alternatives should be proactively considered for projects supporting load growth and/or reliability. Load forecasts for many WECC utilities are flat to small. However, there may be regions that experience steep growth, or transition a new generation mix that may require new transmission. Reliability driven projects come about from changes in power flows (load/supply mix) and contingency planning requirements.

In many cases when a transmission project is proposed, developers are being asked to consider "non-wire" alternatives. Non-wire alternatives may include changes in network configuration, redispatching generation, remedial action schemes, and Demand Side Resources, e.g., DER and Energy Efficiency.

As the WECC generation portfolio and DER penetration occur, transmission utilization will also change. E3 conducted research for WIEB on impacts of EPA 111(d) and RPS on regional electricity trading patterns.[29] The study found substantial changes to flow patterns in instances of high renewable penetration levels. Understanding the differing levels of DER by location is important to forecast changes in power flows and ability to address transmission constraints and reliability.

Examples

When planning to build a new transmission line, Bonneville Power Administration and other utilities often conduct "non-wires" analysis to evaluate potential for DER and other strategies to provide alternatives. Examples of non-wires reports:

Puget Sound Energy:
http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/attachment_5_-_screening_study.pdf
Bonneville Power Administration:
https://www.bpa.gov/Projects/Initiatives/NonWires/ScreeningStudy_NonWires_I-5_Corridor_Jan2011.pdf

Regulator Questions to Transmission Developer

1. Has the technical and market potential for DER in affected areas been assessed?
    a. What is the timeline or forecast for DER for both technical and market potential?
    b. What is the cost estimate to move from market potential to technical potential?
    c. What types of DER would be required to address utility need?

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29 CREPC/SPSC/WIRAB April 6, 2015 E3 Presentation: http://westernenergyboard.org/wp-content/uploads/2015/04/04-06-15_CREPC-SPSC-WIRAB_olson_E3_Electricity_Trading_Patterns.pdf

Transmission projects meet a variety of different needs, e.g., peak capacity, access to less expensive generation, reliability. The timing and amount of power required will dictate the DER requirement required as an alternative. Reliability will usually be for certain conditions, e.g., peak period and line outages.

2. What is the scenario that requires new investment? What is the expected capacity and number of hours per year it will be needed?

   The need for many transmission projects is driven by reliability concerns that occur during a small number of hours per year when load conditions combined with outages on other facilities stress the ability to continue normal load service.

3. Are there third parties that can aggregate and provide DER to utility?

4. If maximum DER potential can be achieved on affected areas of the system, is the T&D investment still required? If so, provide supporting analysis.

5. What is the cost and timeline of achieving the technical potential DER in affected areas?

6. Have all alternative transmission and distribution options been considered? For example, investments in DER and distribution equipment could be evaluated as alternatives to a transmission line.

Utilities should consider conducing analysis to evaluate DER potential using accurate and recent assumptions about DER capabilities. Regulators should choose qualified consultants to perform this work or evaluate in-house utility analysis.

3.1.3 Distribution

Distribution investments for load growth include reconductoring lines, distribution transformer upgrades, upgrades to substation and switchgear, etc.

Example: BC Hydro's capital expenditure budget for transmission and distribution is approximately 3 times that needed for generation, and hence a larger impact on rates. They are exploring the regional use of demand management and DER to defer significant investments in transmission and distribution upgrades. Often these new investments are required for N-1 or N-1-1 contingency events for a limited number of hours per year. If demand management and DER can be relied upon by the utility, then some of these projects may not be necessary or the need may be deferred.

Regulator Questions to Utility

1. Many questions will be similar for a proposed transmission project. See Regulator Questions to Transmission Developer.

2. What is the cost of achieving the maximum potential DER in affected areas?

3. Are there third parties that can aggregate and provide DER to utility?

4. If maximum DER potential can be achieved on affected areas of the system, is the T&D investment still required? If so, provide supporting analysis.

5. What is the scenario which requires new investment? What is the expected capacity and number of hours per year it will be needed?
   Many transmission projects are promoted for reliability, or to continue normal transmission service in the event of an outage.

6. Have all alternative transmission and distribution options been considered? For example, investments in DER and distribution equipment could be evaluated as alternatives to a transmission line.

3.2 My utility is much simpler than California. Why should I pay any attention?"

Some jurisdictions have very limited numbers of DER systems already installed and there are few incentives to encourage more DER installations. The idea of including mandates for smart inverters or distribution resource plans seems unnecessary and excessively complicated. However, some possible issues to explore in this situation are:

- Maybe regulatory mandates are not important at this time, but possibly some of the "smart inverters" functionality could be useful in special situations. Since the DER manufacturers will soon have products that will be certified for many of these smart inverter functions, a requirement to include such functionality could be part of those special utility-customer agreements.
- Utilities and regulators could use some of the financial and technical data that are being discussed during the development of the California Distribution Resource Plans. The actual data would be different for different jurisdictions and some may not be relevant, but using the types of data as a checklist (see 2.5.3) could help utilities provide good arguments for their plans while regulators could use the checklist in their assessments of the utility distribution plans.
- Given that the advanced DER technology is available, some commercial or industrial customers may feel it could be in their best interest to offer certain ancillary services to the utility if the incentives were right. They might pressure the utility and/or regulators to allow them to either establish a customer agreement or develop a special tariff. Seeing what California or Hawaii or other States could provide guidelines for such discussions.
- The utility might become interested in providing some DER-based services, including owning and operating DER systems in "rent-a-roof" schemes. The utility could learn from these other States on both the challenges and the benefits of such efforts.

- Regulators and utilities with currently limited DER should review their interconnection policies. Because of infrequent use, often these have not been reviewed and updated based on current information, updated IEEE 1547 standards or are based on FERC interconnection procedures that were generally designed for larger DER systems -- making interconnection more costly and challenging than it needs to be for customers.

3.2.1 DER is not a big concern. Why do Distribution Resource Planning?

There will be benefits and costs to instituting DRP. Different types of analysis, additional software, and potentially increased stakeholder involvement will incur costs.

Jurisdiction with high DER
For utilities in this circumstance, pressure will be placed on planning processes regardless of the presence of any planning reform action. States in this position may find it beneficial to take a closer look at planning, as has happened in California and Hawaii.

Jurisdiction with increasing DER
Utilities should get in front of planning for DER and look for opportunities to provide system value (reliability, distributed capacity, T&D deferral, operation efficiencies) while providing a platform to integrate DER.

Jurisdiction with Integrated Resource Planning
DRP can provide a more accurate load forecast into an IRP, as well as assist identify integration costs and DER values.

Arizona is an example of a state that has increasing DER and an integrated resource planning process in place for regulated utilities. In a 2014 consultant report assessing utilities' IRPs, new distribution related topics were suggested for future plans.[30]

3.3 Utility Proposing Investments in DER and Distribution

3.3.1 Utility proposing to invest directly in or incentivize DER

A utility is proposing to invest in or incentivize DER to provide system benefits, lower cost service, and meet customer demand.

Arizona Example

Arizona Corporation Commission (ACC) has provided a "No Objection" to APS and Tucson Electric Power (TEP) to install rooftop solar systems on customer rooftops. The ACC also mandated that both utilities limit their programs to research projects and to ratepayers with low credit scores, and that they offer solar at cost parity with the

[30] Global Energy & Water Consulting INC. suggested Distribution Automation, Voltage Optimization, and additional renewables integration strategies.
http://www.azcc.gov/Divisions/Utilities/Electric/IRP2012/2014/2014%20IRP%20Final%20Draft%20Report%20for%20the%20AzCC%2013-0070%20(NON-REDLINED)%20as%20docketed.pdf?d=779

existing market. Compromise measures added by the commission were designed to ensure APS and TEP don't have a blank check when it comes to rolling out rooftop solar projects.[31] In its proposal for the customer rooftop program, APS cited grid benefits of being directly able to control inverters.

New York Example

New York Public Service Commission, in a February 2015 order, is discouraging utilities to directly own DER:

> "*Because of their incumbent advantages, even the potential for utility ownership risks discouraging potential investment from competitive providers.*" "*Markets will thrive best where there is both the perception and the reality of a level playing field, and that is best accomplished by restricting the ability of utilities to participate*."

The commission said utility ownership would be permitted under three exceptions:[32]

- **Energy storage integrated into distribution systems.** "*Storage technologies integrated into grid architecture can be used for reliability and to enable the optimal deployment of other distributed resources, and we agree with staff that this application of storage technology should be permitted without the need for a market power analysis. REV (Reforming the Energy Vision)[33] will support a greater understanding of how storage strategically used on the grid can support greater penetration of intermittent renewable resources without compromise to system reliability. It will be advantageous for utilities to gain this experience and, as part of their DSIP plans and rate plans, utilities should develop information on optimal locations and levels of storage either on the system or behind the customer's meter*."
- **Projects enabling low- or moderate-income residential customers** to benefit from DER where markets are not likely to satisfy the need. "*This potential is particularly acute in the case of rental customers that cannot control improvements to premises.*"
- **Demonstration projects.** "*We recognize that demonstration partnerships with utilities and third parties can accelerate market understanding and the development of sustainable business models. In limited circumstances, utility investment and ownership of assets to support such demonstrations is warranted.*"

Regulator Questions

31 http://www.greentechmedia.com/articles/read/arizona-utilites-get-the-go-ahead-to-own-rooftop-solar
32 New York PSC February 26, 2015 Order, Case 14-M-101
http://www.dps.ny.gov/
33 Reforming the Energy Vision is an initiative by the New York PSC to change the way utilities in New York conduct business. Core policy outcomes sought by the PSC relate to: customer knowledge, market animation, system-wide efficiency, fuels and resource diversity, system reliability, and carbon reduction.

1. **Has the utility developed a distribution resource plan to justify program investment?**

   Using enhanced planning and operational tools discussed in section 4.6, a utility can evaluate a set of choices that may include DER along with traditional distribution investments.

2. **What are the costs and benefits to all ratepayers for proposed program? How do these compare to other alternatives to meet service requirements?**

   A utility may find that there are opportunities to offset or defer traditional distribution investments by implementing specific DER contributions. These DER could be provided by 3rd parties, or could be utility owned. Either way, the utility needs to have certainty about the reliability of the DER contribution if reliability is to be maintained.

3. **How is traditional distribution grid investment different from what is needed for a system with increasing or high penetration DER?**

4. **Are there types of distribution investments that are important to accommodate DER but are not made as a result of traditional distribution system planning?**

   Yes, for a system without much DER, required upgrades will be different.

5. **Who pays for upgrades – traditional or otherwise – that are associated with increased levels of DER?**

   All customers of that utility, perhaps all customers on that feeder, or maybe just customers with DER. There are many ways to allocate costs, and many jurisdictions have initiated proceedings to address this. Increasing the quality of information available to stakeholders about distribution system investments will be valuable in future cost allocation discussions.

3.3.2 Utility wants to invest in advanced tools for distribution planning and real-time operations.

The distribution system is becoming much more complex from both the planning and operations perspectives. In the planning horizon, new tools and procedures are seen by many as necessary in order to improve the way utilities determine what distribution investments are required, evaluate interconnection requests and policies, and in some cases enhance stakeholder involvement in these areas. In the operation horizon, utilities are finding that legacy systems are or will be overburdened by the new demands of DERs interconnection and operation.

Utility Examples
California utilities are investing in distribution planning tools with enhanced capabilities in order to implement new distribution resource planning procedures. They are also developing DER Energy Management Systems (DERMS) that will support real-time

distribution operations with significant DER installations. Xcel Energy[34] (PSCO), Arizona Public Service[35], and BC Hydro have implemented or in the process of investing in a DMS that provide advanced operations and analysis tools.

Regulator Questions

1. What is inadequate with current distribution planning/operations and why are new tools needed?

    Traditional distribution planning focuses on evaluating conditions present at single point in time, the forecasted peak load on each circuit. This method is often adequate without DERs, but it may omit other non-peak time periods when DER related problems may arise. The solution involves conducting time series analysis over a significantly larger number of time intervals than is common practice today. Some distribution analysis software will need to be upgraded.

2. Are these advanced tools needed to prepare for increased DER? What portion of utility system will see significant increases in DER? What are the reasons for this increase? What is the forecast of DER penetration?

    Utilities have not traditionally addressed this question in planning processes, at both the distribution level and the IRP level. For more effective distribution planning, utilities need to know where DER growth will happen, be it policy-driven, or customer choice driven e.g. rooftop PV or community solar initiatives. One example is a DER forecast PG&E provides as part of the California Integrated Energy Policy Report. See section 4.1.3.

3. What new tools and data sources is the utility proposing? Why these?

4. How is the planning horizon related to the operations horizon, and is there overlap in tools and investments?

    There is expected to be overlap going forward. Utilities are beginning to implement advanced distribution management systems (ADMS) that may replace and enhance functionality of multiple existing distribution operation tools. In addition, an ADMS is also capable of augmenting existing planning tools and some utilities and vendors are beginning to investigate an integrated approach.

For ADMS (Advanced Distribution Management System):

1. What is required for an ADMS?

    An ADMS often makes use of a full distribution network model containing accurate information of as much of the distribution network as possible. This

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[34] https://www.xcelenergy.com/staticfiles/xe/Marketing/Files/CO-Regulatory-Direct-T-A-Harkness.pdf
[35] http://smartgrid.ieee.org/october-2013/988-sun-solar-and-the-grid

model also needs to be maintained when topology changes occur across the distribution system due to routine maintenance, forced outages and more substantial upgrade work. See Section 4.7.6.

2. What are the advantages of an ADMS for your utility?

   Real time state estimation allows operators to get closer to safe operating limits and improve capacity utilization of the distribution wires and integrate more DERs.

3. What new operational procedures are needed to accompany these new tools? E.g., interconnection, metering, communication, real time operations.

   Improving interconnection screens and operating procedures is a potential benefit from these planning and operation tools.

4. What is the benefit/cost ratio of the proposed investment?

3.3.3 Utility proposing distribution equipment to manage DER

A utility wants to invest in power electronics based voltage regulation equipment to be installed next to 120V transformers to mitigate poor voltage quality (e.g., over-voltage, power factor) associated with locally high levels of PV penetration.

Regulatory Questions

1. **What analysis has been conducted to determine the likelihood of voltage excursions in the future? How far in the future are these expected to occur?**

2. **Has the utility considered any alternatives, such as using Smart Inverters on PV installations in the local area? If yes, then:**

3. **How are Smart Inverters Controlled?**

   Modeling and experimentation have shown that power factor modification by inverters feeding power onto distribution systems is able to mitigate many over and under voltage situations.[36] The inverter can be programmed to respond autonomously to voltage variations or could receive a communications signal from the utility or 3rd party aggregator to trigger power factor adjustments when needed. Pros and cons of these methods:

   Autonomous: Once the inverters are configured, and this could include remote reprogramming of existing inverters, communication with the

[36] Smart Inverter Capabilities for Mitigating Over-Voltage on Distribution Systems with High Penetrations of PV, Sandia National Lab.
http://energy.sandia.gov/wp/wp-content/gallery/uploads/2013_PVSC-VoltVar.pdf

utility is not required. A disadvantage of this options is the lack of coordination among separate units. A concern here is the possibility that if pre-established settings are not coordinated, the lack of coordination among separate units could cause line regulators and inverters to "fight" each other, resulting in a sub optimal response. An additional disadvantage is that these settings could not be updated to reflect changing conditions.

***Coordinated with communications**:* This option improves upon autonomous operation, but requires implementation of a communications infrastructure. Inverters could receive near real-time signals requesting a power factor adjustment, or they could receive periodical configuration updates. Implementing a communications network and selecting a communications method is the most critical factor here.

4. What are the various Risks with Smart Inverter approach?

The SIWG in California is looking at different communications standards that could be used and has selected IEEE 2030.5 (SEP3) as the default protocol, The IEEE 1547 revision may recommend different aspects of communications but cannot mandate a specific protocol. At the same time there are a number of contenders for DER communications, such as DNP3, GOOSE, IEC 61850, OpenADR, CIM, as well as SEP2, depending upon the functional requirements, the performance requirements, the cyber security needs, and the availability of different types of communication networks. This means a utility that implements an inverter communications system without coordinating with other utilities and some standards efforts faces a risk that the equipment deployed will be obsolete or locked in with a particular vendor or subset of vendors that can service this equipment.

There may also be uncertainty around whether customers can be incentivized to participate in volt-var control unless mandated or part of their tariff agreement with the utility. Utilities can be concerned that they may not have direct control over these PV systems. Utilities may want to consider a backup plan if choosing to rely on DER incentives or requirements to mitigate feeder voltage problems. Utilities generally have the ability to quickly implement upgrades to existing distribution networks, indicating the possible need for positioning the utility-side investment as a backup that is ready to quickly deploy if the DER solution doesn't materialize.

3.4 DER Causing Utility Distribution Concerns

A utility wants to limit the interconnection of Customer DER because of technical concerns, e.g., reverse power flow, distribution power quality.

While there is no fundamental problem with two-way power flows on any segment of the electric power system, it is often the case that traditional operation procedures at the distribution level were designed with only one-way power flows in mind. This simplifying legacy assumption means certain modifications are needed to equipment and procedures to accommodate two-way power flows at the distribution level. The questions below serve to inform readers about some of the most important issues and remedies that arise when there are reverse power flow and voltage constraints associated with DERs.

3.4.1 Utility Slows or Halts DER installations

Utility Examples (Hawaii, Minnesota)

Hawaii

One of the most prominent examples of a utility limiting interconnection of DERs occurred in Hawaii, where HECO slowed connections on circuits with high penetrations of PV due to voltage concerns associated with reverse power flow conditions. However, by early 2015, HECO determined that their concern about system stability was not due to the PV systems, but to some older utility wires and equipment. Once that was realized, they rapidly started to allow the backlogged PV implementations.

Minnesota[37]

In Minnesota, 58% of community solar projects connected to the distribution system are proposed to be over 10MW in nameplate capacity. The utility, Xcel Energy, filed a response that laid out 4 categories of concerns with these projects, one of which addresses interconnection. This concern was mitigated by requiring additional studies, specifically, if a project nameplate capacity exceeds the distribution substation minimum load then projects must go through interconnection process with MISO (Midcontinent Independent System Operator) and be subject to additional requirements and FERC review.

Regulator Questions

1. What steps are required for Utility to accommodate reverse power flow? Explain concerns?

    This question involves the interconnection process. (See section 4.4.3) Because there is often a cost – be it large or small – associated with the decision to allow and accommodate reverse power flows, this needs to be

[37] http://www.utilitydive.com/news/solar-advocates-clash-with-xcel-on-size-of-community-solar-arrays/367575/
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bAE9FC948-4354-49EF-A3CF-32AD59E11424%7d&documentTitle=20152-107208-01

evaluated to determine if these costs are appropriate and to whom they will be allocated.

2. Is the distribution system under consideration configured as radial or network?

   Most are radial, meaning a customer is served by a feeder with a single source of power at any one time. However in densely populated urban areas, utilities sometimes use networked distribution systems where multiple sources can feed a customer for improved redundancy. Networked distribution protection systems (see section 4.2.2) are often not designed to allow customer export, and this limitation typically cannot be overcome without substantial upgrades.

3. Is distribution substation equipment capable of handling reverse power flow?

   Modern equipment is fully capable of reverse power flows from a feeder, but existing components such as load tap changing (LTC) transformers and protection schemes may not be properly configured. Upgrades are generally straightforward, and costs vary from software updates to change settings to capital outlays for new equipment.

4. Is the expected reverse flow serving other feeders or backfeeding into the transmission system?

   Reverse flow from a single feeder will often supply other feeders connected to the same substation, resulting in only a reduced load as seen from the transmission system perspective. But if a sufficient number of feeders connected to a given substation are experiencing reverse flows, export to the transmission network will result. There is no fundamental restriction to prevent this from safely occurring, but new considerations will emerge and need be addressed such as transmission substation protection schemes that may assume one-way power flows across certain components, transmission scheduling, and effects on generation dispatch. Generally, an individual feeder exporting power is not likely to require significant physical upgrades, but when multiple feeders backfeed, causing the entire substation to export power to the transmission system, additional studies and possibly upgrades may be needed.

5. Can increased DER penetration cause voltage problems?

   When DERs begin to supply more electricity to feeder segments that were not designed with generation in mind, existing methods of voltage control may become inadequate. Generally, increasing the amount of DER-based generation present along a feeder will cause an increase in voltage and add stress to voltage control equipment, which may become burdened by increased frequency of control actions due to DER variability.

6. Is transient over voltage a concern for your utility?

   Also called load rejection over voltage, it can occur on an exporting feeder when an event interrupts normal feeder operation, such as opening of the feeder breaker (load rejection overvoltage) or a ground fault (ground fault overvoltage). Should either of these occur, there is a risk of over-generation leading a short duration voltage spike. Inverter-based DER has been shown to be capable of mitigating this concern with proper software configuration that quickly curtails output during this situation. (See section 4.5.3) Ongoing work by NREL has shown inverters typically will not cause excessive voltage during a load rejection overvoltage event.[38] Study of inverter response to ground fault overvoltage is under way.

7. Does increased DER create voltage flicker?

   This is rapid changes in voltage due to variation in DER production. Many inverters have the ability to adjust ramp rates that can mitigate this problem.

8. What demand side solutions is the utility considering to address supply/demand balance on distribution system? E.g., energy storage, inverter communication.

9. What utility side solutions is utility considering to address supply/demand balance on distribution system? E.g., communication to DER, energy storage at substation.

3.4.2 Utility concerned about using new advanced DER functionalities. What could the Hawaii, Europe, and other high penetration experiences help us with?"

The use of the advanced DER functionalities is still in its infancy. Although some basic understandings have been developed, it is clear that additional research is necessary, particularly for anomalous or emergency situations. Some possible issues to explore in this situation are:

- PG&E does interconnect DER systems up to 20 MW on its 21 kV system (using dedicated feeders) since 21 kV feeders can be designed to accommodate the larger DG. Since the interconnection impacts are mitigated prior to interconnection for these large systems, PG&E does not have the problems that Hawaii experienced, even though PG&E does have feeders with over 100% DER penetration, and back-feeding of the transmission system does occur at a few locations. From a power engineering perspective, reverse flow into the transmission system is not a problem so long as the impacts are mitigated prior to interconnection.
- Utilities can explore the use of other feeder equipment, such as static var compensators, to determine if these are more cost-effective and more reliable for handling voltage problems than DER systems using either fixed power factors or dynamic volt-var control.
- Some utilities are undertaking research and lab projects to try to better understand the impacts, both good and bad, of the advanced DER

[38] Inverter Load Rejection Over-Voltage Testing
http://www.nrel.gov/docs/fy15osti/63510.pdf

functionalities. The results of these efforts could be provided to other utilities and/or used as a basis for further pilot projects.

- Utilities could partner with other stakeholders to explore specific issues, such as coordination of DER volt-var capabilities with the utility feeder equipment and determining the most appropriate DER voltage ride-through settings for ensuring safety as well as reliability of service.
- Utilities could review both the Hawaiian situation and the European situations where high penetrations of DER are being experienced. These differences in situations have to be carefully assessed before they can be applied to other situations, since Hawaii is an island, while the distribution systems of Europe have very different configurations to US distribution systems[39]. That said, Hawaii (see 4.5.3) is permitting far more DER generation on its feeders than in most other locations, with support from DER systems that can "cease to energize" at high voltage levels, and "ride-through" short-lived over-voltage situations.

3.4.3 Utility proposing to accommodate DER with Conventional Distribution Investments

Traditional distribution investments include increasing capacity to allow more power to flow across constrained elements by actions such as reconductoring or installing new transformers. Traditional equipment also includes voltage regulation hardware at substations and at locations along feeders. (See section 5.1.1 for examples of these and other traditional investments) Below are some relevant questions regarding use of traditional investments to accommodate increasing levels of DER:

1. What alternatives to utility-side investments to accommodate DER have been considered? Describe these alternatives

2. Do DERs have the capability to self-mitigate some portion of the problems identified?

3. What utility-side investments are the best candidates for deferral or offset by utilizing these alternatives?

3.4.4 Utility Proposing Smart Inverters for DER

A utility wants to require all new inverter-based systems to have "smart" capabilities and to support a communication system to control these generators.

[39] European distribution grid is called Medium Voltage (MV) and Low Voltage (LV). The LV system is 240 volts and each LV circuit can support up to 500 customers. In the US, laterals use distribution transformers to support about 5 customers.

As certain States start to mandate “smart” inverters, it may soon be difficult to obtain “dumb” inverters, although the smart capabilities may be disabled. Communications capabilities will also be available for these smart inverters, although utilities implementing communications systems may still be costly.

Regulator Questions

1. What benefits will smart inverters provide your utility and its customers?

   Because most DERs connect to the distribution grid using inverters, and these devices typically use modern power electronics with significant built-in flexibility, researchers, utilities and vendors are investigating the benefits of more fully utilizing their capabilities. The ability of inverters to provide distribution grid supporting services has been proven, and will in some cases provide an alternative to traditional grid reinforcement investments.

2. What are the value to utility and customers of Smart Inverters?

   The grid support services include (see section 3.3.3)

   - **Autonomous** – the devices respond to grid conditions based on pre-established functions.
   - **Centrally controlled** – the utility or aggregator communicates utility specified instructions to them.

   Either way, the bottom line is they are able to **self-mitigate** a number of the problems they cause, or mitigate these same issues caused by other DERs located nearby. Below are some key functions, with over 40 additional functions recognized as providing various benefits (see Appendix 1.2):

   - **Voltage and frequency ride through** – in a short-lived frequency or voltage disturbance, inverters can make the problem worse by disconnecting and removing their generation from the grid. Utilities are continuously improving the settings that instruct inverters when to stay connected, when to partially trip off, when to completely trip off, and how long to stay off. (See 4.5.2 for more information about the California Smart Inverter Working Group)
   - **Steady state over/under voltage mitigation** – in a location with high DER penetration that is experiencing extended periods of high voltage, the inverters can adjust their power factor, thereby injecting vars and lowering voltage to acceptable levels. This comes at a cost in real power production however, which must be considered and possibly compensated. Control of this function is under development and is generally not ready for deployment beyond pilots at this point.
   - **Dynamic over/under voltage mitigation** – engineers also are concerned about short-lived over or under voltage excursions that could damage equipment or threaten reliability. Inverters are able to quickly react to these conditions and reduce the impact. They can adjust ramp rates in a situation where DER production is increasing too rapidly (cloud

movement), or they can very quickly curtail power production in a transient event.

3. Will mandating smart inverters reduce the cost of utility side investments over time?

   Using smart inverters could reduce the need for utility side investments to accommodate DER, e.g., solid state voltage control - static var compensators, voltage regulators.

4. Has the utility developed a coordination and communication system to work with proposed smart inverters?

   At this time there is no clear roadmap to guide a utility to integration of smart inverters with legacy and new equipment used by utilities to operate feeders and substations. Utilities can look to states like California and Hawaii that are beginning to head in this direction. California is in phase 3 of its smart inverter interconnection ruling process, and Hawaii is currently piloting utility-inverter communications systems.

5. Can the utility demonstrate the proposed investment will not lead to stranded investments or be at high risk of technological obsolescence?

   Ensure the communication system between the utility and inverters is using the best available industry standards instead of a different or proprietary communications method that may not be supported in the future.

6. Does proposed equipment use existing standards, IEC 61850, IEEE 1547, UL1741 updated UL listing?

7. Is the utility actively participating in standards development organizations like IEC 61850, IEEE 1547, SunSpec Alliance, MESA, and others? Should it be required to do so?

8. If utility wants to use the SIWG standards, is there a possibility they won't align with upcoming revisions of IEEE1547, possibly resulting in having obsolete equipment in the field?

9. What is the additional cost to customers of requiring smart inverters?

10. What operational costs are involved on the utility side to integrate smart inverters? (e.g., new IT systems, communication, etc.)

11. Does the utility plan to rely upon grid support/ancillary services from smart inverters?

12. If the utility is receiving grid support services from smart inverters, does the utility have a plan for acquiring these services?

13. If the utility plans to rely on smart inverters in distribution planning, has it assessed deployment risks in comparison to those of traditional distribution investments?

14. How can utilities know if they can rely on DERs to deliver promised grid support services in order to maintain reliability in absence the traditional upgrade that would have otherwise been required?

3.4.5 How to change Utility DER concern into system benefit? Example to defer reconductoring projects using DER.

Problem: DER customers located at the end of a distribution feeder might lead to overvoltage on a portion of the feeder and require reconductoring.

Solution: Interconnection process and smart inverter installation either limits DER output (voltage-watt function) or decreases voltage through vars (volt-var function) to ensure output does not result in the overvoltage problem.

Benefit: Managed DER reduces line load on entire feeder and defers reconductoring investment that would have been necessary due to regional load growth.

4 Discussions of Specific Topics

4.1 Regulatory Environment Affecting Distribution Utilities

4.1.1 Regulatory Structures

Unlike most other countries, the U.S. has many regulatory bodies with different jurisdictions. The Federal Energy Regulatory Commission (FERC) has jurisdiction over interstate electricity sales and wholesale electric rates, which affect primarily the bulk power system. Each State has a public utility regulatory authority (state commission) that has jurisdiction over the tariffs and services for certain utilities, such as investor owned utilities, and/or over any retail energy markets. Municipal utilities are owned by the municipality while electric cooperatives are owned by their customers. These usually smaller utilities are governed by different regulatory structures such as city ordinances or charters. Similarly, the federally-owned utilities (Bonneville Power Administration, Tennessee Valley Authority, and Western Area Power Administration) have unique governance structures that set them apart from the remainder of the bulk grid.

4.1.2 Challenges for Regulatory Activities with New Distribution Automation and DER Systems

This plethora of regulatory bodies creates challenges for the companies which are developing distribution automation plans and in particular, are installing and interconnecting increasing numbers and sizes of DER systems. Not only does each utility have its own DER interconnection procedures, but their governing regulations may be very different between neighboring towns, cities, and states. This leads to increasing conflicting technical requirements, jurisdictional confusion, and expensive delays.

To help ameliorate these problems and in response to the Energy Policy Act of 2005, many jurisdictions considered or adopted IEEE 1547:2003 **(see 4.7.1)** (and the associated safety testing and certification standard, UL 1741 **(see 4.7.3**) as the basis for interconnection requirements, with modifications to meet local needs. This use of standards has greatly simplified the regulations, providing key technical requirements and providing some badly needed stability.

However, since the early 2000's, new technologies and new market concepts are again raising serious challenges to regulations, which will once more require better technical understandings, innovative financial and market ideas, and new regulations. These advances in technologies and new market ideas are discussed in the following sections.

4.1.3 WECC Renewable Portfolios

The regulatory environment in the US strongly affects DER interconnections. Many States have developed "Renewable Portfolio Standards" (RPS) or "Renewable Portfolio Goals" which require or incentivize the increased energy production from any of a list of renewable or alternative sources (see Figure 7). Although similarities exist throughout most states' RPS programs, they vary significantly in terms of size, organization and execution.

