FINAL PROJECT REPORT

# ROADMAPPING THE CALIFORNIA SMART GRID THROUGH RISK RETIREMENT

## Technology Manufacturer and Vendor Perspective


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# PREFACE

This report documents a study conducted by the NASA Jet Propulsion Laboratory under contract to the California Energy Commission, Public Interest Energy Research Program. The nine-month study took place in the 2009-2010 timeframe and recommended key technology developments, system demonstrations and other actions on a roadmap to achieve the Smart Grid 2020 targets provided at that time. The smart grid in California remains a work in progress, as technologies continue to evolve and mature, and new understanding is gained from demonstrations and deployments to-date. Noteworthy aspects of the study are:

- The perspective taken herein (as directed by the Energy Commission)—that of suppliers of smart grid goods and services— to our knowledge has not been collectively represented before. This perspective complemented two other studies (also commissioned by the Energy Commission) representing the investor-owned utilities and municipal utilities, respectively, in the State.
- Much can be gleaned from the information gathered in the course of this study, which took primary inputs from more than 300 members of the smart grid stakeholder community. The study focuses on how this community can, over a decade or more, play a key role in origination, infusion, supply and maturation of innovative technologies into the California smart grid. Many of the findings are applicable to smart grids anywhere.
- The Energy Commission currently has several microgrid grid demonstration projects underway around the State, and a modest-sized portfolio of relevant R&D projects. The study anticipated the growth of the interest in and perceived importance of microgrids in meeting challenges on both the supply and demand sides of the grid, as the penetration of renewables increases. This report, through its comprehensive roadmap, recommends ways to accelerate their maturation process and adoption into the California grid.

As there's still a need for a range of perspectives and ideas on how to meet California Smart Grid targets, the report's primary findings are relevant today.

*Roadmapping the California Smart Grid Through Risk Retirement* is the final report for the Defining the Pathway to the California Smart Grid 2020 project (Contract Number 500-09-021).

# ABSTRACT

Variations in electricity demand, growth in generation with clean and distributed energy resources, and requirements for secure and reliable power set the context for assessing technology solutions for the California Smart Grid 2020. The smart grid is a complex engineering system that provides benefits to utilities, technology manufacturers and vendors, ratepayers, and to the State in meeting its integrated energy policy objectives. The smart grid is key to enabling the integration of renewable resources with more efficient grid operation, as distribution systems expand and the ratepayer participates more in energy management decisions. New business opportunities are arising, ranging from the manufacture of equipment and smart devices to third-party services. This report documents perspectives from a project team comprising manufacturers and vendors. The study used the *Technology Infusion Maturity Assessment* process and software tool, and addressed nine energy policy objectives, the combination of which achieves significant reduction of greenhouse gas emissions through clean energy supply and reduced electricity demand. Findings and recommendations are documented. Researchers present six cases that use fundamental smart grid technologies, encompassing selected communications and automation and other critical technologies, and end-use applications. Microgrids are highlighted as system architecture options that incorporate distributed energy generation, storage, and management versatility. Microgrids enable energy efficiency and operational advantages to accommodate the uncertainties in renewable energy supply, energy costs, climate change and natural events possible in the decades ahead. Time frames are given and are subject to real-world constraints associated with regulatory and policy changes, funding availability for technology development and demonstration, the evolution of key smart grid technologies as they are evaluated, and models developed and risks retired through pilots, followed by scaled-up deployments of smart grid technologies as a sustainable market takes hold.



**Keywords:** Smart grid, greenhouse gas (GHG), microgrid, combined heat and power (CHP), distribution automation, demand response, Advanced Metering Infrastructure (AMI), energy efficiency, rooftop photovoltaics, electric vehicles, renewables, net zero energy construction, peak reduction, natural gas, energy storage, thermal energy, battery, fuel cell, biomass, hydrogen generation, distributed generation, systems engineering, risk retirement, grid parity, ratepayer, loading order


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# EXECUTIVE SUMMARY: California Smart Grid 2020 Roadmap

The California Energy Commission seeks to address the major changes needed in California's electricity infrastructure to meet clean energy conversion and greenhouse gas (GHG) emissions reduction targets by 2020. Variations in electricity demand, the growth in electricity generation with clean and distributed energy resources, and the requirements for secure and reliable electrical power throughout the grid drive the search for different technology solutions to design and deploy the California Smart Grid 2020. The need for new investments in transmission, energy efficiency, smart grid applications and increased use of renewable resources is widely recognized. The smart grid is key to enabling the integration of these intermittent renewable resources and reducing the potential disruptive impact of plug-in electric vehicles with more efficient grid controls and operation, particularly as distribution systems expand and the ratepayer begins to participate more in energy management decisions in both generation and consumption.

The smart electric power grid represents many, varied functionalities and benefits to investor-owned and public utilities, technology manufacturers and vendors, ratepayers in the residential and in the commercial and industrial segments, and ultimately to the State in meeting its energy policy objectives. The prospect of the smart grid is spurring development and demonstration of advanced energy conversion, energy storage, and reliable and secure power delivery technologies. New business opportunities are arising, ranging from the manufacture of equipment and smart devices to third-party services. Workforce education and training, as part of a sustainable California Smart Grid, is anticipated to help drive economic development in the state through the year 2020 and beyond.

A smart electric power grid is in fact a complex engineering system. Its high-level system architecture encompasses major smart grid subsystems for power generation and reduced, efficient consumption, ranging from distributed generation using residential rooftop photovoltaic installations, combined heat and power (CHP) stations, and energy storage options to Advanced Metering Infrastructure – a system of two-way communicating electricity meters, for enabling approaches for demand response.

This report provides manufacturer and vendor perspectives on the California Smart Grid. These perspectives were attained through direct involvement of the project team with wide representation from these communities. Six cases where smart grid technologies were used represent the manufacturer and vendor perspectives of the project team and are included in this report. The use cases encompass selected subsystems, communications and automation and other critical technologies, and end-use applications. They also incorporate key technology roadmaps from the current smart grid baseline through recommended pathways to a 2020 smart grid system state. The study approach uses the *Technology Infusion Maturity Assessment* process and software tool to address top-level priorities from state energy policy and to capture recommended actions and milestones identified in the suite of key technology roadmaps, use cases, and from a series of project team workshops that were held in the course of the study. The integrated California Smart Grid 2020 Roadmap that is recommended herein is based on the aforementioned perspectives and the results of this process, and provides guidance on how to get from one point to another in smart grid deployment. The focus is the retirement of risks for meeting the high-level objectives of the smart grid as a system with domains in both energy generation (supply) and electricity consumption (demand).

In this study, microgrids were frequently cited as the preferred smart grid architecture option for enabling the attainment of specific distributed generation and energy efficiency objectives,

thus contributing to meeting both energy generation and reduced consumption goals. A microgrid is an integrated power delivery system consisting of interconnected loads and distributed energy resources that, as an integrated system with attendant controls, can operate in parallel tied to the grid or in an intentional island mode. The project team recognizes the benefits that microgrids afford the California Smart Grid 2020. These benefits range from enabling supply and demand at a local level (that is, giving ratepayers more flexibility in power delivery configuration and operation) to providing enhanced grid resiliency, reliability, and security through the ability to aggregate distributed generation and interconnect with the bulk grid, up to and including the ability to separate from the bulk grid. Microgrids enable energy efficiency and operational advantages to accommodate the uncertainties in renewable energy supply, energy costs, climate change and natural events possible in the decades ahead. The California Energy Commission has looked at the potential of microgrids.[1] There are several competing generation, storage, and control technology possibilities that may provide the fundamental basis for microgrid systems at various scales of operation. The anticipated California Smart Grid 2020 must involve more than just the present-day electrical grid to provide the ratepayer with the advantages that can be derived from more efficient generation, storage, and use of available energy, in whatever form that may be. This report recommends how microgrid alternatives should be evaluated to promote their ideal use within the California Smart Grid 2020.

## The Integrated Roadmap

An overarching integrated California Smart Grid 2020 Roadmap was developed as part of this project. This roadmap is the outcome of the study method described in this document and addresses nine specific goals obtained from the *2010 Integrated Energy Policy Report Update*:

1. 33 percent of generation by renewables (~104,000 GWh/yr) in 2020
2. 20 percent of renewable power supplied by biopower sources (landfill gas, biogass, etc.) in 2020 (~20,000 GWh/yr)
3. 3,000 megawatts (MW) of new rooftop solar photovoltaic (PV) by 2016 (~5000 GWh/yr)
4. 10 percent reduction in total forecasted electrical energy consumption in 2016
5. Additional 5,400 MW of combined heat and power (CHP) in 2020
6. Demand response that reduces 5 percent of peak demand in 2020
7. Electricity peak demand reduction goal of 4,885 MW in 2013
8. All new residential construction is net zero energy (homes that use the same amount or less energy than they produce) in 2020
9. Reduce GHG emissions to 1990 levels across all sources in 2020

This roadmap, divided into two principal smart grid system domains of energy supply/ generation and electricity demand/consumption, assimilates the various key pathways and recommendations offered by the project team of technology manufacturers, vendors, and industry trade representatives, toward attaining the smart grid system objectives over the next decade from today's baseline. Within each of these two domains, various technology solutions are recommended to meet corresponding goals in clean generation and reduced consumption. Microgrids, for example, are both power distribution systems on the generation side of the roadmap and a means of enabling options for peak reduction and efficiency improvement. As such, microgrids at various scales of operation reside in both the supply and demand side of the roadmap. Similarly, storage is a source of offsetting power generation for reducing demand on the bulk grid during peak conditions and a means of reducing the effects of intermittent renewables and potentially disruptive plug-in hybrid electric vehicle/plug-in electric vehicle

[1] See: Navigant Consulting Inc. Final Report *Microgrids Research Assessment for the US Department of Energy's Office of Electricity Delivery and Energy Reliability and the California Energy Commission's Public Interest Energy Research Program*, May 2006.

(PHEV/PEV) loads on bulk grid power quality through storage approaches for frequency regulation. Storage (appropriately sized at various scales) likewise sits in both the supply and demand sides of the roadmap depending on the primary function for which it is intended

The energy policy objectives ultimately lead to the reduction of GHG emissions through clean energy supply and reduced electricity demand. The various pathways to meeting the objectives are overlaid on this roadmap development framework and fall into three time frames – now to year 2014, years 2014 to 2016, and from 2016 to 2018. The time frames are estimates subject to real-world constraints associated with regulatory and policy changes, funding availability for technology development and demonstration, approaches to project capitalization, and the natural evolution of key smart grid technologies as they are evaluated, models are developed and risks are retired through pilots, followed by scaled-up deployments of smart grid technologies as a sustainable market takes hold. The lack of roadmap elements beyond 2018 reflects the project team's position that if energy policy objectives are to be met in the 2020 time frame, market-driven implementations must be well underway by that point in all aspects of smart grid technology. In other words, actions by California beyond that point will have little effect on attaining the 2020 goals on schedule.

One of the study's key outcomes is recognizing the need to examine electricity production and efficiency and consumption differently than in the past. This is a result of the study's approach, namely to view the smart grid as a complex engineering system where the various functional requirements on a California Smart Grid 2020 are intricately interrelated. Technology options are explored in a manner that attains the greatest level of energy policy objectives collectively. This consideration also incorporates California's loading order – energy efficiency, demand response, renewables, and distributed generation – into the roadmap strategy.

# CHAPTER 1: Introduction to California Smart Grid 2020 Roadmap Study

The Energy Commission is seeking to address the major changes needed in California's electricity infrastructure in order to meet clean energy conversion and greenhouse gas (GHG) emissions reduction targets by the year 2020.[2] Anticipated variations in electricity demand, the growth in electricity generation with clean and distributed energy resources, and the requirements for quality and reliable electrical power throughout the grid set the stage for describing the value of different technology solutions to designing and deploying the California Smart Grid 2020. The need for new investments in transmission, energy efficiency, smart grid applications and increased use of renewable resources is recognized. The smart grid is key to enabling the integration of these intermittent renewable resources with more efficient grid operation, particularly as distribution systems expand and the ratepayers in all segments (residential, commercial and industrial) are enabled to participate more in energy management decisions.

The prospect of the smart grid is spurring the development and demonstration of advanced energy conversion, storage, and reliable and secure power delivery technologies. New business opportunities are arising, ranging from the manufacture of equipment and smart devices to third-party services. While many technological solutions have been proposed for advancing the grid to a "smart" grid, the options are multifaceted and require a detailed, balanced and unbiased approach that looks at technology evolution, availability and implementation possibilities from realistic technical and business perspectives. ***Clean transportation and reducing GHG emissions from electricity production create the need to examine production, efficiency and energy consumption differently than has been done in past operations.*** The California energy environment is far from static and calls for a structured but flexible approach to the smart grid.

At issue is that the present electric power system has a vertically integrated architecture, generally with little interconnectivity, and limited monitoring or control out in the distribution system. Ensuring grid reliability, security, interoperability and sustainability, given the inherently intermittent and distributed nature of renewable energy resources, are fundamental requirements as renewable energy penetration and utilization grow to meet Renewable Portfolio Standards (RPS). The simultaneous emergence of renewable energy resources, particularly distributed generation, and clean transportation in the form of plug-in electric vehicles place additional and completely new system interface requirements on the decades-old grid.

There is a wealth of technology research, development and demonstration (RD&D) needed for meeting the requirements of a year 2020 electric power grid [see EPRI Report, 2008] and beyond.[3] The adoption and integration of these technologies, which are at various stages of maturation, commercial availability and standards definition, must be driven by objective systems analyses and consideration of attendant business cases. Pilot demonstration projects are keys for retiring risks and better understanding infrastructure design options and predicting the impact of proposed new standards on operations and business processes. Such analyses

[2] Changes also may be needed in natural gas infrastructure in order to enable and capitalize on smart grid options. Water resource management is another critical consideration in the State. Advanced metering technologies, as part of Advanced Metering Infrastructure (AMI), often comprise electrical, natural gas and water usage depending on the responsibilities and needs of a given utility.
[3] See also: Bonneville Power Administration, Technology Innovation Office, Sept. 2006, *Transmission Technology Roadmap*.

should address near- and midterm priorities that are responsive to the needs of technology consumers and utility ratepayers for cost-effective, end-use applications and value-added services, in addition to recognizing electricity and natural gas market dynamics in a smart grid context.  For example, developing an open architecture for integration of renewable resources and energy storage, as well as augmenting the automation, protection and operation of the California power system is a near-term priority.  In this time frame, technical and integration issues surrounding customer communications and metering technologies must be addressed. This is already ongoing through the implementation of Advanced Metering Infrastructure (AMI), including the relatively more recent development of Meter Data Management (MDM) systems, consideration of different communications protocols, and the prospect of services integrating these advanced metering functions with the value-added needs of utilities and ratepayers, as enabled by a Home Area Network (HAN) in the residential segment for example. Midterm priorities include evolving state-level infrastructures for integrating legacy utility systems into an overall state infrastructure with appropriate interfaces between the California Independent System Operator (CAISO), Western Electricity Coordinating Council (WECC), utilities and third-party generators and service providers [EPRI Report, 2008, p. 42]. Appropriate pathways must be considered for the California Smart Grid 2020 that capture these key time frames and attendant priorities.

With the increasingly integrated and distributed nature of the power grid, in tandem with the rapid responsiveness, security and reliability required for the system, there is a need for a more flexible "smart network" or "smart grid" to distribute the power cost-effectively, efficiently and in a timely and reliable manner.  Addressing this need will provide better quality of service to energy consumers, and help reduce service interruptions and associated economic losses.  The benefits to the ratepayers will be measured both in the aggregate through reduced emissions and reliable and secure energy and, particularly for larger energy consumers, through definitive opportunities for cost savings by better managing consumption with electricity pricing information and implementation of their own options for distributed generation and energy storage.

The magnitude of the implementation scale-up across all energy supply and demand sectors cannot be underestimated.  The implications of this industrial and commercial scale-up effort will have a direct impact on workforce development programs, consumer awareness campaigns, technology investment, and development of new finance models.  The potential impact on every ratepayer in the State is such that understanding the dynamic role that reaching grid parity by technology and by region will have on the technology adoption rate needs to be better understood.  By understanding the relationship between falling technology implementation costs and rising energy rates imposed through new tariffs, the State can prepare better for the magnitude of this scale-up effort and ease the economic transition on every ratepayer.

## 1.1 Smart Grid Definition

The smart grid represents many and varied functionalities and benefits, to utilities, technology manufacturers and vendors, and to ratepayers in both the residential and the commercial and industrial (C&I) segments, and ultimately to the California Energy Commission in order to help meet integrated energy policy objectives.  This study adopts the following definition of a smart electric power grid from Austin Energy:

> *The Smart Grid is the seamless integration of an electric grid, a communications network, and the necessary software and hardware to monitor, control and manage the generation, transmission, distribution, storage and consumption of energy by any customer type.*[4]

[4] See http://www.austinenergy.com

A broader vision of the smart grid encompasses the integration of large-scale renewable energy, distributed generation[5], and electric vehicle infrastructure. The unique requirements and characteristics of the California system add further characteristics that are reflected in California Smart Grid 2020 system architecture options explored in this study – such as emphasis on distributed generation, energy storage and the potential for microgrids at various scales.

## 1.2 The California Energy Landscape

The smart grid must address California-specific environmental and sociopolitical factors. According to the IEPR [2007]:

- Reducing California's GHG footprint to meet AB 32 goals will require a ~29 percent cut in emissions below the levels the state is currently projected to produce in 2020.

- California has led the nation in effective action to improve air quality and has held the line on per capita consumption of electricity. But, with a growing population and economy, California must ensure that energy supplies keep pace with growth while simultaneously reducing its GHG footprint.

- Today, one in eight Americans, over 37 million people, lives in California. The state's population has doubled since 1965, a growth rate faster than that of any other developed region in the world. The state Department of Finance expects California will add another 7 million people in the next dozen years, to more than 44 million by 2020, moving toward 60 million residents by 2050.

- Affordable and reliable energy is essential to California's successful economy. Energy represents nearly $100 billion in annual expenditures.

- Fossil fuels dominate the state's energy system: petroleum to serve the transportation sector and natural gas to heat homes and generate electricity. Most of California's GHG emissions, 81 percent, are $CO_2$ produced from fossil fuel combustion, with roughly 28 percent from electricity generation and 39 percent from transportation.

Electricity generation and transportation account for two-thirds of GHG emissions. It is evident why addressing the efficiency of the power grid, and clean energy and clean transportation are keys to meeting the State's environmental policy by 2020.

Legislation, policies and incentives that are not carefully structured in view of business, market, and ratepayer-driven smart grid architecture options attune to integrated system and technological readiness can have formidable long-term negative impact on meeting 2020 objectives. For instance, it is evident to Californians that the continued predominant reliance on coal, oil, and/or natural gas to generate electricity is unsustainable since it compromises the ability of future generations to meet their own energy needs. Thus, while natural gas may be a cleaner energy source than coal, its use in California should be seen only as an interim solution. How a California Smart Grid 2020 can address this matter remains to be seen; some recommendations are offered in this Report for combined heat and power (CHP) systems with

[5] Distributed Generation (DG) is defined as electricity production that is on-site or close to a load center and is interconnected to the utility distribution system. In practical terms, this limits the definition of DG to less than 20 megawatts (MW) since systems larger than this would be interconnected at sub-transmission or transmission system voltages. This definition includes technologies such as photovoltaics; small wind; small biomass; small CHP or small cogeneration; small combined cooling, heat and power; and small non-CHP systems. From: Rawson, Mark and John Sugar. *Distributed generation and cogeneration policy roadmap for California*. March 2007. CEC-500-2007-021.

hydrogen generation for storage in fuel cells, for example. The impact to the market, particularly to the natural gas ratepayer, is anticipated to be significant in that the dependence on clean, renewable energy sources will become cheaper for the entire state.

Consider the implications of the geographic layout of the electric power system. California is a long, thin state, with major power loads in the center and the south (the San Francisco Bay Area in northern California and Los Angeles to San Diego in southern California). There is a net import of power from outside the state. In 2010 approximately 30 percent of California's electricity was imported from out-of-state; California imports more electricity from other states than any other state. Hydro-generated power is imported from the Pacific Northwest via the AC/DC Pacific Intertie. Coal power is imported from the east from Four Corners (2040 MW), and via AC/DC connections to the Intermountain Power Project (1800 MW in Utah), and from the south via interconnections at 500 kV and lower.

Moreover, Californians tend to be concerned over land use and environmental impact. The cost associated with new and expanded transmission lines and the inefficiencies of long-distance power transmission are additional major concerns. As a result, the siting of additional power generation, and particularly power transmission, is likely to be contentious. Furthermore, California faces grave water resource issues; and climate change will exacerbate the looming problems associated with water availability and use. This will create new problems and demands on the electrical energy grid if, for instance, the need for energy-intensive local water recycling grows rapidly, or watersheds migrate, requiring more energy to move water to users.

One way to defer the need for new generation capacity is to improve the load factor, so that the difference between the average power demand and the peak power demand is reduced. In the past, a number of load management (or demand-side management) techniques have been employed with this in mind. Demand response, enabled by advanced meters, for example is now planned to reduce California's peak load by 5 percent by 2020. A power delivery system fully equipped with control and communications (of which AMI is a key technology component out on the ends of the distribution system) will allow the integration of distribution automation functions and customer applications enabled through HAN and home energy management systems, for example. It also will permit the smooth operation of inherently intermittent renewable energy sources by helping to address power quality issues as part of the overall energy mix. This has direct impact on increasing the market penetration of renewable energy technologies, as the uncertainty of intermittency will be of increasing concern as RPS targets are approached.

In addition, addressing power quality as measured by power factor ratings on the ratepayer side of the meter should be considered. With the growth of resistive loads in the past 30 years inside commercial businesses and residences and the emergence of new "smart appliances," improving power quality will play an increasingly important role in improving the load factor by reducing total demand through the delivery of better quality power. Plug-and-play technologies are now available that hold great promise to improve power quality and reduce electrical demand without compromising function or utility. This could have an immediate and significant impact on peak demand while promoting overall reduced consumption.

## 1.3 The California Smart Grid – A Complex Engineering System

The California Smart Grid system objectives of 33 percent of generation by renewables (~104,000 GWh/yr) in 2020, demand response that reduces 5 percent of peak demand in 2020, reduction of GHG emission to 1990 levels across all sources, plus six others (see Section 2.1) comprise the high-level objectives of this system architecture study for prescribing a roadmap development framework for the California Smart Grid 2020. The overarching recommended roadmap is an integration of the various key pathways towards attaining a corresponding integrated view of the smart grid objectives over the decadal period to 2020. The perspective herein is that of the technology manufacturer and vendor communities represented in the project team; perspectives of the investor-owned and municipally owned utilities are contained in parallel studies funded by the Energy Commission for *Defining the Pathway to the California Smart Grid 2020*. The integration of the three perspectives is a necessary next step to ensure that the system design is optimized to meet the needs of all stakeholders.

A smart electric power grid is in fact a complex engineering system. The architectural design, sustainable transformation without disruption, and maturation of the California Smart Grid to 2020 and sustainability beyond is one of the most critical infrastructural challenges being faced today, with ramifications ranging from environmental impact (i.e. mitigation of climate change through reduction in GHG emissions) to economic security from decreased dependence on predominantly foreign sources of fossil fuel to sustainable in-State job creation. A deliberate, disciplined process of system engineering and tradeoff space exploration ensures that investments in technology RD&D not only are economically viable but also technologically sound in view of an ultimately optimal California Smart Grid 2020 system design.

Prof. M. Ilić of Carnegie Mellon University offers the following perspective on smart grid infrastructure and the need for a systems engineering framework:

> *The primary energy producers have entered a race to make traditional energy resources cleaner and safer, as well as to develop scientific principles in support of entirely novel energy resources. Right now, we do not have the infrastructure to transport the energy effectively. The infrastructure for converting our primary energy resources and delivering energy in the form required by the end users was designed with qualitatively different objectives from the functions of today; it is aging and far from what it should and could become.*
>
> *A systems engineering framework is needed that is fundamentally driven by connections to the market. The basic challenge is transforming today's passive electric power grids into active enablers of efficient and reliable utilization of emerging unconventional energy resources. Any large-scale penetration of intermittent resources is practically impossible without equally large-scale sensing, actuation and on-line data-assisted decision-making by various industry participants – from Independent System Operators (ISOs), Load Service Entities (LSEs), power producers/aggregators, to end-users. These resources cannot succeed without significant improvements to the control of the infrastructure.*[6]

The evolution of today's electric power grid to a smart grid system calls for new business models. These models drive, in part, the functional requirements of the smart grid architecture. The existing grid structure is ill suited to accommodate significant levels of flexible and distributed energy resources without dramatic changes in operations, infrastructure, and development strategy. The evolution and modernization of the electric power grid is a system engineering and integration issue that spans multiple stakeholders in both the supply and demand sides of energy, transportation, and environmental markets.

Moreover, to significantly enhance the state of traditional network control systems for a smart grid, there is an equally if not greater need to accelerate market adoption, stimulate business and create jobs. Workforce education and training are key elements. Enterprise architecture therefore also is needed to align the introduction of enabling information technology infrastructure with business needs and processes.

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[6] Presentation at JPL and California Institute of Technology, by Prof. Marija Ilić, Carnegie-Mellon University, May 12, 2008.

# CHAPTER 2: Study Objectives

The study addresses the need for high-level system architecture design in developing and implementing the California Smart Grid 2020. The high-level architecture comprises major smart grid subsystems for power generation and efficient consumption, such as distributed generation through rooftop photovoltaic installations and residential-scale CHP stations, and energy storage options and Advanced Metering Infrastructure (AMI) for enabling approaches for demand response and potentially power quality management out in the distribution network.[7] It also shows how these major grid subsystems are interrelated, such as CHP tied to biomass and natural gas sources, so as to achieve the desired smart grid functionality and meet the set of top-level energy policy objectives.

Six use cases are described that are centered on key technologies representative of the manufacturer and vendor perspectives of the project team, encompassing selected smart grid subsystems, communications and automation technologies, and end-use applications in the 2010 to 2020 time frame. These provide key technology roadmap elements, from the current (defined for 2010) baseline through recommended pathways to a 2020 smart grid system state.

The set of use cases, in addition to top-level priorities from the 2010 Integrated Energy Policy Report Update (IEPR), levy requirements on architectural options that are explored with a comprehensive system tradeoff space analysis methodology – *Technology Infusion Maturity Assessment (TIMA)*. This methodology was developed by the National Aeronautics and Space Administration (NASA) Jet Propulsion Laboratory (JPL) over the last decade and applied successfully to technology developments and complex system designs within and outside the aerospace engineering enterprise. The attendant software tool integrates various system options, easily and readily, for evaluations and comparisons based on insights that are not apparent when options are studied in conventional ways. The use cases likewise offer recommended pathways and actions for mitigating the barriers to meeting the functional requirements, through sequences of needed steps to 2020.

This Final Report describes the results of this methodology, albeit preliminary in a sense given the scope and complexity of the challenge (and considering that the perspectives of the investor-owned and municipal utilities need to be incorporated thereafter in a fully integrated roadmap). In addition to findings and recommendations, a more elaborated model would provide greater insights into the interrelationships between energy policy objectives, key technology roadmap elements, needed investments, market incentives, research and development, pilot demonstrations, and policy and regulatory changes, and the overall magnitude of the commercial scale-up implementation challenge across California.

Provided herein is a suite of risks (also referred to as "barriers") to attaining the State's objectives as elicited in a series of study workshops, along with a recommended set of actions to mitigate those risks, following the engineering process of risk retirement.[8] The impact of these risks on meeting energy policy objectives, and the effectiveness of investments, incentives, R&D, demonstrations, and policy and regulatory changes, and standards would be elaborated

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[7] One of the key challenges facing the evolution of the power grid into a smart grid is not just the development of necessary component technologies, but also the tools to design, model, deploy, use, and maintain those components *in the context of an overall system*.

[8] Risk retirement is a term borrowed from the aerospace industry to describe the series of actions that are undertaken in a project to mitigate identified risks to meeting the project's objectives. Over the lifecycle of the project, the progress towards meeting the objectives of the project is measured through a progression of risk retirement profiles that indicate a) the levels to which identified risks are deemed mitigated, and b) the levels to which the projects objectives are being attained.

through an additional set of workshops. This would ***integrate the results of this study with the results of the investor-owned and municipal utilities studies under a common framework and shared high-level set of Smart Grid 2020 objectives***, through workshop participation of investor-owned and municipal utilities in the State, technology manufacturers and vendors and Energy Commission stakeholders.

## 2.1 Smart Grid Priorities Reflecting Energy Policy Goals

Findings and recommendations that are the outcome of the TIMA process (which is described in greater detail in Chapter 3, Study Approach) address nine specific objectives that were obtained from the 2010 Integrated Energy Policy Report Update:

1. 33 percent of generation by renewables (~104,000 GWh/yr) in 2020
2. 20 percent of renewable power supplied by biopower sources in 2020 (~20,000 GWh/year)
3. 3,000 MW of new rooftop solar PV by 2016 (~5000 GWh/yr)
4. 10 percent reduction in total forecasted electrical energy consumption in 2016
5. Additional 5,400 MW of combined heat and power (CHP) in 2020
6. Demand response that reduces 5 percent of peak demand in 2020
7. Electricity peak demand reduction goal of 4,885 MW in 2013
8. All new residential construction is net zero energy in 2020
9. Reduce GHG emissions to 1990 levels across all sources in 2020

These nine objectives are taken from "Figure 1: Key California Energy Policy Goals and Mandates" as given in the PIER Request for Proposals RFP # 500-08-502. More detail on each objective is to be found in *Integrating New and Emerging Technologies into the California Smart Grid Infrastructure* CEC-500-2008-047, which in turn references the sources of these objectives.

In addition, the top functional priorities for the California Smart Grid are provided in the EPRI [2008] Report (p. 11):

- Ability to increase penetration of renewable technologies
- Improve overall grid system operational reliability, availability, sustainability and maintainability
- Improve the environmental impact of the grid on California (reducing GHG emissions)
- Increase efficiency of the grid
- Reduce costs of operations of the grid

Furthermore, consideration needs to be given to assuring that the State's official Loading Order emphasizing energy efficiency is included first in the framework of this study to assure that statewide allocation of resources to achieve these implementation goals is balanced and consistent with this policy.

Note that only the nine *IEPR* goals ultimately were used to develop the recommended overarching roadmap, addressed in the TIMA process and model by eliciting barriers to their attainment and prescribing actions that mitigate that impact of those barriers or risks. *Elaboration of the model to specifically address functional priorities is proposed for further study, particularly as risk retirement actions thereof would point more to smart grid operational issues, at which stage one also could incorporate priorities related to the operational needs of large-scale deployments and cyber security, for example.*

### 2.1.1 Secondary Objectives – DOE Smart Grid Attributes

Secondary objectives of this research study comprise addressing the following smart grid attributes from the Department of Energy (DOE) Smart Grid System Report [2009]:

- Enables informed participation by customers
- Accommodates all generation and storage options
- Enables new products, services, and markets
- Provides power quality for the range of needs
- Optimizes asset utilization and operating efficiency
- Operates resiliently to disturbances, attacks, and natural disasters

While these were appended to the nine *IEPR* goals in the TIMA model, risks to their attainment and risk mitigation actions were not elicited in the workshops. However, it may prove valuable to specifically call out these objectives in a series of follow-on workshops, as these DOE objectives relate more to customer and market factors, and likewise point to operational efficiency and grid security.[9]

## 2.2 The Pathway to the California Smart Grid 2020

The smart grid is an engineering system whose complexities span technological, operational, policy, regulatory, market and social factors. Planning for its design, development, deployment and sustainability must be driven by objective, top-down systems analyses. Advanced energy conversion, storage, reliable delivery technologies, renewable resources and clean transportation are integral to its system architecture. Customer (ratepayer) expectations and benefits must be met.

System-level risk retirement is needed through an integrated series of key demonstration projects to identify, prioritize, mitigate and *systematically* "retire" risks, and for validation and verification of integrated systems along the following lines:

- Technical performance and cost
- Controls and interfaces, interoperability
- Scale-up, safety, reliability and security
- Codes and standards
- Business model feasibility
- Market transformation needs, including implication of reaching grid parity by technology and region
- Leveraging between applications
- Lessons learned (utilities, developers, customers/public), benchmarks, best practices

[9] The key findings of the Smart Grid System Report, U.S. Department of Energy (July 2009) are relevant to this study, paraphrased here: The ability to connect distributed generation, storage, and renewable resources is becoming more standardized and cost effective (but penetration level remains low). Several other concepts are in a nascent phase of deployment, these include the integration of microgrids, electric vehicles, and demand response initiatives, including grid-sensitive appliances. Advanced metering infrastructure is seen as a necessary step to enabling dynamic pricing and consumer participation mechanisms. The business cases, financial resources, paths to deployment, and models for enabling governmental policy are only now emerging with experimentation. Understanding and articulating the environmental and consumer perspectives also are in their infancy. A smart grid is socially transformational. A cross-disciplinary change that instills greater interaction among all the stakeholders is a necessary characteristic as we advance toward a smart grid.

### 2.2.1 Smart Grid 2020 Vision for the Study

The 2009 Integrated Energy Policy Report (IEPR, 2009) states the following:

> *Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), the Global Warming Solutions Act of 2006, established the goal of reducing greenhouse gas emissions to 1990 levels by 2020, and serves as the comprehensive framework for addressing climate change. However, many of the policies in place prior to passage of AB 32 are also valued for their role in meeting the state's climate change goals. One of these policies is the loading order for electricity resources, which calls for meeting new electricity needs first with energy efficiency and demand response; second, with new generation from renewable energy and distributed generation resources; and third, with clean fossil-fueled generation and transmission infrastructure improvements.*

In accordance with IEPR [2009] and the loading order policy for sources of electricity, this study's vision for the California Smart Grid 2020 is the following:

> <u>*Vision Statement*</u>
>
> *Reduction in energy consumption and GHG emissions from electricity production and clean transportation are inextricably linked. To provide electricity producers, distributors and consumers with options for preferred business models and operations choices means that sustainable, cost-effective, secure and reliable solutions must be developed, demonstrated and implemented.*
>
> *A new paradigm is evolving where electricity generation, storage and control are more distributed, along with an attendant modification to grid interconnections. Microgrids are at the heart of this new paradigm – providing cogeneration options with the integration of renewables, including rooftop PV systems and CHP, while enabling options for reducing consumption through demand aggregation, distributed storage, electric vehicle accommodation and net zero energy buildings.*

Implementing this vision will lead to a smart grid that provides California ratepayers with a greater voice in energy flexibility, efficient and reliable operations, and cost structures.

# CHAPTER 3: Study Approach

The study approach is responsive to the EPRI Report (2008) that states: *"These systems are complex and must be engineered using the latest methods for systems engineering and architecture. These methods are also on pathways to maturity."* Systems engineering integrates all the disciplines and specialty groups into a team effort forming a structured development process that proceeds from concept to production to operation. Systems engineering considers both the business and the technical needs of all customers with the goal of providing a quality product that meets the user needs.[10]

## 3.1 Technology Infusion Maturity Assessment (TIMA)

The smart grid technology roadmap study approach uses the *Technology Infusion Maturity Assessment* (TIMA) process and software tool to address top-level priorities from the *IEPR*. The approach captures recommended actions and milestones identified out of a suite of key technology roadmaps and corresponding use cases representing technology manufacturer and vendor perspectives on key smart grid elements, critical technologies and end-use applications. The use cases (Chapter 5) prescribe key interfaces within prospective smart grid architectures. Moreover, the use cases, to various degrees, also offer functional requirements describing the desired behavior of smart grid subsystems, with roadmap elements that define a current baseline state (defined as 2010) and steps to meeting 2020 objectives. These steps or pathways consider operational qualities of the system, cost effectiveness, compatibility with existing industry practice and current and emergent standards and codes, ease of commercialization, and technology adoption rates and market penetration when grid parity is reached. Elements of the use cases were entered into the TIMA model but were not addressed in the workshops specifically to link actions therein to barriers to attaining the *IEPR* objectives. Rather, this is recommended for follow-on study.

The TIMA process is enabled by an interactive software tool that establishes the relative significance of specific risk elements to system architecture by evaluating the impact of their occurrence on system requirements or objectives (i.e. the nine *IEPR* goals). TIMA quantifies the effectiveness of particular mitigations or actions for mitigating the risks to achieving architectural requirements levied by the top-level priorities. TIMA is an interactive and iterative process, mediated by the software tool. The TIMA process of eliciting and structuring the multiple use cases, risks and mitigations relies on an initial phase of data collection from a "critical mass" of domain experts on the system under design evaluation. The project team industry subcontractors[11] provide perspectives on cost effectiveness, cost/benefit, price targets, return-on-investment metrics, previous market experience, compatibility with existing industry practice and emerging standards for the smart grid, current state-of-the-art and state-of-practice, ease of manufacturing and operations and maintenance (O&M), future technology RD&D, codes, standards, cyber security, etc.

TIMA emphasizes identifying drivers, barriers, actions and pathways that represent the consensus views of the relevant supplier communities. The TIMA process in the smart grid research systematically quantifies the performance differences between a baseline system state and evolutionary snapshots in time towards more enhanced later states along the maturation

[10] Definition of the International Council on Systems Engineering (INCOSE)
[11] The project team is comprised of representatives from different segments of the industries that are developing, demonstrating and implementing hardware, software and connectivity in a smart grid. This is complemented by the perspectives of the member organizations of the industry trade associations in the Project Advisory Committee (PAC).

pathway to California Smart Grid 2020 objectives. The outcome of the TIMA analytical methodology allows for quantification of the value of technical, infrastructure and market development contributions in terms of enhanced attainment of system requirements/objectives or reduction of system-wide risks between a 2010 baseline and a subsequent system state.

The strength of the TIMA tool is realized by performing before and after analyses; and by quantifying and visualizing the risk profiles (or incremental residual risk profiles) and attainment of objectives between system states. These analyses correspond to different scenarios involving different rankings or weightings of objectives, assumed impacts of risks and effectiveness of different combinations of mitigations employed. The attendant TIMA model developed for this study is not deemed sufficiently comprehensive at this point to enable the types of what-if analyses possible. However, the structure and breadth of the barriers and actions offers a sense of the issues addressed by the project team and Project Advisory Committee, not only in the Workshops (see Tables A-2 and A-3 in the Appendix) but also throughout the course of the research study. *Additional model development is recommended, ideally with integration of IOU and MOU California Smart Grid 2020 roadmap recommendations, in order to provide the Energy Commission an effective and comprehensive means of evaluating and monitoring progress to 2020. For the PIER Research Program, it would be valuable for establishing R&D priorities that are not only driven by the Integrated Energy Policy but also linked to measures of objectives attainment.*

## 3.2 TIMA Workshops

The overall study philosophy was to depend on the perspectives of a wide range of smart grid industry stakeholders, representing different segments of the industries that are responsible for the development and implementation of hardware, software, connectivity, and the non-utility business and operational aspects of smart grids.

To that end, workshops were held over the course of the study. The first workshop was held on June 21-22, 2010 at the California Institute of Technology, Pasadena, CA, and was used to elicit an initial TIMA set of barriers and actions associated with attainment of integrated energy policy objectives. The second workshop, held on August 17-18, 2010 in Sacramento, CA, was intended to carry out collective correlations of the TIMA data (i.e. assignments of barrier impacts and actions effectiveness on a low, medium and high basis) and to discuss and initiate the definition of key technology roadmaps. The third workshop, held in Washington, DC, on November 9-11, 2010, focused on review of key technology roadmap material under development by members of the study team. The final workshop was an extended virtual workshop, held in March 2011, to review selected roadmap study products and collect final comments for this document.

The preponderance of the workshop attendees (which included no electrical utility representatives) were primarily interested in AMI, distribution automation, PHEV/PEV accommodation, microgrids, distributed generation and storage smart grid architectures, rather than more traditional centralized architectures. While active demand management by residential and C&I consumers was a topic of interest, automated or utility-operated demand management was not.

The barriers offered were balanced nearly between technical factors: technology status, grid system status, security and privacy barriers, and non-technical factors: regulations and standards, economics and finance, customer readiness barriers (although there is a strong non-technical flavor to security and privacy). The study team believes that these behaviors stem from the fact that a large majority of the attendees do not sell primarily to electric utilities, and therefore are more interested in non-traditional, new energy-related markets since, for instance, if demand management becomes the responsibility of residential, C&I electricity consumers, the potential new customer base includes every energy user in California and therefore represents the largest new market opportunity.

