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IEEE JOINT TASK FORCE ON QUADRENNIAL ENERGY REVIEW

July 7, 2014

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IEEE REPORT TO DOE QER ON PRIORITY ISSUES

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Executive Summary

DOE Quadrennial Energy Review (QER) has requested IEEE to provide insights on a set of priority issues. The IEEE PES organization utilizes synergies among private sector (e.g. utilities, vendors), academia, national labs, regulatory organizations, and other industry participants to provide the unbiased and independent technical leadership to electrical power and energy industry in the US and worldwide.

The IEEE has recruited leaders from our membership to develop a document to respond to DOE priority issues. The leaders have engaged a large IEEE volunteer community, including IEEE PES Technical Committees, to support this initiative. Our responses are based on recent work by IEEE members and other industry publications.

Each section addressed in the document and listed below is one of the DOE QER priority topics:

1. Effects of renewable intermittency on the electric power grid and the potential role of storage in addressing these effects
2. Utility and other energy company business case issues related to microgrids and distributed generation (DG), including rooftop photovoltaics
3. The technical implications for the grid (bulk and local distribution) of electric vehicle (EV) integration - and the timing you see as necessary to avoid having the grid status slow down any potential progress
4. The implications and importance of aging infrastructure and the options for addressing these challenges, including asset management
5. Recommendations for metrics for addressing Smart Grid issues, especially to help policy makers determine the importance and necessity of protocols
6. Skilled workforce issues
7. Report cards on the condition and performance of the electric grid -
   This was a lower priority topic not to be addressed in detail. It is planned to be addressed in the future.

The IEEE has delivered to DOE QER:

- The executive summary report consisting of individual executive summaries for each topic, including key findings and recommendations
- The overall report with detailed information on each topic

This document is a draft report that will be further reviewed by the IEEE membership. It is planned to be submitted as a final report by end of August 2014.

Reports on Priority Issues

1. Effects of renewable intermittency on the electric power grid and the potential role of storage in addressing these effects

At low levels of penetration of intermittent (variable and uncertain) renewables, their variable and uncertain output is not a serious issue as bulk power systems are designed to accommodate the inherent uncertainty of load and deal with the contingencies of unexpected equipment outages.

At higher penetration levels, mandated by some state Renewable Portfolio Standards (RPS) extensive studies and real world experience integrating intermittent renewables in the USA power system, up to annual energy penetration levels of around 30+%, have shown that the variability and uncertainty can be tolerated if **traditional power system planning and operations are updated**, assuming availability of options such as demand response and fast responding generation. These changes are beneficial to power system operations and economics even if an RPS mandate is not imposed on that particular power system.

Operational impacts of intermittent renewables include **voltage and reactive power management, frequency regulation, and transients.** Studies of such impacts at various levels of renewable integration are required for proper planning and operation of the power system.[1,2] System reactive power support needs to be provided either by renewable generation with dynamic voltage control or by conventional generation and dynamic reactive power sources (such as SVC[3] and STATCOM[4]). Fast detection of dynamic voltage instability conditions and proper mitigation methods are needed to prevent large system outages[5]. Proper frequency regulation requires enough spinning reserve to accommodate wind ramps and to address impact of lower inertia of renewable generation, compared to conventional. Modern technology, including smart inverters, enables solving the above technical issues, but requires additional **investments in equipment capital and O&M costs, better grid monitoring, and implementation of appropriate interconnection standards.**

There are other unresolved issues such as the **institutional challenges of transmission expansion, balancing authority (BA) consolidation or cooperation, jurisdictional authority, cost allocation, adequate revenues for conventional generation as well as a plethora of market design challenges and regulatory and government policies.**

At these same levels of penetration, energy storage, while a useful and flexible tool is not essential as other, often more cost-effective options are available such as demand response, fast responding generation, and curtailment of

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[1] B. Grant and M. Schuerger, "Minnesota Renewable Energy Integration and Transmission Study," Minnesota Department of Commerce, September 2013. Available: http://mn.gov/commerce/energy/images/MN_RE_Integration_Study_2014_pres_Stakeholder_Mtg_091313.pdf

[2] J. Eto, et al., "Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation," Lawrence Berkeley National Laboratory report, LBNL-4142E, December 2010.

[3] Static VAR Compensator

[4] Static Compensator

[5] M. Glavic, D. Novosel, E. Heredia, D. Kosterev, A. Salazar, F. Habibi-Ashrafi, M. Donnelly, "See It Fast to Keep Calm," IEEE Power and Energy Magazine, July/August 2012.

the intermittent generation. Further, **curtailment is simply less expensive than energy storage up to and above levels of curtailment in the 20+% range. Energy storage is a beneficial resource but it is a grid resource and not a barrier to or enabler for penetration of renewable energy.** Energy storage efficiency is a function of the specific technology and can result in energy losses in the 15-35% range[6].

Energy storage at very high penetration levels of intermittent renewables is a different matter. Pursuit of levels of penetration approaching 100% of the energy supply is driven by policy considerations. Output from wind generation at these levels will often exceed load, especially during the seasons of high wind. Output from photovoltaic (PV) generation at these penetration levels may greatly exceed load during minimum daytime loading conditions, especially in the spring and fall. Incremental PV additions at these penetration levels have a declining economic value unless truly affordable energy storage becomes available. Here the first principle is that energy storage needs to be cheaper than the generation source. The storage duration (length of discharge at rated power) needed to achieve nearly 100% penetration levels (all energy needs supplied by intermittent renewables) is hundreds of hours - effectively seasonal storage. Electricity storage at these levels is generally not affordable at present cost of storage and the alternative of fuel storage or very large hydroelectric projects is the economic choice.[7,8,9]

On the distribution system, high penetration levels of intermittent renewable Distributed Generation (DG) creates a different set of challenges than at transmission system level, given that distribution grids were generally designed to be operated in a radial fashion and DG interconnection violates this fundamental assumption. Impacts caused by high penetration levels of intermittent renewable DG can be complex and severe and may include voltage increase, voltage fluctuation, interaction with voltage regulation and control equipment, reverse power flows, temporary overvoltage, power quality and protection concerns, and current and voltage unbalance, among others. These impacts may be mitigated using a combination of conventional and advanced (Smart Grid) solutions. **Distributed energy storage, particularly battery storage systems, advanced power electronics-based technologies, such as distribution class FACTS devices[10,11], and increased real-time monitoring and control can play an important role in alleviating these issues and facilitating integration.** Moreover, updated modeling, analysis, design, engineering,

[6] A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. B. Chen, A. L. Cotter, D. T. Bradshaw, and W. D. Gauntlett, “DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA,” Sandia National Laboratories, Report SAND2013-5131, July 2013
[7] B. Sørensen, “Dependability of Wind Energy Generators with Short-Term Energy Storage,” Science, vol. 26, pp. 935-937, Nov. 1976
[8] M. Esteban, Q. Zhang, and A. Utama, “Estimation of the Energy Storage Requirement of a Future 100% Renewable Energy System in Japan,” Energy Policy, vol. 47, pp. 22-31, August 2012. Available: http://www.sciencedirect.com/science/article/pii/S0301421512002832
[9] “Does Ireland Need More Storage?,” stoRE Project, July 2013. Available: http://www.store-project.eu/documents/target-country-results/en_GB/energy-storage-needs-in-ireland-executive-summary
[10] Flexible Alternating Current Transmission Systems (FACTS) are “Alternating current transmission systems incorporating power electronic-based and other static controllers to enhance controllability and increase power transfer capability.”, A.A. Edris et al, Proposed terms and definitions for flexible AC transmission system (FACTS), IEEE Transactions on Power Delivery, Volume 12, Issue 4, October 1997, pp. 1848–1853. Distribution-class FACTS devices include distribution Static Synchronous Compensator (STATCOM), Static VAR Compensator (SVC), Dynamic Voltage Restorer (DVR), among others.
[11] J.M. Bloemink, T.C. Green, Benefits of Distribution-Level Power Electronics for Supporting Distributed Generation Growth, IEEE Transactions on Power Delivery, Vol. 28, No. 2, pp. 911-919, Apr 2013

planning and operations practices are required to facilitate integration[12] and ensure reliable and secure operation of increasingly active and dynamic modern power distribution systems.

Because of the very substantive differences and needs for transmission and distribution systems, the detailed discussion below addresses the two topics separately.

1.1 Report: TRANSMISSION

1.1.1 Introduction

Climate change is a major driver of environmental concerns today and many states have adopted renewable portfolio standards (RPS) mandating electric utilities to incorporate significant levels of renewable energy generation into their generation mix. Recent studies indicate that most RPS goals can be achieved.

✓ ***MAJOR PROGRESS IN UNDERSTANDING TRANSMISSION IMPACTS OF INTERMITTENT RENEWABLES***

Some of the transmission level grid integration issues can be addressed with long-term planning, hourly and sub-hourly production cost, and operations simulation tools (to a resolution of 5-10 minutes) up to an annual energy penetration level of around 30+%. These are results of extensive studies, which have largely converged this past year. Additionally, real world experience seems to confirm this convergence. The recent PJM studies[13] may best reflect this status. There are elements requiring additional work, largely regarding voltage, frequency and transient behaviors. There are also unresolved issues such as the institutional challenges of transmission expansion, balancing authority (BA) consolidation or cooperation, jurisdictional authority, cost allocation, adequate revenues for conventional generation as well as a plethora of market design challenges and regulatory and government policies.

1.1.2 Intermittent (variable and uncertain) renewable generation

The USA is rich in renewable energy resources[14]. A study by the National Renewable Energy Laboratory (NREL) concluded that renewable energy could supply about 80% of electric demand by 2050[15]. Although the USA has a diverse portfolio of renewable energy resources in many regions, the most plentiful and widely distributed geographically[16] are wind and PV generation, which are "intermittent" in nature.

While most wind generation installations are developed as large-scale generation sources (wind farms), most PV and a few wind facilities are interconnected at distribution level, presenting additional challenges that are discussed below as well as in Sections 2 and 3.

[12] J. Romero Agüero, IEEE Power and Energy Magazine, pp. 82-93, Sep/Oct 2011
[13] Renewable Integration Study Reports. Available: http://www.pjm.com/committees-and-groups/task-forces/irtf/pris.aspx
[14] NREL Renewable Resource Data Center. Available: http://www.nrel.gov/rredc/
[15] M. Milligan, E. Ela, J. Hein, T. Schneider, G. Brinkman, and P. Denholm, "Bulk Electric Power Systems: Operations and Transmission Planning," NREL/TP-6A20-52409-4, 2012. Vol. 4 of Renewable Electricity Futures Study, Golden, CO: National Renewable Energy Laboratory. Available: http://www.nrel.gov/docs/fy12osti/52409-4.pdf
[16] Enhanced or Engineered Geothermal System resources are also widely distributed but are at an immature state of development

Effects of renewable intermittency on the electric power grid

Intermittent renewables integration studies have been a focus of inquiry by industry, academia and government research for more than a decade[17]. Early studies often focused on the costs of "integration" while more recent studies have focused on operational issues. While there are significant impacts on both costs and operations, the most recent studies find that substantial penetration of intermittent renewables can be accommodated. However, significant changes in operational practices are essential. From the integration studies the following impacts can be identified:

- Significant penetration of intermittent renewables increases the operating reserve requirements provided via conventional generation and increases the frequency of utilization of these resources.
- Increase in planning reserve can be significant as the capacity contribution[18] of both wind and solar PV is substantially lower than their nameplate rating. The capacity value of PV tends to decline as penetration level increases.
- As the intermittent renewables have low variable O&M costs, the integration of intermittent renewables results in lower production costs and lower zonal and locational marginal prices (LMPs). This result does not include the capital investment associated with the intermittent renewables.
- Conventional generation does, however, realize lower revenues as a result of lower hours of operation.

1.1.3 Energy Storage

Energy storage is a family of technologies that serves both as an electric load and as an electric source. This capability can be used to compensate for varying grid conditions by providing or absorbing energy to help correct system imbalances and control voltage or frequency. At the system level energy storage facilities can also be used to meet peak demands (peak shaving), or be charged during low demand periods when prices are typically low and discharged during periods of high demand when prices are high (energy arbitrage).

There are numerous energy storage technologies that have been proposed over the years for application to power systems. Hydroelectric pumped storage and compressed air energy storage are the examples of mature large scale technologies. Battery storage is another technology that is mature in the form of lead acid for "stationary batteries" and UPS systems and maturing in a range of newer technologies from Sodium Sulfur (NaS) to Lithium-Ion. A rather complete review of the technologies and their stage of development is available in the most recent edition of the DOE/EPRI Energy Storage Handbook[19].

In the USA approximately 2.3% or 23,000 MW of power generation is available from hydroelectric pumped storage (HPS). An early assessment of the role of energy storage in USA power systems quantified this potential[20]. Energy storage can be a powerful and flexible tool in power system operations.

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[17] UWIG Variable Generation Integration Library. Available: http://www.uwig.org/opimpactsdocs.html
[18] Effective load carrying capability (ELCC)
[19] A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. B. Chen, A. L. Cotter, D. T. Bradshaw, and W. D. Gauntlett, "DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA," Sandia National Laboratories, Report SAND2013-5131, July 2013
[20] PSE&G (T. R. Schneider, R. V. Snow, V. T. Sulzberger, and J. Zemkowski), "An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities," EPRI EM-264, Project 225, ERDA E(11-1) -2501, Final Report, July 1976, 3 volumes

1.1.4 Energy storage need for intermittent renewables

The role of energy storage is first as a flexible tool in the management of power systems operations. In this context it is the general rapid response and flexibility that is important and the ability to "peak shave" and "load level." At low penetration levels, intermittent renewables effects are well within the ability of the power system[21].

✓ ***STORAGE MAY NOT BE ESSENTIAL EVEN AT 30% PENETRATION OF INTERMITTENT RESOURCES***

As penetration levels of intermittent renewables increases energy storage may become more important for the effective use of intermittent renewables. However, studies of significant penetration, even at levels of 30+% do not show energy storage to be essential. **Curtailment is simply less expensive than energy storage up to and above levels of curtailment in the 20+% range**.

Storage at very high penetration levels of intermittent renewables is a different matter. Pursuits of levels of penetration approaching 100% are driven by policy decisions. Policies that seek to achieve 80% to 100% wind or PV penetration levels are not based on least cost. Wind at these levels will often exceed load, especially during the seasons of high wind. PV output at these penetration levels may greatly exceed load during daytime minimum loading conditions. Incremental PV additions at these penetration levels have declining economic value unless truly affordable energy storage becomes available. Here **the first principle is that energy storage needs to be cheaper than the generation source. The storage duration (length of discharge at rated power) needs to be hundreds of hours that are effectively seasonal storage.** Only fuel storage and very large hydroelectric projects operate in this range.[22,23,24]

1.1.5 Non-storage options available to address intermittency

- The impact of variability and limited predictability of intermittent renewables is reduced by integrating these resources over a larger geographical footprint. Consequently, consolidation and cooperation among balancing areas and expanded transmission is an essential step in integrating increasing levels of intermittent renewables (as has occurred in Texas, PJM, and MISO).
- More efficient markets with shorter clearing periods, down to 5–10 minutes (as is the case already in MISO, PJM, and other regions).
- New ancillary service markets covering a wider range of needs (e.g., flexibility—faster ramp rates) beyond regulation and reserves markets already operating in portions of the United States.

[21] National Academy Press, "Energy Storage for Solar Applications," A Report by the Solar Energy Panel of the Committee on Advanced Energy Storage Systems, Energy Engineering Board, Assembly of Engineering, 1981

[22] B. Sørensen, "Dependability of Wind Energy Generators with Short-Term Energy Storage," Science, vol. 26, pp. 935-937, November 1976

[23] M. Esteban, Q. Zhang, and A. Utama, "Estimation of the Energy Storage Requirement of a Future 100% Renewable Energy System in Japan," Energy Policy, vol. 47, pp. 22-31, August 2012. Available: http://www.sciencedirect.com/science/article/pii/S0301421512002832

[24] "Does Ireland Need More Storage?," stoRE Project, July 2013. Available: http://www.store-project.eu/documents/target-country-results/en_GB/energy-storage-needs-in-ireland-executive-summary

- New conventional generation technologies or modifications to existing generators that allow faster ramp rates, lower minimum output levels, quicker start times and shorter minimum-off times.
- Increased transmission connectivity among neighboring and distant regions.
- Increased use of demand response (as is occurring now in PJM, ERCOT, California, and other regions).
- New, manageable electrical loads such as electric vehicle charging or wider use of older demand management technologies such as storage water heaters or cool storage for air conditioning loads.
- Increased use of grid energy storage.
- Improved visibility of distribution level PV output at the system level.
- Addition of a mid-term commitment (e.g., 4 hours-ahead) with updated and accurate wind and PV forecasts will allow adjustment of commitments from intermediate units, resulting in significantly less combustion turbine commitment in real-time.

1.1.6 Conclusions

High levels of variable and uncertain renewable generation will require increased electric system flexibility from other resources, to enable electricity supply-demand balance. An important aspect of managing supply-demand balance is forecasting both renewable resources and load, particularly as load patterns have been changing due to new uses of electricity, customer-side generation, or high density clustering, such as major data storage and processing operations, e.g., data banks.

Until less expensive storage becomes available, other more cost-effective solutions for addressing the variable nature of renewable energy sources must be explored (e.g. natural gas generation, spinning reserve). When it becomes available, energy storage could complement variable generation and reduce fossil plant usage.

Caveat: There are numerous technical challenges and questions of economics that remain as current research issues. Some cannot yet be answered as sufficient real world experience is lacking or the analysis lacks sufficient granularity. This is particularly true at the highest penetration levels. More research is needed in this area.

1.2 Report: DISTRIBUTION

On the distribution system, high levels of penetration of intermittent renewable DG (such as PV) create a different set of challenges[25] than high levels of penetration at the transmission system level.

DG interconnection to the distribution grid represents a challenge because traditionally the large majority of distribution facilities (substations, feeders, and secondary systems) have been designed to be operated in a radial fashion with unidirectional forward power flows (from the utility grid to customers). Exceptions to this practice are distribution networks, which are typically used in high density downtown areas of a large metropolis.

[25] J. D. McDonald, "Microgrids Beyond the Hype: Utilities Need to See a Benefit," IEEE Electrification Magazine, vol. 2, no. 1, pp. 6-11, March 2014

DG has been a subject of study and interest for the electric power utility industry, DOE, NIST, and IEEE for decades. IEEE in coordination with NIST and DOE has sponsored numerous committees, working groups, and standards to address the needs of the electric power utility industry pertaining to DG integration. Arguably the most prominent efforts are embodied by the IEEE 1547 Series of Interconnection Standards[26], which consists of a series of standards, guidelines and recommended practices that cover a comprehensive set of aspects pertaining to DG integration, including the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems[27], which is a key industry reference in this area. Furthermore, the IEEE Power & Energy Society (PES) has sponsored several working groups to address concerns and needs in this area, including the IEEE Working Group on Distributed Resources Integration[28]. In the particular case of IEEE 1547 the standard was published in 2003 and it set requirements and limitations that were originally envisioned as a means to protect utility grids from potential impacts due to DG interconnection. However, after a decade of business, regulatory and technical developments it required an update to be aligned with current trends and practices in this area. This need was explicitly recognized by the industry through the introduction of IEEE 1547.a[29], IEEE 1547.7 and IEEE 1547.8, which address needs such as voltage regulation and control via DG units, and by the opening of IEEE 1547 for revision[30]. This is an important development, since IEEE 1547 is commonly used by utilities and regulatory entities as a key reference to describe the engineering studies required by interconnection standards and procedures. In this regard, this is a key contribution of IEEE to this specific industry segment.

1.2.1 Effects of renewable intermittency on the distribution grid

- ✓ ***INTERMITTENT RENEWABLE DG CREATES MANY NEW ISSUES, NOT EXPERIENCED WITH CONVENTIONAL DG***

Common impacts of DG in distribution grids are described below.[31, 32]

- Voltage increase can lead to customer complaints and potentially to customer and utility equipment damage, and service disruption.
- Voltage fluctuation may lead to flicker issues, customer complaints, and undesired interactions with voltage regulation and control equipment.
- Reverse power flow may cause undesirable interactions with voltage control and regulation equipment and protection system misoperations.
- Line and equipment loading increase may cause damage to equipment and service disruption may occur.
- Losses increase (under high penetration levels) can reduce system efficiency.