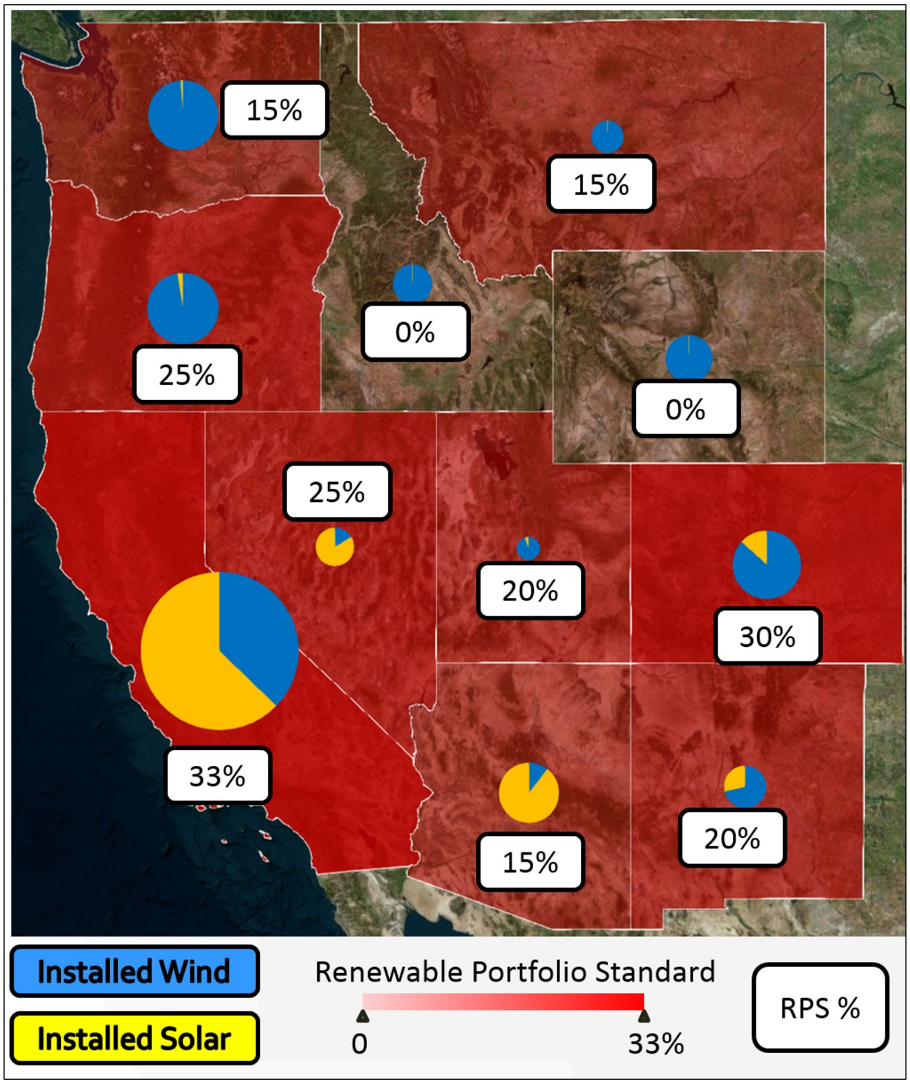


Figure 7: Renewable Portfolio Standards and Goals for Each State with Proportion of Wind and Solar resources installed
Note: Utah % represents a goal rather than a standard.
Sources:
RPS: dsireusa.org
Solar: SEIA
Wind: NREL

For many States, concerns are raised that without governmental mandates, renewable resources cannot initially be market competitive. Although incentives like the Federal Renewable Electricity Production Tax Credit (PTC)[40] and the Federal Residential Renewable Energy Tax Credit[41] were created to subsidize the deployment of renewable energy, using these credits can be problematic for a variety reasons. For instance, they are only available for a short period of time and may or may not be renewed. This causes uncertainty in the renewables suppliers and market participants.

40 http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc
41 http://energy.gov/savings/residential-renewable-energy-tax-credit

In addition, the costs of solar and wind technologies have fallen significantly in the last decade making renewable energy more cost competitive although still not on a par with some bulk power plants. Also, the increasing availability and low cost of natural gas combined with a relatively flat electricity demand may have diluted political support for continued RPS. These changing situations are then used by skeptics of the tax credits to question whether they are still necessary.

The results of these lower costs as well as the political pressures to encourage renewable energy have had a profound effect on utility operations. Wind power and large solar plants, mainly connected to the transmission system, have grown rapidly. Even distribution system solar generation has increased from approximately 4 GW of global installed capacity in 2003 to nearly 128 GW in 2013. However, different countries have been more or less aggressive: Germany has a capacity of about 32 GW solar generation capacity out of 80 GW total generation capacity, while the US is lagging far behind in solar generation having reached only 16 GW in generation capacity in 2013 out of over 1000 GW total generation capacity, as illustrated in Figure 8.

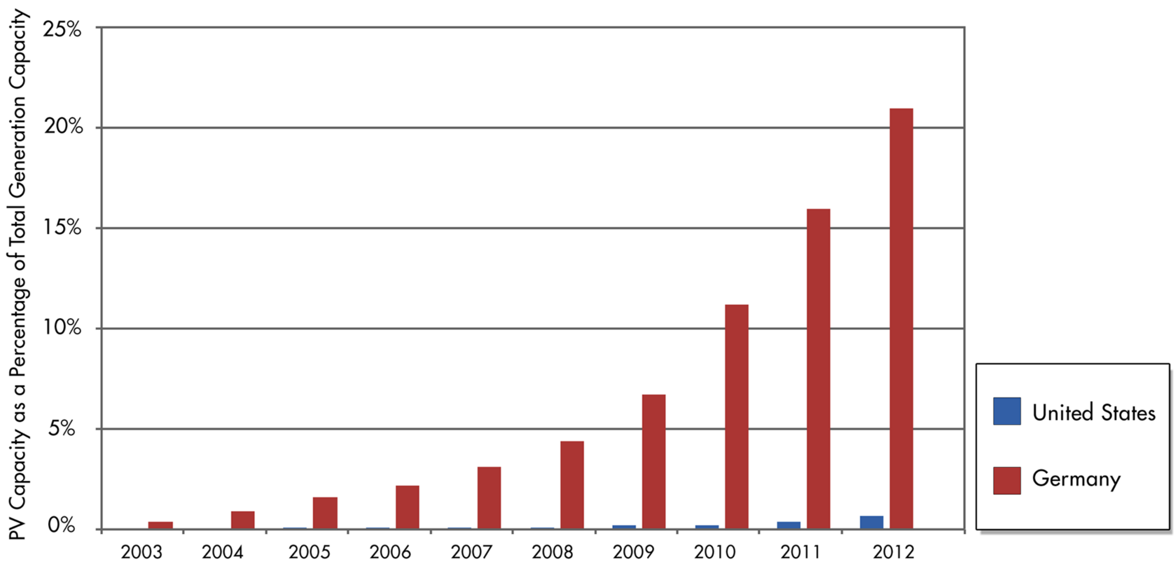
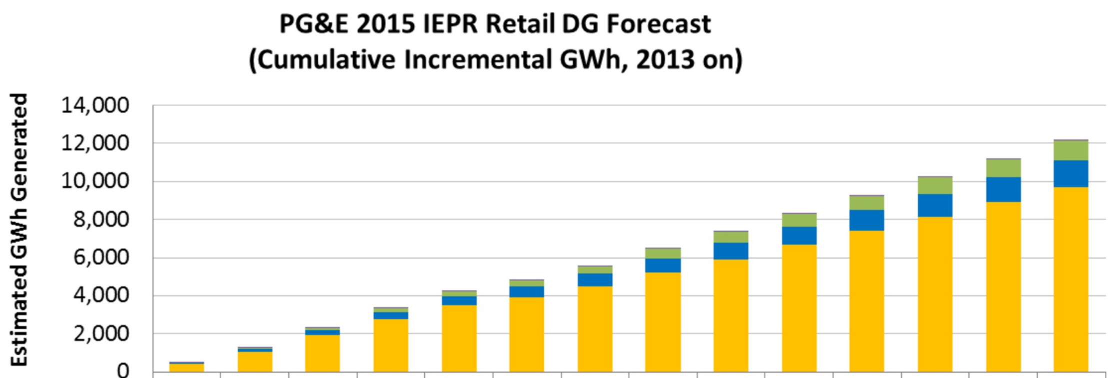


Figure 8: U.S. PV Capacity as a Percentage of Total Capacity Compared with Germany at the Beginning of Its "Energy Transformation"[42]

In California, the forecast for additional DER solar generation is significant, as illustrated in Pacific Gas & Electric's forecast[43]:

[42] EPRI, "The Integrated Grid, Realizing the Full Value of Central and Distributed Energy Resources", 2014 **http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733**

[43] PG&E submittal to the CPUC of 15-IEPR-03, Electricity and Natural Gas Demand Forecast, TN #: 204261-10, "Pacific Gas and Electric Company's Form 6 - Incremental Demand-Side Program Methodology", April 20, 2015 http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN204261-10_20150420T154647_Pacific_Gas_and_Electric_Company's_Form_6__Incremental_DemandSi.pdf



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Wind	2	5	9	13	18	22	26	30	35	39	43	48	52	56
Fuel Cells	34	73	128	188	253	324	401	483	570	663	761	864	968	1,071
Comb. Turb/IC Engine	26	132	238	344	450	556	662	768	874	980	1,086	1,192	1,298	1,404
PV	435	1,058	1,957	2,789	3,510	3,906	4,490	5,197	5,921	6,656	7,401	8,155	8,917	9,686
Total DG	497	1,268	2,331	3,334	4,230	4,808	5,579	6,478	7,399	8,338	9,291	10,259	11,235	12,218

Figure 9: PG&E's Integrated Energy Policy Report Forecast of DER energy between 2013 and 2026

4.1.4 Recent Key DER Regulations in Different Jurisdictions

European DER Grid Codes

Since Europe (see 4.5.1) has implemented far high numbers of DER systems, those countries were the first to recognize both the technical and the financial challenges of installing such high penetrations of DER systems. ENTSO-E (European Network of Transmission System Operators for Electricity), which is responsible for the overall security of the European grid, has taken the lead in addressing DER requirements. They have mandated increased "ride-through" voltage and frequency ranges to ensure that momentary spikes and sags do not cause DER systems to trip off unnecessarily. This requirement was recently extended requirements to upgrade additional DER systems that have already been installed.

Hawaii Grid Codes

Hawaii (see 4.5.3), because it consists of small islands in a location with lots of solar energy, has experienced high PV penetration. On the island of Oahu, many of HECO's feeders have exceeded acceptable levels, which were initially set at 75% of daytime minimum load for projects under 10 kW. This level has since been raised to 120% of daytime minimum load, and HECO is studying the measures required to increase this level.

HECO is also addressing the issue of net metering since they are losing revenue without reducing the costs of providing "wires" to all customers with the same reliability as before DER systems were installed.

California New Renewable Goals

California Governor Jerry Brown had called for 12,000 MW of "localized electricity generation", or DER, to help the State procure 33 percent of its energy from renewable resources by 2020, and has recently increased that goal to 50% by 2030.

California is expecting to extend the current goal of 33% renewables by 2020 to 50% renewables by 2030. PG&E's Anthony Earley, president and CEO, and Kent Harvey, senior vice president, said that Pacific Gas and Electric is planning $5.5 billion in capital expenditures in 2015, including about $1.1 billion for electric transmission and around $2 billion for electric distribution[44].

Through updates to Rule 21, the California utilities are also requiring all new DER installations to include certain advanced DER functionalities and be capable of communications (see 4.5.2)

4.2 Current Distribution Planning and Operational Procedures

4.2.1 Typical Radial Distribution System Design

In North America, distribution systems are designed primarily with radial feeders that start in a substation and stretch out within a utility's territory for short distances (< 1 mile) to long distances (50+ miles) (although many cities have secondary networks). Laterals connect from the feeder to reach customer sites. Most radial feeders also include one or two "normally open" switches between themselves and another feeder, usually fed from a different substation (if possible). The voltage ranges of feeders are typically between 2 kV and 34.5 kV.

There is wide variability in these feeder designs in terms of voltage levels, types of distribution equipment, numbers and sizes of customer loads, etc. At the transmission level, the three phases are balanced since there is no load to disrupt this balance. At the distribution level, the three phases can be split into laterals to provide most customers with single phase service (phase to ground or phase-to-phase). Since these lateral extend in different directions from the main feeder, they are usually somewhat unbalanced as new customer sites are added, but can become seriously unbalanced if care is not taken to configure them correctly.

A typical distribution feeder design can include:

- Substation transformer that lowers the transmission voltage to the distribution voltage.
- Feeder breaker in the substation that protects the grid from feeder faults by tripping off.
- Load tap changer that tries to maintain a set feeder voltage and can raise or lower its transformer taps to modify the feeder voltage

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[44] Electric Light & Power interview: **http://www.elp.com/articles/2015/02/pg-e-invests-in-power-grid-that-flows-in-multiple-directions.html?cmpid=Enl_ELP_Feb-13-2015**

- Recloser within or near the substation which is used to try to reclose 2 or 3 times after a momentary feeder fault to see if the fault clears by itself (e.g. a tree branch swinging in the wind)
- Feeder switches which are normally closed and which separate feeders into feeder segments. These switches are usually manually operated by field crews or may be remotely operated. Switches cannot operate on live feeders (breakers would be needed).
- Tie switch which is normally open and is used to “tie” between two radial feeders in case reconfiguration of the feeders is needed due to emergencies or maintenance activities.
- Voltage regulators along the feeder to boost voltage back up as it naturally declines over the length of a feeder. The rate of voltage drop is affected by the distance and by the amount and types of loads connected to the feeder.
- Capacitor banks judiciously placed along the feeder to compensate for vars (i.e. keep the power factor at its most efficient which is close to 1.0)
- Laterals (usually with protective fuses) which split off single phases from the main feeder to reach to customer facilities
- Distribution transformers which connect a few customers (5 to 12 are typical numbers of customers per transformer) to the lateral, and transform the voltage down to the 120/240 V level for customer appliances.

4.2.2 Secondary Network Distribution System Design

In many cities, industrial parks, and other dense collections of customer loads, the distribution system can be networked with multiple sources of supply operating in parallel. These networks are on the customer side of distribution transformers and are therefore often referred to as secondary networks. These secondary networks provide high reliability to customers since any fault with any one supply is automatically isolated by network protectors and power can still be supplied from the other sources.

In secondary networks, the network protector devices are generally operated to allow power to flow only one way, since their purpose is to detect reverse power flows that could be caused by faults. However, this poses a problem for installing DER systems at customer sites that are connected to secondary networks, since these DER systems could cause backflow through a network protector, causing it to trip since it thinks it is seeing a fault. Some studies have been done to determine how much DER generation should be allowed for different load conditions of secondary networks, but there are no specific answers, other than that the more DER as a percent of load, the more likely that network protectors will trip off. FERC’s Small Generator Interconnect Process (SGIP) states that on a spot secondary network, generation shall not exceed the smaller of 5 % of a spot network’s maximum load or 50 kW[45]. However for grid secondary networks,

[45] **FERC Small Generator Interconnection Procedures (SGIP), effective August 26, 2006**

jurisdictions have many different values or criteria for determining the permitted amount of DER generation.

Some newer network protectors are being designed to try to distinguish between DER generation and actual faults, but this is still a work in progress.

4.2.3 Distribution Planning

Over the last two decades, distribution system planning has been conducted by utilities primarily by estimating new or increased loads expected to be served in each of their feeder areas over the next 3 to 5 years. Most completed by calculating the maximum demand during peak periods for each of these areas, and then designing and building the distribution substations and feeders to meet those maximum demand requirements.

As part of the analysis involved, distribution planners determine new feeder extensions or routes for new feeders and laterals, assess the voltage profiles for each and where to place voltage regulators and capacitor banks along the feeder, and develop fusing, sectionalizing and recloser outage switching processes for each type or location of potential faults.

Generally each feeder is studied separately, with assessments of multiple feeders only where they might impact each other either at the substation or for improved reliability options if used during reconfigurations due to emergencies or maintenance activities.

Capital costs are determined for these modifications, and then presented to regulators in utility rate cases as necessary to meet the projected loads. These costs are generally approved, since the assumptions can be clearly presented, and, in the larger scheme of utility rates, these costs have been relatively small.

In the past, these distribution planning calculations were based on spreadsheets and paper maps. Recently, Geographical Information Systems (GIS) and other automated tools are starting to be used, but the results are still focused on steady-state distribution system design based on maximum demand (peak load). These tools do not yet support advanced distribution automation and DER capabilities, nor do they model dynamic management of the distribution system. For example, the use of CymeDist 4 years ago only had one very basic inverter that could be modeled in that software.

Some discussions have suggested the use of dynamic transmission power flow tools for distribution studies, but transmission models are quite different from distribution models. For example, transmission models legitimately assume that all phases are balanced; however, distribution systems rarely can assume balanced phases. This is due to the presence of single phase residential loads that are randomly allocated to different phases in an attempt to balance, but depending on actual usage, one phase may see heavier loads creating the unbalanced measurements across the three phases.

Transmission models are completely networked, while distribution systems are radial (even if seemingly networked). Transmission models assume fixed kVA ratings and fixed impedance of various equipment, while distribution systems have variable values depending upon customer load characteristics, customer DER characteristics, demand response reactions, weather impacts, and other configuration issues. And distribution systems simply have far more circuits and equipment than transmission systems, making the collection of data more unwieldy and the modeling more cumbersome.

The existing distribution planning tools do not yet have good models for distribution systems with high penetrations of DER or where dynamic distribution system operations are possible through autonomous advanced DER functions and/or more direct control by the distribution operational center. In the future, distribution analyses will therefore need to include:

- **DER systems with advanced functions**, so that these new capabilities can be included in the assessment, even while some feeders may not have high penetrations of DER.
- **Time-based study capabilities**, since DER generation may or may not coincide with peak load conditions, and low load may in fact pose more problems than high load in certain circumstances.
- **Unbalanced modeling of the distribution feeders**, since different phases with different combinations of loads and generation may react differently during the same time of the day.
- **More global analysis of larger numbers of feeders**, so that dynamic reconfigurations of multiple feeders can be assessed.
- **Short-term fault current and fault circuit analysis**, FLISR systems are (or could be) installed since FLISR may result in different types of reconfigurations.
- **Looped and/or meshed feeder configurations**, since these may become more used in the future.
- **Inclusion of microgrids**, since these may disconnect during emergencies and therefore not be available for other mitigating efforts.
- **Performance of contingency analysis**, so that many different scenarios can be assessed to best determine which are the most likely and which are potentially the most damaging.
- **Transient analysis,** so that sub-microsecond harmonics and other transient characteristics can be assessed, for example, for DER interconnection studies.
- **Saturation studies**, so that limits of different types and characteristics of DER systems can be assessed for different locations.
- **Climate zones and weather condition simulation**, so that micro-weather forecasts can be developed, including even micro-locational forecasts of cloud cover for PV systems and of wind bursts for wind power.
- **Energy storage modeling**, so that charging and discharging scenarios of energy storage can be assessed

Load Forecasting on Distribution Feeders

An emerging trend in new building construction is the concept of “Net-Zero” buildings. Building designers are taking advantage of numerous techniques to design and build a building with zero net energy consumption, meaning the total amount of energy used by the building on an annual basis is roughly equal to the amount of renewable energy created on the site. These buildings consequently do not increase the amount of greenhouse gases in the atmosphere. They do at times consume non-renewable energy and produce greenhouse gases, but at other times reduce energy consumption and greenhouse gas production elsewhere by the same amount.

Most zero net energy buildings get half or more of their energy from the grid, and return the same amount at other times. Buildings that produce a surplus of energy over the year may be called “energy-plus buildings” and buildings that consume slightly more energy than they produce are called “near-zero energy buildings” or “ultra-low energy houses”.

The challenge for distribution planners is the old formulas for estimating new connected load for buildings is changing. Now, seasonal differences can change load and voltage characteristics in the planning process. Further, if DER systems fail, the distribution system becomes a back-up system for net-zero buildings, changing the load profile markedly on a daily basis.

This trend can also change the way line extension costs are determined and charged to customers.

4.2.4 Distribution Planning Tools

Although none of the existing tools can yet do all of the functions needed for DER planning, some of the more commonly used commercially-available distribution analysis tools include features that help:

- SynerGEE Electric (GL Noble Denton)
- CymDist (Cooper)
- PSS/Sincal (Siemens PTI)
- DigSilent Power Factory (DigSilent GMBH)
- DEW (EDD)
- Aspen DistriView

These tools are being upgraded to handle some of the issues identified above, primarily to allow engineers and planners the ability to study more scenarios and determine the effects of a larger range of system conditions. In 2014, Emma Stewart, Principal Scientific Engineering Associate at LBNL, authored a report that looked at some of the software challenges in developing future distribution systems, these planning tools were highlighted.

Distribution planning software limitations include, 1) the ability to exchange working data between models is limited, meaning a utility is less likely today to be able to utilize more than one model package as part of its planning process due to the time and cost in manual effort to move data between them, and 2) It also may be hesitant to select a different vendor for similar reasons.

This is in contrast with transmission power flow and production cost models that make greater use of common information model standards (CIM) to move data between models and between vendors. The CIM concept has thus far not been widely adopted by distribution software vendors. (See Section 4.7.6)

Utilities and regulators should encourage data sharing between vendors of the different models, some of which are focused on highly detailed reliability analyses (second and sub-second time scale) while others prioritize something closer to economic analysis over time (8760 hour time series load flow).

While there is not currently a direct corollary in the distribution space to the production cost models utilized at the transmission level, the time-series models can be seen as an initial effort in this direction. However, the extent to which economic concepts will integrate with these distribution models is not known at this time. One reason is that there is not a well-defined framework for distribution economics that is comparable to security constrained economic dispatch, which underpins production cost model design.

The Figure below displays the types of analysis software available along with information about the timescale for which they are used and the type of analysis performed.

Study Type	Time Scale	Analysis Type	Software Options
Load flow, thermal limitations, voltage rise, etc	Hours, weeks, year	Steady state	Synergee, PSLF, PSSE, CymDist, DEW
Variability impact, OLTC cycling	Seconds, minutes	Quasi-steady state	Synergee, PSLF, PSSE, CymDist
Protection and coordination	Sub-cycle, seconds, point in time	Steady state & dynamic	Aspen Distriview, Oneliner, Synergee, PSCAD
Transient voltage impacts (ground fault over voltage, etc.)	Sub-cycle	Transient	PSCAD, PSPICE, SIMULINK
Ride-through, Switching impacts, dynamic response	Cycle and sub-cycle	Dynamic	PSCAD, PSSE , PSLF, CymDist
Harmonics & power quality	Seconds, sub-cycle	Dynamic and quasi steady state	PSCAD, PSS/Sincal, Synergi (radial only)

Figure 10: Distribution Analysis Software Capabilities
Source: 2014 LBNL Software based challenges of developing future distribution grid

4.2.5 Stakeholder Involvement in Distribution Planning

An area where regulators can facilitate the inclusion of DER and net-zero buildings is to add more transparency and alternative advocacy in the distribution planning process during regulatory proceedings. Typically growth projections and utility one-year and five-plans were reviewed for prudency of planned construction activities, now adding additional public input to plans may allow new concepts and issues to be raised. Distribution Resources Plans required of California utilities by the CPUC are instituting a higher level of stakeholder involvement and transparency. (See DRP sections)

Utilities in Australia provide an example of a distribution planning process that changed as a result of infrastructure-driven upward rate pressure[46] to incorporate higher levels of involvement through which 3rd parties can propose "non-network solutions" as alternatives to distribution system plans published by utilities.[47]

For example as shown in Figure 11, the distribution planning process of a utility in Australia includes a public review process where proponents of non-network solutions have the opportunity to review the Distribution Planning Report and provide input and suggestions.

46 http://www.themonthly.com.au/issue/2014/july/1404136800/jess-hill/power-corrupts#.U8FmpAZE1fs.twitter

47 Example of a distribution plan from an Australian distribution utility: https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report

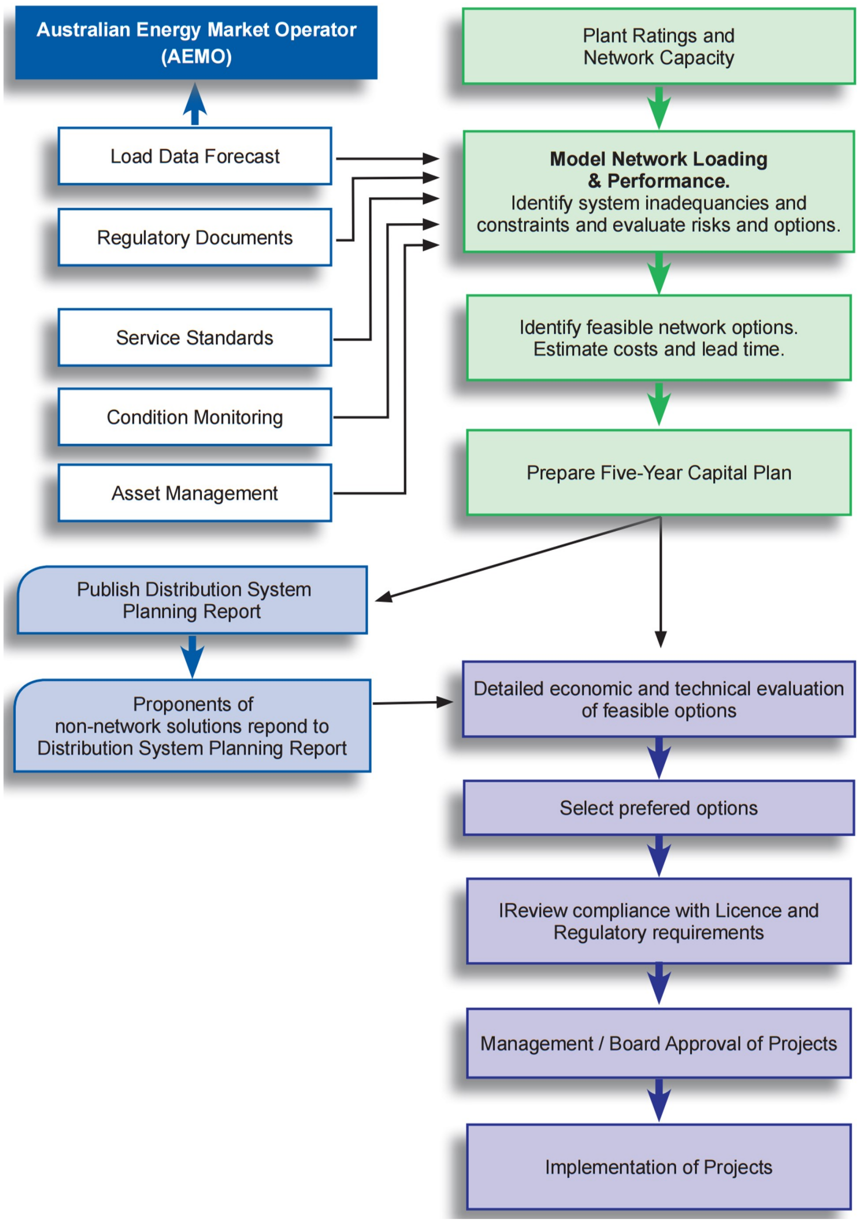

Figure 11: Australian utility distribution planning process. Source: http://jemena.com.au/

4.2.6 Typical Distribution Operations

Distribution operations do not typically have the same degree of automation as transmission systems. Some utilities can monitor the feeder currents in the substations (either directly or from a transmission SCADA), while others may be installing automated switches that can be used for automated fault location, fault isolation, and service restoration, in which a faulted feeder segment can be isolated and the remaining segments re-energized.

The traditional methods of distribution operation now present challenges as utilities move toward larger DER penetration that will require greater integration among systems and access to improved real-time data to optimize operations so as to realize greater control of voltage, frequency, and other critical parameters as DERs introduce increased variability.

A typical distribution control room is shown in Figure 12.

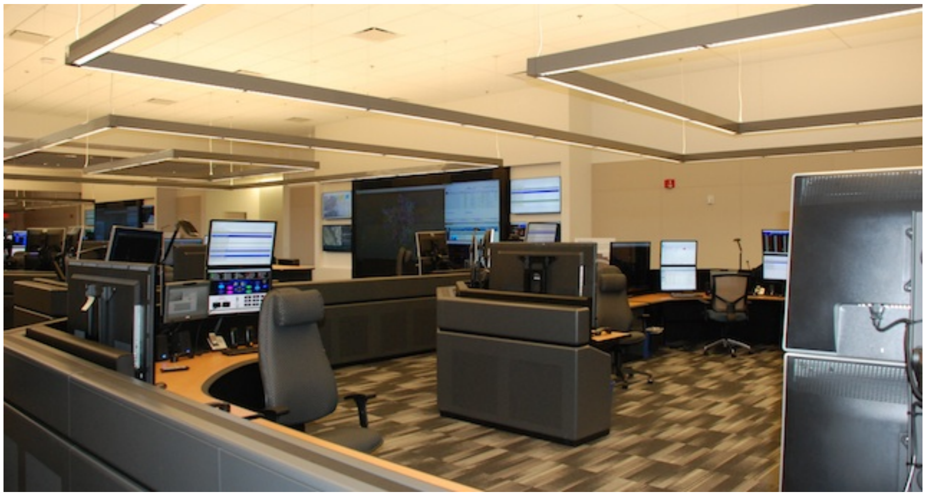

Figure 12: PG&E distribution control room[48]

Utilities are implementing several critical systems to help monitor and analyze distribution operations:

- **Supervisory control and data acquisition (SCADA)** systems are used by control room operators to view information from and control connected devices in the field, usually by monitoring equipment located at substations or indirectly gathered from transmission SCADA systems.
- **Outage management systems (OMS)** are used to coordinate information about forced and planned outages, emergency restoration and planned maintenance. Integrates with geographic information systems (GIS) and other enterprise systems such as customer information systems.
- **Distribution Management Systems (DMS)** are used for near-real-time analyses, including with asset management and mobile job tracking. A DMS can also include power flow models and applications to optimize operation of controllable devices such as voltage regulators, capacitors and switching.
- **Geographic Information Systems (GIS)** are used both to store asset information and to display electronic maps of the distribution system showing the location of these assets.
- **Distribution Automation (DA)** equipment and systems, that includes field equipment that can provide fault location, isolation, and service restoration.
- **Advanced Metering Infrastructure (AMI)** systems are used to collect metering data periodically from smart meters via remote communications. This system can also provide outage information and possibly voltage and other power system data.

[48]http://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20141028_pge_opens_new_285_million_state-of-the-art_electric_control_center_in_fresno

- **Customer Information System (CIS)** includes all the relevant data about customers, including where they are interconnected to the grid.
- **Load Management System (LMS)** can issue load control commands either as direct commands or as pricing signals for demand response actions.
- **Distributed Energy Resources Management System (DERMS)** is a very new type of system that may store DER information, such as nameplate data and interconnection locations. It may also include analysis applications that could assess DER functionality at different locations, such as contingency analysis and CVR status, etc.

4.2.7 Distribution Management Systems and Distribution Automation

Distribution systems have primarily relied on long term planning (3-5 year time frame) rather than any real-time operations. It is for that reason that distribution planning has always been based on "worst-case" scenarios of highest load during peak times, with distribution operations relying on autonomous actions by load tap changers, voltage regulators, and capacitor banks to handle real-time situations.

However, new technologies are now available that can more effectively manage real time operations, particularly for emergency situations. For instance, many distribution operation centers can receive SCADA information from substations, including data on feeder breaker and current. Outage management systems can use this information from substations and add more detailed information from smart meters to detect and report power outages. Distribution automation equipment can be installed that can respond rapidly to faults, including locating the faulted feeder segment, isolating that faulted segment and then restoring service to other segments on that feeder. This FLISR function can dramatically decrease the number and length of outages.

Distribution utilities are also starting to implement DMSs that can perform power-flow-based studies and contingency analysis on much shorter time-frames, such as a week ahead or even within an hour of real-time. As more data can be retrieved from smart meters and from DER systems, utilities can help determine the most effective and efficient settings for their equipment (as well as DER systems) in near-real-time, rather than relying only on the long term plans. The resulting understandings will also be used to identify possible tariff or market-based financial actions.

4.2.8 Distribution Management Systems

Since almost no monitoring of distribution feeders is done outside of the substation, the lack of available operational data is increasingly seen as a barrier to higher accuracy operations that would allow distribution systems to safely operate closer to maximum facility ratings, in a similar fashion to operational characteristics of the bulk high voltage transmission network. A DMS is an option that some utilities are evaluating or implementing that can consolidate functions of multiple of the above systems and are designed to incorporate a larger number of data sources as they become available from additional equipment installed at substations, distributed along feeders and from AMI where applicable.[49]

Some of the components of DMS include:

- **Distribution Network Model:** A component of implementation of an DMS is commonly development of a distribution network model (DNM), which assembles a detailed distribution system topology, often importing data from multiple utility systems. Utilizing system topology and available metering data, a DMS can provide operators with near real-time state estimation across the network, an ability previously only available to operators of the bulk high voltage network. State estimation calculations and methods used for distribution systems are distinct and different than those used for the high voltage system, meaning a separate system is needed.   Moving operations closer to the safe operating limits of the distribution system is aided significantly by knowing in real time how close each system element is to those limits.

  This information can be used by operators or centralized automated control schemes to coordinate operation of equipment installed at substations, along feeders, or at customer sites such as capacitors, voltage regulators, FACTS devices, and smart inverters or other DERs.

- **Switching Contingency Analysis**: Utilities often undertake switching operations between and among feeders, and leave some extra headroom when evaluating DER interconnections to accommodate these actions to ensure reliable operation if reconfiguration occurs due to an outage or planned maintenance. This headroom is often applied as a rule of thumb without detailed studies.[50] Use of a DMS can readily produce contingency analysis using many scenarios in the operations horizon or in the planning horizon. Use of valid system topology data will improve accuracy of these analyses and once again move the system operation closer to safe operating limits.

It is seen as a possibility by some vendors and utilities that both distribution planning and operations activities can make use of a single network model. This has a precedent in transmission planning and operations, where use of a common network model has been shown to streamline both processes.