## 3.3 Developing the TIMA Model

The TIMA model is constructed through the project and stakeholder workshop process to identify the organizational, functional, physical, informational, and lifecycle requirements of smart grid system design, and to elicit a tier-structured set of barriers or risks to meeting these multi-fold requirements, and a corresponding tiered set of actions (i.e. research efforts, pilot demonstrations, incentive programs, educational campaign, regulatory and policy changes, standards, etc.) to mitigate those risks. Elements of the use cases and key technology roadmaps also are incorporated into the model but were not incorporated into the process of assigning relative impacts and effectiveness measures on barriers and actions, respectively. This is left for further consideration as a recommended next step towards developing a comprehensive model for the Energy Commission that would also integrate the roadmap perspectives of the investor-owned and municipal utilities.

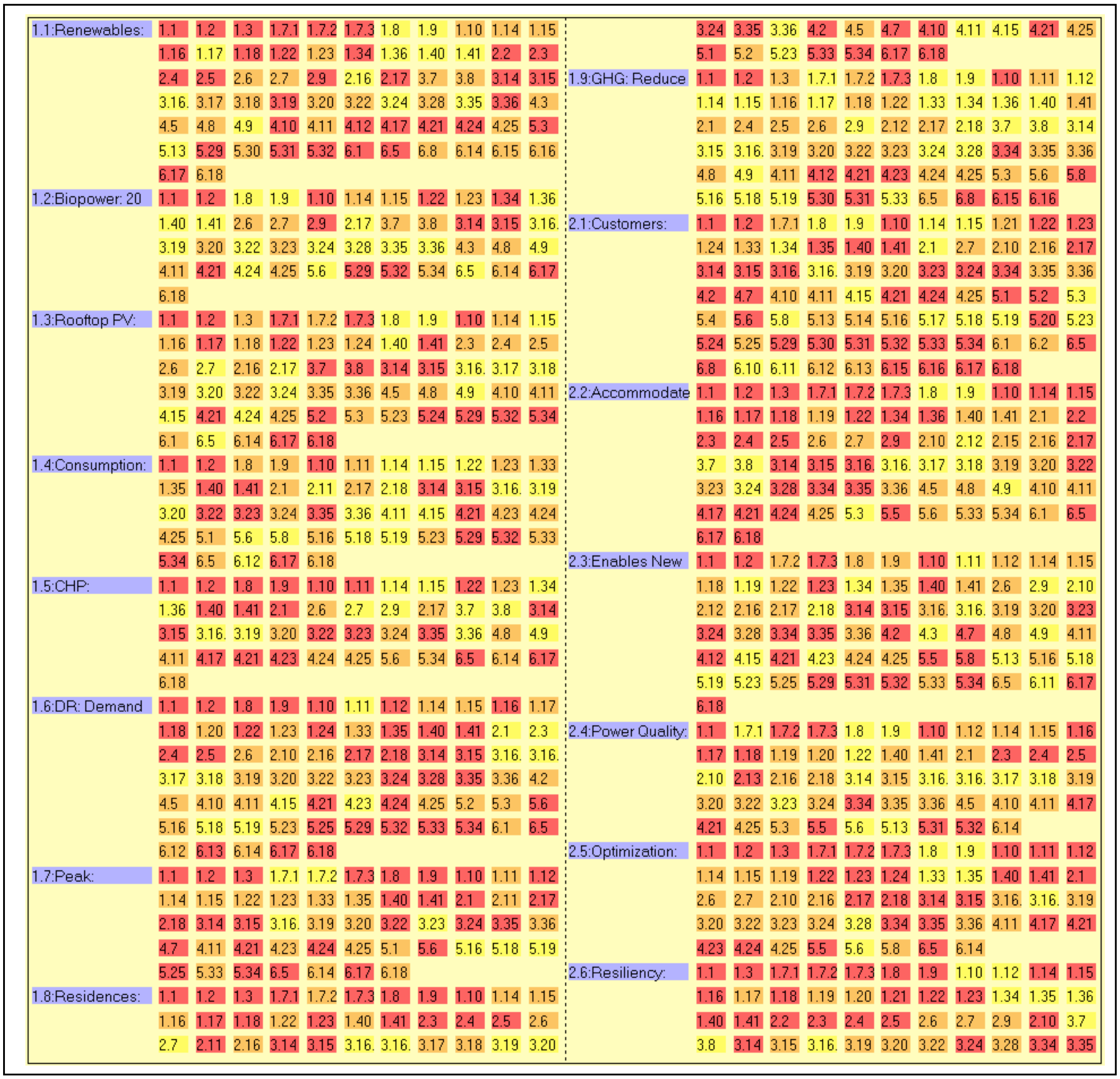
### 3.3.1 Objectives and Barriers

The tiered structure of the system requirements and objectives for the California Smart Grid 2020 is shown in Table A-1 of the Appendix. Each of the nine *IEPR* goals is branched into elements. Note that these objectives typically are nested. For example, the objectives for rooftop PV installations and CHP are part of meeting the RPS target, if these systems are grid-tied. Likewise, peak reduction and demand response, plus net zero energy construction, are means of reducing electricity consumption. Secondary objectives consisting of smart grid attributes from the DOE Smart Grid System Report [2009] are listed for completeness (see Section 2.1.1) but were not carried through the analysis leading to the overall roadmap recommendations.

The fact that the energy policy objectives are nested and have quantitative targets suggests that a simple mathematical model could be developed specifically for this application of TIMA. This is left for further consideration as a separate recommended research project, such that the impact of barriers and the effectiveness of risk mitigation options could be established numerically with traceability to meeting these objectives quantitatively. In so doing, the TIMA model would show percentage attainment of objectives in terms of meeting annualized power levels.

The further sets of information that go into the TIMA model (*barriers* to the objectives, *actions* to overcome those barriers, and correlations between them that provide measures of barrier impact and action effectiveness) were elicited from the study teams present at the first two workshops. The first workshop focused on gathering the lists of barriers and actions, and some qualitative correlation of barriers to objectives (to assess which barriers would likely be obstructions to which objectives, and whether the degree of obstruction would be low, medium or high). The information gathering was done in a series of rounds. In each round the study participants were allowed time to write down their own ideas (of objectives and/or barriers). Then each participant in turn was given time to succinctly describe their inputs to the group, during which time the inputs were incorporated into TIMA. Participants later were allowed to speak within a given round, elaborate further on their inputs so as to engender discussion as well as to contribute additional input. To encourage balanced participation, the different rounds started with different people, so that the same individuals were not always the first (or last) to contribute. In advance of the second workshop this information was consolidated and rearranged where necessary to achieve a more consistent organization.

**Figure 1: Graphic output from TIMA showing the 15 objectives (9 from *IEPR* and 6 from the Department of Energy) and elicited barriers.**




Drawn alongside each objective bar (blue) are smaller boxes, each representing a barrier to that particular objective. The numbers refer to the listing of barriers (see Table A-2 of the Appendix). The colors red, orange and yellow indicate the extent of the obstruction (red = high, orange = medium and yellow = low). Note that at the time of the first TIMA workshop, results of which are captured here, the objectives were simply enumerated and did not have the tiered structure indicated in Table A-1 of the Appendix. Rather, the tiered structure is a result of developing the smart grid roadmap framework in the course of the study.

### 3.3.2 Correlations Between Objectives and Barriers

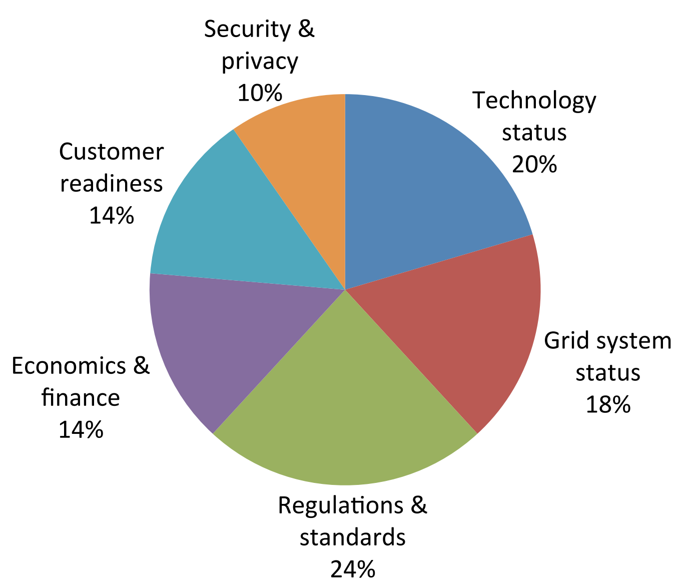
A key part of the TIMA process is to gather information on which barriers obstruct which objectives, and to what extent. Shown in Figure 1 are the results of this information gathering from the first workshop. The main point of this figure is to convey the multiplicity of obstacles that, if left unaddressed, will obstruct attainment of the objectives for the smart grid. Identification of the actions that will need to be taken to overcome these obstacles is the basis of the insight for developing the recommended roadmap.

### 3.3.3 Initial Analyses From the TIMA Workshops

The barriers mentioned to the evolution of the California Smart Grid 2020 are distributed among six major categories as shown in Figure 2. Across all categories, based on frequency of mention, the workshop attendees found the following classes of barriers to the evolution of California's smart grid to a 2020 target and beyond to warrant the greatest attention:

- State of readiness of residential and C&I energy consumers
- Status of distributed generation and microgrid system architecture knowledge
- State of the current traditional utility grid
- Status of energy storage-related technology – *the most frequently mentioned technology status barrier* [12]
- Status of regulations and standards for communications and interoperability
- Availability of suitable financing arrangements for potential stakeholders

**Figure 2: Barrier categories elicited from the first TIMA workshop.**




Across all categories, again based on frequency of mention, the workshop attendees found the following classes of actions to be most important to the evolution of California's smart grid:

[12] Since storage technology was the most frequently mentioned technology status-related barrier, the TIMA tool was used to carry out a preliminary assessment of the barriers and actions associated with storage technology and storage technology development, provided in Section 3.5.

- Incentivize residential, and C&I energy consumers to engage in smart grid-related activities
- Conduct studies, analyses and tests to elucidate alternative smart grid architectures
- Conduct education campaigns to engager all stakeholders
- Conduct demonstrations of smart grid functions and smart grid elements
- Develop improved energy storage technologies

## 3.4 Key Technology Roadmaps

The concept of Key Technology Roadmaps was introduced as the first step toward developing the use cases and the integrated roadmap for the California Smart Grid 2020 from the technology manufacture and vendor perspective. These roadmaps were to address the current state of the technology and the events that must take place to get that technology to the point where it enables the achievement of the state's smart grid goals. The assignees were asked to consider the end state to include:

- Achievement of California energy policy objectives, and mandates from the study RFP
- Achievement of the Smart Grid Attributes from DOE Smart Grid System Report
- Achievement of other targets from California Energy Commission RFPs and bidders' conferences:
  - 30 percent reduction in GHG emission levels in 2020 (i.e. the overarching objective)
  - All economically viable demand response in-place in 2016
  - Modernize the aging utility grid infrastructure
  - Meet the future energy growth needs of California with new and innovative technologies, including:
    - Utilizing existing assets more efficiently
    - Yielding less environmental impact on the state
    - Meeting stringent costs/benefit assessments
    - Providing ratepayers and customers of California new options in meeting their individual energy needs
    - Addressing integration and implementation of electricity and natural gas transmission and distribution
- Resolution of priorities offered by the Manager of the Energy Commission Energy Systems Research Office
  - Demand Response and Automated Demand Response
  - AB 2514 - the "Storage Bill"
  - Distributed storage
  - PHEV/PEVs
  - Meter technology obsolescence
  - HAN privacy, security and ownership
  - Grid cyber security

Instructions for developing use cases that centered on Key Technology Roadmaps were as follows:[13]

1. Identify the current state of the technology (current unit cost, salient performance characteristics, lifetime, reliability, market penetration to date, etc.).
2. Identify the sequence of events, starting with current status, to get to the goals and attributes listed above. Include important preconditions that must be established, other technologies that must be brought along in parallel, any major assumptions, such as the smart grid communications architectures used (e.g. wireless communication systems are available throughout the state).
3. Try to identify the order of events, milestones, actions, activities that will need to be accomplished to get this technology where it needs to be in order to enable the achievement of the goals and attributes. If, however, there are minimum time increments ($\Delta t$'s) associated with steps in the roadmap, please identify them.
4. Include, as needed:
   - Technology development
   - Studies/analyses/tests
   - Education campaigns
   - Demonstrations
   - Incentives (legislative, regulatory, financial, etc; who needs to be incentivized and who needs to make it happen)
   - Other
5. Identify the end state, consistent with achievement of the state's goals, of the technology (i.e., unit cost, salient performance characteristics, lifetime, reliability, market penetration, etc.)
6. Generate an estimate, if at all possible, of the order of magnitude costs of doing this (i.e. costs to utilities, utility customers, suppliers, taxpayers, etc. With this information and the $\Delta t$'s of item 3 above, one would have an initial estimate annual investment budgets needed to achieve the 2020 goals.

The 3rd Workshop, held in Washington, DC, on November 9-11, 2010, focused on review of key technology roadmap material under development by members of the study team. Additional material was presented by The Robert Thomas Brown Co. on California GHG emissions; by ACORE on the study survey of their membership on smart grid issues and actions; by the Grid Protection Alliance on Smart Grid Cyber Security issues; by AT&T on their perspective on the Smart Grid Utility Market; by Honeywell and by Southern Construction, Inc. on net zero energy residential construction in 2020. A discussion also was held of integrated roadmap concepts and components to show how the State's energy policy goals and functional elements of the smart grid are related, and to explore the nature of the smart grid architecture trade space.

The final workshop was part of the review process. Study team members provided review commentary on an earlier draft. The Final Report also was provided to the Project Advisory Committee, through its Chair, for additional comments and recommendations.

## 3.5 TIMA Model of Storage-Related Technology in the Smart Grid

The status of energy storage-related technology was the technology status barrier most frequently mentioned in the first workshop. This motivated an effort that took place between

[13] The Project Team members who took on responsibility for particular key technologies generally followed these guidelines. However, given the differences in the nature of these technologies and/or their application and smart grid functionality, the key technology roadmaps and use cases presented in Chapter 5 (and their 2010 baseline components in Chapter 4) vary to some degree in how they are documented in this Final Report.

the first two workshops to extract and fully correlate the portion of the TIMA model specific to storage technology. The storage technology barriers included in this model portion were:

1. Unprecedented scale of use of batteries - collect/recycle/reuse infrastructure at end of life
2. Unknown where to place storage
3. Unknown how to pay for storage
4. Incompatibility of storage with current regulation
5. How to make it possible for members of the public to buy their own storage (i.e., consumer-led storage industry)
6. Failure to consider off-nominal scenarios (e.g., gray-outs, cyber attacks) when developing storage options and technologies
7. Industrial scale storage is unreliable, immature and too costly
8. Residential scale storage is unreliable, immature and too costly
9. Round trip efficiency losses are higher with storage systems in play
10. Incentives for storage are uneven depending on kind of storage technology

In this model all but two of the original 15 objectives were estimated as being correlated to one or more of the storage technology barriers. The estimated correlations are shown in Table 1, Impact Matrix. Each number in an inner white-background cell indicates the proportion of the objective obstructed by the barrier (e.g., a proportion of 0.2 means the barrier obstructs a notional 20 percent of the objective); this is the measure of barrier impact on attaining objectives.

The storage technology actions included in this model portion were:

1. Legislative requirement to evaluate storage (on an open book basis) as an alternative to peak generation and renewable balancing
2. Legislative requirement to evaluate storage (on an open book basis) as an alternative to new transmission capacity
3. Open up evaluation of storage systems beyond utilities, DOE and EPRI (e.g. provide for equal weighting of testing and evaluation by commercial partners such as Cisco, Home Depot, Walmart, etc.)
4. Open and realistic on-peak/off-peak pricing
5. Credits for domestic-scale storage
6. Require ISO 14,000 compliance (environmental life cycle) for storage and other smart grid systems
7. Develop technologies and guidelines for best approaches to future-proof technologies
8. Develop wind and solar (near-real-time) forecasting to inform storage and/or DR systems

The estimated correlations between actions and barriers are shown next in Table 2, Effectiveness Matrix. Each number in an inner white-background cell indicates the proportion of the barrier overcome by the action (e.g., a proportion of 0.2 means the action overcomes a notional 20 percent of the barrier); this is a measure of the effectiveness of actions on reducing barriers.

Once populated with the above information, the TIMA software is able to calculate the consequences on objective attainment of selections from among the actions; actions overcome barriers, leading to increased attainment of objectives. T he bar chart (Figure 3) shows the total obstructions against objectives remaining due to the storage barriers *assuming all the actions are performed*. The chart shows one row per objective, omitting objectives 1.2 and 1.4 that received no obstruction from the storage barriers. For the sake of simplicity for the exposition here, each objective has been assigned the same relative weight of 1. To the left of each objective's textual description are two bar segments, one colored red, and the other blue. The length of the blue bar indicates how much of the objective is being attained, while the length of the red bar indicates how much is not being attained because of the barriers (despite the effects of the actions to overcome those barriers to varying extents).

A similar chart for the status of each of the barriers is shown in Figure 4 (note the change of scale of the bars as compared to the chart in Figure 3). The chart shows one row per barrier. To the left of each barrier's textual description is a red bar segment. Its length indicates the total obstruction it is causing to the objectives (despite the actions). This gives an indication of the relative magnitudes of problematic areas that remain despite the actions already identified, the ones with the longest red bars being the most problematic.

**Table 1: Impact Matrix.**

| **Objective x Barrier matrix STORAGE SUBSET 1.0 = Objective 100% Lost 0.9 = Large Impact to Objective 0.7 = Medium Impact 0.3 = Small Impact 0.1 = Tiny Impact** | **Objectives** | California Energy Policy Goals and Mandates | | | | | | | DOE Smart Grid System | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 33% of generation by renewables by 2020 (104,000 GWh/yr) | 3,000MW of rooftop Solar PV by 2016 (~5000 GWh/yr) | 5,400MW of combined heat and power by 2020 | Demand response that reduces 5% of peak demand by 2020 | Electricity peak demand reduction goal of 4,885MW by 2013 | All new residential construction is net zero energy by 2020 | Reduce GHG emissions to 1990 levels across all sources by 2020 | Enables informed participation by customers | Accommodates all generation and storage options | Enables new products, services, and markets | Provides power quality for the range of needs | Optimizes asset utilization and operating efficiency | Operates resiliently to disturbances, attacks, and natural disasters |
| **Barriers** | | 1.1 | 1.3 | 1.5 | 1.6 | 1.7 | 1.8 | 1.9 | 2.1 | 2.2 | 2.3 | 2.4 | 2.5 | 2.6 |
| Unprecedented scale of use of batteries - collect/recycle/reuse infrastructure at end of life | 1 | 0.8 | 0.5 | 0.2 | 0.2 | 0.3 | 0.8 | 0.4 | 0.1 | 0.9 | 0.5 | 0.3 | 0.7 | 0.9 |
| Unknown where to place storage | 2 | 0.9 | 0.5 | 0.2 | 0.2 | 0.3 | 0.3 | 0.6 | | | 0.3 | 0.5 | 0.7 | 0.9 |
| Unknown how to pay for storage | 3 | 0.9 | 0.5 | 0.2 | 0.2 | 0.3 | 0.7 | 0.8 | | 0.5 | 0.7 | | | 0.9 |
| Incompatibility of storage with current regulation | 4 | 0.9 | 0.5 | 0.2 | 0.2 | 0.3 | 0.8 | 0.8 | 0.1 | 0.9 | 0.3 | 0.5 | 0.7 | 0.9 |
| How to make it possible for members of the public to buy their own storage - consumer led storage industry | 5 | 0.5 | 0.3 | 0.2 | 0.2 | 0.3 | 0.9 | 0.4 | 0.1 | 0.9 | 0.4 | 0.3 | 0.5 | 0.9 |
| Failure to consider off-nominal scenarios (e.g. gray-outs, cyber-attacks) when developing storage options and technologies | 6 | 0.3 | | 0.1 | 0.5 | 0.5 | 0.5 | | | | | 0.3 | | 0.9 |
| Industrial-scale storage is unreliable, immature and too costly | 7 | 0.7 | 0.7 | 0.2 | 0.2 | 0.2 | | 0.6 | | 0.1 | 0.6 | 0.3 | 0.7 | 0.9 |
| Residential-scale storage is unreliable, immature and too costly | 8 | 0.6 | 0.9 | 0.5 | 0.4 | 0.4 | 0.8 | 0.8 | | 0.2 | 0.6 | 0.6 | 0.7 | 0.9 |
| Round trip efficiency losses higher with storage systems in play | 9 | 0.2 | 0.1 | | | 0.4 | | | | | | | 0.1 | |
| Incentives for storage are uneven depending on kind of storage technology | 10 | 0.2 | 0.1 | | 0.1 | 0.1 | | | 0.1 | | | | 0.5 | |

**Table 2: Effectiveness Matrix.**

| **Action x Barrier matrix**<br>**STORAGE SUB TIMA**<br>**1.0 = Barrier 100% Reduced**<br>**0.9 = Large Reduction to Barrier**<br>**0.7 = Medium Reduction**<br>**0.3 = Small Reduction**<br>**0.1 = Tiny Reduction** | **Actions** | Legislative requirement to evaluate storage (on an open book basis) as an alternative to peak generation and renewable balancing | Legislative requirement to evaluate storage (on an open book basis) as an alternative to new transmission capacity | Open up evaluation of storage systems beyond utilities, DOE and EPRI (e.g. provide for equal weighting of testing and evaluation by commercial partners such as Cisco, Home Depot etc.) | Open and realistic on-peak/off-peak pricing | Credits for domestic scale storage | Require ISO 14,000 compliance (environmental life cycle) for storage and other smart grid systems | Develop technologies and guidelines for best approaches to future-proof technologies | Develop wind and solar (near real time) forecasting to inform storage and/or DR systems |
|---|---|---|---|---|---|---|---|---|---|
| **Barriers** | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
| Unprecedented scale of use of batteries - collect/recycle/reuse infrastructure at end of life | 1 | | | | | | 0.8 | 0.2 | |
| Unknown where to place storage | 2 | 0.4 | 0.4 | 0.5 | | | 0.3 | 0.3 | 0.4 |
| Unknown how to pay for storage | 3 | 0.4 | 0.4 | 0.6 | 0.4 | 0.6 | 0.2 | 0.2 | |
| Incompatibility of storage with current regulation | 4 | 0.3 | 0.3 | 0.3 | | | 0.2 | 0.2 | |
| How to make it possible for members of the public to buy their own storage - consumer led storage industry | 5 | | | | | 0.4 | 0.3 | 0.6 | 0.3 |
| Failure to consider off-nominal scenarios (e.g. gray-outs, cyber-attacks) when developing storage options and technologies | 6 | 0.4 | 0.4 | 0.4 | | 0.3 | | 0.4 | |
| Industrial-scale storage is unreliable, immature and too costly | 7 | 0.1 | 0.1 | 0.1 | | | | 0.6 | |
| Residential-scale storage is unreliable, immature and too costly | 8 | 0.3 | 0.3 | 0.4 | 0.6 | 0.6 | | 0.6 | |
| Round trip efficiency losses higher with storage systems in play | 9 | | | | 0.5 | 0.4 | | 0.2 | 0.2 |
| Incentives for storage are uneven depending on kind of storage technology | 10 | 0.4 | 0.4 | 0.4 | 0.6 | 0.6 | 0.2 | 0.2 | 0.3 |

**Figure 3: Objectives attainment from selection of actions that overcome barriers.**

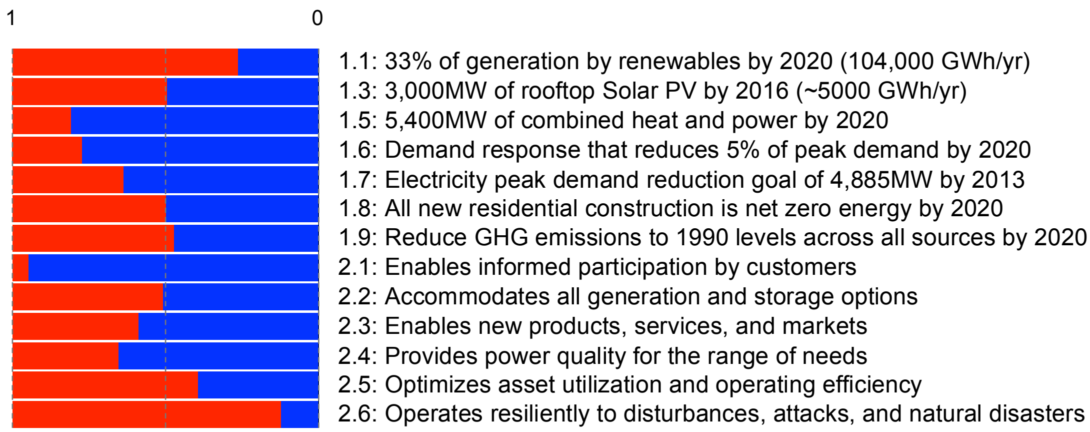
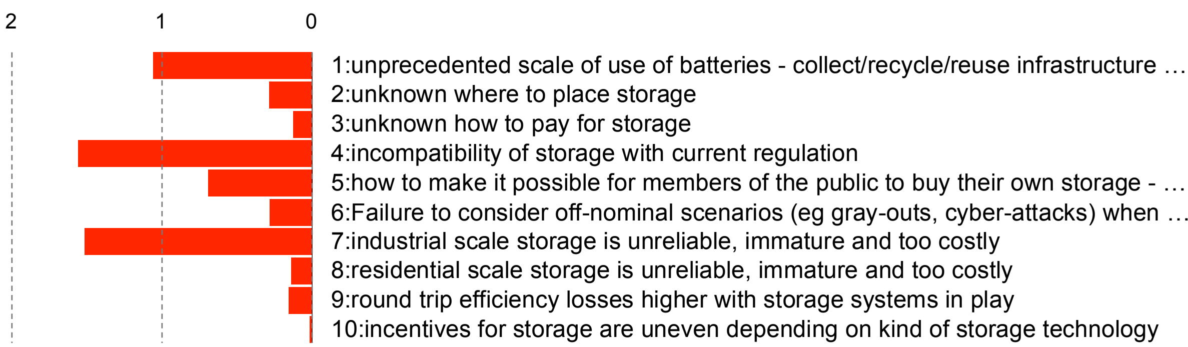
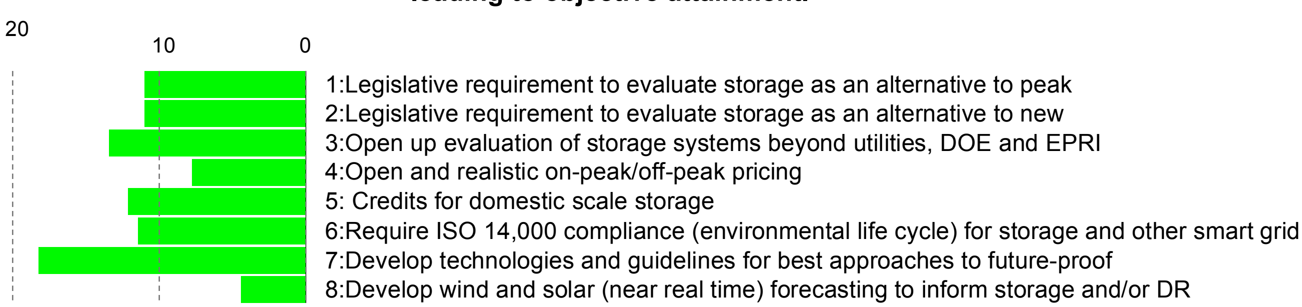



**Figure 4: The reduced impact of barriers after actions are selected.**




Finally, a chart of the contribution each action is making at reducing barriers and thus leading to objective attainment (once again, note the change of scale) is shown in Figure 5.

**Figure 5: TIMA chart of the contribution each action is making at reducing barriers and thus leading to objective attainment.**




This reveals the relative contributions each action makes at overcoming barriers. This brief study of storage technology illustrates the types of findings that can emerge from TIMA.

# CHAPTER 4: 2010 California Smart Grid Baseline

The current states of key smart grid technologies comprise the Smart Grid Baseline 2010. These were obtained from key technology roadmaps and use cases developed by the industry project team members. The list of key technologies is described in this Chapter.

The baseline is established against which progress to meeting the 2020 goals can be measured by monitoring the development and deployment of key technologies, to guide future smart grid investments, and to facilitate stakeholder participation in the development of needed infrastructure. *It is the expectation of the Project Team that continued development of the TIMA model and monitoring the effectiveness of risk mitigation actions on attaining the IEPR goals can provide a valuable management support tool for the California Energy Commission and the California Public Utilities Commission in directing smart grid research (through PIER) and overseeing the evolution of the California Smart Grid to the 2020 targets and beyond.*

## 4.1 Storage

Significant energy storage will be required to integrate future levels of renewable resources, thus allowing better matching of renewable generation with electricity needs. The mix of renewable energy resources, particularly wind and solar, will be both centralized in large “farm” installations and distributed; the storage options and corresponding technical requirements will vary. These technologies also can reduce the number of natural gas-fired power plants that would otherwise be required to provide generation characteristics needed by the smart grid system to operate reliably. Additionally, energy storage may have an important role in grid power quality as more renewable sources of generation come online, and as PHEV/PEV charging presents added indiscriminate load on the grid. If storage is implemented on a large scale in a distributed fashion, the excess electrical power that CAISO is required to maintain may be reduced because the required capacity is available throughout the grid.

However, many storage technologies are still in the R&D stage, are relatively expensive, and need further refinement and demonstration [IEPR, 2009]. The storage baseline is as follows:

- Present-day operations depend primarily on real-time balance of supply and demand
- Meeting daily electrical demands is accommodated through a limited range of options
    - Spinning reserves for increased output
    - Increase output from intermediate load suppliers
    - Load shedding and shifting
    - Thermal storage
- Electrical energy storage is commonly derived from the shifting of energy production during low demand periods
    - Pumped hydro (where applicable, mostly at capacity in California)
    - Compressed air energy storage (CAES) for economical gas turbine operations
    - Steam generator/storage systems
- Some alternatives are in limited use
    - Thermal units which generate ice during off-peak time for day-time air conditioning operation
    - NaS batteries for electrical energy supply during peak demand
    - Li-ion batteries and flywheels for short-term balancing (frequency regulation)
- Most new options are being investigated to a greater extent as part of recent Smart Grid initiatives and demonstration projects (including those funded by ARRA)
    - Ultracapacitors

- Flow batteries

## 4.2 Rooftop Photovoltaics

Recent estimates of the amount of renewable energy needed by the year 2020 to meet the 33 percent RPS target range from 45,000 GWh to almost 75,000 GWh. This wide range reflects different assumptions about energy efficiency achievements, expected electricity demand and retail sales in 2020, and the amount of energy that will be provided by CHP, rooftop solar, and existing renewable facilities [IEPR, 2009].

The California Solar Initiative (CSI) is the solar rebate program for California consumers that are customers of the investor-owned utilities. The CSI Program has a budget of $2.167 billion over 10 years, and the goal is to reach 1,940 MW of installed solar capacity by the end of 2016. The CSI Program is designed to be responsive to economies of scale in the California solar market – as the solar market grows, it is expected solar system costs will drop and incentives offered through the program decline.

- As of September 2, 2010, 22 percent (385 MW) of the target 1750 MW goal has been installed, 25 percent (435 MW) is in the application process, and 53 percent (931 MW) is remaining.
- In addition to the largely consumer or commercial customer-owned PV systems installed under the CSI program, the PV industry is seeing solid evidence of "utility owned and operated" collections of distributed PV systems.

## 4.3 Natural Gas, Combined Heat and Power (CHP) and Biomass

Combined heat and power (CHP) systems utilize many different technologies to produce electricity and are applied in a variety of ways for different operations. Reciprocating engines (Otto and Diesel cycle), Stirling engines, turbines and fuel cells comprise the range of methods by which electricity can be generated, but the waste heat levels and quantities, emissions (GHG in particular), and duty cycle operability cover a plethora of engineering choices from which to choose for any given size and application. There are significant regulatory barriers to CHP in California, including the lack of incentives for applying mature technologies in unconventional ways, such as hybrid systems.

The distinct advantage of CHP is that in the production of electricity, energy in the form of heat, which is normally wasted, is used in any of several ways (e.g., hot water heating, steam generation, absorption chillers, and condensing heat recovery). In CHP systems, the overall savings in energy and reduction in GHG emissions can be substantial. According to a 2009 report issued by the United States Clean Heat and Power Association (USCHPA), CHP systems produce almost 8 percent of the U.S. electric power, save about $5 billion in energy costs, reduce energy use by 1.3 trillion Btu/yr, reduce NOx and SOx emissions by 0.4 and 0.9 million tons/yr, respectively, and prevent the release of over 35 million metric tons of carbon equivalent. The primary way of effectively coupling CHP with this type of savings is through the application to distributed generation (DG).

Two very important goals that are targeted by California for a Smart Grid 2020 are: increased CHP applications and increased use of biomass for electricity. Since biomass also is considered a renewable source of energy, use of biomass then addresses a third goal of California when used in CHP operations. In addition, a fourth goal of the Smart Grid 2020 is to reduce GHG emissions, and through increased efficiency of CHP operations in which either a hydrocarbon fuel or biomass is the energy source, reduced GHG emissions is an obvious common attribute of highly efficient CHP. In short, the applicability of natural gas and biomass in CHP operations that are installed in DG operations expand this area of interest to provide a major role in the development of an efficient California Smart Grid 2020.

The scale of CHP operations is an integral part of how efficiently they can be integrated into the particular overall energy needs at a specific location and how well a set of site-specific energy demands, part of which is electrical and part of which is thermal, are met. In many operations, the electrical and thermal demands are not constant or continuous, requiring a degree of control best managed at the specific site of operation. Several options can be exercised, including energy storage that also can be employed in many different ways, to further expand the efficiency of operation that a centralized electricity generation plant cannot begin to offer. When energy storage is included in a CHP operation, the definition of the system and attendant controls becomes difficult to distinguish from a microgrid-type system.

### 4.3.1 Natural Gas

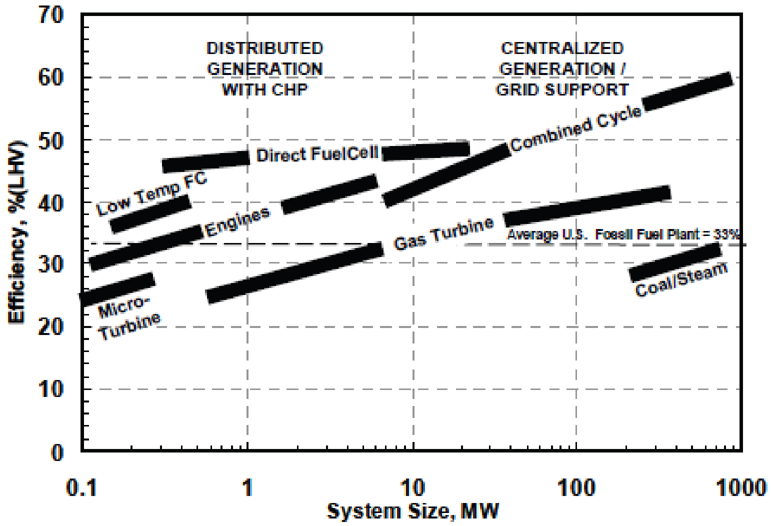
Up to now, electrical utilities have provided customers with electricity from many different locations, using different methods, delivering it in a unidirectional fashion. Large gas turbines, some operating continuously, others used for meeting peak demand, have provided electricity for utilities for the past few decades. Large cogeneration systems are predominantly combustion turbines and high electrical efficiency combined-cycle power plants where there are no very large heat demands. In parallel, natural gas (NG) is used by end-users primarily for space and industrial processing heat. This widespread use is due in part to the cleanliness of burning natural gas (i.e., reduced GHG) as well as its availability (i.e., the expanded supply), and the network of distribution (infrastructure and storage) that has been established. The use of natural gas for electricity production steadily has increased in California from 45.74 percent in 2008 to 56.7 percent in 2009 of the total in-state generation.

However, in order to meet the California Smart Grid goals for 2020, changes must take place, not only in an increase in use of renewable energy sources such as solar and wind, but also in an increase in efficiency of natural gas use. Furthermore, the possibility of integrating natural gas use with the expansion of renewable sources offers a great opportunity to make the transition from current operations to 2020 expectations for the California Smart Grid. Several possibilities exist, some requiring new technology, others requiring innovative adaptations, but some simply from making CHP, as DG, more pervasive throughout the grid.

There are multiple choices of CHP generation technologies as a function of size of application and efficiencies anticipated (Figure 6). It is important to note that since there are choices of technology for the application, engineering analyses for proper choice should be the major consideration, and out-of-date or inappropriate regulations should not be an obstruction in determining how the California Smart Grid 2020 should be assembled in order to gain the greatest advantage offered by CHP.

In the NG distribution network, there are several supply lines and storage facilities that accommodate flexibility in how to meet varying NG demands. These variations are encountered in the electrical utility supply on a day-to-day, week-to-week, and season-to-season basis. Likewise, thermal load demands vary according to site demands, but these may not be synchronous with the electrical demands. However, there is a limit as to how efficient each of these individual electrical generating operations can be with variations in load demands. Of course, because thermal energy use is an integral part of the system efficiency, the limits of part-load operations will vary, but the ability to shutoff certain generators in low demand needs is another option.

**Figure 6: The choices of CHP generation technologies as a function of size of application and the efficiencies anticipated [Courtesy: FuelCell Energy, Inc.]**




## 4.3.2 Biomass

The term "biomass" includes many materials that range from agricultural solid wastes, livestock waste materials, municipal waste/landfill, industrial/food product waste, to wastewater treatment products. An Energy Commission Report[14] states: "Biomass in the state totals 83 million gross bone dry tons per year (BDT/yr) at present and is projected to increase to 98 million BDT/yr by 2020. Biomass that is considered to be available on a technically sustainable basis totals 32 million BDT/yr in 2007, increasing to 40 million BDT/yr in 2020. Of the gross resource in 2007, 21 million tons were from agriculture, 27 million from forestry, and 36 million tons from municipal wastes exclusive of waste in place in landfills and biomass in sewage. The current technical potential includes more than 8 million BDT/yr in agriculture, 14 million BDT/yr in forestry, and 9 million BDT/yr in municipal wastes." The report continues: "Gross electrical generation potential from biomass is currently near 9,500 MWe with more than 1,900 MWe from agriculture, 3,500 MWe from forestry, and 3,900 MWe from municipal wastes including landfill and sewage digester gas. The technical resource generating potential is nearly 3,820 MWe. By 2020, as a result of resource growth and improvements in conversion efficiencies, technical generating potential could reach 6,800 MWe, representing nearly 9 percent of projected statewide peak power capacity."

"Existing and planned biomass power generation capacity in California is currently 968 MWe including solid-fueled combustion power plants and engines, boilers, and turbines operating on landfill gas, sewage digester gas, and biogas from animal manures. Total biomass capacity is 1.5 percent of statewide peak power capacity (63,800 MWe). Electrical energy contributions in 2020 could reach 51 TWh, or nearly 14 percent of projected statewide consumption (363 TWh). Through 2020, the largest resources for development will be municipal solid waste, in-forest biomass, animal manures, landfill gas, orchard and vineyard residues, and field crop residues. State biomass resources are sufficient to supply a substantially larger amount of renewable electricity than is presently generated as well as serving as feedstock for biofuels and bioproducts."

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[14] Williams, Robert B. 2008. *An Assessment of Biomass Resources in California, 2007*. California Energy Commission. CEC 500-01-016.

## 4.4 AMI and Control & Communications

As cited in the IEPR [2009], most California utilities have aggressively expanded their Advanced Metering Infrastructure (AMI) rollouts, with the Department of Energy directing smart grid American Recovery and Reinvestment Act of 2009 (ARRA) funding of AMI demonstration projects to enable demand response approaches and support technologies for energy management systems in homes and buildings. The modernization of the U.S. electric grid is in fact one of the key elements of the ARRA, and AMI deployments are a major benefactor, with the current smart grid baseline as follows, likewise applicable in California:

- Proprietary products developed by a small number of OEM meter vendors, with some sourced proprietary technology by relatively smaller companies
- Largely 915 MHz unlicensed band, short-range mesh network architecture on the utility-to-consumer part of link
- Large and small software vendors provide the utility with the back-end meter data management (MDM) and network monitoring products and technologies
- Government is leading the concurrent development of standards
- Customer benefits not clear

### 4.4.1 Demand Response

The California Energy Commission cites RD&D needs and objectives for Demand Response (DR) in the areas of communications, controls and institutional issues. At a minimum it will be necessary to communicate real-time prices and/or interruption signals. In addition to prices, the kinds of information that may be communicated include total end-user loads, end-user loads available for interruption, billing information, and forecast of weather and prices. A variety of issues need to be addressed including communication protocols, security and reliability. A key to more successful DR programs, especially in the C&I segment, will be the availability of control systems that can respond automatically to price and interruption signals. Some observers argue that the most important impediments to successful DR programs are institutional. While there are a few successful real-time pricing (RTP) programs in the U.S., there also have been a number of failures. Understanding the causes of past failures and devising ways to overcome them in the future may be critical in the development of successful RTP programs for California.