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26 http://grouper.ieee.org/groups/scc21/1547_series/1547_series_index.html

27 http://grouper.ieee.org/groups/scc21/1547/1547_index.html

28 It is worth noting that Distributed Resources or Distributed Energy Resources (DER) is a broad term that includes various technologies, concepts and solutions such as DG, Distributed Energy Storage (DES), Demand Response (DR) and microgrids http://grouper.ieee.org/groups/td/dist/dri/

29 http://standards.ieee.org/findstds/standard/1547a-2014.html

30 http://standards.ieee.org/news/2013/ieee_1547_workshop.html

31 F. Katiraei, J. Romero Agüero, Solar PV Integration Challenges, IEEE Power and Energy Magazine, May/June 2011, pp. 62-71

32 B. Mather et al., Southern California Edison High-Penetration Photovoltaic Project – Year 1, National Renewable Energy Laboratory (NREL) Technical Report NREL/TP-5500-50875, Jun. 2011 http://www.nrel.gov/docs/fy11osti/50875.pdf

- Power factor decrease below minimum limits set by some utilities in their contractual agreements with transmission organizations, would create economic penalties and losses for utilities.
- Current unbalance and voltage unbalance may lead to system efficiency and protection issues, customer complaints and potentially to equipment damage.
- Interaction with Load Tap Changers (LTC), line voltage regulators (VR), and switched capacitor banks due to voltage fluctuations can cause undesired and frequent voltage changes, customer complaints, reduce equipment life and increase the need for maintenance.
- Temporary Overvoltage (TOV): if accidental islanding occurs and no effective reference to ground is provided then voltages in the island may increase significantly and exceed allowable operating limits. This can damage utility and customer equipment, e.g., arresters may blow, and cause service disruptions.
- Harmonic distortion caused by proliferation of power electronic equipment such as PV inverters. The aggregate effect from hundreds or thousands of inverters may cause service disruptions, complaints or customer economic losses, particularly for those relying on the utilization of sensitive equipment for critical production processes.
- Voltage sags and swells caused by sudden connection and disconnection of large DG units may cause the tripping of sensitive equipment of end users and service disruptions.
- Voltage and transient stability: voltage and transient stability are well-known phenomena at transmission and sub-transmission system level but until very recently were not a subject of interest for distribution systems. As DG proliferates, such concerns are becoming more common. To address some of these concerns, the industry is working on updating and developing new voltage and frequency ride-through standards, beyond those already discussed in IEEE 1547, and requiring DG technology manufacturers to include this feature in their products. Notable efforts in this area include those led by NERC.[33,34]

The severity of these impacts is a function of multiple variables, particularly of the DG penetration level. However, generally speaking, it is difficult to define guidelines to determine maximum penetration limits of DG or maximum hosting capacities of distribution grids[35] without conducting detailed studies. Some utilities are evaluating these penetration levels by feeder and making them available to developers[36]. This information may be used as a reference to identify potential interconnection locations.

[33] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/IVGTF17_PC_FinalDraft_December_clean.pdf
[34] http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND-2014-3122-VFRT_Paper_April-2014.pdf
[35] Maximum amount of DG that can be interconnected to a distribution feeder
[36] A notable example is Hawaiian Electric Company (HECO), which has made available up-to-date Locational Value Maps (LVM) for the island of Oahu that show the DG penetration levels of their feeders as a function of peak load and daytime peak load. It is worth noting that these LVM maps area updated on a daily basis http://www.hawaiianelectric.com/portal/site/heco/lvmsearch. Moreover, California IOUs have also made this type of information available:

a) San Diego Gas and Electric (SDG&E) http://www.sdge.com/generation-interconnections/interconnection-information-and-map,
b) Pacific Gas and Electric (PG&E) http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/
c) Southern California Edison (SCE) http://www.cpuc.ca.gov/NR/rdonlyres/2D1ED4EC-ACC9-4746-8726-F6A0D97792BA/0/SCEInterconnectionMaps.pdf

1.2.2 Actions needed to address intermittency

Impacts caused by intermittent renewable DG interconnection are addressed via a variety of mitigation measures that can be grouped into conventional and advanced (or Smart Grid) solutions[37].

Conventional solutions encompass modifying settings and operation modes of voltage control and regulation equipment, setting DG units to absorb reactive power[38], reconfiguring distribution feeder systems, and building express (dedicated) feeders for large DG interconnection.

Smart grid solutions include **dynamic volt-VAR control utilizing DG units, limiting or curtailing the output of DG units, utilizing advanced protection systems such as Direct Transfer Trip (DTT), distribution-class FACTS devices, and Distributed Energy Storage (DES)**. These advanced solutions are more complex and expensive to implement, but also more effective in alleviating complex and severe impacts. Conventional solutions are generally suitable for solving simple and moderate impacts, such as those usually found at low DG penetration levels, while advanced solutions are reserved for complex and severe effects that are more common at high DG penetration levels.

Since PV is the predominant technology being deployed in distribution systems and inverters are a key component of this type of intermittent renewable DG units, a **solution that is particularly attractive due to its cost-effectiveness and flexibility is the utilization of smart inverters**. Smart inverters are power electronics devices that besides the basic function of DC to AC conversion found in conventional inverters also include advanced features such as reactive power injection and absorption, dynamic volt-VAR control, voltage and frequency regulation, active power curtailment, voltage and frequency ride through, two-way communications, etc. The industry, and particularly utilities in the West Coast, represented by the Western Electric Industry Leaders (WEIL) Group[39], are actively advocating for the utilization of smart inverters[40]. On the technical side, the Rule 21 Smart Inverter Working Group (SIWG) sponsored by the California Energy Commission (CEC) has played a key role in increasing awareness about the advantages of this technology and its potential benefits for system operations and intermittent renewable DG integration[41].

Although engineering solutions, such as smart inverters, are available for mitigating a large variety of impacts, utilities are **constrained by technology costs, standards and regulatory practices**. The industry and IEEE have recognized this need and are currently discussing some of the technology and application aspects as part of its IEEE 1547 series of standards; however, more work is needed on the regulatory and policy side.

1.2.3 Open questions

Intermittent renewable DG is still an area of study for the industry, with several open questions. Some of these questions are strategic in nature and have business, regulatory and policy implications. What is the "optimal" or

[37] J. Romero Agüero, Review of Industry Experiences with PV Impact Studies, 2014 IEEE PES T&D Conference and Exposition, Chicago, IL, Apr. 2014 http://www.ieee-pes.org/presentations/td2014/td2014p-000546.pdf

[38] S. Teleke et al., Analysis of Interconnection of Photovoltaic Distributed Generation, 2011 IEEE IAS Annual Meeting, Oct. 2011, Orlando, FL, USA

[39] WEIL members include leaders of some of the largest IOUs in the country, such as Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) http://www.weilgroup.org/members.html

[40] http://www.weilgroup.org/WEIL_Smart_Inverters_Letter_Aug-7-2013.pdf

[41] http://www.energy.ca.gov/electricity_analysis/rule21/

recommendable balance between centralized generation and DG? Should it be left to market, regulatory and policy-making forces to define that balance? For some utilities either the balanced or high DG penetration scenarios are being considered or mandated by regulators.[42,43] Under these scenarios there is an evident need to update distribution system design, engineering, operations and planning practices. What should this distribution system of the future look like? What should be the role of DES, microgrids, and other emergent technologies and concepts under these scenarios?

1.2.4 The role of distributed energy storage

As previously discussed Energy Storage Systems (ESS) are very **effective and flexible, although expensive, solutions** to mitigate impacts and facilitate seamless integration of high penetration levels of intermittent renewable DG. Battery Energy Storage Systems is arguably the ESS technology most commonly utilized for distribution applications. Some of the most common applications of combined ESS and intermittent renewable DG[44] include output smoothing, “firming up” and intentional islanding of DG units, distribution system capacity deferral, energy arbitrage, and frequency and voltage regulation.

1.2.5 Conclusions

The fundamental problem is the fact that **distribution practices were not envisioned for a highly active and dynamic grid with bidirectional power flows and significant penetration levels of DG**. A few leading utilities are dedicating efforts to propose alternative engineering designs, e.g., close-loop operation of distribution feeders[45,46,47,48], planning, and operations practices for the distribution system of the future. Such a system has to **consider DG, either intermittent or conventional, as an intrinsic component and shift the focus from mitigating impacts or restricting proliferation to fully exploiting their potential benefits**, such as improved efficiency and reliability. This is an area of growing interest, which is part of the electric power industry’s system resiliency efforts, and that requires further support from the U.S. government.

The operation of such a complex, dynamic and active distribution grid requires a wider utilization of modern protection systems, shifting to advanced protection and automation technologies such as those used in sub-transmission and transmission grids. Moreover, modern voltage regulation and control technologies are needed, including smart inverters, and faster and continuous voltage regulation and control equipment (capabilities provided

[42] http://puc.hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf
[43] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327
[44] It is worth noting that ESS can also be utilized independently, i.e., in applications where no DG units are available. Most of the benefits described in this section are still valid for independent applications of ESS. Examples of this applications are reported extensively in the literature http://energystorage.org/energy-storage/applications-energy-storage-technology
[45] J. Romero Aguero et al., Closed-loop Operation of Power Distribution Systems for Integration of High Penetration Levels of Distributed Energy Resources, 2013 DistribuTECH, San Diego CA, Jan. 2013 http://s36.a2zinc.net/clients/pennwell/dtech2013/Public/SessionDetails.aspx?SessionID=3681
[46] R. J. Yinger, Self-Healing Circuits at Southern California Edison, 2012 Transmission and Distribution Conference and Exposition, Orlando, FL, Apr. 2012
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by distribution class FACTS devices and power electronic-based equipment) to address DG-driven intermittency issues and replace traditional technologies such as step-voltage regulators and switched capacitor banks, which provide slow and discrete (stepwise) voltage regulation and control. Additionally, extensive utilization of advanced sensors, including Phasor Measurement Units (PMU)[49], real-time monitoring, automation and control, and more effective utilization of existing AMI infrastructures, may be needed to increase system visibility and facilitate real-time operation. One of the important steps in assuring that the distribution PMU technology deployment is justified and properly developed and implemented is to define requirements and architecture needs based on a business case, including applications and infrastructure roadmaps.

High proliferation and reliance on intermittent renewable DG also requires **detailed and accurate distribution system modeling, simulation, and analysis[50], as well as DG output forecasting**. Finally, operating this type of distribution system also requires: a) the adoption of operation practices and systems similar to those used in subtransmission and transmission systems, where very-short and short term forecasting and operations play a critical role, and b) a more closely coordinated operation of transmission and distribution systems. Therefore, more advanced and integrated Energy Management Systems and Distribution Management Systems (DMS) are likely to be required. All these areas require further support and action by the U.S. government to incentivize innovation and research and development of pertinent solutions.

1.3 Recommendations

Support technology R&D and standards development

- Power electronics-based equipment to replace or complement conventional transformers, load tap changers, voltage regulators, and capacitor banks for more efficient voltage regulation and control on the distribution system.
- Low-cost distributed energy storage technologies and systems to facilitate integration of high penetration levels of intermittent renewable DG in the distribution grid.
- Modern and future distribution system designs that are suitable for active and highly dynamic grids and consider DG as an intrinsic component, and corresponding analysis, engineering, planning and operations practices.
- Unified and enforced renewable generation interconnection standards based on analysis of operational (including dynamic) system conditions to define necessary integration requirements.
- Interconnection standards for integration of distributed energy resources and implementation of concepts such as microgrids in distribution systems.
- Standards and common practices for using and handling large volumes of data available from real-time-measurements, e.g. synchrophasor, as well as business case for justifying use of those measurements based on application needs, particularly at the distribution level.

[49] G. Sanchez-Ayala, J. Romero Agüero, D. Elizondo, M. Lelic, Current trends on applications of PMUs in distribution systems, 2013 IEEE Innovative Smart Grid Technologies Conference, Washington, DC, Jan. 2013

[50] Some of the ongoing efforts in this area include the development of GridLAB-D by Pacific Northwest National Laboratory (PNNL) http://www.gridlabd.org/

Support software development

- Software tools and processes for renewable resource forecasting, energy load forecasting and market price forecasting.
- Software tools and processes for real-time, coordinated and integrated operation of distribution, subtransmission, and transmission systems (e.g., EMS/DMS).
- Improvements in current software tools (e.g., GridLab-D) for
  - Comprehensive modeling and analysis of distribution systems with high proliferation of DG, e.g., development of joint models for steady-state and dynamic/transient analyses
  - Integrated modeling and analysis of distribution, sub-transmission, and transmission systems.

Foster coordination across jurisdictions

- Resolve technical and jurisdictional issues associated with devices, such as batteries and PV inverters, that simultaneously serve both the distribution and transmission grids; and operate across institutional, regulatory, and information architectural boundaries[51].
- Support and accelerate, as practicable, regional and interconnection-wide transmission planning practices and system operating procedures, to support integration of intermittent renewable generation for public benefit.
- Support a multi-agency State and Federal Collaborative to develop model regulations and integration policy to plan for operational issues (e.g., voltage fluctuation, bidirectional power flows, etc.) to promote the most efficient deployment of variable generation.

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2. Utility and other energy company business case issues related to microgrids and distributed generation (DG), including rooftop photovoltaics

Technology innovation, decreasing costs and consumers' interest in improved power reliability, resiliency and sustainability have led to **increased uptake of distributed generation (DG), primarily solar photovoltaics (PV)**. These trends are expected to drive the microgrid market as utilities seek to manage DG – and capture other microgrid benefits – and energy service companies (ESCOs) and other sponsors seek similar goals for non-utility benefits.

Utilities must adapt to and compete with the ESCO- and customer-initiated challenges, which may require a new business model. Meanwhile, utilities are likely to implement microgrids for their own business and operational purposes. They may find that non-utility microgrids can serve their purposes as well, as the latter can provide manageable loads, an alternative source of supply and ancillary services such as voltage control and frequency regulation. Beyond managing the operational impacts of high DG penetration, **utilities can also employ microgrids to defer capital investment in additional capacity, manage problematic circuits and address localized load growth.** On the business side, microgrids may also enable a utility to offer customers differentiated quality-of-service options and participation in transactive energy markets. On the policy front, utility-sponsored microgrids can help meet the requirements of energy efficiency, peak load-reduction and load-shaping programs, as well as assist in meeting renewable portfolio standards (RPS) and goals for lower carbon emissions.

In this new mix of utility and non-utility players, **traditional grids and microgrids must be purposefully integrated as hybrid grids**. A positive microgrid business case for utilities, ESCOs and others depends on apportioning quantifiable benefit streams against costs among all stakeholders. As the performance of power electronics, PV panels and energy storage technologies improve and costs continue to drop and policy adapts to enable new business models, the market for both utility-sponsored and third-party microgrids is likely to expand. The increasing uptake of distributed generation at commercial/industrial and residential premises, largely in the form of rooftop solar photovoltaic (PV) systems, is driven by several factors.

First, improvements in solar photovoltaic performance, coupled with dropping prices, have made the technology more accessible and affordable with a shorter payback period for utility customers. **Second**, customers are seeking more control of their energy destiny in response to an aging, less reliable grid, extreme weather events, uncertainty over costs and a desire to reduce their fossil fuel-related carbon footprint. **Third**, state-level policies have created incentives for PV installations by customers.

The current and projected growth in microgrids is a separate but related trend occurring among large utility customers captured by the acronym MUSH. Military installations, universities, schools and hospitals – as well as other civic institutions and corporate campuses – increasingly require improved energy surety, reliability and resilience. Microgrids can provide large utility customers with the ability to manage distributed generation (DG) in the form of diesel- and natural gas-driven microturbines and generators, solar PV and other renewable energy sources, prioritize and manage loads and achieve a degree of autonomy from the grid through self-sufficiency and, during grid outages, by "islanding" – operating apart from the grid – during grid outages.

Utilities are rightly concerned that greater customer autonomy will reduce traditional, regulated revenue streams that depend on cost-of-service rate making and volumetric pricing. Investor-owned utilities, in particular, make money by investing in infrastructure and selling electricity by the kilowatt hour. This concern could be allayed if utilities developed a positive business case for implementing their own microgrids and optimally integrating non-utility microgrids, while obtaining regulatory rewards for quantifiable customer benefits unrelated to infrastructure investment and volumetric electricity sales. **It behooves all stakeholders to develop a comprehensive understanding and quantification of microgrid-related benefits and costs to drive a new multi-stakeholder policy and regulatory paradigm**. Relevant policies, however, are developed at the state level, which creates a national policy patchwork – adding an additional level of complexity for utilities with multi-state operations. In contrast, technology standards – at least in concept – tend to be global in nature. Though fundamental standards related to grid-microgrid interconnections and other operational needs have been articulated and adopted, existing standards are being reviewed and revised and gaps identified and addressed.

From the utility perspective, high PV penetration and non-utility microgrid implementations shift the legacy, centralized, unidirectional power system to a more complex, bidirectional power system with new supply and load variables at the grid's edge. This shift introduces **operational issues such as the nature, cost and impact of interconnections, voltage stability, frequency regulation, and personnel safety.** And it impacts resource planning and investment decisions. Research and current implementations are expanding the toolkit available to utilities to address these emerging issues.

Taken together, these myriad issues mean that a positive utility business case for microgrid implementation is a complex calculus that includes evolving technology (including controls, protection and energy storage), policy and standards. How utilities address microgrids – useful asset or disruptive force? – may reflect how they handle the larger, shifting market landscape that includes flat load growth, rising costs and competitive pressures. By developing a positive business case for sponsoring or accommodating microgrids, a utility may well envision its path to a **future-oriented business model that includes new product and service offerings and favors partnerships and collaborations over customer "ownership"**. Microgrids in conjunction with Demand side management (DSM) enable a new business model, in which users pay for the level of reliability, power quality, and overall service.

2.1 Report

The key drivers for utility evaluation of microgrid sponsorship or accommodating third party- or customer-sponsored microgrids include the increasing need for reliability, resilience, capital deferral, other operational imperatives, lower carbon emissions, as well as addressing market forces, including customers' need for energy surety and sustainable practices, growing competition and customer expectations, and shifts in policy and business models.

Among the fundamental trends is the issue of aging infrastructure and related erosion of the grid's reliability. According to Lawrence Berkeley National Laboratory, 80-90 percent of grid failures begin at the distribution level. Estimates by the Galvin Electricity Initiative place the cost of grid outage to U.S. consumers well above $100 billion a year [1].

Extreme weather events such as Hurricane Sandy and its predecessors have brought attention to the need for improved resiliency on the distribution system to provide power to as many customers as possible when the grid is under physical assault. ESCOs, third-party microgrid developers and large utility customers have acted on that need by proceeding with solar PV installations and microgrids to improve energy surety, manage supply and load, manage energy use and costs and obtain a degree of control over their energy destiny – that is, a future, sustainable supply, manageable loads and the means to balance them.

The proliferation of variable output DG in the form of intermittent rooftop solar PV – often driven by increasing functionality, decreasing prices and/or policy – has introduced operational challenges including voltage stability issues, which require mitigation. Voltage instability can also cause undue wear on distribution hardware, such as load tap changers [2]. The concomitant growth in microgrid implementation by ESCOs, third-party developers and large customers likewise requires attention to the technology, policy and standards governing the interconnection between grid and microgrid at the point of common coupling (PCC). Put simply, utilities must address related operational issues.

Due to the market interest in solar PV and microgrids and the well-quantified growth in their implementation, however, utilities must manage the risk that these implementations present. Passively connecting customers' solar PV and interconnecting with their microgrids is untenable. These resources must be integrated operationally as well as incorporated into resource planning and business models. Their growth must be anticipated.

Growth in solar PV uptake in the U.S. is prodigious and likely to continue, according to the Solar Energy Industries Association: 2013 represented another record year for the U.S. market, which saw 4,751 MW of new capacity installed in 2013. That's a 41 percent increase over the prior year. Solar PV accounted for just under one-third of all new electricity generation capacity added last year; that's 29 percent growth, up from just 10 percent in 2012 over 2011. Thus, solar is the second largest source of new capacity behind natural gas.

General data on U.S. solar uptake do not necessarily reflect the clustering of solar PV that requires immediate attention. But as these trends continue, issues faced in, say, Southern California today will in time be relevant to other regions as well. Thus, energy service companies (ESCOs), third-party developers and customers have become significant market forces, putting pressure on utilities to weigh the costs and benefits associated with DG and microgrid implementations. According to Navigant Research forecasts, global capacity in megawatts offered by microgrids will rise from less than 1,000 MW in 2014 to in excess of 4,000 MW by 2020. The largest projected growth is in North America [3].

The microgrid business case for non-utility market participants will affect the utility business case. ESCOs seek to profit from providing value to utilities and customers by improving reliability, resilience and power quality through microgrid implementation. For municipalities, microgrids may offer improved reliability where aging infrastructure is known to fail, improved resilience in response to extreme weather events, economic productivity, stability and development and emissions reductions where policy calls for economic self-sufficiency and environmental goals. I.e., microgrids may be sought where energy, economic and environmental goals are embodied in local policy.

A variety of commercial/industrial utility customers also experience drivers that make microgrids an attractive option. The acronym MUSH (military installations, universities, schools and hospitals) captures a large swath of customers with the potential to benefit from microgrids, primarily but not entirely based on energy surety. Microgrids can provide beneficial support to energy surety, particularly where uninterruptible power (UIP) is required. For commercial/industrial customers including airports, factories, ports, mines, etc., UIP is required for continuity of operations and/or manufacturing processes. For hospitals, the safety of patients must be guaranteed. For universities, the integrity of special collections and continuity of processes in labs must be protected. Energy surety and its costs in these cases are typically weighed in light of the cost of the consequences of power failure. On corporate campuses, especially in regions where the cost of grid-based electricity is high or very volatile, a microgrid offering a mix of DG and load control creates an attractive business case. The same is true for isolated, off-grid communities where fossil fuel must be shipped in at great cost. In fact, “remote microgrids” may initially present the most attractive business case for utilities mandated to serve isolated communities, as is the case in Canada [4]. For military bases, mission criticality and lives trump the business case [5].

- ✓ ***A LOCAL MICROGRID SPONSOR WILL FIND LESS RESISTANCE IF IT CAN MEET ITS OWN OBJECTIVES IN A MANNER THAT ENABLES THE UTILITY TO DEFER MORE EXPENSIVE INVESTMENT OR TO MANAGE ITS GRID IN A LESS COSTLY MANNER***

State-level mandates for energy efficiency (lower overall electricity use), peak load reduction and lower emissions, as well as utility and customer incentives for achieving these goals is driving increasing rates of solar PV uptake and microgrid implementations.

