

CALIFORNIA
ENERGY
COMMISSION

**DISTRIBUTED GENERATION AND
COGENERATION POLICY
ROADMAP FOR CALIFORNIA**

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ABSTRACT

This report defines a year 2020 policy vision for distributed generation and cogeneration for California. It also defines megawatt penetration targets for different distributed generation technologies and cogeneration. Additionally, this report describes long-term strategies, pathways, and milestones to take California from today's situation to attain the 2020 vision and the distributed generation and cogeneration capacity targets.

KEYWORDS

Distributed generation, cogeneration, photovoltaics, wind, biomass, combined heat and power, roadmap

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EXECUTIVE SUMMARY

Distributed generation (DG) and cogeneration are seen by many as potentially attractive energy resource options for California, both in the near-term and long-term. They can provide added capacity to meet peak demand, provide additional energy supply, and can be integrated into the current electrical infrastructure to reduce congestion. However, DG and cogeneration are, in many regards, major departures from how energy is procured, generated, and delivered to end-use customers. Therefore, policy issues need to be considered in a comprehensive, integrated approach.

In this context, staff defines DG 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 such technologies as photovoltaics; small wind; small biomass; small combined heat and power (CHP) or small cogeneration; small combined cooling, heat and power (CCHP); and small non-CHP systems.

Cogeneration is defined as electricity and heat production that is on-site or close to the load center that could be interconnected at distribution, sub-transmission, or transmission system voltages. Cogeneration in many instances can be systems from several kilowatts (kW) to hundreds of MW in size. For this roadmap, staff will define DG to mean systems less than 20 MW (including small cogeneration) and large cogeneration to mean systems greater than 20 MW.

Just as it is important to define what is considered DG and cogeneration, it is equally important to define what is not considered DG or cogeneration for the purposes of this roadmap. Hydroelectricity, geothermal, and non-CHP-related digester gas, landfill gas, and municipal solid waste are not considered DG as load is typically not close to generation and onsite load is negligible. Large (>20 MW) wind and large biomass projects are not considered DG as they are not likely to be interconnected at the distribution level.

The DG and Cogeneration Policy Roadmap (Roadmap) will provide a long-term perspective for DG and cogeneration policy. The Roadmap includes a 2020 DG and Cogeneration Vision and a Pathway with detailed actions and milestones for implementing policies. The Roadmap responds to current energy policy as directed by the *Integrated Energy Policy Report* (IEPR) and the *Energy Action Plan* (EAP).

The 2020 DG and Cogeneration Vision will require some new energy policy initiatives, which neither the EAP nor IEPR processes have addressed to date. The Roadmap presents potential policies to consider and the timing necessary to implement those policies for California to attain the 2020 DG and Cogeneration Vision. To continue pursuit of the Vision, the Roadmap will need periodic updates to adapt to and reflect changes in related policies and conditions. Implementing this

Roadmap will require the participation of agencies and stakeholders outside the Energy Commission.

The current regulatory framework encourages DG through subsidies, incentives, and recognition of DG in procurement and planning processes. Rules and regulations have been developed and put in place that encourage some forms of DG. The current rate structure in California is based on controlled averaged pricing. Externalities (for example, environmental impacts and locational value) are not incorporated into these rates. This approach assumes, from the customer's perspective, all electrons have the same value regardless of how, when, and where they were generated. Lack of a price signal that will change customer behavior undervalues the environmental, temporal, and locational aspects of many resources, including DG and cogeneration. In addition, the California Independent System Operator (California ISO) rules (for example, high DG aggregation requirement and metering requirements) highly discourage DG and cogeneration customers from participating in wholesale markets.

Large cogeneration is a major component of the generation fleet in California, serving about 15 percent of the peak demand in California. Most of these systems are long established and provide heat and electricity to industrial applications such as petroleum refining, paper, food processing and primary metals. Other significant cogeneration exists in the commercial sector for wastewater treatment facilities. Despite being a mature industry, the cogeneration industry struggles to sustain itself in California primarily due to market and some institutional barriers.

The DG industry is still a nascent industry that survives despite some difficult market conditions. There are numerous institutional, industry and market barriers that have impeded the growth and adoption of DG to date. Due to low penetration rates, DG installations do not have a large impact on, nor is it integrated with, the state's electric and natural gas infrastructures.

Although DG's potential is recognized, it is not currently a significant energy resource. The current DG penetration is 2.5 percent of total peak demand in California. As a result, many projects are highly customized and rely on incentives. The industry is fragmented with many small developers installing PV and natural gas engines provided by large equipment suppliers.

The Energy Commission staff developed a DG and Cogeneration Vision (Figure ES-1) based on current policy, future scenarios, and the market potential for DG and cogeneration:

California 2020 DG and Cogeneration Vision Statement

DG and cogeneration are significant components of California's electric system, meeting over 25% of the total peak demand.

- Customers have multiple options, including DG and cogeneration, to consider as part of their energy sourcing strategy.
- DG (customer and utility-owned) and cogeneration are integral to procurement, Transmission and Distribution planning and operations.
- A robust DG industry fulfills consumer and utility needs for affordable clean DG.
- Large cogeneration has maintained and increased its position as an important resource to California, and these facilities can readily participate in the wholesale power market.
- Transparent, dynamic rates and market structures are in place that account for environmental attributes and incorporates locational and temporal power system needs.
- The Renewables Portfolio Standard (RPS) mandates were satisfied, and there is no new RPS mandate. Regulated incentive programs have been phased out, and no new incentives are being put in place.
- Other barriers to DG have been removed and all DG permitting is efficient and environmentally responsible.

Table ES 1: 2020 DG and Cogeneration Vision Statement

To achieve its Vision, California will implement a strategy with three key elements:

1. *Support Incentives in the Near-term* – Over the next 10 years, California should continue to provide incentives for DG and cogeneration. Many of these incentives are identified in the IEPR, or are implemented by the California Public Utilities Commission (CPUC). However, these incentives will be discontinued over time as DG and cogeneration gain access to other markets.
2. *Transition to New Market Mechanisms* – To remove incentives and still encourage vibrant growth of DG and cogeneration in California, incentives will have to be replaced with market mechanisms, including transparent dynamic rates, which encourage DG and cogeneration. The roadmap will transition to these market mechanisms through – portfolio standards; allowing DG and cogeneration to compete more directly with central plants and traditional T&D; and providing access to emissions markets.
3. *Reduce Remaining Institutional Barriers* – California has made tremendous strides in the past several years in removing barriers to DG and cogeneration. However, there is still work to be done. The last strategic thrust addresses remaining barriers.

CHAPTER 1: INTRODUCTION

Need for Policy Roadmap

Distributed generation (DG) and cogeneration are potentially attractive energy resource options for California, both in the near-term and long-term. The DG and cogeneration concepts are major departures from how energy is procured, generated, and delivered to end-use customers. This raises many regulatory issues that public policy makers need to address in an integrated manner. In 1999, California made a concerted effort to begin to address policy issues related to DG¹. Since that time the *Integrated Energy Policy Report* (IEPR) and *Energy Action Plan* (EAP) process has become the main policy planning activity for energy in California. In the *2005 IEPR*, the Energy Commission addressed further policy issues for DG and expanded the discussion to cogeneration.² The IEPR/EAP process is the vehicle for state energy policy and drives all energy policy. While this process has provided a focal point for integrated policy discussions and has included many DG and cogeneration related issues, it is not a vehicle to provide implementation of DG and cogeneration specific policy.

DG and Cogeneration Definition

Defining what is and is not DG has continued to be an issue in California. In the last DG rulemaking at the CPUC, parties could not reach consensus on a definition. In the *2005 IEPR*, stakeholders had varying definitions for DG and cogeneration. For this report, staff defines DG 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 typically be interconnected at sub-transmission, or transmission system voltages. This definition includes such technologies as photovoltaics; small wind; small biomass; small combined heat, and power (CHP) or small cogeneration; small combined cooling, heat, and power (CCHP); and small non-CHP systems.

Cogeneration is defined as electricity and heat production that is on-site or close to the load center that could be interconnected at distribution, sub-transmission, or transmission system voltages. Cogeneration in many instances can be systems from several of kilowatts (kW) to hundreds of MW in size. For the purposes of this roadmap, staff will use the DG definition to mean systems less than 20 MW (including small cogeneration) and large cogeneration to mean systems greater than 20 MW.

Just as it is important to define what is considered DG and cogeneration, it is equally important to define what is not considered DG or cogeneration for this roadmap.

¹ California Energy Commission, *Distributed Generation Strategic Plan*, Publication # P700-02-002, June 2002

² California Energy Commission, *Integrated Energy Policy Report*, Publication #CEC-100-2005-007CMF, November 2005

Hydro, geothermal, digester gas, landfill gas, and municipal solid waste are not considered DG as load is typically not close to generation and onsite load is negligible. Large (>20 MW) wind and large biomass projects are not considered DG as they are not likely to be interconnected at the distribution level, nor located near load.

Purpose of Policy Roadmap

The cogeneration Policy Roadmap (Roadmap) will provide a long-term policy perspective for DG and cogeneration with detailed actions and milestones for implementing those policies. The Roadmap responds to energy policy as directed by the IEPR/EAP and will, in the future, inform the IEPR/EAP process. The detailed Roadmap will feed into the ongoing IEPR/EAP process and identify current and future policy issues for IEPR/EAP based on a Pathway to a 2020 DG and Cogeneration Vision. The Roadmap will also link existing and future DG and cogeneration policy initiatives with the correct policy implementation mechanisms.

Understanding the desired end-state for DG and cogeneration will provide context and a long-term perspective for policy makers, regulators, legislators, and industry stakeholders. Therefore, the Roadmap will look at policy initiatives aimed at achieving the 2020 Vision end-state. The robust adoption and integration of DG and cogeneration into the California energy enterprise is expected to take more time than the near-term planning horizon of the IEPR/EAP. For example, some policy initiatives may take longer and may be best supported by research and analysis that has yet to be completed. In addition, many DG technologies are still emerging, and the policy strategies for DG are likely to change as these technologies mature and California energy policy continues to evolve post-energy crisis. Therefore, the Roadmap will provide the Public Interest Energy Research program with a basis for future research and analysis to support these longer-term policy decisions.

Development of the Policy Roadmap

The Roadmap was developed by the Energy Commission DG Policy Team comprising Melissa Jones, Gary Klein, Tim Tutt, Lorraine White, Marwan Masri, Mike Smith, Scott Tomashefsky, Darci Houck, Art Soinski, John Beyer, John Sugar, and Mark Rawson. The development of the Roadmap relied on existing policy, both within and outside the DG area, and research performed under the PIER Distributed Energy Resources Integration Research Program. Additional market analysis and research was performed by the Policy Team to close knowledge gaps.

The Policy Roadmap has three major elements – the Current Situation in 2005, the Vision in 2020, and the Pathway to the Vision. The current market penetration for DG and cogeneration technologies (in MW) was determined to provide a baseline for the Current Situation in 2005. The Current Situation description was further augmented to include a characterization of the existing regulatory framework in 2005, as well as the key industry characteristics that define the health of the DG and cogeneration industry today.

The Vision in 2020 was developed by examining potential scenarios for California's energy future in 2020. The team used previous scenario planning efforts³ to identify a detailed Vision for DG and cogeneration in California. This Visioning activity was informed by existing policy documents and PIER-Distributed Energy Resource Integration Program research⁴ to be consistent with current policy and to leverage the latest industry and academic research.