DR programs motivate changes in electricity use by ratepayers in response to changes in the price of electricity over time, or give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized.[15] Price-based DR programs such as RTP, critical peak pricing (CPP) and time-of-use (TOU) tariffs, charge customers time-varying rates that reflect the value and cost of electricity in different time periods. Incentive-based DR programs pay participating customers to reduce their loads at times requested by the program sponsor, triggered either by a grid reliability problem or high electricity rates.

#### *4.4.1.1 Price-Based DR Options*

TOU rates are the most prevalent time-varying rate program. Customers who are exposed to some form of TOU rates experience seasonal rates or daily peak and off-peak rates. CPP is a relatively new form of retail TOU rates that relies on very high critical peak prices, and is dispatched on short notice. RTP rates vary during the day, directly reflecting wholesale

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[15] Information on demand response options is obtained from: J. Osborne and D. Warrier, *A Primer on Demand Response: The Power Grid: Evolving from a "Dumb" Network to a "Smart" Grid*, Thomas Weisel Partners, October 16, 2007, which provides a good overview.

electricity prices. RTP links hourly prices to hourly changes in the day-of or day-ahead cost of power. The first RTP programs were introduced in California in the mid-1980s [see further details in Osborne and Warrier, 2007].

#### 4.4.1.2 Incentives-Based DR Options

Direct Load Control (DLC) programs refer to those in which a utility or system operator remotely shuts down or cycles customer electrical equipment on short notice to address system or local reliability contingencies in exchange for an incentive payment or bill credit. DLC has been in operation for at least 20 years. The most common form of DLC is a program that cycles the operation of appliances such as air conditioners or water heaters, using advanced, programmable remote switch technology. Other DR options include Interruptible/Curtailable Rates, Emergency Demand Response, Capacity Market Programs and Demand Bidding/Buyback Programs for large customers, operated by the ISOs [see further details in Osborne and Warrier, 2007].

### 4.4.2 Demand Aggregation

Demand aggregation is a load response method through a third-party with the responsibility to the participating users to provide the necessary load level according to the parameters of an offer cleared by the ISO, to notify customers of the necessary demand rescheduling resulting from accepted offers, and to assist customers in the determination of the best demand response policies mix according to demand curtailment period and price levels [Valero et al., 2007][16]. The customer participants must have the capacity to bid load curtailments through an aggregator. Since customers find it difficult to participate directly in the electricity market due to its complexity, a third-party aggregator can identify, in day-ahead and real-time energy markets, the customer groups and distributed energy resource (DER) strategies with better possibilities to manage and reduce energy costs [Valero et al., 2007]. The smart grid baseline for demand aggregation is simply:

- Net zero energy buildings in commercial space: 31 Tannery Road project in Branchburg, NJ, as an example of a Demand Management Zone[17]
- Difficult to determine the extent to which any DMZ is deployed because of little media exposure

### 4.4.3 Distribution Automation

Distribution automation (DA) is being viewed in the electric utility industry as the next logical Smart Grid milestone after AMI. As a result, utilities are beginning to contrast the cost of a standalone DA infrastructure with that of an AMI solution coupled with a DA deployment that leverages a common communications platform.[18] The smart grid baseline for DA is as follows:

- Proprietary products developed by small number of Original Equipment Manufacturers (OEMs)
- Research is needed to determine if AMI communications networks are suitable for DA applications
- Government is leading the concurrent development of standards

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[16] S. Valero, M. Ortiz, C. Senabre, C. Alvarez, F.J.G. Franco and A. Gabaldon. Methods for customer and demand response policies selection in new electricity markets. *IET Gener. Transm. Distrib.*, Vol. 1, No. 1, January 2007.

[17] http://www.ferreiragroup.com/31_tannery_road.html

[18] *Enabling Cost-Effective Distribution Automation through Open-Standards AMI Communications*, Itron Inc., 2009.

- Control and protection products and deployment lags transmission communication systems and AMI

## 4.5 Net Zero Energy Construction and Energy Efficiency Retrofits

A net zero energy building merges highly energy-efficient building construction and retrofit construction, IP-addressable state-of-the-art appliances, controllable thermostats, automated dimmer-controlled lighting systems, high performance building envelope improvements, and power quality improvement technologies to reduce a building's load and peak requirements and can include onsite solar water heating and renewable energy, such as solar photovoltaic, to meet remaining energy needs. The result is a grid-connected building that draws energy from, and feeds surplus energy to, the grid [IEPR, 2009]. The two principal elements and smart grid baseline of net zero energy construction comprise distributed generation and energy efficiency:

- Distributed Generation (solar PV, wind, CHP):
  - Financing and incentives available; single transaction
- Energy Efficiency:
  - Prescriptive solutions (compact fluorescent lamps (CFLs), refrigeration rebates, weatherization)
  - Multiple transactions, financing not readily available, e.g. reduced availability and increased uncertainty regarding Property Assessed Clean Energy (PACE) funding. Federal Investment Tax Credit (ITC) and IOU rebates available, applied /funded by measure, not whole-house or performance-based incentives.

Representative attendant costs:

- Distributed Generation (Solar PV)
  - $7-8 installed watt (before incentives) < 10 kW systems
- Energy Efficiency
  - $1.50 - $2.50 installed Watt, depending on Energy Conservation Measure (ECM)

The total contribution to GHG reduction goals to be achieved from the building retrofit market is substantial. Expanding consumer awareness campaigns, focusing whole-building retrofits, making multiple financing options available, including low-income housing improvement financing, and simplifying incentive structures will be key to realizing the potential for this segment. Though PACE funding holds great promise, solving the financial barrier is perhaps the single greatest roadblock to rapid market transformation.

## 4.6 PHEV/PEV Accommodation

Several infrastructure barriers must be overcome to stimulate greater penetration of electric vehicles into the marketplace, particularly recognizing that California is a transformational market for the automotive industry nationwide. Utilities will have to develop procedures, standardized equipment, and rates that meet the needs of vehicle users. Initially, utilities should probably focus on in-home recharging. Most consumers would be comfortable with home charging if time-of-use metering rates and equipment were available, as recharging could easily be accomplished in mostly off-peak hours. Consumers could be further motivated if they were able to receive the carbon credits that accrued with the use of this energy source [see IEPR, 2009]. The current smart grid baseline for PHEV/PEV accommodation is as follows:

- Technology factors and load impacts need to evolve
- Advancements in batteries are being made, but more are needed
- Charging infrastructure requires much more support

- Communication technology and systems are currently inadequate

Automakers already have begun commercial production of a new generation of PHEV/PEVs in California. As these vehicles enter the market, infrastructure developers and installers have begun offering charging stations (also known as electric vehicle service equipment, or EVSE) for residential, C&I and public locations. There are three levels of charging available to consumers that provide different levels of power:

- Level 1: 110V, single phase, 15 amps. This level of service is provided by a typical domestic electricity outlet and is most appropriate for PHEV/PEVs with relatively small batteries. With Level 1 charging, PHEV/PEVs can fully charge overnight. Those with smaller battery packs can fully charge in just a few hours.

- Level 2: 240V, single phase, 32 amps. This level of service is appropriate to fully charge battery electric vehicles overnight and PHEV/PEVs with large batteries in a few hours.

- Level 3: 480V, three phase, 100's of amps. This level of service is often referred to as "fast charging." It applies to high-current service that can charge electric vehicles fitted for Level 3 capability to about 80 percent of capacity in 20 minutes or less. Although a number of charging stations can provide Level 3 service, no Level 3 charging standard currently exists in the U.S.

Currently, California has about 1,300 Level 2 public charge points at 400 locations that were installed to serve the first wave of PHEV/PEVs ten years ago. The Energy Commission is funding upgrades to this existing equipment so that it meets the new industry-standard plug design. The number of charging locations should expand quickly, as several projects are underway to develop infrastructure to support early PHEV/PEV markets. The Energy Commission has allocated $15.3 million with matching federal stimulus funds of $55.8 million to install more than 4,000.[19]

## 4.7 Microgrid Accommodation

Microgrids are a key architectural option for the California Smart Grid that help address specific 2020 targets. Functionally, microgrids are local distribution-based power systems that use Distributed Energy Resources (DER) to manage the local energy supply and demand. They increase the viability of DER in the bulk grid by aggregating them into clusters with better grid stability properties than a multiplicity of standalone generators. Moreover, microgrids have the ability to separate themselves from the bulk grid and function in island mode, so they have the potential to enhance grid resiliency and customer reliability and security by reducing susceptibility to faults and disturbances. In addition, being a distribution power system they have the responsibility to manage microgrid distribution system voltage as well as reactive power.

The following is from the DOE-Energy Commission Microgrid Workshop / Navigant Consulting:[20]

[19] From: California Energy Commission Staff and Statewide Plug-In Electric Vehicle (PEV) Collaborative PEV Infrastructure Joint Workshop, October 19, 2010.
[20] Navigant Consulting Inc. Final Report Microgrids Research Assessment for the US Department of Energy's Office of Electricity Delivery and Energy Reliability and the California Energy Commission's Public Interest Energy Research Program, May 2006.

- A microgrid is an integrated power delivery system consisting of interconnected loads and DER that as an integrated system can operate in parallel with the grid or in an intentional island mode.
- Integrated DER is capable of providing sufficient and continuous energy to a significant portion of the internal load demand even in island mode.
- The microgrid possesses independent controls and can island with minimal service disruption.
- <u>Allows operation with a larger power system; this provides two key capabilities</u>:
  - Flexibility in how the power delivery system is configured and operated
  - Optimization of a large network of load, local DER and the broader power system
- <u>These two capabilities can deliver three important value propositions</u>:
  1) *Custom Energy Solutions*: Provide customized power to individual customers/tenants or groups of customers/tenants
  2) *Independence/Security*: Support enhanced energy and infrastructure availability and security
  3) *Reduced energy cost*: Provide end users with less expensive energy over current rates.

There are currently the following examples of smart grid projects at various scales that are demonstrating schemes for demand-side management (DSM) and direct load control (DLC) at different scales.

- Single Facility (< 2 MW) - Smaller individual facilities with multiple loads (e.g. hospitals, schools).
- Multi-Facility (2-5 MW) - Small to larger traditional CHP facilities plus a few neighboring loads.
- Feeder (5-20 MW) - Small to larger traditional CHP facilities plus many or large neighboring loads.
- Substation (> 20 MW) - Traditional CHP plus many neighboring loads.
- Rural Electrification - Rural villages of many emerging markets of India, China, Brazil etc., as well as rural settlements found in Europe and North America.

Microgrid systems can be designed with different architectures in order to provide the most efficient use of energy while meeting customer needs. *An important aspect of microgrid operations, common to nearly every design that is being proposed, is the inclusion of some type of energy storage.* Although the grid will provide the backbone of the electrical needs in a microgrid operation in most instances in California, the source of electrical energy within the microgrid can be renewable or natural gas, and energy storage can be provided by any of several methods, including electrical, thermal and chemical storage. Sizes of microgrid systems can range from small units of up to 1 MW to as high as tens of MWs, each a function of the particular customer demands and the optimization of efficiency.

Currently, there are several microgrid demonstrations that are in various stages of operation. Although some are similar in overall design and function, there are appreciable differences that illustrate the wide-range of use and benefits that can be derived from well-designed operations. As utilities expand their use of distributed energy storage to incorporate more renewable electricity generation in the grid, microgrids may offer significant benefits by which both customer and utility can benefit. Many examples of microgrid systems have been suggested and proposed that will provide valuable “proof of concept” information, but at this point in time, most of those in the U.S. are still in the design and development stages. Perhaps the most advanced microgrid systems in California exist on the campus of UC San Diego and within the operations of the Sacramento Municipal Utilities District (SMUD). Other examples include Borrego Springs and the Twenty Nine Palms military installation. There are many other options, some of which are being examined in other parts of the United States. Some microgrid systems in which an existing operation has been modified to incorporate other technologies such as fuel cells with CHP, PV or use of storage systems such as refrigeration systems that use thermal energy, provide additional opportunities to examine for applications in California.

Consumer advantages must be identified in concert with the microgrid installations. To date, several installations of microgrids have taken place and lessons have been learned, both in terms of operations of the microgrid and how successful they have been in connecting with the bulk grid. However, the virtues and lessons-learned through these installation have had limited exposure to potential future customers. In most cases, the microgrid operations have been expensive because they have been one-of-a-kind, utilizing technologies that are not mature and not necessarily the type that would ultimately be chosen for practical operations. Control and management equipment have not been optimized because each has employed current technology only as a tool to learn about systems issues, thereby identifying improvements and areas of concern. Models of systems that could utilize different technologies, for example storage, have only recently been examined and some studies have been reported. However, microgrids for any practical use have not matured to the point of reliable and dependable operations at this time and more demonstrations of the potential application advantages are still needed.

# CHAPTER 5: Key Technology Roadmaps and Use Cases

The results of this Defining the Pathway to the California Smart Grid 2020 roadmap research project connect to the market by capturing use case scenarios that prescribe the sequences of events needed to get from the 2010 baseline (current state) to the 2020 goals, as developed with the project industry partners in the technology manufacturing sector. The time frame over which products, knowledge or services will get into the market are driven primarily by such factors as the readiness of technologies, enabling infrastructure, codification, economic and legislated incentives, market pressures and competition, customer demand for value-added products and quality services, ratepayer incentives, and job creation.

## 5.1 Use Case: Increasing the Penetration of Rooftop Photovoltaics

The principal actors in this use case are the developers of rooftop PV systems, residential and C&I ratepayers, and utilities. The functionality pertains to meeting distributed generation policy targets, meeting RPS goals for grid-tied renewable resources, and providing options for reducing grid-supplied energy consumption and peak demand.[21]

Based on the current state of rooftop PV systems for meeting *IEPR* RPS targets in part through distributed generation, requirements for grid integration, lessons learned in the European market, and identified barriers to penetration and growth, the following findings and recommendations are offered towards increasing the penetration of rooftop photovoltaics:

- The growth rate of distribution connected PV deployments under the California Solar Initiative (CSI) needs to significantly accelerate in order to achieve the stated 2016 goal of 3,000 MW of new rooftop solar PV.
- Barriers to accelerating growth are primarily non-technical at this time.[22]
- California efforts at this time should focus on bolstering incentives and simplifying/streamlining the process and requirements for participating in incentive programs.
- Concerns about the costs of reserves or storage needed to accommodate high penetration variable generation are often overstated, because single generator output is often extrapolated without taking geographic diversity of multiple generators or balancing areas into account.[23]
- More emphasis should be placed now on simplifying technical approaches and reducing overall "Smart Grid" complexity with respect to variable generator integration, with increasing focus on using forecasting and modeling techniques rather than relying on real-time monitoring.

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[21] Use case prepared by SunPower Corp. and ACORE.

[22] Clear, prominent examples of incentive-driven, distribution-connected PV growth that have already reached similar or greater penetration levels can be found in Spain and Germany.

[23] A study published by Lawrence Berkeley National Laboratory in September 2010 shows that taking geographic diversity into account can reduce reserve cost estimates by a factor of 20 for the PV systems and conditions studied: A. Mills and R. Wiser, Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power, Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory, September 2010.

- Existing discussions and standards efforts concerning smart grid and electrical interconnection requirements for high-penetration integration of variable generators at the distribution level are critical for continued long-term growth, but should not be considered as technical barriers to achieving this goal.

### 5.1.1 Summary of Current State

#### *5.1.1.1 Ratepayer-Owned Distributed PV*

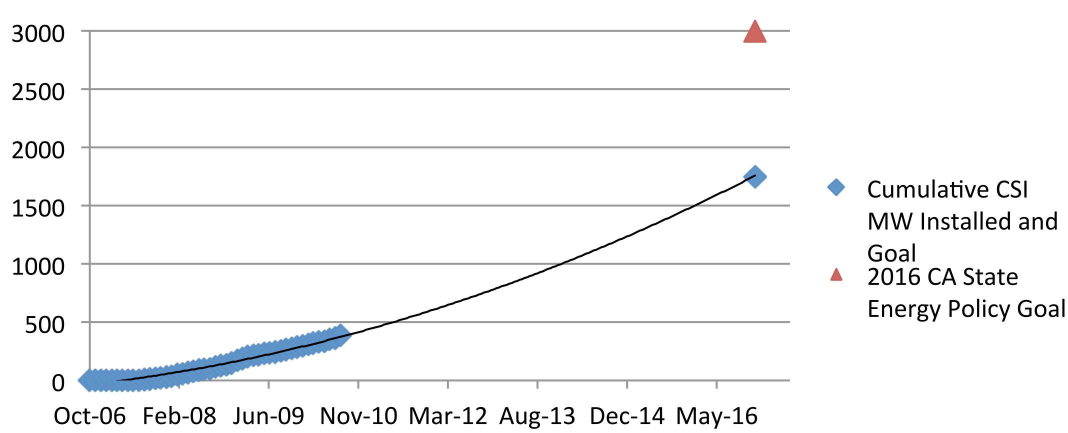
The California Solar Initiative (CSI) is the solar rebate program for California consumers that are customers of the investor-owned utilities - Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E). Established in 2007, the CSI allocates $2.167 billion to incentivize 1,750 MW of new solar PV generation capacity between 2007 and 2016, as well as $250 million between 2010 and 2017 to install 200,000 new solar hot water systems. As of September 2, 2010, 22 percent (385 MW) of the target 1750 MW goal has been installed, 25 percent (435 MW) is in the application process, and 53 percent (931 MW) is remaining.

Figure 7 depicts the cumulative installed MW for the CSI program from September 2006 through August 2010. Note the sizable gap of 1250 MW between the 1750 MW CSI target and the 3000 MW California energy policy goal. This gap will need to be filled in some way very quickly, in a manner that allows sufficient time for the market to react by 2016.

#### *5.1.1.2 Utility-Owned and Operated Distributed PV*

In addition to the largely consumer or commercial customer-owned PV systems installed under the CSI program, *the PV industry is seeing solid evidence of "utility owned and operated" collections of distributed PV systems*, as exemplified by Southern California Edison's July 2010 announcement of a 500 MW rooftop solar initiative, with at least 250 MW owned and managed by SCE directly. PG&E and SDG&E have similar programs for 500 MW and 100 MW, respectively.

**Figure 7: PV MW installed vs. time: CSI – August 2010.**




This chart and accompanying trend line suggests that the PV installed base growth needs to accelerate in order to meet the CSI 1750 MW goal by 2016. Growth needs to accelerate even faster still to meet the California state energy policy goal of 3000 MW of new rooftop solar PV by 2016.[24]

[24] http://www.californiasolarstatistics.ca.gov/reports/9-02-2010/ApplicationStatsByMonth.html

*Growth rates as well as monitoring and control solutions for PV systems in this category seem likely to be driven more by utility-specific needs rather than consumer-oriented incentive program needs.* This represents some risk that any forecasting, modeling, and monitoring/control solutions that evolve for these systems may be driven down a slightly divergent path from solutions for consumer-oriented incentive programs. Ideally, solutions for both categories of PV systems can be aligned for operational efficiency and cost effective future integration.

#### *5.1.1.3 High Penetration PV Grid Integration – Implications and Requirements*

PV system suppliers and utilities actively are discussing the implications of increasing penetrations of variable generators such as PV on distribution circuits. The general implication is that distribution system operators are looking for varying levels of autonomous PV system behavior, situational awareness, forecasting ability, and likely some level of remote control that can be exercised in exceptional situations. However, the minimum acceptable and most cost-effective requirements for high penetration PV integration are still being identified, and working requirements tend to vary widely across system operators.

At the distribution circuit level, there are concerns that PV variability could impact local voltage either by inducing flicker or by excessive cycling of utility equipment such as load tap changers. This concern is based primarily on limited modeling and has not been observed in actual high penetration circuits. In addition, modeling and recent experience also indicates that the technical ability of PV inverters to provide reactive power and even voltage regulation would mitigate or eliminate this concern. Such functionality does not necessarily require a communications infrastructure, though having some communications in place would add the ability to remotely update inverter settings.

Other concerns about distribution system impacts are applicable to distributed generation (DG) in general, such as managing the voltage profile across a feeder, dealing with reverse power flow, and ensuring the right balance between anti-islanding (needed to prevent the flow of power onto a faulted circuit for protection of personnel and equipment) and fault ride-through (to avoid harmful loss of DG due to system-level issues). In many cases these issues can be dealt with by more widespread utilization of available equipment, such as transformers with load tap changers, or even reprogramming existing equipment, such as configuring protective relays to behave appropriately in reverse power flow conditions. In other cases, there is a need for further development of codes and standards which account for high-penetration DG (such as fault ride through), but the technical ability to accommodate such requirements already has been demonstrated in PV inverters intended for large-scale installations that are directly tied to the medium or high-voltage utility infrastructure.

The necessity and economics of integrating energy storage solutions with variable generators also are under debate. While it is likely that there are specific situations in which PV and storage integration makes economic sense, single-point irradiance measurements are at times simplistically used to draw conclusions about widespread PV system variability and therefore grid integration issues and costs. However, single-point irradiance measurements, and the conclusions that follow, do not account properly for smoothing seen when geographic diversity and balancing areas are considered. Numerous studies have been carried out which conclusively demonstrate this smoothing effect. Most recently, a study on the effect of considering geographic diversity on distributed PV variability by Lawrence Berkeley National Laboratory published in September 2010 finds that modeling increasing levels of PV penetration by scaling the variability of a single PV plant leads to a significant increase in estimated cost of system integration and balancing. Correspondingly, the more thorough analysis that includes smoothing due to geographic diversity shows a significant reduction in PV integration costs – 20 times for the parameters used in the study.[25]

#### 5.1.1.4 High Penetration and High Growth-Rate PV Deployments in Europe

Concurrent with the requirements discussions underway in the U.S., it is important to be aware of relevant examples of high penetration and high growth rate distributed PV deployments in Europe. For example, the entire 2016 California energy policy goal of 3,000 MW of rooftop PV was installed in Germany in 2010 between January and August alone (counting systems ≤ 100kW), on an electrical system that is roughly twice California's in capacity. This shows the very large impact market incentives can have on PV deployment rates.

Red Electrica de España provides another perspective regarding distributed PV generation rates. In 2009, approximately 2 percent (5,347 GWh) of annual energy demand of ~252 GWh was generated by PV, 98 percent of which is connected at the distribution level. From a capacity perspective, this is nearly 3400 MW of installed PV capacity. In comparison, California will generate 1.4 percent of its 2016 electrical energy needs from distribution connected PV, if the year 2016 goal of 3,000 MW rooftop PV generating ~5 GWh per year is achieved. [26]

Red Electrica recently participated in a CAISO forum on integrating renewable generation. To date, they have had no issues with integrating this level of PV on their system, despite the fact that the system operator receives very little real-time or historical production data, and they do not currently use a forecast. Red Electrica is currently working to more fully integrate forecasting and data into their renewables operation desk in anticipation of a significant expansion of PV, concentrated solar power (CSP), and wind energy on their system.[27]

#### 5.1.1.5 Interconnection Standards

Existing interconnection standards such as the IEEE 1547 anti-islanding safety requirement become increasingly at odds with distribution system stability as PV penetration increases. For example, without the ability to support Low-Voltage Ride-Through (LVRT is currently not permitted under IEEE 1547) an increasing proportion of generation on a circuit can trip offline during system disturbances, causing additional stability challenges. Similar issues exist around allowing PV inverters to adjust voltage set points; another tool system operators could use to benefit system stability. Work is underway to address these and similar issues within the IEEE 1547.8 working group.

#### 5.1.1.6 Forecasting Accuracy

As seen in Spain and Germany, increasingly accurate wind resource forecasting has had a direct positive impact on spinning reserve costs needed for large-scale distributed wind generation. Work is underway on many fronts to bring solar irradiance forecasting to the accuracy levels that wind forecasting has achieved. Publications from Spanish and German system operators highlight the need for increased insight into distribution-connected variable generation, and there is certainly the same sense from U.S. system operators – forecasting can help provide this insight. In Germany, the four transmission system operators currently utilize regional level, hours- and day-ahead PV production forecasting, which includes all DG installed in the region, with a mean forecast error of 4-5 percent. Conversely, implementing near-real-time monitoring

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[25] A summary of the LBNL variability study can be found at http://eetd.lbl.gov/ea/ems/reports/lbnl-3884e-ppt.pdf.
[26] http://www.energy.ca.gov/reports/2000-07-14_200-00-002.PDF shows projected electrical energy demand in California of 309,868 MWh in 2010, with approximately 2 percent annual growth rate state-wide: 5000 MWh/(309,868 MWh*(1.02^6)) = ~ 1.4 percent)
[27] See http://www.caiso.com/2835/283593c620f30.pdf

systems can be very expensive to deploy and maintain. Forecasting with adequate modeling and knowledge of a generator's location in the distribution network has the potential to ease this burden greatly.

#### *5.1.1.7 Summary of Immediate Barriers*

The following items are the most important barriers to eliminate or reduce in order to achieve the 2016 goal of 3,000 MW of rooftop PV, along with an estimate of the time it would take to reduce the impact of the barriers.

- ***Incentive programs such as CSI need to be both extended and modified to accelerate PV system approval and deployment***. In the case of CSI, program installation targets as well as the attractiveness of the incentives themselves need modification in order to accelerate and sustain growth rates. Simplifying the reporting and interconnection process and requirements also could accelerate the program. As one small but specific example, the CSI program periodically decreases the minimum system size that requires monthly Performance-Based-Incentive (PBI) reporting, as opposed a one-time Expanded Performance Based Buydown (EPBB) rebate based on system-rated capacity. PBI can be an expensive and time-consuming process at many levels. Periodically lowering the minimum size threshold for PBI reporting almost certainly increases system cost and incentive administration costs. Note that in 2008 only 1.5 percent of systems eligible for EPBB chose to enroll in the PBI program. Examination of other incentive models such as feed-in tariffs (FiT) may be necessary. (1 year – extension and modification need to be done immediately to allow time for market growth)

- ***Raise the interconnection threshold for distributed PV***. Currently, distributed PV interconnections are governed by a series of screens, incorporated into California's Rule 21. This allows "fast track" interconnections that do not require an expensive and time consuming study process. Currently, there is a penetration threshold of 15 percent of a feeder line section, above which an interconnection study is mandated. Technical justification exists for raising this threshold for PV, which would enable higher local penetration on particular feeders and thereby help to reach the 2016 goal. (1-2 years)

- ***Develop standardized models and metrics for modeling the impact of multiple variable, distributed generators within a specific distribution circuit, including an accurate representation of geographical diversity on short time frames***. Without a uniform method of assessing the performance of variable generation (either of larger individual systems or grouped into logical units) within a given operating context, cost effective, high penetration of distributed variable generation will be more difficult to achieve. At present, each "high penetration" situation needs to be treated as a unique case, where the analysis approach, tools used, and solutions chosen will change from situation to situation. Agreement on analysis approach, metrics, key models and parameters will help stimulate more cost-effective solutions, and faster analysis and decision-making. (1-3 years)

### 5.1.2 Establish Needed Sequence of Events to Meet 2020 Goals

1. Re-examine CSI program parameters and evaluate feasibility of:
    a. Raising program cap to 3,000 MW
    b. Raising the system size floor for systems that are eligible for EPBB rebates to simplify monitoring and reporting process and requirements.[28]

[28] It may make sense to express this threshold as a percentage of distribution feeder capacity and a percentage of other variable generation on the same circuit, so that this size is meaningful from a system

   c. Simplify the reporting and administration requirements for systems that do continue to require PBI based incentives.
   d. Increasing the incentive rates or parameters to stimulate faster growth
2. Update FERC screens and/or Rule 21 to a higher level of penetration. The Interstate Renewable Energy Council (IREC) currently is working on this issue.[29]
3. Establish combined utility and industry program to define and develop standardized metrics and models for variable generator fleets that can be used to solidify consensus and unify grid integration requirements statewide. Will need pilot program to compare real data against modeled data, although pilots are likely feasible using existing high PV penetration circuits.

### 5.1.3 Longer-Term Mitigation Actions to Risks Impacting Growth Beyond Stated Goal

- ***Private industry needs easier-to-obtain-and-administer state and federal funding for high penetration variable generation R&D***. Intellectual property (IP) rights must be possible to retain for industry growth. Currently, IP retention is completely shut out of California State funding which makes applying for and accepting California State funding controversial and much less compelling than it could be.

- ***Forecasting systems need to be developed, refined, and integrated with transmission and distribution operational systems and procedures***. For instance, day-ahead and hour-ahead forecasting for both large individual PV systems as well as fleets of distributed PV systems that are treated as logical units likely would be extremely helpful for system integration and operation. This type of forecasting approach is in use successfully today for hundreds of MW of large-scale wind generation.[30]

- ***Develop monitoring and control tools for both large individual PV systems as well as fleets of distributed PV systems treated as logical units, in a manner that can be integrated into existing distribution automation and grid operation/forecasting tools***. The averaging effects of geographic diversity of PV systems in a logical grouping, as well as any balancing area considerations the system operator is responsible for should both be taken into account. Doing so will reduce the cost and complexity of managing variability.

- ***Continued cost reduction of PV systems and components, and continued evolution of financing, maintenance, and customer service options and models***. This will facilitate an accelerated pace of PV deployments, to meet California's 2016 energy policy goal of 3,000 MW of distributed PV.

- ***Net metering caps may need to be raised, as PV penetration grows in the medium to long term.*** Currently at least two utilities in California are in the 1.75 percent range out of currently allowable 5 percent cap.

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operator point of view as well. In other words, make the monitoring requirements for future distribution integration purposes match up with CSI program monitoring requirements, at least at a coarse level.

[29] http://www.irecusa.org

[30] While regional-level forecasting of over 15,000 MW of installed PV has been successfully achieved in Germany, work remains to adapt and validate these techniques for US weather and installation conditions. Additionally, forecasting on shorter time frames and at higher spatial resolution would be of particular value for distribution system operators.

### 5.1.4 End State (2020)

- ***Solar irradiance forecasting with sufficient spatial and temporal resolution***, and usable both statewide and in surrounding geographies. Surrounding geographies are important in order to enable additional energy exchange/balancing area options.

- ***Modeling tools that can take irradiance forecasting and PV system size and location attributes, and distribution system topology as inputs***, with results used to minimize the complexity of real-time monitoring, control and data processing requirements for integration into distribution automation systems. Variability smoothing due to geographic diversity, as well as distribution system context, must be accounted for in these tools.

- ***Fleet management tools*** (minimized in complexity by forecasting and modeling tools) that enable sufficient generator control and demand management such that high penetration levels of variable generators are straightforward to operate and fit within larger distribution automation operational procedures.

- ***Electrical interconnection standards that allow variable generators to complement grid stability at high penetrations***. Low/high voltage ride through, Droop behavior, voltage set points and more need to be agreed upon at a standards level so that equipment and control system manufacturers can build products relevant to the widest possible market.

- ***Lowest possible cost for installing new PV systems and/or incentive systems.***

## 5.2 Use Case: Demand Aggregation

The use case and key technology roadmap presented here pertains to the establishment of a Demand Management Zone (DMZ) as an approach to Demand Aggregation (Table 3). It encompasses the incorporation of technologies such as PV systems, storage and building efficiency technologies through net zero energy buildings and demand response.[31]

A commercial real estate management company (unregulated entity) operates an office park and launches a DMZ involving their tenants. Taking advantage of the demand response incentives offered by a local electricity provider, the company installs a Direct Current (DC) buffer on the feeder lines to the office park, and installs a variety of renewable energy (PV and solar) and energy storage technologies in the park. They also create a centralized building operations control center (BOCC) in one of the properties in order to manage the demand zone program. In general, the building operator will use as much of the renewable power as possible, and establish bulk power purchase agreements to feed the park, thus lowering the cost. Load management and power quality from the renewables will be balanced via the storage network, so that the Demand Response (DR) incentives from the utility provider can be maximized.

### 5.2.1 Current State of the Technology

It is difficult to determine the extent to which any DMZ is deployed today because there is not a lot of press that is available on this. However, individual net zero energy buildings in the commercial space are out there, such as the 31 Tannery Road project in Branchburg, NJ.[32] The Ferreira Companies completed the construction of the new 42,000 sq. ft. headquarters building

[31] Use case prepared by P. Molitor, NEMA.
[32] www.ferreiragroup.com/31_tannery_road.html

in 2006. The building includes a 223 kW solar photovoltaic system, solar domestic hot water, nine miles of radiant heat, high performance rooftop HVAC units, a 96 percent efficient condensing boiler, an integrated web-based direct digital controls (DDC) system with the capability to monitor in real time the performance of the PV array and the total energy use of the facility. In 2007, the building was officially recognized as the First Net-Zero Electric Commercial Building in the United States.

A DC barrier would encircle and identify the service area. The DMZ operator would install as much PV service and electricity storage as possible, and get involved in the wholesale power market as a net purchaser, like a mini-RTO (Regional Transmission Organization). During the overnight hours, the DMZ provider would be one of very few purchasers of bulk power – at a time when kilowatt-hour prices would be extremely low. This would be used to charge the storage assets, and provide building cooling services to a decentralized network of devices like the Ice Energy Boxes[33] that would be located in the buildings inside of the service area. During the course of the day, when demand peaked (as well as the cost per kW in the bulk market) the DMZ provider would supply their buildings with the cheaper power that was purchased overnight and stored.

**Table 3: Actors and descriptive functional roles in establishing a DMZ Demand Aggregation approach**

| Actors[34] | Description |
|---|---|
| Demand Aggregator | The commercial, unregulated entity that builds, owns, and operates the demand management zone. The demand aggregator owns all B2B relationships with the utility power providers and the office park tenants. |
| Utility Providers | This is the company or companies which provide feeder lines and bulk power services to the Demand Aggregator |
| Building Operations Control Center (BOCC) | A function provided by the Demand Aggregator, actors in the BOCC include: |
| Monitoring (machine) | Network Operation Monitoring actors supervise network topology, connectivity and loading conditions, including breaker and switch states, and control equipment status. They locate customer telephone complaints and field crews. |
| Control (machine) | Actors in this domain coordinate network control, although they may only supervise wide area, substation, and local automatic or manual control. |
| Fault Management (human-machine) | Fault Management actors enhance the speed at which faults can be located, identified, and sectionalized and service can be restored. They provide information for customers, coordinate with workforce dispatch and compile information for statistics. |
| Analysis (human-machine) | Operation Feedback Analysis actors compare records taken from real-time operation related with information on network incidents, connectivity and loading to optimize periodic maintenance. |
| Reporting and Stats (human-machine) | Operational Statistics and Reporting actors archive on-line data and to perform feedback analysis about system efficiency and reliability. |
| Calculations (human-machine) | Real-time Network Calculations actors provide system operators with the ability to assess the reliability and security of the power system. |
| Operational Planning (human) | Operational Planning and Optimization actors perform simulation of network operations, schedule switching actions, dispatch repair crews, inform affected customers, and schedule the importing of power. They keep the cost of imported power low through peak generation, switching, load shedding or demand response. |

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[33] www.ice-energy.com

[34] Adapted from the Smart Grid Interim Report, Deliverable (7) to the National Institute of Standards and Technology (NIST) under the terms of Contract No. SB1341-09-CN-0031.

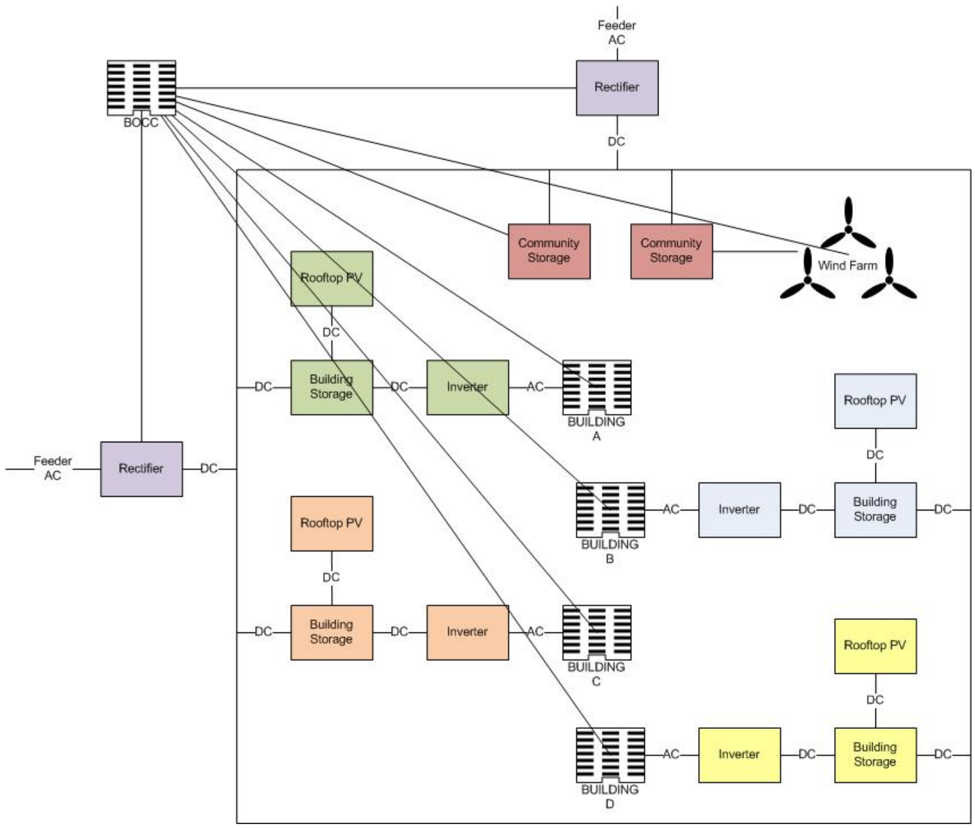
| | |
|---|---|
| Maintenance and Construction (human) | Maintenance and Construction actors coordinate inspection, cleaning and adjustment of equipment, organize construction and design, dispatch and schedule maintenance and construction work, capture records gathered by field personnel and permit them to view necessary information to perform their tasks. |
| Customer Support (human) | Customer Support actors help customers to purchase, provision, install and troubleshoot power system services, and relay and record customer trouble reports. |
| Extension Planning (human) | Network Extension planning actors develop long term plans for power system reliability, monitor the cost, performance and schedule of construction, and define projects to extend the network such as new lines, feeders or switchgear. |
| Meter Reading and Control (human-machine) | Meter Reading and Control actors perform a variety of functions on the metering system including data collection, disconnect/reconnect, outage management, prepayment point of sale, power quality and reliability monitoring, meter maintenance and asset management, meter data management including validation, estimation and editing (VEE), customer billing, and load management, including load analysis and control, demand response, and risk management. |
| Supply Chain and Logistics (human) | Supply Chain and Logistics actors manage the processes for acquiring necessary supplies; tracking acquired and ordered supplies; and allocating them. |
| Communications Network (human-machine) | The planning, operations and maintenance of all communications network asset that are required to support Operations. |
| Security Management (human) | The management of security policies, distribution and maintenance of security credentials, and centralized authentication and authorization as appropriate. |
| Safety Management (human) | The management of safety policies and quality control procedures for safety management. Includes safety training and the distribution of changes and updates to the policies. |
| Business Planning and Reporting (human) | These actors perform strategic business modeling, manpower planning, reporting, account management, and both assess and report on risk, performance and business impact. |

In terms of the technology readiness levels, the components identified in the physical architecture are as follows and are mature or nearly so:

- AC to DC Rectifier
- DC Distribution Management
- Rooftop PV
- Wind Turbines
- Building Storage
- DC to AC Inverter
- Building Operations Control Systems
- Communications Network

With the rapid advent of microgrids, the real question is not whether this physically can be done, but how utility operators would handle the idea of their meter-level control ending at the rectifier. There would be large questions about how the DMZ operator's management systems would provide operational information to the utility company. In theory the process should be no different than passing across the area of control boundaries between utilities, but there is one significant difference. Generally, either a federal (Federal Energy Regulatory Commission, FERC) or state (Public Utilities Commission, PUC) regulatory body governs the utility-to-utility space. The DMZ is not a regulated body and because they could potentially swing large volumes of electricity on and off the utility grid, which creates a very tenuous business relationship between the two. A proposed architecture for what the DMZ project would look as shown in Figure 8.