The benefits of microgrid adoption, in the face of these drivers, include the improvement of system reliability and resiliency for shareholders’, stakeholders’ and customers’ benefit, deferral of capital investment in capacity (new baseload and/or peak generation), improved management of the benefits and impacts of distributed generation, an improved ability to cope with problematic circuits, serve remote or isolated communities in their service territory and promote energy efficiency, load shaping and transactive energy markets at grid’s edge. These benefits extend to improved resource planning as well as the development of new products and services that can engage customers.

The Electric Power Research Institute (EPRI) draws a useful distinction between simply “connecting” DG and “integrating” DG, a more manageable and sustainable approach to grid modernization and value creation. “As distributed resources penetrate the power system more fully, a [utility] failure to plan for these needs could lead to higher costs and lower reliability.” [6] In fact, the Tennessee Valley Authority and its local power companies (LPCs) have observed that DG’s location within the system impacts interconnection viability. Potential reliability impacts are a function of system location, DG protection and power quality. It may behoove utilities to review where they can and cannot accommodate additional DG, which could speed the review of DG and microgrid proposals. System frequency regulation, harmonics and voltage support must be reviewed [7].

Further, with regard to the available toolkit and its impact on a positive business case, EPRI suggests that an “integrated grid” should not favor any particular energy technology, power system configuration or power market structure. Instead, stakeholders must identify optimal architectures and the most promising configurations; recognizing that the best solutions vary with local circumstances, goals, and interconnections [8]. This statement underscores our aforementioned point on the relationship between quantifiable benefits and the business case. In fact, all stakeholders will benefit from a bundling of value propositions that make microgrids simultaneously attractive to utilities, their large customers and third-party enablers.

It’s important to keep in mind that a microgrid is not a single asset or type of asset; instead, it is a portfolio of assets, each with its own value stream, risk and depreciation schedule. One such asset, which will play a prominent role in operations and the business case, is energy storage. Energy storage, as explained in section 1, has several applications of potentially high value in the microgrid context, including expanding capacity, providing backup power, reducing and/or shaping load, smoothing the intermittency of variable DG, voltage control and a role in frequency regulation. Cost-effective energy storage relies on multiple though disparate applications and its value rises as it is applied closer to the grid’s edge (See Section 1 for more on the need for bundled value streams to develop cost-effective energy storage) [9].

✓ ***MICROGRIDS' VALUE PROPOSITION, PARTICULARLY FOR UTILITIES, IS POSITIVELY AFFECTED BY THE CONTINUED LOW COST OF NATURAL GAS***

The above could lead to more combined heat-and-power (CHP) natural gas-fueled projects at the distribution level, which facilitates managing the cost of peak load [10]. Utilities have a number of concerns relating to technology, policy and standards, whether they sponsor microgrids or assent to non-utility microgrids and related DG, including non-aligned policy across the states. Microgrids need anti-islanding features to prevent unintentional DG-related power flows onto a circuit where an outage or planned maintenance is occurring. Distribution protection gear is needed to safely prevent short circuits caused by DG running in synchronous, parallel interconnection to the grid. Synchronized generators in a microgrid that fluctuate to follow microgrid loads or intermittent DG can cause voltage instabilities, requiring expensive capacitor banks and voltage regulators. Utility grid operators may have no visibility into customer-owned DG, resulting in sub-optimal operations for both parties. Recent developments in interconnection technologies and microgrid controls are anticipated to provide cost-effective solutions to these concerns.

Policymakers rarely consult with a utility's technologists to understand what's feasible in terms of the electrical infrastructure required to support DG penetration when creating RPSs. For instance, on circuits (Southern California, e.g.) where the penetration of solar PV among customers is so high that substation-based load tap changer controls, attempting to maintain secondary voltage constant with a widely varying primary voltage, operate perhaps 80 times per day; they are designed to operate perhaps a half-dozen times per day. So accommodating DG comes with an O&M cost to the utility [11].

Clearly, policy can have unintended consequences. Germany is an international example of this axiom. There, the drive to achieve a high penetration of DG (wind, PV) had negative consequences for price, power quality and reliability. German policymakers had to revise interconnection rules, DG connectivity requirements, wind and PV incentives and other integration policies as a result. Per EPRI's earlier point, in Germany DG had been connected to, but not integrated with, the distribution system.

The typical, state-level regulatory approach – cost-of-service rate making and volumetric pricing – puts IOUs and microgrids at odds. Most states regulate synchronous interconnections based on IEEE 1547 (see section 1 for more details) and FERC's small generator interconnection procedures (SGIP) in FERC Order 2006.

Some states require utilities to study potential impacts of faults and unintentional islanding. But utilities can use this to prolong a decision and make it costly. Non-utility microgrid sponsors might be required to pay for added protection measures costing thousands of dollars per kilowatt hour (kWh) of capacity. In areas with low kWh prices, such a requirement can kill a microgrid project. Just anticipating these costs can inhibit a microgrid proposal. The California PUC's Rule 21 on interconnection policies – driven, in turn, by policies resulting in high penetration of DG – sets time limits on interconnection studies and mechanisms to resolve utility-microgrid sponsor disputes between utilities and non-utility microgrid sponsors.

A 2013 white paper, "Results-based Regulation: A Modern Approach to Modernize the Grid," addresses the limitations of cost-of-service regulation and offers alternative regulatory models that each state could consider adopting [12]. A recent study of policies relating to microgrid adoption in Minnesota reveals that state regulatory policies often don't address microgrids at all. But the Minnesota study suggests that state policy define and acknowledge the opportunities presented by microgrids to achieve state policies regarding energy surety and the adoption of renewable energy sources and to "ensure that microgrids are properly valued and considered in energy resource and policy initiatives." The Minnesota study identified both regulatory and legislative steps to achieve these objectives [13]. FERC policy covers DG-related projects up to 20 megawatts (MW) and how they interconnect with interstate transmission systems, relevant if the project plans to sell wholesale power into an independent system operator (ISO). FERC has issued a NOPR that it will amend its SGIP and SGIA (small generator interconnection agreement) to "ensure the time and cost to process small generator interconnection requirements will be just and reasonable and not unduly discriminatory" [14].

2.1.1 Options

These drivers and issues present utilities with a gamut of options: discourage and fight microgrids, sponsor them for operational, customer or business model benefits, accommodate ESCO-, third-party- and/or customer-sponsored microgrids, cooperate and/or partner with ESCOs, third parties or customers on such projects – or some form and/or combination of any or all of these scenarios.

Utilities will need technology, policy and standards that support any or all of these scenarios in order to integrate microgrids for optimal benefit of all stakeholders. Such a move may require changes in the utility's business model. In Germany, a high penetration of DG, encouraged by policy, has wrought changes in utility business models. First, affected utilities' business model suffered under high DG penetration. In response, the second-largest utility, RWE, re-tooled as a renewable energy service provider. The largest, EON, looks poised to follow. No such move in the U.S., yet [15].

- ✓ ***DECISION SUPPORT TOOLS TO EVALUATE THE COSTS AND BENEFITS NEEDED TO MAKE A POSITIVE, COMPLEX, MULTI-STAKEHOLDER BUSINESS CASE NEED TO BE DEVELOPED***

2.1.2 Quantifiable benefits

Yet a utility's implementation of a microgrid in various use cases can also yield quantifiable benefits both akin to and beyond those sought by a large customer. A microgrid can help a utility manage the effects of a high penetration of solar PV, particularly in the case of PV "clusters," which can cause voltage instabilities that impact utility operations and voltage-management hardware. A microgrid therefore can play a role in energy efficiency, peak load reduction and load-shaping programs, as well as assist in achieving an RPS and lowering carbon emissions. Utilities can also employ microgrids to defer capital investment in additional capacity (more generation), manage problematic circuits and address localized load growth. In the near- and mid-term future, microgrids may also enable a utility to enable customers to engage in transactive energy markets.

A utility can also benefit from customer-owned and managed microgrids as the latter can provide potentially manageable loads, a source of supply and a provider of ancillary services such as voltage control and frequency regulation.

The potential benefits, of course, must be weighed by the operational challenges introduced or exacerbated by a high penetration of solar PV and customer microgrid implementations. This trend shifts the legacy, centralized, unidirectional power provision paradigm to a more complex bidirectional power system with new supply and load variables at the grid's edge, microgrid interconnection issues and other potential impacts and costs related to grid planning, management and operations, as well as the potential threat to the utility's business model. An expanding toolkit is available to address these variables and customer and regulator attitudes on reliability, resilience, energy and operational efficiencies, sustainable energy sources and environmental impacts are shifting to accommodate change.

2.1.3 The business case

In discussing the "microgrid business case," it's important to note several distinctions.

A microgrid is defined by four qualities: it manages a group of interconnected loads, it utilizes DG, it has a clearly defined electrical boundary between it and any other power system and it has the ability to island and support load on its own.

Clearly, microgrids are not a single asset or type of asset but, rather, a portfolio of assets, each with different value streams, risks and depreciation schedules. Assets include generation, distribution, loads and storage and its operation requires advanced monitoring, control and automation. Typically, microgrids are created in multiple, overlapping phases. Underlying systems such as energy management systems (EMS) and distribution management systems (DMS) must be employed and/or upgraded for proper microgrid integration into the distribution system [16].

Reducing capital and O&M costs, while creating value streams, will help speed and increase ROI and payback time. Capital funding may be less expensive for utilities than for ESCOs, third parties and customers, based on credit ratings. Conversely, utilities that do not address market developments such the proliferation of microgrids might find credit ratings downgraded, as has happened in Germany. A shift in a utility's business model away from one that rewards capital investment and volumetric sales to one that rewards other value streams may lead to new sources of capital. Utility assets that serve non-utility manage microgrids may earn revenue. Conversely, microgrid implementation may lead to stranded assets and cost recovery that could dampen regulatory approval of utility-sponsored microgrids. Balancing shareholder and stakeholder interests may affect the business case. Thus pilot and demonstration projects with multiple stakeholders, including utilities, may present an opportunity to explore mutual benefits and value streams. Shared governance, ownership and operation may make sense. A portfolio of microgrid projects might attract financing and reduce overall risk. For one example of how to assess a microgrid-related business case, see "Microgrid Revenues, Costs, and Expenses" in [17].

The business case has multiple components and calculating return-on-investment (ROI) isn't a simple calculation, based on the drivers and desired outcomes. Beyond technology's capital costs other factors loom, including energy surety, improved reliability and resilience, economic stability, and environmental issues, among others. Some benefits are more easily quantified than others. For instance, energy surety for a profitable enterprise may be measured by the productivity lost to an outage, but energy surety for a military installation is less quantifiable. Until or unless a quantifiable price is assigned to carbon emissions, for instance, cutting emissions may be difficult to plug into a business case.

One area in which microgrids can support a known, positive business case is when they act as virtual power plants (VPPs), where the generation resources they control and the loads they can relieve (demand response, particularly automated demand response, or ADR) may be bundled as a service to a customer or the utility and grid to which they are tied. Microgrids and VPPs have a large overlap in their array of assets, but key differences as well –

therefore, the two terms clearly are not synonymous. But a microgrid that can act as a VPP taps into another value stream that can contribute to a positive business case [18].

Further, a collection of quantifiable benefits, in general, do not necessarily equate to a positive business case. A positive utility business case for microgrids is difficult to generalize and depends on each utility's unique circumstances, challenges, alternative solutions, financial calculations and the details of the proposed project itself.

Policymakers, regulators, sponsors, stakeholders and customers may value various benefits differently and, ultimately, a market may set the value, which may change over time. The business case is also affected by local policy incentives and/or grants such as that encouraging energy efficiency, demand response, etc.

Still, understanding the quantifiable benefits and the components of the microgrid toolkit should enable individual utilities to explore their own business case.

Following are detailed recommendations related to technology, policy and standards.

2.1.4 Technology

The U.S. DOE could offer technology roadmaps and R&D investments via national labs and selected pilot projects to foster microgrid implementation by utilities to assess business and operational issues.

- ✓ ***THE TECHNOLOGY OF CONTROLS AND SENSORS, SMART INVERTERS, ENERGY STORAGE AND POWER ELECTRONICS FOR MICROGRID OPERATION AND APPLICATIONS EXIST TODAY AND ARE EVOLVING RAPIDLY TO SERVE THE MYRIAD AND DIVERSE USE CASES PRESENTED BY UTILITIES, ESCOS AND CUSTOMERS***

Federally sponsored R&D is needed on power electronics applications (e.g., load tap changers, grid-edge controllers) to address operational challenges, including voltage stability, from high penetration of DG. Such products are just emerging from private sector labs for commercialization.

Recent developments in interconnection technologies and microgrid controls will provide cost-effective solutions to utilities' main concerns about sponsoring or accommodating microgrids.

New testing and simulation methods can rapidly prove the safety of microgrid-related technologies and practices. Every utility must establish the safety and operational integrity of microgrid interconnections and controls for themselves through active testing. But utilities can place the onus for such testing on a non-utility sponsor and require expensive, time-consuming studies that in effect thwart microgrid investment and development.

Performance data from the field in demonstration and pilot projects will allow utilities to establish a technological basis for quantifying benefits for a business case for both microgrids and energy storage's role in a microgrid [19]. ARRA projects that include storage should yield some of this data. Additional pilot projects that involve all stakeholders may provide a risk-free opportunity for utilities, which operate under a public mandate for safe, reliable, affordable power, to establish the operational procedures and impacts of microgrid adoption and to assess first-hand the related business case.

The bundling of energy storage's multiple applications and value streams remains a work in progress. The California Public Utilities Commission has mandated that utilities explore roles for energy storage and that should yield additional performance data and insights into the business case. One technology challenge for energy storage is providing controls to the end user so applications don't step on each other. Control logic must be developed so the end user can put storage to multiple uses.

2.1.5 Policy

✓ ***POLICY REMAINS THE SINGLE BIGGEST INFLUENCE ON THE BUSINESS CASE***

State-level PUCs wield the most influence. Many states are reviewing related policies as they balance utility interests with ESCO competition and the needs of the commercial/industrial and residential utility customer sectors. A state-level, results-oriented regulatory approach that rewards utilities for adopting innovations that directly benefit their customers may encourage microgrid adoption.

In terms of a federal role in microgrid-related policy development, states will continue to exercise (and defend) their role in microgrid-related policy-making. With access to resources – possibly facilitated by the U.S. DOE – on related technology and standards, regulatory reform and stakeholder impacts, however, state regulators can create policies that favor microgrid development and balance the diverse interests involved.

FERC's small generator interconnection procedures (devised by SGIP, embodied in FERC Order 2006) also are relevant to this discussion.

State policies may also need to evolve with standards through a regular, consistent process, both to encourage microgrid development and reward utilities for cooperating with a customer benefit that cuts into its revenue. Policy and standards should work in hand-in-hand.

One area ripe for revision: where a state has a restrictive definition for DG capacity for its interconnection requirements. Current rules require large microgrid proposals to forge unique agreements with a utility at great cost and uncertainty.

California regulators have articulated many of the issues that policy must address, as has the National Regulatory Research Institute. [20] Both efforts provide an in-depth look at the complexity and interrelated nature of many microgrid-related policy issues as utilities, independent system operators, ESCOs, customers and other stakeholders are linked technologically and in wholesale and retail markets.

Critical regulatory issues currently being reviewed include, among many others:

- How costs and benefits are apportioned to myriad stakeholders (and how that affects cost recovery for utilities),
- Whether a microgrid relies on the distribution system (or transmission system) for backup and how that might affect reliability,
- Whether and how to treat non-utility microgrid sponsors as utilities, and
- Multiple possible business models for utilities offering microgrids.

2.1.6 Standards

Interconnection standards, specifically IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems, continue to evolve to accommodate utility concerns on microgrid control and safety particularly regarding interconnections, islanding and anti-islanding modes for microgrids.

A primary goal for interoperability of advanced microgrids is the revision of IEEE 1547 including appropriate electrical standards for microgrids that enable stable and secure interconnection, enable high penetration of renewable energy resources and PEVs, and include grid supportive functionalities. Further considerations include end-use operational support, applications, and regulatory and related technical needs. More detailed description of efforts related to IEEE 1547 Series of standards is described in Section 1.

Furthermore, SGIP 2.0, Inc., with continued federal support, has taken the lead in identifying gaps in standards through its Priority Action Plans (PAPs) to coordinate the work of standard development organizations (SDOs) on microgrid-related standards. We recommend that federal support continue for this effort.

The recently finalized draft for the SGIP PAP for microgrid standards provides an overview:

"To optimize both the needs of the microgrid and the needs of the broader grid, the microgrid controller must communicate with and interact with the macrogrid operations and markets and with other microgrids, in addition to communicating with the individual resources within the microgrid.

Coordinated and consistent electrical interconnection standards, communication standards, and implementation guidelines are required for microgrids and their interaction with the macrogrid. Although there are standards that define the basic microgrid connection and disconnection process, there are no standards that define the grid interactive functions and operations of microgrids with the macrogrid. Since standards already exist for managing loads and DER devices themselves within the various physical domains of the microgrid, the priority action plan (PAP) will focus on the grid facing functionalities and communications (e.g., microgrid to/from macrogrid). That said, the PAP will address consistency and interoperability of the information models and signals used by microgrid controllers.

A broad set of stakeholders and SDOs is needed to address this coordination and evolution in order to revise the IEEE 1547 electrical interconnection standard as appropriate to accommodate Smart Grid requirements and to extend the DER object models in IEC 61850-7-420 to microgrids as distinct interconnected entities. Coordination with IEEE SA, IEEE PES, DOE, national laboratories, NIST, IEC, EPRI, UL, SAE, NEC-NFPA70, and regulatory bodies will be necessary to ensure optimal implementation of standards supporting likely future scenarios across a wide range of use cases. This effort will need to address the microgrid at community, industrial, commercial, military, university and critical infrastructure locations. The cooperative relationship between the microgrid, distribution utility, ISO and markets needs to be given particular attention."

Standards development organizations (SDOs) with which the microgrid PAP will communicate with are the IEEE PES, IEC and NEMA. The microgrid PAP will communicate with are EPRI, DOE, CPUC, distribution utilities, NARUC and ISOs. A deliverable of the PAP will be IEEE 1547 revision, including requirements for microgrid interoperability.

"At the same time attention must be paid to defining information models for the microgrid controller communication with the Distribution Management System (DMS) and communication with other microgrid and EMS controllers. The information model interoperability requirement will be delivered to SDOs for inclusion in CIM and MultiSpeak."

"In the course of developing the interoperability requirements for microgrid interconnection standards, microgrid controller standards, and information model standards for grid facing communications of the microgrid, the PAP will document associated considerations for testing microgrid interconnection equipment and microgrid controllers, and for performing grid impact studies of microgrids. These considerations will be documented in a white paper that will inform IEEE P1547-REV and UL 1741…” [21].

IEEE’s Smart Grid Interoperability 2030 Series offers a draft guide for IT, electric power systems and end-use loads and applications. The working group involved is continuing efforts on EV integration (IEEE Standard P2030.1) and energy storage (IEEE Standards P2030.2 and P2030.3) [22].

An IEEE Power & Energy Society (PES) and IEEE Standards Association (SA) Working Group, DC@Home, is exploring the potential for DC-generating DG (wind, solar) to directly supply DC loads, which can include the bulk of business and home electronics-based appliances. DC-based microgrids could improve efficiencies by eliminating dc-to-ac, then ac-to-dc conversions, and address many utility concerns on reactive power, the need to synchronize multiple, diverse generation sources to a single ac grid frequency, the ease of interconnection of dc generation sources (solar, wind, fuel cells) and electrochemical devices (flow and other advanced batteries).

Next steps in technology, policy and standards might include a federal role in technology research and development, sponsorship of microgrid demonstration projects to quantify benefits and business cases, policy alignment and support for state policies and continued support for the standards development process.

✓ ***A PATH TO ACCELERATED UTILITY ADOPTION OF MICROGRIDS SHOULD BE SUPPORTIVE OF CLEAR, ATTRACTIVE BENEFITS FOR THE UTILITY IN THE CONTEXT OF A HYBRID GRID***

Where a microgrid is sought by a third-party developer or customer, utility accommodation should, at a minimum, not adversely impact the affected utility financially or operationally. The identification of mutual or complementary value streams will accelerate microgrid adoption. Decision support tools for quantifying benefits and composing a business case would be highly useful to utilities. Costs and benefits must be apportioned to each relevant party in a microgrid business case. Policy should support value creation, with results-based rewards for utilities, and not unduly favor incumbent utilities over non-utility microgrid sponsors.

Utility business case-, operations- and safety-related lessons learned from utility-sponsored microgrids developed with U.S. DOE participation under the ARRA should be documented and disseminated. New projects involving the gamut of stakeholders, including distribution utilities, should provide the latter with operational, safety and financial insights to inform their perspective. The U.S. DOE could offer research and development as well as technology roadmaps to foster microgrid implementation by utilities.

2.2 Recommendations

The IEEE QER Team recommends that a path to accelerated utility adoption of microgrids be supportive of clear, attractive benefits for the utility. Where a microgrid is sought by a third-party developer or customer, utility accommodation should, at a minimum, not adversely impact the affected utility financially or operationally.