A strategy was formed – based on the tools available to policy makers in the near- and long-term – that would allow California to reach its DG and Cogeneration Vision. This strategy provided a foundation for the Pathway including defining milestones from the 2005 Current Situation to the 2020 Vision. To ground the Vision – to ensure it has stretch but realistic goals and to determine the timing of milestones – market potential and penetration. Growth rates for technology penetration were determined and compared against historic penetration of similar technologies to make certain that the penetration growth rates are realistic.

³ California Energy Commission, *Identifying Distributed Energy Resources Research Priorities Through Emerging Value Networks*, Navigant Consulting (NCI), Publication #700-02-002, July 2002; *Energy and Environment Scenarios for California*, Global Business Network (GBN), 2002; California Energy Commission, *California's Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios*, (Electric Power Group) (CERTS), Publication #500-03-106, November 2003; California Energy Commission, *Final DG Scenario Development Report*, UC Irvine, Publication #500-00-033, September 2003; *Policy and Regulatory Roadmaps for Integration of Distributed Generation and the Development of Sustainable Electricity Networks*, European Commission, August 2004

⁴ California Energy Commission, *2003 Integrated Energy Policy Report*, Publication #100-03-019, December 2003; California Energy Commission, *2005 Integrated Energy Policy Report*, Publication #100-2005-007-CMF, November 2005; California Energy Commission and California Public Utilities Commission, *Energy Action Plan II – Implementation Roadmap for Energy Policies*, September 21, 2005; California Energy Commission, *Recommended Changes to Interconnection Rules*, Publication #100-2005-003-CMF, February 2005; California Energy Commission, *Assessment of California Combined Heat and Power Market and Policy Options for Increased Penetration*, Publication #500-2005-173, November 2005; California Energy Commission, *Distributed Generation Strategic Plan*, Publication # P700-02-002, June 2002; California Energy Commission Project, *Evaluation of Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based Distributed Generation/Combined Heat and Power, Competitive Energy Insight Inc.*, Contract # 500-04-015, Publication #CEC-500-2006-068; California Public Utilities Commission, *Distributed Generation Policy Proceeding (R.04-03-017)*, <http://www.cpuc.ca.gov/proceedings/R0403017.htm>; California Energy Commission, *Distributed Generation OII (Order Instituting Investigation) Implementation and Distribution Planning (Docket #04-DIST-GEN-1, #03-IEP-1)*, http://www.energy.ca.gov/distgen_oii/index.html; California Air Resources Board, *Distributed Generation Certification Program*, <http://www.arb.ca.gov/energy/dg/dg.htm>; California Energy Commission, *Rulemaking Pertaining to Data Collection for Qualified Departing Load CRS Exemptions, Docket #03-CRS-01*, http://www.energy.ca.gov/exit_fees/index.html

CHAPTER 2: CURRENT SITUATION

Current DG and Cogeneration Regulatory and Industry Framework

Developing a Vision and a Pathway to the Vision requires a clear understanding of the Current Situation for DG and cogeneration in California in terms of the regulatory framework (Table 1) and DG and cogeneration industry characteristics (Table 2). The current regulatory framework encourages DG through subsidies, incentives and recognition of DG in procurement and planning processes. Rules and regulations have been developed and put in place that encourage some forms of DG. In the case of large cogeneration, there are limited incentives and little consideration of cogeneration in procurement and planning processes. Static, controlled-average electric rate structures and pricing, which do not account for the full costs of electricity and do not send consumers the proper price signals are preventing the realization and compensation for some of the locational, temporal, and environmental benefits of DG and cogeneration.

Table 1: Summary of Current Regulatory Framework

Regulatory Characteristics	Current Situation
Planning and Procurement Policy	<ul style="list-style-type: none"> • State energy policy aims to incorporate DG into utility procurement and DG into distribution planning processes. • Cogeneration has little consideration in utility procurement and planning processes. • Renewables Portfolio Standard (RPS) exists.
Rate Structures	<ul style="list-style-type: none"> • Energy prices are not transparent; inhibits customer response to actual costs. • Current rate structure is based on controlled averaged pricing that does not include locational and environmental externalities. • It is difficult for DG to participate in wholesale power markets. • It is difficult for cogeneration to execute new contracts with utilities.
Incentives	<ul style="list-style-type: none"> • Incentives (subsidies, tax credits, low interest loans) are in place to promote clean DG. • Incentives are limited for cogeneration.
Rules and Regulations	<ul style="list-style-type: none"> • Rules and regulations (e.g. interconnection rules, net metering, and exemptions from standby charges) have been changed to benefit some or all DG.

Current state energy policy aims to incorporate DG and cogeneration into utility procurement and DG into distribution planning processes. The *2003 Energy Action Plan* identified a preferred loading order for California. DG is a preferred resource in the loading order, following energy efficiency, demand response, and renewables. In addition, the *2003 IEPR* aimed to create a transparent distribution planning process that addresses the benefits of DG and determines the extent to which DG can/should be incorporated into utility resource planning and procurement. There are other related policies aimed at environmental aspects that also impact DG. The *2005 IEPR* broadened the policy consideration for DG and addressed cogeneration for the utility system benefits, energy efficiency improvements, other critical infrastructure security and reliability support, and greenhouse gas benefits it affords California. California has an RPS requirement for utilities to increase use of energy from renewable resources annually until 2010, when the RPS would be at 20 percent. The CPUC requires utilities to use a “greenhouse adder” of \$8 per ton in their long-term procurement plans.

The current rate structure in California is based on controlled averaged pricing. Externalities (for example, environmental impacts and locational value) are not incorporated into these rates. This approach assumes, from the customer’s perspective at the retail level, all electrons have the same value regardless of how, when, and where they were generated. Lack of a price signal that will change customer behavior undervalues the environmental, temporal and locational aspects of DG or cogeneration. In addition, California ISO rules (for example, high DG aggregation requirement and metering requirements) highly discourage DG and cogeneration customers from participating in wholesale power market.

Incentive programs are in place to promote clean DG. The Energy Commission administers the Emerging Renewables Program (ERP) that provides rebates for residential and small business customers. The CPUC administers the Self-Generation Incentive Program (SGIP), which provides rebates for certain DG technologies and unit sizes not covered by the ERP rebate. Low-interest loans are available from the Energy Commission for renewable DG projects at government facilities and institutions. State tax credits for PV and wind systems exist; however, there are no state tax credits for cogeneration.

While rules and regulations are in place that benefit DG in some instances, other rules and regulations hinder some forms of DG. Most renewable DG qualifies for net energy metering and is exempt from departing load⁵ and standby charges. “Clean DG” is currently exempt from standby charges and partially exempt from departing load charges. Some interconnection requirements are standardized under Rule 21, reducing the time and costs for interconnecting DG. A new California Air Resources Board standard for 2007 may make it difficult for some DG technologies to be air-permitted without restrictive higher costs. Existing tariffs for natural gas require large DG facilities to purchase natural gas from a third-party supplier.

⁵ A customer with departing load generally refers to utility customers that leave the utility system in part or entirely to self-generate electricity.

Table 2: Summary of Current DG and Cogeneration Industry Characteristics

Industry Characteristics	Current Situation
Economics	<ul style="list-style-type: none"> • DG equipment costs typically too high (i.e., some DG technologies not economical without incentives); however, some CHP projects are economically attractive even without incentives. • Some cogeneration projects are cost-competitive without incentives. Large cogeneration projects have attractive economics, particularly those with large thermal loads and the ability to export.
Financing	<ul style="list-style-type: none"> • Capital is available for attractive projects.
Technology	<ul style="list-style-type: none"> • DG projects dominated by natural gas engine CHP or photovoltaics. • Large cogeneration projects dominated by combustion turbines and combined cycle systems.
Value Proposition to Customer	<ul style="list-style-type: none"> • Lower electricity costs – cogeneration. • Green power – photovoltaics.
Industry Participants	<ul style="list-style-type: none"> • For DG, “large” equipment suppliers and “small” DG developers. • For large cogeneration, “large” equipment suppliers, “large” developers, and sophisticated customers. • Many early DG entrants have been unsuccessful and exited the market.
Infrastructure	<ul style="list-style-type: none"> • With the current DG penetration, both the natural gas and electric distribution systems can accommodate DG. For large cogeneration, natural gas and transmission systems can accommodate these facilities. • Adequate communications, control, and net metering technology is available.

The current state of DG and cogeneration is shaped in large part by the current regulatory framework and by other industry characteristics (Table 2). The DG industry is still a nascent industry that survives despite difficult market conditions. Many projects are highly customized and rely on incentives. The industry is fragmented with many “small” developers installing PV and natural gas engines provided by large, well-established equipment suppliers. There is fragmentation by technology type and diverse business models. Many early market entrants were unsuccessful and have exited the market; however, new players continue to enter

the market attracted by current conditions such as high energy prices and incentives.

Due to low penetration rates, DG installations do not have a large impact on, nor are they integrated with, the state's electric and natural gas infrastructures. Although DG's potential is recognized, it is not a significant energy resource in terms of capacity or energy. A perception exists that in the future the electric and natural gas infrastructures will not be able to accommodate a large penetration of DG. Adequate communication, control, and net metering technologies are available, although a robust communications and control infrastructure is not in place to facilitate a large penetration of DG. Due to its larger inventory, California is dependent upon large cogeneration, and these plants are integrated to a large extent into the operations of the state's electric and natural gas infrastructure.

Installed costs (equipment, engineering, and construction) for recent DG projects are typically too high and would not likely go forward without incentives. There are some DG CHP projects that are economically attractive even without incentives. Most large cogeneration projects are economic without incentives. High electric prices create opportunities for DG projects; however, increasing natural gas prices limit the opportunities for non-renewable projects. Capturing more of the benefits of these DG projects could improve the economics for DG. Large cogeneration projects at industrial facilities are designed to meet thermal needs with electricity as a byproduct. However, the inability to cost-effectively export excess electricity has limited the size of many of these plants. Simply being able to economically export would improve the investment outlook for these industrial and commercial sector end-users. Financing DG and cogeneration projects is typically not a barrier. There is a range of financing options (debt, project capital, third-party service providers, and so forth) for attractive projects. Low-cost loans are available for some DG projects.

The majority of DG installations are photovoltaic (by number of installations) and natural gas-fired CHP systems (by capacity). Most DG customers are installing these systems for green power or to reduce energy costs. However, many customers are placing value on other aspects of DG (for example, Carbon dioxide emissions and reliability). Large cogeneration systems are dominated by combustion turbines and combined-cycle power plants. To a lesser degree, boiler/steam turbine plants are also used.

With the current DG penetration, both the natural gas and electric distribution systems can accommodate DG.

Current DG and Cogeneration Market Penetration

The current DG penetration is 2.5 percent of total peak demand in California (Table 3). The majority of DG capacity is CHP units (reciprocating engines fueled with natural gas). The current penetration of large cogeneration is 14.5 percent.