4.2.9 Distribution Automation (DA), Outage Reductions, and Voltage Management

Distribution automation (DA) involves providing more local automated equipment on distribution systems as well as including more centralized monitoring and control from distribution SCADA systems. DA capabilities can also include applications that can help analyze the data and suggest (or even carry out) control commands.

49 DMS vendors are offering solutions to integrate data from multiple sources, including AMI: http://www.greentechmedia.com/articles/read/ges-path-to-the-advanced-grid-operations-platform
50 HECO uses 50% according to DGIP documents

The primary purpose of DA is to improve power quality, including reducing the number and length of outages, maintaining appropriate voltage levels, improving efficiency, and minimizing harmonics.

Outage Management

Of these issues, probably the most important to most customers is the reduction of outages. Since most customers are connected to radial feeders (see 4.2.1) (except those on secondary networks, see 4.2.2), if any point of the circuits between the substation and the customer experiences a short circuit or other fault, that customer will experience an outage. Utilities have designed most of these radial feeders with a "normally open" tie switch to another feeder so there can be a second source of power. However, that tie switch cannot be closed unless the faulted segment of the feeder is isolated. Without distribution automation, that process of locating the faulted segment, isolating it, and then restoring power to the unfaulted segments has required field crews to "walk the line" and manually take the appropriate actions.

FLISR is the automated function that can perform some or all of these manual actions. FLISR autosectionlizers and autoreclosers can be installed on each feeder segment that communicates with each other and/or with a centralized site. This FLISR equipment can detect faults, locate them to the affected segment, and then initiate pre-established switching schemes to isolate the faulted segment and to restore power to the unfaulted segments from nearby substations or feeders from the same substation – thereby isolating power outages keeping more customers with power to their homes and businesses. Switching , that used to require 20 minutes to an hour for a crew to be dispatched to reconfigure a feeder, can be done in seconds by these intelligent line switching systems and SCADA control operations. The interaction of these systems with DER adds to the complexity of distribution planning for the next decade and beyond.

Voltage and Var Management

Voltage and var management is managed by voltage regulators and capacitor banks respectively. To compensate for the decrease in voltage along a feeder, the voltage regulators are set at fixed levels to boost the voltage along the feeder.

Reactive power, often generated by motors and other types of equipment, causes decreased efficiency of feeders. To counteract excess reactive power, capacitor banks are strategically placed along a feeder. Typically, these capacitor banks are switched on and off based on timers, which do not always correspond to when they were actually needed. More recently, these capacitor banks are switched based on current, rather than time. With distribution automation, capacitor banks can include communications so that they can be activated from a central site as needed.

Static var compensators (SVC), which are electrical devices for providing fast-acting reactive power, are also used to manage reactive power more effectively, in particular to solve voltage fluctuation problems. Fast and repetitive voltage fluctuations are usually caused by motor-starting or other pulsating or irregular loads such as welders. Voltage regulators or capacitor banks are not effective in controlling such fast and repetitive voltage fluctuations.

Conservation Voltage Reduction

In some jurisdictions, CVR is mandated or recommended. CVR is basically just reducing the voltage to customers (without violating the voltage limits) so that their energy usage is lower. This can benefit utilities when they want to shave peaks, and certainly benefits customers by lowering their bills, but of course does lower utility revenues if it is implemented at all times, not just during emergency peaks.

4.3 DER Impacts on Distribution Systems

4.3.1 Types and Characteristics of DER Systems

DER systems include generation devices and storage devices, and often includes "controllable load".

DER systems are being interconnected to the distribution grid in increasing numbers, and changing the operational characteristics of the basic distribution grid design that has been in used for decades. In contrast to the larger bulk generators, these DER devices are typically smaller and are (by definition) interconnected to grid at the distribution level or sometimes at the subtransmission level.

The DER systems which generate electrical power may have renewable sources of power or may be driven (directly or indirectly) by fossil fuels. Some of these DER devices are synchronous generators, such as the diesel generators often used for backup in hospitals and business complexes. Most of the more recent DER systems are inverter-based generators or storage devices, including (non-renewable) microturbines, most combined-heat-and-power (CHP) systems, and fuel cells, as well as (renewable) energy DER systems.

Non-synchronous DER systems include one or more inverters to convert non-60-cycle current to 60-cycle alternating current (60 Hz)[51]. For instance, photovoltaic systems convert direct current (dc) to alternating current (ac) via inverters, while a microturbine which generates 400 Hz output would first convert the 400 Hz to direct current, and then convert the direct current to 60 Hz alternating current.

Common renewable DER generation systems include photovoltaic systems, wind power systems, small hydro plants, geothermal, and biomass systems.

Energy storage DER systems have inverters which are used in both directions: to convert to 60 Hz ac when "discharging" or generating power, and, in reverse, to convert from 60 Hz typically to dc when "charging" or storing energy. The more common energy storage technologies include batteries, flywheels, pumped hydro, compressed air, super-capacitors, and superconducting magnetic energy storage. Another potential storage technology is the electric vehicle (i.e. vehicle-to-grid) if permitted technically and by regulations. One trend today is to combine a renewable energy DER with a storage device (e.g. a PV system directly combined with a battery) so that fluctuations can be smoothed out.

[51] In many countries, the grid uses 50-cycles – 50 Hz – but in the US, all grids use 60 cycles.

Controllable load can be seen as the inverse to generation. Increasingly controllable loads can be considered in the mix for managing energy. Controllable loads can often just involve shifting the load to a different time, such as running washing machines or water pumping stations during off-peak times. Another example is pre-cooling large plenums during off-peak and then cycling off air conditioners during on-peak.

4.3.2 Challenges Associated with High Penetrations of Renewable DER

Increased numbers of DER systems interconnected to distribution systems pose both challenges and benefits to distribution operations. The challenges include the variability inherent in some renewable DER systems (loss of output power when the sun stops shining or the wind stops blowing), but also include the variable needs of the DER owners to meet their own energy requirements rather than just providing energy to utilities (as most bulk generators are designed to do).

Adding significant amounts of generation sources to a distribution feeder can also change its operational characteristics in many fundamental ways. These changes could require mitigation techniques if penetration levels start to impact the power quality or reliability of the feeder. Determining if and when to mitigate certain DER system impacts varies significantly, depending on feeder characteristics, the profiles of the DER generation and customer loads over time (time of day, day of week, season, etc.), and expected future growth of both generation and load.

Some of these DER challenges include:

- **Intermittent or fluctuating power output**. Solar and wind power are clearly driven by sources that can change in strength frequently and rapidly. Run-of-the-river hydro can also fluctuate in output although more slowly. In addition to the unpredictable short term fluctuations, there are better anticipated but still extreme changes in power output, for instance as PV systems rapidly decrease their output during the late afternoons. This has led to concerns about how to supply compensating power equally rapidly from bulk power or other sources. California ISO has a famous "Duck Curve" illustrating this concern of rapid changes in sources of generation, which not only stress the bulk power generators that must pick up the load, but also the distribution feeders and even the transmission circuits which must rapidly accommodate the shift in generation sources.
- **Unreliable availability**. The output from DER systems can vary not only because of fluctuating renewable power sources, but because providing power to the grid may be only a secondary purpose from a customer's perspective. DER systems installed in commercial and industrial sites may create large swings of their exported power and in absence of an agreement with the utility to do so they may not necessarily have additional power available if the grid needs it during peak times.
- **Impacts on power quality**. In part due to the change in load profiles for customers with DER systems and in part due to the swings in power output from DER systems, the power quality on feeders may change in ways not anticipated during the design of the feeder, potentially causing power harmonics, excess reactive power, and voltage spikes and sags. These

problems may require the utility to add compensating equipment or to upgrade the feeder before it might otherwise need upgrades. In some cases, such as in Hawaii, the excessive generation on feeders can cause damaging high voltage levels, power outages, and other serious grid problems. If the DER systems have appropriate voltage ride-through settings, they can at least avoid unnecessary outages. If they have power factor management capabilities, they can also minimize any reactive power problems.

- **Steady-state over voltage**. Typical feeder design takes into account a voltage drop along the length of the circuit, with the voltage level leaving the substation set high enough and with voltage regulators judiciously placed along the feeder to ensure the end-of-line voltage is adequate. But with the introduction of DER such as inverter-based PV generation along the feeder, voltages will not necessarily decrease at the rate assumed in the planning process. In some cases the voltage can actually increase in areas of high penetration. Making the problem worse in some locations is the reduction in conductor size along the feeder, which can exacerbate the over voltage problem. Mitigation techniques include reconductoring, adding more voltage regulation equipment, or adjustment of the fixed power factor of DER. If the DER systems have the advanced volt-var capability, they can dynamically modify the voltage levels up or down to bring them closer to the nominal voltage.
- **Transient overvoltage**. Transient overvoltage can occur if a circuit is experiencing reverse flows through the substation transformer and an event causes the substation circuit breaker to open. If the anti-islanding settings of the DER systems on the feeder are not correctly established according to existing regulations and standards, those DER systems could over-generating and cause the voltage to increase to excessively high voltages for a short period of time, possibly as high as 200%, and potentially damage customer and utility equipment. Therefore it is very important that DER systems are configured with the correct anti-islanding and voltage ride-through settings.
- **Reverse power flows in substations**. Distributions systems have been designed with one-way flow of power out from a substation to the customers on a feeder. However, if large amounts of DER power are located on a feeder, it could become larger than the customer load and therefore actually change the direction of the power flow (see Hawaii's Lock Ness curve). For radial distribution feeders, there is no fundamental physics problem with power being exported from one feeder to serve other feeders or provide supply to subtransmission or transmission voltage networks. However, issues can arise if existing protection and control equipment is not configured to support reverse flows. Legacy LTC controls often do not have the capability of sensing the direction of power flows and may operate improperly during times of reverse flows. Mitigation methods for coping with this situation can be implemented, with the most common being the limiting of the amount of DER generation that is permitted to interconnect on any one feeder. For instance, some utilities limit the total DER generation to 15% or 30% of the minimum load on the feeder. Other solutions are to install LTCs that can handle reverse power flows and to reconfigure substation protection schemes that may be affected.

- **Reverse power flows in secondary networks**. Reverse power flows on secondary networks are more difficult to mitigate, and significant work is still going on to determine the most effective methods other than just limiting the amount of DER generation allowed on any secondary network segment.
- **Impacts on reliability**. There is no question that DER systems add to the number of factors that must be understood, planned for, and operated on in order to maintain power reliability. Along with the renewable energy causing fluctuations, the changing requirements of customers in using DER systems to support their own loads as well as feed back to the grid can cause disruptions. Utilities do not as yet have very good distribution planning software, power flow contingency analysis, or access to real-time information that could help assess situations with reliability issues.
- **Load Masking**. For feeders with a high penetration of generation DER such as solar PV, distribution utilities may have trouble understanding how much load is present when load and DER generation share a common meter. It may become important for distribution utilities to separately meter DER in high penetration locations to ensure reliable operation. In the event DER trips offline, the utility needs to be confident it will be able to provide full load service without power quality or voltage issues.

4.3.3 Benefits of DER Systems to Distribution Systems

Some of the benefits that DER systems, particularly in high penetrations, can provide to distribution systems include:

- **Deferring construction**: DER systems that can offset loads, particularly peak loads, can be factored into whether and which distribution feeders need to be upgraded. For instance, reconductoring of some feeders or substation transformers may be deferred or completely avoided by using reliable DER sources to reduce loads.
- **Increased reliability:** DER systems can improve reliability particularly if they are configured in microgrids or even “nanogrids” consisting of a single home or office building. After Japan’s devastating earthquake and tsunami in April 2011, the only operational hospital in the badly destroyed Sendai region was part of the Tohoku Fukushi University microgrid which never lost power.
- **Minimizing power outages:** DER systems with advanced functionality can “ride-through” short voltage and frequency sags and spikes, thus avoiding some power outages that might be caused by such anomalous events.
- **Improved power quality:** DER systems with advanced functionality can provide voltage support through autonomous volt-var control, thus maintaining voltage levels within the specified ranges.
- **Improved efficiency:** Advanced DER capabilities can improve efficiency through the power factor management and through maintaining voltage for purposes of CVR.

- **Emission reduction**: Renewable DER systems, by their nature, reduces emissions by offsetting fossil fuel generation
- **Congestion management**: DER systems can provide local generation to offset the transmission of power from remote bulk power generators. This can support transmission systems that are experiencing congestion.
- **Frequency support:** DER systems can provide frequency support to Independent System Operators (ISO) through either frequency smoothing (autonomous response to frequency deviations) or direct automatic generation control (AGC).
- **Equipment Preservation**: DER systems, in managing voltage deviations, can minimize the switching on and off of capacitor banks or the shifting of load tap changers.
- **Bulk generation support**: DER systems, by providing additional generation, can support the bulk generators by providing peak power, local power, and/or efficient power.
- **Ancillary services**: DER systems can provide, in aggregate, many of the ancillary services needed by the bulk power system, including operational reserve for different time frames, frequency support, reactive power support, peaking support, congestion support, etc.

4.3.4 Coordination of DER Systems and Voltage Management Equipment

As high penetrations of “smart inverter-based” DER systems are deployed, their settings must be coordinated with existing distribution equipment, such as load tap changers, capacitor banks, and voltage regulators. For instance, the smart inverter DER volt-var function automatically modifies its vars to counteract voltage fluctuations. The settings of this DER volt-var function must be coordinated with the settings of the distribution equipment on the circuit so as to dispatch them in a strategic manner that maximizes value.

Since DER systems can cause voltage changes, their voltage actions must be coordinated with the feeder load tap changer (LTC) and voltage regulators, in order to avoid voltage problems or “hunting” or “fighting” between by LTCs and voltage regulators. The lifespan of these mechanical devices can be shortened if they are activated more often than necessary, so uncoordinated voltage actions can impose a system cost by increasing maintenance activities on these devices. Mitigations include using power electronics-based voltage control devices such as a static var compensator or emerging solid state voltage regulator technology, as well as making sure the advanced DER voltage functions are appropriately coordinated with the distribution devices.

One of the most evident impacts of DER systems are on distribution voltages along feeders. Not only will load profiles change with higher penetrations of DER, but the feeder voltage profiles will change. There are many types of feeders with differing characteristics e.g. short urban vs. long rural, that affect equipment settings. In general DER systems can cause new stresses on distribution circuits, but at the same time, some of the advanced capabilities of DER systems could mitigate these effects.

4.4 DER Capabilities and DER System Architectures

4.4.1 Overview of Advanced “Smart Inverter” Capabilities

Many of the challenges posed by DER systems may have solutions or mitigations of their impacts through the advanced “smart” inverter capabilities, more comprehensive planning and near-real-time studies, and communications with DER systems. Some of these solutions involve combining intermittent renewable DER systems with energy storage systems which can smooth out or eliminate the changes in power output.

Some of these challenges can also be offset by the capabilities provided by advanced DER technologies. These newer DER technologies generally include electronic controllers that can adjust output properties of “smart inverters” to mitigate impact on power quality and reliability in response to local voltage and frequency issues as well as modify generation and storage actions based on communicated requests.

A smart inverter is not only capable of performing traditional inverter functionalities (i.e. converting DC to AC) but also has the capability of providing advanced features that support grid reliability and stability. These capabilities include reactive power support, volt/VAR response, voltage and frequency ride-through, and the addressing of ramp rate issues, in conjunction with enhanced management controls.

Studies have identified many functions that DER systems could provide to support the grid. The following list identifies the advanced capabilities of “smart” DER systems (more details can be found in Appendix 1.2):

- **Anti-Islanding**: Support anti-islanding in cases of unintentional islanding
- **L/HVRT**: Provide ride-through of low/high voltage excursions beyond normal limits within preset voltage-time limits
- **L/HFRT**: Provide ride-through of low/high frequency excursions beyond normal limits within preset frequency-time limits
- **Frequency-Watt**: Counteract frequency excursions beyond normal limits by decreasing or increasing real power
- **Dynamic Current Support**: Counteract abnormal high or low voltage excursions by providing dynamic reactive current support
- **Soft-Start Reconnection**: Reconnect autonomously after grid power is restored
- **Command DER to Connect or Disconnect or Delay Connection**: Perform soft or hard connect or disconnect from grid via direct command
- **Backup**: Provide backup power after disconnecting from grid
- **Support Creation and Operation of Islanded Microgrid**: Disconnect from the Area EPS while establishing a pre-designed microgrid

- **Decrease Export of Real Power at PCC**: Response to command/ requests either to increase import or to decrease export of real power
- **Limit Maximum Real Power**: Limit maximum real power output at the ECP or PCC to a preset value
- **Increase Export of Real Power at PCC**: Response to command/ requests either to decrease import or to increase export of real power
- **Set Real Power**: Set actual real power output at the ECP or PCC either as a specific real power setpoint or as a percentage of local load
- **Follow Schedule of Real Power**: Follow schedule of actual or maximum real power output at specific times
- **Follow Schedule for Storage**: Set or schedule the storage of energy for later delivery, indicating time to start charging, charging rate and/or "charge-by" time
- **Volt-Var Control**: Execute volt-var control in response to settings that define reactive power output for different voltages
- **Operate by Fixed Power Factor**: Provide reactive power by a fixed power factor
- **Use Ramp Rates**: Use the different ramp-up and ramp-down rates that have been defined for normal, emergency, and reconnection
- **Voltage Smoothing**: Modify real power output in response to local voltage variations
- **Frequency Smoothing**: Smooth minor frequency deviations by rapidly modifying real power output to counteract these deviations
- **Automatic Generation Control (AGC)**: Support frequency regulation by direct automatic generation control (AGC) commands
- **Operational Reserves**: Provide "spinning" or operational reserve by increasing real power from generation or storage as bid into market and upon command
- **Black Start Capability**: Provide black start capabilities upon command
- **Emission-constrained Dispatch** : Set output real power on command, based on emissions produced
- **Support Situational Awareness**: Provide real-time or near-real-time DER information
- **DER Registration**: Provide operational characteristics at initial interconnection and upon changes

4.4.2 Hierarchical Architecture of DER

Scientists studying DER and future grid operations techniques have hypothesized that direct interface with thousands if not millions of DER systems with a centralized optimization architecture such as security constrained economic dispatch is not feasible.[52] Instead a hierarchical approach is suggested for utilities and system operators to exchange information with these widely dispersed DER systems. At the local level, DER systems must manage their own generation and storage activities autonomously, based on local conditions, pre-established settings, and DER owner preferences. However, DER systems are active participants in grid operations and must be coordinated with other DER systems and distribution grid devices. In addition, the DSOs must interact with transmission system operators (TSOs) (also known as regional transmission organizations (RTOs) and/or independent system operators (ISOs)) for reliability and market purposes. In some regions, retail energy providers (REPs), aggregators, or other energy service providers are responsible for managing groups of DER systems either through operational actions or market actions.

DER systems can range in size from 1 kW to more than 10 MW. The impact of aggregated smaller DER systems can be the same as a single larger DER system, so making size distinctions for requirements is becoming less common in standards and regulations. Utilities usually try to identify the net energy or net impacts of DER systems at the Point of Common Coupling (PCC) where a customer's facility interconnects with utility grid.

As shown in Figure 13 below, DER systems typically are implemented as a hierarchical architecture.[53]

[52] Ron Melton, Pacific Northwest National Laboratory.

53 Smart Grid Interoperability Panel's (SGIP) Distributed Renewable Generation and Storage (DRGS) "Hierarchical Classification of Use Cases and the Process for Developing Information Exchange Requirements and Object Models" White Paper (http://www.sgip.org/Publication-Distributed-Energy-Resources)"

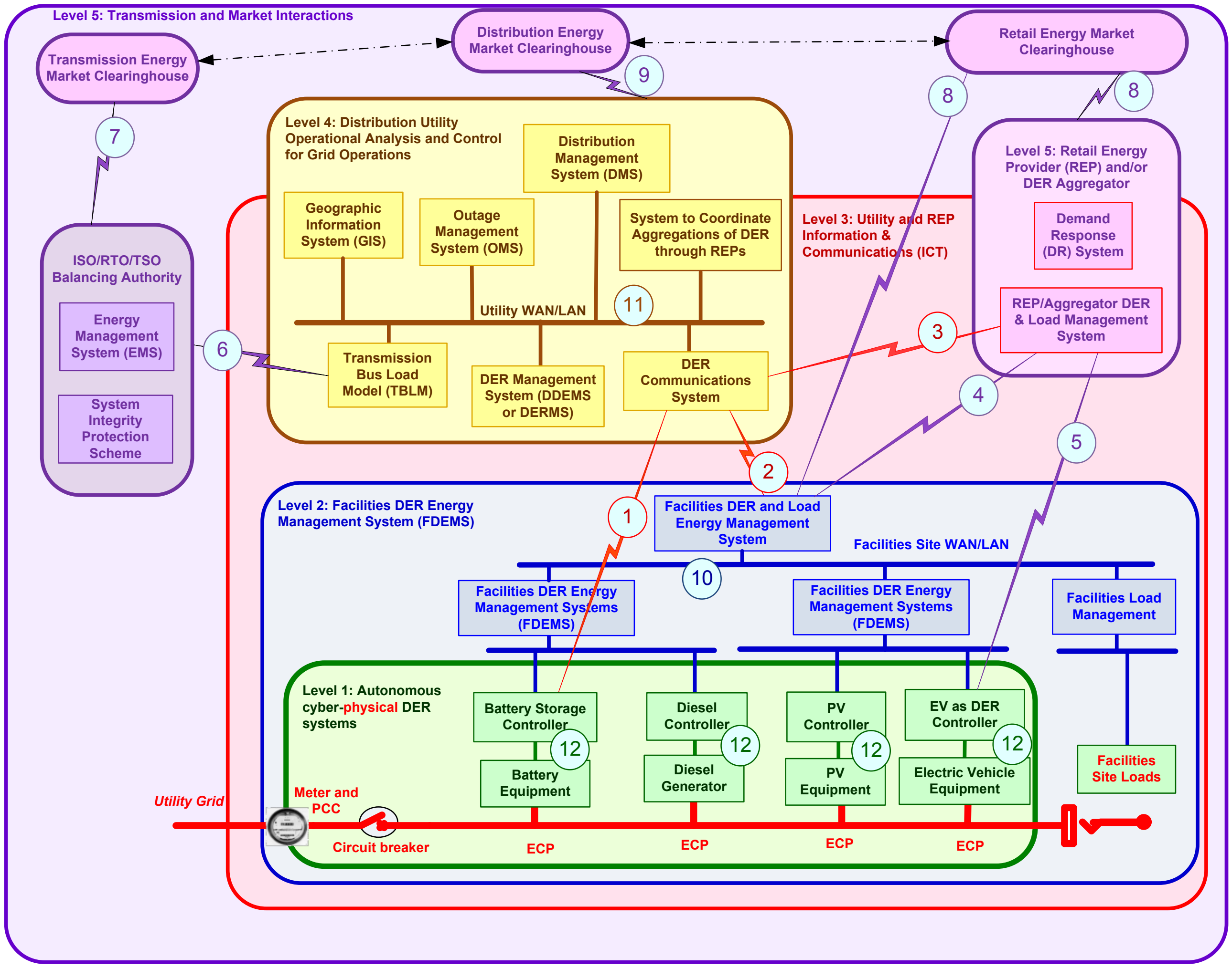

Figure 13: Hierarchical Organization of DER systems[54]

- Level 1 DER Systems (green in the Figure) is the lowest level and includes the actual cyber-physical[55] DER systems themselves. These DER systems will be interconnected to local grids at Electrical Connection Points (ECPs) and to the utility grid through the Point of Common Coupling (PCC). These DER systems will usually be operated autonomously. In other words, these DER systems will be running based on local conditions, such as photovoltaic systems operating when the sun is shining, wind turbines operating when the wind is blowing, electric vehicles charging when plugged in by the owner, and diesel generators operating when started up by the customer. This autonomous operation can be modified by DER owner preferences, pre-set parameter, and commands issued by utilities and aggregators.

- Level 2 Customer DER Management (blue in the Figure) is the next higher level in which a customer DER management system (FDEMS) manages the operation of the Level 1 DER systems. This FDEMS may be managing one or

[54] Xanthus Consulting International, 2015
55 Cyber-physical means that it is a system that employs software control applications to manage power system hardware. This can have cyber security impacts

two DER systems in a residential home, but more likely will be managing or coordinating multiple DER systems in commercial and industrial sites, such as office buildings, university campuses, and shopping malls. Utilities may also use a FDEMS to handle DER systems located at utility sites such as substations or power plant sites. A particularly important type of FDEMS is the Microgrid Energy Management System which must also be able to manage the disconnect and connection to the main grid, as well as balance load and generation when the microgrid is islanded.

- Level 3 Utility and REP WAN Communications (red in the Figure) extends beyond the local site to allow DSOs and market-based aggregators and retail energy providers (REP) to request or even command DER systems (typically through a FDEMS) to take specific actions, such as turning on or off, setting or limiting output, providing ancillary services (e.g. volt-var control), and other grid management functions. REP/aggregator requests would likely be price-based focused on greater power system efficiency, while utility commands would also include safety and reliability purposes. The combination of this level and level 2 may have varying scenarios, while still fundamentally providing the same services.

- Level 4 Distribution Utility Operational Analysis (yellow in the Figure) applies to DSO applications that are needed to determine what requests or commands should be issued to which DER systems. Utilities must monitor the power system and assess if efficiency or reliability of the power system can be improved by having DER systems modify their operation. This utility assessment involves many utility control center systems, orchestrated by the DMS and including the DER database and management systems (DERMS), Geographical Information Systems (GIS), Transmission Bus Load Model (TBLM), Outage Management Systems (OMS), and Demand Response (DR) systems. Once the utility has determined that modified requests or commands should be issued, it will send these out as per Level 3.

- Level 5 Transmission and Market Operations (purple in the Figure) is the highest level, and involves the larger utility environment where TSOs, RTOs, or ISOs may need aggregated information about DER capabilities or operations and/or may provide efficiency or reliability requests to the utility that is managing the DER systems within its domain. This may also involve the bulk power market systems, as well as market functions of retail energy providers. (Note: if a TSO is directly managing a generation or storage system on the HV power system, it is not considered a DER system.)

Although in general DER systems will be part of a hierarchy, different scenarios will consist of different hierarchical levels and variations even within the same hierarchical level. For instance, small residential PV systems may not include sophisticated FDEMS, while large industrial and commercial sites could include multiple FDEMS and even multiple levels of FDEMS. Some DER systems will be managed by Retail Energy Providers through demand response programs, while others may be managed (not necessarily directly controlled) by utilities through financial and operational contracts or tariffs with DER owners.

The management of DER systems involves multiple levels of information exchanges (see circled numbers in Figure 13.

- Interaction 12 – Autonomous DER behavior in which the controller responds to sensors that sense local conditions within Level 1. Controllers are focused on direct and rapid monitoring and control of the DER hardware. Common types of autonomous DER controls include managing one or more inverters, such as a small PV system, a battery storage system, or an electric vehicle service element (EVSE). In addition to basic control, this autonomous behavior can perform advanced “smart inverter” functions using one or more of the pre-set modes and/or schedules that respond to locally sensed conditions, such as voltage, frequency, and/or temperature. Responses could include anti-islanding ride-through protective actions, volt-var control, frequency-watt control, ramping from one setting to another per a schedule, soft-restart, and other functions that may be pre-set. Interaction latency requirements are typically milliseconds to seconds.

- Interaction 10 – DER management system interactions within Level 2 with multiple DER systems managed or coordinated by a DER facility energy management system (FDEMS). Peer to peer interactions can also occur between DER controllers, such as between a PV controller and a battery storage controller. The FDEMS has a more global vision of all the DER systems under its control, and can allocate tasks to different DER systems, depending upon the facility operator’s requests, load conditions within the facility, and possibly demand response pricing signals. It understands the overall capabilities of the DER systems under its management but may not have (or need) detailed data. FDEMS can issue direct commands but will primarily update the autonomous settings for each DER system. Interaction frequency may be seconds to minutes, hours, or even weeks.

- Interaction 1 – Direct DSO interactions with DER systems within Level 3, between Level 4 and Level 1. These direct DSO interactions usually imply that the DER system is under contract to be managed by the DSO, such as providing energy storage for smoothing fluctuations or counteracting spikes and sags. The DSO generally uses its SCADA system for these interactions. Interaction latency requirements are typically a few seconds.

- Interaction 2 – DSO interactions with FDEMS within Level 3, between Level 4 and Level 2. These interactions may be for the purpose of the DSO monitoring the aggregated generation and load, usually at the PCC, with the ability of the DSO to request ancillary services, such as reactive power support, frequency support, or limiting real power output at the PCC. The DSO could also request data on generation capabilities, load forecasts, and other longer term information. The DSO could also provide updated settings and schedules for specific advanced functions, such as volt-var control or frequency-watt control. It could also include pricing signals. These DSO-FDEMS interactions would probably not use the real-time SCADA system (due to concerns about the volumes of data and cyber security) and could be every few minutes, or hourly, weekly, or seasonally

- Interaction 3 – DSO interactions with aggregators within Level 3, between Level 4 and Level 5. These interactions would be primarily for the DSO to monitor aggregated groups of DER systems that are under the aggregator's management. These groups of DER systems would be established by the DSO, such as all DER systems on a particular feeder or feeder segment, or all DER system capable of performing the volt-var function. The DSO could then issue commands (or requests, depending upon the contractual relationships) to specific groups of DER systems via the aggregator.

- Interactions 4 and 5 – Aggregator interactions with DER systems or FDEMS within Level 3 between Level 5 and Levels 2 and 1 (respectively). These interactions consist of monitoring and control (or requests) so that the aggregator has visibility of all DER or FDEMS under its management.

- Interaction 11 – Internal DSO interactions among applications and systems involved with DER systems within Level 4. These interactions between applications provide the capability of the DSO to make decisions on operating the distribution system with DER systems.

- Interaction 6 – DSO interactions with the TSO or ISO/RTO within Level 3, between Level 4 and Level 5. These interactions provide the TSO with the ability to request ancillary services from DER systems, FDEMS, and/or aggregators, by going through the DSO. The TSO can also request forecasts, information on emergency situations, and other DER-related data.

- Interactions 7, 8, and 9 – Market interactions by the TSO, aggregators, FDEMS, and DSO (respectively), within Level 5. These interactions would be for sending and receiving market offers, bids, and/or pricing signals.

4.4.3 Typical Interconnection Processes for DER

Utilities have always required DER interconnection processes to be followed in order to ensure the protection and safety of the distribution grid. When only a few DER systems were being interconnected, these processes were developed by each utility, leading to a large variety to specifications and requirements. As more DER systems began to request interconnection to the grid, these one-off requirements become a barrier to efficient interconnections.

In early 2000s, an efforts was started to develop an interconnection standard, IEEE 1547 (see 4.7.1), which defined the electrical and protection requirements. Regulators and utilities quickly updated their interconnection procedures to be based on this standard, although often adding modifications.

At the same time, testing and certification of DER systems was formalized under the UL standard, UL 1741 (see 4.7.3), as a means of certifying the safety of the DER systems in meeting the IEEE 1547 requirements.

These interconnection procedures, even though more standardized electrically, still required utilities to study each interconnection request. Once again as increasing numbers of DER interconnection requests built up, some utilities modified their procedures to "fast track" the smaller or simpler interconnections. A typical flow chart of this process is shown in Figure 14 below.