- Policy should support value creation, with results-based rewards for utilities, and not unduly favor either incumbent utilities or non-utility microgrid sponsors.
  - Include managing life cycle costs, efficiency, reliability, safety, and grid supporting resilience.
  - Costs and benefits must be apportioned to each relevant party in a multi-stakeholder microgrid business case to accelerate microgrid adoption.

- o Regulatory policy must be reviewed and revised to reward a utility for the costs incurred in planning, operational changes and the optimal integration of these customer- or utility-owned assets. New projects involving the gamut of stakeholders, including distribution utilities, should provide operational, safety and financial insights to support the policy.
- Utilities need to review where and how best to accommodate microgrids and DG given existing policy, which could speed the review of DG and microgrid proposals, including system frequency regulation, harmonics and voltage support.
- The U.S. DOE to continue offering technology roadmaps and R&D investments via national labs and selected pilot projects to foster microgrid implementation by utilities.
- Utility business case-, operations- and safety-related lessons learned from utility-sponsored microgrids developed with U.S. DOE participation under the ARRA should be documented and disseminated.
- The DOE should continue sponsoring R&D in power electronics applications (ex. load tap changers, grid edge controllers) and microgrid controls to address operational challenges, including voltage and frequency regulation, from high penetration of DG.

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2.4 Potentially useful graphics

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    - Value to customers, see Figure 1, page 96
    - S&C MG cost evaluation tool, Table 2, page 99

3. The technical implications for the grid (bulk and local distribution) of electric vehicle (EV) integration - and the timing you see as necessary to avoid having the grid status slow down any potential progress

Vehicles with electric drives have been on the market in modern times for more than a decade, starting with the Toyota Prius conventional hybrid (HEV – hybrid electric vehicle) in about 2000. Plug-in Electric Vehicles (PEV) have started entering the market only very recently. Most major automakers have a plug-in hybrid or battery-only powered vehicle on the market. So far in 2014, conventional hybrids and PEVs are almost 3 percent of the market[1,2]. More than 1 million of such vehicles have been sold to date, of which more than 225 thousand have been plug-ins. With fuel prices rising again in 2014, sales of PEVs have doubled from May of 2013[2]. If that trend should continue on the current trajectory, the country will see more than 1 million plug-in vehicles sold by 2025[3].

To help accelerate this pace eight states have formed an electric vehicle compact.[4] These states include California and New York and account for 28% of the total vehicle market in the US. The goal of the compact is to make it possible for more than 3.3 million "zero-emission" vehicles to be on the roads in those 8 states by 2025. This would be a tripling of the current pace of growth for electric vehicles and plug-ins specifically.

On the West Coast, there is work underway to provide a North to South fast charging infrastructure that will allow a driver to make the drive from Mexico to Canada without having to wait for regular charging[5] times.

The growth in charging infrastructure gives PEVs a leg up on other zero emissions vehicles (ZEVs). More than 1,000 public charging stations exist today and more than 14,000 are planned or under contract[6]. In addition, Plugshare offers pointers to more than 50,000 charging locations in North America[7]. These include many private chargers that the owners are willing to share with others who are traveling.

For Generation and Transmission, 8 to 12 million PEVs can be accepted into the grid quickly and with little impact. For distribution there is a lot of existing infrastructure that is more than 50 years old that may or may not be able to accept PEVs without some rework. Transformer cooling can be an issue. Tariffs can channel charging to specific periods of time, this has been proven across the country. Installing significant charging infrastructure in an existing parking structure can be a major undertaking. Overall PEVs are good for the grid.

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3.1 Report

3.1.1 Generation Impacts

PEV electricity use

As with conventional and hybrid vehicles, the actual (vs. EPA-sticker) consumption varies with driving patterns, climate, wind loading, and weather conditions. A number of studies have and continue developing actual electricity use data, which is needed to establish the impact on the power system. Some of the readily available data includes The EV Project[8] indicating an average of 5 to 10 kWh/day. San Diego Gas Electric suggests a range of 6 to 8 kWh/day.[9]

PEVs have a shorter electric range on very cold and very hot days because the drivers run the heaters or air conditioners. This means that on those days PEVs may actually consume more electricity to fully charge, raising the total demand on the grid. This increase in demand may correspond with critical peak days on the grid. So far there is only anecdotal information, but the impact is worth watching. Anecdotal evidence includes an Upper Peninsula Michigan user[10] who averaged 38 kWh per 100 miles (~12 kWh/day) on his Chevy Volt over the last 12 months, which included the coldest winter in history. Idaho National Laboratory Advanced Vehicle Testing Activity report[11] finds that air conditioning at moderate temperatures (up to 80 deg F) adds 354 Wh/mile (~1.1 kWh/day) to a Chevy Volt's electricity use.

- ✓ ***3.3 MILLION PEVS SUGGESTED BY THE 8 STATE COMPACT SHOULD NOT HAVE A NEGATIVE IMPACT ON THE GENERATION CAPABILITY OF THE GRID***

Should the eight state compact be successful and the majority of those 3.3 million vehicles be PEVs, then the total consumption on a daily basis will be a minimum of 1.7 Giga-watt hours (GWH). While this is a small percentage of the total daily consumption of electricity, it is a significant amount of energy to produce.

It should also be noted that there may be a high degree of synergy between PEVs and renewables — battery charging is expected to be mostly an overnight activity and the wind resource tends to be strong at night. Even if all of the 190 million cars were replaced by PEVs, it may not be an insurmountable problem for the grid of the future. A roughly 20 percent penetration of wind power could provide the entire electricity supply needed for battery charging.[12]

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The original plan for charging PEVs was to charge them off peak, at night, using excess baseload generation. With the recent draft ruling by the EPA[13] and changes in the generation capacity of renewables as best illustrated by the California Duck Curve[14] the time of charging may change from off peak at night to daytime to correspond with peak solar production.

The current 8 hour charging period for slow charging of cars is longer than the solar maximum period which is approximately 5 hours[15], this may mean in the long run that some changes to the charging cycle may be needed to best fit the available solar generation. Diurnal wind patterns vary by location, though generally the highest production is expected from late evening to early morning hours. Again this may mean adjusting the charging rates for PEVs to match the maximum production periods.

Manufacturers are planning vehicles where the batteries can be used to deliver electricity back to the grid, as well as providing power for transportation. This has a possibility to stabilize the overall generation on the grid, depending on number of PEVs that are available. This will depend on users' willingness to use PEVs as a resource to the grid as it will reduce the life of a battery and make the PEV use more complicated.

- ✓ ***8 TO 12 MILLION VEHICLES WOULD NOT REQUIRE ANY ADDITIONAL OFF-PEAK CAPACITY***

If the existing generation environment continues to exist, the generation capability off-peak should be able to charge approximately 8 to 12 million electric vehicles without additional off peak generation capacity[16]. With the exception of the difference in peak production times for wind and solar compared to typical charging times for PEVs, there seems to be no real issues with growth of PEVs and the ability to generate electricity to charge them.

3.1.2 Transmission

The bulk electric or transmission system is built to move large amounts of energy from one location to another. The system was built with the growth in energy consumption in mind. The system has redundancy built into it by design, since it is critical to moving energy from the generation plants to the distribution system.

- ✓ ***AT THE PRESENT TIME, NERC DOES NOT SEE A MAJOR ISSUE WITH THE NEEDS OF THE TRANSMISSION SYSTEM BASED ON EVEN THE HIGHEST PROJECTION OF PEV GROWTH***

With most PEV charging happening off peak at night, the transmission system should be able to handle the load from between 8 and 12 million PEVs without any major upgrades. This assumes a reasonably even distribution of PEVs around the United States. Should most or all of the PEVs cluster in a single region, then they may drive off peak demand enough to change when the peak demand for transmission services are and with that drive the need for

[13] Carbon Pollution Standards, EPA. Available: http://www2.epa.gov/carbon-pollution-standards

[14] "What the duck curve tells us about managing a green grid," California ISO Fast Facts. Available: http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

[15] Ibid

[16] X. Fang, S. Misra, G. Xue, and D. Yang, "Smart Grid - The New and Improved Power Grid: A Survey," Communications Surveys and Tutorials, IEEE (Volume: 14 ,Issue: 4) October 2012. Available: http://ieeexplore.ieee.org/xpl/articleDetails.jsp?arnumber=6099519&sortType%3Dasc_p_Sequence%26filter%3DAND%28p_IS_Number%3A6341161%29

additional transmission capability. The North American Electricity Reliability Council (NERC) does an annual planning exercise that looks into the needs over the next decade.[17]

3.1.3 Distribution

The local electrical distribution system (distribution) runs to each building that consumes electricity. In many cases the transformers that step down the voltage serve only a couple of homes. The equipment in many neighborhoods was installed in the 1950s and was set up to provide electricity to homes that did not have air conditioning or consumer electronics. In 1960 the average connection between the grid and a residence was 60 A, today many homes demand 1 A or more 200 A connections.[18] This change in demand from the 1950s to today leaves many older neighborhoods running at the edge of the capacity of the overall distribution system in those neighborhoods. In order to keep the distribution equipment running many utilities count on the over-night off-peak time periods as a time for equipment to cool.[19] Without this ability to cool, the equipment tends to fail.

- ✓ ***IT IS NOT ONLY THE TRANSFORMERS THAT ARE AT RISK, BUT ALSO THE CONDUCTORS (WIRES) THAT FORM THESE OLDER CIRCUITS***

Because of the way economic regulation works, utilities cannot just upgrade these circuits for some future need. Rather they have to demonstrate the need to state regulators in order to be allowed to make the required upgrades.

Newer suburban areas and urban areas tend to have a more robust infrastructure. Since many of these areas are the areas that attract the higher end consumers that tend to be the demographic that purchases new PEVs[20]. The problem with older, weaker infrastructure is masked in many cases.

Using Sacramento California as an example of what PEV growth might look like, both in newer and older residential neighborhoods; it is possible to see what the impact of PEVs may be on the distribution system.[21] In the case of Sacramento, even in the older neighborhoods, it is not the first PEV connected to a transformer that causes, problems, rather it is the 2nd to 4th PEV that is connected that causes problems.[22] The older the neighborhood, the sooner the issues manifest themselves, since the infrastructure was designed and constructed for an era where the load was lower. Similar issues have been found in Detroit, Columbus, Atlanta, and Miami.

Because on hot summer days, drivers tend to use the air conditioning, PEVs tend to use more electricity from the battery to go the same distance as on days when the air conditioning is not running. These are the same kinds of days when the load on the distribution grid is already at peak. The hotter the day, in general, the more likely the system is to be at peak load during the daytime and the hotter the distribution equipment is in the evening. Based

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[17] "2013 Long-Term Reliability Assessment," December 2013, NERC. Available: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf
[18] "Smart Grid 101 – The Basics of Smart Grid," IEEE Tutorial TUT09
[19] Ibid
[20] G. Tal, M. Nicholas, J. Woodjack, and D. Scrivano, "Who Is Buying Electric Cars in California? Exploring Household and Vehicle Fleet Characteristics of New Plug-In Vehicle Owners," Institute of Transportation Studies, University of California, Davis, Research Report UCD-ITS-RR-13-02, February 2013. Available: http://www.its.ucdavis.edu/research/publications/publication-detail/?pub_id=1839
[21] Berkheimer, J., Tang, J., Boyce, B., and Aswani, D., "Electric Grid Integration Costs for Plug-In Electric Vehicles," SAE Int. J. Alt. Power. 3(1):1-11, 2014, doi:10.4271/2014-01-0344, April 2014. Available: http://papers.sae.org/2014-01-0344/
[22] Ibid

on Sacramento's situation the second vehicle to go onto a transformer will have an average cost to the Sacramento Municipal Utility District (SMUD) of approximately $1,300. This cost is based on the upgrades that had to be done to date for PEV installations in the SMUD territory. Because SMUD has a special rate for PEV charging, most customers call SMUD and tell the utility that they have PEVs. This allows SMUD to check and make upgrades prior to problems occurring. Again this clustering effect has been found in other cities in the US.

Sacramento has found that once the first PEV goes into a neighborhood, that others tend to cluster in that neighborhood as well, based on the demographics of the neighborhood.[23] The larger concern is when PEVs are resold on the second hand market in areas without special rates for PEV charging. Finding these PEV locations and checking the infrastructure prior to issues developing is not likely. Anecdotal information indicates that these vehicles are most likely to go into older neighborhoods that are gentrifying. These are the neighborhoods least likely to be able to support the introduction of PEV charging, because of the nature of the older homes, and infrastructure.

✓ DISTRIBUTION PLANNERS UNDERSTAND THE ISSUES, AND HAVE SOLUTIONS TO FIX THE ISSUES

In most cases wholesale proactive improvements in the distribution infrastructure to support the future load from PEVs is not justified in the eyes of the state regulators. With more than 2.2 million miles of distribution network in the United States and more than 50% of it being rural, older suburban, or older residential urban neighborhoods[24] at roughly $200,000 per mile for upgrades[25], to make a wholesale set of changes would be measured in trillions of dollars of upgrades. Most state regulators will opt for a more measured, reactive upgrade policy for PEV charging, rather than raising electrical rates by enough to cover a wholesale upgrade.

Transformers in the distribution system can be an issue as well. A significant portion of the pole-top and pad-mount transformers in the distribution grid are between 5 kilo-volt-amps (KVA) and 20KVA. The 15-20KVA transformers will support 1 modern 3 ton air-conditioner (A/C) starting (20KVA startup current), 3 homes running a normal overnight load (1.5KVA on average) and 1 PEV (6.6KVA load) and remain serviceable. With a second A/C unit startup or a second PEV charging on that size of a transformer, there is high probability that the transformer will fail. There are between 28 million and 44 million distribution transformers in this size range installed today in the distribution grid.[26]

Distribution companies are also highly aware of the price sensitivity of charging. As Sacramento has shown, using special charging tariffs not only moves the vast majority of the charging into the desired window of time, but it also helps pinpoint the location of the PEV.[27]

[23] Ibid

[24] "Transmission & Distribution Infrastructure," Harris Williams & Co. White Paper, Summer 2010. Available: http://www.harriswilliams.com/sites/default/files/industry_reports/final%20TD.pdf

[25] "Smart Grid 101 – The Basics of Smart Grid," IEEE Tutorial TUT09

[26] "Mid-2013 Assessment and Outlook for the North American Market for HV and MV Instrument Transformers", Newton-Evans and Associates, 2013. Available: http://www.newton-evans.com/our-reports/transformers/

[27] Berkheimer, J., Tang, J., Boyce, B., and Aswani, D., "Electric Grid Integration Costs for Plug-In Electric Vehicles," SAE Int. J. Alt. Power. 3(1):1-11, 2014, doi:10.4271/2014-01-0344, April 2014. Available: http://papers.sae.org/2014-01-0344/

3.1.4 Standards for PEVs and Grid Integration

A list of both the existing standards for PEV integration and those that are in progress within IEEE are listed in Section 3.4. Beyond this work there are a number of areas where PEV standard work is required to support large numbers of PEVs being integrated into the grid. In the IEEE's GridVision 2050[28] a number of items were identified, they include:

1. **Physical grid equipment** - Transformers, conductor sizing, planning guidelines and other parts of the actual electrical grid, primarily at the distribution level. In many cases experimental work is required to establish sizing and implementation guidelines.
2. **Sensors** -Today the residential meter is the last sensor that is available to support understanding of what is going on with the PEV. Standards for PEV monitoring sensors, both for charging and discharging the PEV back into the grid need to be developed, along with supporting regulations.
3. **Controls** - Today the customer has complete control on what the PEV can and can't do. Secure controls that allow the utility, under an agreed to contract, to start and stop charging are one of the next steps.
4. **Security** - The security of communications to and from any PEV and/or charging station is critical to the integrity of the grid.
5. **Modeling and Forecasting** - How to determine what will happen tomorrow in terms of electrical demand with the increase in PEV and other distributed energy resources (DER).
6. **Direct Current** (DC) - The losses that occur in changing electricity from Photovoltaic Cells on the roof to the grid, back to DC to go into the PEV can be up to 50% of the total electricity generated on the roof.

3.1.5 Future Changes in the Grid

There are a number of changes in the grid that may occur, most of them are enumerated in the IEEE's GridVision 2050. The changes that may directly impact the integration of PEVs are:

1. The growth in Photovoltaic use on homes and businesses
2. The change in time when "off-peak" occurs, based on the increase in variable renewable generation.
3. The changes in cost and use of energy storage
4. Decreasing cost and increasing acceptance of electric vehicles
5. Increased range of electric vehicles
6. Two way batteries and electrical systems in electric vehicles

Each of these technological and economic changes will impact both acceptance of the PEVs and amount of energy consumed by them. It will also change the nature of charging times, and the way that PEVs best integrate into the grid for the highest economic benefit. It is very important that standards and research keep pace with the real world technological changes in PEV and storage technology. It is also important to realize that regulation will be the largest driver in adoption rates and the investment in the grid to support PEV integration.

[28] IEEE Grid Vision 2050 Roadmap, April 2013. http://smartgrid.ieee.org/standards/ieee-smart-grid-research/889-ieee-grid-vision-2050-roadmap

3.2 Recommendations

- **Develop a fast charging infrastructure** on all of the existing Interstate Highways. This would allow owners of PEVs to feel comfortable taking longer trips, rather than renting a non-PEV for these trips. Additional amenities at these rest stops to occupy the PEV owners during the charge period would also help to reduce the frustration of waiting.
- **Promote battery research** focused on transportation focused on longer range and battery chemistries that allow the battery to be charged in an episodic fashion so that distributed variable resources can be efficiently used for charging.
- **Promote improved cost and efficiency of various AC/DC and DC/DC converters**. Another option is to identify if a residential and small business infrastructure could allow direct current (DC) from roof mounted Photovoltaic (PV) to PEVs without a need to convert the energy to alternating current (AC) to move it to the car. Standards and building code changes are needed. IEEE's DC@Home initiative is currently looking at how to integrate DC distribution into homes and small businesses to avoid the conversion losses.
- **"Fast track" IEEE and IEC standards and research to support higher penetration of PEVs in the grid.** DOE and NIST could have an important role in helping with this process. Specifically, the proposed standards and research include:
    a. **Physical grid equipment**, primarily at the distribution level. Experimental work is required to establish sizing and implementation guidelines.
    b. **Sensors** for PEV monitoring, both for charging and discharging the PEV back into the grid, along with supporting regulations.
    c. **Controls** that allow the utility (in addition to the customer), under an agreed to contract, to start and stop charging the PEV.
    d. **Security** of communications to and from any PEV and/or charging station.
    e. **Modeling and Forecasting** to determine what will happen tomorrow in terms of electrical demand with the increase in PEV and other distributed energy resources.
    f. **Reduction in losses**. The losses that occur in changing electricity from Photovoltaic Cells on the roof to the grid, back to DC to go into the PEV can be up to 50% of the total electricity generated on the roof.
    g. **Garaging PEV** - Research on where PEVs are likely to be garaged both during the day and at night.
    h. **Natural disasters -** Use of the PEV batteries to support electric needs during natural disasters.
- **Modeling tools** (e.g. GridLab-D) need to be expanded to allow them to support distribution grid modeling for short-term and long-term forecasting, both static and dynamic, as well as integration of demand response and Transactive energy into the PEV fleet.

Each of these technological and economic changes will impact both acceptance of the PEVs and amount of energy consumed by them. It is very important that standards and research keep pace with the real world technological changes in PEV and storage technology. It is also important to realize that economics regulation will be the largest driver in adoption rates and the investment in the grid to support PEV integration.