Table 3: Current Situation – DG and Cogeneration Penetration⁶

Technology	2004 (MW)
DG Technologies	
Small Biomass	80
Small Wind	1.4
PV	93
Co-generation (CHP)	975
Non-cogeneration (Peaking / Primary)	234
Total DG Technologies	1,383
Total Large Cogeneration	8,155
DG Technologies + Large Cogeneration	9,538
Net Peak Demand	56,435
Penetration of DG	2.5%
Penetration of Large Cogeneration	14.5%
Penetration of DG + Large Cogeneration	17.0%

⁶ Note: See *Appendix A: Current Situation DG and Cogeneration Penetration – Sources and Assumptions*

CHAPTER 3: DG AND COGENERATION POLICY VISION

DG and Cogeneration Scenarios

The team used the existing strategic planning frameworks and reports to construct four possible scenarios for DG and cogeneration in California⁷ (Figure 1). In the “Market Competitive Energy” scenario, California’s electricity needs are met by a large fleet of central power plants, supported by a robust transmission and distribution (T&D) system and a robust, wholesale competitive electricity market that encourages investment. This scenario is typified by few environmental constraints to building out the central generation and delivery system, and where regulations are structured to rely on market forces to dictate electricity system investment and energy consumption (for example, transparent and dynamic pricing exists).

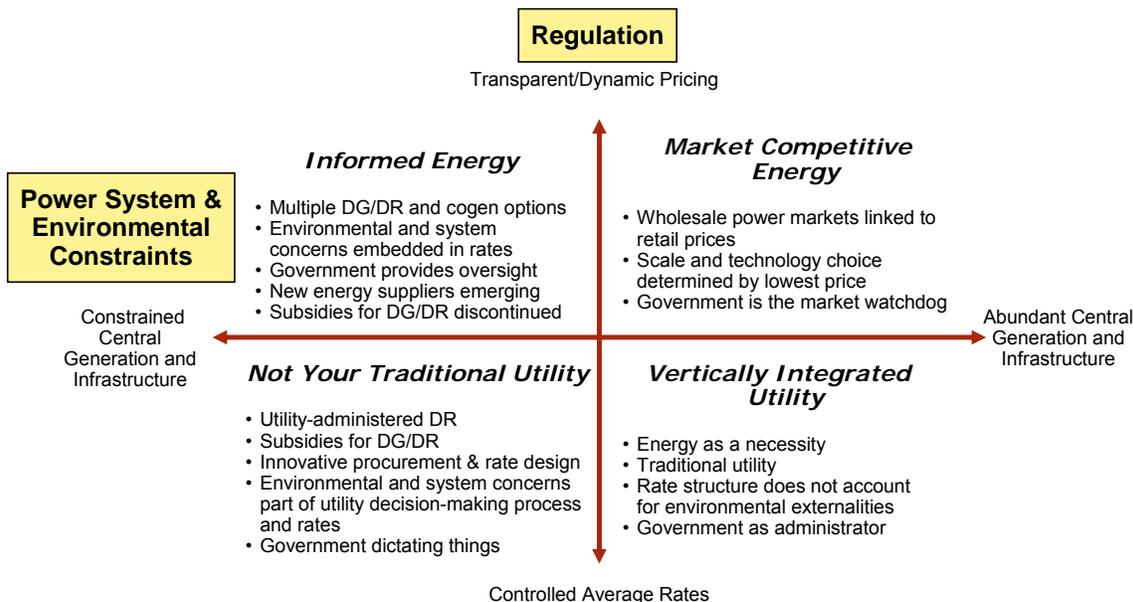
The “Vertically Integrated Utility” scenario is similar to the “Market-Competitive Energy” scenario in terms of energy infrastructure but would rely on regulations to provide sufficient economic incentives for investment. This scenario is further typified by controlled-averaged pricing of electricity where there is little transparency to the price for electricity and its true cost at any given time throughout the day.

The “Not Your Traditional Utility” scenario also would depend heavily on regulations to encourage energy infrastructure investment; however these regulations would offer more incentives for alternatives (DG, demand response, energy efficiency) than for traditional central power plants. Controlled-averaged pricing of electricity would still exist; however, consideration of environmental and peak power system constraints and costs would be evaluated as part of the utilities’ procurement and rate design processes.

The “Informed Energy” scenario would leverage market structures that would allow alternative resources to compete more readily with central power plants to meet California’s energy needs. This scenario is further typified by existence of transparent and dynamic pricing where customers see the true costs of electricity throughout the day that reflect the higher economic and environmental cost of electricity when the power system is constrained during peak periods. The “Informed Energy” scenario was selected as the basis for the DG and Cogeneration Vision since it provides the best balance in achieving the IEPR’s objectives of affordable energy, energy reliability, public health, economic well-being, and environmental quality. It also provides the best market opportunities for DG and cogeneration since many of the external costs of providing electricity during peak system demands are internalized and not lost to the effects of controlled-averaged pricing, thus resulting in more equal economic and environmental footing between central generation and DG and cogeneration.

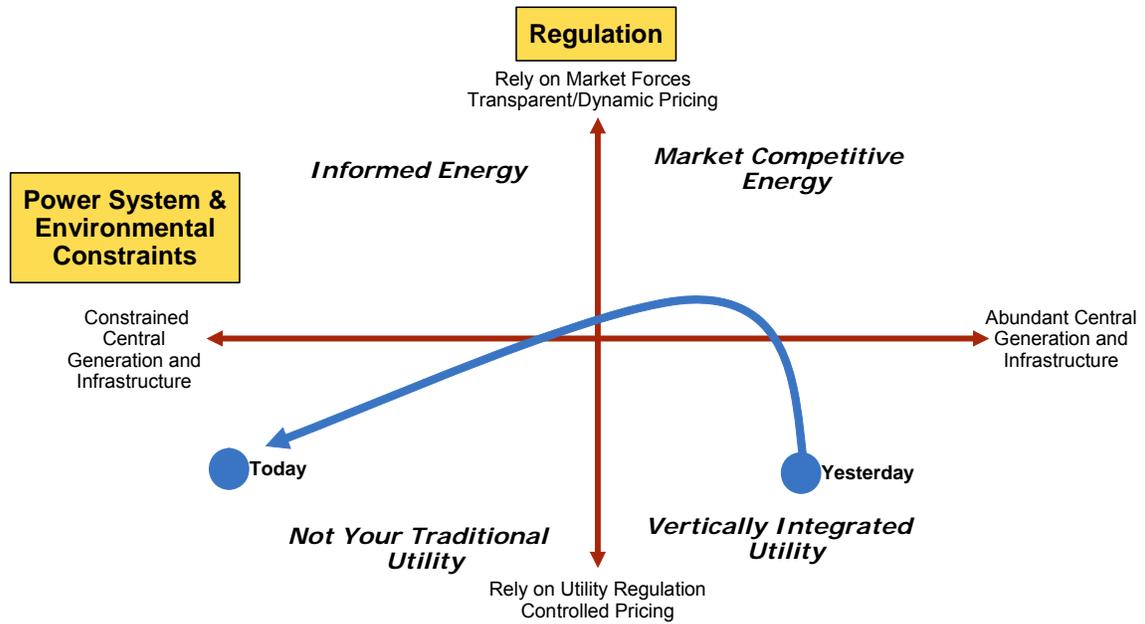
⁷ See *Appendix B: DG Scenarios – Background* for a description of the key elements used to construct the scenarios and Table B-1 for more detailed description of scenarios.

Figure 1: DG and Cogeneration Scenarios



Three of the four scenarios are very similar to conditions that California has been in or aspired for in the last decade. Indeed, one could say that California followed a path through these scenarios over the last decade (Figure 2). Our failed attempt to get to the “Market Competitive Energy” scenario led us to a situation where the state had an underinvestment in central plants and the related T&D infrastructure to support them, and a heavier reliance on utility regulations and controlled pricing. Regulatory uncertainty and other financial and environmental constraints have limited the amount of new central station capacity. The 2020 DG and Cogeneration Vision would again move California to more transparent, dynamic pricing of electricity. However, it is unlikely, nor desirable, for California to rely solely on a strategy that included only central power plants – it is currently the last option in the state’s *Energy Action Plan* loading order. This would perpetuate the boom/bust or abundance/constraint cycle of central generation that California experienced in decades past. It would also not ensure that more environmentally friendly generation sources are developed. Finally, it would not address the reliability and security problems becoming more prevalent with today’s central generation system paradigm. Allowing all potential resources to compete equally for the same or greater value will reduce the risks and costs of providing electricity to California.

Figure 2: DG and Cogeneration Scenarios and the 2020 DG and Cogeneration Vision



DG and Cogeneration Policy Vision Statement

Consideration of the “Informed Energy” scenario leads to the following vision statement for DG and cogeneration:

California 2020 DG and Cogeneration Vision Statement
<p>DG and cogeneration are significant components of California’s electric system, meeting over 25% of the total peak demand.</p> <ul style="list-style-type: none">• Customers have multiple options, including DG and cogeneration, to consider as part of their energy sourcing strategy.• DG (customer and utility-owned) and cogeneration are integral to procurement, Transmission and Distribution planning, and operations.• A robust DG industry fulfills consumer and utility needs for affordable clean DG.• Large cogeneration has maintained and increased its position as an important resource to California, and these facilities can readily participate in the wholesale power market.• Transparent, dynamic rates and market structures are in place that account for environmental attributes and incorporate locational and temporal power system needs.• The Renewables Portfolio Standard (RPS) mandates were satisfied, and there is no new RPS mandate. Regulated incentive programs have been phased out, and no new incentives are being put in place.• Other barriers to DG have been removed, and all DG permitting is efficient and environmentally responsible.

Table 4: 2020 DG and Cogeneration Vision Statement

Regulatory and Industry Framework for Vision 2020

The 2020 DG and Cogeneration Vision can be further detailed by examining the regulatory framework (Table 5) and DG and cogeneration industry characteristics (Table 6) required to achieve this Vision.

In the 2020 Vision, there is a diversified portfolio mix, including central generation, demand response, energy efficiency, DG, and cogeneration. Market mechanisms are in place that allow DG and cogeneration to compete with central power plants equally. Transparent rate structures connect customers more closely to market forces. Externalities are internalized in rates, including environmental impacts and T&D constraints. DG and cogeneration customers are allowed to more easily participate in the wholesale power market. Aggregation tools, which are in place, allow DG customers to fully participate in wholesale power market.

In the 2020 Vision, regulated incentive programs have been phased out, and no new incentives are being put in place. The Energy Commission's ERP and California Public Utilities Commission's SGIP have ended. There are no utility incentives for promotion of DG, but utilities can own DG. State tax credits for cogeneration owners or suppliers have also ended.

Other rules have changed to allow DG and cogeneration to compete as an energy resource on a more level playing field. Net-metering for DG that provides net societal benefits is in place. Departing load charges have ended for all customers. DG customers pay for standby service at volumetric rates. All DG permitting is efficient and environmentally responsible.