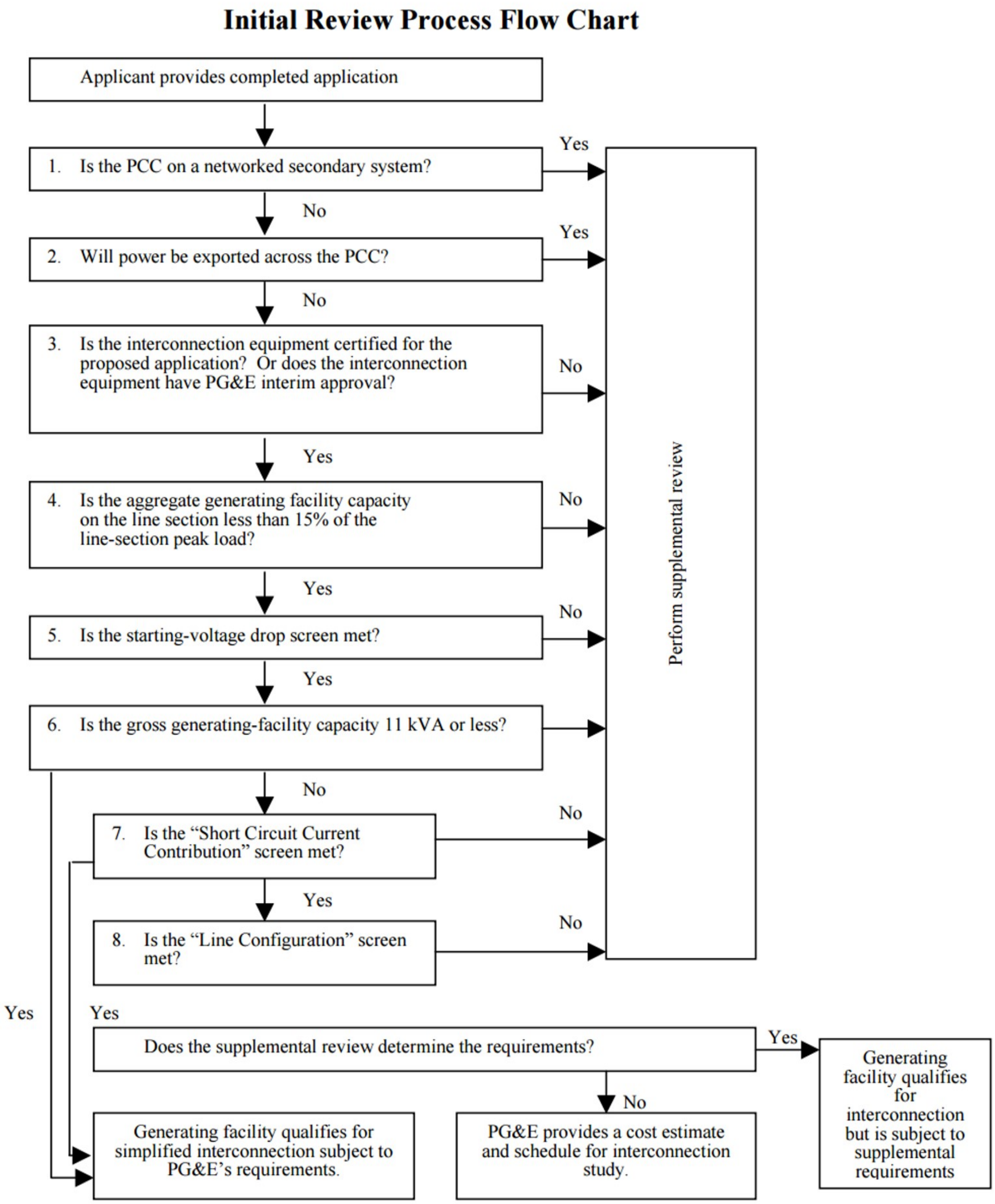

Figure 14: Example PG&E flow chart for DER screening[56]

Utilities screen DG interconnection requests against various criteria to make an initial assessment of impact to the distribution system. In many cases, utilities use this process to determine if a fast-track interconnection procedure that bypasses detailed system impact studies is appropriate.

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56 http://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/sampleofinitialreview.pdf

FERC order 792, issued in November 2013 revised small generator interconnection standards to include a 100% of minimum daytime load screen to supplement the previous screen of 15% of peak load[57] (in place since the SGIP was established in 2005). NREL and industry groups advocated use of a daytime load screen instead of a peak load screen for PV.[58]

In California, Rule 21 specifies "screens" of checklists are used to determine if additional studies are needed or not. These screens also capture the relevant data about the DER systems, including their (electrical) location and the DER nameplate information.

It expected that in the future, additional data may be factored into the screens and studies, such as what advanced functionalities the DER systems are capable of, what communications are available, and who is responsible for managing the DER system (e.g. facility owner or aggregator). This additional information could then be used to establish the detailed interconnection requirements, such as which advanced functionalities would be required to be enabled and whether communications must be established.

IEEE 1547.8 (draft)[59] provides guidelines for categorizing the recommended information exchanges by DER size and EPS "sensitivity", in which small DRs or small groups of DRs (e.g. <100 kW, medium (e.g. 100 kW – 1 MW) and large DRs or large groups of DRs (e.g. > 1 MW) (based on nameplate information) are located within different environments:

- Low sensitivity environment is characterized by:
- Low generation-to-load ratio, such as smaller than 1-to-2 or 1-to-3
- Strong or stiff EPS (the EPS at the DER location is very stiff and can handle significant fault current,
- Small variability of generation and/or load within area, including due to feeder switching
- High sensitivity environment is characterized by:
- High generation-to-load ratio, such as larger than 1-to-2 or 1-to-3
- Weak Area EPS (there is significant impedance between the DER and the EPS source substation)
- Large variability of generation and/or load within area

Although these are strictly guidelines, they can be used as metrics to identify the "sensitivity" of a particular feeder.

Once all the screening and studies are completed, the DER interconnections go through checkout and startup.

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57 FERC Order 792:
http://www.ferc.gov/whats-new/comm-meet/2013/112113/E-1.pdf
58 Updating Interconnection Screens for PV Integration, 2012 NREL
http://www.nrel.gov/docs/fy12osti/54063.pdf
59 IEEE 1547.8 (draft – not yet published) "P1547.8™/D8 Draft Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Standard 1547"

4.4.4 Hierarchical DER Example

Currently, California ISO markets incorporate system peak capacity delivered from DERs by including these resources in its centralized market optimization. The CAISO conducts an annual analysis to determine, by substation, the system-wide capacity quantities that can be delivered from the distribution level. In order for a smaller resource to deliver system capacity, it must participate in the resource adequacy (RA) program, which entails submitting a bid into CAISO energy markets. It has been suggested that, with increasing numbers of DER systems participating, the centralized market optimization may become overburdened.

An alternative is to make use of the hierarchical architecture described above where an aggregation of DERs interfaces to the transmission operator rather than each DER individually. Figure 15 shows a concept in which the distribution operator is an intermediary between the transmission level and the end-use customer level. Note that there is not a linkage in this image between the transmission level and the end use level, which is consistent with the hierarchy depicted in Figure 15 below.

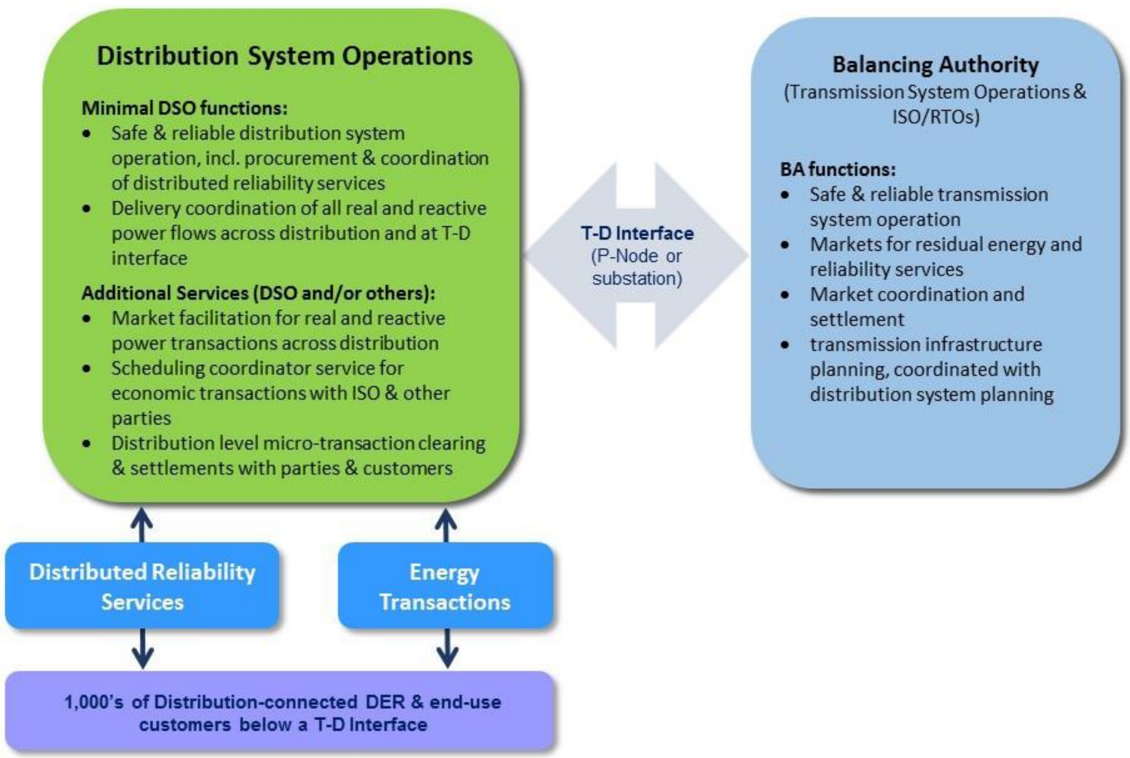

Figure 15: Distribution Interface to Transmission Operations
Source: Kristov, De Martini 2014[60]

4.4.5 Distribution Energy Storage Systems (DESS)

Energy Storage Systems (ESSs) are by their nature flexible resources and therefore beneficial to reliable, low-carbon grid operations. ESSs can be used to shift loads during

[60] http://smart.caltech.edu/papers/21stCElectricSystemOperations050714.pdf

high peak load conditions and provide the operational flexibility to quickly change electricity production and consumption and maintain needed output levels for the time required, particularly as increasing amounts of variable renewable energy resources are interconnected to the grid. ESS systems can be connected at the transmission level, such as in substations, but may often be connected to the sub-transmission or distribution levels.

In California, the CPUC identified energy storage procurement targets for each of the Investor Owned Utilities (IOUs) totaling 1,325 MW to be completed by the end of 2020 and implemented by 2024[61]. This decision has led to significant discussions on the different types of values of ESS energy capacity and ability to provide flexible resources (ramping) for off-setting transmission costs. Similarly discussions are being held in the Distribution Resource Planning (see 4.6.1) process on the value of energy storage to off-set both transmission costs as well as locational distribution costs. Stakeholders are particularly interested in how to identify the need for flexible capacity and the valuation methodology for that capability in the CPUC resource adequacy program, and second, to clarify tariff treatment of storage facilities, in particular between charging and discharging of electricity.[62]

In addition to providing resource adequacy and flexibility for the transmission system, distribution-connected energy storage systems (DESS) have special capabilities that make them particularly important in the management of distribution systems with high penetrations of DER systems. Since they are controllable, include inverter functionalities, and can both generate and act as loads, they can be used to counteract many of the fluctuations and variability of not only renewable resources but also loads.

DESS systems have the potential to cancel or minimize the "intermittency" associated with renewable resources. As opposed to transmission-level energy storage, which is often deployed in a central location such as a substation, DESS systems can be deployed at various points on the distribution circuit, either as part of a combined generation-storage system or at least close to the sources of intermittency.

DESS systems may also be used to respond autonomously to frequency deviations by changing their charging or discharging rates, thus smoothing the frequency deviations. They may also be used, possibly in aggregate, for more traditional automatic generation control (AGC). These DESS devices may be utility-owned or the advanced storage functionality may be available through third party owners/operators.

Utilities that are evaluating the deployment of DESS systems for their own grid management purposes generally need to assess some of the following issues:

- Evaluation of the distribution system to identify circuits that have a high penetration of renewables which can lead to intermittency problems
- Evaluation and testing of DESS devices for intermittency mitigation
- Development of interoperable communication requirements to ensure that the devices acquired are able to interface with utility SCADA systems
- Deployment of pilot installations to evaluate the performance of the equipment

[61] AB2514 was approved on September 29, 2010 and was entered into California Public Utilities Code, Chapter 7.7, Sections 2835-2839; C PUC decision D14-10-045, October 16, 2014.
[62] http://www.caiso.com/informed/Pages/MeetingsEvents/PublicForums/Default.aspx

- Development of a plan to install these devices on distribution transformers that are serving EV charging stations

One of the current discussion areas are how to treat DESS devices that are ostensibly “behind the meter”. For instance, should they be treated as just load (if they are truly “non-exporting”), or if they could impact exports of power across the PCC, should they always be treated as DER systems and go through the same assessment processes for interconnection. For instance, if they are truly behind the meter, then they should qualify for a fast-track interconnection process. In addition, stakeholders are interested how they could move from being under Rule 21 jurisdiction to the Wholesale Distribution Access Tariff (WDAT) if their business interests were to change.

Another major rate issue is what rate should be applied for charging energy storage systems. There are two types of storage applications:

- Energy that is stored for later injection back to the grid to provide grid services (e.g. resource adequacy capacity, flexible capacity, frequency support)
- Energy stored and injected at different times of the day to change customer consumption patterns (e.g. load shifting, often for the benefit of the customer facility to help mitigate demand charges and minimize consumption during higher rate periods)

For the first case, grid services can be provided to the wholesale market or to the utilities for transmission support and/or distribution system management, thus consistent with other generation sources[63]. In California, the rates for these are determined by the ISO interconnection tariff (for transmission-connected) and by the FERC jurisdictional WDAT (for distribution-connected). For the second case, the applicable tariff is determined by the Rule 21 interconnection agreement with the utility. Issues can arise when DESS might be used for multiple purposes for both the wholesale market and the distribution grid. For instance, the DESS could provide reliability services to the distribution grid and capacity services to the wholesale market. Even though the DESS may be providing benefits to the distribution system, tariffs and rules are not in place to value these capabilities and procurement does not recognize these additional values. Another example is when DESS is combined with renewable resources to provide “hybrid configurations”. The value of this combination as well as the individual values of the component units are not clearly understood or included in rates.

4.4.6 Microgrids and “Nanogrids”

A microgrid is defined as small grids that may be connected to the utility grid but can also disconnect from that grid and continue to operate. Nanogrids are just very small microgrids and could range from an office building down to residential homes or even smaller.

Some microgrid characteristics include:

- Geographically delimited

[63] FERC addressed the issue of storage charging under a PJM filing by stating that electricity “stored for later delivery” is not “end-use” consumption and is therefore not subject to the jurisdiction of regulatory authorities over retail costs. Docket ER10-1717-000

- Connected to the main grid at a single Point of Common Coupling (PCC)
- Capable of operating either connected to the utility or in islanded mode
- Includes DER systems as the source of power, which may be combinations of renewable, fossil fuel-based, inverter-based, synchronous, energy storage, and controllable load
- Includes an energy management system that manages (among other activities) the disconnection from the main grid, the islanded operation, and the reconnection back to the main grid

A microgrid can provide several different services to the utility grid. From the system operator's perspective, a microgrid can either serve as:

- A flexible energy resource that can be bid into the electric market;
- A fast-responding remedial action scheme implementation that can have varying impact to the customer (i.e. on-demand islanding);
- An ancillary service resource, or;
- A "ramp down" variable consumption resource (in response to over generation conditions)

Technical requirements are still being developed on the transitions from connected to disconnected and back to reconnected. Additionally, the financial issues around deploying and utilizing microgrids for grid support are still under wide-ranging discussions. A standard, IEEE 2030.7, is being developed on these topics.

4.4.7 Electric Vehicles with V1G and V2G Capabilities

Plug-in electric vehicles (PEVs) and all-electric vehicles (EVs) are presenting new challenges to utilities. Although their main purpose is transportation and not energy management, they can have impacts on distribution systems, particularly in aggregate.

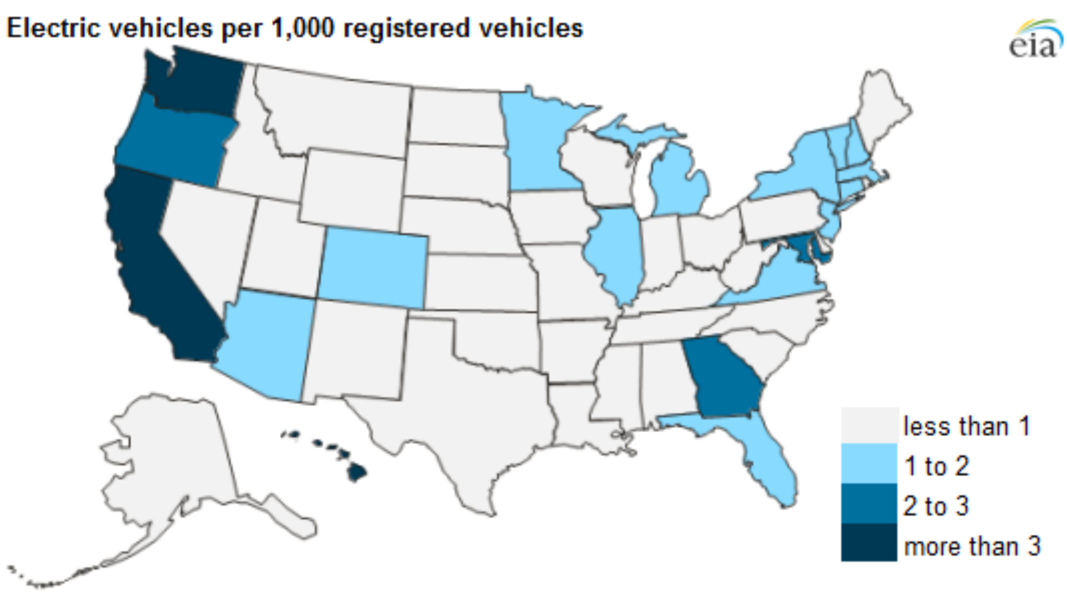

Figure 16: EV Penetration by State (EIA 2013)

On the one hand, utilities can benefit from the increased revenues from these new loads; on the other hand, these loads can potentially cause local peak loads that could cause utility over-voltage situations or even equipment damage. However, if utilities can help manage EV loads through rate incentives or direct signals, PEV/EVs could actually smooth load curves, support frequency regulation, and improve reliability. In this sense, PEV/EVs can be considered as similar to DER systems.

Today all PEV/EVs models provide an on-board charger so that they can be plugged into normal outlets. Since an inverter is also present, some of the “smart inverter” functions could also be provided, so long as these functions do not impact the primary purpose of transportation. There are many technical, economic, and regulatory issues associated with the charging of PEV/EVs, but with respect to their interactions with the distribution grid, two types of connections are possible.

The first is the most common type where PEV/EVs are only charged (termed V1G). Utilities could request that charging times and charging rates be modified in order, for example, to decrease peak loads or even smooth frequency deviations, usually with the proviso that the vehicle is still completely charged by the time the driver needs it. For instance, if EV owners are incentivized by time of use rates (see 4.9.1), then they may choose to (automatically) let the EV chargers only charge the EVs during lower pricing times, such as after the evening (residential) peak, between midnight and 5 am for example.

A new capability known as Vehicle to Grid (V2G) is being discussed with some small pilot projects exploring the capabilities. In V2G, energy can be extracted from a PEV /EV battery and supplied to the electric power system. If V2G is implemented, then it would be expected that all regulatory DER interconnection requirements would need to be met, such as those defined in IEEE 1547 and certified through compliance with UL 1741.However, some issues are raised because PEV/EVs roam across regulatory jurisdictions, making it difficult to determine which regulations must be met. In particular, the UL 1741 certification standard cannot be used as is for inverter systems which are integrated into a PEV, since it is targeted for stationary inverters in a “box” and not for an assembly of devices which are integrated into an automotive vehicle. SAE is creating SAE Standard J3072, *Interconnection Requirements for Onboard, Utility-Interactive Inverter Systems*, to be used in place of UL 1741. J3072 also requires conformance to IEEE 1547.

Another issue is that different jurisdictions could permit or require different capabilities so that the PEV/EVs would have to “be told” dynamically what functions it could provide. This might be provided through communications, but very little work has as yet been done on this issue.

One popular V2G function is the idea that vehicle owners could use their PEV/EV as backup power during a power outage. This would quickly provide customers with mini-microgrids.

In February 2015, PG&E sought CPUC approval to invest $654MM over a 5 year period in electric vehicle (EV) charging systems, with the goal of supporting the expected 1.5 million EVs by 2025. If approved, PG&E customers would share the costs, with residential customers expected to pay about 70 cents more per month from 2018 to

2022. The PG&E request is very contentious and consumer advocates will argue that these costs should not be borne by ratepayers. PG&E argues that their EV program will benefit disadvantaged communities (10%) and support time variant pricing.

4.5 Examples of DER Grid Codes for Advanced Functions

4.5.1 European 2003 Blackout and Updated Grid Codes

On September 28 2003, large parts of Italy and portions of neighboring companies experienced a blackout[64]. The primary cause was transmission problems in Germany and Switzerland, but the ultimate result was a rapid cascading of equipment that tripped off. Of interest to distribution utilities is that about 1700 MW of DER generation precipitously tripped off-line when the frequency reached 49 Hz. This caused an even more rapid cascading effect as this generation was lost.

In part because of this event, the European power industry determined that in areas of distribution grids with increased amount of dispersed generation capacity, certain electrical faults could no longer be managed by the existing protection schemes to avoid unintentional islanding or undefined system conditions. *"Consequently the risk of serious system disturbances due to an uncoordinated disconnection of a high amount of distributed generation corresponding to a multiple of the available primary control power reserve cannot be excluded anymore. It can be foreseen that the resulting system balance might be managed only by the activation of large scale underfrequency load shedding."*[65]

Therefore, the decision was made to require DER systems to "ride-through" short-term spikes and sags of voltage and frequency. At the request of ENTSO-E (the European Network of Transmission System Operators for Electricity), several European countries, led by Germany and Italy, have updated the interconnection requirements of new distributed generating units in order to ensure the disconnection thresholds are set to deviations beyond 47.5 Hz or 51.5 Hz. In addition, Germany and Italy started large programs to upgrade (or retrofit) most of the existing noncompliant units to these new thresholds. The upgrade programs were expected to be finalized by end of 2014. No exact cost figures have yet been firmly established for this retrofitting requirement, After analysis and revisions to the grid codes, the larger DER systems were refitted to include ride-through functionality, but at great cost. This cost has not been fully determined, but additional concerns by ENSTO-E are leading to additional retrofits and other programs for minimizing the risk of major blackouts.[66]

Subsequently, in an international effort to develop the communications requirements for enabling these DER functions, the International Electrotechnical Commission (IEC)

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64 UCTE, Final Report of the Investigation Committee on the 28 September 2003 Blackout in Italy, 2004
65 European Network of Transmission System Operators for Electricity (ENTSO-E) "Dispersed Generation Impact on CE Region Security Dynamic Study, Final Report", 22-03-2013
66 Dispersed Generation Impact on Continental Europe Region Security - ENTSO-E Position Paper - 15 November 2014

expanded these requirements in the communications standard IEC/TR 61850-90-7.[67] This communications standard provides interoperability for DER systems across all DER manufacturers. In Germany, the key DER functionalities are mandated and enabled and the communications protocols have been specified so that utilities can monitor these DER systems, update their settings, and issue commands.

4.5.2 California's Rule 21 Grid Code Update

Origins

California recognized that it was becoming increasingly important to address the challenges posed by higher penetrations of DER systems. California Governor Jerry Brown had called for 12,000 MW of "localized electricity generation", or DER, to help the State procure 33 percent of its energy from renewable resources by 2020, and has recently increased that goal to 50% by 2030.

The policy driver for most of California's distributed generation programs to meet these ambitious goals has been to stimulate market development and support emerging technology. However it became increasingly clear that additional elements were needed beyond market incentives. The policies would also have to address the technical issues of integrating and coordinating DER systems since high penetrations of DER systems that are required to trip-off instantaneously in the event of any distribution system disturbance can lead to grid stability problems, as experienced in Europe. Specifically, a widespread outage could occur if a period of under or over voltage or frequency that causes many PV or other inverter-connected systems to trip off simultaneously.

As a result this recognition of pending problems, the CPUC and the CEC jointly formed the Smart Inverter Working Group (SIWG) in January 2013. The purpose of the SIWG is to explore and define the technical steps needed to integrate inverter-based DER functionalities and allow efficient management of the distribution system while maintaining standards of reliable and safe service. While DER ride through settings to prevent a repeat of the European DER integration problems was one of the first priorities of the SIWG and were addressed in phase 1, additional advanced functions are expected to substantially contribute to other DER operational challenges, discussed below in the advanced functions section.

Phases

The CPUC noticed the formation of the SIWG to the service list of the interconnection proceeding, R.11-09-011. From its inception, the SIWG has been open to all interested stakeholders, including California's investor-owned utilities, DER developers and integrators, inverter manufacturers, ratepayer advocates, trade associations, and advocacy groups.

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67 These DER functions are also described in the publicly available Smart Grid Interoperability Panel (SGIP 1) web site: "Advanced Functions for DER Systems Modeled in IEC 61850-90-7" http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/PAP07Storage/Advanced_Functions_for_DER_Inverters_Modeled_in_IEC_61850-90-7.pdf
The IEC standard formally defining these functions and the communications models for implementing them, IEC 61850-90-7, was published in February 2013.

From January through December 2013, the SIWG discussed and assessed the list of autonomous and advanced smart inverter functionalities, communications protocols, and implementation plan contained in this document through biweekly conference calls, a CEC-sponsored web site[68], an active e-mail list, and an in-person workshop held in June 2013. The result was a document submitted to the SIWG in January 2014, titled "*Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources: Smart Inverter Working Group Recommendations*". This document recommended a 3-phased approach to update the CPUC's Rule 21 Interconnection requirements. These phases cover the following:

- **Phase 1: Seven (7) critical autonomous functions**. Phase 1 was approved by the CPUC on December 18, 2014 with mandatory implementation of the functions by about mid-2016. These autonomous functions consist of :
  - Support anti-islanding to trip off under extended anomalous conditions, coordinated with the following functions.
  - Provide ride-through of low/high voltage excursions beyond normal limits.
  - Provide ride-through of low/high frequency excursions beyond normal limits.
  - Provide volt/var control through dynamic reactive power injection through autonomous responses to local voltage measurements.
  - Define default and emergency ramp rates as well as high and low limits.
  - Provide reactive power by a fixed power factor.
  - Reconnect by "soft-start" methods (e.g. ramping and/or random time within a window).
- **Phase 2: Communications** capabilities for monitoring, updating settings, and control. These communication requirements include the capability of all DER systems to include communications, as well as specific communication protocol, performance, and cyber security requirements for interacting with utilities.
- **Phase 3: Additional DER functions**, many requiring communications. This list is essentially the same as shown in Appendix B, Section 1.2

The SIWG is also working with Underwriters Laboratory (UL), Sandia National Laboratory, and other testing experts to establish UL 1741 testing and certification requirements for the advanced DER functionalities to ensure that they operate according to California safety and reliability requirements.

Advanced Functions

The central challenge of the SIWG has been to understand the entire range of possible functions for smart inverters, and to define a phased approach for recommending how California regulators can make policy changes to realize the benefits of smart inverters.

The California Independent System Operator (CAISO) identified another type of problem from high penetrations of PV systems. During afternoons a significant part of the load would be served by these PV systems, but during the evening hours, the PV systems would rapidly decrease their power output, requiring other sources to quickly pick up the

[68] http://www.energy.ca.gov/electricity_analysis/rule21/index.html

load. CAISO staff created the well-known “Duck Curve” that highlights the need for fast-ramping resources during evening intervals.

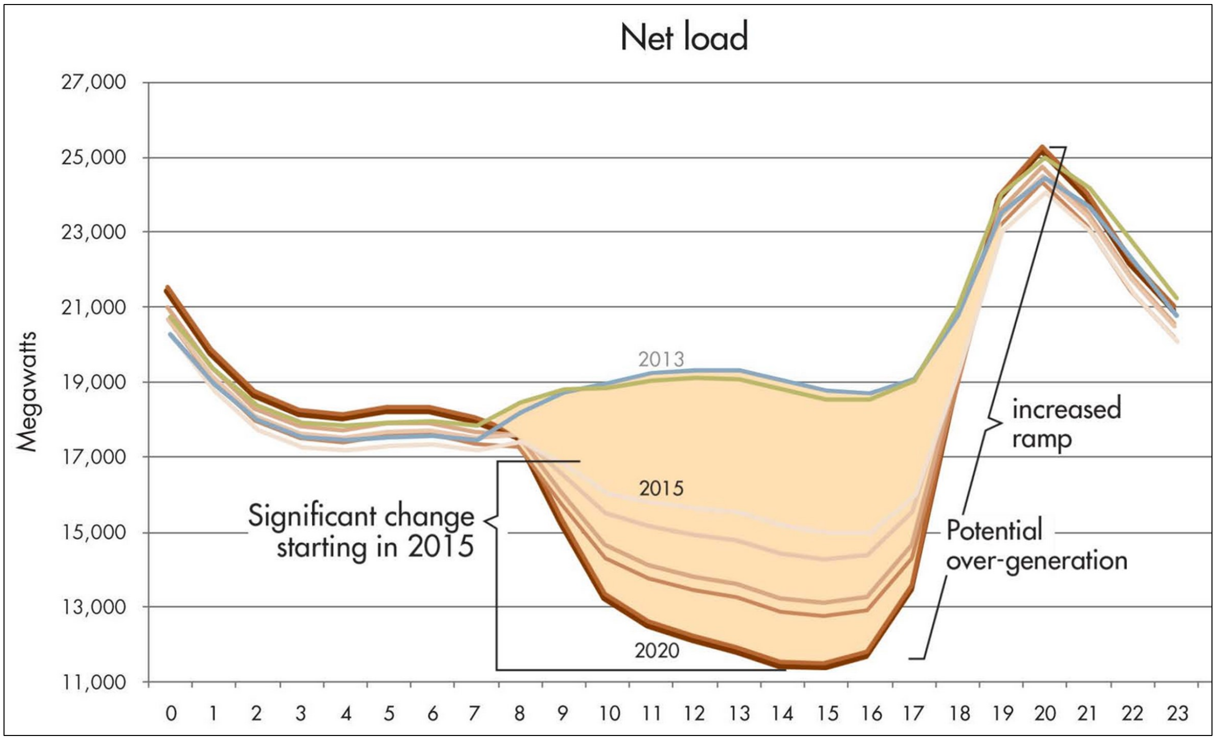

Figure 17: California ISO “Duck Curve” Source: CAISO

Smart inverters could enable dispatch of inverter-based DERs to match the evening ramp or to quickly respond to frequency deviations. Appendix B contains a list of smart inverter functions that can be used to address the steep evening load ramp depicted by the CAISO’s Duck Curve.

The steep slope shown indicates a high ramping rate will be required for generation resources, both on a sustained basis for as long as 4 hours during the evening ramp, and also during especially volatile intervals that could occur throughout the day. Smart inverter functions such as frequency smoothing (fast, autonomous frequency response) could provide a mitigation strategy to the latter problem and help ensure the bulk electric system stays within NERC frequency standards. An example of a short-duration event where this function could be used is during an interval that experiences loss of solar generation due to cloud movement in the afternoon – steepening an already steep ramp rate requirement and possibly exceeding system capabilities.

4.5.3 Hawaiian Situation

Hawaiian Electric (HECO) on Oahu was required to slow down the installations of new PV systems due to concerns that more solar could cause voltage problems in some neighborhoods. In 2013, about 300 megawatts of rooftop solar were interconnected at 40,000 locations, comprising around 10 percent of its customers. In some neighborhoods, PV systems were generating more than the utility's daytime minimum load causing back-feed and were also creating over-voltage problems on these feeders.

This situation is giving rise to the "Lock Ness Monster Curve[69]" which is similar but more exaggerated than CAISO's Duck Curve. In this diagram, there is back feed from one feeder to another feeder, causing a mid-day sag in residential energy demand, as rooftop solar PV energy supply exceeds the energy demand on those circuits, then the steep curve upward as solar fades away and late afternoon demand increases.