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19. IEEE Grid Vision 2050 Roadmap, April 2013. http://smartgrid.ieee.org/standards/ieee-smart-grid-research/889-ieee-grid-vision-2050-roadmap
20. IEEE Transportation Electrification, http://electricvehicle.ieee.org/

3.4 Pertinent IEEE Standards

IEEE Number	Title
1159.3-2003	Recommended Practice for the Transfer of Power Quality Data
1366-2012	Guide for Electric Power Distribution Reliability Indices
1377-2012	Standard for Utility Industry Metering Communication Protocol Application Layer Standard (End Device Data Tables)
1409-2011	Guide for the Application of Power Electronics for Power Quality Improvement on Distribution Systems Rated 1 kV Through 38 kV
1453-2004	Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems
1459 – 2010	Standard Definitions for the Measurement of Electric Power Quantities under Sinusoidal Non-Sinusoidal Balanced or Unbalanced Conditions
1547.1-2005	Standard for Conformance Tests Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
1547.2-2008	Application Guide for IEEE Std 1547(TM), IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems
1547.3-2007	Guide For Monitoring, Information Exchange, and Control of Distributed Resources Interconnected With Electric Power Systems
1547.4-2011	Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems
1547.6-2011	Draft Recommended Practice for Interconnecting Distributed Resources With Electric Power Systems Distribution Secondary Networks
1547.7-2013	Draft Guide to Conducting Distribution Impact Studies for Distributed Resource Interconnection
1547-2003	Standard for Interconnecting Distributed Resources with Electric Power Systems
1686-2013	Standard for Intelligent Electronic Devices (IEDs) Cyber Security Capabilities

1905.1-2013	Standard for a Convergent Digital Home Network for Heterogeneous Technologies
2030.5-2013	Standard for Smart Energy Profile 2.0 Application Protocol
2030-2011	Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), and End-Use Applications and Loads
C37.95-2014	Draft Guide for Protective Relaying of Utility-Consumer Interconnections
1547.1a	Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems Amendment 1

3.4.1 Standards under Development by IEEE that Directly Support PEV Integration

P1547a	Standard for Interconnecting Distributed Resources with Electric Power Systems - Amendment 1
P1704	Draft Standard for Utility Industry End Device Communications Module
P1705	Draft Standard for Compliance Testing Standard for Utility Industry Metering Communications Protocol
P1711.3	Standard for Secure SCADA Communications Protocol (SSCP)
P1854	Draft Guide for Smart Distribution Applications Guide
P1885	Guide for Assessing, Measuring and Verifying Volt-Var Control Optimization on Distribution Systems
P1888.4	Green Smart Home and Residential Quarter Control Network Protocol
P1894	Guide for Online Monitoring and Recording Systems for Transient Overvoltages in Electric Power Systems
P2030.1	Draft Guide for Electric-Sourced Transportation Infrastructure
P2030.1.1	Standard for Establishing the Technical Specifications of a DC Quick Charger for Use with Electric Vehicles
P2030.102.1	Standard for Interoperability of Internet Protocol Security (IPsec) Utilized within Utility Control Systems
P2030.2	Draft Guide for the Interoperability of Energy Storage Systems Integrated with the Electric Power Infrastructure
P2030.2.1	Guide for Design, Operation, and Maintenance of Battery Energy Storage Systems, both Stationary and Mobile, and Applications Integrated with Electric Power Systems
P2030.3	Draft Standard for Test Procedures for Electric Energy Storage Equipment and Systems for Electric Power Systems Applications
P2030.6	Guide for the Benefit Evaluation of Electric Power Grid Customer Demand Response
PC37.237	Standard Requirements for Time Tags Created by Intelligent Electronic Devices - COMTAG™

PC37.237	Draft Recommended Practice for Time Tagging of Power System Protection Events
PC37.238	Standard Profile for Use of IEEE 1588 Precision Time Protocol in Power System Applications
PC37.240	Draft Standard for Cyber Security Requirements for Substation Automation, Protection and Control Systems
PC37.249	Guide for Cyber Security of Protection Related Data Files
P2030.5	Standard for Smart Energy Profile Application Protocol
P1250	Guide for Identifying and Improving Voltage Quality in Power Systems
P1547	Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

4. The implications and importance of aging infrastructure and the options for addressing these challenges, including asset management

Virtually every crucial economic and social function depends on the secure, reliable operation of power and energy infrastructures. Energy, electric power, telecommunications, transportation and financial infrastructures are becoming interconnected, posing new challenges for their secure, reliable and efficient operation. All of these interdependent infrastructures are complex networks, geographically dispersed, non-linear and interacting both among themselves and with their human owners, operators and users.

Although the age of our power infrastructure – particularly underground city networks – is a major issue, it should not be viewed in isolation. **Instead, the power industry's focus should be on a holistic asset management approach to address grid resilience.** That focus should weigh the relative risks and economics of maintenance, repair and replacement or retirement for the infrastructure's various elements. This holistic approach requires viewing the utility fleet of capital equipment as critical strategic assets impacted by age and external forces, and possessing capabilities and characteristics that can be leveraged to improve reliability. Aging infrastructure will benefit from the use of condition-based monitoring and assessment tools. Grid hardening can address extreme weather-related impacts, as well as physical vulnerability and cyber security threats. And power system capabilities and characteristics can be managed to improve reliability metrics, such as SAIDI and SAIFI, as well as system-wide outages. Integrating a holistic asset management approach with rational spending and resource decisions should achieve optimal, cost-effective solutions. An additional aspect requiring new processes and tools is managing new Smart Grid assets such as advanced metering infrastructure (AMI) and intelligent electronic devices (IEDs).

Optimal, cost-effective solutions for holistic asset management, in turn, depend on rational risk assessment and management. While it is impossible to predict when and where future events will occur, it is possible to identify the substations and lines in the system that, as a result of their location, configuration and electrical characteristics, pose the greatest risk for large-scale outages. These results can then be used to **tailor grid resiliency investments to focus on facilities with the greatest risk for future events.**

Thus, while macro-forces have the potential to impact the nation's power infrastructure, risk is dynamic, local, and specific. National policies that support holistic asset management will help, but achieving hardening and resiliency on the ground will be specific to a utility's customers' needs, its legacy systems, location and technology roadmap.

A dynamic risk landscape requires **annual updating to ensure the protection of pertinent assets**. How has the risk portfolio or the spectrum of risk changed? Climate change is a case in point. The variability of weather events has increased. We can expect more extreme, unique events with greater frequency. Hurricane Sandy appears to be an example of this challenge. In fact, considering Hurricane Sandy's impacts on the power infrastructure provides an opportunity to review questions about power restoration in the face of extreme weather and climate change.

First, we must acknowledge that a massive physical assault on the scale of Hurricane Sandy is likely to overwhelm the power infrastructure, at least temporarily. No amount of money or technology can guarantee uninterrupted electric service under such circumstances. Second, the U.S. power industry is just beginning to adapt to a wider spectrum of risk. Third, cost-effective investments to harden the grid and support resilience will vary by region, by utility, by the legacy equipment involved and even by the function and location of equipment within a utility's service territory.

Even a single threat can have disparate impacts, requiring nuanced responses. In Sandy's case, coastal areas were subject to storm surges and flooding, while inland, high winds and lashing rain produced the most damage. Improved hardening and resilience for distribution systems in those different environments would take different forms. Underground substations along the coasts may have to be rebuilt on the surface, while it might be cost-effective to perform selective "undergrounding" for some overhead lines further inland.

The one generalization we can make, however, is that the pursuit of an intelligent, self-healing grid with security built-in into the devices and deployed in a layered defense architecture, has some common characteristics that will make the grid highly reliable in most circumstances. Additional, location-specific steps based on rational risk assessments also can be taken by utilities and customers.

4.1 Report

4.1.1 Aging Infrastructure

Spending on U.S. electric transmission and distribution (T&D) infrastructure has fallen far short of growth in demand for nearly 30 years. Average systems are 40 to 60 years old and 25 percent of electric infrastructure is of an age where condition is a concern. As a system ages equipment operating costs increase and reliability decreases. Limited resources are available for wholesale replacements and/or required investment needs. It is necessary to **develop sound strategies for controlling the symptoms of aging within the utility's overall business plan** to maintain acceptable levels of performance.

- ✓ ***ASSET MANAGEMENT IS KEY ENABLER FOR A SECURE AND AFFORDABLE ELECTRICITY INFRASTRUCTURE***

Asset management provides the integrated approach to ensure assets in T&D systems are strategically managed, effectively coordinated, and economically maintained[1]. The application of asset management tools has brought value to a number of industries, including electricity generation and supply[2]. It is a key enabler for a secure and affordable electricity infrastructure.

The application of a holistic asset management approach leads to improved value extraction of existing and planned assets. Such an effort requires coordination across the breadth and depth of an organization. Risk management requires an understanding of probability of occurrence and an analysis of likely costs resulting from a hazard. Strategies for differing risk scenarios must be identified, evaluated and assigned a cost, and those costs must be balanced against the needs of stakeholders and prioritized for implementation.

For instance, managing a portfolio of multi-million dollar power transformers requires an analysis of a population which is neither homogenous in construction nor uniform in application and operation. It requires statistics on failure modes, failure rates and likely future variation. This example illustrates a complex challenge in which asset age is just a single, possibly misleading, factor. Dealing with such a complex issue requires analysis of the whole fleet in terms of condition and performance and the identification of appropriate responses, which can be numerous and diverse. Condition-based monitoring must applied strategically. How will the utility obtain strategic spares, if a

[1] A. Ipakchi and M. L. Chan, "Implementing the Smart Grid: Enterprise Information Integration," Grid Interop Forum, Albuquerque, NM, November 9, 2007.
[2] IEEE Asset Management Working Group (AM WG) Agenda, 2012 and 2013.

device fails? What is the data-supported justification for the planned replacement of targeted sub-groups? How can a utility improve its purchase specifications and achieve greener operational performance? What are effective approaches to education and training for a workforce which may rarely encounter many of the assets in practice? The questions are many and specific to an individual utility's circumstances. A unified holistic strategy can provide the means to answer them to modernize and reinforce the system where appropriate to improve reliability and resiliency.

Asset management must be undertaken within the confines of a business case. Financial resources are limited and must be employed in a demonstrably economic manner. This fact underscores the foregoing point about how a holistic approach involves the entire utility organization. For instance, a utility must ensure it makes efficient investments within a critical population, such as power transformers. But it must balance those investments against investments in other assets such as towers, switches, system controls and operational security. A utility must look across its entire asset portfolio, sometimes involving different organizational silos, to determine what optimal mix of investments will produce the greatest gains in reliability and resiliency. R&D is a tool which must be used to continue to look for greener designs and more efficient operational capabilities, but also may be leveraged to motivate new entrants to an aging workforce, where experience is essential for safe operation and maintenance. More reliance on indigenous skills, capabilities, and innovation are one possible specific strategic aim of an asset management approach.

4.1.2 Aging Infrastructure Approach

The electrical power industry should **promote the application of widespread condition monitoring**, integrating condition and operational data, which has been shown to benefit real-time system operations, both in terms of asset utilization and in terms of graceful, planned replacement of stricken assets. Condition-based asset monitoring is preferable to reactive "fix-on-fail" approaches which can be both dangerous and costly. Benefits to customers and end users accrue in reduced bills and improved service.

It is not advisable, however, to overload the user with data from various sensors as it requires an additional layer of maintenance and creates a complex environment that is difficult to manage. Some basic sensors plus existing IEDs (e.g., protective relays) may provide sufficient information for condition-based maintenance.

Adding elements of the Smart Grid will aid in achieving holistic asset management approach. The addition of centralized and distributed intelligence — sensors, communications, monitors, optimal controls and computers — to our electric grid with security built-in, can substantially improve its efficiency and reliability through **increased situational awareness, reduced outage propagation and improved response to disturbances.**

The electric power sector is second from the bottom of all major U.S. industries in terms of research and development (R&D) spending as a percentage of revenue, exceeded only by the pulp and paper industry. In fact, R&D represented a meager 0.3 percent of net sales in the period of 1995 to 2000, and declined even further to 0.17 percent between 2001 and 2006 and has continued to hover on the extreme low-end of the spending scale for the past decade.

However, as the digitization of society continues to expand, it becomes increasingly critical that we make investments in development if we want to accommodate the growing need for electricity. In fact, it is projected that the world's electricity supply will need to triple by 2050 to keep up with demand.

We envision a drastically different electric grid than what exists today, one with efficient markets, idealized grid-pervasive demand-response, rapid real-time, end-point control, smart peripheries and fully coordinated networks of microgrids, synergistic electrified transportation, green and automated distribution systems and efficient AC-DC transmission systems. That kind of grid will effectively and securely **meet the demands of a pervasively digital society** in the face of extreme events and climate change while ensuring a high quality of life and fueling economic growth.

4.1.3 Security

The concept of asset management extends to the physical and cyber security of those assets, which introduces new challenges:

- **Physical security** – The size and complexity of the North American electric power grid makes it impossible both financially and logistically to physically protect the entire end-to-end and interdependent infrastructure. For instance, the U.S. has over 450,000 miles of 100kv or higher transmission lines, and many more thousands of miles of lower-voltage lines. As an increasing amount of electricity comes from DG, the problem will be only be exacerbated.
- **Cyber security** – Threats from cyberspace to our electrical grid are rapidly increasing and evolving. While there have been no publicly known major power disruptions due to cyber attacks, public disclosures of vulnerabilities are making these systems more attractive as targets.

Due to the increasingly sophisticated nature and speed of malicious code, intrusions and denial-of-service attacks, a human response may be inadequate and an automated response may be required. Furthermore, currently more than 90 percent of successful intrusions and cyber attacks take advantage of known vulnerabilities and misconfigured operating systems, servers and network devices.

Technological solutions will focus on system awareness, cryptography, trust management and access controls, and advances in these areas are under way. Continued attention to these efforts is needed.

The security of cyber and communication networks is fundamental to the reliable operations of the grid. As power systems rely more heavily on computerized communication and control, system security has become increasingly dependent on protecting the integrity of the associated information systems. For instance, any utility system connected directly or indirectly to the public Internet is "disputed territory." That system is vulnerable to cyber intrusions, which can impersonate field devices to spoof bad data into a control center, possibly misleading operators and potentially leading to erroneous decisions impacting the operation and safety of the grid.

Cyber has "weakest link" issues. Awareness, education and pragmatic tool developments in this vital area also continue to remain challenging. Educating stakeholders and colleagues in the cyber-physical interdependencies has often been difficult, as even distinguished members of the community who understand power systems well – though not the cyber threats – routinely minimize these persistent, novel threats.

Cyber threats are dynamic and evolve quickly and, intentionally or not, often exploit a lack of utility staff training and awareness. Cyber connectivity has increased the complexity of the control system and the facilities the control system is intended to safely and reliably control. Thus, significant challenges must be overcome before extensive deployment and implementation of Smart Grid technologies can begin. In addition, two coordinated areas need to be addressed in close collaboration with the industry:

- Cyber and physical threats to communications and information technology systems
- System-wide interdependencies of communication and cyber threats

What Should We Be Trying to Protect?

1. **Fuel Supply and Generation Assets** - The QER infrastructure team noted that a "successful" attack (i.e., an attack that successfully disables a sufficient segment of the system to produce widespread or long-term interruption of power delivery) on generation assets would not result from a single point failure but is contingent on multiple parameters such as, for example, time of day, time of year, stocks of fuel and the distribution of other generation facilities. It would not be sufficient to target even a large plant without also striking at a peak load time, or a time when other large plants are also down. It was the consensus of the infrastructure team that, from the standpoint of interrupting delivery of electric service, attacks on power plants would be more likely to have a local or regional rather than a national impact. Because of the redundant nature of the power grid and current reserve margins, a relatively large number of power plants would have to be taken down in order to have a major impact on delivery of electricity nationally, making this an item of lower probability and priority.

2. **Transmission and Distribution** - The critical elements of the T&D system that need to be protected include transmission lines (especially those linking areas of the grid), key substations and switchyards, control centers and distribution of national significance. The latter category would include, for instance, feeders to major urban areas or facilities that have national impact. It is important to note that as the duration of an electricity outage increases, its impact broadens in scope. In this way, a local transmission or distribution problem could eventually have regional or national impact. Thus, the response time for recovery is also important to assess. In this context, one needs to be concerned with long lead-time equipment such as some large transformers and the relatively limited extent to which equipment is interchangeable between utility companies.

3. **Controls and Communication** - Protection of power generation, transmission and distribution equipment is insufficient to guarantee delivery of electricity because widespread, coordinated denial of control and communication systems could cause significant disruption to the power grid. This includes SCADA systems, communications between control systems, monitoring systems and business networks. However, the power management control rooms are currently well-protected physically, although they may have cyber vulnerabilities. NERC requires a backup system and there are also manual workarounds in place. The Federal Energy Regulatory Commission (FERC) is working toward a common set of security requirements that will bring all electric sector entities up to at least a minimum level of protection.

4. **Other Assets** - These include the ancillary facilities and services from other sectors that are needed to keep generating facilities operating. A review is needed of the ability to maintain a reliable supply of coal, natural gas or nuclear fuel for generation. There are significant interdependencies on other networks such as communications, railroads, water supplies for cooling, pipelines and storage facilities.

What Issues Impede Protection?

1. **Inability to share information** on threat, vulnerabilities, and protection strategies - Many federal statutes (e.g., Freedom of Information Act (FOIA), anti-trust, liability) impede information sharing. The challenge is to define sensitive information and access requirements so as to facilitate vulnerability analysis and implementation of protection, without allowing public access to such information. Many states also have information-release requirements so that this will require federal-state coordination, as well as better definition of the roles of each federal agency.

2. **Increased cost of security** - Fixes and upgrades to security systems will be costly. Individual companies pay for a level of security consistent with their resources and the needs of their customers. If the federal government identifies a higher level of security as being in the national interest in order to protect critical infrastructure, then there needs to be an equitable distribution of costs between the government and other sectors.

3. **Data on and analysis of interdependencies** - The electric power grid is dependent upon other infrastructures (e.g., transportation, pipelines, water, communications, finance). NERC has the data and capability for analysis of the electric power grid but has not yet tied this to the interdependencies on other infrastructures. This could be an assignment for the National Infrastructure Simulation and Analysis Center (NISAC); however, it will be crucial for NISAC to build on what is already in place, e.g., at NERC, in order to avoid "re-inventing the wheel." Analysis of the time-phased effect of the failure of one infrastructure on another, including loss metrics, would be extremely useful for prioritizing protection strategies. Cross-sector coordination will be critical to acting on the results of the analysis to assure basic electric sector needs from other infrastructures.

4. **Widely dispersed assets** - The power grid assets that need protection are numerous and widely dispersed. Local resources simply do not exist to guard all generation facilities and key substations and switchyards. Even if those resources existed, the cost of total protection would far outweigh the benefits. Moreover, transmission lines extend over long distances and are mostly above ground and widely accessible, and consequently very difficult to protect physically.

5. **Widely dispersed owners and operators** - The owners and operators of the power grid are a large and heterogeneous group. Industry associations such as NERC, the Edison Electric Institute (EEI) and the American Public Power Association (APPA) serve as clearinghouses, but some owners and operators are not members of any organization and thus will be hard to include in programs to increase security.

6. **Finding, training, empowering security personnel** - Current employer liability statutes and privacy concerns greatly hinder background checks of security personnel. Standards are also lacking for both physical and cyber security personnel. Current statutes do not permit the use of deadly force to protect equipment or provide penalties for bringing weapons or explosives onto power grid sites.

7. **Commercial off-the-shelf (COTS) controls and communications** - The prevalence of COTS control and communications systems limit the technological approaches to protection (e.g., encryption strategies) and increase the pool of potential attackers.

8. **Siting constraints** - One approach to protection is to reduce vulnerability through redundancy or increased reserve margins. This is greatly hindered, especially for T&D, by difficulty in obtaining right-of-ways, state and local siting requirements, public opposition (NIMBY) and low rates of return relative to competing investments.

9. **Long lead-time equipment** - Rapid recovery and restoration after a successful attack can be hindered by the need to replace custom-designed equipment with insufficient inventory and long lead-time for orders, especially large transformers and facilities that have non-U.S. suppliers.

10. **Availability of restoration funds** - Currently, only public entities, and not private sector firms, are eligible for Federal Emergency Management Agency (FEMA) restoration funding, which leaves a large number of sites that need protection for which there will be limited funds for recovery and restoration after a successful attack.

11. **R&D on less-vulnerable power grid** - Protection of current grid components falls to the owners and operators, but there is no provision for long-term R&D to design and develop a less-vulnerable grid. Such R&D should be part of a long-term national electricity and energy strategy.

4.1.4 Security Approach

General

1. Determine the level of security upgrades that are to be performed in the national interest and require federal, state and local authorities to assume the costs beyond what the owners or operators would have done for business purposes.

2. Promote legislative action to remove impediments and obtain benefits through changes in the requirements of FOIA, anti-trust, liability, privacy statutes, etc. that hinder security efforts, both in personnel practices and in development and sharing of data.

3. Reform, clarify and coordinate roles among federal agencies and with state governments. Infrastructure security requires a new model for private sector-government relationships, and overlapping and inconsistent roles and authorities hinder development of productive working relationships and operational measures. This would facilitate, for example, recovery hindered by access limitations to a site of attack classified as a crime scene or state and local regulations preventing siting of federally identified key facilities.

4. Perform critical spares and gaps analysis. A detailed inventory is needed of critical equipment, the number and location of available spares and the level of interchangeability between sites and companies. Mechanisms need to be developed for stockpiling long lead-time equipment and for reimbursement to the stockpiling authority, be it private or government. Other approaches include standardizing equipment to reduce lead times and increase interchangeability.

5. Improve sharing of intelligence and threat information and analysis. The owners and operators of the power grid need access to more specific threat information and analysis in order to develop adequate protection strategies. This may require either more security clearances issued to electric sector individuals or treatment of some intelligence and threat information and analysis as sensitive business information, rather than as classified information.

6. Plan for system restoration and recovery in response to structured adversarial attacks and natural disasters. The electricity sector has an excellent record of reconstitution and recovery from events that have caused system disruption in the past, but today it faces a significant array of new threats, which should be considered in the development of these plans.

The following possible strategies have been discussed by power industry organizations including IEEE, EEI, NERC and the Electric Power Research Institute (EPRI):

Generation

1. Perform risk assessments for specific facilities, following approved methodologies such as those spelled out in the U.S. Nuclear Regulatory Commission's 10CFR73.55 requirements for physical protection of licensed activities in nuclear power reactors against radiological sabotage (references: http://www.nrc.gov/reading-rm/doc-collections/cfr/part073/part073-0055.html, http://www.nrc.gov/reading-rm/doc-collections/cfr/part073/full-text.html) and in the aforementioned standards for nuclear plants. There is an existing Risk Assessment Methodology for dams (RAM-D), for transmission (RAM-T) and one in development for fossil-fuel plants (RAM-F).
2. The protection of nuclear generation facilities needs improvement, particularly the training, vetting and equipping of guards. The federal government could facilitate physical security by changing statutes and regulations (in particular, privacy and employer liability) to allow detailed/expedited background checks of security personnel. Training could be via a national training academy, run either by the government or the private sector. Guards at nuclear generation facilities (at which a successful attack would have high-value consequences for denied electricity delivery or for collateral damage) need a better definition of the use of force against attackers. Questions remain unanswered: Should these guards be equipped with automatic weapons similar to guards at U.S. DOE nuclear weapons facilities? The federal government should consider criminalizing certain non-destructive yet terrorist-type activities such as bringing weapons and explosives onto a protected site.