Table 5: 2020 Vision Regulatory Framework

Characteristics	Situation in 2005	2020 Vision
Planning and Procurement Policy	<ul style="list-style-type: none"> • State energy policy aims to incorporate DG into utility procurement and DG into distribution planning processes. • Cogeneration has little consideration in utility procurement and planning processes. • Renewables Portfolio Standard (RPS) exists. 	<ul style="list-style-type: none"> • Diversified portfolio mix, including central generation, demand response, energy efficiency, and DG, and cogeneration. • Market mechanisms are in place that allow DG and cogeneration to compete with central generation. • RPS has been satisfied, and mandate has ended.
Rate Structures	<ul style="list-style-type: none"> • Energy prices are not transparent; inhibits customer response to actual costs. • Current rate structure is based on controlled averaged pricing that does not include locational and environmental externalities. • It is difficult for DG to participate in wholesale power markets. • It is difficult for cogeneration to execute new contracts with utilities. 	<ul style="list-style-type: none"> • Rate structures are transparent and connected to market forces. • Externalities are internalized in rates, including environmental impacts and Transmission and Distribution constraints. • DG customers and cogeneration are allowed to more easily participate in wholesale power market.
Incentives	<ul style="list-style-type: none"> • Incentives (subsidies, tax credits, low-interest loans) are in place to promote clean DG. • Incentives are limited for cogeneration. 	<ul style="list-style-type: none"> • No regulated incentive programs are in place.
Rules and Regulations	<ul style="list-style-type: none"> • Rules and regulations (e.g. interconnection rules, net metering, exemptions from standby charges) have been changed to benefit some or all DG. 	<ul style="list-style-type: none"> • DG and cogeneration compete on a level playing field.

In the 2020 Vision, the DG and cogeneration industry is strong, growing, and dynamic (Table 6). Technology advances and mass customization have reduced DG installation costs, whereas large cogeneration facilities continue to be cost-effective. DG and cogeneration are an economically attractive option for many customers. Investment and operating costs are predictable and favorable. DG and cogeneration benefits are captured by customers, rate structures, and other markets. Simple, low-cost financing is available for attractive DG and cogeneration projects. There are multiple DG technology and fuel options that compete with one another. Some DG technologies cannot compete, while others have been successful. This “survival of the fittest” environment has encouraged innovation and new products that meet customers’ needs for low-cost, green, and premium power. This situation attracts well capitalized companies to complete the DG value network: project developers, project financing, insurance, equipment suppliers, and so forth.

DG and cogeneration have reached a considerable penetration level and are seen as a significant resource. A communications and control backbone, which supports the “Informed Energy” scenario, allows suppliers and customers to be informed of energy demands and pricing on a near to real-time basis. This information technology infrastructure allows DG to be an integral part of the larger electricity infrastructure. Electric and natural gas distribution systems can accommodate the increasing penetration of DG, as can the transmission system for large cogeneration facilities.

Table 6: 2020 Vision DG and Cogeneration Industry Characteristics

Characteristics	Situation in 2005	2020 Vision
DG Economics	<ul style="list-style-type: none"> • Equipment costs typically too high (i.e., some DG technologies not economical without incentives); however, some CHP projects are economically attractive even without incentives. • Some cogeneration projects are cost competitive without incentives. Large cogeneration projects have attractive economics particularly those with large thermal loads and the ability to export. 	<ul style="list-style-type: none"> • DG and cogeneration are economically attractive option for many customers without incentives.
Financing	<ul style="list-style-type: none"> • Capital is available for attractive projects. 	<ul style="list-style-type: none"> • Simple, low-cost financing is available for DG and cogeneration projects.
DG Technology	<ul style="list-style-type: none"> • DG projects dominated by natural gas engine CHP or photovoltaics. • Large cogeneration projects dominated by combustion turbines and combined-cycle systems. 	<ul style="list-style-type: none"> • Multiple technology options exist, “survival of the fittest.”
Value Proposition to Customer	<ul style="list-style-type: none"> • Lower electricity costs – cogeneration. • Green power – Photovoltaics. 	<ul style="list-style-type: none"> • Customer options include low cost, green, and premium power.
Industry Participants	<ul style="list-style-type: none"> • “Large” equipment suppliers and “small” DG developers. • For large cogeneration, “large” equipment suppliers, “large” developers, and sophisticated customers. • Many early DG entrants have been unsuccessful and exited the market. 	<ul style="list-style-type: none"> • Environment attracts well capitalized world class companies: project developers, project financing, insurance, and equipment suppliers.
Infrastructure	<ul style="list-style-type: none"> • With the current DG penetration, both the natural gas and electric distribution systems can accommodate DG. For large cogeneration, natural gas and transmission systems can accommodate these facilities. • Adequate communication, control, and net metering technologies are available. 	<ul style="list-style-type: none"> • Electric and natural gas distribution systems can accommodate the amount of DG, as can the transmission system for large cogeneration facilities. • Information technology and communication backbone that allows for “Informed Energy.”

DG and Cogeneration Market Penetration in the Vision 2020

To achieve the Vision 2020 market penetration target of 26 percent of total peak demand being met by DG and large cogeneration, a mix of technologies and fuels will be required (Table 7). The basis of the 2020 targets for the various technologies are based on current policy (for example, Million Solar Roofs Initiative, extrapolation from Renewables Portfolio Standards) or market studies that include the market conditions described in the Vision (for example, California Energy Commission, *Assessment of California Combined Heat and Power Market and Policy Options for Increased Penetration*, Publication #500-2005-173, November 2005).

Table 7: 2020 DG and Cogeneration Vision – DG and Cogeneration Penetration

Technology	2020 (MW)	2020 Projection Assumptions
DG Technologies		
Small Biomass	300	In 2004 electricity from all renewables generates 10.6% of CA's electricity. Assuming an RPS of 33% in 2020, 2020 renewable generation would be 3.8 times greater than 2004.
Small Wind	10	The share small wind DG composes of renewable generation will increase by a factor of 2 in 2020 compared to 2004. Therefore, 2020 small wind generation would be 7.6 times greater than 2004.
PV	3,000	Governor's Million Solar Roof Initiative 3,000 MW target is achieved in 2020.
Co-generation (CHP)	3,300	2005 EEA California CHP Study aggressive market scenario. Considered installations < 20 MW. Includes small biomass CHP projects.
Non-cogeneration (Peaking / Primary)	790	Same growth as CHP
Total DG Technologies	7,400	
Total Large Cogeneration	11,200	2005 EEA California CHP Study aggressive market scenario. Considered installations >20 MW.
Total DG + Large Cogeneration	18,600	
Net Peak Demand	70,776	California Energy Demand 2006 – 2016. The annual growth rate of 1.2% for the forecast period, 2008 – 2016, is used for 2016 – 2020.
Penetration of DG	10.5%	Total DG/Net Peak Demand
Penetration of Large Cogeneration	15.8%	Total Large Cogen/Net Peak Demand
Penetration of DG + Large Cogeneration	26.3%	

CHAPTER 4: DG AND COGENERATION POLICY PATHWAY TO ACHIEVE VISION 2020

Overall Strategy

To achieve its Vision, California will implement a strategy with three key thrusts⁸:

- Support Incentives in the Near-Term.
- Transition to New Market Mechanisms.
- Reduce Remaining Institutional Barriers.

Support Incentives in Near-Term

Over the next 10 years, California should continue to provide existing incentives and add new incentives for DG and cogeneration. Many of these incentives are identified in the IEPR. However, these incentives will be discontinued over time (Figure 3) as new market mechanisms are implemented.

There are four areas of incentives:

- Provide tax credits for the capital expense of renewable and clean DG systems in the near-term.
- Continue ERP and SGIP programs in the near-term.
- Support adoption of renewable and clean DG systems by providing low-interest loans in the near-term.
- Provide value for environmental attributes in the near-term through use of production tax credits (PCT) for criteria pollutants and CO₂ emission reductions.

⁸ In addition to these three key thrusts, the Energy Commission will continue to engage in R&D activities that will reduce the cost of and improve the performance of DG technologies.