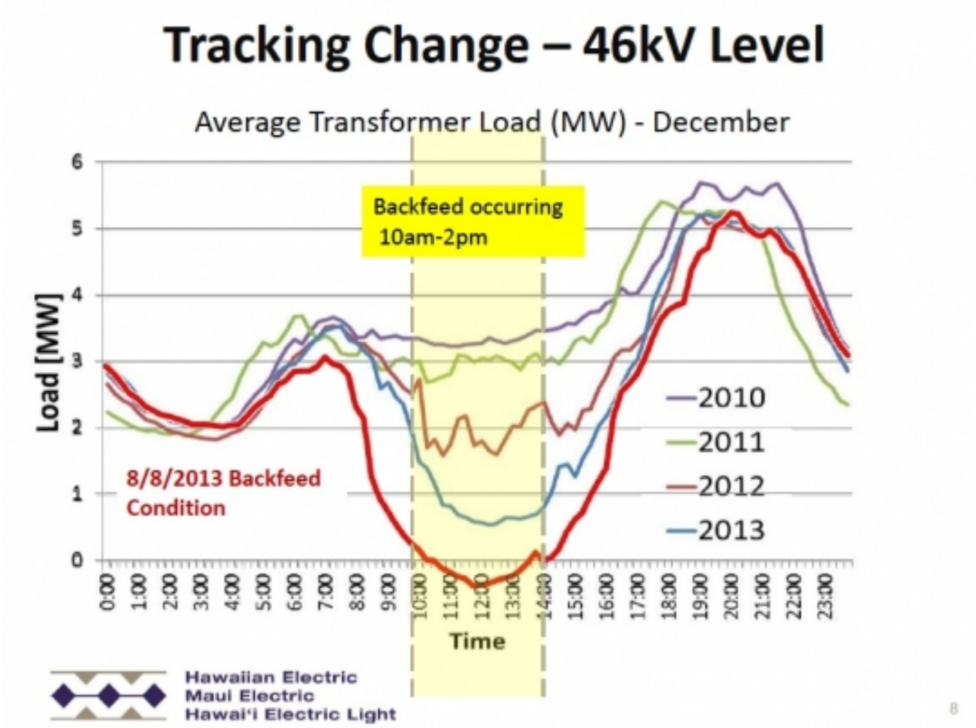

Figure 18: Hawaii Load Shape with Solar and Backfeed

The electric system in Hawaii upstream of distribution and subtransmission substations is significantly different than for utilities in WECC due to the isolated island location. Lack of access to a broader grid can cause system impacts in Hawaii that require a modified set of solutions than would be applicable on the mainland. In Hawaii, reverse flow from distribution circuits that serves other feeders or even the higher voltage network requires a change in dispatch of the HECO generation portfolio. HECO is exploring more flexible generation options as a possible mitigation strategy for the afternoon "loch ness curve."[70]

April 2014 Hawaii PUC Decisions

On April 29, the Hawaii PUC announced four decisions[71] that directed HECO to accelerate work to process stalled rooftop PV interconnection requests and generally put pressure on the company to bring business practices into alignment with changing expectations for it in Hawaii. HECO's IRP was rejected and the company was required

[69] Dora Nakafuji, director of renewable energy planning for Hawaii Electric Co. (HECO) presentation at Distributech, 2014
[70] HECO PSIP Report: http://files.hawaii.gov/puc/3_Dkt%202011-0206%202014-08-26%20HECO%20PSIP%20Report.pdf
[71] **http://puc.hawaii.gov/wp-content/uploads/2014/04/Press-Release-Summaries.2014-04-29.pdf**

to take a fresh look at its island power systems. Included was the much discussed "Commission Inclinations on the Future of Hawaii's Electric Utilities" whitepaper that provided new guidance and a strategic direction to inform future capital investments. Also required were two new studies, which were completed in summer of 2014 which contain valuable information about the Hawaii situation:

- Distributed Generation Interconnection Plan(DGIP)[72]
- Power Supply Improvement Plan(PSIP)[73]

The DGIP provides insight into issues caused by DER, mainly PV, and the mitigations actions HECO determined were necessary. High PV penetration on many of HECO's feeders has exceeded acceptable levels, above which HECO has required interconnection studies, significantly slowing the pace of completed new rooftop PV projects. In the past year, the PV penetration circuit threshold has been increasing as summarized in the following excerpt from HECO:

> "Hawaiian Electric Companies announced that IRSs would not be required for Distributed Generation ("DG") (< 10 kW) systems that would be interconnected on circuits with penetration levels < 75% of Gross Daytime Minimum Load ("GDML"). On September 6, 2013, the Hawaiian Electric Companies announced that IRSs would not be required for DG (< 10 kW) systems that would be interconnected on circuits with penetration levels < 100% of GDML. On February 26, 2014, Hawaiian Electric issued a notice to the solar industry that IRSs would not be required for DG (< 10 kW) systems that would be interconnected on circuits with penetration levels < 120% of GDML, provided that the PV systems utilize fast-trip inverters or automatic transfer switches for installations where the penetration level is > 100% GDML and< 120% of GDML."[74]

Limiting Factors

High PV penetration on many of HECO's feeders has exceeded acceptable levels, which were initially set at 75% of daytime minimum load for projects under 10 kW. This level has since been raised to 120% of daytime minimum load (DML) for projects under 10 kW.[75] This level was raised to 120% of DML, but HECO still was under pressure to increase this level. HECO cites[76] two primary concerns preventing PV penetration higher than 120% of DML:

1. Transient over voltage spikes
2. Headroom on circuit to accommodate switching actions or contingency situations. This is applied as a 50% thermal limit on conductors or substation transformers,

72 DGIP Docket 2014-0192 http://files.hawaii.gov/puc/4_Book%201%20%28transmittal%20ltr_DGIP_Attachments%20A-1%20to%20A-5%29.pdf

73 http://files.hawaii.gov/puc/3_Dkt%202011-0206%202014-08-26%20HECO%20PSIP%20Report.pdf

74 HECO 01.20.15 proposal in docket 2014-0192 Appendix 1 P.4

75 http://www.renewableenergyworld.com/rea/news/article/2014/02/the-interconnection-nightmare-in-hawaii-and-why-it-matters-to-the-u-s-residential-pv-industry

76 HECO DGIP

above which this equipment is flagged for upgrade or replacement. Ensuring that excess capacity is still maintained within the thermal limit of the feeder to transfer power without using heuristic methods will require more advanced scenario-based planning and interconnection study processes

Inverter manufacturers have been working with HECO to ensure that their inverters “cease to energize” during ride-through of large transient voltage spikes to ensure that voltages never reach excessive levels which might damage utility and customer equipment. These ride-through requirements are based on California’s Smart Inverter Working Group (SIWG) functions. HECO subsequently sponsored a project with NREL and Solar City to test inverter functions and reliability during transient overvoltage events.[77]

The work conducted by NREL examining[78] over-voltage mitigation capabilities of inverters, which has largely been successful in demonstrating that inverter-fed PV production will generally not be the source of damaging over-voltage conditions in a load rejection event (opening of feeder breaker isolating the circuit from the utility). These results may have much broader implications for other utilities even though they were carried out for island conditions.

In response, HECO released a proposal[79] in the DGIP docket on January 20, 2015 to increase the penetration threshold to 250% of daytime minimum load, subject to some conditions such as utility accessible PV system disconnect capability. The interconnection proposal was bundled with a net metering reform proposal, which is opposed by a Hawaii solar trade organization.

As of April 2015, HECO interconnection policies indicate that requests on circuits above 120% daytime minimum load may be able to avoid a more detailed interconnection requirements study if the inverter is certified to be capable of mitigating overvoltage conditions.[80]

The circuit-level issues HECO has analyzed to determine the penetration level standard recommendation are not the only factors that stand to limit overall penetration of DER on the islands. System-level issues are those HECO describes as arising more broadly across its entire system rather than only on individual circuits. At that level, a primary concern is excess energy production mid-day when distribution substations may be backfeeding to higher voltage systems, affecting HECO’s resource dispatch and reducing the quantity of synchronous generation on-line that is typically relied upon for system stability and ancillary services.

It is notable that the Hawaii PUC Inclinations document discussed the notion of unbundling ancillary services and suggested the potential value in opening up opportunities for DER to provide these services.

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77 http://www.nrel.gov/news/press/2014/15427.html

78 Inverter Load Rejection Over-Voltage Testing. NREL, Solar City. http://www.nrel.gov/docs/fy15osti/63510.pdf

79http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A15A20B13419D2782918+A15A20B45226C873931+14+1960

80 Current Summary of HECO Interconnection Policies (accessed 04.28.15) http://www.hawaiianelectric.com/heco/_hidden_Hidden/CorpComm/Reducing-Time-and-Cost-of-an-Interconnection-Study?cpsextcurrchannel=1

4.5.4 PJM and Other ISOs Use of DER Frequency-Watt Function

PJM has integrated many types of generators into their system, and has recently started to include DER systems as well. For instance, PJM is interested in using the fast responding frequency control capabilities of electric vehicle chargers and other DER systems (called the Frequency-Watt function). This autonomous Frequency-Watt function can respond to frequency variations in milliseconds. In 2013 PJM implemented a program to use two AGC signals as a method for compliance with FERC Order 755 (a ruling that requires RTOs and ISOs to compensate frequency regulation resources based on the actual service provided). A traditional AGC (Reg-A) signal is used for the slow responding generators and a dynamic (Reg-D) signal for the fast responders. NYISO uses only one AGC but differentiates the compensation for fast and slow responders.

Starting in 2011, Beacon Power operates a 20 MW flywheel farm in Stephentown, NY, which covers up to 30% of the area control error (ACE) in NYISO with 10% of the capacity, clearly showing the benefit of the fast responder. Beacon was one of the companies that pushed FERC to come out with Order 755. But the flywheels only last for 15 minutes so NYISO must manage the AGC to bring them to neutral within the 15 minutes. Beacon has another 20 MW farm responding to the PJM Reg-D signal which reached full capacity in July 2014. PJM is unique in lowering the minimum capacity to participate in regulation to only 100 kW. This was driven in part because of their interest in electric vehicles.

For small grids such as ERCOT, a small isolated utility on a real island or in Alaska, or an islanded microgrid, the use of autonomous Frequency-Watt by DER systems could perform most of the frequency regulation. For any grids that have large amounts of PV and where there may be insufficient frequency response from droop generators in fossil fuel plants, the autonomous DER Frequency-Watt function may really be needed.

On larger grids such as the Eastern and Western Interconnection with many balancing areas, the choice of using DER systems for frequency control becomes more of a business and operating issue. The AGC for a balancing area is derived from the Area Control Error (ACE) where NERC defines ACE as the difference between the actual and scheduled net interchange of the balancing area less a factor times the difference in actual versus scheduled frequency. In ERCOT and small grids, there are no interchange errors so the AGC is always proportional to frequency error. But for the other balancing areas, it becomes more complex to figure out how to integrate the autonomous Frequency-Watt function. As an example, it could be set to only operate during a high/low frequency ride-through event or other an emergency. But it could also be used with large aggregations of DER systems to respond to frequency variations very rapidly so that frequency is smoothed out significantly. Then AGC frequency regulation would only be needed to deal with interchange errors.

4.5.5 Other DER Functions for ISOs and RTOs

The capabilities of smart inverters to solve power system problems are also drawing interest up by ISO/RTO transmission operators.

For example, PJM has recently (March 6, 2015) requested that FERC revise the Open Access Transmission Tariff to incorporate changes to PJM's generator interconnection rules to require "enhanced inverter" capabilities be utilized by prospective Interconnection Customers contemplating the interconnection of wind and other non-synchronous generation facilities . PJM has requested that this filing become effective on May 1, 2015. In justification, this filing states, "*In addition, traditional interconnection settings relative to long-term system fluctuations for variable generation resources has been historically very conservative, typically resulting in such units "tripping" off-line during relatively minor frequency and voltage system events. For many years, engineering standards – most notably the Institute of Electrical and Electronics Engineers ("IEEE") standard 1547- have prescribed that variable energy resources should trip or cease to energize in an effort to protect the resource whenever a contingency would drive frequency or voltage out of its normal operating range (i.e. a "must trip" requirement). However, in more recent years, the expected performance of these units during and after system disturbances has been re-evaluated and the need for mandatory "ride-through" requirements for variable energy resources in particular has been expressed by the North American Electric Reliability Corporation ("NERC"), acknowledged by the IEEE in their more recent IEEE 1547a standard.*"

4.6 Distribution Resource Planning With DER Systems

4.6.1 Distribution Resource Planning Process in California

In compliance with California's recent law AB 327, which added section 769 to California Public Utilities Code,[81] California IOU utilities are required to file Distribution Resources Plans (DRP) with the CPUC with annual updates. These DRPs are expected to define (electrical) locational benefits and optimal locations for DER systems, to identify possible augmented or new tariffs and programs to support efficient DER deployment, and to remove specific barriers that may be limiting the deployment of DER systems. The DRPs are likely to make use of sophisticated power-flow-based analysis software which would also include the modeling of different types of DER capabilities. The DRPs would provide roadmaps for distribution system planning requirements for a shorter planning cycle of 2 years ahead.

The primary purpose of these DRPs is to require utilities to modify their normal distribution planning process to take into account the benefits that DER systems could provide, particularly if different types of DER systems with compensating capabilities can be placed optimally to help defer construction costs, to improve efficiency, and to ensure safety, while still continuing to provide reliable power. Specifically:

- DRPs would identify optimal locations for the deployment of DERs. In the DRP context, DERs could include distributed renewable generation, energy efficiency, energy storage, electric vehicles, and demand response.
- DRPs would evaluate locational benefits and costs of DERs based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings DERs provide to the grid or costs to ratepayers.

[81] Assembly Bill 327, **https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327**

- The DRP process would propose or identify standard tariffs, contracts, or other mechanisms for deployment of cost-effective DERs that could satisfy distribution planning objectives. It could also identify how to coordinate existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of DERs
- The DRP would identify additional utility spending necessary to integrate cost-effective DERs into distribution planning and would determine what barriers might exist to the deployment of DERs, such as safety standards and reliability requirements.

For instance, if energy storage systems can be coupled with feeders that experience strong fluctuations in power due either to the native load characteristics or renewable generation, then the energy storage system can be used to counter these fluctuations. Locating an energy storage system in the feeder's substation could allow the utility to defer upgrades to the feeder or to avoid adding new voltage management devices.

Another example would be if utilities were able to request that certain DER systems limit their power output at certain times to avoid back feed, to correct serious over-voltage situations, or to stay within the CVR limits. Utilities could either issue commands or could activate the advanced volt-var control function of selected DER systems. This approach would both permit more DER systems to be interconnected on such a "sensitive" feeder as well as avoiding additional utility costs for voltage regulation equipment.

For the purposes of distribution resource planning, "DER" is defined as including not only the generators, energy storage, and controllable loads, but also energy efficiency and demand response. In other words, the concept of "distribution resources" which are available for use in planning is expanded to incorporate any measures that might affect distribution operations.

4.6.2 "More Than Smart" Distribution Planning Principles

A White Paper was developed and edited for the Greentech Leadership Group by Paul De Martini of the Resnick Sustainability Institute at the California Institute of Technology, called *"More Than Smart, A Framework to Make the Distribution Grid More Open, Efficient and Resilient"* which was included as an attachment in the CPUC's DRP order instituting rulemaking[82]. It outlines four key principles around distribution grid planning, design build, operations and integrating DER into operations to create a more open, efficient and resilient grid:

- Distribution planning should start with a comprehensive, scenario driven, multi stakeholder planning process that standardizes data and methodologies to address locational benefits and costs of distributed resources.
- California's distribution system planning, design and investments should move towards an open, flexible, and *node-friendly network system* (rather than a centralized, linear, closed one) that enables seamless DER integration.
- California's electric distribution service operators (DSO) should have an expanded role in utility distribution operations (with CAISO) and should act as a technology-neutral marketplace coordinator and situational awareness and

[82] http://energystorage.org/system/files/resources/102036703.pdf

operational information exchange facilitator while avoiding any operational conflicts of interest.
- Flexible DER can provide value today to optimize markets, grid operations and investments. California should expedite DER participation in wholesale markets and resource adequacy, unbundle distribution grid operations services, create a transparent process to monetize DER services and reduce unnecessary barriers for DER integration.

4.6.3 DRP Economic Analysis

On February 6, 2015 the CPUC released a ruling providing guidance to IOUs with respect to the DRPs that are to be filed by July 1, 2015. The document[83] provides additional guidance to utilities beyond AB 327. The guidance specifics 11 components that are to be included, at a minimum, in the locational DER benefits analysis.

	Locational Value Component
1	Avoided Sub-transmission, Substation and Feeder Capital and Operating Expenditures: DER ability to avoid Utility costs incurred to increase capacity to ensure the system can accommodate forecasted load growth
2	Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures: DERs ability to avoid Utility costs incurred to ensure power is delivered within required operating specifications, including transient and steady-state voltage, reactive power and harmonics
3	Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures: DERs ability to avoid Utility reliability related costs incurred to prevent, mitigate and respond to routine outages (Utilities shall identify specific reliability metrics DERs could improve), and resiliency related costs incurred to prevent, mitigate, or respond to major or catastrophic events (Utilities shall identify specific resiliency metrics DERs could improve)
4	Avoided Transmission Capital and Operating Expenditures: DERs ability to avoid need for system and local area transmission capacity
5	Avoided Flexible Resource Adequacy (RA) Procurement: DERs ability to reduce Utility flexible RA requirements
6	Avoided Renewables Integration Costs: DERs ability to reduce Utility costs associated with renewable integration (for this line item, the Utilities shall attempt to coordinate their efforts with the development of the updated RPS Calculator and the Renewables Integration Charge)
7	Any societal avoided costs which can be clearly linked to the deployment of DERs
8	Any avoided public safety costs which can be clearly linked to the deployment of DERs
9	Definition for each of the value components included in the locational benefits analysis
10	Definition of methodology used to assess benefits and costs of each value component explicitly outlined above, irrespective of its treatment in the E3 Cost-Effectiveness Calculator

[83] Docket R14-08-013 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF

11	Description of how a locational benefits methodology can be a into long-term planning initiatives like the Independent System Operator's (ISO) Transmission Planning Process (TPP), the Commission's Long Term Procurement Plan (LTPP), and the California Energy Commission's (CEC) Independent Energy Policy Report (IEPR), including any changes that could be made to these planning process to facilitate more integrated analysis[84]

Figure 19: DRP locational value components (CPUC DRP Guidance)

Notes:

The Resource Adequacy (RA) program, administered by the CPUC and CAISO is a 1-year forward bilateral capacity market. Utilities must procure sufficient resources to meet their expected peak load. Since it began in 2006, utilities were required to procure system-wide peak-load resources, and local resources as needed in constrained areas. In 2013, a flexible resource requirement was added.

4.6.4 California DRP Requirements Further Discussion & Relevance to other utilities

Investor owned utilities in California must comply with requirements set forth in AB327, passed in 2013, which is the main driver behind the current distribution planning discussion. The CPUC has addressed this legislature-mandated planning process with a proceeding to oversee development of the plans, and may modify the plans after they are submitted on July 1, 2015 as appropriate to:

> Minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.[85]

The CPUC issued plan content guidance[86] to utilities on February 6th, 2015. While the CPUC's guidance continues to emphasize the importance of DER, it also injects elements of overall distribution planning reform that give rise to comparisons with integrated resource planning/least cost planning conducted by many utilities in the west. These IRP processes typically do not address distribution systems to the point of instituting formalized least cost analysis for distribution investments. The CPUC order on DRP states:" *Coordination with the Transmission Planning Process, the Long-Term Procurement Planning Process and the Integrated Energy Policy Report is essential, both as the DRPs are developed, and as they are executed.* [87]

The DRP guidance discusses the tools needed to compare "portfolios of DERs as alternatives to traditional grid infrastructure" – subsequent commission action could formalize such comparisons, not only involving DER, but among traditional grid infrastructure investments themselves. This type of robust planning process may be valuable if current trends continue to drive more generation resources to the distribution

[84] Image of California planning and DRP. http://greentechleadership.org/wp-content/uploads/2014/12/141209-DRP-alignment-with-IEPR-LTPP-TPP-Draft-2.pdf

85 CA PU Code 769. http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=761-788

86 CPUC DRP Guidance filed 02.06.2015 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF

87 page 12, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF

grid and continue modernization efforts to enhance control and reliability, especially as the number of options available stands to only increase, both on the DER side and utility wires side.

There are four main components to the CPUC DRP guidance, of which two are discussed below as they relate do distribution planning methods:

- **Integration capacity analysis**, which determines the capability for the distribution system to host DERs as it exists today. This is to be conducted down to the line section or nodal level and the results are to be presented in worksheets and with online maps.
- **Optimal location benefit analysis**. This is mainly an avoided cost calculation at a more granular level taking into account distribution investments, and the ability to influence DER operations
- DER growth assessments will project 10-year growth scenarios for DER.
- DER demonstrations – a series of pilot projects to show DER effectiveness at meeting grid planning objectives

Integration Capacity Analysis

This analysis determines DER quantities (real power export capability) by location that can operate reliably without impact to the distribution grid when interconnected to each feeder as those feeders exist today. The result represents the DER penetration level that each feeder can host without requiring mitigation, a number that is expected to be different for each feeder and for each feeder section.[88] The CPUC doesn't specify the analysis methodology, other than to say "dynamic modeling methods" are to be used but it does require it to be common across all utilities and results are to be published online in map form.

This analysis an important one for western states and provinces because it is an incremental step a utility can take to determine how far away it may be from a point where DER-driven investments are needed. Development of standardized analysis tools and methods could lower the cost of the analysis process, but there will likely be many utility-specific assumptions and data inputs. If a utility conducts this analysis, the work it does is likely applicable to optimizing distribution planning in general beyond just DER integration.

Distribution Network Topology Interrelation

For many utilities, the distribution network topology changes frequently. Automated and manual switching temporarily reconfigures distribution circuits during outages or for maintenance. Further, circuits may be permanently reconfigured as a standard practice to serve new customer load or decrease phase imbalance. This means identifying a single DER integration quantity for a given circuit is challenged by the existence of connections to other circuits – analysis for a given feeder will no longer be valid if it were to pick up part of an adjacent feeder during an outage, for example.

[88] Work by EPRI has determined a wide variety in the ability of feeders to host DER. EPRI Integrated Grid Cost/Benefit Framework, February 2015

An approach taken by some utilities during distribution planning and operations is to hold back feeder capacity to ensure equipment will not be overloaded during a reconfiguration. HECO states in its DGIP that it holds back 50% of transformer and/or conductor capacity to "allow load transfer from alternate backup circuit configurations during contingencies." For other utilities, distribution system design incorporates fewer reconfiguration capabilities, indicating feeder hold-back quantity is less of a concern, but conversely, emergency reconfiguration options to preserve reliability may be more limited.

The way utilities determine hold back feeder capacity for reconfiguration is an area for further study, especially with increasing DER. Understanding network topology interrelation will only become more significant as utilities install more switching and automation as part of FLISR schemes and grid modernization in general makes for a greater number of topology combinations.

It is likely that California utilities will have to process greater numbers of scenarios than is common practice today. Use of a heuristic approach (e.g. across-the-board hold back figure such as HECO's method) is possible, and may be an appropriate starting point. The relative improvement possible from a more sophisticated method analyzing the multitude of circuit interactions is a question the DRP process will have to address. Utilities across the west will be able to learn from this, and may be able to implement similar solutions, to the extent best practices or standards are developed.[89]

DER Location Assumptions

Because the presence of DER at a given feeder node will have material impact on DER quantities that can be hosted at other nodes, the DER hosting capacity to be published for a given node will be heavily dependent on DER quantities assumed to be present at adjacent nodes in the modeling process. Because the requirement is to determine a quantity of DER by node, development of a base case of DER locations/quantities will be important to this analysis. Two general directions have been identified:

1. Steer DER default quantity assumptions toward advantageous locations (i.e. where greater DER quantities can be connected with fewer reliability issues)
2. Rely on granular DER forecasts (i.e. DER default quantities are located per forecast, which may result in limitations if sufficient quantity are predicted on weaker feeder sections)

There is a logical relationship with the DRP locational benefit analysis, which raises the question of how the two components will interrelate. DER growth by location stands to be influenced by locationally targeted incentives, but uncertainty about timing and adoption of such incentives make incorporation into integration capacity methodologies challenging, as well as how long a particular locational benefit may be valid.

Regardless of the DER base case determination method, the process outcome of producing DER integration quantities will inform a utility about the DER interconnections that can be accepted on a feeder before significant reinforcements will

[89] Some parties in the DRP proceeding suggested the process may benefit if the CPUC or another entity created standards by which utilities would conduct distribution planning.

be required. Making this information available to DER stakeholders, such as the CPUC is requiring utilities to do in map form[90], may serve as a beneficial first step before subsequent cost allocation discussions that would occur should DER penetration increase further and require upgrades. A framework to decide how DER-driven circuit upgrade costs will be allocated may need to be developed, and utilities may find it beneficial to establish and communicate this framework to stakeholders prior to the point in time when these upgrades are needed.

Optimal Location Benefit Analysis

A significant component of the DRP proceeding will be comprised of establishing a method of calculating locational DER benefits for particular time frames. California IOUs will be proposing methods to address this. Many utilities now have AMI data that could inform more granular load forecasting processes including DER and new loads such as EVs.

Circuit Analysis Modeling

Typically, utilities identify worst case scenarios that determine the conditions under which circuits are modeled. Typically the worst case used is the peak load forecast for a given feeder, the condition utilities have always built distribution systems to handle. Limiting analysis to peak load conditions could mean engineers will overlook other intervals that may be warrant closer examination and may require mitigations that are not required during peak load hours. The variability of DERs such as Solar PV can cause problems such as over or under voltage that may be more severe during times of lighter feeder loading and could contribute to DER integration limits or require mitigation.

Some software vendors offer the capabilities to run simulations across a range of inputs, such as changing conditions over time (time-series modeling). The CPUC does not appear to require utilities to use time-series modeling in DRP analysis, and it is not known the extent to which this or similar methods will be needed as part of the integration capacity analysis. It has been suggested by researchers that use of time-series or similar methods will likely be necessary to appropriately scrutinize distribution systems with high DER penetration.[91]

A barrier often encountered to incorporating a larger range of modeled states is determining the inputs, which could be historical data, or use of probabilistic methods for such study cases as equipment failure, DER production or topology configurations. Many utilities now have AMI data to provide granular historic data that could be used as in input to time-series modeling.

Increasing the number of distribution system configurations and conditions studied allows utilities to evaluate the costs and benefits of deploying both emerging and traditional solutions to find the least-cost best-fist solution in a similar fashion as is

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[90] California utilities currently make information about accessibility of potential PV sites to distribution feeders (Renewable Auction Mechanism Maps)
http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/index.page
[91] Emma Stewart LBNL Paper
http://eetd.lbl.gov/sites/all/files/lbnl_6708e.pdf

used for IRP analysis. For example, a utility with a weakly meshed distribution network may find that adding connections between feeders and switching automation equipment to make the best use of load diversity among feeder line sections could reduce capacity related expenditures. But such an analysis may require use of more complex distribution planning models, and real-time contingency analysis and mitigation tools to successfully implement.

Decisions about formalized distribution planning processes that require utilities to assess all the options before making distribution investments need to weigh the additional cost and complexity against potential benefits. Due to the additional complexity that may be introduced into distribution planning processes, a threshold level may need to be developed to identify the types of investments to be considered by a DRP and those that may continue to be conducted through the utilities' normal course of business.

4.6.5 Smart Meters Data for Distribution System Planning

Smart meters can collect data that can be used for both long term and shorter term planning. This data consists primarily of revenue energy readings taken periodically, such as every 5 to 15 minutes or every hour. However, other data can also be retrieved, such as outage indicators, voltage levels, and peak demand within a time period. In the future, some smart meters may be required to track actions by DER systems, such as whether they responded to utility commands for energy and ancillary services.

Although some investigations have been undertaken to see if the smart meter AMI systems can also support near-real-time interactions with DER systems, it appears that only limited data exchanges may be possible due to the configurations and limited bandwidths of many of the AMI communication systems, but this situation may change over time.

4.7 Interoperability, DER Interconnection, and Communication Standards and Technologies

4.7.1 Interoperability for Distribution Utilities

Interoperability – What is it and why it is important for DER & distribution utilities

Utilities in this country have for many years, been required to choose a single vendor for major purchases. For example, when building a large turbine generating facility, an RFP is issued and multiple vendors bid. The winning bidder gets the huge contract, but they also often get a 40 year+ marriage to that utility for operational support, consulting, spare parts and preventive maintenance on the turbine.

This philosophy, if carried into DER development and distribution equipment policies will limit competition, cause increased costs for utilities, and their customers, and ultimately restrict development of innovative products and services.

Interoperability opens the door for multiple vendor solutions, multiple vendor competition, lower costs and innovative products and services. Every energy policy maker, utility regulator or PUD board member should embrace interoperability, promote it, fund it and require it in utility RFPs.

Interoperability is composed of three important elements:

1. A shared understanding of the information exchanged between devices & systems
2. An agreed expectation for the response to the information exchange
3. A requisite quality of service: reliability, fidelity, and security

Shared Understanding of Information Exchanged – Develop Common Language & Methods

The Common Information Model (CIM) is a standard officially adopted by the International Electrotechnical Commission (IEC) for application-to-application interactions. It aims to allow application software and systems to exchange information about an electrical network. IEC 61850 is the IEC's standard information model for interactions with field equipment. This standard ensures interoperability between systems and devices as well as between devices.

Generally, the IEC CIM and the IEC 61850 standards have helped to reduce the communication issues associated with Device-to-Device and Software-to-Device communications as global manufacturers have moved in supporting that standard. In the US, not all manufacturers and certainly not many US utilities have had their systems built to these IEC standards.

For Example: *Most utility SCADA engineers have been trained by industry or within the utility. As a result, a SCADA-employee in a utility recruited from a related industry has their own syntax and method of doing things. Many pieces of programming for devices in a substation or distributed generator controller is unique—a so called "one-off." This means that when changes need to be made by a SCADA engineer, other than the one who programmed the equipment originally, the new engineer must spend weeks going through every data point and every connection interface and programming code to understand what the original programmer did. Then, that person must rewrite that code—still with their own method of doing things, to perform the needed functions. The result: another "one-off" programming function in the utility devices. Many utilities have developed their own "standards" for communication in devices, but moving from one utility to another is not standardized. The most common form of standardization for utilities is staying with the same vendor's product lines. That way, they require their vendor of choice to maintain interoperability of their products.*

This approach is no longer sustainable with the vast numbers of vendors and products available in the DER and smart grid space. It is no longer the least cost option.

Interoperability Standards, an agreed expectation for the response to the information exchange and a requisite quality of service: reliability, fidelity, and security

To be considered interoperable, interactions between systems, applications, and/or devices must share three things between them:

1. A Shared Meaning of Content (Common Information Model)
2. Properly Formatted Messages (Common Language)
3. A Collaboration Agreement that Specifies the behaviors and interface (Common Agreement)

A “Standard” is a written document that specifies all three requirments, it is a technical specification, usually produced by a Standards Development Organization (SDO). There are three general types of SDOs that enables wide adoption of technology by multiple competing and complimentary vendors:

1. Recognized standards bodies (NIST, IEC, IEEE, ANSI, etc.)
2. Trade alliances (Zigbee, Wifi, OpenADR, MultiSpeak)
3. Vendor (Siemens, ABB, Microsoft, etc.)

In the case of item 3, Vendors must agree to license or provide open source specifications to other vendors to allow interoperability, otherwise their communication is proprietary and requires a translation from one vender to another.

Embedded in standards or by use of co-dependent standards, the concept of quality of service, reliability, fidelity and security are key requirements in the the Standard between devices.

Interoperability Standards Maturity Levels and Standards Development Organizations

Historically, Interoperability Standards and their Standards Development Organizations, like Trade Alliances, are poorly funded and supported. Large national and international vendors want their product concepts to be adopted as the “De-facto Standards,” that way they retain a potential revenue source for licensing to all potential competitors. So, they either don’t participate and fund SDOs or they participate with limited cooperation or an agenda for favoring their product formats – drastically extending the approval time-frame for any particular standard by an SDO.

As a result, it is difficult for an open Standard to reach full maturity. Standard maturity is defined in four steps:

1. Proprietary Interfaces – No Standard exists so a custom integration must be performed for devices to communicate and interoperate (Common for Inverters)

2. Interface Mapping – A basic Standard is forming so that a published list of communication registers or inputs and outputs can be mapped or transformed to link with other devices. (SunSpec Alliance Standard for Inverters)

3. Common Model – A more detailed Standard is formed with a common model structure of the way the data/information is organized and a standard naming convention is documented.

4. Plug & Play – A Standard has reached final maturity with a published format with a Shared Meaning of Content, Properly Formatted Messages, and detailed Collaboration Agreement that specifies the behaviors/security and interface.

Plug & Play Standards are the ultimate goal to assure interoperability between systems and devices. Getting to that level of Standard is challenging for even the best funded SDO. That is why, more support is needed from the beneficiary of standards, such as electric utilities and their customers – relying on vendor only support for SDOs results in poor quality standards and lack of movement to Plug & Play maturity.

With Plug & Play maturity comes the concept of "interchangeability" between devices. Interchangeability allows DER devices and distribution equipment to be swapped out to other vendor devices without having to undergo a major re-engineering project. This is because the interfaces, communications, security and other functions have all been coordinated between vendors and devices. Interchangeability allows utilities to purchase lower cost products with many vendor choices and allows easier market entry for new vendors – lowering the cost for utility customers.