Transmission Lines

1. **Physical security is not the answer here**, because there are too many transmission lines and they are mostly out in the open. We need to address this vulnerability either through redundancy or through mitigation strategies.
2. The federal government could facilitate the redundancy approach by expedited siting of needed transmission lines and work with state and local governments to facilitate **coordinated regional planning of a more redundant and less vulnerable transmission grid**. This might include changes to the location, size and energy-efficiency of generators to provide more distributed generation closer to load centers. Note that greater energy efficiency of end uses will reduce societal vulnerability to transmission and generation disruptions.
3. R&D is needed on the design and construction and maintenance of transmission lines, including transmission grid configuration, to reduce vulnerability. The use of safe, energized work techniques (e.g. using robotic technologies) to maintain, repair, re-conduct, and rebuild lines and equipment is one of the solutions to reduce congestion and associated costs and minimize service interruptions[3].
4. Mitigation strategies include design for easier repair, stockpiling of assets and prior agreements in place to facilitate recovery.

[3] D. Elizondo, T. Gentile, H. Candia and G. Bell, "Ground based robots for transmission line work–technology description, field projects and technical-economical justification of its application," IEEE PES Transmission and Distribution 2010 Latin America, Brazil.

Key Substations and Switchyards

1. Physical security can be applied here, but the correct level of security needs to be determined via a triage process under which utilities protect their most valuable resources.
2. Recovery from an attack is impeded by the long lead-time required to obtain transformers and other components. What can be done to stockpile or make these more widely available? Assistance in emergency transport of recovery equipment is a good federal role, since there is a shortage of specialized railroad cars for transporting large transformers. The federal government could help by assessing the functionality of the rail lines when needed and facilitating workarounds including special routing for trucks. One possibility is to send equipment in emergencies by military aircraft.
3. Implement spare equipment programs, such as Edison Electric Institute (EEI) Spare Equipment Transformer Program (STEP) and NERC spare equipment database[4]. Another possible solution is a federal spares program, under which the user would pay for the component when it is needed, but the federal government would keep a sufficient inventory so that the components are available for quick recovery.
4. Other possible mitigation strategies include R&D on self-healing transformers or grids and standardization or modularization of key equipment to make replacement easier.

Distribution of National Significance

1. There is a need to strengthen federal, state, and local coordination because this is under state and local control.
2. Definition of what constitutes "national significance" needs to be agreed-upon, based on, e.g., the level of economic impact from disruption, protection of national icons, etc.
3. Grid redesign could be considered to make the distribution system less radial and more interconnected for the re-routing of power around outages.
4. Fast recovery is important because these assets are not cost-effective to protect.

Controls and Communications

1. For process control systems, the objective is to improve the technology (e.g., through R&D) so as to increase security without decreasing reliability and functionality.
2. Immediate actions include federal government outreach and awareness and the development of standard requirements, e.g., for control system personnel, procedures, and technology. Also, the use of firewalls by the private sector should be encouraged.
3. The need for secure communications systems (e.g., out-of-band) will require coordination between federal agencies such as U.S. DOE and the Federal Communication Commission (FCC).

[4] P. W. Parfomak, "Physical Security of the U.S. Power Grid: High-Voltage Transformer Substations," Congressional Research Service, June 2014.

4. The federal government could promote and facilitate communications and cyber security audits, redundancies, and back-up systems.
5. Communications systems could be designed for more limited failure. For instance, it would require designing decentralized systems so that segment failures do not bring down the entire system.

4.1.5 Pertinent IEEE Standards

End of Life Assessment for Protection and Control Devices

The IEEE Power & Energy Society's (PES) Power Systems Relaying Committee (PSRC) has a working group, I22, End of Life Assessment for Protection and Control (P&C) Devices, which focuses on electromechanical, solid-state and microprocessor-based devices.

The report explores further the reasons for replacing P&C devices, and will discuss how the industry is managing and planning for devices reaching useful end of life, and how risk and reliability indices help determine the priority for managing decisions on the useful end of life. (This report is due to be completed by the end of 2014.)

IEEE Standard 692-2013: Criteria for Security Systems for Nuclear Power Generating Stations: Criteria for the design of an integrated security system for nuclear power generating stations are provided in this standard. Requirements are included for the overall system, interfaces, subsystems and individual electrical and electronic equipment. This standard addresses equipment for security-related detection, surveillance, access control, communication, data acquisition and threat assessment.

This standard focuses on the design, operation and maintenance of security-related electrical and electronic equipment, including integration, to achieve an acceptable security system. To be effective, the electrical and electronic aspects of such an integrated security system, as described in this standard, need to include the following 11 essential elements:

1. Perimeter intrusion alarms
2. Security lighting
3. Video surveillance
4. Access control
5. Interior intrusion detection
6. Data acquisition, processing and display
7. Voice communications
8. Line supervision
9. Duress alarms
10. Power supplies
11. Maintenance and testing

See the IEEE Standard 205-2014: IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Electrical Equipment Used in Nuclear Power Generating Stations and Other Nuclear Facilities. Guidelines are provided for assessing, monitoring and mitigating aging degradation effects on electrical equipment used in nuclear power generating stations and other nuclear facilities. This guide also includes informative annexes on aging mechanisms, environmental monitoring, condition monitoring, aging program essential attributes and examples demonstrating the application of the basic principles described in this guideline.

Other pertinent IEEE standards include:

IEEE PES Substation Committee work in Aging Infrastructure and Resiliency: The Substation Committee has a number of released products as well as current efforts that pertain to this topic.

1) IEEE 1402 – This standard establishes minimum requirements and practices for physical security of electric power substations. It is designed to address a number of threats, including unauthorized access to substation facilities, theft of materials and vandalism. It describes the requirements for positive access control, monitoring of facilities and delay/deter features which shall be employed to mitigate these threats. This standard also establishes requirements for different levels of physical security for electric power substations. The standard does not establish requirements based on voltage levels, size or any depiction of criticality of the substation. The user will make these decisions based on threat assessment and criticality assignment by the substation owner. Overt attacks against the substation for the purpose of destroying its capability to operate, such as explosives, projectiles, vehicles, etc. are beyond the scope of this standard.

P1402 – Current title is: GUIDE FOR ELECTRIC POWER SUBSTATION PHYSICAL AND ELECTRONIC SECURITY. It is currently being revised. This standard's new scope establishes minimum requirements and practices for physical security of electric power substations. It is designed to address a number of threats, including unauthorized access to substation facilities, theft of materials and vandalism. It describes the requirements for positive access control, monitoring of facilities and delay/deter features which shall be employed to mitigate these threats. This standard also establishes requirements for different levels of physical security for electric power substations. The standard does not establish requirements based on voltage levels, size or any depiction of criticality of the substation. The user will make those decisions based on threat assessment and criticality assignment by the substation owner. Overt attacks against the substation for the purpose of destroying its capability to operate, such as explosives, projectiles, vehicles, etc. are beyond the scope of this standard.

2) IEEE 1686 – Standard for Intelligent Electronic Devices (IEDs) Cyber Security Capabilities –

This standard defines the functions and features to be provided in substation IEDs to accommodate critical infrastructure protection programs. The standard addresses security regarding the access, operation, configuration, firmware revision and data retrieval from an IED. George Becker and John Boggess, both from K, presented a conference paper at the T&D Expo on "Storm & Flood Hardening of Electrical Substations." This paper discusses alternative approaches to consider in the design and construction of electrical substations in locations vulnerable to storm surge and/or prone to flooding. In addition, there are a number of other cyber security efforts under way, including:

a. Working Group C10 – (JOINT WITH PSRC H13 WG) REQUIREMENT AND APPLICATION OF THE SUBSTATION CYBER SECURITY Standard: 1646

Scope: Provides technical requirements for substation cyber security. It presents sound engineering practices that can be applied to achieve high levels of cyber security of automation, protection and control systems independent of voltage level or criticality of cyber assets. Cyber security includes trust and assurance of data in motion, data at rest and incident response.

b. Working Group C6 - TRIAL USE STANDARD FOR A CRYPTOGRAPHIC PROTOCOL FOR CYBER SECURITY OF SUBSTATION SERIAL LINKS Standard: 1711

Scope: Defines a cryptographic protocol to provide integrity and optional confidentiality for cyber security of substation serial links. It does not address specific applications or hardware implementations, and is independent of the underlying communications protocol.

4.2 Recommendations

- Support **holistic, integrated approach** in simultaneously managing fleet of assets to best achieve optimal cost-effective solutions addressing the following: **Aging infrastructure, Grid hardening (including weather-related events, physical vulnerability, and cyber security) and System reliability**.
- **Urgently address managing new Smart Grid assets** such as advanced metering infrastructure (AMI) and intelligent electronic devices.

Aging Infrastructure

- Infrastructure security requires a **new model for private sector-government relationships**. Overlapping and inconsistent roles and authorities hinder development of productive working relationships and operational measures.
- Perform **critical spares and gaps analysis**. A detailed inventory is needed of critical equipment, the number and location of available spares and the level of interchangeability between sites and companies. Mechanisms need to be developed for stockpiling long lead-time equipment and for reimbursement to the stockpiling authority, be it private or government. Other approaches include standardizing equipment to reduce lead times and increase interchangeability.
- Increased federal R&D for emerging technologies that may impact T&D grids, including new types of generation, new uses of electricity and energy storage, with an additional focus on deployment and integration of such technologies to improve the reliability, efficiency and management of the grids.
- Application of pro-active widespread condition monitoring, integrating condition and operational data, has been shown to provide a benefit to real-time system operations, both in terms of asset utilization and cost-effective, planned replacement of assets. However, it is important to not overload the user with data from various sensors as it requires an additional layer of maintenance and creates an environment difficult to manage. Some basic sensors plus existing electronic devices (e.g., protective relays) need to be efficiently utilized first.

Security, Privacy, and Resilience

- Facilitate, encourage, or mandate that secure sensing, "defense in depth," fast reconfiguration and self-healing be **built into the infrastructure**.

- Mandate consumer data **privacy and security for AMI system**s to provide protection against personal profiling, real-time remote surveillance, identity theft and home invasions, activity censorship and decisions based on inaccurate data.
- Utilities should reduce or **eliminate the use of wireless telecom networks and the public Internet** as such uses increase grid vulnerabilities.
- Improve **sharing of intelligence and threat information** and analysis to develop proactive protection strategies, including development of coordinated hierarchical threat coordination centers – at local, regional and national levels. This may require either more security clearances issued to electric sector individuals or treatment of some intelligence and threat information and analysis as sensitive business information, rather than as classified information. National Electric Sector Cybersecurity Organization Resource (NESCOR) clearing house for grid vulnerabilities is an example of intelligence sharing.
- Speed up the development and enforcement of **cyber security standards**, compliance requirements and their adoption. Facilitate and encourage design of security from the start and include it in standards.
- Increase investment in the grid and in R&D areas that assure the security of the cyber infrastructure (algorithms, protocols, chip-level and application-level security).

Markets and Policy

- Use the National Institute of Standards and Technology (NIST) Smart Grid Collaboration or the NARUC Smart Grid Collaborative as models to **bridge the jurisdictional gap** between the federal and the state regulatory organizations on issues such as technology upgrades and system security.
- More transparent, participatory and **collaborative discussion** among federal and state agencies, transmission and distribution asset owners, regional transmission operators (RTOs) and independent system operators (ISOs) and their members and supporting research is needed to improve these parties' understanding of mutual impacts, interactions and benefits that may be gained from these efforts.
- Continue working at a federal level on better **coordination of electricity and gas markets** to mitigate potential new reliability issues due to increasing reliance on gas generation; and update the wholesale market design to reflect the speed at which a generator can increase or decrease the amount of generation needed to complement variable resources.

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5. Recommendations for metrics for addressing Smart Grid issues, especially to help policymakers determine the importance and necessity of protocols

The rapid changes in systems, technology, lifestyles, and policies have created both new opportunities and new expectation from the electric grid. Indeed, adding and utilizing existing intelligence — sensors, communications, monitors, optimal controls and computers — to our electric grid with security built-in, can substantially improve its efficiency and reliability through increased situational awareness, reduced outage propagation and improved response to disturbances and disruptions. Smart Grid can also enable consumers to better manage their energy costs.

Because the opportunities are almost limitless and a broad array of functions is feasible, there are many differing expectations as to what will be facilitated by the Smart Grid. In absence of limitless funds, it is important to decide on the priorities and timing of various elements of the ultimate functionality, which in turn implies a need for a metric.

Any Smart Grid metric depends on the definition of the Smart Grid, specifically the performance requirements of the system. Conversely, it is difficult to derive a meaningful qualitative or quantitative metric without clear performance requirements.

IEEE uses the definition developed by the U.S. DOE's Modern Grid Initiative, which articulates seven key characteristics of a modern grid[1]:

1. Enable active participation by consumers
2. Accommodate all generation and storage options
3. Enable new products, services, and markets
4. Provide power quality for the range of needs in a digital economy
5. Optimize asset utilization and operating efficiency
6. Anticipate and respond to system disturbances in a self-healing manner
7. Operate resiliently against physical and cyber-attack and natural disaster

IEEE has used these to develop a set of key drivers, which are the basis of the work IEEE is doing on establishing metrics.

If the metric is to provide a meaningful guidance for the evolution of the U.S. DOE Smart Grid technology portfolio, it is important to acknowledge that there are other definitions and viewpoints. Ultimately **the metric and the measure of value will depend on the perspective and the framework of the stakeholder**.

5.1 Report

IEEE is deeply involved in the Smart Grid effort at all levels, including developing standards that provide such benefits as supporting interoperability and best practices. IEEE has already taken initiatives to highlight issues

[1] "Metrics for Measuring Progress Toward Implementation of the Smart Grid," U.S. DOE, June 2008. http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Smart_Grid_Workshop_Report_Final_Draft_07_21_09.pdf

pertaining to the benefits of Smart Grid technologies. Further, IEEE has been investigating the relative merits of different metrics for evaluating the value of smart grid technologies.

5.1.1 Smart Grid Definitions

Because of a broad array of functions expected to be facilitated by the Smart Grid, there are various definitions of the Smart Grid, some broad and quantitative, others very specific with set goals. This should not be surprising as the **definition reflects the perspective and framework of a stakeholder.**

Several different examples are presented below.

IEEE uses the definition developed by the U.S. DOE's Modern Grid Initiative, which articulates seven key characteristics of a modern grid[2]:

1. Enable active participation by consumers
2. Accommodate all generation and storage options
3. Enable new products, services, and markets
4. Provide power quality for the range of needs in a digital economy
5. Optimize asset utilization and operating efficiency
6. Anticipate and respond to system disturbances in a self-healing manner
7. Operate resiliently against physical and cyber-attack and natural disaster

These characteristics were then used to develop the following key drivers[3], which are the basis of the work IEEE is doing on establishing metrics:

- Increasing Share of Electricity as fraction of Total Energy Consumption
- Demand Patterns
- Technical Losses
- Reliability
- Integration of Renewables
- Carbon Mitigation
- System Adequacy
- Manufacturing for Export
- Capacity Management (Long Term)
- Industry Restructuring
- Asset Optimization
- New products and services
- Electric vehicle integration
- Security of Supply
- Resiliency
- Grid Extension
- Energy market integration (full)
- Fluctuation of prices in electricity
- Non-technical losses
- Capacity Management
- Customer Participation
- Power Quality
- Energy Market Integration (prices)
- Customer Satisfaction

[2] "Metrics for Measuring Progress Toward Implementation of the Smart Grid," U.S. DOE, June 2008. http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Smart_Grid_Workshop_Report_Final_Draft_07_21_09.pdf

[3] Electric Distribution Utility Roadmap, Phase III: Common Infrastructure, CEA Technologies Inc. (CEATI), Distribution Asset Life Cycle Management (DALCM) Interest Group, CEATI Report No. 6011b; to be published

Examples of other definitions include:

- European Technology Platform SmartGrids[4]
  A Smart Grid is an electricity network that can intelligently integrate the actions of all users connected to it -- generators, consumers, and those that do both -- to efficiently deliver sustainable, economic and secure electricity supplies.
- IEC (International Electrotechnical Commission) Smart Grid Strategic Group (SG3)[5]
  Smart Grids [are defined] as the concept of modernizing the electric grid. The Smart Grid is integrating the electrical and information technologies in between any point of generation and any point of consumption. Consequently, the IEC remarks: "'Smart Grid' is today used as marketing term, rather than a technical definition. For this reason there is no well-defined and commonly accepted scope of what "smart" is and what it is not." It is worth noticing that according to the IEC definition a "Smart Grid" is not a *grid* but a *concept*.[6]
- An Approach to Smart Grid Metrics[7]
  The authors propose a simple definition: An electrical distribution grid is smarter than a reference grid if it meets a given ***set of grid performance targets*** better.
  The metric is then based on the degree of fulfillment of these targets.

5.1.2 Metrics

A metric is a set of measurable (qualitative or quantitative) attributes of a system or portfolio, which individually or jointly (in the form of a scorecard) provide a figure of merit for the system or its elements.

✓ ***SMART GRID METRICS AND FIGURES OF MERIT DEPEND ON THE "EYE OF THE BEHOLDER"***

Any Smart Grid metric depends upon the Smart Grid definition, specifically the system's **performance requirements** or **functional specifications**. Conversely, it is difficult to derive a meaningful qualitative or quantitative metric without clear performance requirements. However, as discussed above, there are many different Smart Grid concepts and, as a result, we should not expect to readily stipulate a single set of metrics.

Although the set of U.S. DOE's Modern Grid Initiative characteristics (see above) is very broad, it can be used to establish metrics for evaluating grid modernization investment. For example, DOE workshop participants proposed the following set of metrics for the first objective – *Enable Active Participation by Consumers*[8]:

- Percent of customers/premises capable of receiving information from the grid
- Percent of customers opting to make decisions and/or delegate decision-making authority
- Number of communication-enabled, customer-side of the meter devices sold
- Number of customer-side of the meter devices sending or receiving grid related signals

[4] European Technology Platform, SmartGrids, "Strategic Deployment Document for Europe's Electricity Networks of the Future," April 2010. http://www.smartgrids.eu/documents/SmartGrids_SDD_FINAL_APRIL2010.pdf
[5] IEC Smart Grid Strategic Group (SG3): IEC Smart Grid Standardization Roadmap, Edition 1.0, June 2010 (www.iec.ch/smartgrid/.../sg3_r...)
[6] Arnold, M.; Rui H.; Wellßow, W. H.: An Approach to Smart Grid Metrics
[7] Ibid
[8] Details associated with these metrics, issues with definition and measurement, and metrics for the other six modern grid characteristics can be found in the workshop report at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Smart_Grid_Workshop_Report_Final_Draft_07_21_09.pdf

- Amount of load managed
- Measurable customer energy savings

Commonwealth Edison has developed a similar metric for use in tracking progress of its Smart Grid Advanced Metering Infrastructure (AMI) Deployment Plan. The metrics includes the following measurable attributes[9]:

- Number of customers enrolled on a Net Metering tariff and the total aggregate capacity of the group.
- Load impact in MW of peak load reduction from the summer peak due to AMI-enabled demand response programs as a percentage of all demand response in portfolio.
- Number and percentage of substations monitored or controlled via Supervisory Control and Data Acquisition (SCADA) systems.
- Number and percentage of distribution circuits equipped with automation or remote control equipment including monitor or control via SCADA systems.
- Average number of customers per automated three phase 12kV line segment. (An "automated line segment" is a segment of 12 kV three phase mainline circuit between automated devices which include circuit breakers, reclosers, automated switches, etc.)

The authors of An Approach to Smart Grid Metrics (see above) cluster the performance targets in five categories:

- Economic Performance,
- Technical Performance,
- Customer Quality,
- Environmental Friendliness
- Safety

Qualitative or quantitative metrics are then defined for each of the targets, and used to assess the value of Smart Grid concepts, and/or elements proposed to meet the objectives.

✓ *Focus the Smart Grid metric on the customer*

Ideally, the priorities for Smart Grid elements should be driven by electricity users' needs and preferences. At this time, IEEE is not aware of metrics or scorecards to achieve this and recommends that DOE develops one. A scorecard would help clarify the needs for and urgency of various Smart Grid technology elements, as well as potential customer service options. For example, a recent market survey[10] found that "Knowledgeable Electricity Customers Seek Greater Choice and More Control of Energy Value Chain," but notes that the needs of residential vs. commercial customers are different:

- Residential consumers continue to look for opportunities to reduce their electricity bills, mainly through energy efficiency measures and solar panels.
- About one-third (32%) of Gen Y consumers say they definitely/probably will buy a smart energy application.

[9] "Smart Grid Advanced Metering Annual Implementation Progress Report," Submitted to the Illinois Commerce Commission by Commonwealth Edison Company, April 1, 2014

[10] *Deloitte reSources 2014 Study*, May 2014 (http://www.deloitte.com/view/en_US/us/Industries/power-utilities/43ac460aedbd5410VgnVCM1000003256f70aRCRD.htm) and
Do utilities know what their customers really want?, UtilityDIVE May 2014 (http://www.utilitydive.com/news/do-utilities-know-what-their-customers-really-want/262952/)

- An increasing number of consumers blame weather, not the electricity providers, for electricity outages and they are buying backup generation, including solar.
- All business sectors across the U.S. — with the exception of energy — have changed their focus from cost-savings to growing the top line.
- More than half (53%) of businesses reported participating in demand response programs, at least somewhat regularly, and their commitment to energy management is getting stronger year after year.