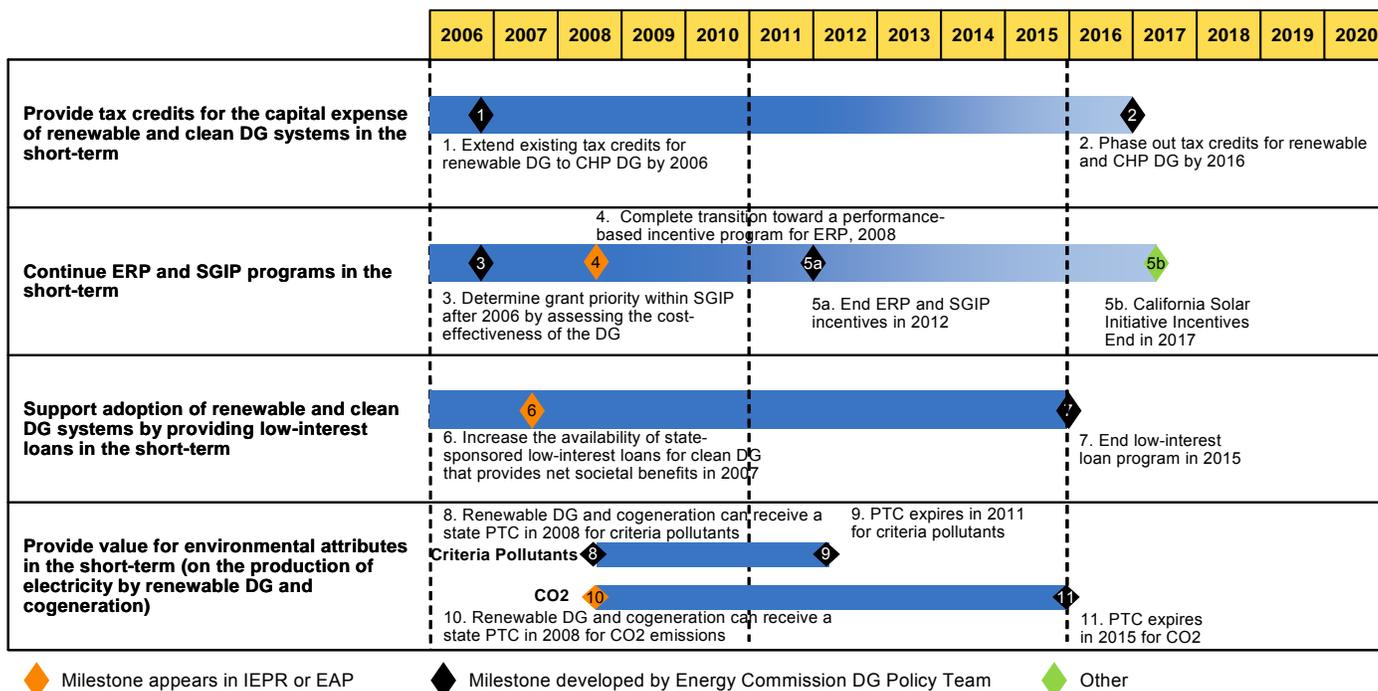


Figure 3: Strategic Thrust – Support Incentives in the Near-Term⁹

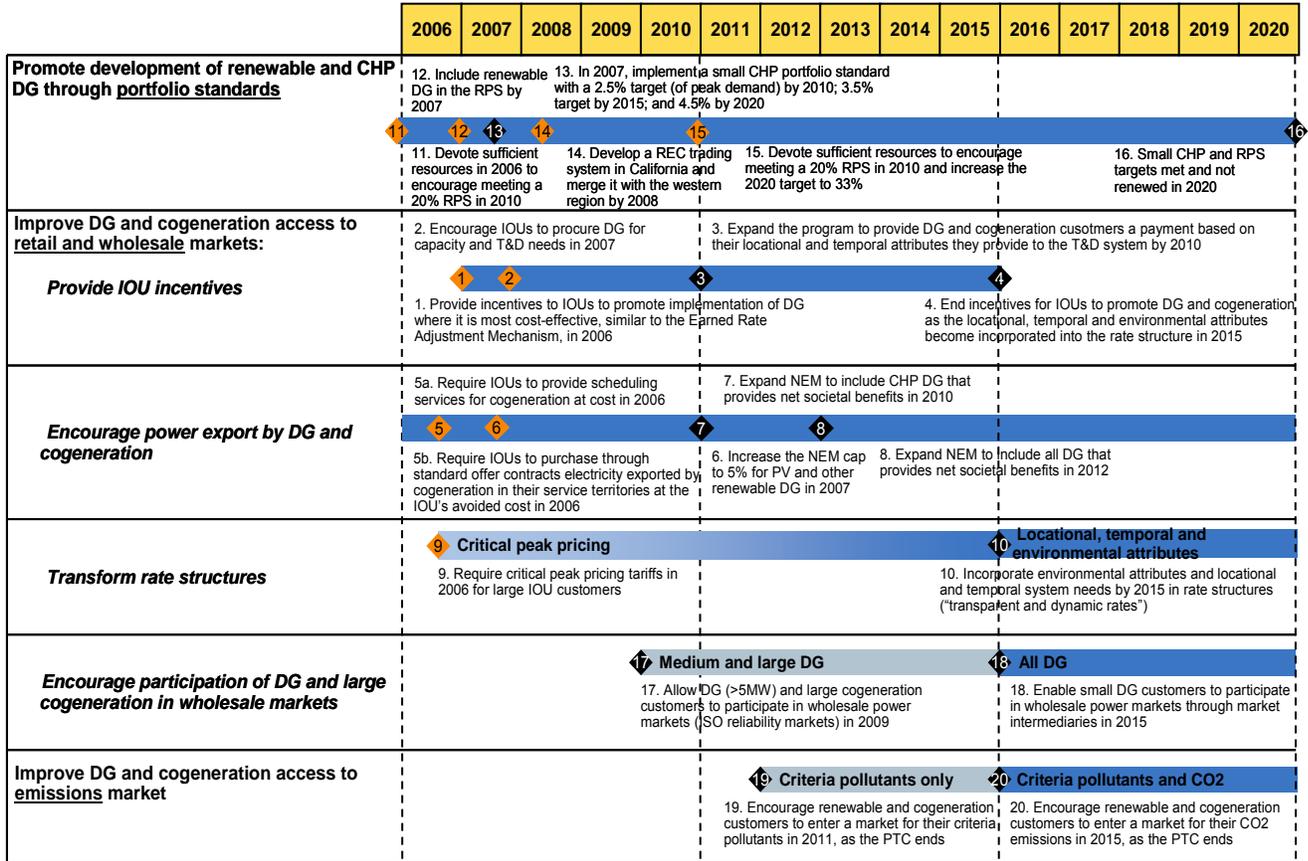
Transition to New Market Mechanisms

To remove incentives and still encourage vibrant growth of DG and cogeneration in California, incentives will have to be replaced with market mechanisms that encourage DG and cogeneration (Figure 4). Key transition activities on the roadmap will:

- Promote development of renewable and CHP DG through portfolio standards.
- Establish market mechanisms to allow DG to compete with central plants and traditional T&D:
 - Provide utility incentives to procure DG while remaining revenue neutral.
 - Encourage power export by cogeneration so that systems are optimized for onsite heat loads and installations are large enough to provide T&D capacity to utilities.
 - Transform rate structures to internalize location, temporal and environmental benefits.
 - Encourage participation of DG and cogeneration in wholesale markets.
- Create access to emissions markets:
 - Develop emissions markets that include and appropriately value DG and cogeneration.

⁹ Note: For specific references to IEPR/EAP milestones, see *Appendix C: DG and Cogeneration Policy Pathway/IEPR and EAP Milestone Cross References*.

Figure 4: Strategic Thrust – Transition to New Market Mechanisms¹⁰



◆ Milestone appears in IEPR or EAP

◆ Milestone developed by Energy Commission DG Policy Team

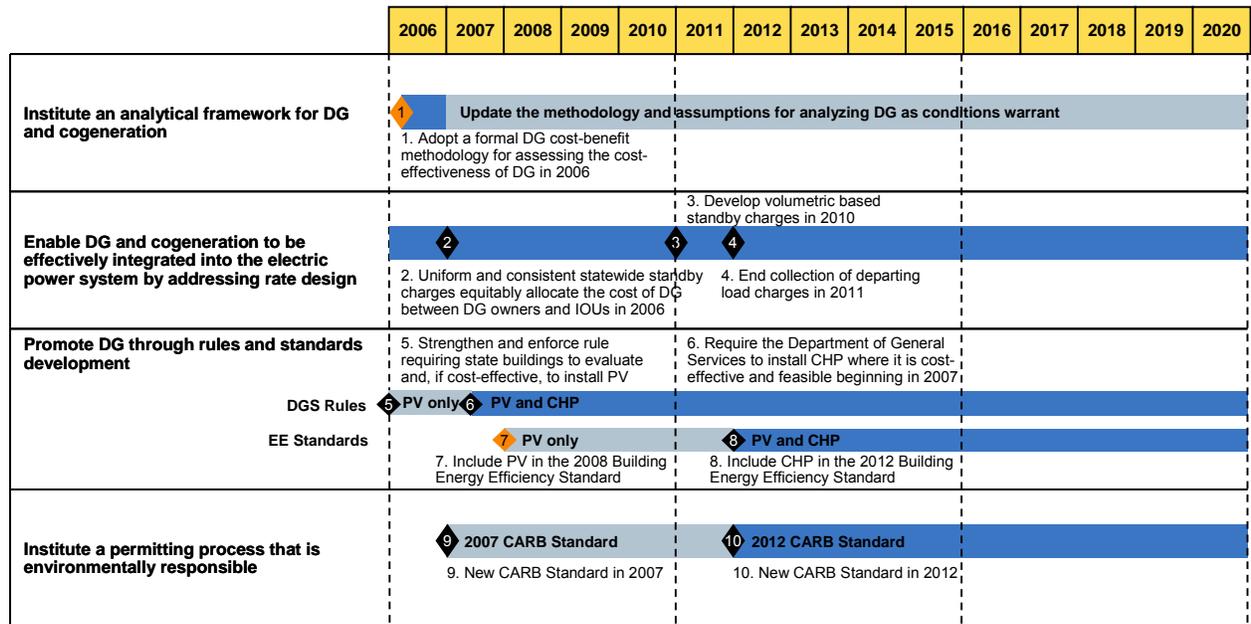
Reduce Remaining Institutional Barriers

California has made tremendous strides in the past several years in removing barriers to DG and cogeneration. However there is still work to be done. The last strategic thrust would address remaining barriers (Figure 5):

- Institute an analytical framework for DG and cogeneration for assessing costs and benefits.
- Enable DG and cogeneration to be effectively integrated into the electric power system by addressing rate design.
- Promote DG through rules and standards development.
- Institute a permitting process that is environmentally responsible.

¹⁰ Note: For specific references to IEPR/EAP milestones, see *Appendix C: DG and Cogeneration Policy Pathway/IEPR and EAP Milestone Cross References*

Figure 5: Strategic Thrust – Reduce Remaining Institutional Barriers¹¹



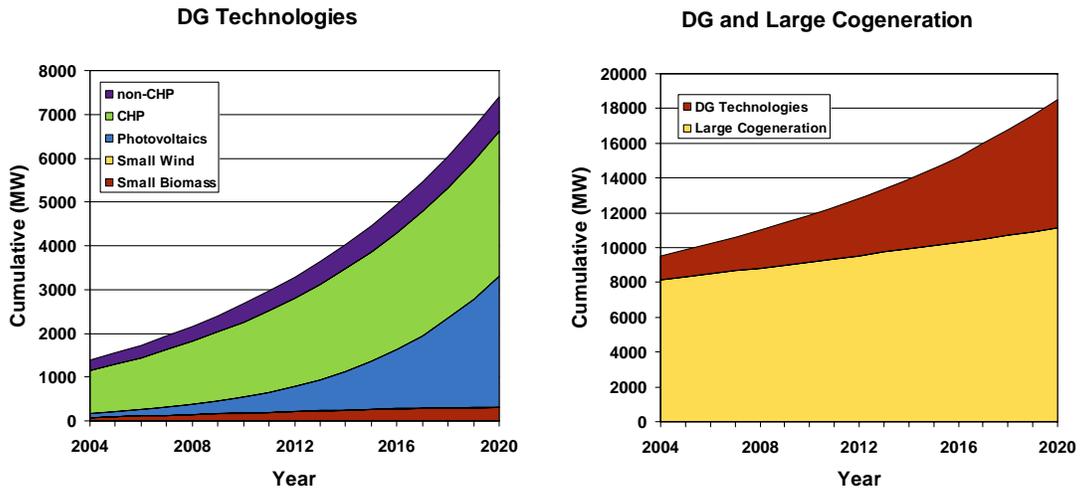
◆ Milestone appears in IEPR or EAP ◆ Milestone developed by Energy Commission DG Policy Team

DG and Cogeneration Market Penetration Curves

It will require a mix of DG technologies and cogeneration (as in Table 7) to reach the Vision’s penetration target of 26 percent by 2020 (Figure 6). Technologies penetrate the market at different rates depending on the maturity of the technology and the market. Large cogeneration, which uses mature technology and has relatively high market saturation, will grow at a slower rate as compared to some of the DG technologies. For example, photovoltaics is still a growing technology and is not likely to reach its maximum penetration rate until after 2020. Small CHP, which uses mature reciprocating engine and gas turbine technology and still has a large technical market, will reach its maximum penetration rate (in terms of annual MWs added per year) before 2020. This will cause, in the future, for photovoltaic technology to make up a greater percentage of DG. While CHP will still be an important component of the DG portfolio, decades of incentives, pent-up technical market potential and improved technology performance will lead to a greater penetration of PV capacity.

¹¹ Note: For specific references to IEPR/EAP milestones, see *Appendix C: DG and Cogeneration Policy Pathway/IEPR and EAP Milestone Cross References*.

Figure 6: DG and Cogeneration Penetration Curves¹²



¹² These penetration patterns were determined based on the projected installations in 2020 and the pattern of similar technologies using a Fischer-Pry analysis (see Appendix D: DG Penetration Curves).

CHAPTER 5: RECOMMENDATIONS FOR ADOPTION AND IMPLEMENTATION

IEPR/EAP Interaction

The DG and Cogeneration Vision requires some new energy policy initiatives that have not been addressed nor discussed in the IEPR/EAP process yet. The Roadmap will now provide a prospective view to the IEPR committee on potential policies to consider and the timing necessary to implement those policies for California to attain the 2020 DG and Cogeneration Vision. It is also expected that other policy initiatives not in the Roadmap will be identified by the IEPR/EAP process, or greater emphasis will be placed on some policy initiatives. Therefore, the Roadmap will need periodic updates to reflect these changes.

Roadmap Implementation

Implementing this Roadmap will require the participation of agencies and stakeholders outside the Energy Commission. This Roadmap will need to be reviewed with those stakeholders, and an implementation plan will need to be developed to begin to implement the Roadmap. There is a need to assign responsibility either within or outside the Energy Commission for the adoption and implementation of the Roadmap since some policy activities on the Pathway fall under the regulatory or legislative authority of other parts of state government.