**Figure 8: A proposed architecture for a Demand Management Zone (DMZ) project, for illustration.**




*5.2.1.1 Sequence of Events (over 2-year period)*

1. An agreement would need to be struck between the DMZ operator and the utility provider. This would be similar to the way that Gridpoint and Xcel energy collaborated on the Smart Grid City project in Boulder, Colorado.
2. The utility would need to file the appropriate notices with the state regulatory body.
3. The DMZ operator would install and test the devices that form the DC buffer around the DMZ.
4. The utility operator would prepare to groom the feeder lines into the office park to support the DMZ.
5. DMZ operator would install and test the rooftop PV, wind turbines and storage devices to complete the renewable integration.
6. DMZ operator would install and test the inverters serving as the new feeders into the individual buildings.
7. DMZ operator would install the communications and control network over which it would manage its operations within the DMZ.
8. DMZ operator would establish its BOCC with the management information links to the utility operator. (In parallel with steps 3 through 7 above.)
9. Launch the DMZ.

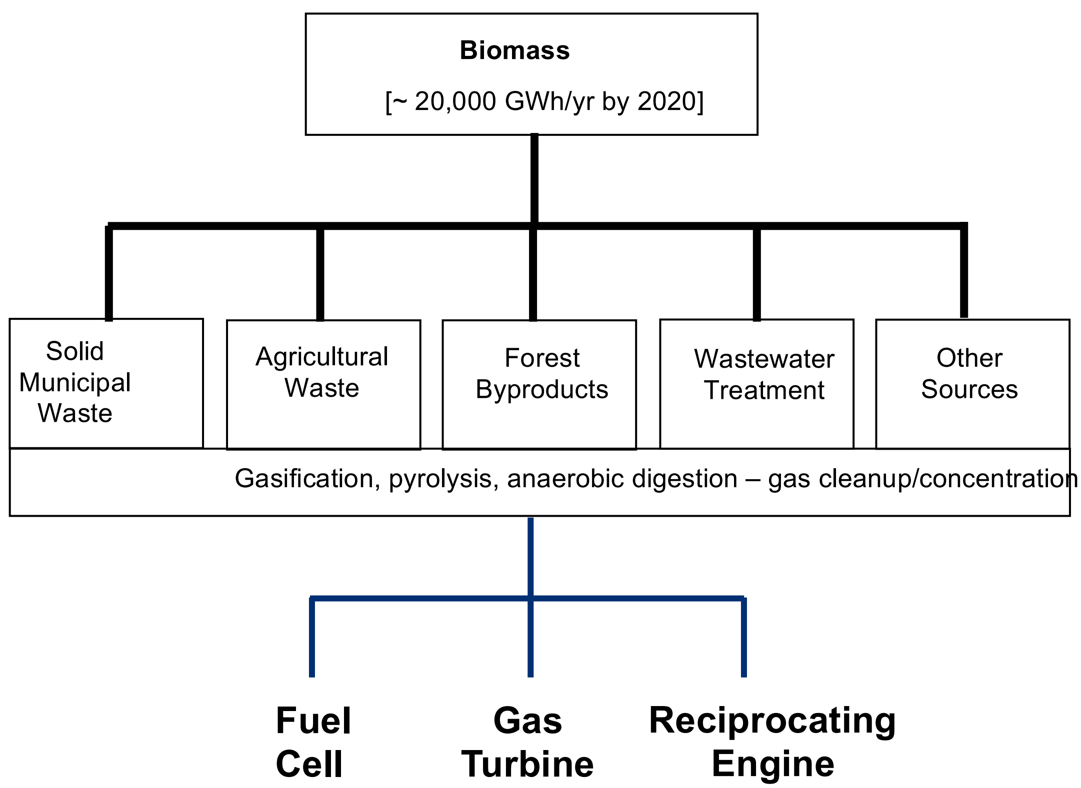
The end state is a self-sustaining DMZ that takes advantage of as much of its own generating capacity as possible, while shifting a certain amount of the weekday generation requirements to off-peak hours. Coupling this with the collocation of PV and wind assets, this strategy supports multiple *IEPR* objectives:

- 33 percent generation by renewables in 2020
- 3,000 MW of new rooftop solar by 2016
- Demand Response that reduces 5 percent of peak demand in 2020
- Electricity peak demand reduction goal of 4,885 MW in 2013
- Reduce GHG emissions to 1990 levels across all sources in 2020

## 5.3 Use Case: Natural Gas, Biomass, CHP and Fuel Cells

Biomass is an important element of the future implementation of a smart grid in California for several reasons. First, it is considered a renewable source of electricity and therefore will contribute in part to meeting the RPS goal of 33 percent of generation by renewables (~104,000 GWh/yr) by 2020. It also addresses the goal of 20 percent of renewable power supplied by biopower sources by 2020 (~20,000 GWh/yr). Second, biomass consists of many sources, including agricultural, forestry, landfill, wastewater, and food processing waste. The entire state will be able to participate to some extent because of the broad range of material sources. Third, biomass conversion to electricity, predominately via "biogas," a low heating value gas, can take place via any of several modes of technology, including reciprocating engines, turbines and fuel cells. Figure 9 shows the relationships between biomass sources and conversion processes.

**Figure 9: Relationship between the biomass sources and the conversion processes pertaining to biomass contribution to smart grid operations.**



With several options available, the most efficient and economical means by which the biomass can be converted to electricity will be a function of the particular location and the supplier. Biomass conversion most likely will take place onsite, suggesting that the most efficient means of processing and the system design could be a CHP operation. This addresses an approach to meeting the goal of 5,400 MW of CHP in 2020. In the event that CHP is used as the process for conversion to electricity, the goal of reducing GHG emissions to 1990 levels across all sources in 2020 will also benefit. Basically, the treatment of biomass offers several opportunities to help meet California Smart Grid 2020 goals; the unlikely collocation of biomass resources with conversion and power generation facilities and distribution system interconnection must be taken into consideration.

### 5.3.1 Current State (2010)

The important factors that determine how successfully the use of biomass can be expanded to meet the goals set for contributing to the California Smart Grid 2020 are: an increase of source material (i.e., biomass of whatever type, Figure 9, the proximal availability of the biomass for conversion to electricity, the applicability and efficiency of CHP systems to/in biomass conversion, and the policies affecting the acceptance and use of the electricity generated from biomass. Use of CHP for biomass conversion has been practiced for many years, some instances successfully and still in practice (i.e. conversion of agricultural and forest residue), while others have ceased operations (i.e. dairy farms).

The report entitled "An Assessment of Biomass Resources in California," [2008][35] projects that there will be a continued increase in biomass resource for electricity production through 2020. The total biomass is projected to grow from 83 million to 98 million bone-dry tons/yr from 2007 to 2020. However, only approximately one third is available for conversion which, combined with landfill waste already in place, generated roughly 3,800 MWe and 29 TWh of electricity in 2007. The generation potential by year 2020 is projected to approach 6,800 MWe and 51 TWh, as much as 8.7 percent of the state's electrical capacity and 13.9 percent of the electrical energy. Although the largest resources expected to be available to meet these projections were municipal solid waste, in-forest biomass, animal manures, landfill gas, orchard and vineyard residues, and field crop residues, it was acknowledged that there are several problem areas that must be addressed to achieve such projections. Among these are appropriate policies, incentives, R&D, and technical and economical reviews.

#### *5.3.1.1 Biogas Production*

Three areas that offer significant potential for biogas are agricultural waste, food and beverage processing, and municipal wastewater treatment operations. It has been projected, based on the U.S. Environmental Protection Agency (EPA) database, that municipal facilities in the state large enough to support 1 MW of electricity production are capable of producing enough biogas to generate 187 MW of power. As an example, the Hyperion plant in Los Angeles, the largest in the state, has approximately 7 million cubic feet of digester gas generated daily.

While it is not known at this time how much gain could be realized from improvements on existing operations of biomass treatment and processing that could expand the projected availability of fuel for electricity production, it seems that this area offers much incentive to utilize for the 2020 smart grid advantage. A current problem associated with applying new technology, as part of the California Self Generation Incentive Power (SGIP) is the maximum of 3 MW of power generation capacity that is eligible for capital rebate incentives. If this were

[35] Williams, Robert B. 2008. *An Assessment of Biomass Resources in California, 2007.* California Energy Commission. CEC 500-01-016.

expanded in capacity, or if other incentives could be applied, such as renewable feed in tariff, more power generation per site could be installed and increase the capacity toward the goals.

Another way in which the biogas production at existing facilities could be increased for electricity is by bringing in more feedstock. A recent study by Kulkarni [2009][36] suggests that if other supplies of biomass feedstock, such as food oils and grease, food processing waste, and dairy manure, were brought to a central wastewater treatment site, for example, the total amount of CHP electricity production could be greatly increased. The Energy Commission-funded research has indicated that this type of feedstock augmentation could increase the biogas production capacity by more than 450 percent. However, the costs associated with hauling waste materials (tipping fees) beyond an estimated 50 – 70 mile radius will reduce the advantage of the central CHP operation.

Onsite agricultural manure waste has been a potential source of electricity production, but has met some problems with policy issues dealing, in part, with amount of electricity produced and how much is used. The California Biomass Collaborative (CBC) evaluated the power generation potential from agricultural manure waste biogas (onsite digester) to be 855 MW in 2010 which could grow to more than 1000 MW by 2020, based on heat engine generators. Onsite generation offers advantages over hauling waste to a central plant, as suggested above, in that no transportation costs would be incurred.

### 5.3.2 Needed Sequence of Events to Meet 2020 Goals

From a technology standpoint, there are several options that can be considered for CHP operations, ranging from typical reciprocating engines (rich or lean burn), gas turbines (various configurations) and fuel cells (phosphoric acid, molten carbonate and solid oxide). Advantages and disadvantages exist for each, including such topics as electricity generation efficiency, produced heat quantity and temperature available, GHG emissions ($NO_x$, $SO_x$, $CO_2$), maintenance, cycling ability, feed gas cleanliness requirements. For example, molten carbonate fuel cells offer very low emissions, excellent electricity production efficiency operation, projected to produce 1300 (2010) and 1600 MW (2020) compared to the 855 and 1000 MW in the CBC study cited above. Heat engines, on the other hand, can be cycled, are cheaper, but are not as efficient in generating electricity and produce slightly higher levels of GHG emissions. Each site operation must examine the options and advantages that each of the CHP electricity generation choices offers the planned application.

Molten carbonate fuel cells also have been demonstrated in food processing and brewery operations. By use of onsite digesters, and CHP operations to utilize the waste heat in digester operation, solid waste has been reduced by as much as an order of magnitude. The CBC has estimated that renewable fuel production potential from food processing operations is equivalent to 340 MW in 2010 and could reach 450 MW with highly efficient operations.

In addition to some of the potential barriers that prevent California from reaching full potential for utilizing biomass to produce electricity, there are other issues to be dealt with. Biogas from digesters and landfill has contaminants that can create problems, either in converting to electricity, such as in the case of fuel cells, or otherwise present in the exhaust of reciprocating engines. Cleanup processes to remove these contaminants need to be improved from a technical and economical standpoint. Another problem is that in some cases, such as small wastewater treatment plants, the quantity of waste material is small, or inconsistent, resulting in an undependable source of electricity or is expensive to maintain, particularly if the use is small and the unit sits idle for long periods of time. There is also the understandable concern that the

[36] Kulkarni, Pramod. 2009. *Combined Heat and Power Potential at the California Wastewater Treatment Plants*. California Energy Commission. CEC-200-2009-014-SF.

utilities are not interested in unreliable sources of electricity. However, according to a recent report [Kulkarni, 2009] of the 268 wastewater treatment plants in California that process a million gallons or more per day, only 117 have digesters and plants smaller than 3-4 million gallons per day cannot operate a CHP unit cost-effectively. 30 kW to 3 MW is the range of generating capacity and as of 2005 only 23 units were operating in the state, producing only 35 MW of power. In some cases, such as some landfill locations that are small or remote, simply flaring the gas is cheaper than attempting to convert the gas to electricity because of added requirements placed on emissions controls. One of the distinct advantages associated with the use of CHP is that the methane produced at the location is actually put to valuable use besides reducing the quantity of exhausted $CO_2$ for the energy generated.

As part of the current emphasis in the U.S. to seek new methods for producing transportation fuels from various bioprocesses, the U.S. Department of Agriculture and Department of Energy have entered into a joint effort to support R&D in "advanced biofuels, bioenergy and high-value biobased products." There are three technical areas highlighted:[37]

- Feedstock Development – improving biomass feedstocks and their supply (harvest, transport, preprocessing, storage) for biofuels and biobased products
- Biofuels and Biobased Products Development – use of cellulosic biomass in the production of biofuels and biobased products (including animal feeds)
- Biofuels Development Analysis – improve sustainability, environmental quality, etc. for rural economic development of biomass technologies.

Because of the large agricultural base in California, particularly throughout the San Joaquin Valley, there maybe several opportunities by which the current, as well as advanced processing, of agricultural products and by-products, can be combined with smart grid development, both in the need for electricity in the processing, but also in supply of electricity for the processes.

#### *5.3.2.1 Advantages and Issues Regarding CHP for Biomass Treatment*

The advantages of increasing the use of CHP for biomass treatment are:

- Less solid waste to have to move and dispose
- Production of energy, both heat and electricity, from a waste gas stream
- Highly efficient operation of the treatment unit
- Several options from which to choose for the given operation
- Biomass disposal is real and will grow with population growth
- Reduced GHG emissions relative to electricity demand

Barriers/issues that have been identified which need to be resolved in order to take greatest advantage of CHP in biomass treatment are:

- State incentives are lacking for expanding use of CHP in smaller units, larger size applications, and alternative operations
- Improvements in biogas cleanup processes
- Limited demonstration plants at different sites throughout the state
- Limited options for providing digesters to utilize a broad range of feedstock
- Policy/regulatory issues with integrating remote operations with utility/grid operations

[37] See www.energy.gov April 15, 2011. U.S. Departments of Agriculture and Energy Announce Funding for Biomass Research and Development Initiative

- Limit to opportunities for expanding potential onsite biomass treatment operations
- Air emissions and water discharge permitting difficulties
- The tradeoff between landfill gas cleanup to sell methane as pipeline gas versus generation of electricity

California state efforts to expand biomass CHP operations will need to gain the impetus that helped to establish a large base of CHP in the 1970s. New technology and more efficient operations have been developed that offer advantages to these CHP operations and warrant evaluation.

Although biomass, in its variety of sources, offers significant advantages for meeting the 2020 Smart Grid goals for California, it is merely an extension of a broader CHP application in the use of natural gas. There are multiple choices of CHP generation technologies as a function of size of application and the efficiencies anticipated as a function of the systems options that can be exercised to help balance the thermal and electrical load differential. Use of electrical heating to assist in the thermal demand through transient periods is possible as are variables in the equipment and operation of the thermal side of the generator. Waste heat can be recovered in any of several ways. Hot water heating, steam generation, absorption cooling, and condensing heat recovery are the most common of a wide range of possibilities. The amount and level of heat at different temperatures is largely a function of the choice of generator, providing another means by which to choose the method for a given DG system operation. It is worth reiterating that one valuable option to installing CHP for DG operations is that modules of smaller units, rather than single or fewer larger size units, can be installed. This allows the installations to be more flexible in operation and expandable with growth, as well as being able to integrate with other resources, such as solar and wind, to develop hybrid operations that are currently not available for comparison.

#### *5.3.2.2 Role of Onsite Energy Storage*

In order to optimize the benefits of the use of natural gas as an energy source throughout a broader range of installations than exists with biogas, it is possible to incorporate energy storage to assist in leveling the demand with respect to the availability and the duty cycle periodicity. For example, incorporating more use of chillers or thermal storage to assist in air conditioning loads can provide a balance of thermal and electrical loads. Mature, current gas turbine technology can be compared with emerging molten carbonate fuel cell (MCFC) technology. Commercial and industrial installations, such as hotels, hospitals, shopping centers and warehouses, and data centers, present strong potential cases for incorporating onsite generation and storage to balance the current electrical demands on the bulk grid, and for building a more efficient smart grid by use of more CHP.

#### *5.3.2.3 Role of Natural Gas*

The key to understanding the impact of the California Smart Grid to natural gas ratepayers lies in the perceived value-added or the incremental benefit to incremental cost in the presence of the smart electric power grid infrastructure. This infrastructure will yield the predominance of benefits to operations and maintenance (O&M), compliance, security and liability factors, among others. In time, this will accrue savings to consumers, although in the short-range the utilities will be the first to benefit from reductions in O&M costs, and the additional benefits of better consumption management (i.e. demand-side response). There will be upward and downward pressures on pricing to ratepayers – the ultimate net effect will be determined by such drivers as market forces, competition, leveraging of smart grid infrastructure and services, and legislation to reduce GHG emissions.

There are several similarities, and integral dependencies, between natural gas and electric utility operations. Both utilities have an extensive infrastructure that has evolved to meet customer demands over the past several decades. Both have the option of using their respective extensive infrastructures as a means to accommodate changes in demand and act as limited storage capacity. However, natural gas delivery must be connected to relatively localized sources, such as ports for liquefied natural gas (LNG) and pressurized pipelines from natural gas fields found either in various locations in the U.S. or imported from Canada. On the other hand, electricity can be generated from various sources, in state or out of state, and transported over high voltage power lines to the points of use. California is dependent upon various sources of both natural gas and electricity from out-of-state and, therefore, has limited control of cost or availability of either. Due in part to the recent desire to reduce the $CO_2$ production associated with demand for electricity, California has shifted to a greater dependency upon natural gas (46.5 percent of electricity from natural gas in 2008, 45.2 percent in 2007, and 43 percent in 2006, per the California Energy Consumption Database Management System) and a lesser dependency on coal. The relative lower $CO_2$/electricity production ratio associated with natural gas compared to coal is a definite advantage. Use of natural gas is a mainstay for peaking turbines as a means by which all electric utilities can meet customer needs during highest demands, inextricably integrating the two utilities.

In addition to the increased demand for natural gas to help meet a larger electrical demand, natural gas recently has seen greater use for transportation. Both commuter buses and large trucks have replaced diesel fuel consumption with natural gas in order to reduce the sulfur and nitrogen oxides and particulate emissions. As a result, additional natural gas demand has grown beyond the increase for electricity production. There are currently more than 33,000 vehicles in California using LNG or compressed natural gas (CNG).

Looking to the next decade, natural gas could be viewed as a "bridge" which the electrical utilities may find themselves increasingly dependent upon to span the transition to increased use of renewables. The role of renewable electrical production is anticipated to increase to reduce the "carbon footprint," but the need to meet the demand for an uninterrupted supply of electricity will remain constant. Although not necessarily the most efficient option, peaking natural gas-fired gas turbines also serves as a means to meet the electrical storage demands. Placement, capacity, efficiency and control equipment all factor into this consideration as a plausible option.

Other options exist for using natural gas to efficiently produce electricity. Fuel cells have been demonstrated to be efficient electricity producers with natural gas as the energy source. The efficiency of fuel cells, with molten carbonate and phosphoric acid types being the most mature, is of the order of 50 percent. Proper thermal integration with commercial operations can provide higher efficiencies. Solid oxide fuel cells (SOFCs) are technically less mature, but offer higher electrical energy production efficiency and are gaining in exposure in a variety of installations. One other unheralded advantage of fuel cells and gas turbines, and the natural gas infrastructure, is the option of being able to provide electricity in a "modular" fashion.[38]

[38] Arguments also can be made for modularity in the electrical grid to offset potential security breaches or other unplanned interruptions whereby natural gas can serve as an important electrical grid backup. This feature is of particular importance to California because of the inherent potential for devastating disruption of electrical power caused by earthquakes. Despite the desire to build large, efficient and central electricity generators, localized, modular generators have certain important advantages. For instance, Tokyo Electric Power (TEPCO) nuclear and thermal power facilities were severely damaged due to the Tohoku-Chihou-Taiheiyou-Oki magnitude 9.0 earthquake and tsunami that occurred on March 11, 2011. TEPCO's total capacity of normally ~40 GW initially was reduced by about 20 GW as several nuclear and conventional power plants went offline after the earthquake, and several weeks after was able to provide only about 30 GW. In-house conventional power generation of about 500 MW at each of

Combining the use of natural gas with biogas/digester operations has many advantages. For example, a brewery (Miller Brewing Co., Irwindale, CA) has installed an anaerobic digester onsite to treat the waste beer and coupled two 540 kW gas turbines with the digester to combust the biogas to generate electricity, becoming a valuable DG unit. By combining the low heating value fuel with some natural gas "make-up" to ensure the turbine operation, the unit also could operate independently from the biogas source, providing a constant supply of distributed electricity generation in the event the biogas source is interrupted or reduced in quantity. Another recent example is the installation of a MCFC in an Orange County, CA, wastewater treatment plant, in which the effluent from the anaerobic digester is fed (after scrubbing trace sulfur compounds and other contaminants) to the fuel cell. The methane content of the biogas serves as the energy source and the waste heat from the fuel cell, in addition to the electricity produced, is utilized within the wastewater treatment plant. In both cases, biomass becomes a useful source of electricity in a DG operation. By coupling these operations with natural gas distribution and availability, continuous operation can be maintained which makes the reliability of electricity extremely high with low system-wide GHG emissions.

There are many options for CHP applications within the design of the California Smart Grid 2020 in which natural gas and biomass can be the energy source for efficient generation of electricity and GHG reduction. As discussed, many factors enter into the decision as to how to most effectively and efficiently design a biomass operation (i.e., different technologies and means of heat recovery, sizes, and others). New technologies, and new applications of these technologies, both mature and new, need to be installed and operated to demonstrate the advantages. In all the projected values, the advantages offered by reduced electrical transmission and distribution costs, the benefit of installing upgraded electrical equipment to replace old equipment, and wide range of applicability that will drive costs down are typically not included. Benefits of new technologies, such as fuel cells, can only be realized with more demonstrations and opportunities to create business cases that will expand the options of DG to meet the varied applications.

## 5.4 Use Case: Advanced Metering Infrastructure (AMI)

The functional objectives of Advanced Metering Infrastructure (AMI) are to: 1) enable demand response that reduces peak demand in 2020; 2) enable new products, services, and markets; 3) optimize asset utilization and operating efficiency; and 4) enable the grid to operate resiliently to disturbances, attacks, and natural disasters. Intelligent network solutions and software that support AMI by addressing time-of-use and interruptions, demand response, and wireless network solutions will be particularly important.

The principal actors in this use case are manufacturers and vendors of advanced meters, communications networks and services, data translation systems for advanced meter data, and the advent of meter data management (MDM) system developers.[39]

The current state of AMI communication technology consists of proprietary products developed by a small number of OEM meter vendors, some of who have sourced proprietary technology by small companies. Most of these systems employ a 915 MHz unlicensed band, short-range mesh network architecture on the utility-to-consumer data link. Additionally, there are a wide number of large and small software vendors who provide the utility with the back-end meter

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three large steel manufacturing facilities contributed power to the grid to help alleviate the shortage. Anticipation of increased demand due to warmer weather and possible continued disruption of service as power stations are restored to service resulted in the possibility of implementing rolling blacks outs during the summer. While this was a disaster of enormous scale, the implications for grid design and options for distributed generation and microgrid-type operations are illustrated.

[39] Use case provided by GE Global Research.

data management and network monitoring products and technologies. This patchwork of technologies, products, and approaches is characteristic of the electric utility market evolution over the past decade, demonstrating a lack of focus, standards, and national strategy on grid modernization. Government funding through the ARRA is driving the large-scale deployment of AMI systems.

Communications for electrical transmission systems largely consists of fiber optic systems (for primary control) and other technologies (power line carrier and point-to-point microwave) as backup. All of these technologies have a moderate to high level of penetration for transmission systems compared to AMI and distribution automation applications.

### 5.4.1 2010 AMI Deployment Statistics

There are many government-funded (i.e. ARRA) Smart Grid development and demonstration projects in progress focusing on AMI, cyber security, and distribution automation technologies. Details regarding the number of meters deployed and cost breakdown per residential customer can be found in a 2010 Cleantech report posted on the DOE website.[40]

### 5.4.2 2010 State of Grid Control and Communications

Today, wireless meter communications is limited to automated meter reading (AMR) applications. Similarly, wireless / remote controls and communications for distribution and transmissions systems is mostly limited to substation automation and supervisory control and data acquisition (SCADA) applications (see Table 4).

### 5.4.3 Needed Sequence of Events to Meet 2020 Goals

#### *5.4.3.1 Technology Development*

- ***Economic planning and decision tools***. System planning and design tools that enable utilities to economically model, design, deploy, and support wide-area data communications systems. Such tools may include tradeoff analysis of economic payback vs. deployment architectures, impact of building and vegetation growth over extended periods of time, support of increased bandwidth and end point growth requirements towards the 2020 period.
- ***AMI standards***. Rapid ratification and support of open standards to replace proprietary solutions within a time frame that does not delay deployment and impact utilities, regulators, and consumers.
- ***Deployment of standards-based cyber security reference designs and evaluation tools that are extensible to meet evolving and new threats***. Such tools will have to minimize deployment costs and performance impact to Smart Grid data communications.
- ***Open, interoperable software standards that support a multivendor environment for deployment and on-going support of software system***. These standards must support the various "domains" within utilities, including protection & control, operations, maintenance, workforce management, compliance reporting, finance, and others. An example of this in the process control industry is the emergence of IEC61804-3 (Electronic Device Description

[40] "2010 U.S. Smart Grid Vendor Ecosystem", Cleantech Group Report, Cleantech Group LLC. http://www.oe.energy.gov/DocumentsandMedia/2010_U.S._Smart_Grid_Vendor_Ecosystem_Report.pdf

Language (EDDL)) that is being adopted to enable end-devices and systems to be self-aware, self-identifying, and self-configuring.

- ***"Future-proof" communication solutions***. Extensible communication systems that do not strand utilities with outdated solutions yet do not require significant investment on an annual basis. Such solutions will enable utilities to maintain the security and performance of utility owned communications systems for transmission, distribution, and AMI systems.
- ***Communication-enabled Distributed Generation***. As distributed generation systems become supported by economics and policy, communication systems will be needed to provide low latency protection and control and integrate seamlessly with DA and AMI systems.
- ***Plug-and-play Demand Management devices and systems***. Consumers and commercial demand management devices will need to be self-configuring (i.e. plug-and-play). An example of this today is the cable/broadband set-top boxes that largely configure themselves and/or are configured remotely by their provider upon deployment.
- ***Spectrum for critical Distribution Automation control***. It is highly desirable to have dedicated frequency spectrum for Distribution Automation control to mitigate interference with unlicensed utility (e.g. AMI) and consumer electronics.
- ***A robust communications infrastructure that supports PHEV/PEVs to ensure their successful adoption and operations***. Electric utilities are positioned to be a significant factor in the successful and rapid adoption of this technology.

#### *5.4.3.2 Regulatory Development*

- <u>Electricity reselling for PHEV/PEVs</u>. Allow third parties to sell and/or distribute electricity for PHEV/ PEVs. Currently, in some regions, non-regulated entities are precluded from selling electricity. For example, if a multi-family building manager or commercial parking garage owner wanted to promote PHEV/PEVs and sell electricity at favorable rates, regulation may preclude this from being permissible. This will need to be addressed to support the goal of reduced GHG, meet demand response objectives, and reduce total energy consumption. Consumer acceptable solutions to portability of PHEV/PEV.
- <u>Spectrum allocation</u>. Anticipate the need for dedicated RF spectrum for critical smart grid applications such as Distribution Automation (DA).
- <u>Performance certification.</u> Companies with communications expertise that do not currently provide products to the utility market need to be able to do so. For example, startups or suppliers from consumer grade communications may desire (and should be encouraged) to provide technology and products for Smart Grid applications, but may lack the domain expertise to provide suitably qualified products and services. Certification standards and agencies should be supported to ensure compliance of all potential products with specific performance requirements. An example of this is the establishment of the Wireless Compliance Institute (WCI) for ISA100 wireless communications for industrial process monitoring and control. A similar type of institute could be created for AMI, DA, and transmission communications.
- <u>Distributed generation interconnection policy</u>. To support the deployment of renewables, geothermal, and net-zero construction, and reap their environmental benefits, DG interconnection policies need to be favorable to the consumer/owner of DG resources so that interconnection/disconnection costs are not major impediments to the overall end goals.

**Table 4: Comparison of AMR and Transmission & Distribution scale parameters pointing to control and communications growth at the distribution substation to advanced meter segment of the grid.**

| | AMR | Distribution Substation SCADA | Transmission Substation SCADA |
|---|---|---|---|
| Current unit cost | Less than one hundred dollars per node for communications. Includes communications in-meter as well as infrastructure costs | On the order of one thousand dollars per node for substation communications. Includes communications and infrastructure costs | On the order of ten thousand dollars per transmission station. Does not include costs to deploy / lease fiber. |
| Performance characteristics | Number of messages per day to meter (meter reads, connect/ disconnect, etc.)<br>Number of messages via meter to home devices[41]<br>Latency between home and central/distributed dispatch | Polled performance (number of requests/ responses / day)<br>Unsolicited message response for events<br>Bandwidth needed to support features such as file upload/download, and oscillography transfer | Transfer trip and control command from sub to sub<br>Bandwidth needed to support ancillary functions such as video, voice, data, and configuration<br>Support for data transport services provided to other entities |
| Lifetime reliability | 20 years | 10-20 years | 10 years |
| Market penetration | <20% | <5% | ~50% |

### *5.4.3.3 Studies/Analyses/Tests*

1. Grid communications analysis and bandwidth decision tools to account for varying topologies, population densities, vegetation patterns, applications, and latency. This will allow the most economical decisions on grid communication topology designs and deployment.
2. Required security testing of systems for potential gaps in accordance with the recommendations of security standards bodies. Analysis of the potential monetary and environmental gains achieved by consumers for specific Smart Grid use cases such as demand response, distributed generation, PHEV/PEV support, etc.
3. System level testing, such as:
    a. AMI network forming / reforming
    b. Impact/capability of DA actions within the context of an AMI system
    c. Maximum supporting HAN messages given specific AMI topologies
    d. Impact on smart grid communication networks of uncontrollable events (natural disasters, terrorism, cyber attacks) on transmission, distribution, AMI systems

[41] Large-scale AMI deployment in US – proprietary RFQ with Meter/AMI OEM(s)

#### 5.4.3.4 Education Campaigns

Educate the public on the individual and societal benefits (monetary, societal, national security, and environmental) achieved through participation in AMI and demand response programs. Provide consumer-oriented campaign/webinar on what an AMI system actually is/is not and how it works; this could be further targeted at various "future grid workers" as found in universities, high schools, and trade schools.

<u>Demonstrations</u>

- Demonstration of typical and maximum achievable gains (demand reduction, net zero energy capability, and GHG emissions) by various permutations of communications-enabled services such as demand management, renewables integration, and active PHEV/PEV engagement
- Monetary gains realized by consumers participating in demand management, distributed generation, renewables integration, and PHEV/PEV pilot programs.
- Demonstration of ease of installation, configuration, and integration of HAN devices into the overall AMI solution.
- Demonstration of the positive impact and implementation costs to utility operational metrics (e.g. SAIDI, SAIFI)[42] through the use of distribution automation technologies.
- Demonstration of the PHEV/PEV impact on distribution systems, showing how proper communication system deployment can accelerate PHEV/PEV acceptance, maximize their impact, and minimize their disturbance of distribution systems.

<u>Incentives</u>

- Consumer incentives for participation in demand management programs. Could be either through a monthly offset to bill for participation in programs, financial gain in proportion to the amount of peak/constant demand reduced, or other incentive that motivates the consumer to participate in evolving programs.
- Incentives and/or tax credits to IOUs, regional municipal utilities, or other entities for deployment of technologies that adhere to open standards for communication systems that enhance the situational awareness and control of distribution networks.
- Utility incentives to accelerate PHEV/PEV accommodation and provide supporting communications technologies for their active participation.

[42] System Average Interruption Duration/Frequency Index, reference IEEE Standard 1366™-2033.

**Table 5: Comparison of goals, cost and performance for automation of transmission and distribution and in the AMI domain**

| | AMI | Distribution Automation | Transmission Automation |
|---|---|---|---|
| **Goals** | Lowest total support cost to utilities<br><br>Level of future proofing to support emerging applications and needs<br><br>Open standards support that provide greater resource pool for low-cost development, configuration, support<br><br>Systems and infrastructure that are interoperable with Distribution Automation systems<br><br>Extensible bandwidth to support new capabilities and demand | Reliable, robust communications for monitoring and control that supports<br><br>Autonomous, closed-loop control for novel active distribution control<br><br>Leveraging PV and other distribution renewables and support Demand response actions<br><br>DA communication systems that are interoperable with transmission systems to optimize the whole energy food chain<br><br>Volt/VAR control | High bandwidth communication systems to support Wide Area Management via synchrophasors<br><br>Systems that support new types of storage, control, and renewables integration<br><br>Dispatchable energy storage (battery, thermal, etc.)<br><br>FACTS & HVDC control<br><br>Grid integration and control of high penetration wind & transmission level PV on “challenged” transmission systems |
| **Cost** | Total delta system cost (above non-AMI) including end-point and infrastructure communication costs - less than one hundred dollars per end point for physical hardware price<br><br>Access point/repeater costs minimized due to higher throughput, distance, and capabilities (less than ten thousand dollars) | Communications integrated into product (similar to Wi-Fi capability integrated into laptop and mobile devices today).<br><br>Delta system cost per DA endpoint, approximately several hundred dollars.<br><br>Number of required access point/repeaters minimized due to higher throughput, convergence, distance, and capabilities (less than ten thousand dollars) | New capabilities and architectures for fiber and wireless (e.g. SONET, IP, Wireless.)<br><br>Already significant levels of penetration … expect less than 10% cost reduction to 2020 time period |
| **Performance** | Bandwidth on the order of 1 Mbps.<br><br>Total system sizes completely scalable to meet 90% of customers in a service territory<br><br>Robust cyber security, defined as standards are developed. | Bandwidth on the order of 100 Mbps.<br><br>Low latency (msec) and high availability (5x9s) for control applications.<br><br>Robust cyber security; defined as standards are developed. | Commensurate with SONET fiber optic communications systems today.<br><br>Low latency (ms) and high availability (5x9s) for control applications.<br><br>Robust cyber security, defined as standards are developed. |

### 5.4.4 Order of Events and Milestones

It is anticipated that some of the current government-funded demonstration programs can be leveraged to minimize the estimated study and prototype cycles to achieve the "Δt" estimates listed below. Smart grid standards currently being developed also can be leveraged to minimize development time and costs.

1. Develop requirements (installed cost, life, maximum LOC, reliability, etc.). Δt of 1 year
2. Design studies to develop select communications architectures, control algorithms, and cyber security protocols (including standards development) Δt of 1 year for AMI, 2 years for Distribution Automation (DA):
   - Distributed control algorithms, architectures
   - System planning tools
   - Cyber Security: standards, design and testing tools
   - Interoperable control and communications standards
   - Future-proof communication solutions
   - Dedicated spectrum for critical control and protection distribution automation applications
3. Prototype DDT&E (design, development, test and evaluation). Δt of 1 year
4. Decision point/ milestone: down-select communications architectures, control algorithms, and cyber security protocols
5. Develop joint field demonstrations with utilities and vendors. Δt of 1 year
6. New product development: product design (i.e. electrical, mechanical, testing, certifications, etc.) Δt of 1 year
7. Sales and operations 5 years from start for AMI, 6 years for DA. Work with other stakeholders to seek needed PUC approvals and tax incentives, regarding the financing of continued growth

### 5.4.5 2020 State of Grid Control and Communications

In the future, wireless meter communications will enable AMI applications that will go well beyond today's wireless automated meter reading. Similarly, wireless controls and communications for distribution and transmissions systems will expand to include advanced applications such as fault detection, isolation, and restoration (FDIR) and volt/VAR control, for example. These smart grid capabilities will require high bandwidth, low latency, high availability communications capabilities, and robust, distributed control architectures and algorithms (see Table 5). The projected 2020 state is:

- Market penetration for all of three areas will be at least 50 percent
- Robust cyber security will be required for all three applications; defined as standards are developed.

## 5.5 Use Case: Distribution Automation

The functional objectives of distribution automation (distribution substation and feeder automation, protection, and control) are to provide power quality for the range of utility needs; and 2) to operate resiliently to disturbances, attacks, and natural disasters.[43]

[43] Use case provided by GE Global Research.

### 5.5.1 Current State (2010)

Details regarding current Distribution Automation deployments can be found in the Cleantech 2010 Report.[44] Outside of the substation, feeder protection largely consists of stand-alone, pre-programmed protection devices such as reclosers, breakers, and sectionalizers that operate independently of each other. A small number of vendors are starting to provide protection devices with advanced, distributed control capabilities. For this roadmap, focus herein is on the feeder-based protection devices for distribution automation applications such as fault detection, isolation, and restoration and volt/VAR control.

While there is interest in leveraging the wireless AMI communications infrastructure currently being deployed, the data requirements (e.g. latency, reliability, bandwidth) for distribution automation are quite different from AMI; research needs to be undertaken.

For distribution substation automation applications, a very wide set of monitoring and control technologies have been deployed including landline telephone, cellular, and manual visual/drive-by technologies. These are due to the relatively vast quantity and historically lower priority of distribution networks compared to transmission systems. The predominant technologies currently being deployed for distribution system applications include licensed point-to-point microwave, cellular telephone, and POTS. Communications systems for distribution automation could have numerous technical synergies with those for transmission applications, yet they face more significant economic and deployment hurdles due to cost, design, configuration, lack of right of way access, among other challenges. In California, as in North America, a higher percentage of electric utility transmission systems are equipped with data communication systems, compared to distribution systems. Historically, economics (cost to deploy vs. benefit), technology maturity, and lack of right-of-way ownership have presented challenges to communications deployment for distribution automation applications.

From a standards point of view, existing communications protocols such as IEC61850 can be leveraged to interface with distribution automation devices, but there is no standard communications technology specified, and similar to AMI, each vendor is currently providing a proprietary solution. Further, there is no existing standard for cyber security; NIST is leading the current development of cyber security standards development for the Smart Grid.

### 5.5.2 Needed Sequence of Events to Meet 2020 Goals

It is anticipated that some of the current distribution automation product offerings and government-funded demonstration programs can be leveraged to minimize the estimated study and prototype cycles to achieve the "Δt" estimates listed below. Smart grid standards currently being developed also can be leveraged to minimize development time and costs. The recommended sequence of events is as follows:

1. Develop requirements (installed cost, life, maximum life ownership cost (LOC), reliability, etc.). Δt of 1 year
2. Design studies to develop select communications architectures, control algorithms, and cyber security protocols (includes standards development) Δt of 2 years
    - Distributed control algorithms, architectures
    - System planning tools
    - Cyber security: standards, design and testing tools
    - Interoperable control and communications standards
    - Future-proof communication solutions

[44] "2010 U.S. Smart Grid Vendor Ecosystem," The Cleantech Group, 2010.

- Dedicated spectrum for critical control and protection distribution automation applications

3. Prototype DDT&E. Δt of 1 year
4. Decision point / milestone: down-select communications architectures, control algorithms, and cyber security protocols
5. Develop joint field demos with utilities and vendors. Δt of 1 year
6. New product development: product design (i.e. electrical, mechanical, testing, certifications, etc.) Δt of 1 year
7. Sales and operations 6 years from start. Work with other stakeholders to seek needed PUC approvals and tax incentives, etc, regarding financing continued growth.

Existing stand-alone, pre-programmed protection devices will be replaced and/or upgraded to secure, intelligent electrical devices that communicate with each other to autonomously minimize outages faster than can be done today, and isolate the effects of cyber and physical attacks not possible today. Other intelligent electrical devices (IEDs) such as volt/VAR systems will maximize grid performance, stability, and power quality more efficiently than done today.

The cost of the communications and control equipment for the reclosers is incremental; it is reasonable to assume that the price of the advanced recloser and associated controller would remain on the order of several thousand dollars.