✓ ***INCREASE FOCUS ON COMMERCIAL & INDUSTRIAL CUSTOMERS IN THE NEAR TERM***

The results of this market research would imply that the near-term focus of Smart Grid efforts should be on commercial and industrial customers – they are ready for energy management and automation. Even in rural areas, many large power users rely on their G&T coop's peak demand forecasts to best schedule their demand response actions.

5.1.3 Protocols and Interoperability

For Smart Grid technology solutions to function properly, it is important to assure interoperability. Interoperability needs to be addressed in two forms: the ability for automation devices to communicate with one another, and the delivery of standard outputs from energy sources. The first form is compatible with the traditional definition of *interoperability*. For instance, IEC standards, such as IEC 61850 for field device communications, and IEC 61968, for application programming interfaces, allow for almost any application server to access data from a data mart for processing. Possessing this interoperability facilitates the implementation of these Smart Grid applications. As another example, smart meters need to comply with ANSI C12.19 standard for data tables to ensure that stored data from meters can be retrieved and passed to data repositories. If the interoperability issue is resolved, then individual devices can truly become "plug-and-play." Currently, under EISA Title XIII, the federal government has designated the National Institute of Standards and Technology (NIST) as the lead agency to define the standard protocols to ensure interoperability. The entire utility industry should work closely with NIST to expedite this process.

The second form of interoperability could be interpreted as a standard. It pertains to distributed energy resources. With the proliferation of solar PV, wind generators, and PEVs, it is important that the electrical output from such distributed generation and storage resources should subscribe to voltage and current standards, appropriate protective relays for the bidirectional flow of power, and power quality standards (e.g., harmonic content for different harmonics). The distributed resources should also include a standard set of remote monitoring and control capabilities that will be fed into a hierarchical control system. This will ensure that microgrids can function with integrity without introducing harm to the larger grid when interconnected.[11]

✓ ***AVAILABILITY OF STANDARDS IS CRITICAL TO SUCCESSFUL IMPLEMENTATION***

Our industry has realized the importance of developing interoperability standards for technology deployment. NIST has been coordinating the development of interoperability standards for Smart Grid and has established the Smart Grid Interoperability Panel to accelerate Smart Grid standards harmonization and development. NIST Interoperability Framework and Roadmap Release 2.0 have added 22 standards, specifications and guidelines to the

[11] Chan, M.L , *Real-World Planning for Smart Grid*, Grid-Interop Forum 2008, Paper Id-1

75 previously recommended. IEEE PES and Standards Association (SA), in cooperation with DOE, NIST, IEC, and other organizations have taken major efforts to develop required standards and support those international efforts.

- ✓ ***BUILD ON SUCCESSES – U.S. DOE CAN "FAST-TRACK" STANDARDS DEVELOPMENT***

IEEE PES and SA have shown that standards and guides could be put on the fast track to satisfy industry needs and still assure quality review process. For example, a number of utilities and independent system operators have been deploying GPS-based synchrophasor measurement technology and associated applications[12]. As synchrophasor measurement system components consist of relatively new technology with new products coming to the market (such as Phasor Data Concentrators), inter-operability standards and guides are required for successful and seamless system deployment. With help from U.S. DOE, IEEE was able to accelerate the release of standards IEEE C37.118.1-2011 for Synchrophasor Measurements for Power Systems and IEEE C37.118.2-2011 for Synchrophasor Data Transfer for Power Systems. Furthermore, NIST has supported North American Synchrophasor Initiative (NASPI), Performance and Standards Task Team, to develop Phasor Data Concentrator Requirements Guide and Guides for Synchronization, Testing, Calibration and Installation of PMUs. Those documents have become base for IEEE C37.242 Guide for Synchronization, Calibration, Testing, and Installation[13] and IEEE C37.244 Guide for Phasor Data Concentrator[14]. In addition, NIST and IEEE members supported IEC TR 61850-90-5 that addresses new communication requirements taking advantage of the IEC 61850 environment.

- ✓ ***KEEP AN EYE ON ENERGY EFFICIENCY***

A potential issue with connecting large numbers of devices to the network is the related energy use, particularly in stand-by mode. There is a general awareness of these issues, including standby electricity use by computer and entertainment systems, such as TVs, computers, set-top boxes, modems, and printers. A recent report[15] estimates that some of these systems use as much as 80% of their total energy consumption by simply maintaining their network connection, amounting to about $80 billion worldwide. Technical solutions, standards, and policy options will be needed to assure that Smart Grid measures will not aggravate this problem. Some of countries already putting policies in place include U.S., EU, Switzerland, and Korea.

5.1.4 Smart Grid Value

- ✓ ***MAJOR SOURCES OF SMART GRID VALUE ARE DEMAND RESPONSE AND SYSTEM EFFICIENCY – PRIMARILY DUE TO IMPROVED INFORMATION***

Because of the fundamental importance of the mission and the costs involved, it is important to take a critical approach to the enormous investment needed to modernize the grid. According to an article[16] on Self-Healing Grid

[12] D. Novosel, V. Madani, B. Bhargava, K. Vu, and J. Cole, "Dawn of the Grid Synchronization," IEEE Power and Energy Magazine, Vol. 6, pp. 49-60, January/February 2008.

[13] IEEE Guide for Synchronization, Calibration, Testing, and Installation of Phasor Measurement Units (PMU) for Power System Protection and Control, IEEE PC37.242

[14] IEEE Guide for Phasor Data Concentrator Requirements for Power System Protection, Control, and Monitoring, IEEE PC37.244

[15] "More Data, Less Energy: Making Network Standby More Efficient in Billions of Connected Devices," International Energy Agency, June 2014. (http://www.iea.org/etp/networkstandby)

[16] Amin, M., "The Self-Healing Grid," Electricity Today Magazine, pp. 40-47 and 58, April 2013 http://online.electricity-today.com/doc/electricity-today/et_april_2013_digital/2013041501/#40

> "A smarter, stronger grid would reduce the low-end estimate of current outage costs -- $80 billion annually – by $49 billion. This smarter grid would increase the system's efficiency by about 4.5 percent, which is worth another $20.4 billion, annually. Together, improving just those two aspects – reducing outages, improving efficiency – brings about $70 billion in annual benefits".

The Israeli Smart Energy Association (ISEA) has recently developed a Smart Grid Roadmap[17]. As part of the process, ISEA assembled an extensive amount of data from the United States and Europe, and used it to carry out a cost-benefit analysis. Because the Israel Electric Company (IEC) has already installed advanced control and supervisory systems in the T&D segments, the ISEA analysis focused on advanced metering and system integration. For example, ISEA found that the total benefits of enhanced smart metering are 9.447 billion NIS[18] (using a seven percent discount rate and a 15-year time horizon). About half of these benefits are due to demand response. Most of the balance is due to network optimization, particularly reduction in network upgrades, due to better planning, and a 10 percent reduction in T&D losses.

- ✓ ***FRAGMENTED U.S. REGULATORY SYSTEM IS AN OBSTACLE TO PROGRESS***

The report makes an insightful observation about some of the U.S. obstacles to success in implementing the Smart Grid:

> "…significant share of total investments by federal grants is due in part to the lack of policy coordination and consistency between the state and federal regulators. The lack of coordination and uniformity is largely in the area of rate recognition of the investment costs associated with smart grid by state-level regulators. This variation in state regulatory policy is creating uncertainty that is deterring regulated electric utilities from investing in Smart Grid, unless they receive preferential financing conditions from "non-rate" sources, such as grants. The friction between the federal and the state regulators has also been reflected in the stagnation regarding critical transmission investments (most of whose benefits flow to consumers beyond state borders). Smart Grid development has therefore become overly dependent on the "selfish" interests of state regulators and their respective constituencies, regarding renewable energy and the state's benefits from trade with neighboring states, rather than on broader national policy interests."

This issue impacts not only Smart Grid, but also other technology that crosses the transmission-distribution boundary. Indeed, utilities respond first and foremost to the requirements created by the legal and regulatory regime in which they operate. For that reason, attention must be focused on how utilities are regulated. The essential problem of 21st century electric utility regulation in the U.S. is how to compensate utilities fairly while providing incentives to pursue society's broader policy goals.

[17] Road Map for Smart Grid Implementation in Israel, The Israeli Smart Energy Association, November 2013 http://www.isea.org.il/#!sg-road-map-homepage/c1bwf

[18] Approximately $2.7 billion

5.1.5 Questions and Observations

Smart Grid Assessment

- Is there a system to differentiate levels of smart grid sophistication / capability / maturity?

IEEE is not aware of a metric for either of these attributes.

Key Characteristics?

- Is there any ability to tie grading on SG metrics, to achievement of any subset or portion of the seven key characteristics of the smart grid?

Indeed, at high-level, the metric would be a qualitative or quantitative measure of progress or goal for each of the seven key characteristics.

- More broadly, the seven key characteristics are likely not a binary all or nothing bucket of capabilities. So is there an ability to iteratively build, construct, and expand smart grid capability through incremental improvement / investment to achieve measured gains?

Such ability would be achieved by using the metric to evaluate requisite new grid technologies, upgrades, etc. with respect to their contribution to progress to any or all of the characteristics. The process would provide an assessment of the relationship between Smart Grid measures (technology) and capabilities (functions) delivered in each of the selected characteristics and relate incremental improvements in technology to gains in functionality and vice-versa.

5.2 Recommendations

Metrics & Priorities

- Metrics, and hence priorities for Smart Grid elements depend on viewpoint of the stakeholders. We recommend development of **two sets of metrics**
    i. One driven by electricity users' needs and preferences and
    ii. Another, driven by national priorities

  Such an effort should strive to secure support for these metrics by both federal and state regulators.

- As there is a number of various scorecards under development or in use, we also recommend that DOE support ongoing private sector development of metrics and combine the results into a **"super-metric"** that could be configured by users to reflect the stakeholder and regional needs.

- Increase emphasis on providing Smart Grid functions to the **commercial customer sector** (incl. small commercial).

Protocols and Interoperability

The Smart Grid cannot function without standardized, inter-operating protocols. In fact, availability of standards is the key to successful implementation and long-term viability of Smart Systems.

- **Standards:** Work with IEEE's Standards Association, other Standards Developing Organizations (SDOs), and the stakeholder community to improve the timely development of Smart Grid standards, and promote their widespread deployment, including putting selected standard development on "fast-track".
- **Smart Grid Interoperability Panel:** Continue federal government support for the Smart Grid Interoperability Panel (SGIP) as the principal coordinator of Smart Grid standards under EISA 2007, to the extent needed to ensure the viability and continued operation of this evolving private-public partnership.
- **Testing and Product Certification:** Develop an institutional infrastructure for testing and certification of products claimed to be compliant with Smart Grid standards; and means for rapidly resolving technical issues and ambiguities, either prior to or immediately following, adoption by SDOs.
- **Broadband Communications:** Support the advancement and the deployment of broadband and other communication technologies that are essential for achievement of Smart Grid benefits.

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2. Guide for Control of Hydroelectric Power Plants, IEEE Standard P1010
3. Guide for Identifying and Improving Voltage Quality in Power Systems, IEEE Standard P1250
4. Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, IEEE Standard P1547
5. Draft Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Standard, IEEE Standard P1547.8
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6. Skilled workforce issues

The energy industry is undergoing a significant transition, described by some as a revolution. Driving this change are many technology breakthroughs aimed at addressing a growing and aging population, rising cost of energy, increasing environmental awareness and concerns and escalating cybersecurity needs. Advancements have been realized and are continuing to facilitate carbon management, electric transportation, sustainability and increased system reliability and flexibility. There are now more renewable generation and storage options coming, with the promise of increased ability to control and manage electric systems, and demand-side capabilities. Much of this progress has stemmed from market developments and a wide-range of technical advances in the areas such as electric machines, power electronics, batteries, photovoltaics, wind turbines, controls, communications, and embedded intelligence.

Workforce requirements and competencies are evolving to successfully innovate, plan, design, operate and maintain reliable, secure, and safe systems in the future. There is more uncertainty, advanced threats, increased complexity and a need to involve those with a wide variety of capabilities and backgrounds than ever before.

As new technologies come online, power may be generated and managed at new scales (at the home, local/ distributed, and large-scale levels). The intersection of the power and transportation sectors will likely grow with increasing electrification of the auto fleet, and more individuals, small-businesses and private entities will play important roles in changing how people interact with the energy system on a daily basis. This will lead to a larger number of individuals, with a broader and diverse range of skills and interests interacting with the energy system and markets.

Workforce implications should not be viewed separately from research or policy review but as a key factor in the potential success of the action. Changes in the size, scope, location and competency levels of the energy workforce can have significant impact on the ability of the current workforce to advance the industry and implement the technological advances that will make our energy future cleaner and more reliable.

DOE can play a role as a convener of the key parties, both inside and outside of government. While many dimensions of workforce development lie outside the main missions of DOE, DOE has real and significant opportunities to serve as the catalyst that brings information to other agencies and state/community/industry partnerships. As the economy is primed for recovery, energy technology jobs may well be a cornerstone of our economic growth across American cities.

The energy sector in the US is among the most robust and reliable in the world. Indeed, while there are many urgent needs and persistent cries for improvement, **the issues of aging workforce, aging equipment and new technologies plague Europe and developed countries all over the world**. The salient features of US markets that balance private and public assets with robust environmental and market regulations may well be America’s most valuable export. In many countries across the world, not having this balance and equilibrium of regulation, markets, and public power make private investment too risky. We should celebrate what we have while seeking to improve it.

6.1 Report

The workforce that currently serves the industry is shrinking and continues to mature. According to the Center for Energy Workforce Development (CEWD) 2013 Gaps in the Energy Workforce Pipeline survey, the change in the total number of employees in the industry is leveling off, but there are still fewer employees than in 2010. In 2010, Economic Modeling Specialists International (EMSI) calculated approximately 525,000 employees while in 2012, there are approximately 517,000. Almost 40%, or 204,000, of the employees in the industry are in the job categories considered critical, and there were changes in the number of employees in each of those job categories:

- Engineers decreased by 3.2%
- Plant / Operators decreased by 2.3%
- Linemen and Technicians decreased by about 1.4% each

✓ ***OVERALL, THE INDUSTRY HAS CONTINUED TO MATURE WITH MORE EMPLOYEES THAN IN PREVIOUS SURVEYS OVER THE AGE OF 53***

But the survey also showed an increase in employees under the age of 37, indicating a steady increase in hiring younger workers. The average age continues to increase and has gone from 45.7 in the 2006 survey to 47.2 at the end of 2012. In looking at the more defined breakdown of critical jobs, Lineworkers and Engineers are the youngest, and Electric Transmission and Distribution Technicians are the oldest.

Clearly the retirement wave has begun. CEWD calculates a percentage of workers who are “Ready Now,” ready to retire over the next five years, and ready to retire over the next 6-10 years. This percentage of “Ready Now” has increased by a full percentage point from 8.9% in 2010 to 9.9% in 2012. Those ready to retire in the next five years remains steady at around 15%, and the number of workers potentially ready to retire in the next 6-10 years has decreased by almost 3% from 16.4% to 13.5%. This change shows that older workers have begun to leave and more are in that critical age and years of service range, which means they could leave at any time.

✓ ***FOR THE INDUSTRY AS A WHOLE, ALMOST 55% OF THE WORKFORCE MAY NEED TO BE REPLACED IN THE NEXT 10 YEARS, DOWN FROM PREVIOUS ESTIMATES AND REFLECTING THE PROGRESS OF WORKFORCE DEVELOPMENT EFFORTS ACROSS THE INDUSTRY***

This includes all jobs in the company, such as supervision, clerical, accounting, and information technology, as well as the key job categories.

Almost half of the skilled Technicians and Engineers in the industry may need to be replaced in the next 10 years, with the potential for the next five years estimated at 36%. Technicians and Plant Operators have the highest potential percentage of replacements. Attrition for other reasons, such as separating from the company, transferring to other jobs, or promotions within the company, totals approximately 11% of employees in these job categories. The normal attrition rate for utilities is historically low, ranging between 2-3% a year for most job categories. In 2013, the survey forecasts that the rate of retirements will increase above normal attrition and continue to rise during the forecast period.

In addition to changes in technology and an aging workforce, there will be significant investments in the grid over the upcoming years to modernize it, both by the power sector and by consumers who integrate new technology in their homes and businesses. EPRI has estimated $338 - $476 billion will be needed through 2030; the Brattle Group predicts the investment will be $880 billion. This significant capital outlay and the types of investment being made will certainly increase the demand for skilled workers well beyond the levels needed in recent years.

NERC recognizes that electricity reliability is in large part dependent upon the workforce: reliability is at risk if the workforce lacks the necessary skills and knowledge or if workers are overtaxed by their responsibilities. Furthermore, the success of grid modernization will require a well-trained, professional workforce to build, operate, and secure it, as well as discover and implement innovations.

✓ ***ACROSS THE INDUSTRY, NEW TECHNOLOGIES IN TRAINING, COMPUTER USAGE AND INTERNET BASED SIMULATIONS AND DELIVERY SYSTEMS ARE MEETING CHANGES IN TALENT MANAGEMENT AND CAREER DEVELOPMENT HEAD ON***

Prolonged economic difficulties have left many energy organizations resource short, with insufficient supply of ready internal talent to replace pending attrition in a timely fashion. Specifically, many energy organizations are finding themselves in situations where key positions historically filled from promotion are now increasingly difficult to source internally.

Another emerging Electricity Workforce challenge centers on the dearth of skilled cybersecurity resources necessary to support grid modernization and reliability. These are the same security specialists who will be required to design network architectures, establish security processes and practices, and secure infrastructure design and operation that defend, monitor, and respond to cybersecurity threats facing the grid. As such, cybersecurity workforce development and maintenance must become a top priority to meet future needs and threats with the same level of urgency as non-cyber workforce requirements.

The traditional pipeline for System Operators that has been fed largely by former generator operators, substation operators and linemen that became System Operators at the end of their career is decreasing. NERC Certification requirements, greater emphasis on reliability and modern computer applications, require candidates that have a more advanced analytical knowledge. The profile established for System Operators includes numerous soft skills including:

- Agile reasoning: logic and methods of use in assessing problems and finding alternatives.
- Planning: the ability to anticipate situations and steps to establish goals.
- Attention: the ability to check data in routine work.
- Overview: understanding the implications alternatives may have on the system as a whole.
- Communication: ability to develop and communicate ideas verbally and in writing.
- Teamwork: show empathy, a sense of affiliation and ability to understand feelings and needs of the team.
- Leadership: the degree to which defines objectives, controls and involves people in the group work.
- Flexibility: the ability to question and evaluate the cost vs. benefits of the initiatives adopted.
- Influence: persuasiveness and ability to negotiate.
- Emotional Control: ability to deal with unexpected situations and keeping the pressure field on the reactions.
- Adaptation: the ability to integrate the changes and conduct themselves in accordance with procedures.

Graduates of engineering schools in the USA typically need years of on the job training and experience to develop these soft skills.

6.1.1 Recommended Strategies

IEEE-USA urges federal, state and local governments, along with quasi-governmental organizations, and stakeholders in industry and academia, to develop and pursue strategies to prepare for future workforce needs in the U.S. energy sector [1]:

- America COMPETES Act: Congress should reauthorize the America COMPETES Act, which provides critical support for investments in physical sciences; and engineering research and science, technology, engineering and mathematics (STEM) education.
- Education Partnerships: Governments and other stakeholders should support the development of partnerships within the education, labor, industry and government sectors, to develop new curricula and enhance secondary and post-secondary energy sector workforce training programs, apprenticeships and best practices.
- Certification Programs: Universities and professional organizations should create industry recognized credentials or certifications that can be awarded after the completion of education or training, to demonstrate an individual's achieved skill level.
- Assess Workforce Issues: Congress should direct the Department of Energy and the Department of Labor to take necessary actions to better understand the implications of a maturing workforce, technology advancements, and policy changes on future workforce requirements.

The following is summarized and adapted from Reference [2]:

A. Training

A.1: Identify scalable solutions from ARRA electricity delivery workforce training grants. The DOE awarded nearly $100 million to 54 workforce training projects to help prepare the next generation of workers to help modernize the nation's electric grid. DOE should evaluate the ARRA electricity delivery workforce training grants and identify: competencies addressed, scalable solutions, programs that were sustained without DOE support and what worked well to develop real employment and hiring. The curriculum developed and lessons learned should be disseminated and shared among the grantees, education communities and professional societies.

A.2: Identify workforce lessons from ARRA-funded smart grid investment projects. DOE should obtain feedback on workforce needs from smart grid demonstration and investment projects in order to successfully plan, install, maintain, and operate a high penetration of these technologies in the future.

A.3: Incorporate workforce elements in future DOE technology development efforts. DOE regularly invests in technology development as part of its mission. It is critical that the workforce is trained to appropriately apply new technologies. Often processes are also changed as a result of technology development, which can save costs, increase organizational efficiencies and impact the workforce competencies. Anticipating future workforce needs of the 21st century electric grid community and future issues in the technology of training design and delivery should be factors in designing technology research and development plans. A process is needed to methodically define emerging workforce development requirements and continually apply criteria to technical development efforts to improve labor efficiency, "foolproof" designs, improve safety-related conditions and streamline operational activity. DOE should pilot and implement this process across its own programs including the National Labs. DOE and other agencies (like NSF, DOL, SBIR) should adopt best practices and metrics for identifying, encouraging and recognizing high-quality programs that address workforce issues.