APPENDIX A: CURRENT SITUATION DG AND COGENERATION PENETRATION – KEY SOURCES AND ASSUMPTIONS

Key Sources

- 1) CA Power Plants > 0.1 MW (Accessed 02/18/2005):
http://www.energy.ca.gov/database/POWER_PLANTS.XLS
 - a) DG is considered any generation < 20 MW (except geothermal and hydro, which are not DG).
 - b) Any renewable DG that is also used for cogeneration is counted under “Cogeneration/CHP.”
 - c) Considers only CA generation operational before 2004.
- 2) Rule 21 Interconnection Authorizations > 10 kW (Accessed 02/18/2005):
http://www.energy.ca.gov/distgen/interconnection/rule21_stats.html
 - a) DG is considered any generation < 20 MW (except hydro, which is not DG).
 - b) DG is not used for standby or backup electricity.
 - c) Any renewable DG that is also used for cogeneration is counted under “Cogeneration/CHP.”
 - d) The wide majority of DG < 10 kW approved in Rule 21 is assumed to be PV.
 - e) Data for PGE&E, SCE, and SDG&E.
- 3) Energy Commission Emerging Renewables Program (ERP) (Accessed 02/18/2005): http://www.energy.ca.gov/renewables/emerging_renewables/2005-01-13_ERP_Cmptd_Apprvd.XLS
 - a) Only considered DG with status of “Payment Claim Processed.”
 - b) Calendar year based on the date in the “Completed” column.
 - c) Includes < 10 kW wind installations not listed in the Rule 21 authorizations.
 - d) Data for mainly for PG&E, SCE, and SDG&E. Some cells are blank or for POUE and BVE.
- 4) Grid-connected PV in CA (Accessed 02/18/2005):
http://www.energy.ca.gov/renewables/emerging_renewables/2005-01-18_GRID_PV.XLS
 - a) Data for all grid connected PV in CA.
- 5) CPUC Self-Generation Incentive Program (SGIP) (Accessed 02/23/05):
http://www.sdenergy.org/uploads/SelfGen_Statewide%20Data_Jan05.xls

- a) There may be overlap with DG installations in the Rule 21 Authorizations and CA Power Plants databases
 - b) Only considered DG with status “Completed”.
- 6) California Energy Commission, *Assessment of California Combined Heat and Power Market and Policy Options for Increased Penetration*, Publication #500-2005-173, November 2005:
- a) Appendix A provides complete data on installed cogeneration capacity in California in 2004.

Key Assumptions

Small Biomass – Energy Commission CA Power Plants database. Considered biomass projects under 20 MW. Excludes Small Biomass CHP estimated at 126 MW

PV – Energy Commission report of grid-connected PV from 1991 to present.

Small Wind – Energy Commission Emerging Renewables Program. Includes net-metered wind projects.

Cogeneration (CHP) – EEA CHP Study. Considers all cogeneration installations in California. Includes small biomass CHP projects. Breakdown included in Appendix.

Non-cogeneration (peaking and primary) – Energy Commission CA Power Plants database. Considered installations < 20 MW

Peak Demand – Forecast of California Energy Demand 2006 – 2016

APPENDIX B: DEVELOPING DG AND COGENERATION SCENARIOS

DG Scenario Drivers

Future scenarios for electricity, cogeneration and DG in California are strongly influenced by six key drivers:

- Power System and Environmental Constraints – Ability to add new central generation capacity and new transmission and distribution infrastructure to meet load growth. Based on environmental and power system (or, electric generation, transmission and distribution) constraints.
- Regulation – Whether regulatory policy shifts toward allowing market determination of prices or toward stronger regulatory control of prices.
- Load growth – The increased demand for electricity based on the estimated rates of economic and population growth and the rate at which electricity is consumed.
- Spark Spread – The difference between natural gas and electricity prices.
- Environmental Push – Degree of consumer and government support for environmentally friendly energy solutions.
- Transportation Tech Transfer – Degree to which the transportation industry develops technologies that can be transferred to the DG industry (for example, fuel cell, battery or power electronics technology).

These drivers vary in importance to future scenarios based upon the impact they will have on the future of DG and cogeneration in California and level of uncertainty associated with the respective drivers. “Regulation” and “Power System and Environmental Constraints” are the two drivers that will shape and bound the scenarios for electricity, cogeneration and DG in California because they are likely to have the greatest effect on adoption of DG and cogeneration and tend to have higher uncertainties than the other drivers (Figure B-1). Therefore, these two drivers were selected to build the scenarios around.

Figure B-1: DG and Cogeneration Scenario Drivers

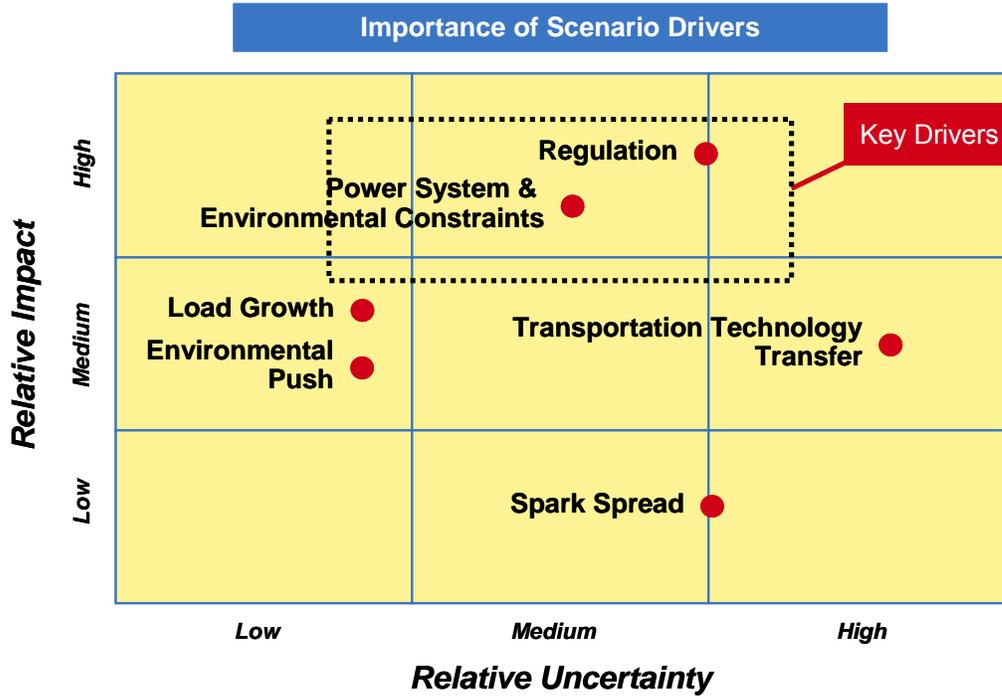


Table B-1: Detailed Description of Scenarios

	Informed Energy	Market Competitive Energy	Not Your Traditional Utility	Vertically Integrated Utility
Power System/ Environmental Constraints	<ul style="list-style-type: none"> Limited new central generation and Transmission and Distribution capacity due primarily to environmental concerns and years of regulatory uncertainty. 	<ul style="list-style-type: none"> Adequate generation and robust transmission infrastructure. Environmental objectives are easily met. 	<ul style="list-style-type: none"> Limited generation and Transmission and Distribution capacity due primarily to environmental concerns and ongoing regulatory uncertainty. 	<ul style="list-style-type: none"> Adequate generation and robust transmission infrastructure. Environmental objectives are easily met.
Regulation	<ul style="list-style-type: none"> Limited, relying on market forces. 	<ul style="list-style-type: none"> Limited, relying on market forces. 	<ul style="list-style-type: none"> Highly regulated utilities and energy markets; formula not clear; trial and error approach. 	<ul style="list-style-type: none"> Highly regulated utilities and energy markets.
Character Of Rate Structure	<ul style="list-style-type: none"> Transparent, dynamic pricing structure with embedded environmental externalities and system needs (locational and temporal). 	<ul style="list-style-type: none"> Transparent, dynamic pricing structure. Wholesale power markets. Competition at retail level. 	<ul style="list-style-type: none"> Controlled pricing, with environmental and system concerns embedded in rates with no customer choice. 	<ul style="list-style-type: none"> Controlled averaged pricing. Utility offers single power option to all retail customers.
Government Role	<ul style="list-style-type: none"> Oversight, supports development of free markets, ensures rules are followed. 	<ul style="list-style-type: none"> Arm's length watchdog. 	<ul style="list-style-type: none"> Heavily dictating things, achieves policy objectives through regulation. 	<ul style="list-style-type: none"> Administration and oversight.
Energy Supply	<ul style="list-style-type: none"> Large penetration of central power, with multiple energy options driven by customer demand (e.g., green, nuke, gas, hydro, DG). New business models and market entrants in industry. 	<ul style="list-style-type: none"> Central fossil fuel-based power plants dominate. Boom and bust cycles are mitigated by long-term contracts. 	<ul style="list-style-type: none"> Regulated mix that will achieve policy objectives. 	<ul style="list-style-type: none"> Vertically integrated utilities. Increased reliance on fossil fuels.
Dg Ownership	<ul style="list-style-type: none"> Customer, third party and utility owned. PV and CHP are primary technologies. 	<ul style="list-style-type: none"> Customer, third party and utility owned, mostly CHP and microgrids. 	<ul style="list-style-type: none"> Utility-owned DG to meet Renewable and CHP portfolio mandates, and Transmission and Distribution constraints. 	<ul style="list-style-type: none"> Limited, end-user owned.
Demand Response Role	<ul style="list-style-type: none"> Market driven. Customers will be exposed to transparent, dynamic price signals for capacity and system constraints. 	<ul style="list-style-type: none"> DR available, but normally plays a limited role; will play a larger role during capacity "bust" cycles. Market driven, based on wholesale capacity markets. 	<ul style="list-style-type: none"> Utility administered programs. 	<ul style="list-style-type: none"> Limited
Energy Efficiency Role	<ul style="list-style-type: none"> Market driven. Customers will be exposed to transparent, dynamic price signals for capacity and system constraints. 	<ul style="list-style-type: none"> Market driven, but low energy cost make it difficult for EE to compete. 	<ul style="list-style-type: none"> Utility administered programs. 	<ul style="list-style-type: none"> Strong continuing thrust but entering area of diminishing returns due to success in programs in 2000- 2015.
Customer	<ul style="list-style-type: none"> Well informed; choose energy on environmental impact, cost, and quality. 	<ul style="list-style-type: none"> Buying decisions based on cost. 	<ul style="list-style-type: none"> Little choice and high prices. 	<ul style="list-style-type: none"> No choices.
Price Volatility	<ul style="list-style-type: none"> Highest 	<ul style="list-style-type: none"> Medium high, as a function of infrastructure building cycles. 	<ul style="list-style-type: none"> Medium low. 	<ul style="list-style-type: none"> Lowest.