There are two key recognized interoperability standards organizations that are involved with DER development. These are a bit of an exception to the poorly funded and supported field of Standards Development Organizations. They include:

- **International Electrotechnical Commission (IEC)**, a non-profit, non-governmental international standards organization prepares and publishes International Standards for all electrical, electronic and related technologies. There are IEC standards for a vast range of technologies related to power generation, transmission and distribution, all the way down to home appliances, office equipment, semiconductors, fiber optics, batteries, solar energy, nanotechnology and marine energy as well as many others. The IEC also manages three global conformity assessment systems that certify whether equipment, systems or components conform to its International Standards. Many countries have participated in the development of IEC standards, including the US. But not all industries in the US have become involved with the IEC.
- **Institute of Electrical and Electronics Engineers (IEEE)** (pronounced "i triple e") is another key standards-making organization that is international in scope but is primarily looked to by the US. The IEEE standards involve a wide range of industries, including not only power and energy, but biomedical, healthcare, Information Technology (IT), telecommunications, transportation, nanotechnology, and many others. In 2013, IEEE had over 900 active standards, with over 500 standards under development. Some of the more relevant IEEE standards are IEEE 1815 (commonly called DNP3) for SCADA interactions, the IEEE 1547 group of standards for DER Interconnection, the IEEE 2030 series, and the IEEE 802 LAN/MAN group of standards which includes the IEEE 802.3 Ethernet standard and the IEEE 802.11 Wireless Networking standard.

More Information on Interoperability Standards

The GridWise Architecture Council (GWAC) is a team of industry leaders who are shaping the architecture and guiding principles of a highly intelligent and interactive electric system. They have developed a structure that should lead to better communications and interoperability of systems and devices for a smarter grid by coordinating organizational, informational and technical elements for clear communications and functionality. One of their key strategies is what is known as the GWAC Stack. The GWAC Stack is an organizational structure that outlines the relationship of economic and regulatory policy through all the methods of communications right down to how devices are physically connected to each other.

A key output from GWAC is the Context-setting Framework for interoperability and "Introduction to Interoperability and Decision-Maker's Interoperability Checklist"[92] (see Figure 20).

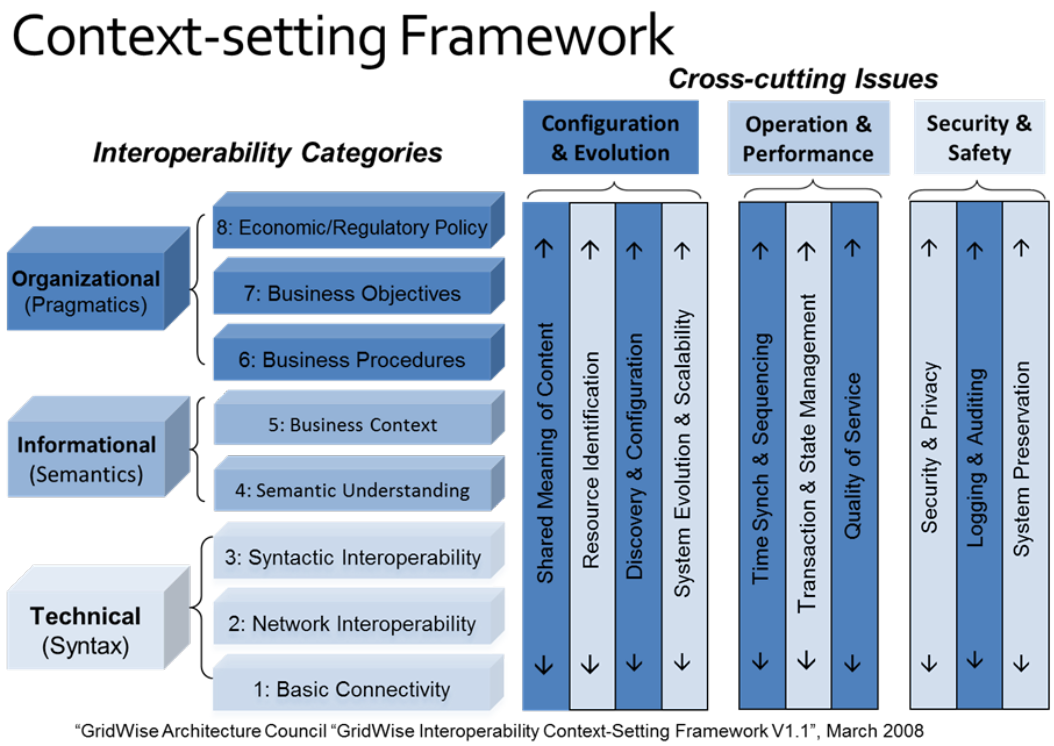

Figure 20: GWAC Stack Context-setting Framework

4.7.2 IEEE 1547 Status

The interconnection requirements of most jurisdictions are based on the Institute of Electrical and Electronics Engineers (IEEE) 1547 DER interconnection standard. Section 1254 of the Energy Act of 2005 requires IEEE 1547 unless other requirements are developed by local PUCs:

> ***SEC. 1254. INTERCONNECTION.*** *(a) ADOPTION OF STANDARDS.—Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)) is amended by adding at the end the following: (15) INTERCONNECTION.—Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term "interconnection service" means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and*

[92] http://www.gridwiseac.org/pdfs/gwac_decisionmakerchecklist_v1_5.pdf

procedures shall be established whereby the services are offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

At the time it was first developed, high penetrations of DER systems were not yet foreseen as a major issue, so the current version of IEEE 1547(2003) requires that systems interconnected to the distribution grid automatically shut-off in the event of even a brief power system anomaly. Therefore that version of the IEEE 1547 standard prevents DER systems from providing any type of grid support or from "riding-through" short-lived anomalous conditions, and thus prohibits DER systems from actively participating in distribution system operations.

As higher penetrations of DER systems started to have undesirable impacts on the grid and as the potential benefits of emerging DER capabilities became better understood, for instance, during California's Smart Inverter Working Group (SIWG) effort, the IEEE recognized that an update to the 1547 interconnection standards was required. In mid-2013 the IEEE members of the 1547 standards community initiated a "fast-track" amendment to IEEE 1547, labeled IEEE 1547a.

Balloted and approved by IEEE in September 2013, IEEE 1547a[93] is a "permissive" update to the existing IEEE 1547: its main purpose is to permit some DER actions that are not currently allowed in the IEEE 1547 standard. For example, IEEE 1547a permits the DER system to actively regulate voltage at the point of common coupling under certain conditions. IEEE 1547a also permits the high and low limits of voltage and frequency to be extended for specific time periods so that voltage and frequency ride-through by DER systems can occur.

Additional related efforts include the development of IEEE 1547.1a[94] and IEEE 1547.8.[95] IEEE 1547.1a will provide the testing requirements for IEEE 1547a, and therefore will serve as an addendum to the original IEEE 1547.1 testing requirements. Coordination between the UL 1741 testing and certification requirements and these IEEE testing requirements are taking place.

Additional IEEE 1547 series standards have also been developed over the last few years to address specific types of issues, ranging from islanded grids, to communications, to the types of studies needed to ensure safe interconnections, and to high penetrations of DER (see Figure 21). IEEE 1547.8 provides recommended practices for high penetrations of DER and is still in progress, but is expected to extend the permissive capabilities in IEEE 1547a with specific recommendations for DER functions and settings in high-penetration scenarios. In addition, the base IEEE 1547 standard is being updated to reflect the new DER requirements, with expectations of rapid progress given both California's and Hawaii's experiences.

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[93] IEEE Std P1547a/D2□Amendment, "*Draft Standard for Interconnecting Distributed Resources with Electric Power Systems Amendment 1,*" June 2013. The standard was balloted and passed with 91% approval by IEEE members. Final release of the amendment is expected by the end of 2013.

[94] Preliminary work has taken place but no actual document has been produced

[95] IEEE P1547.8™/D5.0, "*Draft Recommended Practice for 1 Establishing Methods and Procedures that Provide 2 Supplemental Support for Implementation Strategies 3 for Expanded Use of IEEE Standard 1547*", July 2013

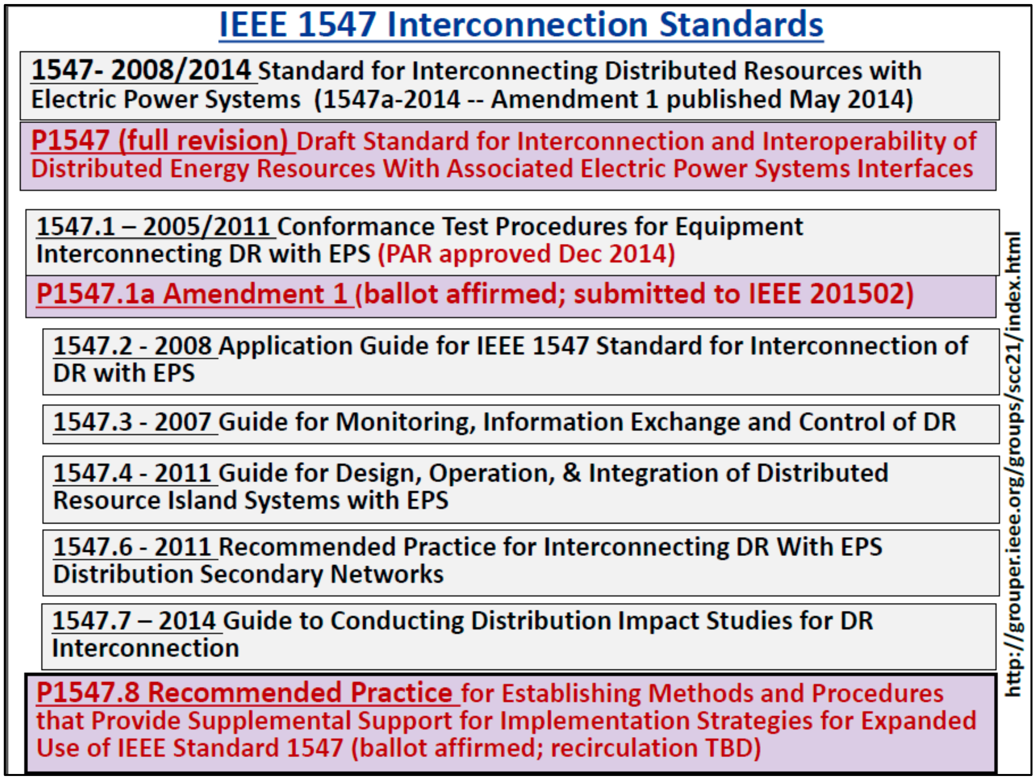

Figure 21: IEEE 1547 series of DER Interconnection Standards

The IEEE standardization process necessarily takes a long time to ensure the recommendations are both appropriately constrained and yet flexible enough for utilities operating under a wide range of grid conditions, from the Hawaiian Islands to the congested East Coast. However, California's expectations for distributed generation and the observed impact of higher penetration levels in other countries led the CPUC and the CEC to establish the SIWG and pursue development of the technical steps needed to optimize the role of distributed generation in supporting distribution system operations.

One of the areas of discussion in the updating of IEEE 1547 is exactly where the focus should be: the PCC (as in the IEEE 1547:2003) or the ECP (where testing of DER systems must be done) or some combination. Some inverter-based DER systems may be directly connected to the utility grid, while others may be "behind the meter" in a commercial or industrial facility or as part of a microgrid:

- **Point of Common Coupling (PCC)**: For those ECPs that demarcate the point between a utility EPS and a plant or site EPS, this point is identical to the point of common coupling (PCC) defined as "*the point where a Local EPS is connected to an Area EPS*" in the IEEE 1547 "Standard for Interconnecting Distributed Resources with Electric Power Systems".
- **Electrical Coupling Point (ECP)**: In either case, the inverter-based DER systems will have a point of electrical connection, which is defined as: *"The electrical coupling point (ECP) is the point of electrical connection between the DER source of energy (generation or storage) and any electric power system (EPS). Each DER (generation or storage) unit has an ECP connecting it to its local power system; groups of DER units have an ECP where they interconnect*

to the power system at a specific site or plant; a group of DER units plus local loads have an ECP where they are interconnected to the utility power system.

Many functions reflect conditions at the DER's ECP. For instance, the measured voltage levels used for volt-var management are those at the DER's ECP. Other functions would need to reflect the PCC, such as limiting output at the PCC.

ECPs are also hierarchical, such as in a university campus environment where the PCC is between the campus and the utility, but where multiple ECPs exist for the different DER systems located in different university buildings. Requests for DER actions can be made at the highest level, say for volt-var settings at the PCC. The university DER energy management system would then allocate different volt-var settings for each of the DER ECPs to reflect their DER capabilities, the needs/desires of the university buildings (people), and the overall campus reliability and efficiency requirements.

This hierarchical concept is illustrated in Figure 22.

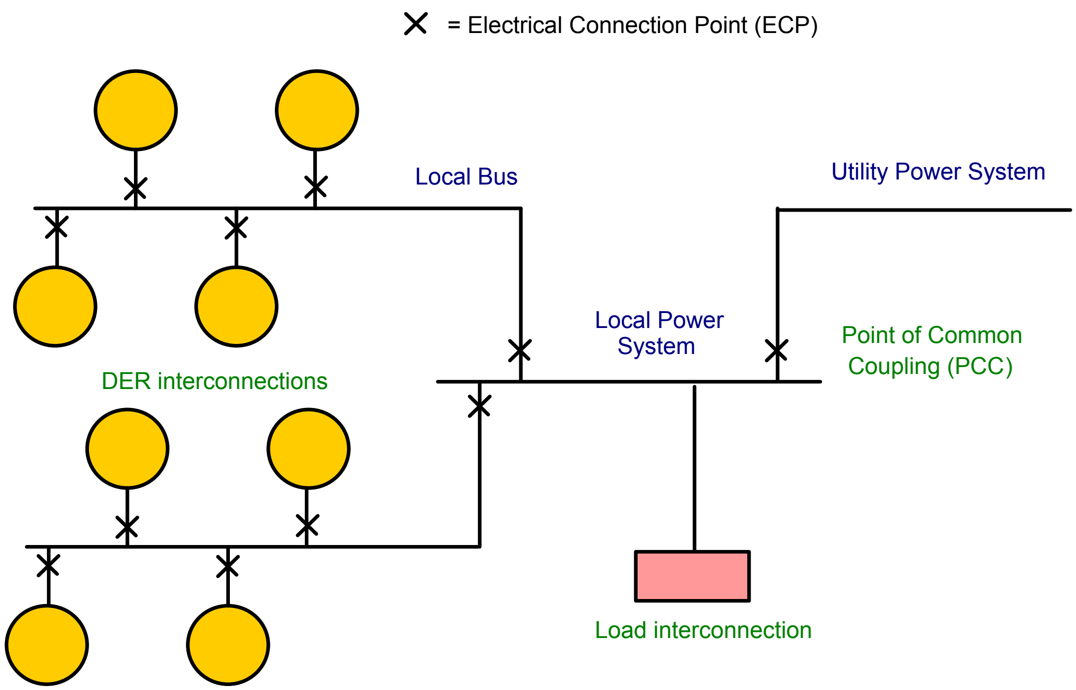

Figure 22 – Electrical Connection Points (ECP) and Point of Common Coupling (PCC)[96]

4.7.3 UL 1741 and IEC 62109 Certification Testing for Product Safety

UL 1741 is a product safety standard that defines the testing and certification requirements for DER systems that must meet the IEEE 1547 requirements. This UL1741/IEEE1547 combination of requirements is used to evaluate grid tied DG products for both electrical safety and utility interconnection.

The standard covers PV systems, fuel cells, microturbines, wind and hydro turbines, engine gen-sets, and other inverter-based DER systems. In many jurisdictions,

[96] Xanthus Consulting International, 2015

compliance with UL 1741 testing is mandatory for certifying that these DER systems meet the interconnection requirements.

The areas covered UL 1741 include electrical ratings requirements for components, electrical and environmental requirements for enclosures, and electrical spacings. It also addresses fire hazards related to operating temperatures, short-circuit situations, and overload conditions. Software is also certified and tested, since it is viewed as the main critical component of a utility interactive inverter as the software often controls most of the utility interaction of the inverter.

As DER certification and testing has become increasingly important worldwide, the US is moving to adopt IEC 62109. IEC 62109 was born out of UL1741 and was expanded / updated to address cutting edge safety aspects of PV power conversion equipment. UL was granted rights to develop UL 62109-1 & UL62109-2; UL62109-1 has been published and UL62109-2 is expected to be published Q1 2015. These will then become the equivalent IEC 62109-1 and -2 standards. Although IEC 62109 is focused only on PV systems, it can be applied to other inverter-based DER systems.

4.7.4 IEC 61850 Standard for Substation Operations

The IEC 61850 standard manages the control functions and data flow of information primarily within electric utility substations, but has recently been extended to DER and other services. Each fully deployed 61850 system manages the integration of numerous multifunctional Intelligent Electronic Devices (IED) located at various locations within a substation. The IEDs typically implement advanced distributed protection and control functions, for example over and under current protection in a relay IED which can command an electronically operated circuit breaker to open and/or close.

An IEC 61850 system deployment is composed of a communications “Station Bus” which is a local area Ethernet network that allows the substation Human Machine Interface (HMI) to view information from and issue commands to the IEDs in the substation. The Station Bus may also include a gateway for the System Control and Data Acquisition (SCADA) system to access the substation from the utility’s system control center. This is a fairly common type of Ethernet network used today by many utilities in the US, except the DNP3 protocol is most likely to be used to communicate to the IEDs instead of the IEC 61850 communications standard.

The true value of a 61850 deployment occurs when the “Station Bus” is combined with the “Process Bus.” The Process Bus is another network deployment that allows very rapid communications among the IEDs, generally without human intervention. (See Figure 23)

Binary Units connect to controllable devices such as switches or circuit breakers and allow detection of a signal representing an open or tripped circuit breaker. These Binary Units are connected to Merging Units that process information from different types of sensors. Binary and Merging units may be combined into a single device called a “Process Interface Unit” (PIU). PIUs may take a Generic Object Oriented

Substation Event (GOOSE) message generated by an IED and take action by opening or closing a circuit breaker as a result of an event such as an electrical fault on a distribution feeder.

Because the IEC 61850 standard was designed to eliminate the historic requirement of single vendor solution for interoperability, a utility using the standard can now have interoperability using different vendor's IEDs and move much closer to allowing interchangeability of one vendor's IED with another vendor's IED. To make this work, the IEC 61850 uses a standard naming convention and standard data objects that can be deployed in any vendor's products.

Current deployments using DNP3, require a utility to keep detailed records of each data point of communication. The IEC 61850 standard requires each IED to self-report each data point used in the IED. This standard requirement makes a safer and easier to modify device because points lists are self-reported and do not require documentation that may fail to get updated by operators when changes are made over time.

In a traditional substation, all devices' communications messages were sent over copper wires, significantly adding to the complexity of the installation. By using the Process Bus and Station Bus networking, most of the wiring for communications can be eliminated and instead, much fewer fiber-optic cables can be used carrying much more information and adding to safety. The fiber-optic cables transfer the GOOSE messages of control & information signals to IEDs thereby eliminating the hundreds of wires used for dry contact messages to a typical RTU in existing substations.

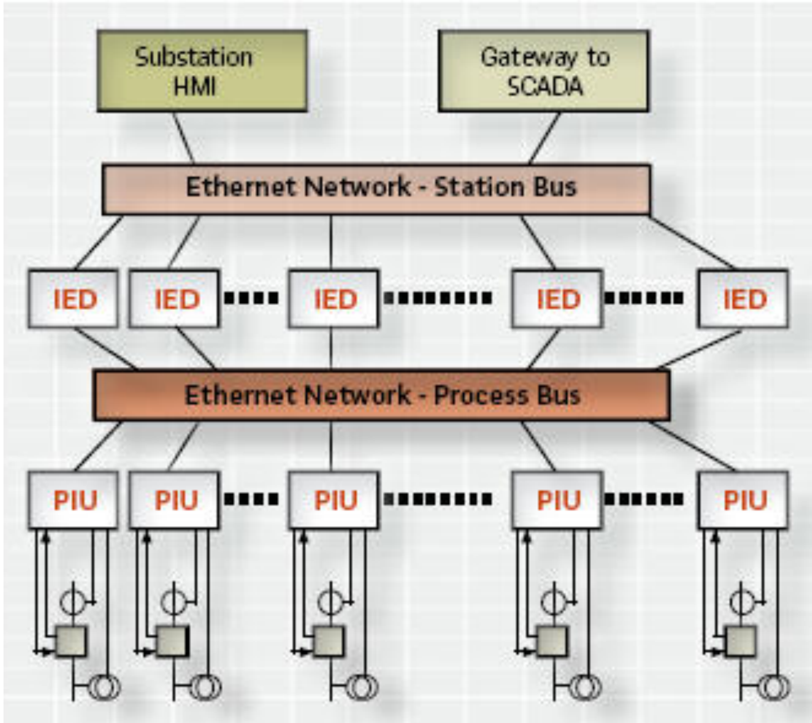

Figure 23: 61850 Substation Configuration[97]

In order for the Station Bus to work smoothly, designers of IEC 61850 moved away from the traditional Client/Server model, whereby the IED is the Server and the HMI is the client in a DNP3 installation. Instead, IEC 61850 utilizes a peer-to-peer or publisher/subscriber communications type. With publisher/subscriber communications, an IED will publish a piece of information; another IED is a subscriber to that information. Publisher /Subscriber communications are used to perform protection, control, monitoring and recording functions.

IEC 61850 functions are defined in the standard, such as a circuit breaker control function and all the data elements associated with a circuit breaker, such as position(open/closed), tripped, racked-out(for safety) and charged (typically a spring is compressed that could spring the breaker open if a trip signal is received). All functions are further broken into their smallest parts, these are called Logical Nodes. A circuit breaker is labeled XCBR1 and is a defined logical node in IEC 61850.

Figure 3 shows a breakdown moving from the physical device (the IED) to the Logical Device (the Relay function) to the Logical Node (the Circuit Breaker) and finally to the specific data objects in the standard.

Merging Units

A Merging unit in an IEC 61850 implementation allows multiple analogue inputs from devices like Current Transformers (CTs) and Voltage Transformers (PTs). It also

[97] "IEC 61850: Interoperability, Principles and Benefits" by Christoph Brunner, Switzerland and Alex Apostolov, USA in PacWorld Magazine, summer 2009 edition

merges discrete binary inputs with analog inputs to produce multiple time synchronized serial unidirectional multi-drop digital point to point outputs. A Merging unit is similar to an analog input module of a conventional protection or other multifunctional IED. The major difference is that the Process Bus network performs like a digital data bus between the Merging Unit and the protection function objects in the IED.

In IEC 61850 all Merging Units are time synchronized with accuracy better than 1 microsecond and uses a fixed number of samples per cycle at the nominal frequency. They are transmitted from the merging unit (publisher) to all IEDs (subscribers) that need these sampled values.

There are two modes of sending sampled values between a merging unit and a IED:

- For protection applications the merging units send 80 samples/cycle in 80 messages/cycle, so an Ethernet frame has the MAC Client Data that contains a single set of Voltage and Current samples.

- For waveform recording, 256 samples/cycle are sent in groups of 8 sets of samples per Ethernet frame sent 32 times/cycle.

This design standard allows very fast communications of large amounts of data within the Ethernet framework.

IEC 61850 benefits

- Utilities that have moved to the IEC 61850 standard have identified the following benefits of the move:
- Reduced dependence on multiple communication protocols
  High degree of integration and interoperability, although challenges still exist
  Reduced construction cost by eliminating significant amounts of copper wiring by moving instead to fiber-optic based communications issuing the GOOSE messages.
- Flexible programmable protection schemes
- Communication network speeds in lieu of numerous hard-wired connections
- Advanced management capability
- High-speed, peer-to-peer communications
- Improved security/integrity
- Reduced construction and commissioning time

The bottom line benefits of the standard result in savings in engineering time, savings in capital costs, and savings in on-going operation & maintenance costs. In exchange, utilities have easier access to real-time information and that opens a world of possibilities for the evolving smart grid, including enhanced DER management.

4.7.5 IEC 61850 as Information Model for DER

IEC 61850 was originally developed as an information model and protocol for substation automation. However, it became clear that this information model could be extended to cover DER systems and eventually the advanced “smart inverter” functionality as well.

The IEC 61850-7-420[98] standard on information models for DER was published in 2009. It covers the management of DER systems as well as details on reciprocating engines, fuel cells, microturbines, photovoltaics, combined heat and power, energy storage, and other generation and storage systems connected at medium and low voltage levels.

IEC 61850-90-7[99] was published in 2013. It provides the information models for inverter-based DER functions, covering the following[100]:

- Immediate control functions for inverters
  - Function INV1: connect / disconnect from grid
  - Function INV2: adjust maximum generation level up/down
  - Function INV3: adjust power factor
  - Function INV4: request active power (charge or discharge storage)
  - Function INV5: pricing signal for charge/discharge action
- Volt-var management modes
  - Volt-var mode VV11: available vars support mode with no impact on watts
  - Volt-var mode VV12: maximum var support mode based on WMax
  - Volt-var mode VV13: static inverter mode based on settings
  - Volt-var mode VV14: passive mode with no var support
- Frequency-watt management modes
  - Frequency-watt mode FW21: high frequency reduces active power
  - Frequency-watt mode FW22: constraining generating/charging by frequency
- Dynamic reactive current support during abnormally high or low voltage levels
  - Dynamic reactive current support TV31: support during abnormally high or low voltage levels
- Functions for “must disconnect” and “must remain connected”
  - “Must disconnect” MD curve
  - “Must remain connected” MRC curve
- Watt-triggered behavior modes
  - Watt-power factor WP41: feed-in power controls power factor
  - Alternative Watt-power factor WP42: feed-in power controls power factor
- Voltage-watt management modes
  - Voltage-watt mode VW51: volt-watt management: generating by voltage
  - Voltage-watt mode VW52: volt-watt management: charging by voltage
  - Non-power-related modes
  - Temperature-function mode TMP: ambient temperature indicates function

98 https://webstore.iec.ch/publication/6019
99 https://webstore.iec.ch/publication/6027
100 http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/PAP07Storage/Advanced_Functions_for_DER_Inverters_Modeled_in_IEC_61850-90-7.pdf

    - Pricing signal-function mode PS: pricing signal indicates function to execute

- Parameter setting and reporting
    - Function DS91: modify inverter-based DER settings
    - Function DS92: event/history logging
    - Function DS93: status reporting
    - Function DS94: time synchronization

- Scheduled commands, in which a schedule is sent to the inverter with commands scheduled for particular times. These commands can also invoke pre-established parameters. Examples include:
    - Week-day schedule for volt-var actions
    - Weekly schedule for frequency-watt actions

The IEC 6150 information models have been "mapped" to different protocols:

- IEC 61850-8-1 MMS (Manufacturing Messaging Specification). It is the primary and most implemented mapping for substation automation
- IEEE 1815 (DNP3) and IEEE 1815.1 (DNP3 mapping to IEC 61850)
- IEEE 2030.5 (SEP 2.0 – Smart Energy Profile Application Protocol)
- IEC 61850-8-2 (pending) Web services (Extensible Messaging and Presence Protocol (XMPP), OPC/UA, or other).

The IEC 61850 information model has been selected as providing the basis for the communications required for the California SIWG Phase 1 and Phase 3 functions, while IEEE 2030.5 has been selected as the default protocol

4.7.6 IEC 61970/61968 Common Information Model (CIM) for Transmission and Distribution Applications

The IEC 61970 Common information model (CIM) is a standard developed by the electric power industry to allow power system application software to exchange information about power system components in an electrical network. In particular, it has developed Unified Modeling Language (UML) structures for utility organization information, power system topologies, and market exchange information. It was developed to standardize the information flows among different applications in Energy Management Systems (EMS), primarily at the transmission level. For example an economic production cost model (8760 hours) can export its data to a reliability power flow model with minimal use of manual processes.

CIM can also be used between planning and operations applications. For instance, CIM is being used by ERCOT to exchange the shared transmission network model between operations and planning. The transmission owners in the ERCOT footprint share transmission network topology data with ERCOT via CIM compliant data exchanges to ensure that all topology change is reflected in ERCOT's real time operations model as well as the planning model. This concept is being studied by EPRI and others for organizational benefits such as reduction of duplicative manual processes conducted by engineering staff.[101]

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[101] American Electric Power example:
http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002003056

The IEC 61968 CIM standard for distribution management has focused on the exchange of messages between various distributions applications. It has recently focused on the exchange of messages between AMI head ends and other metering applications, such as meter management and billing. However, it has not yet been widely adopted by distribution planning and operations software vendors or utilities.

4.7.7 Distribution Utility Communication Requirements

Distribution utilities can use many different types of communications systems for distribution operations. The selection of which media and what types of networks depend upon the performance requirements of the distribution applications. For protection functions, the communications channels typically need to support millisecond latency. For SCADA interactions with distribution substations, usually the communications networks support latency and performance requirements in 1 – 10 seconds. For any communications between the control center and equipment on feeders, the latency requirements are typically much longer, with 10s of minutes seen as adequate. In distribution automation, the communications between field equipment could be within a few seconds and a few minutes. A detailed discussion of these communications performance requirements can be found in IEEE 2030.

Communication networks for non-SCADA interactions between utilities and meters, DER systems, or other customer-sited equipment can use many different types of media. Utility backbone communication systems can be utility-owned or could be provided by telecommunication providers. AMI systems use combinations of backbone systems and radio-based media for the "last-mile" to reach the customer meters. These meters can then be read every 5, 15, or other periodicity, while additional data such as outages and voltage levels can also be retrieved.

For DER system communications, cellphone systems are commonly used between utilities and DER systems, although the public Internet and other public telecommunication provider networks are also possible. These DER communications networks provide the means to request or even command DER systems to take specific actions, such as turning on or off, setting or limiting output, providing ancillary services (e.g. volt-var control), and other grid management functions.

4.7.8 Smart Grid Communication Protocol Standards

Communication protocols provide the means to exchange data electronically and can be viewed as electronic languages. Just as there are many different human languages, there are many communication protocols, often developed to meet different types of requirements. Communication protocols also often have a life cycle of being invented, used for a while, and then falling out of favor, typically because the state-of-the-art has developed new capabilities or technologies.

Communication protocols are also usually defined in layers although usually some of the layers can be combined in a particular standard. Common layers (although these too can include sublayers) consist of:

- **Information models and profiles**, which identify the types of data and their abstract formats, with a focus on the business purpose of the data. For instance, an information model can identify the data elements of “phase A voltage”, “price for energy”, and “customer name”.

- **Application layer protocols**, which define the message structures (header, body, cyber security parts), services (read, write, get, post, etc.), and translation of the abstract data formats into “bits and bytes”.
- **Transport layer protocols**, which provide the mechanisms for navigating through networks, such as across the Internet or within a local area network. The most common protocols used are the Internet Protocol (IP) which identifies the address of systems and devices, and the Transport Control Protocol (TCP) which ensures that even long messages that have been cut into pieces (e.g. for efficiency and for sharing the media) are correctly reassembled at the far end. Another common protocol is Ethernet, used primarily on local area networks.
- **Media-specific protocols**, which are tailored to manage the different characteristics of various media, such as fiber optic cables, microwave systems, WiFi, Bluetooth, etc.

Figure 24 and Figure 25 include some of the more commonly used communication protocols for Smart Grid applications. Of these, the most frequently used by utilities for distribution and DER communications are:

- **IEEE 1815 (DNP3)** is the communication protocol most North American utilities use for SCADA communications. It does not include an information model
- **IEC 61850** is the international information model and protocol for DER and distribution automation. Even when IEC 61850 is not used as the protocol, the IEC 61850 information model forms the basis of other protocols used for communications with DER systems.
- **IEEE 2030.5 (SEP2)** is a new protocol that was developed for home area networks but may be used for other applications such as utility interactions with DER systems. Its information model is based on IEC 61850.
- **OpenADR** is another recent protocol, developed explicitly for providing pricing data in demand response applications.