## 5.6 Use Case: PHEV/PEV Accommodation

The principal actors are automotive Original Equipment Manufacturers (OEMs), battery manufacturers, suppliers of Electric Vehicle Supply Equipment (EVSE), and utilities for the accommodation of PHEV/PEVS on the grid without power quality disturbances due to increased load, especially in high-penetration communities. The functional objectives are to: 1) accommodate electric vehicles onto the smart grid; and 2) reduce GHG emissions to 1990 levels across all sources in 2020.[45]

The primary goals of OEMs are to determine how to meet customers' needs/expectations in order to generate a viable, saleable vehicle product that is dependable, safe, cost-effective and appealing to consumers. Moreover, the vehicles help reduce (a) dependency on oil and (b) GHG emissions. Additionally:

- PHEV/PEVs should integrate into smart grid infrastructure with minimal effort and expense
- Coordinate charging procedures with SAE standards
- Efficient vehicle operation and convenient recharging equipment/procedures are needed.
- Additional benefits that may be derived from grid-connection should be evaluated, such as the use of fleet electric vehicles as an option for aggregated storage tied to the grid
- Load profiles and distribution throughout grid should be compatible with incremental increase in PHEV/PEV purchases
    - o Incorporate PHEV/PEV operations into smart grid as the grid evolves over the next decade
    - o Role of utilities and third parties needs only to be unified through required standards

[45] Use case provided by GE Global Research.

### 5.6.1 Options for Enhancing Overall PHEV/PEV Benefits

Although several suggestions have been postulated regarding potential alternative roles that PHEV/PEVs may serve in smart grid infrastructure operation, no specific direction has been identified. Automotive operation and customer satisfaction is paramount at this time. Expect to gain better understanding about technology improvements (batteries, vehicle operations, etc.), infrastructure compatibility (charging equipment and availability) and customer needs over the first 5 years of marketing PHEV/PEVs.

### 5.6.2 Current State (2010)

While hybrid electric vehicles that charge their batteries through the vehicle's internal combustion engine have recently demonstrated commercial success, there has been no large-scale consumer deployment of their plug-in counterparts.

EV development to-date has focused largely on technology demonstration vehicles. Automobile OEMs have developed prototype plug-in models over the last century.[46] However, two major auto manufacturers, Nissan and General Motors, have developed commercial PEV models have shipped plug-in electric cars in small quantities beginning in late 2010, scaling up to greater production (~50,000 anticipated[47]) in 2011.

Several technology and social factors have nurtured the realistic expectation that electric vehicles will take hold this time. The degree of acceptance of PHEV/PEVs largely will be based on three factors: 1) learning how to deal with "range anxiety" (i.e., gauging the distance between charging based on climate, driving habits, and charging locations); 2) expansion of charging station infrastructure; and 3) the performance and life of the battery packs. Regarding the last factor, different OEMs deal with battery temperature maintenance differently and the battery temperature is critical to its life of operation. Another factor that will affect PHEV/PEV acceptance is the cost of gasoline and diesel fuel – as the cost continues to rise the interest in electric vehicles will grow.

#### *5.6.2.1 Technology*

- Advancements in battery technology and capabilities that have improved EV performance
- Charging infrastructure: the commitment from several vendors to produce and market chargers, known as Electric Vehicle Supply Equipment (EVSE)
- Prevalence of wide-area communication technology that can be leveraged to facilitate EVSE deployment

<u>Social/Economic</u>

- Desire for energy security: ~$500 billion sent offshore for petroleum products
- Perceived reduction in GHG emissions from vehicles: ~3.1 Gt
- Consumer acceptability demonstrated by hybrid vehicle commercial success

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[46] The Steinmetz Electric Car Company, circa 1914, developed one of the original electric vehicles in the U.S. This vehicle was capable of 40 mph and used 6V batteries (Charles Steinmetz, the electric car company's founder, was the chief engineer of General Electric). Additionally, GE developed an all-electric vehicle in 1977 (GE-100) and General Motors developed the EV1 in 1996.

[47] Forbes Autos, Hincha-Ownby, M, "Nissan Leaf 2011 Production Begins in Japan", October, 2010

**Table 6: Electric vehicle charging system parameters.**

<table>
<tr><td></td><td colspan="4">Charging Infrastructure</td><td>PHEV</td></tr>
<tr><td>Current unit cost</td><td colspan="2">Unit<br><br>L1 - $500<br><br>L2 - $1,000<br><br>L3 - $100,000</td><td colspan="2">Estimated Installation<br><br>L1 – $1,000<br><br>L2 - $1,500 - $5,000<br><br>L3 - $50,000</td><td>Extra $2-5K acquisition cost</td></tr>
<tr><td rowspan="4">Performance characteristics</td><td></td><td>L1</td><td>L2</td><td>L3</td><td rowspan="4">Miles on charge – 47-138 miles[48]<br><br>Operation cost;  $0.02-$0.04/mile[49]</td></tr>
<tr><td>Charge Rate (kW)</td><td>1.4</td><td>3.3-6.6</td><td>50-150</td></tr>
<tr><td>Time to charge (hr)</td><td>4-8</td><td>2-4</td><td>0.25</td></tr>
<tr><td>Efficiency</td><td>~80%</td><td>~90%</td><td>>90%</td></tr>
<tr><td>Lifetime reliability expectations</td><td colspan="4">>10 years</td><td>Average 3-5 years for battery refresh</td></tr>
<tr><td>Market penetration to date</td><td colspan="4"><1%</td><td><1%</td></tr>
</table>

A major companion technology to the electric vehicle itself is the charging infrastructure. Based on past experience, all of the relevant and related standards for the infrastructure, such as communications and charging cable conventions, should be developed concurrently. There are three basic charger levels planned (denoted by L1, L2, L3), shown in Table 6.

### 5.6.3 Needed Sequence of Events

#### *5.6.3.1 Supporting Technologies / Important Preconditions*

- Standardization of charging cable/connectors along with backhaul communications from car to charger, to larger system. These communications will include time-sensitive information such as authentication, billing, and scheduling
- Embedded intelligent metering and communications electronics into battery and charging systems
- Continuous improvement of battery technologies and charging systems
- Third-party battery and charging system deployments for fleet, retail, and parking systems
- Consolidation of standards to ease importing/exporting foreign vehicles into market

[48] Loveday, Eric, "Nissan pegs Leaf range between 47 and 138 miles …", Autoblog Green, June 2010
[49] CalCars – The California Cars Initiative "All About Plug-In Hybrids – 3. PHEVs Are Cheaper to Run and Cheaper to Maintain"

#### 5.6.3.2 Technology Development

- Increase in battery energy density, reduction in weight, and increase in battery lifetime
- Goal: Increase range to ameliorate consumer anxiety
- Cost reduction on battery technology
- Established communications between EVSE and EV (i.e. standards)

#### 5.6.3.3 Studies/Analyses/Tests

1. Impact on distribution networks of relatively large penetration of PHEV/PEV deployment (so-called "clustering")
2. Detailed analysis of real world implementation of PHEV/PEVs that address all facets: charging time, range, support needs, etc. from a consumers perspective
3. Analysis on the required geographic coverage of publicly available EVSEs.
    a. Should EVSEs match the convenience of gasoline stations when the majority of charging will be done at the consumer's home?
4. Detailed analysis on crashworthiness, post-crash survivability, and pedestrian safety due to the relatively inaudible sound emanating from EV "engines"
5. Cradle-to-grave studies need to be performed. What to do with batteries at end of life when EVs account for a majority of the vehicles on the road
6. Accurate lifetime cost-of-ownership compared to current vehicle choices

#### 5.6.3.4 Education campaigns

Educating consumers in the new meaning of "fuel" and a "full tank," (i.e., what the meaning of the "low-fuel" dashboard indicator light is for PHEV/PEVs).

#### 5.6.3.5 Demonstrations

- Demonstration on PHEV/PEV "communities"
- Demonstrate crashworthiness, post-crash survivability, and pedestrian safety due to inaudible sound from EV "engines".
- Use of PHEV/PEV technology within vehicle fleets (e.g., commercial local delivery trucks, rental cars, etc.)

#### 5.6.3.6 Incentives

- For consumers to adopt PHEV/PEVs so as to offset cost of charging infrastructure
- For utilities from regulators to promote consumer PHEV usage
- For domestic manufacturing to ramp up manufacturing for both PHEV vehicles, and charging infrastructure equipment

#### 5.6.3.7 Regulatory

- Utilities will be supportive of PHEV/PEV charging systems (EVSE), including needed upgrades in distribution networks
- Regulation/policy needs to be established around "portability" of electricity rates and/or establishment of personal rates that promote and simplify rates for consumers
    - Currently, in some regions, non-regulated entities are precluded from selling electricity. For example, if a multi-family building manager or commercial parking

garage owner wanted to promote PHEV/PEVs and sell electricity at favorable rates, regulation may preclude this from being permissible. Consumer acceptable solutions to portability of PHEV/PEVs.

#### *5.6.3.8 Business*

- Establishment of vehicle and battery manufacturing capacity to support PHEV/PEV demand

**Table 7: Desired end state for PHEV/PEVs.[50]**

| | Charging Infrastructure | PHEV |
|---|---|---|
| **Goals** | • Accelerate technology development for a holistic "systems" approach towards charging infrastructure<br>• Robust 3rd party retailers and service providers providing charging services<br>• Active utility support of PHEV/PEV programs and build out of distribution networks to support load growth | • Improved battery technology to achieve 30-50% improvement in battery life and range and total reduced support costs of 20% AAGR<br>• Manufacturing capacity growth to meet 2020 projected demand needs |
| **Attributes** | • Open standards for physical plug connectivity, communications, and data interchange<br>• Partnership between car manufacturers, charging infrastructure OEMs, and service providers | • Vehicle cost parity with internal combustion engine vehicles so as to support < 1 year consumer payback |
| **Cost** | • Installation cost is expected increase but only due to inflation<br>• Material cost could come down due to economies of scale | • 50% reduction in $ per kWh for the vehicle battery |
| **Performance** | • Standards-based interfaces<br>• Robust communication modalities enabling monitoring, controls, and services that allow for plug and play demand management<br>• Level II at home<br>• Level II & III Infrastructure Deployed | Reduction in battery weight by minimum 50%<br><br>Increase in energy density by close to 6x<br><br>Enables extended range PEVs & longer lifetime |
| **Lifetime** | 12-15 years | ~8-10 battery refresh cycle |
| **Market Penetration** | Total EVSE (commercial/public, residential, and fleet): ~3.5M | ~3-5% of all new car sales |

### 5.6.4 Order of Events and Milestones

It is anticipated that some of the current government-funded demonstration programs can be leveraged to minimize the estimated study and prototype cycles to achieve the "$\Delta t$" estimates

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[50] Channels to market will be shaped largely by market forces, utility pace of engagement, and regulatory actions.

listed below. Smart Grid standards currently being developed also can be leveraged to minimize development time and costs.

1. Develop requirements (installed cost, life, maximum LOC, reliability, etc.). Δt of 1 year
2. Design studies to develop select communications architectures, control algorithms, and cyber security protocols (includes standards development) Δt of 1 year
    a. Distributed control algorithms, architectures
    b. System planning tools
    c. Cyber security: standards, design and testing tools
    d. Interoperable control and communications standards
    e. Future-proof communication solutions
    f. Dedicated spectrum for critical control and protection distribution automation applications
3. Prototype DDT&E. Δt of 1 year
4. Decision point / milestone: down-select communications architectures, control algorithms, and cyber security protocols
5. If yes to all of (4), develop joint field demos with utilities and vendors. Δt of 1 year
6. New product development: product design (i.e. electrical, mechanical, testing, certifications, etc.) Δt of 1 year
7. Sales and operations ~5 years from start. Work with other stakeholders to seek needed PUC approvals and tax incentives, etc., regarding financing continued growth.

### 5.6.5 2020 State of PHEV/PEVs

Grid-connected vehicles started in 2010, and estimates place 750,000 electric vehicles on the road by 2015. Assumption by 2020 is that for each car sold, approximately 2 EVs are sold, with the key constraint being manufacturing supply constraints of vehicles. The desired end state for accommodation of PHEV/PEVs on the grid is shown in Table 7.

#### *5.6.5.1 Channels to Market for PHEV/PEV Charging Infrastructure*

As initial, larger volume sales of PHEV/PEVs establish a foothold in the California automotive marketplace, so will the electrical and charging infrastructure required to support this growth. In addition to technology development, evolution of channels to market will occur over the next ten-year window, ranging from a relatively immature supply base to one that is established, serves numerous levels of need, and fosters new, innovative business models.

It is envisioned that consumers and third parties will be the main constituents in the procurement of the L2 and L3 PHEV charging infrastructure (others, such as municipalities will emerge). Third parties will consist of those who will provide charging services as ancillary offerings to the primary course of business. Parking garage operators, retail shops, educational institutions, and fleet operators are among those who will look to provide charging infrastructure for the purpose of customer attraction/retention, attainment of environmental goals, or due to economic benefits. Such third parties will look to consultants, experts, and OEMs for recommendations on deployment strategies, payback analysis, and equipment selection. If business-to-business specification and purchasing patterns follow traditional trends, these third parties will in turn procure systems from automotive manufacturers, distributors, electrical contractors, electric utilities, and/or service providers. The latter group could be comprised of those who will provide unique and innovative services such as battery replacement/condition monitoring services, leasing agents, and other entrepreneurial providers arising to meet the unique needs of this growing market.

## 5.7 Microgrid Accommodation

Many definitions are available to describe microgrids; the name would imply that the microgrid is a system similar to a conventional grid, but much smaller in size. Broadly speaking, this remains the intent, but recent definitions emphasize a control system with the ability to provide customers the ability to tailor electricity supplies to suit their individual needs for power, power cost, environmental impact, reliability, and power quality.

A microgrid can be a composite of electricity generators, incorporating efficient methods of demand management as well as storage and distribution of energy that, although grid-connected, can be isolated (islanded) to continue meeting customer needs in the event of grid failure. By incorporating microgrids into the overall grid, which introduces distributed generation (DG) and distributed energy storage, widespread two-way flow of electricity is inherent, which poses a control issue that is not common in the current grid. However, as more storage is introduced into the conventional grid to help accommodate the expected growth of renewable electricity generation, a more complex control system will be required in any case.

Microgrids admittedly are in their infancy. Some islanded remote community microgrids have been operated (e.g., Bella Coola microgrid in Canada); some bulk-grid connected microgrids also exist (Sacramento Municipal Utility District and several military operations are in the planning and development phase – e.g., Twentynine Palms Marine Corp Base, CA). Pike Research has recently reported that there are a total of more than 160 projects worldwide, with generating capacity of more than 1.2 GW, but most are pilots or research projects. However. Adoption of IEEE islanding standards is expected, which may accelerate the growth in commercial islanded projects.[51]

**Figure 10: Schematic for a concept of interconnected microgrids [provided by P. Molitor, NEMA]**

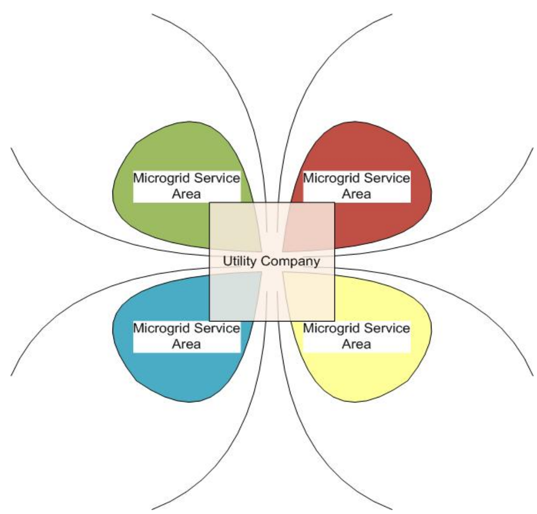


Figure 10 above provides a sketch conveying the notion of an electric grid as a nexus of interconnected microgrids. However, while microgrids offer much potential, electric power distribution grids are not set up to accommodate, or evolve into, an integrated system of microgrids.

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[51] Pike Research, 2011. Microgrids Smart Energy Aggregation Platforms for Distributed Power Generation, Safe Grid Islanding, Reliability, Security, and Emergency Services.

## 5.7.1 The Case for Microgrids

In the development of a California Smart Grid 2020, *widespread use of microgrids, which captures the broader concept of a network of energy providers, could become a key ingredient in providing customers with many sources of energy – electricity, natural gas and "renewables," in a more efficient way of operating*. In the long-term, this will result in lower energy consumption and GHG emissions, which is the overarching goal. By developing a system of microgrid operations within the current California electrical grid, several advantages can be realized in the overall grid operation both for baseload and peak electricity demands. However, because of the inherent established operation of the electrical grid throughout the State, there are some disadvantages that must be reconciled (see Table 8).

**Table 8: List of the apparent advantages and disadvantages of microgrid incorporation into the current grid structure.**

PROS

1) Offers many options as to size, sophistication and control, as well as location and duty cycle operations
2) Provides the opportunity for isolated, independent continuation of electricity in the event of a catastrophic event, such as an earthquake
3) Includes the ability to incorporate cyber security to system via the independent checkpoints between each microgrid and the grid (although see 3 below)
4) Allows the use of several combinations of electricity generation and storage to accommodate the particular demand
5) Takes advantage of advances in technology that are being implemented in several DOD sites
6) Will be applicable to a wide range of operations, concepts and business models
7) Offers the possibility of ownership by the specific microgrid site users or the utility to whose grid the microgrid is tied
8) Provides an excellent opportunity for new business generation, from the standpoint of installation, operation, maintenance and utility connectivity
9) Provides the opportunity to reduce the peak demand on the grid, and to achieve a greater efficiency of operation, thereby reducing GHG emissions and perhaps the cost of electricity
10) Permits the opportunity to introduce various methods of distributed energy storage
11) Provides a natural progression to new technologies while replacing old equipment that is out-dated or in need of upgrade, in a more flexible manner
12) Offers a means for improving the detection of faults and safety measures for repair personnel
13) Can provide grid balancing and power quality management as well as peak shaving

CONS

1) Introduces a new level of complexity in grid operations
2) Requires additional expenditures by utilities to accommodate this new approach to operation
3) Increases the degree of complexity of cyber security because of more points for possible interference
4) Alters the method by which utilities operate, i.e., cost structure and CAISO interaction
5) Requires different standards for operations in certain applications
6) Implementation will raise the initial cost to customer
7) Changes the control architecture that utilities have in place
8) Is not proven in many potential operations
9) Can create interface problems between a utility and independent owners/operators

#### 5.7.1.1 Microgrid Application to a California Smart Grid System

Several changes and modifications in grid operations are required in order to develop a California Smart Grid 2020, although it is evident that centralized generation will continue to play a large role in the California energy system for the foreseeable future, especially within the time frame of the 2020 roadmap. However, based on the inputs received from the numerous contributors and participants in this study, the need for describing distinct advantages to the customer that can be derived from a smart grid development is extremely important.

Integration of microgrids into the bulk grid, at several different levels of scale and application (residential, industrial and commercial), can be done in a fashion such that user benefits will become apparent. Residential customers benefit from direct involvement, such as installed PV feeding into a local storage system that will allow local control of additional electrical energy supplies. Communities can benefit where microgrid installations can be grid-disconnected in the event of an earthquake or other natural disaster to help maintain local emergency operations. Industrial and commercial users likewise can benefit from microgrid approaches such as incorporation of fuel cells, eliminating the need for auxiliary onsite uninterruptible power supply. Businesses can derive advantages from microgrid systems (i.e., in strip malls, hotels, hospitals and entertainment centers, etc.) that would be designed not only for improved efficiency of operations but also with specific customer applications in mind (e.g., EV charging).

With increased emphasis on their use for transportation and utilities, batteries have received significant interest for use at several different sizes and operations of microgrids. Packaged Li-ion battery units at the 1 MW size currently are being evaluated in various field demonstrations. However, there are many other methods of storing energy that can serve either as a replacement for the demand for electricity or as an alternative means for producing electricity. Batteries can provide many advantages, including shorter-term power quality management as well as longer duration power peaking or emergency supplies. Batteries can serve as an intermediate electricity provider when placed between an intermittent source, such as PV, and the user to maintain a constant, uniform supply of electricity. Production and storage of ice from readily available or cheap electricity for use in peak demand air conditioning can replace the electricity demand during peak operating hours. Onsite production of hydrogen from a MCFC operation can provide peaking electricity (or fuel for fuel cell vehicles) by including proton exchange membrane (PEM) fuel cells onsite to assist in meeting peak periods of electricity demand. The demand for constant, uniform electrical power quality creates a need for other storage methods such as flywheels and ultracapacitors for shorter duration of operation. The breadth of possibilities for designing microgrids to meet the specific onsite needs of the customer, in a very efficient manner (with low GHG emissions as well), while providing a uniform, reliable and secure link to the utility grid, provides a very valuable method of meeting customer and utility goals.

#### 5.7.1.2 Microgrid Architectures

One very important element in implementing microgrids is that the system efficiency can be much greater than can be derived from renewable electrical sources long distances away from the consumer that require the installation of transmission lines and dedicated large-scale storage to firm intermittent operations. Local operations of microgrids permits a much more significant use of CHP and other distributed generation options, with a broader use of different available sources of energy (i.e., biomass, renewable PV, natural gas) and closer matching of energy production with demands, incorporating any of several types of energy storage. In addition, when energy storage is part of the microgrid and the microgrid is integrally tied to the grid operation, the microgrid storage can be expanded to become part of the grid storage, capturing energy that is generated during off-peak or reduced demand, and providing energy to a broader range of customers than the immediate microgrid segment. Although utilities may want to make a case for ownership to tie the microgrid operation directly to their own grid operations, third-party ownership could make sense.

There are basically three scales of microgrid architectures that merit discussion here: small scale on the order of residential sizes of operations (< 1 MW); medium scale on the order of a commercial operation (~1 – 5 MW); and large scale on the order of industrial operations (> 5 MW). Variations among these are entirely possible, creating a myriad of possibilities, but for simplicity, only three will be discussed here.

Residential scale is a function of the direct locale demands. An example of this would be a neighborhood where a combination of microturbines and PV electricity generators could be considered. A shared storage facility, probably one of several types of batteries, would be central to this microgrid. The microturbine duty could be cycled to meet the shortfall between the intermittent PV availability from rooftop units on the local microgrid members' residences or open spaces (gated community, specific neighborhood, condominium, parking lot, etc.) and to provide the margin required to accommodate peaks and sudden changes in local demand. This would allow the utility to plan on providing a preplanned element of baseload and no more than minor variations above this. Controls for this type of operation would require monitoring and supply of electricity at the 120 V AC level, DC/DC for generator/storage and DC/AC conversion within the microgrid, as well as monitoring of the storage supply and demands of the microgrid for the utility information to accommodate the baseload supply and determine the margin within the microgrid storage. The mutual sharing of information between microgrid and grid operations could be an extension of smart metering that is currently being pursued for demand response and control, although presumably the utility would not require data from each customer, but rather the microgrid as an entity.

In the case of a commercial-scale microgrid, more flexibility in the generation of electricity, storage options, and duty cycles will be possible. In addition to taking advantage of the availability of PV within the site (e.g. rooftops, parking lots, structure surfaces), systems that could utilize more efficient generation of heat and electricity from natural gas can be employed in tandem. For instance, fuel cells could be utilized for a baseload supply of electricity at a level that would augment the supply from the utility, and in this capacity provide additional efficiency and operating flexibility by accomplishing electrical, thermal or chemical (e.g. hydrogen) energy storage. In the event that the load cycle is quite variable, perhaps a gas turbine would be used in place of a fuel cell because the gas turbine could more readily be shut off during very low energy demands, although in this latter case, storage methods would be somewhat limited and efficiency reduced. In certain CHP operations the balance of electrical and thermal requirements can be altered by the use of storage (generation of ice for thermal storage with electricity with the ice assisting in air conditioning during peak to offset electrical demand) and this allows the microgrid operations another degree of flexibility.

In the case of industrial microgrids, the degree of technological and operational flexibility is further expanded. In additional to various renewable options, depending on the industry, fuel cells and turbines can take advantage of natural gas availability to provide CHP and alternative storage technologies. Location and economies of scale may affect the amount of storage selected for onsite operations and the margin that could be made available for grid access. Broader participation of the microgrid with grid operations may dictate electrical storage technology (batteries, ultracapacitors) in order to meet the grid response demands. This poses the issue of who will own and operate such units. If the microgrid becomes more interactive with the grid and the grid is more dependent upon the microgrid operation, the utility may be the logical owner, while if the microgrid serves only a relatively small segment of the grid, or serves to maintain power quality for short periods, the ownership may be shared, or the microgrid may be linked contractually to the utility, but separately owned.

#### 5.7.1.3 Microgrid Control and Management

The degree of sophistication in the internal operation of the microgrid and at the microgrid/ grid interface must be governed by appropriate standards or reliability and quality. This will require sensors for monitoring the "health" of the microgrid that share information with the bulk grid operations as well the microgrid control center. At the present time, there are no standards that the project team is aware of that address microgrid operations or their relationship to the grid, and therefore the potential impact of microgrids to the grid, but many study participants noted the need for such. While many industrial operations have controls that might meet such standards, the same is not true of commercial and residential levels of operation. However, with the introduction of smart meters and AMI into grid operations, the ability to carry out contiguous operation throughout a multi-microgrid/utility grid infrastructure seems feasible. This is necessary in order to take full advantage of a statewide integration of microgrids connected to the bulk electric grid. Microgrid integration demonstration projects are therefore recommended, in order to consider such factors as power quality impacts, approaches for demand response, implications of different storage options, controls and interfaces, in addition to capitalization, ownership and operations models.

There have been serious discussions about microgrids versus virtual power plants (VPPs). VPPs have been described as clusters of microgrids that are integrated through the grid. The methods of combining microgrids, either together or separately on the grid, is a function of many factors, such as ownership, customer duty cycles, cost of energy, intermittency of supply (renewables), and utility acceptance of different operation and control options. The issue of determining optimal levels and modes of aggregation, and unifying and integrating controls is one that will require work, but is not outside the capability of today's technology, and much of the groundwork has already been laid. Standards and controls that will provide safety throughout the operation, both on and off the grid, will be necessary.

Other microgrid issues needing attention include:

- Lack of viable business cases either for the utility or for independent providers
- High cost of renewable and energy storage DER assets
- Lack of a flexible and scalable microgrid energy and power quality management platform that is suitable for a broad range of microgrid applications (e.g. two-way power flow devices for real-time protective relaying, and seamless synchronization that allows micro-grids to connect/disconnect /reconnect to the grid)
- Lack of a flexible and adaptable network protection controls for fault detection, isolation and restoration
- Lack of an adaptable, cyber secure communication infrastructure
- Lack of a Common Information Model (CIM) for microgrids and associated DER assets
- Lack of integration of microgrids into wider Distribution Management System operations
- The danger of electricity back-feed into the wider bulk-grid, which can endanger linesmen

Overall, microgrid systems development will be an important wild card in the California Smart Grid 2020 in several ways:

- If and when will benefit to the customer in terms of cost savings, flexibility and dependability of energy availability be proven?
- If and when will benefits to grid operations be proven, and solutions to controls/monitoring/security needs emerge?

- When will clarity emerge in transportation demands for electricity, and the prospects for natural gas use to meet electricity demands?

Although barriers exist, much technology that can be used in microgrid operations is available today, and technical advances in fuel cells, batteries, and controls over the time period between now and 2020, as well as changes in quantity and periodicity of energy demands, will provide significant opportunities to illustrate the value of using microgrids and take advantage of distributed generation.

#### *5.7.1.4 Pathway Forward for Microgrids*

Microgrids, especially with storage elements, offer enough benefits to meeting the California Smart Grid 2020 goals that they demand significant attention and support. Careful study of location advantages and education of customers as to the advantages are necessary first steps that should be carried out in tandem. Expanded demonstrations of the wide range of operating options and associated advantages will serve to illustrate the customer benefits. Utility grid operators must be integral to the plans and implementation, but the owner/operator of the microgrid can vary, depending upon the circumstances. Business and operational models need to be built, using past experience and demonstration projects as much as possible.

It is important to note that microgrid operations offer an excellent opportunity to mesh the combined use of natural gas with electricity. Currently, natural gas is used for a significant amount of California electricity generation, and is used for space heating. By focusing on microgrid development, not only is the value of distributed generation being illustrated but also a significantly more efficient use of natural gas is possible (e.g., via CHP systems). This results in greater efficiency to the customer and may provide the opportunity to expand the use of electricity in transportation via electric vehicles within the current infrastructure. If microgrids are allowed to develop in the near term, the funds required for an expanded transmission system for electrical utilities can be reduced, while simultaneously providing for an improved distribution system at the customer level.

There are several competing generation, storage, and controls possibilities that may provide the fundamental basis for developing grid-tied microgrid systems. The value of incorporating CHP into a microgrid operation has potential advantages that can address three of the Energy Commission goals, namely use of renewable energy, use of biomass, and reduced peak demand on the electrical grid. CHP offers the greatest overall efficiency savings, but also requires the most demanding controls in its operation.

In order to move forward in understanding what role microgrids should fill in the next ten years in meeting California's electricity use and production goals, several efforts need to proceed in parallel. Microgrid systems must be demonstrated with several combinations of generation, storage, and controls in order to provide microgrid designers with operating data covering the wide range of system options available to carefully evaluate potential impacts to the grid. Scale will be important, but field operations over time that shed light on the robustness and dependability of the technology and operations are of utmost importance. Advantages and disadvantages must be clearly shown and understood to be able to define what eventually can become a set of business cases for this industry. In addition, the value of microgrids to the customer must be demonstrated and defined in order to support this change in utility operation. The customer must be clearly aware of benefits and drawbacks, based on factual and demonstrable information, in order to help decide whether a business case can be made.

### 5.7.2 Needed Sequence of Events

1. Development of viable business cases for each type of microgrid (e.g. utility vs. independent operator, Life Cycle Cost, life, reliability, ROI, etc.). $\Delta t$ of 2 to 4 years
2. Development of flexible and scalable microgrid energy and power quality management platforms with real-life implementations that produce the benefits identified for microgrids (i.e., improved energy surety, efficiency, cost of electricity, availability, power quality, customer participation, etc.). $\Delta t$ of 3 to 6 years
3. Development of an adaptable, cyber secure communications infrastructure for microgrids and distribution systems. $\Delta t$ of 3 to 6 years
4. Decision point about 6 years from start: Which business case models are most viable? Is capital to fund wide-scale deployment available? If yes, are microgrids appearing because it makes business sense or are additional incentives needed?
5. Continue sales and operations. Work to seek needed PUC approvals and tax incentives to enable continued growth.
6. Development of a Common Information Model (CIM) for microgrids, DER assets, and other Distribution Control assets that are incorporated by suppliers into their systems enabling "plug-and-play" or "configure-and-play" capabilities. $\Delta t$ of 10 to 15 years
7. Development of low cost renewable and energy storage options. $\Delta t$ of 10 to 20 years
8. Work with microgrid stakeholders to improve DER asset mix (renewables, energy storage). Seek needed PUC approvals, and tax incentives, and financing to enable continued growth. $\Delta t$ 15 years from start

## 5.8 Energy Storage

Throughout the next decade it is anticipated that natural gas-fired turbines will continue to play a significant role in electrical energy demands above the baseload supply. However, in order for the grid to meet the California Smart Grid goals by 2020, and beyond, so will energy storage. Energy storage is needed for a variety of smart grid applications—such as peak shaving, islanding, VAR support, renewable energy integration, PHEV/PEVs, and frequency regulation in view of increased penetration of inherently intermittent renewable resources and thus uncertain supply. The application type and location of the implemented energy storage also will be affected by the extent and type of DG that will be placed throughout the smart grid.

Smart grid systems will take advantage of various options available for electrical energy storage, in order to support new approaches to grid stabilization through modeling, controls, communications, integration and hybridization across a broad range of operations. Battery technology applicable to transportation could contribute to changes in electrical grid use in several ways, such as charging options, supporting (and altering) peak demand, and demand response. The modeling and simulation of new devices, systems, and operating concepts and their interaction or impact with the electrical grid is a gateway requirement prior to any future adoption by the utility industry.

An EPRI Report [2008] identifies that large-scale energy storage is poised to "enter the utility inventory" (p.43).[52] For example, A123 Systems (a member of this study's project team) has chosen a Li-ion chemistry battery-based storage system as a platform for demonstrating several advanced grid and renewable resource supportive functions. The storage technology is not the emphasis of the A123 demonstration. Rather, the intent is to develop and demonstrate new

[52] Chuang, A., J. Hughes, M. McGranaghan, and X. Mamo, 2008. *Integrating New and Emerging Technologies into the California Smart Grid Infrastructure.* EPRI, Palo Alto, CA; California Energy Commission, Sacramento, CA. 1016535. CEC-500-2008-047.

modes of control and operation to meet specific grid goals including increased efficiency, increased reliability, and increased renewable energy content.

California should undertake a carefully planned campaign to address the need for language updates in tariffs and standards to ensure proper valuation of storage in a range of smart grid applications. ***Trade-offs between the cost-effectiveness of modifying existing infrastructure and aged equipment vs. changes that will provide longer-term advances that include new storage technology with flexibility and modularity for continual improvements should be analyzed. In such a manner, once proper valuation of storage is established, California should consider augmenting the subsequent increase in private investment in technology development in key barrier areas.***

The incorporation of energy storage in microgrid operations offers several opportunities that could enhance efficiency savings, power management and peak demand reduction; specifically:

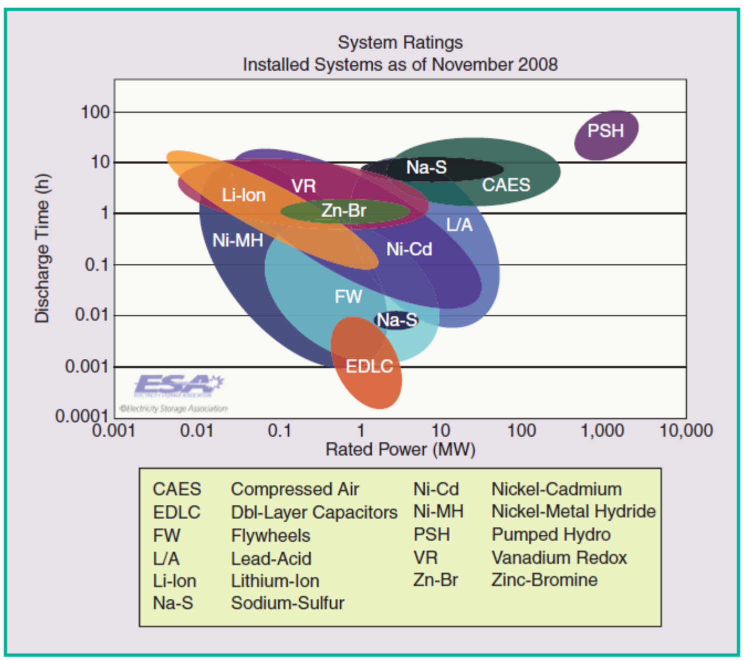
- Use of flow batteries and Li-ion batteries offers rapid response to assist in power management and voltage control at customer location
- Batteries can be modularized to accommodate growth of microgrid demand
- Ice production/storage from thermal energy operation can reduce electrical demand for air conditioning during daytime peak periods
- Energy storage coupled with microgrid operations allows for islanding during emergencies
    - Allows continued uninterruptible operations
    - Takes load from grid operations during high demand or emergency operations
- Customer use can be tailored with minimal grid impact
    - Local generation coupled with storage
- Rooftop PV coupled with battery storage
- CHP couples electric grid with natural gas and thermal storage
- Various methods of energy storage can be used in CHP operations
- EV impact in future uses unclear at this time
    - Modular installations
- Both generation and storage can be altered to meet changes
- Grid integration can be customized to meet changing customers/demands
    - Grid can benefit from DG
- Flexibility in storage location (i.e., at load vs. at bulk generation)

## 5.8.1 The Case for Energy Storage

Technically, energy storage for smart grid application can take many forms, but the choice depends upon the operational environment in which the energy storage is required (Figure 11). Energy can be stored thermally, electrically, mechanically or chemically (i.e., hydrogen) depending upon the source and the system demands. Up to now, electrical energy storage for utilities has been largely limited to mechanical storage approaches such as pumped hydro and compressed air (compressed air energy storage, CAES). Pumped hydro involves pumping water back into the reservoir when the electricity generation from water flowing through a dam or elsewhere is in excess of the demand. Compressed air involves compressing air and storing it, preferably below ground in geologic caverns, for use with natural gas-fired gas turbines operating without the penalty of a compressor because the air is delivered from the cavern at operating pressure (tens of atmospheres). Pumped hydro can be used on a large scale, ~100's of MWs, and is very efficient, but except for occasional above ground storage, both options are completely dependent upon the availability of geologic conditions that are not widely available or currently in use.

Flywheels are another form of mechanical energy storage, but because it has such limited capacity, its use is more for power quality maintenance than for quantity of energy. Energy stored in an electrical form includes all types of batteries and ultracapacitors. Battery storage has many alternatives and varies from high temperature sodium/sulfur to room temperature Li-ion, expensive flow batteries such as vanadium redox to cheap lead acid. While batteries can capture large quantities of energy to react at the electrodes, ultracapacitors retain relatively little capacity, but can discharge extremely rapidly. Thermal energy storage in either hot or cold medium offers the opportunity to provide a system with extended correspondingly hot or cold conditions that would normally require a source of electricity to maintain, thereby storing energy in a form that reduces the electrical demand rather than generating electricity. Chemical energy storage is principally found in the form of hydrogen which when used in a fuel cell, generates electricity (DC) directly. Use of NG in gas turbines or heat engines can be considered a form of chemical storage, since the energy is actually in the natural gas, but the generator that produces the electricity is mechanical. A comparison of some of these energy storage forms is shown in Figure 11 where the capacity (discharge time) and power (MW) relationship is indicated.

**Figure 11: Options for energy storage[53]**




As the source of electrical energy for the California Smart Grid 2020 becomes more dependent upon renewable sources (i.e., solar and wind), the uncertainty and intermittency inherent with these generation sources places a greater demand on storage. There seem to be four options for insuring a dependable continuation of electricity: (1) install more solar and wind generation over a wide range of sources that greatly exceeds the electrical demand at any time; (2) install large amounts of electrical storage to accommodate the interruptions in generation; (3) install large amounts of distributed generation that reduces the demand and accommodates supplemental storage; or (4) some combination of 2 and 3 in amounts commensurate with the

[53] See Energy Storage Association, http://www.electricitystorage.org/ESA/technologies/technology_comparisons/

demands of the renewable generation supply. The goal to reduce the peak demand by 5 percent, in addition to the 33 percent increase in regenerative electricity generation, while also requiring the electrical quality and availability to be continuously maintained, implies that some type of energy storage is necessary.

Assurance of a supply of electricity that meets demands and quality needs to be further dissected in order to determine what type of storage is required. Electrical energy storage may not be the only choice of energy that needs to be stored. The application should determine which method of storage is most appropriate. Whether to meet a high power demand (e.g. flywheel, ultracapacitor) or a high-energy demand (battery, hydrogen/fuel cell, turbine), the quantity of energy that needs to be stored and the energy type that is required in the application will be key considerations. Other major aspects of energy storage are a function of the physical size and the storage location. In the scenario where distributed energy becomes a major part of the Smart Grid 2020, distributed energy storage as part of distributed generation can become an integral part of the system. Furthermore, if the onsite energy demand includes both thermal and electrical energy, and can benefit from stored thermal or electrical energy, the range of storage possibilities increases. In these instances, integrating energy storage with a DG system that operates as a CHP operation, with natural gas or biogas, both the system efficiency and ability to assist California Smart Grid operation is magnified.

Thermal storage is a rather unique method of assisting the grid. First, it is only valuable when applied onsite, almost requiring it to be associated with a CHP operation. This distributed generation (DG) system, which in many instances operates to match a thermal load, permits the electricity product to either be exported or stored thermally by either generating ice and storing it for later use when either the electricity is in demand or the thermal capacity is reached and air conditioning is still required. Likewise, heating oil or some medium, for later use for space heating, for example, when the thermal/electrical loads are not synchronous, will permit the efficiency of the DG system not to be compromised and thereby maintain an operation that will contribute to reducing the peak electricity demand. As is the case with most of the storage scenarios, efficient energy storage reduces the GHG emissions if a hydrocarbon fuel or biogas is used in the electricity generation.

Another advanced approach to storing energy is the generation and storage of hydrogen during low electricity demands. MCFCs, for example, can be operated in a fashion whereby the onsite fuel, natural gas or biogas, can be converted to hydrogen and stored at pressure for subsequent use, when the electrical demand requires, by operating a proton exchange membrane-type fuel cell. This combination offers a means by which constant electrical and thermal energy can be supplied, but peaking electrical demand can be accommodated by use of the hydrogen. Thereby, three objectives of the California Smart Grid 2020 are addressed: additional CHP, reduced GHG emissions, and reduced electrical peak demand on the grid.