APPENDIX C: DG AND COGENERATION POLICY PATHWAY/IEPR AND EAP MILESTONE CROSS REFERENCES

Support Incentives in the Near-term

California Energy Commission DG Policy Pathway Milestone	Milestone Identified in IEPR and EAP Process
4. Complete transition toward a performance-based incentive program for ERP, 2008.	2004 IEPR Update, pg 45. "The Energy Commission supports performance-based incentive programs for PV." 2005 Draft IEPR, pg 124: "A truly sustainable solar program will pay for kWhs produced rather than for system installation with no measure of performance to ensure that systems are appropriately installed and functioning correctly."
6. Increase the availability of state-sponsored low-interest loans for clean DG that provides net societal benefits in 2007	2005 EAP II, pg 4. "10. Increase the availability of State-sponsored low-interest loans for energy efficiency and clean distributed generation projects."
10. Renewable and CHP DG can receive a state PTC in 2008 for CO2 emissions	2005 Draft IEPR, pg 79. "California should explore establishing production credits for CO2 reductions from CHP."
Milestones 11-15	2005 EAP II, pg 7. "Implement a cost-effective program to achieve the 3,000 MW goal of the Governor's "Million Solar Roofs" initiative."

Transition to New Market Mechanisms

California Energy Commission DG Policy Pathway Milestone	Milestone Identified in IEPR and EAP Process
1. Provide incentives to IOUs to promote implementation of DG where it is most cost-effective, similar to the Earned Rate Adjustment Mechanism, in 2006.	2005 Draft IEPR, pg 78. "The CPUC should immediately develop a method to provide DG and CHP incentives to utilities and implement them by the end of 2006." 2005 Draft IEPR, pg 79. "By the end of 2006, the CPUC should direct utilities to make transmission and distribution capacity payments to CHP projects."
2. Encourage IOUs to procure DG for capacity and T&D needs in 2007.	2005 Draft IEPR, pg E-4. "The CPUC and the Energy Commission should establish annual utility procurement targets by the end of 2006." 2005 Draft IEPR, pg 79. "The CPUC should require utilities to implement comparable planning models to determine where DG and CHP is most beneficial from system transmission and distribution perspectives."
5a. Require IOUs to provide scheduling services for CHP customers at cost in 2006.	2005 Draft IEPR pg 77. Utilities should be required to offer CA ISO scheduling services at cost to their CHP customers.
5b. Require IOUs to purchase through standard offer contracts electricity exported by CHP plants in their service territories at the IOU's avoided cost in 2006.	2005 Draft IEPR pg 77. "By the end of 2006, the CPUC should require IOUs to buy, through standardized contracts, all electricity from CHP plants in their service territories at their avoided cost, as defined by the CPUC in R.04-04-025.118"
6. Increase the NEM cap to 5% for PV and other renewable DG in 2007.	2004 IEPR Update, pg 48. "The Energy Commission believes that a higher net metering cap is necessary to facilitate the orderly development of PV markets and other renewable DG."
9. Require critical peak pricing tariffs in 2006 for large IOU customers.	2005 EAP II, pg 5. "2. Expedite decisions on dynamic pricing tariffs to allow increased participation for summer 2006 for customers with installed advanced metering systems and encourage load shifting that does not result in increases in overall consumption." 2005 Draft IEPR, pg 72. "In 2005, IOUs filed applications to implement default critical peak pricing tariffs for large customers, beginning in summer 2006. The CPUC expects to issue a decision on these tariffs in early 2006."
Milestones 5, 6, and 9	2005 EAP II, pg 8. "9. Develop tariffs and remove barriers to encourage the development of environmentally-sound combined heat and power resources and distributed generation projects."

Transition to New Market Mechanism (Continued)

California Energy Commission DG Policy Pathway Milestone	Milestone Identified in IEPR and EAP Process
11. Devote sufficient resources in 2006 to encourage meeting a 20% RPS in 2010.	2003 EAP, pg 5-6. <i>“Accelerate the State’s Goal for Renewable Generation”</i> 2004 IEPR Update, pg 35. “As originally specified in SB 1078, the RPS requires all IOUs to increase their portfolio of renewable resources by at least one percent of sales every year to reach the target of 20 percent renewable resources by 2017. The Energy Action Plan accelerated the 20 percent target to 2010.” 2004 IEPR Update pg 37-38. <i>“Develop Ambitious RPS Goals”</i> 2005 EAP II, pg. 6 “5. Evaluate and develop implementation paths for achieving renewable resource goals beyond 2010, including 33 percent renewables by 2020, in light of cost-benefit and risk analysis, for all load serving entities.”
12. Include renewable DG in the RPS by 2007.	2003 EAP, pg 8. “4. Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program.” 2005 Draft IEPR, pg A7. “Status: Achieved. The CPUC determined that the owner of renewable DG facilities owns the renewable energy credits associated with the generation of electricity from those facilities and is eligible to participate in the RPS program.”
14. Develop a REC trading system in California and merge it with the western region by 2008.	2004 IEPR Update, pg 40-41. <i>“Unbundled Renewable Energy Certificates”</i> 2005 Draft IEPR, pg 114. “In the longer-term, however, California should move toward full REC trading in the state and western region once WREGIS is operational,” 2005 EAP II, pg 6. “11. Complete the Western Renewable Generation Information System to accurately account for renewable generation through an electronic certificate tracking system. 2005 EAP II, pg 6. “12. Implement a renewable energy certificates trading system for meeting RPS goals.”
15. Devote sufficient resources to encourage meeting a 20% RPS in 2010 and increase the 2020 target to 33%.	2005 EAP II, pg. 6 “Evaluate and develop implementation paths for achieving renewable resource goals beyond 2010, including 33 percent renewables by 2020, in light of cost-benefit and risk analysis, for all load serving entities.”
17. Allow medium and large DG customers to participate in wholesale power markets (ISO reliability markets) in 2009.	2005 Draft IEPR, pg 76. By the end of 2006, the CA ISO should modify its CHP tariffs in recognition of the unique operational requirements of CHP and allow CHP owners to sell their power to the state’s electric grid at reasonable prices”
Milestones 1 and 2	2005 Draft IEPR, pg. 79. “The state should require utilities to design and build distribution systems that are more DG and CHP compatible.”
Milestones 1 and 2	2003 IEPR, pg 16. “Create a transparent electricity distribution system planning process that addresses the benefits of distributed generation.”

Reduce Remaining Institutional Barriers

California Energy Commission DG Policy Pathway Milestone	Milestone Identified in IEPR and EAP Process
1. Adopt a formal DG cost-benefit methodology for assessing the cost-effectiveness of DG in 2006	2003 EAP, pg 8. “3. Determine system benefits of distributed generation and related costs.”
7. Include PV in the 2008 Building Energy Efficiency Standard	2003 EAP, pg 5. “8. Incorporate, as appropriate per Public Resources Code section 25402, distributed generation or renewable technologies into energy efficiency standards for new building construction.” 2005 Draft IEPR, pg 124 “... leveraging energy efficiency improvements should be a key consideration in deploying PV, new homes should be required to exceed current building efficiency standards, while existing buildings should be required to improve their efficiency by a fixed percentage.” 2005 EAP II, pg 4. “9. Adopt new building standards for implementation in 2008 that include, among other measures, cost effective demand response technologies and integrated photovoltaic systems.”

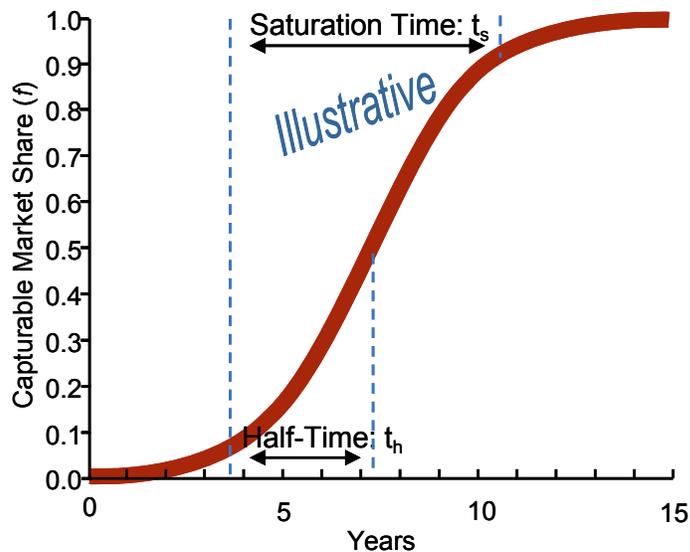
APPENDIX D: DG AND COGENERATION PENETRATION CURVES

Fisher-Pry Technology Substitution Methodology

The Fisher-Pry technology substitution model is used to estimate the rate at which the marketplace will adopt a new technology. In 1971, Fisher and Pry published a paper describing a model of technological change, which is extremely effective in modeling the competitive substituting of one technology by another. In addition to the 17 substitutions listed in Fisher and Pry's original work, at least 200 other examples are in the public record and support the Fisher-Pry approach. The Fisher-Pry technology substitution model predicts market adoption rate for an existing market of known size. The fraction of market adoption, f , by technology substitution for an existing segment is represented as:

$$f = \frac{1}{1 + e^{-\alpha(t-t_h)}}$$

- α is an empirical constant
- The half time t_h is the time at which $f = 0.5$.
- The takeover time t_s is the time between $f = 0.1$ and $f = 0.9$.



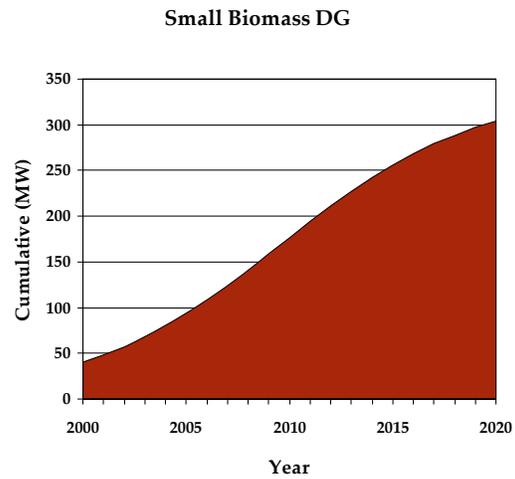
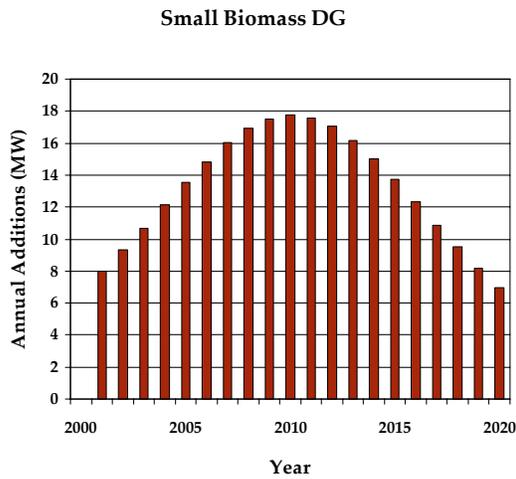
To predict the annual penetration of each DG technology the following steps were performed:

- Step 1 – Estimate the current installed capacity (Table 3) and 2020 target (Table 6).
- Step 2 – Estimate the total market that is addressable using existing data.
- Step 3 – Fit a Fisher-Pry curve to obtain key parameters.
- Step 4 – Calculate the annual cumulative installations and the annual additions.