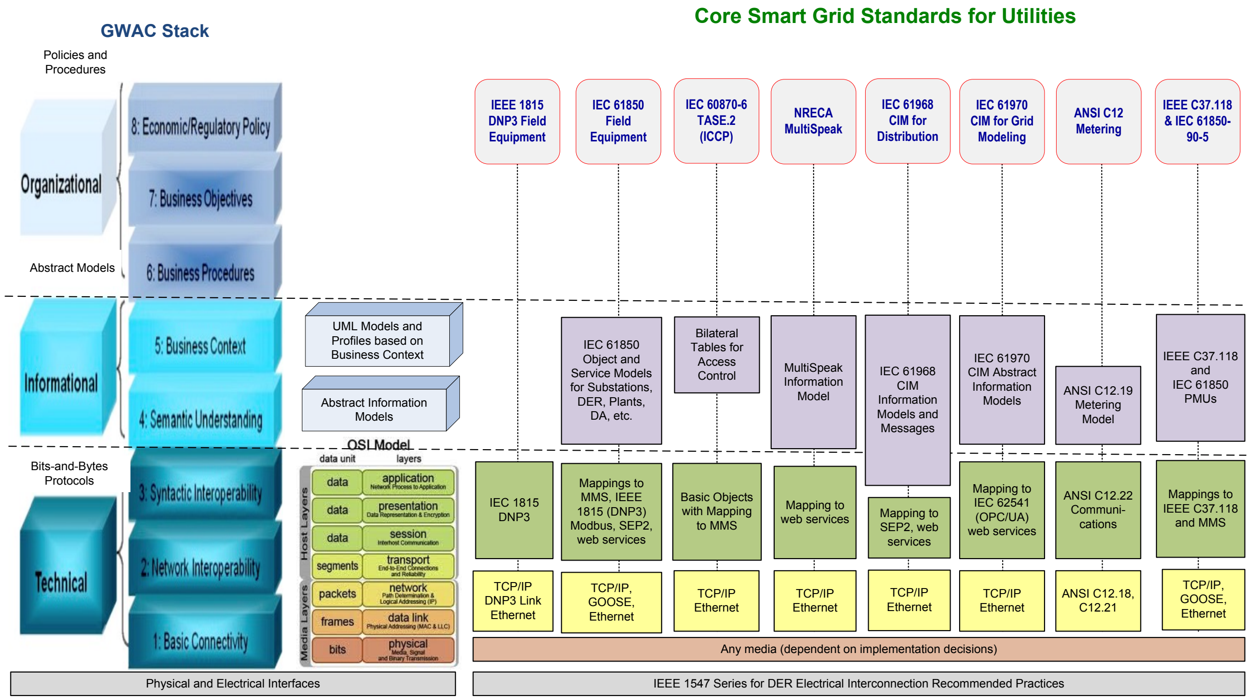

Figure 24: Smart Grid standards commonly used by utilities[102]

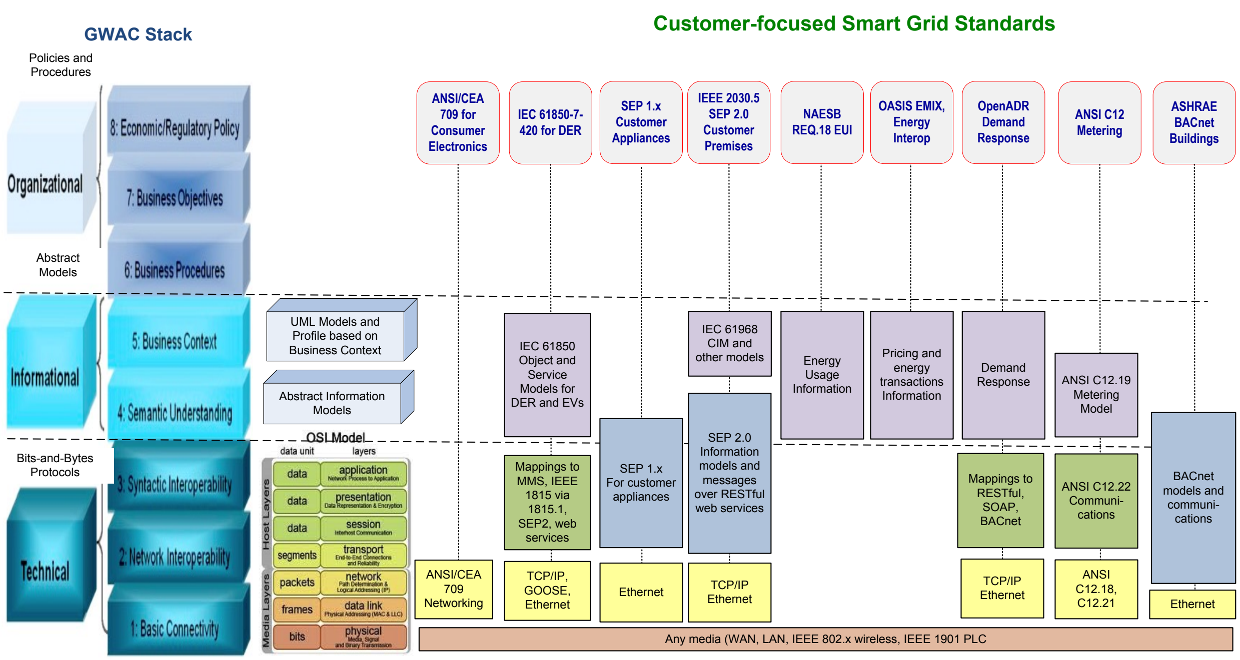

Figure 25: Smart Grid standards commonly used in customer communications[103]

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[102] Xanthus Consulting International, 2015
[103] Xanthus Consulting International, 2015

4.8 Cyber Security Issues Affecting Distribution

4.8.1 Cyber Security Vulnerabilities and Attacks

The threats can be realized by many different types of attacks, some of which are illustrated below in Figure 26. Often an attack takes advantage of a vulnerability, which may be due to human carelessness, an inadequately designed system, or circumstances such as a major storm. As can be seen, the same type of attack can often be involved in different security threats. This web of potential attacks means that there is not just one method of meeting a particular security requirement: each of the types of attacks that present a specific threat needs to be countered.

Although importance of specific cyber threats can vary greatly depending upon the assets being secured, some of the more common human and system vulnerabilities that enable attacks are:

- **Lack of security**: Security, even if it exists, is never "turned on".
- **Indiscretions by personnel**: Employees write down their username and passwords and place them in their desk drawer.
- **Simple or easy-to-guess passwords**: Employees use short alpha-only passwords or use their dog's name and/or their birthday as their password.
- **Social engineering**: An attacker uses personal information or subterfuge to learn a user's password, such as pretending to be from a bank or leaning over someone's shoulder as they type their password.
- **Bypass controls**: Employees turn off security measures, do not change default passwords, or everyone uses the same password to access all substation equipment. Or a software application is assumed to be in a secure environment, so does not authenticate its actions.
- **Integrity violation**: Data is modified without adequate validation, such that the modified data causes equipment to malfunction or allows access to unauthorized users or applications.
- **Software updates and patches**: The software is updated without adequate testing or validation such that worms, viruses, and Trojan Horses are allowed into otherwise secure systems. Alternatively, security patches needed to fix vulnerabilities are not applied.
- **Lack of trust**: Different organizations have different security requirements and use different cyber security standards.

Some common types of attacks include:

- **Eavesdropping**: a hacker "listens" to confidential or private data as it is transmitted, thus stealing the information. This is typically used to access intellectual property, market and financial data, personnel data, and other sensitive information.

- **Masquerade**: a hacker uses someone else's credentials to pretend to be an authorized user, and thus able to steal information, take unauthorized actions, and possibly "plant" malware.
- **Man-in-the-middle**: a gateway, data server, communications channel, or other non-end equipment is compromised, so the data that is supposed to flow through this middle node is read or modified before it is sent on its way.
- **Resource exhaustion**: equipment is inadvertently (or deliberately) overloaded and cannot therefore perform its functions. Or a certificate expires and prevents access to equipment. This denial of service can seriously impact a power system operator trying to control the power system.
- **Replay**: a command being sent from one system to another is copied by an attacker. This command is then used at some other time to further the attacker's purpose, such as tripping a breaker or limiting generation output.
- **Trojan horse**: the attacker adds malware to a system, possibly as part of an innocent-appearing enhancement or application, and possibly during the supply chain (e.g. during component manufacturing or system integration or shipping or during installation). This malware does nothing until some circumstance locally or remotely triggers it to cause an unauthorized action.

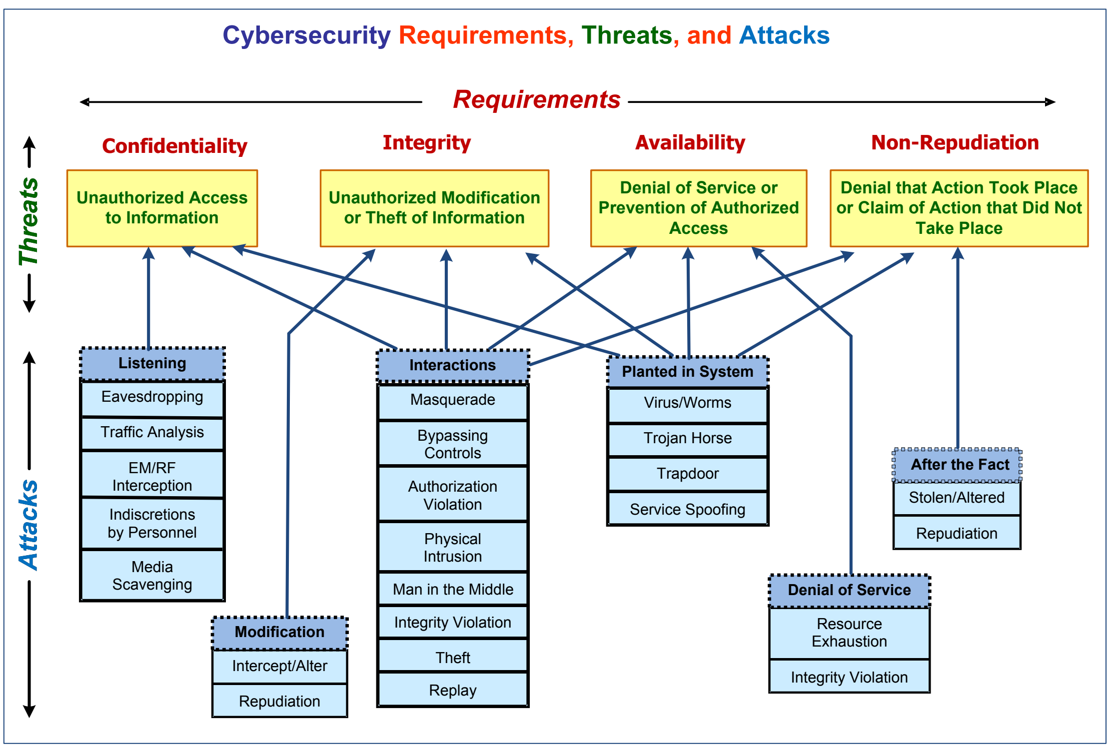

Figure 26: Security Requirements, Threats, and Possible Attacks[104]

[104] Xanthus Consulting International, 2015

4.8.2 Cyber Security Requirements

The principle cyber security goal is for "end-to-end" security, meaning that there are no gaps or weak areas that an attacker could exploit (i.e. the strength of a chain is measured by the strength of its weakest link). Absolute security is impossible, but minimizing the weaknesses must be the main focus. Using state-of-the-art security technologies and defense-in-depth strategies are key ways to improve overall security. NISTIR 7628[105] provides excellent guidelines on cyber security of the power industry, while the NERC Critical Infrastructure Protection (CIP) 002-009 standards[106] provide cyber security requirements for the bulk power system, some of which can be applied to distribution systems and DER systems.

Cyber security applies to both communications between entities and to stored information. The most complex for distribution and DER management is cyber security for communications since so many stakeholders are involved which are not under a single management.

Cyber security technologies were primarily developed by the information technology (IT) industry to protect against malicious attackers, while the power industry has developed many engineering strategies and operational techniques to secure the power system against inadvertent problems such as equipment failures and natural disasters. Only in combination can cyber security and power system security mechanisms provide the resilience needed to operate the Smart Grid.

IT cyber security is typically seen as providing confidentiality, integrity, and availability to cyber assets, while power system security is based on engineering design and operational strategies. IT and power system security strategies and technologies can be combined to provide resilience of the power system.

DER systems and their interactions with power systems have five basic security requirements, which protect them from five basic threats:

- **Authentication** – preventing unauthorized interactions
- **Integrity** – preventing the unauthorized modification or theft of information
- **Confidentiality** – preventing the unauthorized access to information
- **Non-Repudiation/Accountability** – preventing the denial of an action that took place or the claim of an action that did not take place.
- **Availability/Resilience** – preventing the denial of service and ensuring authorized access to information. This concept is extended in cyber-physical concepts to include the resilience of the power system: preventing outages if possible, coping with those outages, and recovering rapidly from outages

The first four security requirements are generally met by cyber security technologies, while the fifth security requirement of preventing denial of service is usually best met through engineering strategies. However, a tightly entwined combination of cyber and engineering strategies can build on each other to provide defense-in-depth and defense-in-breadth.

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[105] See http://csrc.nist.gov/publications/PubsNISTIRs.html

[106] See http://www.nerc.com/pa/Stand/Pages/CIPStandards.aspx

For DER systems, authentication and integrity are the most important security requirements, although the others follow close behind. Authentication ensures that only authorized interactions can take place, while integrity assures that DER systems operate safely and reliably, and some modifications to data located within the DER controller or sent to the DER controller may impact that safety and reliability.

Confidentiality is usually associated with market-related data and intellectual property, as well as managing security procedures and techniques. Competitors and thieves should not be able to access sensitive information.

Non-repudiation/Accountability is usually associated with financial transactions, such as responding to control commands or demand response requests. Providing time-stamped proof of receiving such a request and taking action on that request can be vital to billing and settling these transactions.

4.8.3 Cyber Security Risk Mitigation Categories

Mitigations against the effects of attacks and failures are often described as having eight categories. Associated security countermeasures can mitigate one or more of these purposes.

- **Prevention of attack**, by taking active measures that are in effect at all times and are designed to prevent a failure or attack. These usually are engineering designs and procedures, as well as cyber security design and architecture measures.
- **Deterrence to a failure or attack**, to try to make failures and attacks less likely, or at least delay them long enough for counter actions to be undertaken.
- **Detection of a failure or attack**, to notify the appropriate person or systems that an attack or failure event took place. This notification could also include attempts at attacks or failures that "self-healed". Detection is crucial to any other security measures since if an attack is not recognized, little can be done to prevent it. Monitoring of systems and communications is critical, while intrusion detection capabilities can play a large role in this effort.
- **Assessment of a failure or attack,** to determine the nature and severity of the attack. For instance, is the entry of a number of wrong passwords just someone forgetting or is it a deliberate attempt by an attacker to guess some likely passwords.
- **Response to a failure or attack**, which includes actions by the appropriate authorities and computer systems to stop the spread of the attack or failure in a timely manner. This response can then deter or delay a subsequent attack or failure, or mitigate the impact of cascading failures or attacks.
- **Coping during a failure or attack,** which includes initiating additional activities to mitigate the impacts, such as performing switching operations to improve the Resilience of the power system, sending crews to failure sites, requiring increased authentication measures for any interactions with compromised systems, and gracefully degrading performance as necessary.

- **Resilience during failure or attack,** which involves sustaining minimum essential operations during attack despite system compromise and some operational degradation.
- **Recovery from a failure or attack,** which includes restoration to normal operations after a failure has be corrected, requiring full virus and validation scans of affected systems, or changing passwords for affected systems.
- **Audit and legal reactions to a failure or attack,** which could include analyzing audit logs, assessing the nature and consequences of the event, performing additional risk assessments, and even pursuing litigation against those responsible for the event.

4.8.4 Cyber Security Standards

Some of the available cyber security standards that could be applicable to distribution systems and DER systems include the following[107]:

- DOE / DHS Cybersecurity Capability Maturity Model for the Electricity Subsector
- DOE/NIST/NERC Electricity Subsector Cybersecurity Risk Management Process Guideline
- DOE / DHS Electric Sector Cybersecurity Risk Management Maturity Initiative
- IEC 62351 Parts 1-13 data and communications security (*used for cyber security of IEC 61850, DNP3, and power system communication networks)*
- IEC 62443 series on security for industrial process measurement and control *(work in process based on ISA SP99)*
- IEEE 802.11i wireless security (*e.g. for WiFi)*
- IETF cybersecurity RFCs, including RFC 5246 Transport Layer Security (TLS) (*used on the Internet and many other networks)*
- IETF RFC 6272 Internet Protocols for the Smart Grid (*identifies RFCs used in the Smart Grid)*
- ISO 27000 Information Security Standards *(used by the international industries, including electric utilities)*
- NERC Critical Infrastructure Protection (CIP) 002-009 *(used for transmission systems, but may be useful for distribution systems)*
- NIST SP 800-82 Guide to Industrial Control Systems (ICS) Security
- NISTIR 7628 Vol. 1 thru 3 Guidelines for Smart Grid Cyber Security

107 A more complete list can be found at http://iectc57.ucaiug.org/wg15public/default.aspx

4.8.5 Resilience and Cyber Security

In the energy sector, two key phrases are becoming the focus of international and national policies: "**grid resilience**" and "**cyber security of the cyber-physical grid**". Grid resilience responds to the overarching concern: *"The critical infrastructure, the Smart Electric Grid, must be resilient – to be protected against both physical and cyber problems when possible, but also to cope with and recover from the inevitable disruptive event, no matter what the cause of that problem is – cyber, physical, malicious, or inadvertent."*

"*Grid resilience … includes hardening, advanced capabilities, and recovery/reconstitution. Although most attention is placed on best practices for hardening, resilience strategies must also consider options to improve grid flexibility and control.*"[108] Resilience of the grid is often associated with making the grid able to withstand and recover from severe weather and other physical events, but resilience should also include the ability of the cyber-physical grid to withstand and recover from malicious and inadvertent cyber events.

Resilience, sometimes defined as "*the fast recovery with continued operations from any type of disruption*" can be applied to the power system critical infrastructure. A resilient power system is designed and operated not only to prevent and withstand malicious attacks and inadvertent failures, but also to detect, assess, cope with, recover from, and eventually analyze such attacks and failures in a timely manner while continuing to respond to any additional threats.

The "cyber-physical grid" implies that the power system consists of both cyber and physical assets that are tightly intertwined. Both the cyber assets and the physical assets must be protected in order for the grid to be resilient. But protection of these assets is not enough: these cyber and physical assets must also be used in combination to cope with and recover from both cyber and physical attacks into order to truly improve the Resilience of the power system infrastructure.

All too often, cyber security experts concentrate only on traditional "IT cyber security" for protecting the cyber assets, without focusing on the overall resilience of the physical systems. At the same time, power system experts concentrate only on traditional "power system security" based on the engineering design and operational strategies that keep the physical and electrical assets safe and functioning correctly, without focusing on the security of the cyber assets. However, the two must be combined: resilience of the overall cyber-physical system must include tightly entwined cyber security technologies and physical asset engineering and operations, combined with risk management to ensure appropriate levels of mitigation strategies.

As an example, DER systems are cyber-physical systems that are increasingly being interconnected to the distribution power system to provide energy and ancillary services. However, distribution power systems were not originally designed to handle these dispersed sources of generation, while DER systems are generally not under direct utility management or under the security policies and procedures of the utilities. Many DER systems provide energy from renewable sources, which are not reliably available at all

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108 "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages," Executive Office of the President, August 2013. See link: http://www.smartgrid.gov/sites/default/files/doc/files/Grid%20Resilience%20Report_FINAL.pdf

times. Therefore, the resilience of power systems to even typical disruptions is increasingly at risk as more of these DER systems are interconnected.

Although arguably the resilience of individual DER systems can be seen as less important than the resilience of a single large bulk power generator, in fact the combined resilience of aggregations of large numbers of even small DER systems can ultimately be more critical than a single bulk generator in the overall resilience of the power system.

4.9 Tariff and Market Issues

4.9.1 Time of Use (TOU) and Tier Pricing

Utility tariffs vary greatly from jurisdiction to jurisdiction with respect not only the actual price per kW for electricity, but also structured to take into account the time that the energy is used as well as the total amount of energy used within a period of time. Utilities typically identify on-peak and off-peak times of the day and the week, where on-peak reflects high load times. It is often more expensive to add “peaking” generation to meet these peak loads, so various methods are typically used to try to lower on-peak loads, usually by trying to shift them to off-peak times or by reducing the overall loads.

Two common tariff structures are:

- **Time of Use (TOU) tariffs** in which on-peak rates are higher than off-peak rates. These TOU tariffs are used to encourage shifting loads to off-peak.
- **Tier pricing tariffs** in which the amount of energy used during a period (e.g. one month) is binned into different tiers, with the lowest tier the lowest price, and each higher tier with a higher price. This tariff structure is used to encourage conservation and the reduction of overall load.

4.9.2 Load Control (LC)

Load control and interruptible load schemes have been used for decades to minimize demand charges and manage peak load conditions. The most common controlled loads include the cycling of water heaters, air conditioners, and pool pumps. The interruptible loads have primarily belonged to industrial customers who agree to decrease load if requested.

Direct load control is handled by the utility issuing broadcast commands to the selected appliances to start their cycling, while indirect load control involves phone calls to selected customers to ask them to reduce load. A typical load control tariff includes a reduced rate while permitting the utility a certain number of hours per year of reducing customer loads.

Load control is mostly used to shift peak loads, with the understanding that there will be a “recovery” later that often uses more net energy but has shifted to off-peak.

Load control is considered to be a part of the broader concept of demand side management. Although still used, direct load control has become less favored, with the idea that it can be replaced by demand response.

4.9.3 Demand Response (DR)

Demand response (DR) provides customers with energy pricing information for different times or incentive payments, thus permitting them to decide whether to reduce their loads, by how much and for how long. So, like load control, the purpose is to shift loads from on-peak to off-peak. However, unlike load control, any types of “controllable” load can be included, and the decision on whether or not to change the load is under the control of the customer, and is not directly controlled by the utility.

Since customers are not likely to watch these energy prices on a continuing basis, they are most likely to implement energy management systems with customer-specified responses to different levels and times of prices.

DR requires more automation than load control, since energy management systems must be able to affect the operation appliances (such as washing machines, thermostats, and clothes dryers) and systems (such as HVAC systems, water pumps, and certain industrial devices) as well as a way of providing pricing information to a large number of customers

4.9.4 Net Metering for DER Systems

Under the Section 1251 of the Energy Policy Act of 2005, net metering is defined as a service to an electric consumer where electric energy generated by a customer DER system is used to off-set the electric energy provided by the utility to the customer at the customer’s rate during the equivalent billing period. For instance, on-peak generation would off-set on-peak load, and vice versa. Smart meters were developed to handle the time-sensitive, two-way flow of power, and monitor the net power flow as well as the generation (and/or load) for each time period (typically each hour or each 15 minutes).

With net metering, utilities purchase power generated by the DER systems at a rate that is expected to reflect the avoided marginal generation costs that the utility would otherwise have to purchase. Most net metering laws involve annual settlement of credits and debits, with only a small monthly connection fee.

In the short term, this appears to benefit both the DER customer and the utility. However, as more customers acquire DER systems, these avoided marginal generation costs generally turn out not to reflect the true distribution utility cost for serving these customers with DER systems. In fact, those additional costs would have to be shifted to other customers without DER systems if the utility were to be able to continue operating and maintaining the distribution system. For example, a 2012 report on the cost of net metering in the State of California, commissioned by the CPUC, showed that those customers without distributed generation systems will pay $287 in additional costs to use and maintain the grid every year by 2020. The report also showed the net cost will amount to US$1.1 billion by 2020[109].

[109] See **cpuc.ca.gov NEM Report**

Many utilities and their regulators are trying to find equitable solutions to this net metering problem. It is a thorny problem and no one answer can solve all the issues.

4.9.5 Feed-in Tariffs Concepts

Feed-in tariffs have been developed primarily as an incentive to accelerate investment in renewable energy technologies. It achieves this by offering long-term contracts to renewable energy producers, typically based on the cost of generation of each technology. Feed-in tariffs typically include three key provisions:

- Guaranteed grid access
- Long-term contracts
- Cost-based purchase prices

Under a feed-in tariff, eligible renewable electricity generators, including homeowners, business owners, farmers and private investors, are paid a cost-based price for the renewable electricity they supply to the grid. This enables diverse technologies (wind, solar, biogas, etc.) to be developed and provides investors a reasonable return. As a result, the tariff may differ by technology, location (e.g. rooftop or ground-mounted for solar PV projects), size (residential or commercial scale) and region. The tariffs typically offer a guaranteed purchase agreement for long (15–25 year) periods and are often designed to decline over time to track and encourage technological change.

4.9.6 Retail Energy Market Concepts and Structures

Although the market rules used for bulk power are sometimes seen as applicable to the retail (distribution level) market, there are many very important distinctions. First, the retail market is State dependent with some States having no retail market. Other States have enacted very detailed regulations which are vastly different from either the bulk power market or other State retail markets.

For instance, in some jurisdictions, distribution utilities are excluded as generation suppliers, so they are limited in what DER systems they can install for reliability and efficiency purposes. In addition, the type and purpose of stakeholders in the retail market could be very different. For example, most customers install DER systems for their own use, rather than primarily to sell energy on the bulk power market. Often non-exporting generation and storage are installed that just meet a part of the facility's load. As another example of differences, some third party stakeholders can aggregate groups of DER systems they do not own, but are under contract to manage, in order to provide ancillary services. However, a combination of self-use and exporting is probably the most common DER architecture, with the use of net metering and feed-in tariffs the most "popular" approaches.

New market areas are now starting to evolve. For instance, locational incentives are being studied to see whether they can entice DER stakeholders to locate their DER systems where they can best benefit the utility's goals of reliable and efficient power delivered to all customers. Another evolving area is community-based DER systems, where customers within the community do not necessarily own the DER systems, but can benefit from agreements for sharing the energy sold back to the grid.

Some very old market concepts are also re-emerging, such as load management or "demand response" which was originally developed as incentives to decrease loads during peak power times. Now it is being used not only for managing loads, but also for managing DER generation and storage, as well as providing ancillary services.

4.9.7 Transactive Energy

Transactive energy refers to the use of a combination of economic and control techniques to improve grid reliability and efficiency. These techniques may also be used to optimize operations within a customer's facility[110]. It combines demand response programs that help customers manage their loads, with utility control programs that could eventually incentivize customers to manage both their loads and their DER systems to reflect utility needs as well as their own needs. These incentives could be tariff-based or market-based.

4.9.8 Market equitability issues

DER systems owned by some customers may result in financial impacts on other customers. While most customers with DER systems generate some or all of their electricity for their own use, thus displacing some utility generation, those same customers usually remain connected to the local distribution system. They use the electric grid to purchase supplemental power from their local utility and to sell power to their utility when their systems generate a surplus. As revenues from these DER-owners decrease, utilities will not able to recoup all of their on-going maintenance and expansion costs. Therefore, if no overall rate adjustments are made, they will be forced to increase rates for customers without DER systems.

Not only electrical rates may be impacted. Services to non-DER customers may also be affected by the implementation of DER systems since operational issues can arise when DER systems are added to the distribution grid. For example, since many DER systems only generate intermittently, this fluctuating power can cause power quality issues for other customers. As another example, DER systems may change voltage levels on a feeder, thus possibly causing voltage problems for other customers. In addition, some customers may be able to participate in demand-response programs whose total generation and loads are managed predominantly to lower energy costs for the participants. This "generation-load management" may affect the capacity of the local distribution circuit to provide services to other customers who are not able to participate in such programs. Again, these impacts should be factored into compensation for DER services.

4.10 Location Heat Map

[110] Gridwise Architecture Council, **http://www.gridwiseac.org/about/transactive_energy.aspx**

Assuming DER's follow the sun and high rates, it is clear that attention on DER penetration will be in Southwest. The blue bars are high PV case, red bar = current PV installed, and rates are displayed in rainbow colored circle.

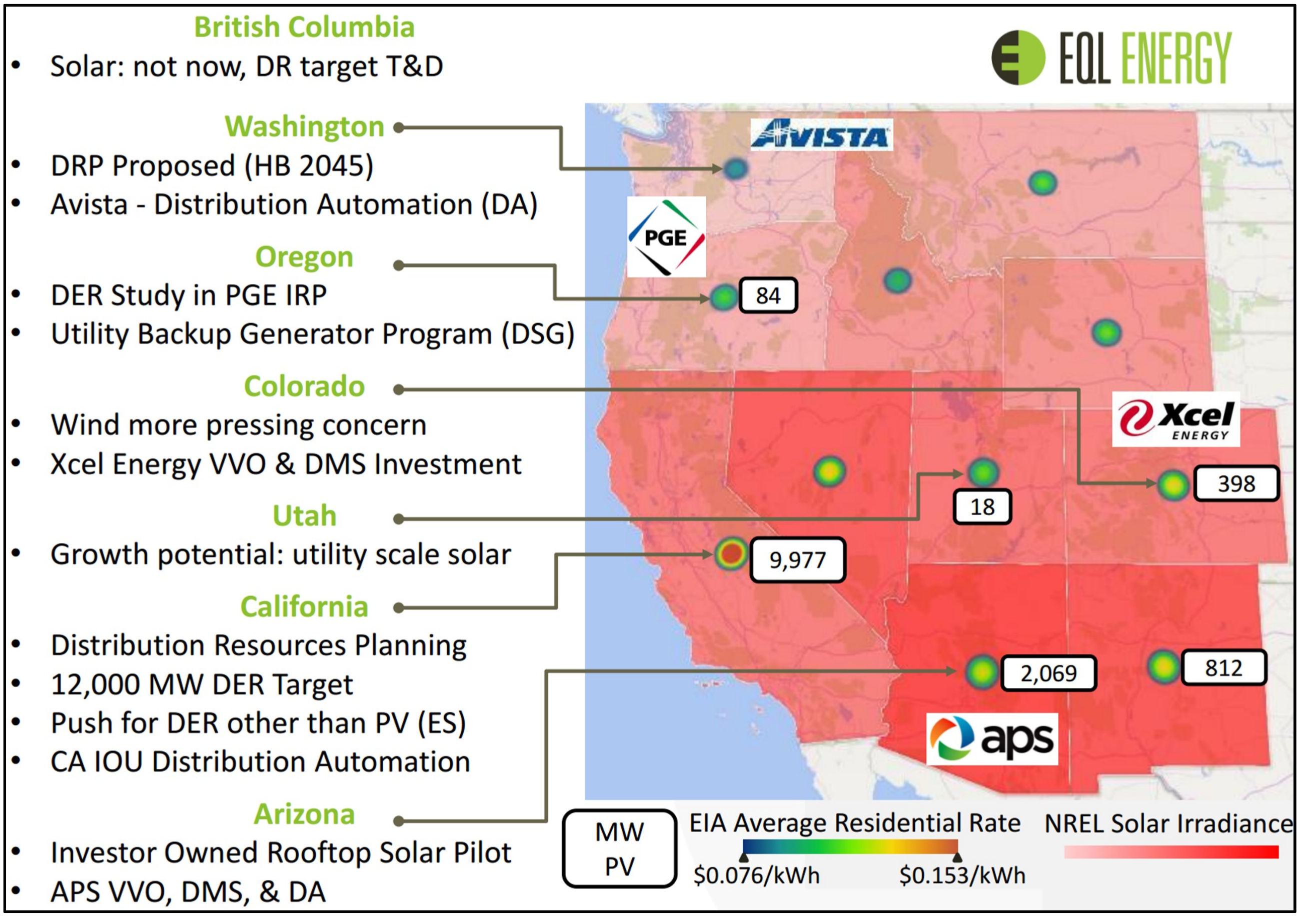

Figure 27: Location Heat Map. Source: EQL Energy

5 Utility Investment Plans

EEI reported in January 2015 Survey that in 2013 utilities spent $20.8B on distribution system, compared with $16.9B for transmission. In addition to upgrades for capacity growth, EEI cited reasons for distribution investments include storm hardening, improved system reliability, and underground infrastructure.

Another reason for distribution investment and the focus on this report is to accommodate increased DER. NREL surveyed 21 utilities across the United States to find and identified types of investments that are planned for Solar PV integration. Hawaiian Electric Utilities have outlined $194 Million needed to accommodate 902MW of Solar PV in the next 15 years.

This in section is comprised of two parts:

- NREL survey for mitigating higher levels of DER
- Investments being considered or implemented by select utilities that address DER and distribution system changes from multiple perspectives.

Utilities we have selected:

- HECO – High DER
- Pacific Gas & Electric – electric vehicle charging proposal
- San Diego Gas & Electric – DER vs. conventional resources.
- Portland General Electric - DER
- Xcel Energy Colorado – VVO

5.1 NREL Utility Survey for Mitigating Higher DER

NREL, EPRI survey of 21 Utilities on DER interconnection practice highlights utility concerns, and common mitigation strategies. Lists the type of concern, from most concerned to least concerned.