Through innovative use of any of the various choices of energy storage, together with either regenerative energy supplied by the grid and distributed storage, or more efficiently in a CHP operation coupled with energy storage, the possibility of meeting the California Smart Grid 2020 goals is significantly enhanced. However, in order to bring the options forward to be effectively recognized and economically possible, several steps are required. Many of the potentially valuable systems must be grid-demonstrated. Novel approaches with supportive, technically viable options need to be evaluated and provided with opportunities to illustrate their value to customers, particularly in commercial and industrial applications. Savings on transmission and distribution lines (T&D), in regards to both the installation of new facilities and in overburdening the current hardware, must be taken into account as the trade-offs are made in the demonstration evaluations.

As evaluations and demonstrations of new energy storage technologies and novel implementations of energy storage proceed, another valuable consideration will be the modularity associated with this implementation to the grid. With installation and evaluation of storage devices at local sites and at scales that will accommodate operational constraints, the value to the overall California Smart Grid 2020 design and operation will be recognized and the expansion can be on an as-needed basis, both in terms of cost and demand.

## 5.9 Net Zero Energy Construction

The potential annual GHG reduction contribution from new home construction can be estimated given 7000 kWh per capita consumption and 3.1 people per household, yielding total energy consumption of 3,689,000 MWh assuming a forecast of 170,000 new homes (single and multi-family units) will be added per year based on 1.2 percent population growth forecast. This corresponds to 2.38 million tons or 4.7 percent of the GHG emissions reduction goal. This compares to 50 MMT per year of $CO_2$ for energy efficiency and renewable energy (business as usual - BAU) and 174 MMT per year by 2020 for all sectors (BAU).[54]

California's official loading order places energy efficiency first, following by renewable energy and then reduction of carbon-based fuels. The RPS level today is roughly 13.9 percent with a 2020 target of 33 percent. The conclusion is that it will take a mix of energy efficiency and renewable energy to achieve the goal.

Financing and incentives are available for single transaction distributed generation (PV, wind, CHP). Prescriptive solutions, such as compact fluorescent lamps, refrigerator rebates and weatherization are available for energy efficiency. For multiple transactions, financing is not readily available with the collapse of Property Assessed Clean Energy (PACE) funding because of Fannie MAE and Freddie MAC. Federal ITC and IOU rebates are available, but applied and funded by measure, not entire residence. Regarding cost, solar PV is about $7 to $8 per installed watt for systems smaller than 10 kW. Energy efficiency systems are about $1.50 to $2.50 per installed watt, depending on the Energy Conservation Measure (ECM).

A typical 4 kW Solar Home should have about 1.7 calculated kW of Energy Efficiency (EE) measures installed whereby Distributed Generation accounts for 70-90 percent of demand and Energy Efficiency about 10-30 percent of demand. This is dependent on age, climate zone, existing code and construction materials.

The payback of Energy Efficiency with no incentives depends on avoided cost of energy, and is a function of ECM; two to fifteen years is the typical range. Investments sometimes blend ECMs with solar, for example, to reduce the overall payback period. The technologies are available today, but at a price; the barrier thus is not technology, but policy and financing.

For Home Automation Networks (HANs), policy and privacy are the principal barriers, again not technology. Automated Demand Response pricing signals today can cause a home to shed load, as shown by studies by the Energy Commission PIER Demand Response Research Center led by Lawrence Berkeley National Laboratory.[55] Some commercial products also are available. Small appliances are forthcoming; communications standards are evolving and by years 2014-2016 new Federal energy standards are expected.

Supporting needs for Net Zero Energy buildings include the Energy Control Measures, building codes and policy and regulation, as listed below.

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[54] Prepared by James Filanc, Southern Contracting Co.
[55] http://drrc.lbl.gov/

Key Energy Efficiency ECMs

- Weatherization (insulation and windows)
- Power Quality
- Programmable thermostats
    - Energy Efficient Appliances
    - HVAC upgrades to SEER 14, 15, 16 (seasonal energy efficiency ratio)
    - Duct Sealing
    - Lighting / Lighting Controls / Daylighting
    - Geothermal
    - Home Automation Networks (HANs)

Building Codes

1. Title 24 base case
2. Municipal codes exceeding Title 24 (e.g. Chula Vista now mandates 15 percent above Title 24)
3. Expand Energy Star / Benchmarking
4. Link to Real Estate transaction-driven Home Energy Rating II (HERS II) and mandate energy efficiency upgrades be made (once fair and equitable finance models are put in place)

State-level evaluation on cost-benefit

- Policy / Rate Tariffs evolution
    a. Feed-in-tariff
    b. Renewable Energy Credits and Carbon Trading
    c. Cap-and-trade
    d. TOU-pricing (beyond tiered pricing)
- Ease the market off of incentives and rebates, toward price-driven cost-benefit decisions
- Low-income solutions are a necessity

IOU R&D, PIER-funded R&D, and private sector financing are making advancements in emerging technology. In addition, data and communications are being developed for HANs (i.e. Zigbee, BACnet, Modbus, Z-Wave). Education campaigns are underway at the IOU and at the State level. Improvements also are needed in Measurement and Verification (M&V).

Furthermore, in addition to solving the PACE issue, emphasis should shift to performance-based incentives:

- New Construction – Accelerate Title 24 upgrades
- Retrofit – invent new whole home performance incentives with an emphasis on high persistence (M&V-based)

# CHAPTER 6:
# Developing the Integrated Smart Grid Roadmap

The overarching California Smart Grid 2020 Roadmap is an assimilation of the various key pathways and recommendations towards attaining an integrated view of the smart grid objectives over the next decadal period from the year 2010 baseline. The roadmap comprises regulatory and policy issues, technology evaluations, demonstrations and assessments, development of models and metrics, and aspects of financing and incentives to engender continued technology deployment but ultimately market-driven implementations approaching year 2020.

The diagram below (see pages 82-83) is a representation of the roadmap (Figure 12). The nine *IEPR* objectives are structured in a nested manner, all ultimately leading to the reduction of GHG emissions through clean energy supply and reduced electricity demand. Microgrids are highlighted as architectural options in both energy generation and consumption, to enable distributed generation and energy efficiency frameworks, respectively. The various pathway elements to meeting the objectives are overlaid on this structure and fall into three time frames – now to year 2014, years 2014 to 2016, and from 2016 to 2018 and beyond. The time frames are notional, subject to real-world constraints associated with regulatory and policy changes, funding availability for technology development and demonstration, and the natural evolution of key smart grid technologies, including their evaluation, development of models and retirement of risks through pilot demonstrations, as a sustainable market takes hold.

The California Smart Grid 2020 Roadmap that meets the state's policy goals is actually a set of integrated individual goal-oriented roadmaps, consisting of both relatively independent roadmaps for some of the state's policy goals, and highly interdependent roadmaps associated with other goals. An "independent" roadmap is defined as one whose implementation and accomplishment is relatively independent of implementation and accomplishment of other roadmaps.

An example of an independent roadmap is that associated with meeting the new rooftop PV goal of 3,000 MW by 2016 (~5,000 GWh/yr), implementation and accomplishment of which may be achieved more or less independently of the status of implementation and accomplishment of other goals – except, of course, in the sense that all the roadmaps are competing for limited resources. Contrast that with the roadmap associated with the renewable portfolio goal of 33 percent of generation by renewable (~104,000 GWh/yr) in 2020. The nature and contents of that roadmap heavily depend on the implementation and accomplishment status of the grid-tied rooftop PV roadmap, the roadmaps dealing with demand reduction and net zero energy construction, as well as biomass and CHP. This roadmap is highly "dependent," as is clearly the GHG roadmap.

Given the interrelated structure between the energy policy objectives, the roadmap was divided into two principal smart grid system domains: energy supply/generation and electricity demand/consumption. The nine energy policy goals (indicated by the numbered circles) are located on this roadmap so as to convey the interrelated and nested structure of those goals. Within each of these two domains, various technology solutions are recommended to meet corresponding goals in generation and reduced consumption. Microgrids, for example, are both power distribution systems on the generation side of the roadmap and also a means of enabling options for peak reduction and efficiency. As such, microgrids at various scales of operation reside in both the supply and demand side of the roadmap. Similarly, storage is a source of offsetting power generation for reducing demand on the bulk grid during peak conditions and also a means of mitigating the impacts of intermittent renewables and potentially disruptive PHEV/PEV loads on bulk grid power quality through storage approaches for frequency regulation due to variable demand. As such, storage (also appropriately sized at various scales) sits in both the supply and demand sides of the roadmap depending on the primary function for which it is intended.

*Clean transportation and reducing GHG emissions from electricity production create the need to examine production, efficiency and energy consumption differently than has been done in past operations.* Recognizing the urgency of this need is one of the key outcomes of this study. This is a result of the approach undertaken, namely to view the smart grid as a complex system where the various functional requirements on a California Smart Grid 2020 are intricately interrelated. Technology options are explored in a manner that attains the greatest level of energy policy objectives in the aggregate. This consideration also incorporates California's loading order–energy efficiency, demand response, renewables and distributed generation–into the roadmap strategy.

The lack of roadmap elements beyond 2018 reflect the study team's position that if the energy policy objectives are to be met in the 2020 time frame, market-driven implementations must be well underway by that point in all aspects of smart grid technology. In other words, actions by California beyond then will have little effect on attaining the 2020 goals on schedule.

**Figure 12: The California Smart Grid 2020 Roadmap Development Framework**

The California Smart Gris 2020 Roadmap Development Framework is shown with a top panel (see page 82) and a bottom panel (see page 83) for illustration in this Report. The Roadmap spans the years 2010 to 2020. Along the middle of the diagram the electric grid and the natural gas grid are shown to represent these two large infrastructures for transmission and distribution. The policy goal of reducing GHG emissions to 1990 levels across all sources in 2020 is met by implementation of roadmap elements in both smart grid system domains: energy supply/generation and electricity demand/consumption. See Section 6.2 for the listing of integrated roadmap elements, which are listed here per roadmap panel (top and bottom) according to domain and time frame.

The energy policy goals are numbered as follows and indicated on the roadmap.

1. 33 percent of generation by renewables (~104,000 GWh/yr) in 2020
2. 20 percent of renewable power supplied by biopower sources in 2020 (~20,000 GWh/year)
3. 3,000 MW of new rooftop solar PV by 2016 (~5000 GWh/yr)
4. 10 percent reduction in total forecasted electrical energy consumption in 2016
5. Additional 5,400 MW of combined heat and power (CHP) in 2020
6. Demand response that reduces 5 percent of peak demand in 2020
7. Electricity peak demand reduction goal of 4,885 MW in 2013
8. All new residential construction is net zero energy in 2020
9. Reduce GHG emissions to 1990 levels across all sources in 2020

Top panel: <u>Energy supply/generation domain from years 2010 to 2012</u>. Energy policy: Goal 1 (33 percent of generation by renewables); Goal 2 (20 percent of renewable power supplied by biopower sources); Goal 3 (3,000 MW of new rooftop solar PV by 2016); Goal 5 (5,400 MW of additional CHP by 2020). Small hydro, geothermal, wind and solar, and biomass are shown as sources of renewable power. Rooftop PV is indicated at local distributed solar. Within biomass, various sources are indicated ranging from solid municipal waste to agricultural waste, forest byproducts and wastewater treatment. Within CHP, different scale systems are listed ranging from microturbines to steam turbines. Fuel cells in the 1-5 MW range are shown. Microgrids are introduced at commercial scale, with storage.

- Evaluate utility-owned and operated and other ownership/operational approaches; ensure that technology, standards and support services development converge
- Evaluate efficiency improvements from equipment upgrades and technology

Energy supply/generation domain from years 2012 to 2016. Introduction of microgrids at industrial and residential scales, including storage options at corresponding scale.

- Study local voltage stability concerns due to PV variability, addressing technical solutions and obsolescent interconnection standards
- Evaluate feasibility of extending and modifying CSI Program
- Evaluate raising CA Rule 21 penetration cap for PV interconnection
- Develop requirements for standardizing utility interconnection statewide
- Evaluate Li-ion batteries at various sizes and locations for operation and lifecycle cost
- Develop economic models for both utility and privately owned microgrids
- Develop open standards for distributed generation and performance certification for both existing and suppliers from adjacent markets
- Demonstrate/evaluate fuel cells with hydrogen generation for peaking & transportation
- ISO 14000 compliance for storage and related smart grid systems
- Develop ratepayer education programs regarding benefits of renewables, irrespective of ownership model
- Demonstrate renewables in non-traditional application (e.g. DG, DMZs, microgrids, etc.) and incentivize investments thereof
- Develop improved private/public sector communication to lead to unified federal, state and local renewables regulation.
- Evaluate flow battery advantages and potential (e.g. system operations vs. cost)
- Evaluate small community microgrid operations throughout various operations in California
- Evaluate combined PV and micro-turbine installations for system value and controls
- Evaluate combined utility/commercial microgrid systems for utility-distributed energy storage and capacity
- Demonstrate community-owned microgrids to improve customer awareness
- Study/evaluate value of electricity generation vs. site cleanup and putting methane into NG pipeline
- Demonstrate electricity generation (e.g., turbines, fuel cells) from landfill waste
- Demonstrate fuel cells in wastewater treatment anaerobic digesters for biogas utilization and CHP
- Assess applicability of ethanol production-biomass conversion to electricity
- Assess economics for expanding food processing waste for electricity production
- Assess alternative biomass-to-electricity conversion approaches, including integration with natural gas

- Evaluate thermal energy storage options with turbine and fuel cell installations for unifying thermal and electrical load profiles
- Evaluate the degree of integration of thermal and electrical loads with operational control complexity and GHG advantages
- Determine regulatory barriers and cost disadvantages to integrating biomass with NG for continuous operation

Energy supply/generation domain from years 2016 to 2020. Recognizes that by 2018 market-driven implementations must be underway in order to meet the 2020 goals.

- Evaluate biomass treatment systems for thermal/temperature requirements to match with electrical generation options (electrical heat/thermal cooling)
- Evaluate advantages of overlapping electrical and thermal demands with onsite generation technology (turbine, piston engine, fuel cell)
- Re-evaluate the benefits of turbines/piston engines/fuel cells with respect to electrical efficiency, thermal/temperature availability, GHG emissions and cost projections using NG as the standard.

Bottom panel: Electricity demand/consumption domain from years 2010 to 2012. Integrated Energy Policy: Goal 4 (10 percent reduction in total forecasted electrical energy consumption by 2016); Goal 6 (demand response that reduces 5 percent of peak demand in 2020); and Goal 7 (Peak demand reduction of 4,885 MW in 2013). Peak reduction and DR are nested within consumption reduction, along with grid efficiency in both power production and distribution. Microgrids at all scales (utility, commercial, industrial and residential) are introduced for efficiency gains in production. Demand Management Zones (DMZs) are introduced for efficiency gains in distribution, with attendant communications and control technologies. Accommodation of PHEV/PEVs is indicated in the consumption domain of the smart grid system as a means of offering options for consumption reduction and efficiency gains through the potential of aggregated or fleet storage (further study is required).

- Assess impediments to storage caused by current regulations; reform regulation so as not to preclude effective use of storage

Electricity demand/consumption domain from years 2012 to 2016. Introduction of microgrid integration, and Goal 8 (all new residential construction is net zero energy in 2020).

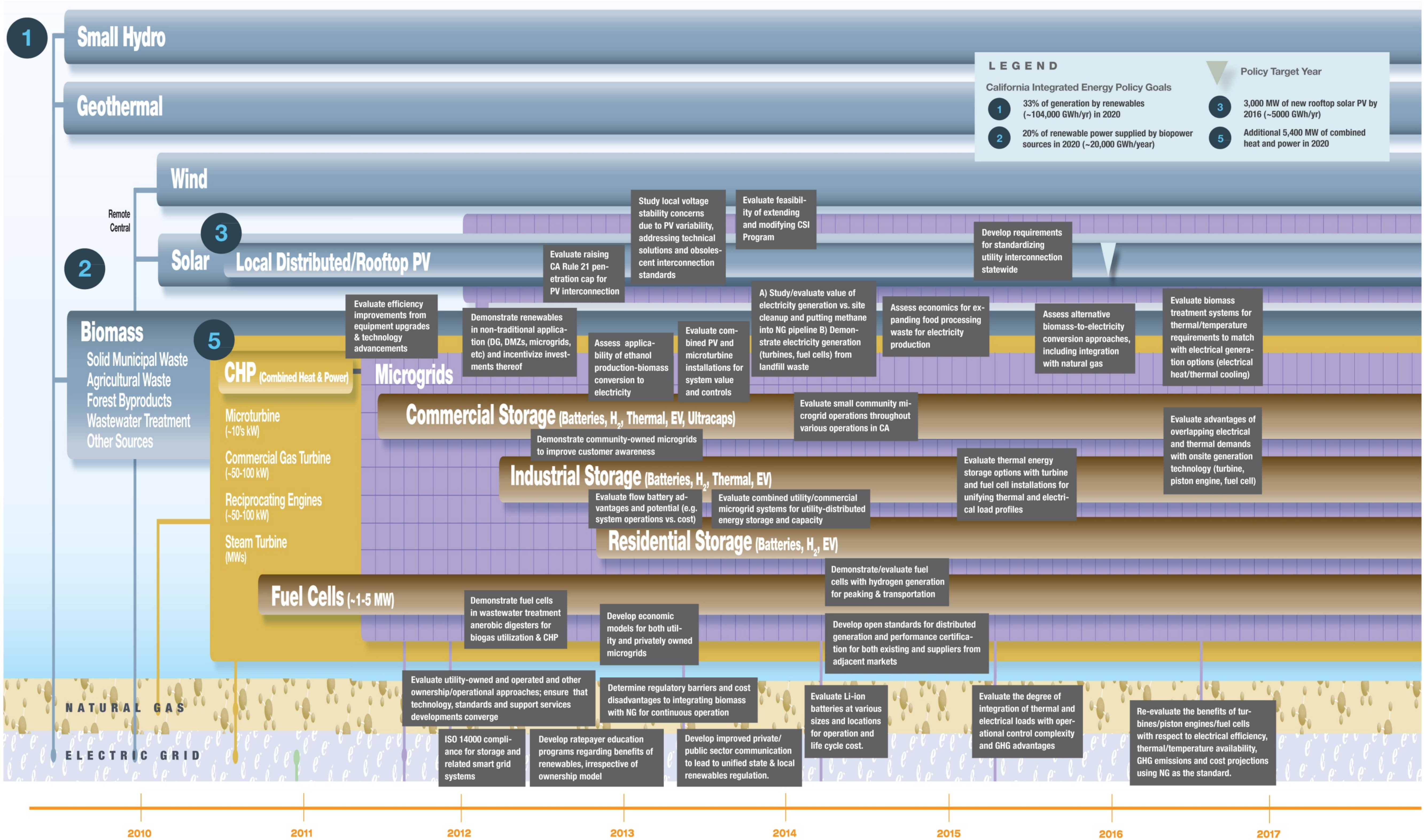
- Develop improved solar irradiance forecasting capability to reduce spinning reserve
- Incentive programs for "whole-house" financing of energy efficiency improvements
- Address policy and financing solutions to excessively long payback of ECMs
- Monitor progress of federal smart appliance standards
- Develop efficiency measurement, verification models and methods
- Evaluate community-specific net impact of PHEV/PEV penetration on GHG emissions
- Develop lessons learned and best practices from assessment of DMZs and microgrid deployments throughout California

- Develop and test fast storage systems for transportation and stationary applications
- Develop Distributed Automation control and protection products; and explore synergies with AMI
- Increase development emphasis on standards-based cyber security technologies and system planning tools
- Monitor federal development of distribution automation standards
- Develop roadmap for PHEV/PEV infrastructure, standards and incentives (including charging infrastructure, storage technology), based on net impact analysis
- Develop economic models for both utility and privately owned microgrids
- Develop utility/industry/early adopter metrics and models for standardizing microgrid and DMZ interconnection requirements
- Assess allocation of spectrum for demand management devices and accommodation of PHEV/PEVs
- Develop open communication standards for AMI, HAN and distribution automation devices
- Demonstrate/evaluate ultracapacitors and flywheels for distributed grid energy storage
- Demonstrate/evaluate thermal (ice) energy storage for air conditioning load offset
- Demonstrate storage options with natural gas fuel cell generators
- Demonstrate storage/thermal/electric tradeoffs with different generation methods
- Develop guidelines and technologies for "future proofing" energy storage systems
- Incentivize creation of DMZs and microgrids (e.g. remove economic, financial and regulatory barriers)
- Evaluate moderate commercial operations at hotels and hospitals for islanding and peak shaving cost-benefit

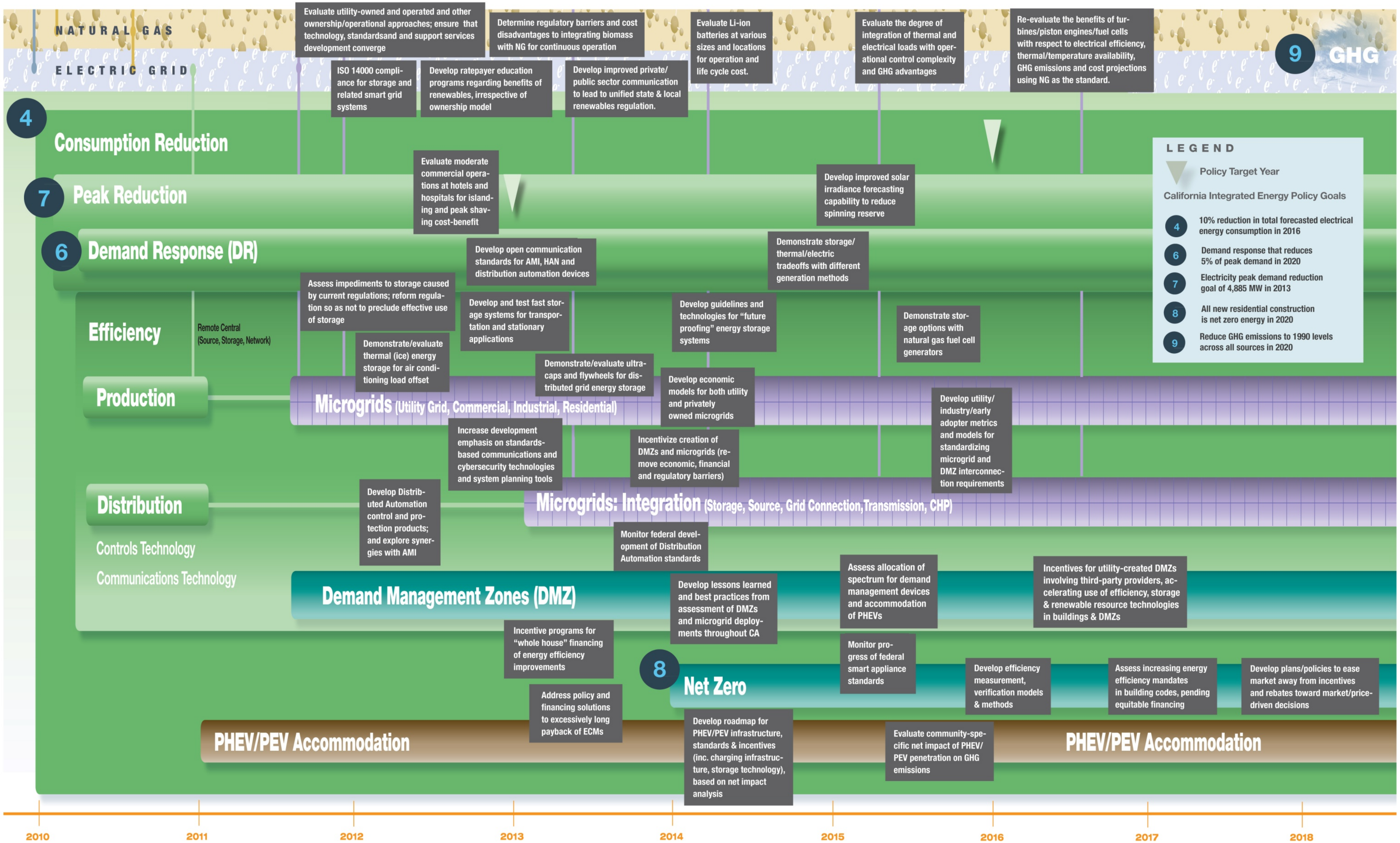
<u>Electricity demand/consumption domain from years 2016 to 2020</u>. Recognizes that by 2018 market-driven implementations must be underway in order to meet the 2020 goals.

- Assess increasing energy efficiency mandates in building codes, pending equitable financing
- Develop plans/policies to ease market away from incentives and rebates toward market/price-driven decisions
- Incentives for utility-created DMZs involving third-party providers, accelerating use of efficiency, storage & renewable resource technologies in buildings and DMZs

# Smart Grid Roadmap Development Framework | Energy Supply/Generation



# Smart Grid Roadmap Development Framework | Electricity Demand/Consumption



In an effort to reduce the complexity of develc
the independent roadmaps was developed sej
reducing (i.e. risk mitigating) actions elicited f
sources such as the TIMA actions data and the
the relationships among the goal roadmaps ar
elements of the independent roadmaps were l
and gaps identified and filled based on assum
architecture. Hence, the final integrated road
dependent roadmaps built around a specific a
assumptions.[56]

**Figure 13: Relationships among the goal**

Goal Roadmaps and Suppor

notes: 1- X* means that while PHEV Accomodation will have
positive impact...
2- X Indicates a greater impact than x

| GOAL ROADMAP | Rooftop PV | Storage | Demand Aggregation | Biomass, Biogas and Fuel Cells | Micro- Accom -ation |
|---|---|---|---|---|---|
| 33% renewables 2020 | X | X | X | X | X |
| 20 % of renewables as biopower 2020 | | | | X | X |
| 3,000 MW rooftop PV 2016 | X | X | | | X |
| 10% reduction in consumption 2016 | | X | X | | X |
| 5,400 MW of CHP 2020 | | | | X | X |
| Demand response reduces TBD % of peak demand 2020 | | X | X | | X |
| peak demand reduction of 4,885MW 2013 | | X | X | | X |
| All new residential construction is net zero energy 2020 | X | X | | X | X |
| GHG emissions to 1990 levels 2020 | X | X | X | X | X |

[56] This approach might be extended into a roadmap moc
for a given set of architecture assumptions, and/or 2) th

## 6.1 Individual Goal Roadmaps

### 6.1.1 Rooftop PV

- Incentive programs such as CSI need to be both extended and modified to accelerate PV system approval and deployment
- Currently, distributed PV interconnections are governed by a series of screens, incorporated into California Rule 21. This allows "fast track" interconnections that do not require an expensive and time consuming study process. Currently, there is a penetration threshold of 15 percent of a feeder line section, above which an interconnection study is mandated. *Technical justification exists for raising this threshold for PV, which would enable higher local penetration on particular feeders and thereby help to reach the 2016 goal.*
- Standardized models and metrics for modeling the impact of multiple variable, distributed generators within a specific distribution circuit, including an accurate representation of geographical diversity on short time frames.

### 6.1.2 Net Zero Energy Residential Construction

- Investing in energy efficiency on 130,000 homes in the 2010-2012 funding cycle with ARRA SEP money[57]
- New Homes by 2020 – SMART HOMES[58]
- Built space by 2020 – ECM retrofits, HERS II transaction standards, incentivized energy efficiency investment upon sale (higher price tag for better HERS II ratings). Solar PV on percentage of built space.[59]
- TOU pricing that factors in the real cost of energy, including carbon, national security, avoided cost and transmission.
- Let price, not incentives, drive the market by protect the low-income sector.

### 6.1.3 Biomass and CHP

- Integrate electricity production units (turbines, fuel cells) with landfill operations to generate distributed electricity from low heating value fuel to benefit from GHG emitted from landfills (may have to undertake a study to show value of electricity versus cleanup and putting methane into NG pipeline)
- Install fuel cells in more wastewater treatment anaerobic digesters for biogas utilization and CHP operations and incorporate methods (electrical or thermal storage, etc.) by which continuous operation can be maintained.
- Investigate applicability to ethanol production-biomass to fuel plants where solid waste conversion to electricity is employed.
- Explore economics for expanding food processing waste with other anaerobic digestion for electricity production.

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[57] In 2020, will need to build an estimated 170,000 homes from scratch. In the meantime will need to retrofit 12.4 million homes with AMI, ECMs, Solar PV, HANs, et c. That's about 100,000 homes a month. If spent just $3,000 on energy efficiency only per home, looking at $37 billion over 10 years – $3.7 billion per year, or an estimated $300 million per month industry.

[58] SMART HOMES are microgrids run by ECMs that talk to AMI and Smart Appliances, reacting to sensors, price signals and comfort settings to regulate energy.

[59] Significant issues lie ahead for multi-family dwellings regarding both energy efficiency and renewable energy, and for older homes with less than 10 years useful life. Assume AMI everywhere, Smart Appliances; ECM adoption – the home network of the future.

- Determine systems advantages for different conversion approaches of biomass to electricity, i.e., turbines/fuel cells, integration with NG for CHP and continuous operations, gasification/processing options for solid waste material conversion, landfill/biogas cleanup processes that will offer novel operating conditions, such as shut down/start up for reduced loads.
- Investigate potential improvements in efficiencies associated with upgrading existing equipment in mature systems to accept new technology advancements
- Demos at various sizes and locations (with controls) to illustrate system options with grid connect.
- Explore and demonstrate new opportunities to incorporate CHP with processes that could benefit from a range of smaller units in the system operations.
- Develop alternative cost effective biogas cleanup processes for incorporation with fuel cells and clean-burning engines.
- Review changes necessary in legislation and policies that prevent novel technologies from being incorporated in either current or new biomass use systems.
- Update system advantages and tradeoffs in terms of electricity generation and use with thermal load requirements to balance thermal/electricity generation.
- Review technical and policy problems associated with dairy farms use of biogas conversion to electricity for distributed generation inclusion and energy storage with grid connections.
- Review policies and regulations (reporting requirements, etc.) that favor flaring versus CHP operations.

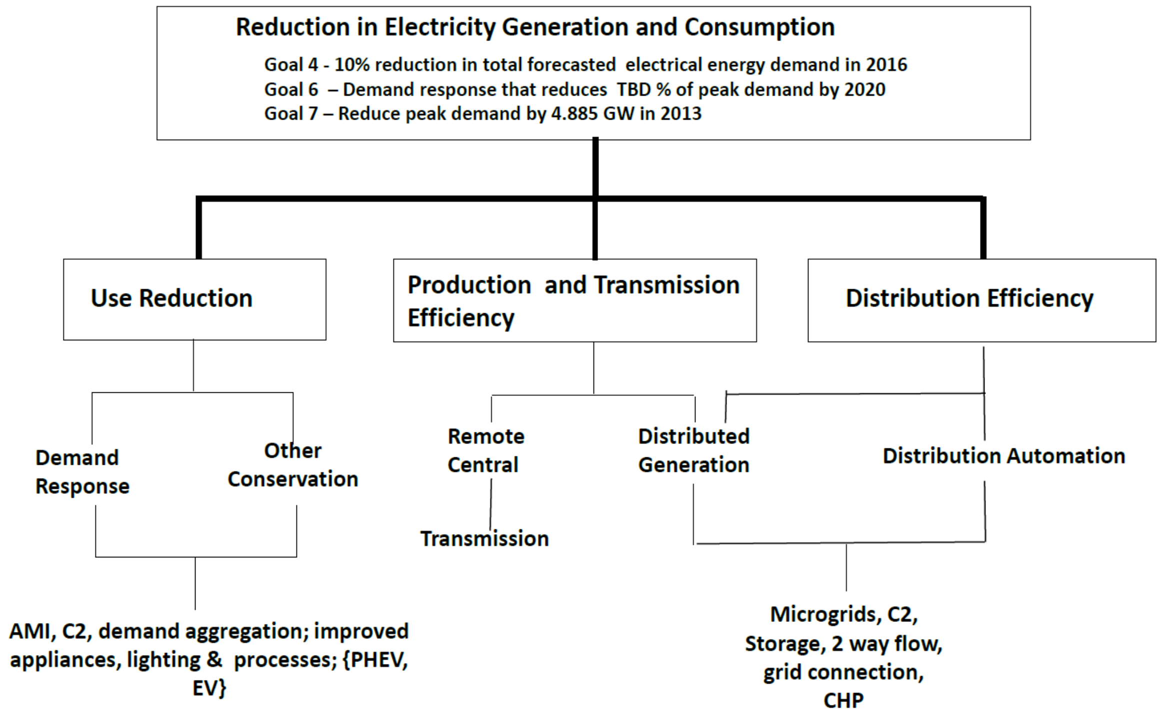
### 6.1.4 Reduced Generation and Consumption

This combination of *IEPR* goals for reduction in forecasted demand, demand response and peak demand reduction is independent of the other goal roadmaps, and is constructed from the Demand Aggregation, Distribution Automation, AMI, Communications and Control, PHEV/PEV accommodation, microgrid accommodation and storage key technology road maps (see Figure 14). Note that implementing the EV accommodation roadmap will tend to ***increase*** generation and consumption, rather than decrease it.

### 6.1.5 Demand Aggregation

- California energy regulations that accommodate the Demand Aggregation scenario, allowing the DMZ provider to participate in the bulk power market. At the same time, regulation that supports some sort of feed-in for the DMZ to return any excess power (nights/weekends) to the utility grid.
- To insure power quality across grid, some regulation to limit the transition behaviors as the DMZ goes from a net provider to a net user of electricity.
- Provisions in regulations for BOCC or similar DMZ control facilities to provide valuable management and communications and control information (i.e. SCADA or similar) to any adjacent grid operators.
- Distributed Generation/Distributed Energy Resources (DG/DER) within the DMZ tracked in order to establish accountability towards key policy objectives such as rooftop solar and other renewable mandates.
- Incentives for: a) commercial building operators and DMZ providers to incorporate proven energy efficiency technologies in their operations; b) utilities to create DMZs with third-party providers. (Possibly as a contributor to the overall peak demand reduction.)
- Continue to incentivize the installation of renewable and storage technologies**.**

**Figure 14: Key technologies for Demand Aggregation, Distribution Automation, AMI, Communications and Control, EV Accommodation, Microgrid Accommodation and storage that address reduced energy consumption, reduced peak demand and demand response *IEPR* goals.**




## 6.1.6 AMI and Control & Communications, and Distribution Automation

- Development and implementation of:
  - Distributed control algorithms and architectures
  - Systems planning tools
  - AMI standards
  - Cyber security standards and tools
  - Interoperable software standards
  - Future-proof communications solutions
  - Communication-enabled Distributed Generation
  - Plug-and-play Demand Management devices and systems
  - Spectrum for critical control and protection
  - Communication capabilities for PHEV/PEV systems
- Regulations that clarify and/or promote:
  - PHEV/PEVs
  - Appropriate spectrum allocation
  - Performance certification that enables new suppliers from adjacent markets
  - Distributed generation interconnection policy

## 6.1.7 Microgrid Accommodation

- Operations and maintenance infrastructure that supports microgrids. This is an essential component that determines safety, reliability and price; more small system (<10 MW) ventures have failed on this point than any other factor.

## 6.2 Integrated Roadmap Elements

Below is the comprehensive list of integrated roadmap elements that are overlaid on the California Smart Grid 2020 development framework (see Figure 12, pages 82-83). These are comprised of recommended evaluations and assessments, demonstrations and deployments.

1. Evaluate utility-owned and operated and other ownership/operational approaches; ensure that technology, standards and support services development converge
2. Study local voltage stability concerns due to PV variability, addressing technical solutions and obsolescent interconnection standards
3. Develop improved solar irradiance forecasting capability to reduce spinning reserve
4. Evaluate feasibility of extending and modifying CSI Program
5. Evaluate raising CA Rule 21 penetration cap for PV interconnection
6. Develop requirements for standardizing utility interconnection statewide
7. Evaluate Li-ion batteries at various sizes and locations for operation and life cycle cost.
8. Incentive programs for "whole house" financing of energy efficiency improvements
9. Address policy and financing solutions to excessively long payback of ECMs
10. Monitor progress of federal smart appliance standards
11. Develop efficiency measurement, verification models and methods
12. Assess the impact of increasing energy efficiency mandates in building codes, pending equitable financing
13. Develop plans/policies to ease market away from incentives and rebates toward market/price-driven decisions
14. Evaluate community-specific net impact of PHEV/PEV penetration on GHG emissions
15. Develop lessons learned and best practices from assessment of DMZs and microgrid deployments throughout California
16. Develop and test fast storage systems for transportation and stationary applications
17. Develop Distributed Automation (DA) control and protection products; and explore synergies with AMI
18. Increase development emphasis on standards-based cyber security technologies and system planning tools
19. Monitor federal development of distribution automation standards
20. Develop roadmap for PHEV/PEV infrastructure, standards & incentives (inc. charging infrastructure, storage technology), based on net impact analysis
21. Develop economic models for both utility and privately owned microgrids
22. Develop utility/industry/early adopter metrics and models for standardizing microgrid and DMZ interconnection requirements
23. Assess allocation of spectrum for demand management devices and accommodation of PHEV/PEVs
24. Incentives for utility-created DMZs involving third-party providers, accelerating use of efficiency, storage & renewable resource technologies in buildings and DMZs
25. Develop open communication standards for AMI, HAN and DA devices

26. Develop open standards for distributed generation and performance certification for both existing and suppliers from adjacent markets
27. Demonstrate/evaluate fuel cells with hydrogen generation for peaking & transportation
28. Demonstrate/evaluate ultracapacitors and flywheels for distributed grid energy storage
29. Demonstrate/evaluate thermal (ice) energy storage for air conditioning load offset
30. Demonstrate storage options with natural gas fuel cell generators
31. Demonstrate storage/thermal/electric tradeoffs with different generation methods
32. Develop guidelines and technologies for "future proofing" energy storage systems
33. ISO 14000 compliance for storage and related smart grid systems
34. Assess impediments to storage caused by current regulations; reform regulation so as not to preclude effective use of storage
35. Develop ratepayer education programs regarding benefits of renewables, irrespective of ownership model
36. Demonstrate renewables in non-traditional application (e.g. DG, DMZs, microgrids, etc) and incentivize investments thereof
37. Develop improved private/public sector communication to lead to unified federal, state & local renewables regulation.
38. Incentivize creation of DMZs and microgrids (e.g. remove economic, financial and regulatory barriers)
39. Evaluate flow battery advantages and potential (e.g. system operations vs. cost)
40. Evaluate small community microgrid operations throughout various operations in CA
41. Evaluate combined PV and micro-turbine installations for system value and controls
42. Evaluate moderate commercial operations at hotels and hospitals for islanding and peak shaving cost-benefit
43. Evaluate combined utility/commercial microgrid systems for utility-distributed energy storage and capacity
44. Demonstrate community-owned microgrids to improve customer awareness
45. A) Study/evaluate value of electricity generation vs. site cleanup and putting methane into NG pipeline
    B) Demonstrate electricity generation (turbines, fuel cells) from landfill waste
46. Demonstrate fuel cells in wastewater treatment anaerobic digesters for biogas utilization and CHP
47. Assess applicability of ethanol production-biomass conversion to electricity
48. Assess economics for expanding food processing waste for electricity production
49. Assess alternative biomass-to-electricity conversion approaches, including integration with NG
50. Evaluate efficiency improvements from equipment upgrades & technology advancements
51. Evaluate thermal energy storage options with turbine and fuel cell installations for unifying thermal and electrical load profiles

52. Evaluate biomass treatment systems for thermal/temperature requirements to match with electrical generation options (electrical heat/thermal cooling)
53. Evaluate advantages of overlapping electrical and thermal demands with onsite generation technology (turbine, piston engine, fuel cell)
54. Evaluate the degree of integration of thermal and electrical loads with operational control complexity and GHG advantages
55. Determine regulatory barriers and cost disadvantages to integrating biomass with NG for continuous operation
56. Re-evaluate the benefits of turbines/piston engines/fuel cells with respect to electrical efficiency, thermal/temperature availability, GHG emissions and cost projections using NG as the standard.

## 6.3 General Findings and Recommendations

The findings and recommendations that support the technology manufacturer and vendor perspective for the integrated California Smart Grid 2020 Roadmap comprise regulatory and policy issues, research, development and demonstrations (RD&D), technology evaluations and assessments, development of models and metrics, and financing and incentives to engender continued technology deployment leading to market-driven smart grid implementations approaching year 2020.