Specific DG Technology Penetration Curves

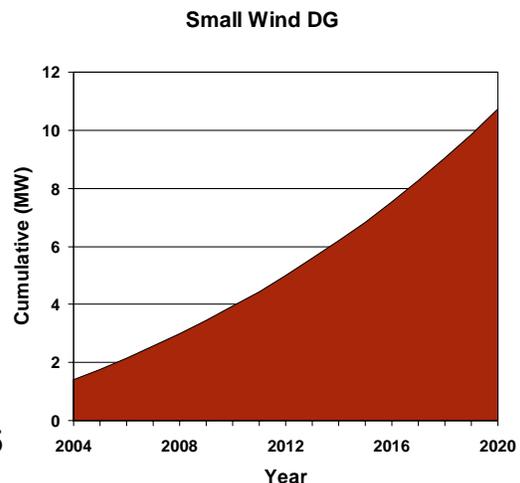
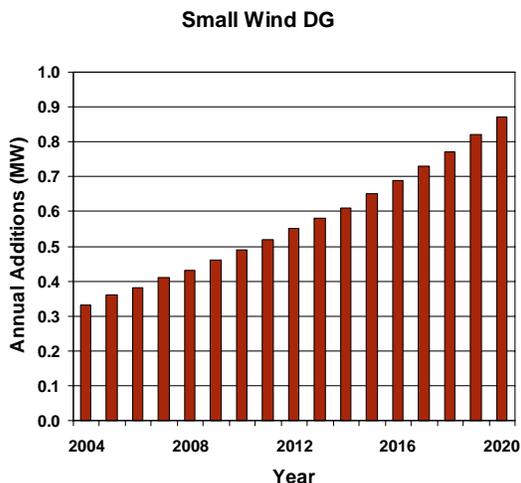
Small Biomass DG

The cumulative small biomass installations increase toward a total of 304 MW in 2020 with annual installations peaking in 2010. The cumulative small biomass installations in 2020 are assumed to be 90 percent of the total market that is addressable, 338 MW. The fit for the S-curve was obtained by Fisher-Pry analysis of the 2004 cumulative capacity, 2020 target, and the total addressable market. The time to saturation time is 20.9 years, and the midpoint occurs in 2010.



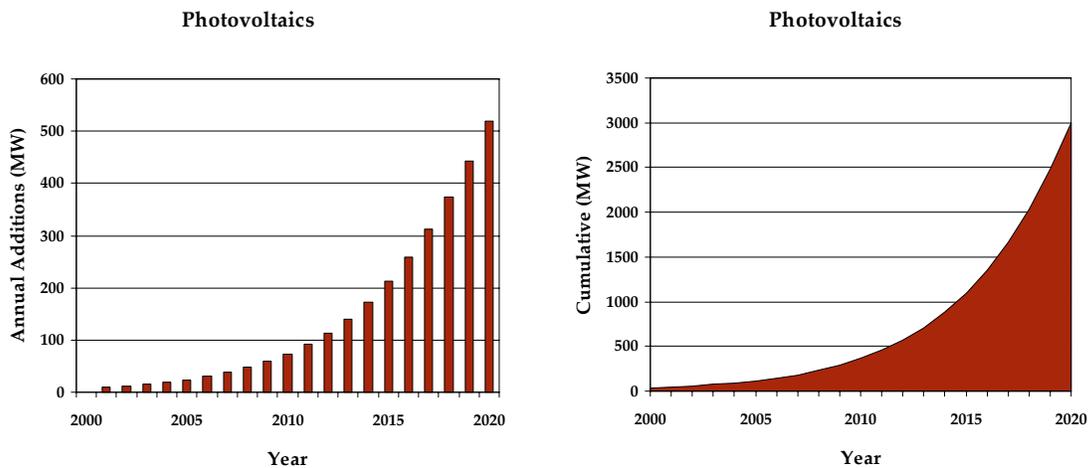
Small Wind

The cumulative small wind installations increase throughout the period toward a total of 10.7 MW in 2020. The technology is assumed to still be in the early stages of adoption curve (<10 percent penetration). The annual additions in 2005 are 6 percent greater than the average annual additions for the prior three years. Between 2005 and 2020 the annual additions of small wind DG grow 6 percent annually.



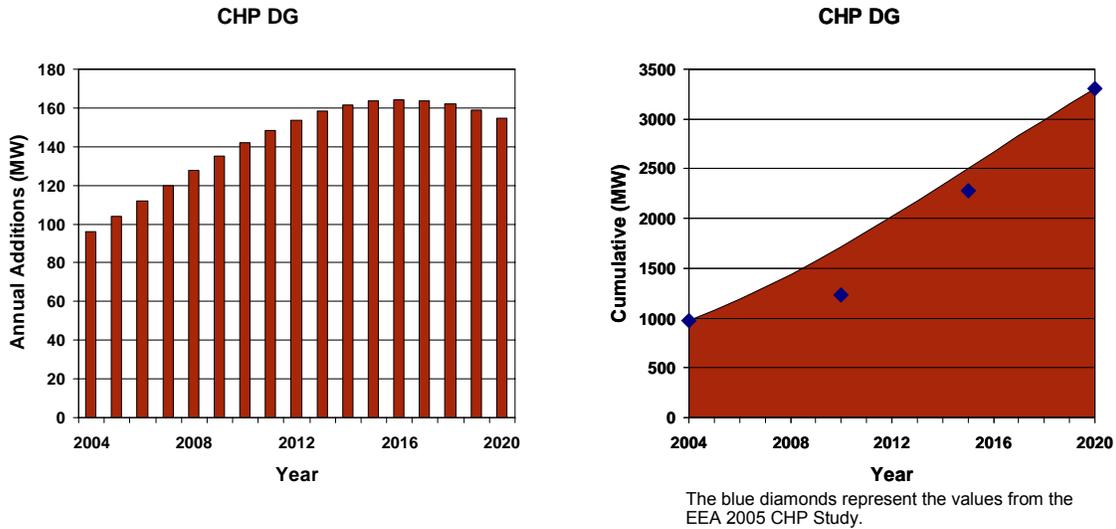
Photovoltaics

The cumulative photovoltaic installations increase toward a total of 3000 MW in 2020 with annual installations peaking after 2020. The total photovoltaic technical potential in California is 85,000 MW, which is the sum of the residential and commercial technical potential from “California Solar Resources,” Energy Commission Draft Staff Report, April 2005, CEC-500-2005-072-D. Navigant Consulting estimates that the PV installations will have an installed cost average \$4 per watt throughout the period as a result of incentive programs and cost reductions. This corresponds to a payback period estimate of six years, which is derived from the Energy Foundation/Navigant Consulting report *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, March 2005. The total addressable market is 18.5 percent of the technical potential. This was determined by analyzing the average payback vs. cumulative market penetration curve provided in the Energy Foundation/Navigant Consulting's, *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, March 2005. The fit for the S-curve was obtained by Fisher-Pry analysis of the 2004 cumulative capacity, 2020 target, and the total addressable market. The time to saturation time is 17.6 years and the midpoint occurs in 2026.



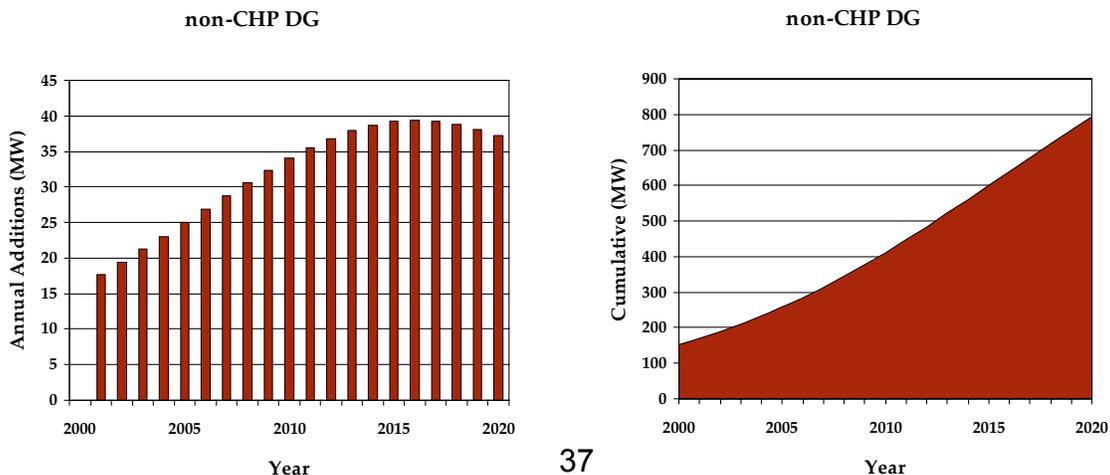
Combined Heat and Power DG

The cumulative CHP DG installations increase toward a total of 3,305 MW in 2020 with annual installations peaking in 2016. The total addressable market is 5,205 MW. This is obtained from the EEA 2005 CHP Study's "High Deployment Scenario" and excludes installations ≥ 20 MW. The fit for the S-curve was obtained by Fisher-Pry analysis of the 2004 cumulative capacity and the EEA 2005 CHP Study aggressive market scenario for 2020, and the size of the total addressable market. The time to saturation time is 34.8 years and the midpoint occurs in 2016.



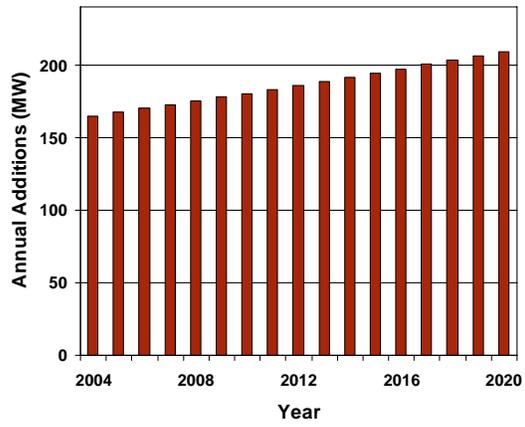
Non-Combined Heat and Power DG

The cumulative non-CHP installations increase toward a total of 790 MW in 2020 with annual installations peaking in 2016. The addressable market for cumulative non-CHP DG is estimated to parallel the market for CHP DG. The share of the current installed non-CHP DG capacity is expected to be the same share initially of CHP DG compared to the total addressable market. The fit for the S-curve was obtained by Fisher-Pry analysis of the 2004 cumulative capacity, 2020 target and the total addressable market. The time to saturation time is 24.0 years, and the midpoint occurs in 2008.

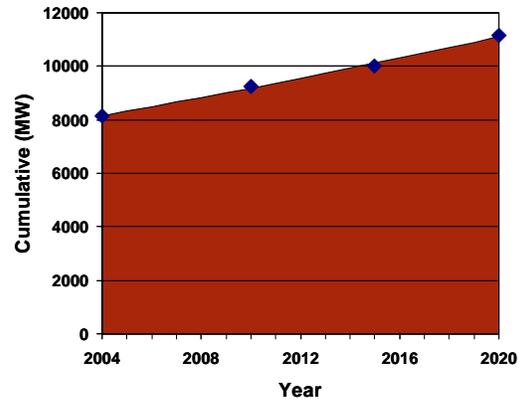


Large Cogeneration

Large Cogeneration



Large Cogeneration



The blue diamonds represent the values from the EEA 2005 CHP Study.