Figure 28: NREL study on Utility DER concerns[111]

Utility Concern	Rank
Voltage Regulation	**16**
Protection System Coordination	**10**
Reverse Power Flow	**11**
Increased Duty of Line Regulators	**8**
Unintentional Islanding	**8**
Secondary Network Protection	**6**
Variability due to Clouds	**5**
Increased Switching of Capacitors	**4**
Flicker	**4**
Reactive Power Control	**3**
Balancing resources and DR	**3**
Overvoltage due to Faults	**2**
Multiple Inverter Stability	**1**
Harmonics	**1**
Relay Desensitization	**1**
Export through Network Protectors	**1**

Source: 2014 NREL Mitigation Measures for Distributed PV

The Questionnaire also included common mitigation strategies used by utilities to resolve issues that have arisen in DER interconnections, as shown in Figure 29 below.

[111] NREL presentation "Interconnection, Screening & Mitigation Practices of 21 Utilities" http://www.nrel.gov/tech_deployment/pdfs/2014-07-09_mitigation-measures-for-distributed-pv-interconnection.pdf

Figure 29: Common DER Mitigation Strategies for 21 Utilities[112]

Type	Southwest (5)	Central (3)	California (4)	Northeast (7)
Voltage Regulation devices (13)	4	1	3	5
Upgraded line sections (16)	4	2	4	6
Modify protection (16)	4	3	3	6
Power factor controls (8)	4	1	x	3
Direct Transfer Trip (12)	2	3	1	6
Static VAR Compensator (SVC) (1)	1	x	x	x
Communication/Control Technology (11)	4	1	2	4
Grounding transformers (8)	2	2	2	2
Advanced inverters (11)	3	2	3	3
Capacitor control modifications (1)	x	x	x	1
Reclosers (3)	x	1	x	2
Volt/VAR Controls (1)	x	x	x	1

Source: 2014 NREL Mitigation Measures for Distributed PV

These mitigation measures are similar to those Hawaiian Electric has determined are needed to integrate DERs, cost estimates for which are included in the next section.

5.1.1 HECO - High DER Now

HECO is planning to spend $195MM in the next 15 years to accommodate 902MW of DG on their system. That is $216/kW estimate for integration cost.[113]

HECO's Distributed Generation Interconnection Plan (DGIP) introduces a significant amount of information about what the utility is doing to mitigate DER integration, as it faces pressure from the PUC and customers to speed up the pace of PV interconnections. Figure 30 below shows a list of issues caused by DER and the mitigation measure required, along with information about cost. Unit Cost in table are high-level estimates based on typical design configurations.

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112 NREL presentation "Interconnection, Screening & Mitigation Practices of 21 Utilities" http://www.nrel.gov/tech_deployment/pdfs/2014-07-09_mitigation_measures_for_distributed_pv_interconnection.pdf

113 http://files.hawaii.gov/puc/4_Book%201%20%28transmittal%20ltr_DGIP_Attachments%20A-1%20to%20A-5%29.pdf

Figure 30 Hawaiian Electric Companies - investments required due to DER

Item	Violation Trigger	2016	2020	2030	Total
Installed DG (MW)	--	547	677	902	
Regulator	Feeder Reverse Flow	$187,000	$55,000	$66,000	$308,000
LTC	Substation Transformer Reverse	$912,000	$264,000	$466,000	$1,642,000
Reconductoring	Exceed 50% Backbone Conductor/Cable Capacity	$-	$-	$75,588,700	$75,588,700
Substation Transformer and Switchgear	Exceed 50% Capacity	$2,541,000	$2,475,000	$49,750,000	$54,766,000
Distribution Transformer	Exceed 100% Loading, % GDML Linear Relationship to % Transformers Upgraded	$4,462,164	$4,386,633	$6,768,738	$15,617,535
Poles and Secondary	Assumed 15% of Distribution Transformer Replacements Include Pole Replacement and Secondary Upgrades	$1,016,605	$993,371	$1,523,365	$3,533,342
Grounding Transformers	Exceed 33% GDML (66% in model) for Selected Feeder for Maui Electric and Hawai'i Electric Light; exceed 50% GDML for 46 kV Lines for Hawaiian Electric	$33,033,000	$6,095,100	$3,917,100	$43,045,200
Total	--	$42,151,769	$14,269,104	$138,079,904	$194,500,777

Source: Table 3-5 August 2014 Hawaiian Electric DGIP (Distribution Generation Interconnection Plan)[114]

GDML means Gross Daily Minimum Load

5.1.2 PG&E – T&D investment and EV charging proposal

California is expecting to extend the current goal of 33% renewables by 2020 to 50% renewables by 2030. PG&E's Anthony Earley, president and CEO, and Kent Harvey,

[114] http://files.hawaii.gov/puc/4_Book%201%20%28transmittal%20ltr_DGIP_Attachments%20A-1%20to%20A-5%29.pdf

senior vice president, said that Pacific Gas and Electric is planning $5.5 billion in capital expenditures in 2015, including about $1.1 billion for electric transmission and around $2 billion for electric distribution[115].

In February 2015, PG&E sought CPUC approval to invest $654MM over a 5 year period in electric vehicle (EV) charging systems, with the goal of supporting the expected 1.5 million EVs by 2025. If approved, PG&E customers would share the costs, with residential customers expected to pay about 70 cents more per month from 2018 to 2022. The PG&E request is very contentious and consumer advocates will argue that these costs should not be borne by ratepayers. Other intervenors argue utilities should not invest this heavily in EV infrastructure so as not to crowd out third parties. PG&E argues that their EV program will benefit disadvantaged communities (10%) and support time variant pricing. This CPUC proceeding is A15-02-009.

5.1.3 SDG&E – DER vs Conventional Investments

California utilities, at the direction of the CPUC and the state legislature, have made acquiring DER a priority in procurement decisions, but determining the appropriate level of DER investment compared with traditional infrastructure options is proving to be challenging. Of many ongoing procurement proceedings before the CPUC, an application filed by SDG&E in July 2014 with the CPUC illustrates tensions between DERs and traditional natural gas power plants with respect to local reliability challenges.

In California, utilities regulated by the CPUC generally request pre-approval for large investments such as generating plants, as is the case here. SDG&E asked[116] for permission to enter an agreement with a new 600 MW natural gas simple cycle power plant in Carlsbad, along with 200 MW of DER, pursuant to a prior CPUC decision[117] that authorized 500 to 800 MW of local capacity, with DER supplying a minimum of 200MW.

On March 6, 2015, the CPUC issued a proposed decision[118] in the proceeding that would deny the application stating conventional natural gas procurement was too high, with insufficient DER procurement. The proposed decision would require SDG&E to further pursue DER and take up the need for conventional resources at a later Date if DER procurement if it was shown that DER procurement was not successful in meeting local capacity needs.

On April 6, 2015, an alternate proposed decision[119] was issued that approves a smaller 500 MW plant and increases DER procurement requirements to 300 MW. The California ISO submitted comments on both proposals describing a need for

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115 Electric Light & Power interview: http://www.elp.com/articles/2015/02/pg-e-invests-in-power-grid-that-flows-in-multiple-directions.html?cmpid=Enl_ELP_Feb-13-2015
116 Docket: A14-07-009, Application dated 07.21.2014
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M098/K406/98406519.PDF
117 D14-03-004
118 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M148/K259/148259638.PDF
119 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M150/K379/150379054.PDF

dependable generation, and SDG&E argued DER options are not yet mature enough to be counted on for reliability purposes. The commission has not yet held a vote on the matter.

5.1.4 Portland General Electric – DER in the future

PGE's next IRP, due by December 2, 2016, will include items relevant to our report, described in the Oregon PUC Order 14-415.[120] This order acknowledged the current IRP and put in place guidance for the next one, including a study of distributed resource potential including "all potential DG sources." This IRP is expected to analyze ways to resolve an expected load/resource balance gap in the relevant time frame due to an RPS deadline in 2020 and a planned large resource retirement the same year.[121]

The distributed generation study to be conducted as part of PGE's next IRP provides an opportunity to assess the extent to which DER can contribute to PGE's system needs. Given what we have learned about current state of DER integration into utility distribution systems in the west, PGE's study stands to benefit by a supplementary analysis of the capability of its distribution system to host varying quantities of DER as may be applicable to DER study outcomes or more broadly to system planners.

We note that the CPUC's DRP process is to include an integration capacity analysis that specifies the quantities of DER that can be added to the existing system. This methodology is to be common to all 3 large California IOU. While the extent to which this methodology will be applicable to utilities outside California is uncertain, information gathered from this process may be applicable broadly across the west, especially in relation to software analysis tool development.

PGE is currently implementing OMS and GIS systems.[122] PGE has stated in a smart grid plan filing that it is considering adding a DMS in the 2018-2020 time frame.[123]

PGE also continues to invest in its distributed standby generation program which has about 85MW of customer generation dispatchable with 10 minute notice. Oregon utilities are required to file annual smart grid plans that include distribution automation pilots.

5.1.5 Xcel Energy – VVO now

Xcel is proposing a $92 million VVO project[124] and is in planning stages for a DMS. These types of investments could be considered a preparation for increased DER on Xcel's distribution system with near term value.

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[120] Docket LC56
http://apps.puc.state.or.us/orders/2014ords/14-415.pdf
[121] PGE Comments 11.07.14 in LC56 http://edocs.puc.state.or.us/efdocs/HAC/lc56hac16041.pdf
[122]http://www.puc.state.or.us/meetings/pmemos/2015/020915/SPM%20Presentation%20PGE%20Update%2002092015.pdf
[123] http://www.puc.state.or.us/meetings/pmemos/2014/092314-SPM%20UM%201657/reg1.pdf

An example of an approved VVO project outside WECC comes from Duke/Progress in North and South Carolina, which began its $292 million[125] Distribution System Demand Response (DSDR) program in 2008 and completed it in 2012, resulting in claimed 235 MW of peak demand reduction.[126] The program entailed constructing a distribution network model which took over two years to complete, and included capital investments such as relocating and adding line capacitors, and addition of new line voltage regulators.[127]

Generally, there are two types of VVO strategies: model-based and measurement based. *Model based systems* require preparation and maintenance of a distribution network model. This allows a small number of measurements, such as substation SCADA to provide operators with state estimation for the entire modeled system by making use of detailed system topology and power flow calculations. *Measurement-based systems* generally do not require a network model and use available meter data such as meters installed at low voltage segments of a circuit, or where AMI data can be integrated.

Both systems are able to reduce voltage to the lowest level possible subject to the lowest-voltage constraining elements on the system. Both systems also have applicability to measuring and managing system elements that will be affected by system voltage issues caused by high DER.

DMS model based systems may be better for managing DER in the future, although they are more expensive today. One concept relating VVO investments and DER-required investments is the notion of implementing voltage control capability in the near term that may have a longer term DER integration benefit, such as a DMS. One question that may arise here is whether the cost justification from VVO alone is sufficient and the extent to which the longer term (and likely more uncertain) DER integration value needs to be considered.

5.2 Distribution System Roadmaps

Several WECC utilities and HEI have developed Distribution System or Smart Grid Roadmaps in the past 6 years. One important quality of these is the inclusion of a

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[124] http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/CO-DSM/CO-DSM-2013-Bloch-Strategic-Issues-Direct-Testimony.pdf
[125] North Carolina Utility Commission reporting: http://www.ncuc.commerce.state.nc.us/reports/EE-DSM%20Report.pdf
[126] http://www.slideshare.net/SchneiderElectric/dtech-2015-the-distribution-management-system-network-model
[127] http://www.duke-energy.com/pdfs/GP2-SC-Program-DSDR.pdf

variety of novel programs on the customer-side and introduction of a range of new technologies on the utility-side. Today, with more emphasis being placed on striking the correct balance between these two increasingly complex investment areas, utilities and regulators may find the roadmapping framework a useful set of tools to evaluate both technologies and policy development.

Most roadmaps created thus far by utilities are focused on technology deployment timelines, creating a visual representation of when the utility expects to deploy certain technologies relative to one another and in some cases incorporating additional information. Below is an example from Southern California Edison showing a 2010 smart grid roadmap.

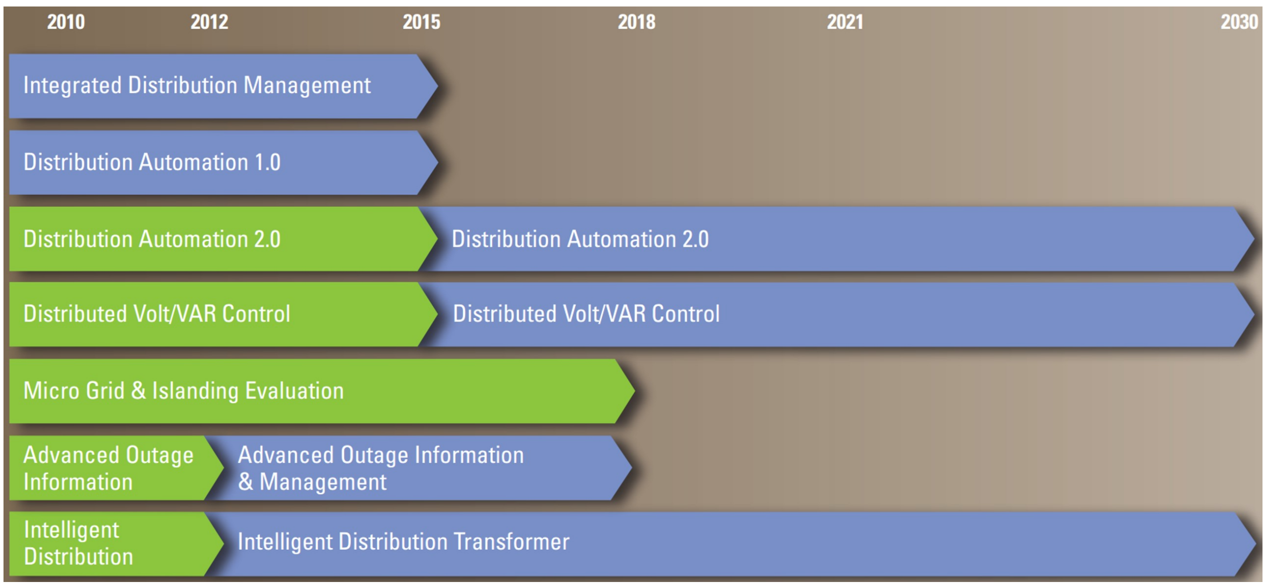

Figure 31: SCE smart grid technology roadmap.[128]

A more recent example from Hawaiian Electric is included below. This was included in its Distributed Generation Interconnection Plan filing in 2014. It depicts an implementation schedule of technologies both on the utility-side and customer-side, while taking into account and identifying additional information, in this case the need for two-way communications capability.

[128] 2010 SCE Smart Grid Roadmap https://www.sce.com/NR/rdonlyres/BFA28A07-8643-4670-BD4B-215451A80C05/0/SCE_SmartGrid_Strategy_and_Roadmap.pdf

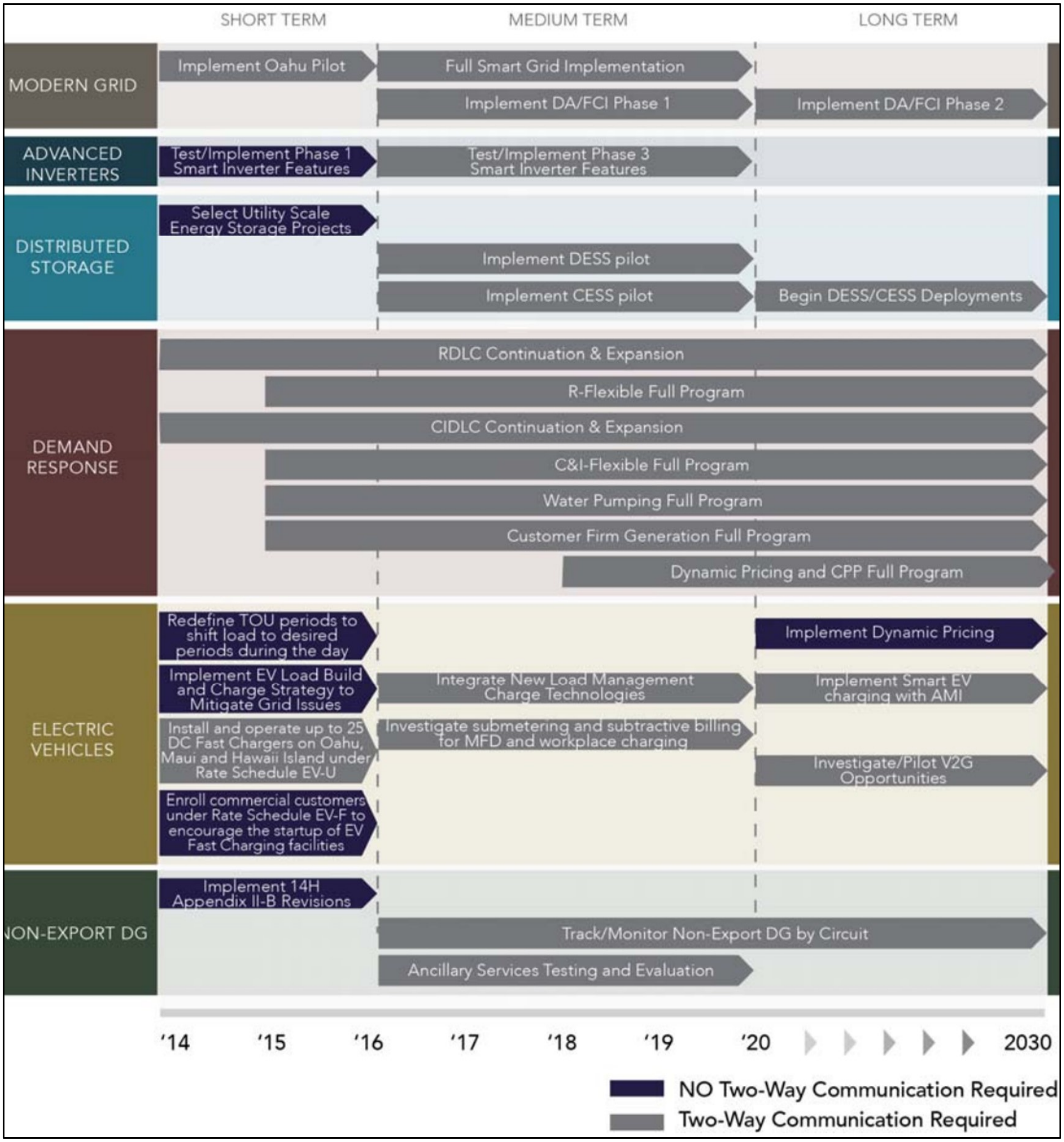

Figure 32: Hawaiian Electric Advanced DER Technology Roadmap[129]

[129] HEI 2014 Distributed Generation Interconnection Plan http://files.hawaii.gov/puc/4_Book%201%20%28transmittal%20ltr_DGIP_Attachments%20A-1%20to%20A-5%29.pdf

Roadmaps can also be useful to outline roles and responsibilities among regulators and the increasing number participants involved in the utility industry. An example is a roadmap constructed by the California ISO, the California Energy Commission and the CPUC suggesting policies and actions to support a viable energy storage market in the state, and outlining what each party should do, shown in Figure 33 below.

Energy Storage Roadmap: highest priority actions

Planning	**CPUC** Describe distribution grid operational needs and required resources characteristics.	**CPUC** Facilitate clarification by IOUs of operational constraints that can limit the ability to accommodate interconnection on the distribution system.	**CPUC** Examine and clarify opportunities for storage to defer or displace distribution upgrades.
Procurement	**CPUC & Energy Commission** Consider refinements to the valuation methodologies used by IOUs to support CPUC decisions on storage procurement and make models publicly available.	**CPUC** Clarify rules for energy storage qualification and counting in an evolving Resource Adequacy (RA) framework.	**CPUC** Consider "unbundling" flexible capacity RA counting.
Rate treatment	**ISO** Clarify wholesale rate treatment and ensure that the ISO tariff and applicable business practices manuals and other documentation provide sufficient information.	**CPUC** Clarify and potentially modify net energy metering tariffs applicable to cases where energy storage is paired with renewable generators.	

Figure 33: CAISO, CEC, CPUC Energy Storage Roadmap[130]

130 https://www.caiso.com/Documents/Advancing-MaximizingValueofEnergyStorageTechnology_CaliforniaRoadmap.pdf

Going beyond categorizing participant roles and technology deployment timelines is accomplished by utilizing an alternate roadmap construction process, one that establishes a process for selecting a particular technology or policy in the first place. This is commonly called technology roadmapping and is used by many organizations to inform R&D investment decisions. One noteworthy example is Bonneville Power Administration's Technology Innovation program that uses roadmaps constructed by team of industry experts to identify areas of R&D need. The process used by BPA includes 4 steps:

1. Drivers
2. Capability Gaps
3. Technology Characteristics
4. R&D programs.

In order to adapt this technology roadmapping process more broadly to include areas like distribution planning policies, modifications have been suggested[131] to align the sequential roadmap steps with underlying reasons for pursuing a policy and identifying what barriers may be present.

1. **Drivers.** The reasons for Change.
2. **Goals**. Identification of ways to address the drivers
3. **Barriers**. Capability gap standing in the way of accomplishing the technology or policy goal.
4. **Solutions**. Technologies, business models, market, and regulatory practices.
5. **Development**. Next steps identified to implement the solution. This could include reference to another roadmap for more detailed examination of a particular item.

Roadmap example

Below is a sample roadmap for DER integration capacity analysis, and a set of drivers a utility or regulator may encounter, and suggesting goals that address them. The relative complexity of the goal increases from left to right, providing a framework for roadmap participants to consider the relative merits of and need for a goal that requires more detailed analysis.

Roadmapping participants that could be internal to a utility or include outside stakeholders, are able to suggest and discuss additional drivers, goals, barriers, and solutions, and appropriate linkages with other roadmap components.

[131] Portland State University Engineering Technology Management Department

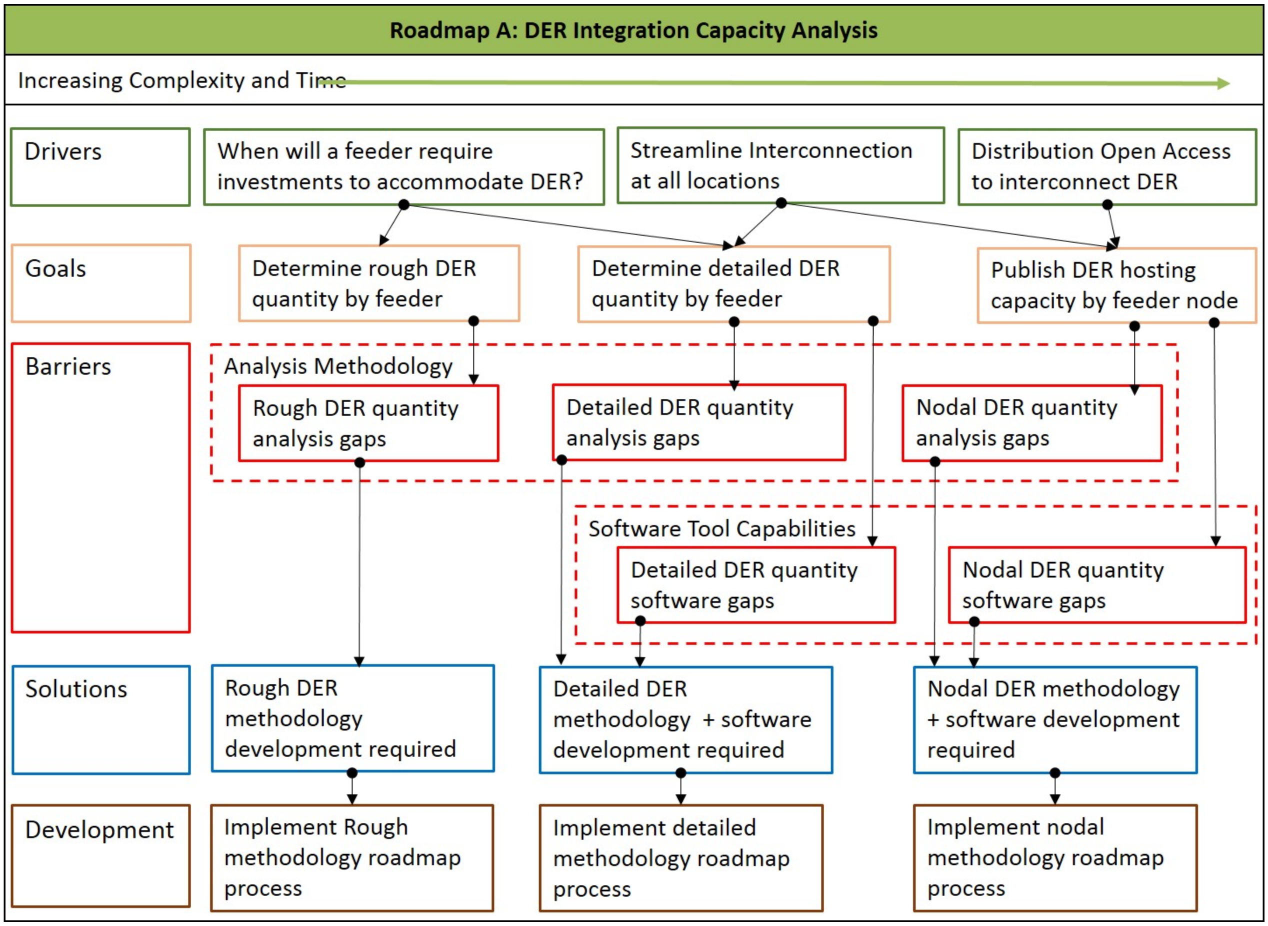

Figure 34: Sample Roadmap Source: EQL

Note: this is a sample roadmap addressing integration capacity analysis as described in section 4.6 and is shown only to illustrate the steps in the roadmapping process described above to lay out one possible method of addressing this analysis A primary goal of the roadmapping process is to generate participant input during each step such that appropriate content is present to best inform the subsequent step. The roadmap sample shown is analogous to a straw proposal, where initial concepts are presented with the expectation that process participants will more fully and appropriately develop the ultimate content.

6 Priority Reading – Review of Literature

Author: Electric Power Research Institute.
Report: The Integrated Grid: A Benefit-Cost Framework
Date: February 2015
Summary: EPRI's paper addresses integrating grid planning concepts across processes that are traditionally separated, such as distribution planning and transmission planning. EPRI lays out a framework for valuing DER on utility distribution systems and for comparison with traditional investments. Integration of DER such as solar PV at the distribution level is discussed, including problems associated with high penetrations, potential solutions and methodology for DER determining hosting capacity.

http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004878

Author: Paul De Martini, California Institute of Technology Resnick Sustainability Institute & Greentech Leadership Group
Report: More Than Smart, A Framework to Make the Distribution Grid More Open, Efficient and Resilient
Date: February 2015
Summary: This paper is associated with the DRP efforts underway by California utilities, proposing key principles for distribution planning and DER integration and suggesting new roles for utilities in distribution operations. A larger contribution to planning and wholesale market operation from DER is contemplated, and a discussion is included around ways the system architecture could be refined in order to achieve this goal. Concepts around distribution system operation are discussed and an enhanced coordination role is suggested for utilities. The Greentech Leadership Group holds an ongoing working group which may produce updated content at a future date.

http://greentechleadership.org/wp-content/uploads/2014/08/More-Than-Smart-Report-by-GTLG-and-Caltech.pdf

Author: California Public Utilities Commission
Report: Guidance for Section 769 – Distribution Resource Planning
Date: February 2014
Summary: This guidance document sets forth requirements for utility DRP filings, due by July 1, 2015. These filings are required by AB 327, signed into law in 2013. While the content required of utilities is more limited in scope than what is contemplated in the More Than Smart paper, the CPUC is asking for more rigorous distribution analysis than is typically conducted today. See section 4.6 on DRP.

http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF

Author: Emma M. Stewart, et al., Lawrence Berkeley National Laboratories
Report: Software-Based Challenges of Developing the Future Distribution Grid.
Date: August 2014
Summary: In many cases, utilities such as those engaged in DRP analysis will need improved distribution modeling tools. This paper outlines drawbacks of the current distribution planning tools used by utilities by describing the types of analysis that will be required with high DER penetrations and suggesting areas where these tools could be improved. One conclusion reached is that some tools are being tasked with analyses for which they were not designed, resulting in new user requirements or new software tool development needs. Another conclusion is that data exchange capabilities between separate models may need to be improved to enable the types of advanced distribution analysis required for utilities with high DER.

http://eetd.lbl.gov/sites/all/files/lbnl_6708e.pdf

1. Appendices

1.1 Glossary of Terms and Acronyms

Acronym	Definition
ADMS	Advanced Distribution Management System. ADMS includes functions that automate outage restoration and optimize the performance of the distribution grid. ADMS functions being developed for electric utilities include fault location, isolation and restoration; volt/volt-ampere reactive optimization; conservation through voltage reduction; peak demand management; and support for microgrids and electric vehicles.
Aggregator	Third party managing aggregations of DER systems located at customer facilities. The aggregator may own the DER systems or may only operate the DER systems
Area EPS	An EPS that serves Local EPSs
CHP	Combined Heat and Power
CIS	Customer Information System. System with customer information, including personal information, billing information, customer load profile information, etc.
CPUC	California Public Utilities Commission
DC EPS	A Local EPS that operates direct current
DER DML	Distributed Energy Resource. A distributed set of one or more energy service resources, including generators, energy storage, controllable load, and ancillary services Daytime Minimum Load. In Hawaii daytime minimum load is from 9am to 5pm on the distribution substation. DML is used as metric to determine how much DER is allowed on a particular substation
DER Operator	Responsible party for operational aspects of the facilities and their DER systems (generation, storage, and controllable load)
DER Owner	Responsible party for market and financial decisions and contracts related to the facilities and their DER systems (generation, storage, and controllable load)
DERMS	DER Energy Management System. System that manages the settings and dispatch of DER systems
DESS	Distributed Energy Storage System
DG	Distributed Generation
DMS	Distribution Management System
DRP	Distribution Resource Planning
DR	Demand Response

Acronym	Definition
ECP	Electrical Connection Point. Point of electrical connection between the DER source or sink of energy and any EPS. Each DER unit has an ECP connecting it to its local power system; groups of DER units have an ECP where they interconnect to the power system at a specific site or plant; a group of DER units plus local loads have an ECP where they are interconnected to the utility power system. NOTE For those ECPs between a utility EPS and a plant or site EPS, this point is identical to the point of common coupling (PCC) in the IEEE 1547 "Standard for Interconnecting Distributed Resources with Electric Power Systems".
Energy Storage	DER unit that includes the capability to store energy in any form which can eventually be converted to electrical energy
EPS	Electric Power System. Facilities that deliver electric power to a load
EV	Electric Vehicle. Automobile which is powered completely or in part by electricity and whose battery can be charged from an EPS
EVSE	Electric vehicle service element
FDEMS	Facility Energy Management System. System that manages the settings and dispatch of DER systems within a facility. This facility could be a residence, a building, a commercial site, an industrial site, or any other generic location.
FDEMS	Facility DER Management System
GIS	Geographic Information System. Geographic model of the distribution system, including the location and characteristics of all distribution equipment and DER systems (individually and/or in aggregate)
GDML	Gross Daily Minimum Load.
ICT	Information and Communication Technology
IEC	International Electrotechnical Commission
IEEE	The Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
L/HFRT	Low and High Frequency Ride-Through
L/HVRT	Low and High Voltage Ride-Through
Local EPS	An EPS contained entirely within a single premises or group of premises
Microgrid	A group of interconnected loads and distributed energy resources with defined electrical boundaries that acts as a single controllable entity and is able to operate in both grid-connected or island mode.
Microgrid EPS	A Local EPS that can operate as an island and is operated as a virtual resource to the Area EPS
Feeder Node	A bus or pole location, or physical point used to localize a piece of equipment, e.g., transformer, switch, or fuse.
PCC	Point of Common Coupling. The point where a Local EPS is connected to an Area EPS.

Acronym	Definition
PURPA	Public Utility Regulatory Policies Act
REC	Renewable Energy Certificates
REP	Retail Energy Provider. Third party managing DER systems based on market information.
RPS	Renewable Portfolio Standard.
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition. Systems used by utilities for centralized monitoring and control of substation and other field equipment
SIWG	Smart Inverter Working Group
UL	Underwriters Laboratory
VAR	**Volt**-Ampere Reactive (**var**) is a unit in which reactive power is expressed in an AC electric power system. Reactive power exists in an AC circuit when the current and **voltage** are not in phase.
VER	Variable Energy Resources, e.g., Solar, and Wind
VVO	Volt/Var Optimization
WECC	Western Electricity Coordinating Council