A.4: Develop an annual DOE-sponsored recognition program on excellence in the state of power system education and training. This program should seek out and celebrate excellence in private – public – educational institution partnerships and especially programs that create employment for veterans, disabled, women and minority graduates. Time to readiness; costs, creativity, effectiveness, long term value and repeatability of success should also be considered.

B. Metrics, Best Practices, and Roadmaps

B.1: Establish metrics on workforce and identify policies that facilitate necessary workforce development activities by the regulated companies. There is a workforce crisis coming that could affect customer services and costs so it is in the public interest that regulators increase their oversight of workforce development.

DOE should facilitate regulator / industry dialog by designing and holding workforce workshops for NARUC, FERC and NERC that create situational awareness for state and national regulators. The NERC System Operator Certification and Training program should be used as an example of a successful program for regulated training. Initially the focus should be on the workforce whose performance is most directly connected to reliability, such as system operators, linemen, planning engineers, protection engineers/technicians and substation operators. DOE should convene a cross functional group of experts to include industry, government agencies (DOL, DOE, NSF, DHS, DOD) and regulators for the purpose of reviewing current practices in workforce benchmarking and create metrics to quantify the threat posed to the electric grid's performance by insufficient replacement workers.

B.2: Increase coordination between NSF and DOE to address workforce issues.

The National Science Foundation (NSF) serves as the Federal government's principal steward of research and education across the broadest range of scientific and engineering endeavors. NSF integrates research and education to support the development of a world-class scientific and engineering workforce as well as nurture the growth of a scientifically and technologically aware public. NSF and DOE should cooperate to ensure university research grants are better leveraged to impact workforce development. Lessons learned from NSF and DOE grants in curriculum development and engineering pedagogy should be disseminated. Collaboration should continue on grid-related Engineering Research Centers and other Center education efforts to find lessons learned / best practices. Community college students should be encouraged to pursue power and energy engineering courses at universities.

B.3: Improve coordination and communication with other agencies at the federal and state levels and with other schools to leverage research, share programs / curriculum and track trends.

There are opportunities to cooperate and share information between federal and state agencies. For example, there are existing cross-agency working groups that could potentially incorporate a subgroup on workforce development. One example is the Interagency Advanced Power Group (IAPG), a Federal membership organization initiated in 1958 to facilitate exchange of information in the area of Advanced Power at the technical level of research and development programs in the member organizations (Army, Navy, Air Force, NASA, DOE, and NIST). The purpose of the IAPG is to increase effectiveness of research efforts by sharing information, avoiding duplications, and identifying gaps. This could be extended to include workforce issues.

The Federal Departments of Labor, Education, Defense, Commerce, State, and Homeland Security and State Departments of Commerce, Education and Labor should be informed on the Energy Sector Workforce Training Issues. States can develop and integrate recruitment, training, employment placement programs in concert with electric utilities and community colleges. The utilities that support K-12 STEMS and Energy Technology initiatives should be publicized and celebrated.

B.4: Convene a group to do workforce scenario planning to improve the understanding of workforce risks given the inherent uncertainty.

Forecasting the longer term development needs for the workforce for the electric grid depends on how its infrastructure and operating requirements will change to meet the needs of future electricity users, markets, regulators and the like. The future beyond the next few years is quite uncertain. There are a number of drivers for change facing the electric grid owners, designers, planners and operators, some of which are particularly influential and uncertain:

- What new technologies will be developed and commercialized, and which ones will and can be adopted by the electric grid industry for operations and training?
- How will tariff regulations and market forces affect energy and demand market structures and practices, and grid operations?
- How will siting and permitting processes affect how much and what kind of new grid infrastructure will be built?
- How will requirements for environmental protection affect not only the design and operations of the electric grid per se, but the type of generation and end-user services it will have to provide?

In responding to these and other drivers over the next decade or so, will the electric grid architecture be just more of the same, or become radically different? The planning will highlight the need for an energy workforce that can accommodate and adapt to change. Examples of engineering educational institutions that are also adapting to change should be identified and celebrated as role models.

B.5: Identify and embrace best practices that effectively accelerate the transition of military veterans to meet industry workforce requirements.

There are large pools of military veterans who can directly contribute to meeting energy industry workforce needs if programs for introducing them to the power industry could be more readily available to them. Many of the top energy industry leaders developed their leadership skills in the military. They mainly entered the energy industry through an ad-hoc process of references from friends and family. More systematic and publicized outreach and transitioning programs are needed. The Joint Force Staff College, Military Academies, Navy Nuclear Power School, Army Prime Power School and other Military Operational Specialty/ technical schools, can all play a helpful role. The CEWD Troops to Energy program has mapped Military Occupational Specialties (MOS's) to energy industry jobs. The DOE sponsored Power4Vets programs successfully transitions Navy Nuclear Electrician's Mates primarily as well as other technical MOS veterans into jobs as power system operators. Programs should be developed to transition Military Electronic Technicians to Substation Relay Technicians and Battalion Commanders to Distribution Field Managers etc.

B.6: Retain the experienced and specialized utility workers and capture their knowledge and skills.

Over the past six years, the Center for Energy Workforce Development (CEWD) has conducted four workforce surveys for the Electric and Natural Gas Utility Industry to identify the impact of an aging workforce and the need for replacement of critical Generation, Transmission, and Distribution positions. Over the next decade, almost 62% of the industry has the potential to retire or leave for other reasons. In many cases, experienced and specialized workers retire and quickly return to the workforce through alternative means via contracting or through service organizations. This contribution has proven extremely valuable. Cognitive Task Analysis methods should be applied so that the implicit knowledge of these experts is converted to explicit knowledge that can be replicated and scaled. Success stories should be documented and tracked so that this practice can be leveraged throughout the industry.

B.7: Develop an educational road-map that aligns with industry needs.

There is considerable variability in the competencies that need to be developed and positions that need to be filled depending upon the rate at which industry adapts to all the new changes. Industry has identified the need for graduates to have stronger soft skills (e.g. leadership, teamwork, communications and operations) on top of a base of strong technical skills. The US Military Academies, Officer Candidate Schools, Navy Nuclear Power Program, Army Prime Power Programs have a track record of graduating men and women with strong technical and leadership skills that are adaptable to world-wide changing threats. The military have been pioneers in adopting the Systematic Approach to Training. Under crisis conditions, a focus on training in everything essential to do the jobs at hand is well justified. ARPA-E is an example of an energy related program that was successfully modelled after the DOD DARPA program. Another example is when the Department of State worked with Iraqi utilities, to turn the industry around in a couple of years.

It would be important to sponsor a study that effectively bundles the supply and demand assumptions, competency requirements, trends, risks, barriers and possible scenarios to be best prepared for the dynamic workforce needs. This can be used to define an educational road-map that develops the talent needed for critical positions that are tightly coupled with reliable system performance for the present and foreseeable future.

6.1.2 Open Questions

What are the specific needs of the electric industry?

The electric industry is unique from all other industries in the sense that electricity is not a storable commodity and customers depend on the continuous delivery of our product. During his / her career, a utility manager may need to operate in very different environments, for example a regulated transmission business, a for profit generation business and an operations business where storm management is a regular seasonal activity and operating errors can risk lives and loss of power to millions of customers with billions of dollars of economic losses. For many years, the main variable driving the change of vertically integrated utilities was percentage load growth. The rate of change being faced by the industry due to restructuring and deregulation and now with high penetration of renewables has been accelerating. Power industry workers need a strong base on how all the existing and legacy equipment operates as well as a strong base on all the newer smart grid applications.

Curriculum development is important, how to ensure there's a need for the curriculum, and that it's put in place and adopted by educational institutions?

The industry needs curriculum that addresses all the traditional fundamentals of utility planning, operation and control across generation, transmission and distribution, as well as all the new Smart Grid and Renewable technologies and processes that are being introduced. The US Power and Energy Engineering Workforce Collaborative Report published in 2009 laid the groundwork for almost $100M of funding under the ARRA Workforce Training for the Electric Power Sector. ARRA Grant recipients built curriculum based on their own local knowledge and local industry partnerships.

The Australian Power Institute (API) provides a model that could be adapted for US Power Engineering Schools. API conducted a Collaborative Power Engineering Curriculum Development Project in which Universities collaborated on development of a common and shared curriculum which was defined based on a survey of industry members and recent graduates [7]. The core included 21 topics in the categories of:

- Systems Engineering
- System Planning, Design and Analysis
- Intelligent Networks and Protection
- Energy Markets and Sustainability

The electives included 19 topics in the categories of:

- Generation
- Transmission and Distribution
- Manufacturing
- Management and Economics

A body similar to the US Power and Energy Engineering Workforce Collaborative should agree on the curriculum and the jobs, tasks and competencies that will be addressed.

How do we ensure that the curriculum is put in place and that it will be adopted by educational institutions?

The development of Massive On-line Open Courses (MOOCs) for the power engineering curricula is picking up slowly. Power engineering programs and professors should be encouraged to develop MOOCs for all the essential power engineering topics. Future DOE funding can request that curricula be available as open source and be available as MOOCs. University consortiums can be encouraged to share their curriculum. Developers of MOOCs should be trained to use sample problems and experiments so that they do not just present but they also demonstrate, direct, facilitate, challenge, coach and evaluate.

Certain popular text books such as "Power System Operation and Control" by Wood and Wollenberg, "EPRI Power System Dynamics Tutorial" and "Power System Stability" by Prabha Kundur provide a foundation for training new faculty. Lectures and applications in these books need to be applied to real-world applications.

One of the approaches to training engineers and operators during the restoration of the Iraq power system by the US Department of State was to make modern software tools available and emphasize the application of these tools rather than the theory of how the program calculations were performed. A set of non CEII hypothetical power system models is needed so that students can perform planning, design and operating studies on practical systems.

What role can shorter term certificate programs have in addressing gaps?

Shorter term certificate programs could facilitate and accelerate the transition of veterans into the power industry. For example the NERC System Operator Certification program is fundamental to the success of the Power4Vets program. This certification test evaluates the competence of the applicants to perform specific power system reliability related tasks. Applicants are not required to have specific education credentials before taking the test. A Power System Relay Technician Certification could be developed by IEEE PES with support from DOE. This would measure the competency of Relay Technicians to perform their tasks. It would facilitate the transition of hundreds of veterans that have an Electronics Technician background into the power industry. New NERC standards on Relay Testing are creating a strong demand for new Relay Technicians.

What options does the industry have for addressing these needs?

The IEEE PES Scholarship Plus Program has had a major impact on increasing the visibility of careers in Power and Energy. The establishment of the IEEE Community Solutions Initiative as an IEEE Foundation Signature Program is going to increase the appeal of Power Engineering to students who have a heart to serve. The US Power and Energy Engineering Workforce Collaborative Report published in 2009 laid the groundwork for almost $100M of funding under the ARRA Program which was a one-time boost. The industry needs more options to accelerate and sustain the positive outcomes of these programs.

The power industry can learn a lot from the US Military Educational and Training institutions and processes. The DOE ARPA-E program has been successfully modelled after the DARPA program. The US Military have adapted to what General Krulak called the "Three Block War" in 1999 [8]. *Within three city blocks, US Marines could be involved moving from humanitarian assistance, peace-keeping, or traditional warfighting. They will be asked to deal with a bewildering array of challenges and threats. In order to succeed under such demanding conditions they will require unwavering maturity, judgment, and strength of character. Most importantly, these missions will require them to confidently make well-reasoned and independent decisions under extreme stress -- decisions that will likely be subject to the harsh scrutiny of both the media and the court of public opinion.*

Power System Operators, Engineers and Managers are being faced with more and more responsibility for systems that are changing rapidly and which are subject to greater threats and more violent weather conditions. The US Military Academies operate similar to Civilian Universities in so far as their Academic and Sports Programs. However the military training programs which are conducted outside of the classroom activities is what sets them apart in terms of building leaders that can adapt and make good decisions under the highest levels of stress. The military training programs to a large extent are managed by the students themselves with one officer and one senior enlisted assigned to each company of around 100 men and women.

The relationship and mutual respect that builds between the senior enlisted and the newly graduated officer is also a role model for the relationship that should ideally build between newly graduated engineers and senior power system operators. Retired power system operators can provide a valuable resource in many university programs, especially when they can demonstrate their knowledge with a real-time simulator, but few programs have taken advantage of this resource.

What's the industry's role in addressing the challenges, possibly in cooperation with IEEE / DOE / NSF?

IEEE, DOE and NSF can look at the problem from a national level. The regional differences are minor compared to the common jobs and tasks and learning objectives that exist across the country. IEEE, DOE and NSF can be a catalyst for change. CEWD has been very active and successful at creating partnerships between industry and community colleges. Power Engineering Universities have created partnerships with their local utilities and equipment suppliers. However, university systems are resistant to the introduction of new ABET accredited curricula. Section 6.2 Recommendations addresses the industry's role in addressing these challenges and for providing an impetus for the nation's power engineering programs to continue to change and adapt.

DOE could facilitate regulator / industry dialog by designing and holding workforce workshops for NARUC, FERC and NERC that create situational awareness for state and national regulators. DOE should seek out opportunities to co-fund industry education and training programs (IEEE examples include Scholarship Plus, WISE, Plain Talk) and fund student and innovation competitions.

The DOE awarded nearly $100 million to 54 workforce training projects to help prepare the next generation of workers to help modernize the nation's electric grid. DOE should evaluate the ARRA electricity delivery workforce training grants and identify: competencies addressed, scalable solutions, programs that were sustained without DOE support and what worked well to develop real employment and hiring. The curriculum developed and lessons learned should be disseminated and shared among the grantees, education communities and professional societies. This would allow identifying scalable solutions from ARRA electricity delivery workforce training and smart grid advancement grants.

Furthermore, it is desirable to incorporate workforce elements in future DOE technology development efforts including industry participants. DOE could pilot and implement this process across its own programs including the National Labs. Federal agencies could adopt best practices and metrics for identifying, encouraging and recognizing high-quality programs that address workforce issues.

DOE can play a role as a convener of the key parties, both inside and outside of government. While many dimensions of workforce development lie outside the main missions of DOE, DOE has real and significant opportunities to serve as the catalyst that brings information to other agencies and state/community/industry partnerships. As the economy is primed for recovery, energy technology jobs may well be a cornerstone of our economic growth across American cities.

6.1.3 Example Nuggets

Putting Veterans to Work as Power System Operators

The Power4Vets program was started by IncSys company under the DOE Smart Grid Workforce Training Program [4], [5]. This program recruits veterans with a strong background in operating electrical systems, primarily veterans with Navy Nuclear EM and ET ratings, and provides them with on-line self-paced tutorials and power system simulation based training. The veterans graduate with a NERC System Operator Certification. The success of the program can be attributed to the NERC certification exam that is open to all veterans which measures competency and not seat time, the close match between the knowledge, skills and experience of the veterans that are recruited and the job requirements of a power system operator, and having a full time former Navy Master Chief recruiter in Norfolk VA who provides coaching and placement assistance. The program is applying for GI Bill status and is sustained by fee that is paid by the veterans only after they have a job in the power industry. During the DOE project program 163 veterans were trained with the Simulator and 69 received their NERC Certification. The post DOE program currently has 76 veterans enrolled.

Humanitarian Outreach Programs for Attracting Students and Developing Soft Skills

Seattle University is a Jesuit institution that is using Humanitarian Outreach Programs to attract students to engineering, and to develop skills and foster perspectives not easily taught in a traditional classroom setting [6]. Electrical engineering students participate in energy development projects—designing and building small-scale wind and hydro turbines, and microgrids—for alleviation of energy poverty in developing countries. The students then travel abroad to local communities to implement their projects. Along the way, students are mentored by faculty and volunteers from industry that share a common desire to apply engineering techniques for the betterment of humanity. The students rapidly grow in maturity as they are challenged to adapt their designs to real-world constraints, often in a location without power or water, with a common sense approach to make the solution work. The program reinforces the connection of energy to prosperity and quality of life, and serves as a motivator for students to pursue careers in energy engineering.

6.2 Recommendations

- **Education Partnerships**: Governments and other stakeholders should support the development of partnerships within the education, labor, industry and government sectors, to develop new curricula and enhance secondary and post-secondary energy sector workforce training programs, apprenticeships and best practices.
    - Develop an educational road-map that aligns with industry needs.
    - Sponsor a study that effectively bundles the supply and demand assumptions, competency requirements, trends, risks, barriers and possible scenarios to be best prepared for the dynamic workforce needs.
    - States can develop and integrate recruitment, training, employment placement programs in concert with electric utilities and community colleges.
- **Certification Programs**: Universities and professional organizations (including IEEE) should create industry recognized credentials or certifications that can be awarded after the completion of education or training, to demonstrate an individual's achieved skill level.
- **Assess Workforce Issues**: Take necessary actions at the federal level to better understand the implications of a maturing workforce, technology advancements, and policy changes on future workforce requirements.
- **Develop Annual Recognition Programs** on excellence in the state of power system education and training. This program should seek out and celebrate excellence in private – public – educational institution partnerships.
- **Coordination and Communication**: Agencies at the federal and state levels and schools should leverage research, share programs / curriculum and track trends. Joint NSF and DOE efforts would ensure university research grants are optimally leveraged to impact workforce development.
- **Military Veterans Transition**: Identify and embrace best practices that effectively accelerate transition to meet industry workforce requirements.
- **Research or Policy Review**: Any review should include workforce implications (size, scope, location and competency levels) as key factors in the potential success of the action.

Pertinent government agencies should aggressively support development of new curricula that add market economics to electrical engineering degrees. The recommendations illustrate ways that the DOE can establish priorities and partnerships, and take on a leadership role to ensure that adequate utility workers are recruited and trained to maintain a reliable electric system for today and for the future.

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7. Report cards on the condition and performance of the electric grid

The American Society of Civil Engineers (ASCE) does an annual report card on the infrastructure in the US. That report card focuses far more on age and subjective responses from members of ASCE than it does on the actual status of the infrastructure. The electric grid is lumped in with pipelines and other energy infrastructure. In 2013 ASCE assigned a grade of D+ to the energy infrastructure, primarily based on the age and replacement rate of assets which may not accurately reflect the status of the electrical infrastructure.

There is a need to create a survey that provides realistic status of the electrical infrastructure that allows rational decisions to be made on where to invest and what the impact of those investments are. There are several organizations that have pieces of an electrical survey, these instruments vary from heavily used to very lightly used. They also vary in the depth of coverage of their topics.

Existing Survey Tools and Missing Pieces

The North American Electric Reliability Corporation (NERC) does an annual report on the reliability of the transmission system that was mandated by the Energy Act of 2005. NERC has developed a deep and consistent methodology for the assessment of the transmission network.

Carnegie Mellon University (CMU) was given the Smart Grid Maturity Model (SGMM) by IBM. This tool assesses the information technology and operational technology (IT/OT) for a modern grid. This instrument does a wonderful job at assessing the IT/OT, communications systems, and the overall organizational design. It is light on field operations and the installation of equipment in the field.

The GridWise Architecture Council (GWAC) has developed the Smart Grid Interoperability Maturity Model (SGIMM) that covers the interfaces between IT/OT systems and the messaging that is sent between the systems. The tool also looks at the security of each of these individual interfaces. This is a detailed survey that can be run for every interface in the organization.

The Department of Energy (DOE) has its Electricity Subsector Cybersecurity Capability Maturity Model tool which provides a tool set for assessment of the cybersecurity.

The Nuclear Engineering Institute and the NRC both have survey tools for Nuclear Power Plants.

For Transmission, the survey tools developed by NERC are complete and should be considered as a pattern for other portions of the grid, such as generation and transmission.

In distribution the tools for CMU, DOE, and GWAC provide strong components to assess the intelligence of the grid and the adequacy of security, communications and information technology. What is missing and could be modeled from the NERC tools, are the installation of field equipment, substation status, failure rates, staffing levels and the other operational components of the distribution grid. The NERC model would need significant work to make it possible to complete the assessment with a reasonable effort.

In generation, FERC has in the Form-1 a large amount of the material needed to support an assessment of the adequacy of the generation fleet. There are operational and maintenance aspects that are not included in the Form-1. FERC Forms 714 and 715 provide some, but not all of this information and Form 556 provides information on smaller generation facilities. Again the existing FERC data would not provide a complete survey, but it is a strong starting point to develop survey results from.

For sales, forecasts, usage, and other consumption related information the Energy Information Agency (EIA) provides the best starting point.

7.1 Recommendations

The recommendations for a survey of the electrical infrastructure:

- Bring together the industry and end-user stakeholders to look at the existing survey tools, and define the overall needs for an industry wide set of survey tools. This working group should provide a clear requirements document on what needs to be surveyed, and the depth that the survey needs to cover.
- Determine what existing materials can be used to support the survey requirements, minimizing new data collection.
- Provide adequate resources to complete a survey tool set that supports the requirements that were developed by the stakeholder group and uses the data from existing sources.

Working with an industry working group, define how the survey tool will be used both improving the infrastructure and in any regulatory actions. The tool set will fail, if there is no consensus among the stakeholder groups. A solid survey tool set for both self-assessments will provide a data driven way for the industry to determine where to focus research, standards development, training, staffing, and operational improvements for the industry. With the rapid changes in the environment this will allow the better deployment of scare resources.