- Economic, financial, regulatory, and social barriers are equally as important as technical barriers to attaining energy policy objectives through development of the California Smart Grid 2020.
- Understanding and planning for the effect of reaching grid parity for each of the considered and future technologies should be taken into account, as reaching grid parity for a given technology in a given region will have a significant impact on the technology adoption rate, a key factor in achieving GHG reduction goals.
- California's official loading order, which compels the State's utilities to meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible," should be fully integrated into the Smart Grid 2020 Roadmap.
- American Recovery and Reinvestment Act of 2009 (ARRA) funding is good but insufficient to overcome the lack of capital needed for large-scale deployments.
- Smart grid system models for use by all stakeholders are needed to help allay uncertainties, although some support service suppliers are beginning to address portions of this need.
- The value of modularization and modernization as the California Smart Grid 2020 evolves should be considered for planning, development, and implementation to prevent myopic changes that do not take advantage of lessons learned from prior smart grid pilots and deployments.
- Understanding the benefits and disruptive effects of accommodating plug-in hybrid electric vehicles and plug-in electric vehicles in the smart grid, including their relationship to reducing GHG emissions, will require a significant degree of joint learning by ratepayers, utilities, regulators, industry, and policy makers.
- Distributed generation (DG), in combination with feasible distributed storage, offers many opportunities to achieve the greatest effectiveness and operational and economic benefits for California as a whole.
- Expanding uses of biomass as a source for heat and/or power offers significant potential for reducing GHG emissions and adding distributed generation capacity.

- While microgrids offer much potential benefit, electric power distribution grids, as well as utility business practices, are not set up to accommodate, or evolve into, an integrated system of microgrids.
- To support the deployment of renewable resources, energy efficiency building retrofits, and net zero energy construction, and to reap their environmental benefits, DG interconnection policies need to favor the consumer and owner of DG resources so that interconnection/disconnection costs are not major impediments while providing distribution networks with adequate protection and control.
- The public needs to be educated on the individual and societal benefits (for example, economic, national security, and environmental) of the smart grid and its key elements, to foster participation in Advanced Metering Infrastructure (AMI), demand response and other smart grid-related programs for reducing energy consumption and peak demand.
- Incentives:
    - Consumer incentives are needed for participation in performance-based demand management programs. Special consideration needs to be given for developing programs for low-income housing.
    - Incentives such as tax credits to investor-owned utilities, regional municipal utilities, or other entities are needed to encourage deployment of technologies that adhere to open standards for communication systems that enhance the situational awareness and control of distribution networks.
    - Utility incentives are needed to accelerate PHEV/PEV and microgrid accommodation and to provide supporting communications technologies for their active participation if their potential for GHG reduction is to be realized.
- Demonstrations are needed of typical and maximum achievable gains (for example, in such areas as efficiency-based demand reduction, net zero energy operations, and GHG emissions reduction) associated with permutations of communications-enabled services such as energy efficiency and demand management, renewables integration, and active PHEV/PEV engagement.
- There are tradeoffs between the cost-effectiveness of modifying existing infrastructure and aged equipment versus changes that will provide longer-term advances and accommodation of new technology with flexibility and modularity to enable California Smart Grid evolution to 2020 and beyond.
- The full benefit of new technologies (for example, fuel cells, microgrids, and so forth) will be realized only through a stepwise progression of appropriately sized demonstrations, pilot programs, and rollouts that will help reduce costs and set the stage for market-driven implementations in the latter half of the decade.

## 6.4 Findings and Recommendations Specific to Key Smart Grid Technologies

### *Energy Storage*

- Most smart grid system architectures require electrical energy storage. Battery technology development and deployment in the transportation sector could contribute to changes in electrical grid use in several ways, such as supporting different electric vehicle charging options and enabling approaches for demand response and reducing peak demand while stabilizing grid performance.
- Energy storage is needed for a variety of smart grid applications—such as peak shaving, reactive power (VAR) support, renewable energy integration, and accommodation of PHEV/PEVs, frequency regulation, and islanding. However, more development is needed

before most energy storage technologies can become economically feasible in many of these applications and achieve beneficial paybacks.

- Inclusion of storage distributed throughout the grid in connection with distributed renewable generation and microgrid installations should be balanced with new transmission installation and centralized storage for large-scale renewables.
- Storage is the most frequently mentioned technological barrier to the smart grid due to its perceived lack of technology maturity and readiness for market.
- The California policy objective most impacted by storage technology barriers is meeting the 33 percent Renewables Portfolio Standards (RPS) target of ~104,000 GWh/yr in 2020.
- The smart grid attribute most affected by storage technology barriers is the ability to operate the grid resiliently to disturbances.
- Ultracapacitors and flywheels for distributed grid energy storage and thermal (ice) energy storage for air conditioning offset deserve further attention.
- There is a need to test and demonstrate a variety of storage options and alternatives, such as thermal/electric storage tradeoffs for appropriate generation methods (using proven systems that have well-established sales and natural gas-powered fuel cells as an alternative to storage service infrastructures).
- There is a need to consider requiring International Organization for Standardization (ISO) 14,000 (environmental life cycle) compliance for storage and related smart grid systems, since it is deemed an effective action in reducing storage technology barriers.
- Avoiding technological obsolescence through development of guidelines and best practices for future-proofing storage technologies could prove to be effective for reducing storage technology barriers.
- From an economic standpoint, energy storage is challenging. Using novel generation technologies such as fuel cells only makes it more challenging.
- Residential storage is unreliable, immature, and too costly, and is incompatible with current regulations.

<u>Recommendation</u>: California should undertake a carefully planned campaign to address the need for language updates in tariffs and standards to ensure proper valuation of storage in a range of smart grid applications.

<u>Recommendation</u>: Incorporation of energy storage in microgrid operations offers several opportunities for efficiency, power quality management, and peak demand reduction and should be considered for targeted demonstration projects.

<u>Recommendation</u>: California should increase development and test emphasis on fast storage systems, for mobile and stationary applications; emphasize best approaches to "future-proof" energy storage systems (for instance, to avoid technological obsolescence).

### *Rooftop Photovoltaics*

- The growth rate of distribution-connected PV deployments under the California Solar Initiative (CSI) needs to accelerate significantly to achieve the stated 2016 goal of 3,000 MW of new rooftop solar PV. Without addressing the recent collapse of CSI incentives for commercial and municipal customers in the Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E) service territories, this growth rate may be severely hampered.
- Integration of rooftop PV with microgrids and distributed storage should be expanded as a dual opportunity in distributed generation and peak reduction programs.

- Grid parity may be achieved through a combination of technology and installation cost reductions combined with implementation of new user rate tariff models such as expanded use of time-of-use (TOU) pricing for residential customers and commercial customers.
- Barriers to accelerating growth of rooftop PV installations are primarily nontechnical at this time.
- Current efforts should focus on bolstering incentives and simplifying and streamlining the process and requirements for participating in incentive programs.
- Concerns about the costs of reserves or storage needed to accommodate high-penetration variable generation are often overstated.
- Existing discussions and standards efforts concerning smart grid and electrical interconnection requirements (for example, with regard to local voltage stability due to PV variability) for high-penetration integration of variable generators at the distribution level are critical for continued long-term growth, but should not be considered technical barriers to achieving this goal.
- There is a need to continue to pursue "utility owned and operated," as well as other ownership and operational approaches, and ensure that technology, standards, and support services development do not cause divergence or competition among different approaches.

<u>Recommendation</u>: Incentive programs such as CSI need to be extended, fixed, and modified to accelerate PV system approval and deployment.

<u>Recommendation</u>: The CA Rule 21 interconnection ceiling for distributed PV should be raised, and a utility/industry program is needed to develop metrics and models for standardizing utility interconnection requirements statewide.

<u>Recommendation</u>: The state should support the development of standardized models and metrics for modeling the impact of multiple variable, distributed generators within a specific distribution circuit, including an accurate representation of geographical diversity and short time frames.

<u>Longer-term recommendations</u>:

- Private industry needs easier-to-obtain-and-administer state (and federal) funding for continuing R&D on networks with high penetration of variable generation such as rooftop PV.
- Forecasting systems need to be developed, refined, and integrated with transmission and distribution operational systems and procedures.
- Monitoring and control tools for both large individual PV systems and groups of distributed PV systems treated as logical units need to be developed in a manner that can be integrated into existing distribution automation and grid operation and forecasting tools.
- California should stimulate continued cost reduction of PV systems and components, and continue to evolve financing, maintenance, and customer service options and models.
- Net metering caps may need to be raised, as PV penetration grows in the medium-to-long term.
- Expanding the definition of net metering may need to be considered in order to address the needs of multitenant dwellings and multi-building owners for rooftop PV systems.
- Forecasting the point in time at which grid parity is reached in California will be essential to integrate accelerated implementation with statewide (and regional) workforce development plans, development of new financing models, and consumer awareness campaigns.

*Microgrids*

- Microgrids, complete with energy storage elements, offer many potentially significant benefits to meeting the California Smart Grid 2020 goals. Education of customers as to their advantages, and careful study to identify their best locations, are necessary first steps.
- Utility grid operators must be integral to microgrid plans and implementation, but the owner/operator of the microgrid could and should vary depending upon the circumstances. Business and operational models need to be explored and built, using experience and past demonstration projects as much as possible, but also new microgrid integration demonstration projects and evaluations from technical to business factors.
- Advantages in modularity and the long-term value offered by microgrid operations will emerge more rapidly as the slow, ponderous process (for example, environmental impact, funding, construction, and installation) for expensive new transmission lines from large distant wind farms and solar arrays take shape and the long-term value of microgrids is illustrated.
- It is clear that systematic benefits can accrue from microgrids (for example, improved efficiency of the electrical system and integration of distributed generation), however there is a need for a business model that rewards the entire range of players (for example, utilities, power providers, operators, and ratepayers) for microgrid deployment and operation in the state.
- Niche microgrid technologies have been developed, primarily for industrial customers and applications.
- There needs to be a willingness to adopt different operational arrangement and integration approaches to microgrid operations.
- Incorporating CHP into a microgrid operation has significant advantages that address three of the Energy Commission goals, namely use of renewable energy, use of biomass, and reduced peak demand.
- There is a need to develop and make publicly and commercially available microgrid software tools and models for evaluating technical alternatives, costs, and economics from utility and private owner operator perspectives; this would include assessing PEV/PHEV load and power quality effects to enable their accommodation on the grid without disruption.

<u>Recommendation</u>: Expanded demonstrations of the wide range of operating options and associated advantages of microgrids to illustrate the customer benefit for different scales, locations, and technology combinations throughout the state, from residential applications and urban sites, to agricultural and industrial settings.

<u>Recommendation</u>: Survey California to identify existing Demand Management Zones and microgrid experiments, demonstration and tests, to enable tracking experience and lessons learned, especially regarding: a) apparent and perceived cyber security threats and concerns over privacy, and b) systems operations and maintenance infrastructure required.

<u>Recommendation</u>: Controls associated with uniformity of operation within the microgrid and externally with the bulk electrical and natural gas grids must be demonstrated.

*Biomass, Natural Gas, and Combined Heat and Power (CHP)*

- California biomass resources are sufficient to supply a substantially larger amount of renewable electricity than is presently generated from these sources, as well as serving as feedstock for biofuels and bioproducts. However, issues related to collocation of biomass sources and attendant conversion and power generation facilities must be considered.

- The possibility of integrating natural gas use with the expansion of renewable sources offers an opportunity to make the transition from current operations to 2020 expectations for the California Smart Grid. Several possibilities exist, some requiring new technology, others requiring innovative adaptations, but some simply from introducing CHP as a distributed generation option throughout the California grid.
- Coproduction of renewable hydrogen and electricity using high-temperature fuel cells offers an attractive option (albeit perhaps requiring subsidization) for addressing multiple California energy policy goals through distributed generation, peak reduction, supporting the integration of solar and wind energy resources, and providing a hydrogen option for clean transportation.
- Barriers such as electricity tariffs and inconsistent availability of subsidies have limited CHP growth, and in many instances sites have closed. New technology and more efficient operations have developed that offer improved CHP operations and warrant renewed evaluation of technologies and barriers in the state.

<u>Recommendation</u>: California should demonstrate CHP technology at scales of 1-10 MW, including demonstration of fuel flexibility, waste biomass gasification with scale-up and reliable operation, and expansion of biomass conversion for use in advanced transportation and industrial operations.

<u>Recommendation</u>: Demonstrations also should take place for onsite generation with smaller units, rather than single or fewer larger size units, to explore and demonstrate flexibility in operation and expandability with growth, and ability to integrate with other resources (for example, solar and wind), to develop hybrid operations that are currently not available for assessment.

<u>Recommendation</u>: To optimize the benefits of the use of natural gas as an energy source, incorporate energy storage to assist in leveling the demand with respect to the availability and the duty cycle periodicity.

<u>Recommendation</u>: There are many options for CHP applications within the design of a California Smart Grid 2020 in which natural gas and biomass can be the energy source for efficient generation of electricity and GHG reduction. New technologies, and new applications of these technologies, both mature and new, need to be installed and operated to demonstrate the advantages.

### *Advanced Metering Infrastructure (AMI)*

- AMI is viewed by many as an enabler to a number of California's goals—demand response, distribution automation, as well as net zero energy construction and electric vehicle accommodation. However, AMI is more of a catchall term than a single technology; it comprises smart meters, communications infrastructure, and utility back office applications and services.
- The current state of AMI communication technology consists of proprietary solutions developed by a small number of original equipment manufacturer meter vendors, some of who have sourced proprietary technology by multiple small companies.
- Government funding through the American Recovery and Reinvestment Act of 2009 is driving the large-scale deployment of AMI systems. However, it is not clear what will happen as that stimulus wanes.
- The commercial service sector is in a position to leverage its wireless and wired networks and know-how with data management and cyber security to support the deployment of smart meters, sensors, and control systems for electricity distribution grids in many markets

where there may be a good fit between the topology and requirements of a given utility and the capabilities of the service providers that are available to work with it.

Recommendation: Support development of economic planning and decision tools such as system planning and design tools that enable California utilities to economically model, design, deploy, and support wide-area data communications systems. Such tools may include tradeoff analysis of economic payback vs. deployment architectures options, as well as ownership options.

Recommendation: Develop processes for rapid ratification of open standards to replace proprietary solutions within a time frame that does not delay deployment and impact utilities, regulators, and consumers.

Recommendation: Encourage utilities wherever possible to find ways to forge partnerships with commercial service providers in smart grid deployment to meet their technical and cost requirements.

Recommendation: Deploy standards-based cyber security reference designs and evaluation tools that are extensible to meet evolving and new threats (i.e. grid resiliency).

Recommendation: Develop open, interoperable software standards that support a multivendor environment for deployment and ongoing support of software systems, with particular attention to software standards developed outside the established grid community.

Recommendation: As distributed generation becomes more widely supported by regulatory and policy changes, California should support development of communication systems for DG that provide low latency protection and control, and integrate seamlessly with distribution automation and AMI systems.

Recommendation: Support a dedicated radio frequency spectrum for critical distribution automation control to reduce interference with unlicensed utility electronics (for example, AMI) and consumer electronics.

Recommendation: Develop plug-and-play demand management devices and systems.

Recommendation: A robust communications infrastructure needs to be deployed that supports PHEV/PEVs to ensure their successful adoption and operations, including extending AMI-enabled demand response to EV charging meters.

Recommendation: Explore how the capabilities and lessons learned of the cellular industry, with requirements like data and voice roaming, can be leveraged to support the deployment and integration of smart grid assets with AMI.

Demand Response

- More attention needs to be paid to mid-to-long-term needs for: 1) plug-and-play demand management devices and systems; 2) spectrum for critical demand management control and protection functions; as well as 3) communication capabilities for inclusion of PHEV/PEV systems.
- No clear-cut ownership preference, either by utility, ratepayer or third-party demand aggregator, emerged from discussion of demand response management issues with the technology manufacturers and vendors in the project team.
- While suppliers are very interested in the markets associated with demand response management, there is no consensus as to the "best" technical or regulatory approach.

Recommendation: The California Energy Commission needs to carry out further studies to determine whether action needs to be taken to focus investment and development efforts on a specific form of demand response management, regulation, incentives, or whether it should be left to market forces.

Recommendation: A clear-cut definition of who will own control of demand management devices and energy use data at the device level should be established as a state policy framework relative to the role of the utilities and ratepayers.

### *Distribution Automation*

- Distribution automation, although not as highly visible as AMI, has the potential for just as significant an effect on system reliability, flexibility, and capacity through increased situational awareness, diagnostics, and control of distribution assets.
- A very wide set of monitoring and control technologies have been deployed. Communications systems for distribution automation could have numerous technical synergies with those for transmission applications, yet they face more significant economic and deployment hurdles due to cost, design, configuration, and lack of right-of-way access, amongst other challenges.
- While there is an interest in approaches that will leverage the wireless AMI communications infrastructure currently being deployed in California, the data requirements (for example, latency, reliability, bandwidth) for distribution automation are quite different from AMI.
- There is a need to increase development emphasis on distribution automation control and protection products, which are needed prerequisites for demand reduction. This will be driven by federal development of distribution automation standards, which need to be carefully tracked by the State.
- From a standards point of view, existing communications protocols such as IEC 61850 can be leveraged to interface with distribution automation devices, but there is no standard communications technology specified, and similar to AMI, each vendor is providing a proprietary solution.

Recommendation: Design studies are needed to develop select priority use cases in California, communications architectures, control algorithms, and cyber security protocols for improving standards development, along with related demonstration and pilot projects.

Recommendation: Research to assess the viability of shared AMI communications infrastructure and the performance (for example, latency, reliability, bandwidth) of expanded AMI-based approaches to supporting distribution automation.

### *Plug-In Hybrid Electric Vehicles and Plug-in Electric Vehicles*

- PHEVs and PEVs present obvious challenges as a potentially disruptive technology to achieving California's smart grid-related demand, generation and GHG reduction goals.
- To engender market penetration, PHEV/PEVs should integrate into smart grid infrastructure with minimal effort and expense; charging procedures should be coordinated with Society of Automotive Engineers (SAE) standards.
- Although several suggestions have been postulated regarding potential alternative roles that PHEV/PEVs may serve in smart grid infrastructure operation, no specific direction has been identified.
- Based on past experience, all of the relevant and related standards for the charging infrastructure (for example, communications, charging cable conventions, and so forth) should be developed concurrently.
- As initial, larger volume sales of PHEV/PEVs establish a foothold in California, which is recognized as a transformational market for the automotive industry, so will the electrical

and charging infrastructure required to support this growth. It is envisioned that consumers and third parties will be the main constituents in the procurement of the Level 2 and Level 3 (that is, how fast a battery charges) Electric Vehicle Supply Equipment (EVSE) charging infrastructure.

Recommendation: California needs to develop an improved understanding of how large numbers and/or concentrated clusters of PHEV/PEVs might adversely affect the grid (through imposing additional loads on the grid, shifting in both time and location), and how the smart grid should be developed to reduce these affects.

Recommendation: Advancements in PHEV/PEV usage, charge use cases, charging controls, battery technology, and capabilities that yield improved EV performance should be pursued, such as increases in battery energy density, controls algorithms, reduction in weight, and increase in battery lifetime.

Recommendation: Additional benefits that may be derived from grid-connection should be evaluated, such as the use of fleet EVs as an option for aggregated or "clustered" storage tied to the grid.

Recommendation: Leverage wide-area communication technology to promote EVSE charging infrastructure deployment, and related standards for this infrastructure.

Recommendation: Standardization of charging cable/connectors along with backhaul communications from car to charger, including time-sensitive information such as authentication, billing, and scheduling.

Recommendation: Embedded intelligent metering and communications electronics into battery and charging systems.

# CHAPTER 7: Following up this Study in the Near-term

Chapter 6 of this report provides a set of high-level findings and recommendations for the Energy Commission and other interested parties to consider as they set out to achieve the California Smart Grid 2020 goals. The most critical of the actions needed over the next decade are presented in roadmap format. The focus in this chapter is on the ***near-term*** activities needed to address remaining risks and uncertainties that block the path forward. While the State's Smart Grid 2020 development will extend over the next decade and beyond, it is clear that some key decisions could be made in the near future that will irrevocably set the course, for better or worse, for much that will follow. The following six areas appear to the study team to be those that most need attention, and that are least amenable to changes in course a few years from now.

## 7.1 Filling Out and Integrating the California Smart Grid 2020 Study Set

The Energy Commission has funded California Smart Grid 2020 roadmap studies from the perspectives of California's investor-owned utilities (IOUs) and from the municipally owned utilities (MOU), in addition to this study from the technology manufacturer and vendor point of view. These perspectives will need to be integrated, and the points of view of energy consumers added to the mix. This is particularly important since, as this study found, the California Smart Grid 2020 may look substantially different from the current grid – many functions currently controlled by electric power utilities may be shared or transferred to those who are currently customers or to an emerging market of third-party service providers.

In addition to the kind of roadmap and use case information that this study and the two parallel studies will have gathered, it will be necessary to develop smart grid energy balance models of grid architectures and grid elements, and cost estimates of alternative ways to proceed. Finally, more work is needed to understand how, when and under what economic scenarios the transition to sustained market-based growth will take place. All this information, with further consideration for the State's official loading order will be needed for California to develop and execute an optimal smart grid roadmap. For example, developing and tracking an approach to a desired or likely 2020 "end-state" statewide energy balance could be used as a quantifiable performance metric to track overall Smart Grid 2020 and GHG reduction roadmap implementation progress.

Moreover, the optimal Smart Grid 2020 Roadmap for California will almost certainly require compromises from all parties. It is crucial, therefore, that the process by which this Roadmap is developed incorporates the strengths of ideas from all those parties (IOUs, MOUs, suppliers, ISOs, customers, and regulators) to derive the most realistic and expeditious plan that can be reduced to practice.

## 7.2 Clarifying the Roles and Impacts of Natural Gas and PHEV/PEVs on the State's Demand and Generation Goals, and the GHG Goal in Particular

Growth in PHEV/PEVs, as well as natural gas substitution for petroleum-derived fuels in transportation and its use in microgrids, have pros and cons that this study was unable to fully investigate. The State needs to decide soon if it should incentivize/accelerate one or both of these approaches in order to lead the plan for meeting the California Smart Grid 2020 goals.

For example, as electric vehicles are brought into the marketplace and electricity demand increases, the heterogeneity of that demand, relative to grid infrastructure and potential distributed electricity sources, may become a driver for grid evolution. This may force non-optimal choices as to where utilities must place storage for peak and vehicle use demand, more expensive options as to how to evolve automated response controls, and so on. Use of natural gas provides an excellent bridge with which electricity generation and CHP operations can be distributed throughout the grid, while assisting in meeting a growth in PHEV/PEVs over the next decade, but has long-term GHG implications of its own. Given that the issues are quite interconnected and the transition is unclear, realistic options need to be developed and pathways for integration into the Smart Grid development need to be evaluated for utilities and suppliers to plan with the State.

## 7.3 Developing a Demand Management Acceleration Strategy

This study found that Demand Management is viewed as very important to meeting the State's goals, but there is not as yet a consensus as to whether there is a "right" approach: Should management be done by utilities, or customers, or third-party demand aggregators, or all of the above? The question of what the State should do—incentivize/accelerate one, two or all three of these approaches, and/or leave such decisions to local policy makers, or let the market decide—needs careful study now. Although there are ways for the major utilities to take the lead role, there are issues associated with this that are being dealt with in different ways throughout the U.S. that need to be examined and evaluated. A study that would consider several viable options that have been shown to have merit is needed.

## 7.4 In-Depth Evaluation of Microgrids in Smart Grid Development

The participants in this study believe that microgrids have a significant role to play in meeting the California energy policy goals. They are distinguished from other grid alternatives (such as large solar and wind farms, or large-scale purchase of hydropower from British Columbia) by the allure of factors such as:

- Providing resiliency (e.g. robustness to grid disturbances and natural disasters)
- Enhanced security (e.g. they may act akin to a computer firewall to impede the flow [either way] of malicious exploits, and assuage customers' privacy concerns by exposing only the microgrid-aggregate information, not the energy patterns of an individual home, apartment or business)
- Spurring the development of new technology investment, markets, businesses and jobs
- Leveling the availability and cost of electricity by providing both generation and storage within localized sections of grid-connected consumers.

However, much remains unknown about the (relatively fledgling) needs and capabilities of microgrids, and how they might integrate with the larger grid.

From the State's perspective, distributed generation (e g, microgrids, perhaps utilizing natural gas) may be a viable alternative to large solar and wind farms and/or the purchase of increased amounts of hydropower from British Columbia. In addition, distributed storage coupled with generation provides a means by which peak demand could be levelized. However, the technical, economic and social factors and figures of merit needed to compare those alternatives are not sufficiently understood. Recent economic studies have begun to show that costs associated with different Smart Grid scenarios and technologies that are being demonstrated on a larger scale need to be evaluated in a more detailed fashion.

As yet there is insufficient knowledge and tools to allow potential participants to intelligently determine the microgrid types, sizes, designs and business models that best meet their needs for given locations and applications. Some of this information may already exist in the public domain, but systematic analysis approaches and software models with which to do trade-off analyses apparently do not. Also, the technology that is available for such operations has been primarily current generator technology, namely reciprocating engines and turbines. For example, implementation of fuel cells and microturbines needs to be given consideration, and opportunities need to be created to evaluate and demonstrate their best application. Better understanding is needed regarding the incorporation of different electrical energy sources, including rooftop solar, and the inclusion of electrical energy storage to reduce the need for additional VAR and phase adjustment equipment associated with PV interfaces with grid operations.

## 7.5 Developing an Integrated Strategy for Emplacing Needed New and Revised Rules, Regulations and Standards

There is an immediate need to accelerate the reevaluation of California grid-related polices, rules and regulations, many of which are outdated and thereby obstruct useful change. In addition to microgrids and grid connectivity, this will need to include PHEV/PEV charging stations, CHP, GHG control from agriculture, customer control options, hybridization of source operations, and many others. Moreover, utility and transmission operations should not be the only drivers; business alternatives and owner/operator options need to be considered with a balanced future-planning outlook. Finally, there are the policies that may be needed to set standards for protecting consumer privacy (i.e. who owns the energy consumption data), and who controls technology devices on the ratepayer side of the utility meter as utilities expand tariff-based or incentive-based Demand Management programs.

## 7.6 Communicating Plans and Progress to the People of California

The state already makes a wealth of energy-related information available via websites such as the Energy Commission's http://www.energy.ca.gov/ and the Go Solar California's http://www.gosolarcalifornia.ca.gov/csi/index.php. These are exemplary uses of the Internet for communicating to the public. However, as California develops and executes its Smart Grid 2020 roadmap, there is a pressing need to find a cogent, structured way to convey, via this and other media, the status, plans, benefits, investments, etc., of that roadmap to the public. Moreover, if the smart grid is to be truly effective, this must be only the first step in providing energy users with the information, tools and knowledge they will need to become much more active in the decision processes controlling their energy use. Since the challenge of developing a smart grid is so large and will take considerable time, it is imperative that the options available for its development, including societal advantages and disadvantages, cost benefits and drawbacks, and options available that are considered in the planning exercise need to be presented in an unbiased manner. This planning and implementation needs to begin within the near future in order not to present societal barriers that will prolong successful implementation of the California Smart Grid 2020.

# CHAPTER 8: List of Acronyms

| | |
|---|---|
| AAGR | Average Annual Growth Rate |
| AB | Assembly Bill |
| AC | Alternating Current |
| ACORE | American Council on Renewable Energy |
| AMI | Advanced Metering Infrastructure |
| AMR | Automated Meter Reading |
| ARRA | American Recovery and Reinvestment Act of 2009 |
| BAU | Business as Usual |
| BDT | Bone dry ton |
| BOCC | Building operations control center |
| Btu | British Thermal Unit |
| C2 | Communications and Control |
| CAES | Compressed air energy storage |
| CAISO | California Independent System Operator |
| CBC | California Biomass Collaborative |
| CEC | California Energy Commission |
| CFL | Compact Fluorescent Lamp |
| CHP | Combined Heat and Power |
| C&I | Commercial and Industrial |
| CNG | Compressed natural gas |
| CO2 | Carbon Dioxide |
| CSI | California Solar Initiative |
| CSP | Concentrated Solar Power |
| DA | Distributed Automation |
| DC | Direct Current |
| DDC | Direct Digital Control |
| DDT&E | Design, development, test and evaluation |
| DE | Distributed Energy |
| DER | Distributed Energy Resource |
| DG | Distributed Generation |
| DLC | Direct Load Control |
| DMZ | Demand Management Zone |
| DOE | Department of Energy |
| DR | Demand Response |
| DSM | Demand-side management |
| ECM | Energy Conservation Measure |
| EDDL | Electronic Device Description Language |
| EPA | Environmental Protection Agency |
| EPBB | Expanded Performance Based Buydown |
| EPRI | Electric Power Research Institute |
| EV | Electric Vehicle |
| EVSE | Electric Vehicle Service Equipment |
| FACTS | Flexible AC transmission systems |
| FC | Fuel Cell |
| FDIR | Fault Detection, Isolation, and Restoration |
| FERC | Federal Energy Regulatory Commission |
| FiT | Feed-in Tariff |
| GHG | Greenhouse Gas |
| Gt | Gigatonne |

| | |
|---|---|
| GTI | Gas Technology Institute |
| GW | Gigawatt |
| H2 | Hydrogen |
| HAN | Home Area Network |
| HERS | Home Energy Rating System |
| HVAC | Heating, Ventilation and Air Conditioning |
| HVDC | High-Voltage Direct Current |
| IED | Intelligent electrical device |
| IEEE | Institute of Electrical & Electronics Engineers |
| IEPR | Integrated Energy Policy Report |
| INCOSE | International Council on Systems Engineering |
| IP | Intellectual Property |
| IREC | Interstate Renewable Energy Council |
| ISO | International Organization for Standardization |
| ISO | Independent System Operator |
| ITC | Investment Tax Credit |
| IOU | Investor-Owned Utility |
| JPL | Jet Propulsion Laboratory |
| kV | kilovolt |
| kW | kilowatt |
| LBNL | Lawrence Berkeley National Laboratory |
| LNG | Liquefied natural gas |
| LOC | Life ownership cost |
| LSE | Load Service Entity |
| LVRT | Low-Voltage Ride-Through |
| M&V | Measurement and Verification |
| MCFC | Molten Carbonate Fuel Cell |
| MDM | Meter Data Management |
| MHz | Megahertz |
| MMT | Million Metric Ton |
| MW | Megawatt |
| NaS | Sodium sulphur |
| NASA | National Aeronautics and Space Administration |
| NEMA | National Electrical Manufacturers Association |
| NG | Natural Gas |
| NOx | Nitrogen Oxide |
| OEM | Original Equipment Manufacturer |
| O&M | Operations and maintenance |
| PAC | Project Advisory Committee |
| PACE | Property Assessed Clean Energy |
| PBI | Performance Based Incentive |
| PEM | Proton Exchange Membrane |
| PEV | Plug-in Electric Vehicle |
| PG&E | Pacific Gas and Electric |
| PHEV | Plug-in Hybrid Electric Vehicle |
| PIER | Public Interest Energy Research |
| POTS | Plain Old Telephone Service |
| POU | Publicly Owned Utility |
| PUC | Public Utilities Commission |
| PV | Photovoltaic |
| RFP | Request for Proposal |
| RFQ | Request for Qualifications |
| RD&D | Research, Development and Demonstration |

| | |
|---|---|
| ROI | Return On Investment |
| RPS | Renewable Portfolio Standards |
| RTP | Real-Time Pricing |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SCADA | Supervisory Control and Data Acquisition |
| SCE | Southern California Edison |
| SDG&E | San Diego Gas & Electric |
| SEER | Seasonal Energy Efficiency Ratio |
| SGIP | Self-Generation Incentive Program |
| SOFC | Solid Oxide Fuel Cell |
| SOx | Sulphur Oxide |
| T&D | Transmission and distribution |
| TIMA | Technology Infusion Maturity Assessment |
| TWh | Terawatt hour |
| TOU | Time-of-Use |
| UPS | Uninterruptible Power Supply |
| USCHPA | United States Clean Heat and Power Association |
| V&V | Validation and verification |
| VPP | Virtual Power Plant |
| WCI | Wireless Compliance Institute |
| WECC | Western Electricity Coordinating Council |

# APPENDIX

## A.1 TIMA Workshops

The objectives structure, elicitation of barriers to meeting the objectives, and set of actions to reduce those barriers are provided in the following Tables (A1 through A3).

**Table A-1: TIMA Smart Grid Objectives Structure**

**1 GHG: Reduce GHG emissions to 1990 levels across all sources in 2020**
**1.1 ENERGY SUPPLY/GENERATION**
**1.1.1 Renewables: 33 percent of generation by renewables (~104,000 GWh/yr) in 2020**
- Utility-scale
  - Solar, wind, geothermal, small hydro
- Distributed resources
  - **Rooftop PV: 3,000MW of new rooftop Solar PV by 2016 (~5000 GWh/yr)**
    - Residential
    - Commercial and industrial
  - Wind
  - **Biopower: 20 percent of renewable power supplied by biopower sources in 2020 (~20,000 GWh/year)**
    - Commercial and industrial
    - Community/microgrid

**1.1.2 CHP: Additional 5,400MW of combined heat and power in 2020**
- CHP for peak shaving
- Base load

**1.2 ELECTRICITY DEMAND/CONSUMPTION**
1.2.1 10 percent reduction in total forecasted electrical energy consumption in 2016
**1.2.1.1 Peak: Electricity peak demand reduction goal of 4,885MW in 2013**
- Voluntary shedding
- Demand Response Aggregation (DRA, third-party)

**1.2.1.2 Demand response (DR) that reduces 5 percent of peak demand in 2020**
- Automated Demand Response (ADR)
- Direct load control (DLC)
- Price signals

**1.2.1.3 Residences: All new residential construction is net zero energy in 2020**
- Clean transportation
- PEVs
- Hydrogen and Hydrogen Fuel Cell Vehicles

**2 Department of Energy [2009]**
**2.1 Customers: Enables Informed Participation by Customers**
- Generation
- Storage
- Efficiency

**2.2 Accommodates All Generation and Storage Options**
- Centralized Generation Options
- Distributed Generation Options
- Centralized Storage Options
- Distributed Storage Options

**2.3 Enables New Products, Services, and Markets**
- Hardware: sensors and controls
- Applications software
- Ancillary services

**2.4 Power Quality: Provides Power Quality for the Range of Needs**

Optimization: Optimizes Asset Utilization and Operating Efficiency
Asset Utilization
Operating Efficiency

**2.6 Resiliency: Operates Resiliently to Disturbances, Attacks, and Natural Disasters**

**Table A-2: TIMA Smart Grid Barriers Structure**

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1. **TECHNOLOGY STATUS**
   - 1.1. Have to know nuances of a new technology, and determine how paying for addressing them
   - 1.2. Supplying the correct price signals, while avoiding disruption to customers
   - 1.3. Developing the technology and deciding the location for storage technologies
   - 1.4. Developing the T&D from remote installations
   - 1.5. Need to upgrade all the meters to get real time use data from all kinds of customers
   - 1.6. Need for increased state level funds to match installation goals including balance between technologies
   - 1.7. Distributed /centralized /dispatched storage - where does it all fit?
     - 1.7.1. Unprecedented scale of use of batteries - collect/recycle/reuse infrastructure at end of life
     - 1.7.2. Where to place storage, how to pay for storage, incompatibility with current regulation
     - 1.7.3. How to make it possible for members of the public to buy their own storage – consumer-led storage industry
     - 1.7.4. Smart grid in general: public won't accept remote switching and demand management
   - 1.8. Equipment mounted on gas distribution systems must be rated intrinsically safe which is an added cost
   - 1.9. Grid equipment on utilities other than electric (gas, water, etc.) must incorporate an explicit power supply
   - 1.10. There is no truly agnostic backhaul channel for Smart Grid data that is equally accessible to all utilities
   - 1.11. Cost effective cooling technology needed for modest sized CHP systems
   - 1.12. Low-cost, longer-life, longer maintenance-interval backup power generators needed to allow for dispatchable power
   - 1.13. PEVs will cluster in early adapters, etc. communities - high nighttime demand on that circuit
   - 1.14. Need to minimize solid waste impact of large scale energy storage
   - 1.15. Energy storage options and technology, in addition to buffering for maximizing sales and brokering also, need to factor in off-nominal emergency scenarios like being able to handle gray-outs/cyber-attack and providing a buffer for recovery options
   - 1.16. Lack of consistent, systematic method of monitoring and controlling PV at all T&D levels, which will be needed to meet state RPS goals
   - 1.17. Customer owned PV not as visible to system operator as it needs to be
   - 1.18. Variability forecasting for PV is not where it needs to be to enable high penetration of PV (approaching it for wind)
   - 1.19. Low interoperability between vendors
   - 1.20. Automation places premium on data and communications
   - 1.21. Exploding need for cyber security and privacy policy
   - 1.22. Technologies must be deployed with the ability to easily upgrade to avoid obsolescence (future proofing)
   - 1.23. Wireless communication challenge - capacity, security, distance - continual turnover/upgrades
   - 1.24. Customer overwhelmed with data - tech must be compatible with customers state of knowledge
   - 1.25. Power quality variation will increase with new power sources (need new technology to handle that)
   - 1.26. Better prediction needed for soft (intermittent) energy
   - 1.27. Conversion process technologies for biomass are currently too complex

1.28. Storage - reliability of storage technology important
1.29. Storage - location is important (i.e. at generation or at load, centralized or distributed)
1.30. Round trip efficiency losses higher with storage systems in play
1.31. Existing grid capacity limited by lack of use of synchrophasor technologies
1.32. The technology doesn't exist in today's homes for the owner to receive granular real-time data n power usage by different users of power: HVAC, water heater, stove, TVs, etc
1.33. Transmissions lines currently in CA are not proximate to all favorable wind, solar, biomass and ocean current generation locations
1.34. Neither the platform(s) not uniform standards/codes have been identified for the data backbone (WAN, LAN and NAN) of the Smart Grid
1.35. Are the technologies and pilot projects for tidal generation and bio-coal (fortified wood waste) receiving sufficient support to be commercially viable by 2020?
1.36. Need more generation capacity
1.37. Transmission lines – decision-making model faces significant issues
1.38. Sell down to ROI for any individual who gets involved (e.g., solar roof) - need help, credits to do this
1.39. The time of day billing rate for electrical power is not universally available in real time
1.40. There is no testing facility for demonstrating true interoperability of equipment, rather than simple conformance with written standards

**2. GRID SYSTEM STATUS**

2.1. DG interconnection standards for all types (e.g. CHP, backup power). Standards specific to CHP, or backup power, or other types of DG need to be categorically defined
2.2. One-way flow assumed in many parts of the existing distribution network
2.3. Current spec for grid tied DG disallows ride-through
2.4. Systematic integration needed of all types of PV systems
2.5. Balancing area implications for variability need to be factored in a more standard way compared to current approaches
2.6. Need to deal with legacy gear
2.7. Current grid operations are based on a highly centralized model
2.8. SG needs more automation to be efficient and effective
2.9. The transmission system currently is inadequate to accept and manage an optimal level of generation from renewables
2.10. The data communication backbone (e.g. WAN, LAN) should have an open architecture if a new software application market is to be created
2.11. Current LEED standards are not sufficiently refined (need different standards/criteria for different types of construction and criteria specifically directed at net zero energy use)
2.12. Load and storage management of PHEV/PEVs will be needed
2.13. Does technology and capability exist to deliver a range of power quality over one grid?
2.14. PEVs: NG cars - not enough stations
2.15. Today's grid system is old, failing and lacks manpower to maintain
2.16. Lack of standard non-proprietary consistent system analysis models etc needed to determine performance requirements for technologies
2.17. Real time pricing available to enable customer decision-making
2.18. In a concept where backup generators are used as dispatchable load control the circuits need to be wired such that the generator is on the main circuit not just emergency circuits

**3. REGULATIONS AND STANDARDS**

3.1. Fragmented regulatory system leads to inconsistent outcomes
3.2. Long time to go through regulatory system, by which time technology is obsolete
3.3. Smart grid is overpromising - expectations too high
3.4. Allowing for future interoperability (as well as innovation) of technologies
3.5. Strict regulatory requirements make it difficult to meet real time grid needs
3.6. Need to balance standards (OSHA, etc.) between union and non union shops, safety and health issues

3.7. Lack of long- and medium-term tax incentives for renewables makes private sector planning impossible / very difficult
3.8. Lack of feed-in tariffs retards development of distributed generation from renewables
3.9. Deregulation impact on utilities (can't own generation) - therefore their role in SG is minimized
3.10. Need for regulation to promote renewable energy and its sale
3.11. Ownership of storage is not clear - may utilities own it?
3.12. Clean energy and green energy are not well defined (inconsistencies abound)
3.13. Relax some of the requirements to decrease complexity of permitting process
3.14. Lack of policy that mandates standardized communications interface for all deployed smart meters to enable direct customer access of near real time (less than 10 second delay) aggregate energy usage data
3.15. Lack of Policy that supports use of existing communications technologies (broadband, cellular, etc.) as much as possible versus installation of new technologies at the rate payers expense
3.16. Who is the "governing body" for smart grid standards?
  3.16.1. Overlap between specification development organizations
  3.16.2. No clear definition for how standards are selected to be part of a smart grid architecture
3.17. Intellectual property clauses for state funding are way too restrictive (some latitude with DOE funding)
3.18. Overly onerous working with federal or state funds
3.19. Lack of policy for land ownership
3.20. Energy quality regulations for small providers needs to be developed
3.21. Bad communication/coordination between ISOs, utilities, control rooms; worsened in bigger grid
3.22. Significant barriers to micro-grids
3.23. Internal combustion engines are efficient for CHP/DG, but precluded in CA by emissions regulations - limits penetration
3.24. There is no clear decision on who controls the final DR action: the utility or the customer
3.25. Lack of models that will predict effects of real time pricing
3.26. Lacking regulations to say when electricity crosses a "jurisdiction", how much information must also cross (and how real time)
3.27. Regulations impede lack of effective utilization of existing transmission network (e.g. T&D with storage)
3.28. Need one set of global [not just US] standards
3.29. Increase of the net metering limits to above 1MW for solar, and the limits utilities are required to accept for net metering
3.30. Regional inconsistency of standards from division of state architect for implementation of renewables on public buildings
3.31. Need for matching regulations between local and public utilities
3.32. Need additional regulations for efficiency of appliances
3.33. Regulations apply to Electric Service Providers as well as utilities
3.34. Need mechanism for standardizing the protocols, without which don't have smart grid
3.35. There is no standard real-time data exchanged at the points where electrical power changes hands
3.36. Land use and litigation planning for distributed power

**4. ECONOMICS AND FINANCE**

4.1. Provide a way to cut costs and provide info to the customer (without impacting them)
4.2. Most consumers will only adopt and use clean technology if it is less expensive, more convenient, and trendier than conventional, and does not require lifestyle change
4.3. Lack of green power providers who offer long term (e.g. 5 year) fixed price power contracts to consumers is a disincentive to "green power" selection by consumers
4.4. Incentives for storage are uneven depending on kind of storage technology
4.5. Lack of clear market mechanism for ancillary services for PV and DG and other
4.6. Lack of the “killer application” that will deliver high ROI (less than 12 months) for residential end consumers to enable adoption & consumer funding of smart grid
4.7. Uncertain Return on Investment (ROI) for Venture Capital (VC)

4.8. Gaps in tax/incentive policies
4.9. Customer value proposition for PV is at odds with system control
4.10. Lack of pro-rated performance-based subsidy to help get small providers on line
4.11. Less appetite to fund these initiatives under current economic climate
4.12. Stimulus (ARRA) money will run out - then what?
4.13. Need for more creative financing (e.g. through private/public partnership - PACE) for SG
4.14. Who will pay and how? Rate-based? Capital constrained? Merchant opportunities - how encouraged?
4.15. Is there a project finance model for non-utility financing
4.16. Infrastructure financing is missing (no longer any trading in tax equity - includes tax credits) for project financing
4.17. Need for long term renewable support - long term contracts, opening RPS market to REC credits
4.18. Federal tax credit set to expire end of this year - specifically the ability to access as a grant
4.19. Who will manage the smart grid, etc? (Utilities, state, local)
4.20. What is the business model for the smart grid?
4.21. Equity financing, deregulation, etc., not palatable - but storage will make pricing options work
4.22. With respect to CHP, the big issue with economics is the need for a heat demand in the summer. Hence, needed is a small cost-effective cooling technology that uses recovered heat
4.23. Also with backup power as applicable to demand control, there needs to be programs in place that send price signals to owners that encourage them to run the machines when peak power is required. Real-time pricing.
4.24. Who pays plans for smaller distributed networks?

## 5. CUSTOMER READINESS

5.1. Net zero energy buildings might require fundamental residential customer mindset change
5.2. Fragmentation across system owner customer base, installers, operators, providers, utilities and system operators - competing expectations and goals
5.3. Lack of high penetration PV operational experience leads to competing and potentially overly restrictive operating environments
5.4. Homeowner ratepayer - quick response needed to customers who think they're overcharged
5.5. System control operator - enormous amount of new information incoming - complexity of job
5.6. Utilities and customers not ready for paradigm shift as microgrid environment focus moves to demand side of meter
5.7. Utilities see DG as a liability, but in paradigm shift it's an advantage
5.8. Refueling infrastructure is not there for widespread adoption of natural gas or electric vehicles.
5.9. Fear of obsolescence in utility down to residential levels of customers
5.10. Majority of customers (all kinds) don't want to be the first adopters - they wait
5.11. Perception that tech products are ephemeral (at all levels of industry)
5.12. Regulatory barriers to acceptance of new time of use rate policies
5.13. Lack of observable/tangible benefits to residential consumers
5.14. Smart Grid doesn't necessarily equate to a reduction in monthly electric costs for residential customers
5.15. Top down communication to consumer has to be explicit, competent, allow for their involvement
5.16. According to survey done for IBM, 57 percent of residential and small commercial electricity customers view power as just a commodity and do not want to spend money for services of equipment or to think about it much
5.17. For rental, residential, commercial & industrial properties, confusion as to who pays
5.18. Could be significant regional differences in customer readiness, driven by local cost of power
5.19. Utility customers are accustomed to throwing inserts in utility bills away. Many customers pay on-line. E.g., they discard safety and PUC rate increase information.
5.20. All parties need to understand benefits
5.21. Utility must have customer support program ready for smart meters questions etc
5.22. PV and grid jurisdiction boundary; who is responsible at the other side of meter?
5.23. SG benefits are at odds with utility business models

5.24. Lack of financing for residential PV
5.25. Slow residential/ratepayer uptake of demand response
5.26. Retrofits (e.g. CFLs) didn't work - customers ignored them, etc.
5.27. Customer concerns and issues are not heard at / elevated to the political level
5.28. Plug and play may be hard to get right (including usage and safety)
5.28 End user needs to see the benefit
5.29. End user needs control of purchasing/cost decisions
5.30. Need cheap, reliable domestic storage
5.31. Utilities need customer pull
5.32. Lack of education for the residential consumer on the benefits of smart grid technologies
5.33. Lack of "plug and play" capability so residential customers can easily deploy smart grid technologies

**6. SECURITY AND PRIVACY**

6.1. Fragmented solutions and varying implementation rigor per utility means wide variety of security vulnerabilities
6.2. Ratepayer/homeowner concerns about Big Brother fears of monitoring
6.3. Grid has millions of new touch points of information - how to maintain security and access
6.4. Need to keep secure the infrastructure of microgrids -need to keep all transmission underground or within structures
6.5. From a privacy standpoint, smart appliances controlled on the supply-side of the meter may bring about more privacy issues than if the appliances are controlled on the demand-side using real time pricing
6.6. Media buzz about security disproportionate to the reality (bad news overly prominent)
6.7. Some utilities feel only way to have secure telemetry is to have their own system in place (not leased)
6.8. Need to avoid "Google Gate" phenomena (Big Brother issue)
6.9. Firewalls won't work against concerted attacks
6.10. Political risk that some groups will seize upon Big Brother aspect, especially if IOUs own the data backbone.
6.11. There are no well-established models for privacy management across a large population
6.12. Difficulty managing volumes of security keys given the number of endpoints
6.13. Inconsistent process for managing security practices across area of control boundaries
6.14. End user needs to own and control their data
6.15. Need to overcome mistrust of government and utilities
6.16. Need technology to continuously update the security of the systems deployed at customer sites.
6.17. Lack of specific policy for the end-customer protection of energy usage data

**Table A-3: Barrier Reduction Actions Elicited from the First TIMA Workshop**

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**1 DEVELOP TECHNOLOGY**

1.1 Legislative requirement to evaluate storage (on an open book basis) as an alternative to peak generation and renewable balancing
1.2 Legislative requirement to evaluate storage (on an open book basis) as an alternative to new transmission capacity
1.3 Open up evaluation of storage systems beyond utilities, DOE and EPRI (e.g. provide for equal weighting of testing and evaluation by commercial partners such as Cisco, Home Depot etc.)
1.4 Open and realistic on-peak/off-peak pricing
1.5 Credits for domestic scale storage
1.6 Require ISO 14,000 compliance (environmental life cycle) for storage and other smart grid systems
1.7 Develop absorption cooling tech for smaller CHP systems
1.8 Develop premium small (10kW) backup generators that can be interconnected to grid (at least 5,000 hours capable)
1.9 Develop advanced net metering framework for multi-application and rigorous network
1.10 Retrofit current substations to make them smarter - interim step towards full SG
1.11 Develop technologies and guidelines for best approaches to future proof technologies
1.12 Finance program (e.g. temporary rate increase w/ matching funds) - measures to pay for increasing transmission and generation via green technologies, also place for private money

**2 CARRY OUT STUDIES/ANALYSES/TESTS**

2.1 Set up an independent testing laboratory that certifies Smart Energy Grid products as being interoperable and compatible
2.2 Create an industry organization that promotes the communication protocols and standards that are part of the Smart Energy Grid ecosystem
2.3 Transfer the virtual private network (VPN) technologies currently used in the financial community to the industrial control and communication space
2.4 Set up a White Hat hacker team that tests the vulnerability of Smart Energy Grid installations and provides findings
2.5 Set up and demonstrate a wireless "telemetry cloud" over a community that capture data from all utilities. This is a distinct entity from WiMax or GSM and is only used by utility entities
2.6 Conduct study to identify the amount of new CHP/DG or backup generation that would penetrate the market if real time pricing were available. The study would need to identify location-based spark spreads required for increased penetration.
2.7 Develop low cost emissions reduction systems for IC engines applicable to smaller systems and test the emissions systems
2.8 Conduct a study to determine utility and customer willingness and knowledgebase for the paradigm shift
2.9 Demonstration ice boxes and PV devices (more generally, PV and storage integration)
2.10 Develop wind and solar (near real time) forecasting to inform storage and/or DR systems
2.11 Prioritize renewable energy regions and location across state, and coordinate with transmission corridor planners, intra-state, inter-state, and international (Mexico, Canada)
2.12 Plan for large employers to be sites for PEV charging, cluster neighborhoods at night - system operator viewpoints important to this
2.13 Develop standardized model and metrics to characterize variable generator behavior in a way that takes balancing area and system context into account
2.14 Reconcile conflicting standards relating to anti-islanding and LVRT (low voltage ride through)
2.15 Study economic models for DG at all levels to participate in grid system control and ancillary services
2.16 Survey how many of sections in distribution network are one-way only (could also compare to outside California)
2.17 Existing technology can address a lot today - need to study those solutions, package, and communicate/recommend results

2.18 Conduct a study to determine best approach for standardizing the technology communication interface technologies for the meter communicating into the home
2.19 Incentivize pilot projects in utilities, and have them expand from that via town hall meetings, education, etc., of results
  2.19.1 Five step process to follow to get this CA package to get adopted
    A. Create task force comprising PUC, Energy Commission, CARB, Finance, DOR, EPA - all California departments- state minimum criteria for smart grid plans from IOU operating in CA
    B. Public hearings of plans and revisions to follow - consensus if not attained would be set by government
    C. Final plans would be published
    D. Hand-off from government to private sector of the roadmaps to respond to RFPs
    E. Time limit on entire process and force adoption of the plans
2.20 Big picture study to define business plan under which smart grid will operate to show how ROI will be achievable
2.21 Additional testing for small technologies to deal with permitting (or change the standards)
2.22 Regulation to cause pricing structures to be created to deliver the right pricing signals
2.23 Conduct a study to determine best approach for standardizing existing high speed technology communications for use between the home and the energy service provider to exchange real time pricing
2.24 Conduct a study to review various SG solutions today for the residential customer and rank in order of importance to the consumer for overall impact and ease of use
2.25 Conduct a study to review various security deployment update methods today for the residential customer to provide guidelines and recommendations

**3 CONDUCT EDUCATION CAMPAIGNS**

3.1 Exciting education campaign for consumers to emphasize efficiency and conservation
3.2 Have the suppliers and the state use "demo home" for education and promotional purposes
3.3 Educate and promote benefits to all parties (ratepayers, utilities, cities, etc)
3.4 Educational campaign or coalition for DG to share best practices to help get DG deployed (some information available at www.acore.org)
3.5 Lessons learned from failed projects, to inform those starting
3.6 Public agencies need help developing Requests for Proposals (RFPs) and Requests for Qualifications (RFQs) for renewable projects (e.g. across towns, districts) - template?
3.7 Permitting agencies at city or state level need education on renewables and technologies in general
3.8 Online availability of info and classes (on Smart Grid and available incentives)
3.9 Permit process smoothing via support from town meetings and communities
3.10 Promote the harmonization and adoption of standards such that they are readily incorporated into regulation
3.11 Conduct an education campaign for consumers explaining the necessity and benefits of SG that does NOT focus on their bill.
3.12 Produce materials that elucidate the costs of residential power purchased from the grid, produced by PV, and produced by natural gas generators and how the cost varies by time of day
3.13 Educate and recruit potential micro-grid stakeholders- Utilities, rate-payers, entities (like cities, developers) identify the benefits of a paradigm shift from supply-side to demand-side focus

**4 CONDUCT DEMONSTRATIONS**

4.1 Compile the highest ranking smart grid value propositions for homeowners, and deploy into homes (supplier funded)
4.2 Multi vendor interoperability demo - ideally full network behind it
4.3 Stage/gate demonstration path to market
4.4 Microgrid demonstration in California incorporating all aspects of smart grid - may be a 5 yr development project; collect data before, during and after to prove

4.5 Google application model - drive towards on-line billing mechanism - a what-if dashboard in hands of consumer
4.6 Make information topical to people: tickertape of power/water etc usage/sources to put info in view of people - online webpage
4.7 Gated community level demos (state funded) allowing third party participation and combinations - microgrids in controlled settings
4.8 Establish and initiate gathering of experience / information base
4.9 Construct a Smart Grid home that incorporates gas CHP, PV, and other alternative energy technologies under one roof
4.10 Construct and operate a gas fired charger for plug in hybrid vehicles
4.11 Construct a telemetry cloud community that allows residential customers to run their energy management application on a virtual machine
4.12 Demonstrations of absorption cooling, premium backup generators, and emissions controls

## 5 ESTABLISH INCENTIVES

5.1 Provide financial relief for utility companies to create/provide communications services
5.2 Define a "transaction-based" energy model to promote distributed resources and renewables
5.3 Create legislation that incentivizes manufacturers for research and development on smart grid technologies, and permits utility companies to accelerate depreciation of legacy equipment in favor of smart grid deployments
5.4 Get the suppliers to provide short term rebates to get customers jump started and "hooked" for certain technologies beginning the journey to using smart grid technologies
5.5 Incentives for market mechanisms for DR and ancillary service participation
5.6 Make energy efficiency performance-based, to encourage more active energy management
5.7 For conforming to load profile/envelope (beyond time of use type)
5.8 Incentives to school districts for energy efficiency curriculum
5.9 Builder incentives for energy efficient construction and DG
5.10 To utilities for maintaining certain customer statistics
5.11 Consistent program to make simpler for utility owned DG to happen - consistent policy and/or state funded
5.12 Phased Small Business Innovative Research (SBIR) -like program for R&D for small scale smart grid - transition towards government loan as matures/succeeds
5.13 Encourage small companies to team to form mid-size entity to achieve administrative, quality control, etc. functions that small companies/providers alone can't handle
5.14 Land: mineral-rights like incentive in which government still owns the land, but get rights to power generation/passage; tax incentives, etc., studies enabled
5.15 Tax incentive for DG sources to meet power quality requirements for interconnection
5.16 Consumer incentives / clever marketing to promote purchase of SG products
5.17 Backup NG systems that can be integrated w/ grid - incentivize the extra cost via special rates (curtailment rates) from utilities
5.18 Additional rebates to bring each technology to parity or meet goals
5.19 Establish other long term renewable incentives such as feed in tariffs or Renewable Energy Credits (RECs) into the market
5.20 Need for extension of federal tax credits esp. as grants
5.21 "Departing load" charges or "standby" charges - eliminate those would be a good incentive
5.22 Optional database for building info (e.g. of large roof space)
5.23 Define standard methods and procedures for the application of security and privacy measures
5.24 Incentives for people/businesses to purchase backup NG engine systems

## Frequency of Mention Analysis from The First Workshop

**I-What barriers/issues stand in the way of achieving State policy Goals – and DOE Smart Grid qualitative attributes? (Total of 186)**

- A-Technology Status Barriers/Issues (38, 20 percent of total)
  - 1-Storage related (12, 32 percent of the category)
  - 2-Communications, command & control (C3) related (5)
  - 3-General new technology related (4)
- B-Grid System Status Barriers/Issues (33, 18 percent)
  - 1-Microgrid/DG Architecture related (15, 45 percent)
  - 2-Current traditional architecture related (14)
  - 3-Electric Vehicle related (4)
- C-Regulations and Standards Status Barriers/Issues (44, 23 percent)
  - 1-Comments on lack of communications/interoperability-related standards and regulations (11, 25 percent)
  - 2-Inhibiting/unbalanced… related comments (9)
  - 3- Inconsistency related comments (5)
- D-Economic and Financial Barriers/Issues (27, 15 percent)
  - 1-Financing arrangements related (10, 37 percent)
  - 2-ROI to attract sources of capital related (5)
  - 3-Business models related (4)
- E-Customer readiness Barriers/Issues (26, 14 percent)
  - 1-Residential, commercial, or industrial consumers related (20, 77 percent)
  - 2-All consumers related (5)
  - 3-Utilities as customers related (1)
- F-Security and Privacy Barriers/Issues (18, 10 percent)
  - 1-Security-related (8, 44 percent)
  - 2-Privacy-related (7)
  - 3-Related to both (3)

**II-What Actions need to be taken to reduce/remove these barriers? (Total of 90)**

- A-Technology Development Actions (17, 19 percent)
  - 1-Storage development related (5, 29 percent)
  - 2-Backup generator related (2)
- B-Studies/Analyses/Tests Actions (21, 23 percent)
  - 1-Grid architectures related (8, 38 percent)
  - 2-Regulations and Standards related (6)
  - 3-(Tie) Testing related (3); Economics and financing studies related (3)
- C-Education Campaigns Actions (14, 16 percent)
  - 1- Stakeholders-related (6, 43 percent)
  - 2- Residential, commercial industrial consumers related (5)
  - 3- Public agencies related (2)
- D- Conduct Demonstrations Actions (12, 13 percent)
  - 1-(Tie) Grid level functions related (6, 50 percent); Grid elements related (6, 50 percent)
- E-Establish Incentives Actions (26, 29 percent)
  - 1-Incentivize residential, C&I consumers related (10, 38 percent)
  - 2-Incentivise utilities related (5)
  - 3-incentivise utilities and customers related (4)
- F-Special Action Category—Proposed 5 Step Plan for Creating Smart Grid 2020:
  - 1 - Create task force PUC, Energy Commission, CARB, finance, DOR, EPA - all CA Departments - state minimum criteria for Smart Grid plans from IOU operating in California

2 - Public hearings of plans and revisions to follow - consensus if not attained would be set by government
3 - Final plans would be published
4 - Hand-off from government to private sector of the roadmaps to respond to RFPs
5 - Time limit on entire process and force adoption of the plans

## A.2 Representing Smart Grid Architectures

There are many ways to represent smart grid architectures. In the course of this study, it was necessary to develop representations of smart grid architectures to allow orderly project team discussions of use cases and roadmaps without getting inundated in details. The need was to find a relatively simple framework to allow comparable representation of different smart grid architectures, ideally at any scale, from the State of California and beyond, down to an individual building.

Applying classical system engineering formalism to the problem, a "system definition" begins with definition of "system functions" and the "system physical elements" embodying those functions. The functional architecture is a combination of the system functions and functional relationships. The physical architecture likewise is comprised of the system physical elements and their physical relationships. The functional architecture is then mapped to the physical architecture, with assignment of ownership or control authority to yield the overall system architecture.

This formalization suggests the following protocols for describing smart grid architectures:

- Identify key **f**unctions associated with smart grids = {f}
- Identify key physical **e**lements associated with smart grids = {e}
- Identify key **s**takeholders associated with smart grids = {s}

Then, a particular smart grid architecture $\mathbf{A}_i$ may be described as $A_i = \{f_i, e_i, s_i, r_i\}$ where $f_i$, $e_i$, and $s_i$, are subsets of f, e and s, and $r_i$ is a set of "ownership" relationships between the $f_i$ and $e_i$, the $f_i$ and $s_i$, and the $e_i$ and $s_i$. In other words, the architecture is described by the set of functions it performs, the functional ownership by stakeholders, how functions are assigned to physical elements, and how those physical elements are owned.

A simple high-level list of smart grid functions {f} might include: energy production, energy consumption, energy storage, T&D, communications and control. A list of possible smart grid physical elements {e} might include: coal-fired generating plants, rooftop solar, microgrids, the internet, smart meters, EVs, hydroelectric storage facilities, regional control centers, etc. A simple list of stakeholder "owners" might include: utilities of all kinds, ratepayers, and third parties (which could include suppliers, owner operators, aggregators, and the like, who are neither strictly utilities nor strictly utility customers). There are other types of stakeholders for a given smart grid and architecture—ISOs, other connected grids, utilities other than electric, and regulators, for example, but for the level of abstraction used in this study, the three types of owners above seem adequate when defining smart grid architectures.

The list of physical elements is very long, but the approach taken here was to look at architecture alternatives at first using only the short lists of functions and stakeholders; then alternative assignments of functions to physical elements for each of the selected function and stakeholder architectural frameworks. Graphically, this yields a two-dimensional architecture framework as shown in Figure A-1.

**Figure A-1: Simplified physical architecture, ownership representation for a traditional utility model.**

| Function ⇨ / Owner ⇩ | Production (fossil fueled, renewables, CHP…) | Consumption | Storage | Transmission & Distribution | Communi-cations | Control |
|---|---|---|---|---|---|---|
| Utility Customer (commercial, industrial, residential, electric vehicle…) | | 30% Residential (ave e = .35)<br>35 % Commercial (ave e = .35)<br>30 % Industrial (ave e = .45)<br>5% EV (ave e=??) | | | | |
| Utility (private, public, electric, gas, thermal…) | 93% central coal<br>5% Peaking NG<br>2% Renewables | | Hydro electric, capacity 10% of daily ave. load | | Internet, telephone, surface mail & meter readers | (5% of residential & commercial customers have smart meters The rest are regular meters) |
| Third party (Supplier, regulator…) | | | | | | 12 |

Any electrical grid that embodies the nine *IEPR* goals for the California Smart Grid 2020 will, however, probably look much different from these traditional architectures. Figure A-2 depicts an advanced smart grid architecture, as it might appear beyond 2020.

**Figure A-2: Simplified physical architecture for an advanced smart grid.**

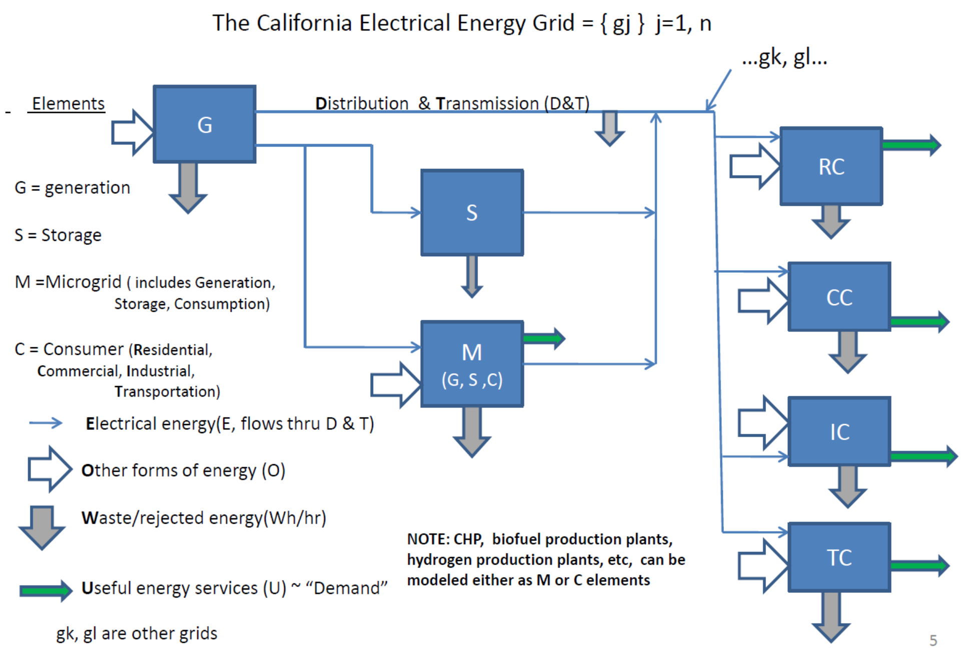
| Function ⇨ / Owner ⇩ | Production (fossil fueled, renewables, CHP…) | Consumption | Storage | Transmission & Distribution | Communi-cations | Control |
|---|---|---|---|---|---|---|
| Utility Customer (commercial, industrial, residential, electric vehicle…) | 60% distributed renewables; includes sellback to utility | 30% Residential (ave e = .40)<br>30 % Commercial (ave e = .40)<br>30 % Industrial (ave e = .50)<br>10% EV (ave e=??) | Distributed, battery packs, 150% of daily ave production, includes some EV | microgrids | | Demand response and sale based on real time prices |
| Utility (private, public, electric, gas, thermal…) | 25%Large STE | | STE thermal, 150% of daily ave production | Microgrid integration & augmentation | | Real time price setting for 40%↑ and 60%↓ |
| Third party (Supplier, owner/ operator, …) | 15% from outside the system, via regional real time energy market & utility | | | | dedicated wireless, shared with other Smart Grids | 13 |

Comparing these two figures, it is likely that utility customers will become much more engaged in most or all of the smart grid functions, owning a greater percentage of the grid generation capacity, storage and distribution elements as well as controlling much more of the daily demand and supply. Third parties also may be more in evidence in several of the functional areas, and microgrids may replace substantial portions of today's distribution systems, as well as perhaps obviating the need for new transmission capacity (a notion that warrants some system trade-off and economic analyses, given that building additional T&D capacity is expensive and requires long lead times and permits).

## A.3 Modeling Smart Grid Architectures

In order to quantify the impacts on GHG emissions of smart grid architectures, it is necessary to have the capability to quantitatively analyze smart grid architectures. A formalism that addresses average demand for electrical energy (MWHR/hr) over a period of time ("cycle time"), average demand for other forms of energy (e.g., MBTU/hr natural gas for space heating) over that period of time, appropriate efficiencies, operating mode durations as a function of cycle time (e.g., storage discharge time/cycle time, and charge time/cycle time), and data on GHG release associated with specific energy use (e.g., MT GHG released per MT of coal burned in typical electrical power plant) is desirable. Recognized as outside the scope of this study, development of such an "energy balance" approach and model is recommended to quantify the *IEPR* objectives attainment through various smart grid architectural options. The model would provide the amount of electrical energy and/or other forms of energy needed as input to the smart grid to satisfy the demand, and the amount of GHGs emitted by that particular smart grid architecture.

**Figure A-3: A simple electric energy flow model for grid architectural representations (proposed for further development).**

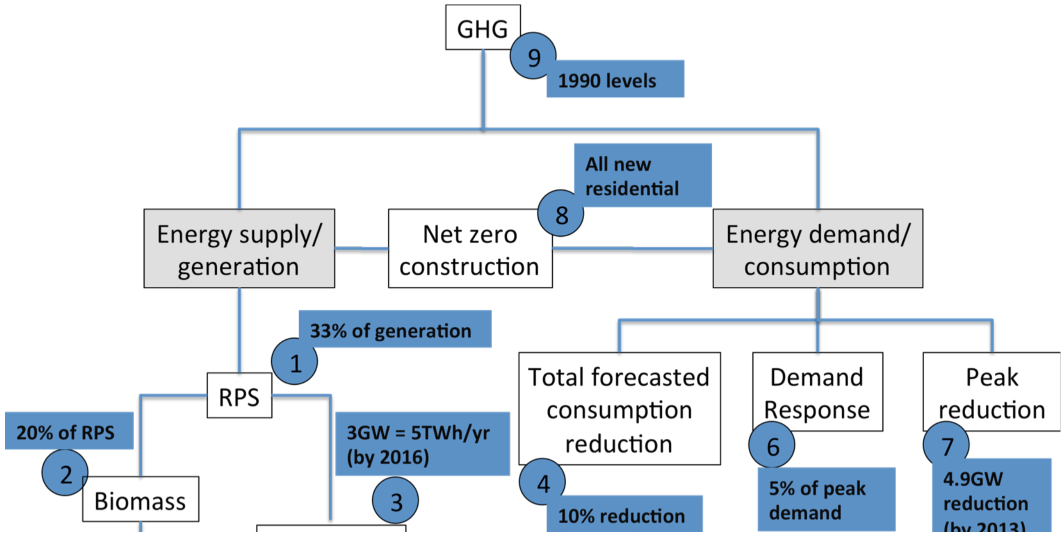



It is suggested that this representation, with suitable tailoring, can be used to represent the entire California Smart Grid and any set smart grid architectural components contained therein. In this approach the entire California Smart Grid may be modeled as an interconnected set of n grids.

The resulting simplified generic smart grid flow diagram to be modeled is shown in Figure A-3 for illustration. Note that a traditional grid would not contain a "microgrid" element, with its own generation, storage and consumption. Physical architecture is represented by selection of efficiencies, operating mode parameters and specific GHG emission parameters. *The inclusion of other forms of energy is necessary to model displacement strategies, where electrical energy displaces other forms of energy and vice versa, as well as CHP and distributed generation approaches.*

The nine *IEPR* goals influence one another – for example, the amount by which energy demand is reduced influences the amount of generation by renewables needed to meet the 33% RPS target. A schematic of these influences is portrayed in Figure A-4. The tiered structure is captured in the smart grid framework over which the recommended roadmap elements are shown.

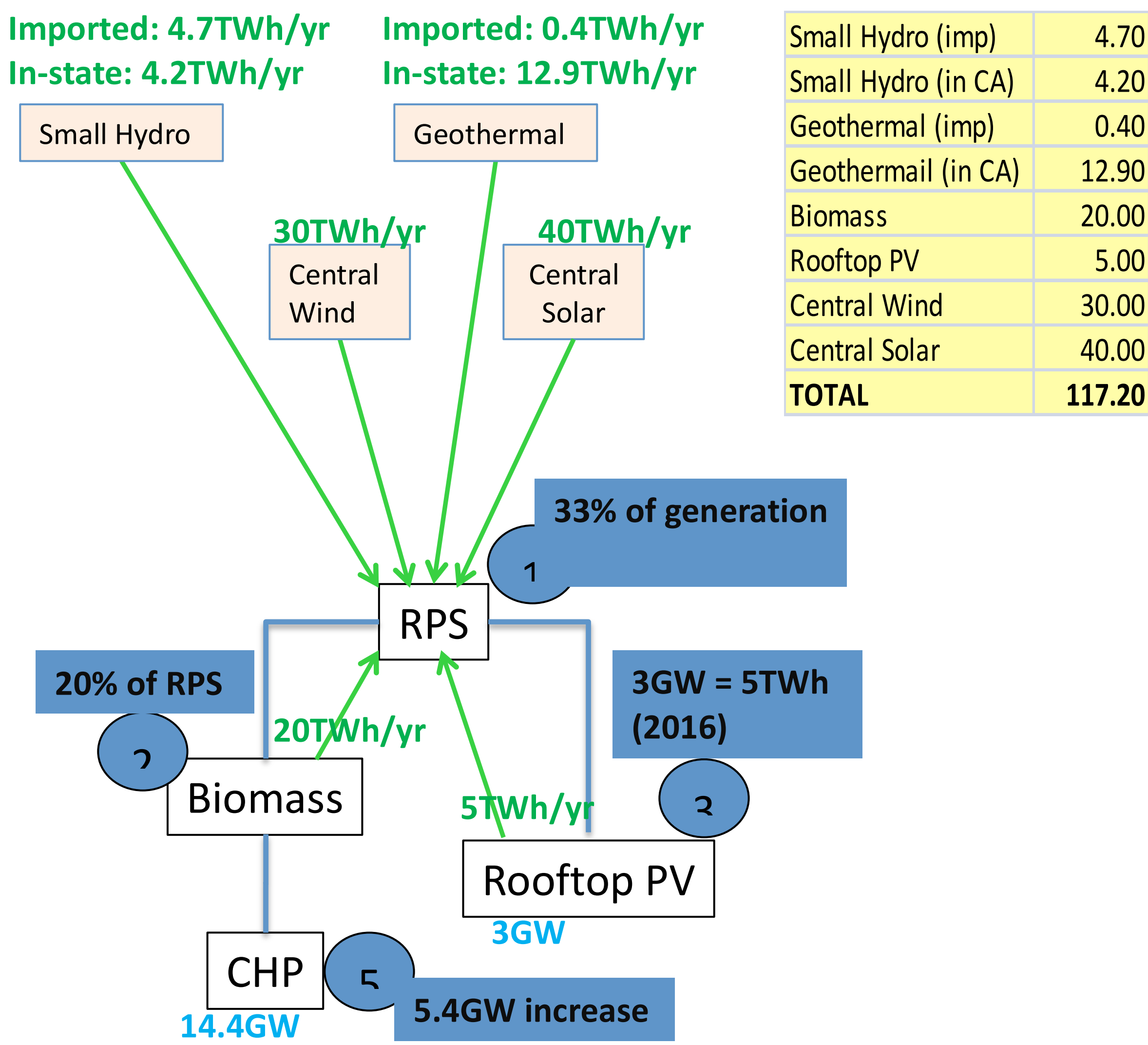
**Figure A-4: Nested structure of *IEPR* objectives in both the supply and demand domains.**




The white boxes represent the nine key policy goals, their adjacent blue circles repeat the 1 through 9 numbering used throughout this report, and the blue boxes summarize the goal targets. Goals are grouped into supply/generation goals on the left, demand/consumption goals on the right, with the GHG and net zero energy construction goals occupying an intermediate position, since these two goals influence, or are influenced by, both supply and demand. Blue lines show the major influences among the goals.

At this stage, the TIMA information collected in the course of this study is insufficient to be able to derive figures at this level of detail. Continued development of the model, including the integration of the perspectives of the utilities, is proposed. Figure A-5 shows a possible 2020 scenario for renewable energy generation.

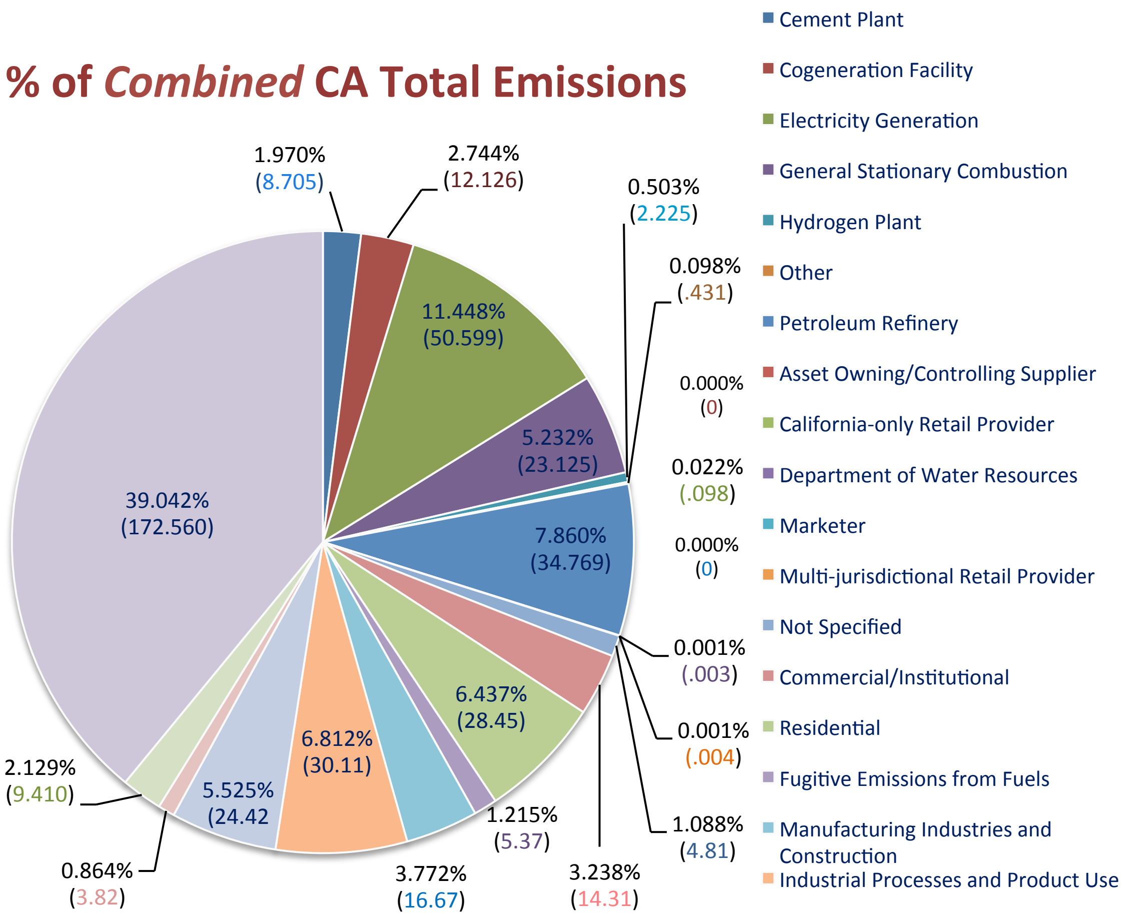
**Figure A-5: A possible 2020 scenario for power generation showing interrelationships between four *IEPR* goals.**




## A.4 GHG Emissions Modeling

To complete the quantitative representation of the California Smart Grid 2020 and its performance in terms of attainment of the *IEPR* goals, GHG release coefficients are needed. Accordingly, the Robert Thomas Brown Co. was contracted to research and capture the present inventory of GHG emissions sources in California with ties to energy-related activities (e.g. power plants, fuels manufacture, fuels transportation, transportation in general, energy conversion device manufacturing, etc.), and provide the estimated fraction that the total sum of all those activities contributes to California's entire GHG emissions (Figure A-6 and Table A-4).

**Figure A-6: Percent of California total GHG emissions by source.**




Such data, when combined with appropriate source inventory data would yield the necessary "average emission rate per specific source" data needed to estimate GHG emission performance associated with a specific smart grid architecture.[60]

[60] *California Greenhouse Gas Emissions Report*, January 2011, Robert Thomas Brown Co.

**Table A-4: Combined GHG Reporting Data – California Totals**
**(*GHG emissions sources in California with ties to energy-related activities)***

| **Activities** | **% of CA Total** | **California CO2e TOTAL (non-biomass + biomass) -million tonnes** | **GHG Energy Emissions Activity Count** |
|---|---|---|---|
| Cement Plant | 1.970% | 8.705 | 11 |
| Cogeneration Facility | 2.744% | 12.126 | 55 |
| Electricity Generation | 11.448% | 50.599 | 195 |
| General Stationary Combustion | 5.232% | 23.125 | 182 |
| Hydrogen Plant | 0.503% | 2.225 | 6 |
| Other | 0.098% | 0.431 | 25 |
| Petroleum Refinery | 7.860% | 34.739 | 22 |
| Asset Owning/Controlling Supplier | 0.000% | 0.000 | 1 |
| California-only Retail Provider | 0.022% | 0.098 | 56 |
| Department of Water Resources | 0.001% | 0.003 | 1 |
| Marketer | 0.000% | 0.000 | 31 |
| Multi-jurisdictional Retail Provider | 0.001% | 0.004 | 4 |
| Not Specified | 1.088% | 4.810 | 2 |
| Commercial/Institutional | 3.238% | 14.310 | 1 |
| Residential | 6.437% | 28.450 | 1 |
| Fugitive Emissions from Fuels | 1.215% | 5.370 | 3 |
| Manufacturing Industries and Construction | 3.772% | 16.670 | 11 |
| Industrial Processes and Product Use | 6.812% | 30.110 | 7 |
| Agriculture, Forestry and Other Land Use | 5.525% | 24.420 | 4 |
| Agriculture/Forestry/Fishing/Fish Farms | 0.864% | 3.820 | 1 |
| Waste | 2.129% | 9.410 | 2 |
| Transportation | 39.042% | 172.560 | 10 |
| ***CO2e EMISSION TOTALS:*** | ***100.000%*** | ***441.987*** | ***631*** |