Modeling Reductions in Greenhouse Gases in Arizona Resulting from California Demand Side Management Programs

By

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A Dissertation Presented in Partial Fulfillment
of the Requirements for the Degree
Doctor of Philosophy

Approved April 2013 by the
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ARIZONA STATE UNIVERSITY

May 2013

ABSTRACT

The State of California has made great strides in reducing greenhouse gas (GHG) emissions through mandated, rate-payer funded Investor Owned Utility (IOU) electricity Demand Side Management (DSM) programs. This study quantifies the amount of reduced GHG emissions in Arizona that result from DSM in that state, as well as the DSM reductions within Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E) during the 2010 through 2012 California Public Utilities Commission (CPUC) DSM program cycle. To accomplish this quantification, it develops a model to allocated GHG emissions based on "operating margin" resources requirements specific to each utility in order to effectively track, monitor, and quantify avoided emissions from grid-based utility resources. The developed model estimates that during the 2010-2012 program cycle, 5,327.12 metric tons (MT) of carbon dioxide equivalents (CO_2e) in GHG reductions (or 1.8 percent of total reductions) can be attributed to reduced demand from Arizona--based resources by California IOUs. By focusing on the spatial context of GHG emission reductions, this study models and quantifies the spill-over effect of California's regulatory environment into neighboring states.

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GLOSSARY OF TERMS

AB 1890	Assembly Bill 1890
AB 32	Assembly Bill 32
AB 549	Assembly Bill 549
AC	Alternating Current
ACC	Arizona Corporation Commission
ANSI	American National Standards Institute
APS	Arizona Public Service
ASHRAE	American Society of Heating, Refrigerating, and Air-Conditioning Engineers
BM	Build Margin
BTU	British Thermal Unit
CAA	Clean Air Act
CAISO	California Independent Systems Operator
CARB	California Air Resources Board
CCAR	California Climate Action Reserve
CCAT	California Climate Action Team
CEC	California Energy Commission
CEF	California Evaluation Framework
CEPA	California Environmental Protection Agency
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CH_4	Methane
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission
CSCSA	California State Consumer Service Agency
CSI	California Solar Initiative
DOE	U.S. Department of Energy
DR	Demand Response
DSM	Demand Side Management
E3	Energy, Energy + Environment
EAP	Energy Action Plan
EE	Energy Efficiency
EEGA	Energy Efficiency Groupware Application
eGRID	Emissions and Generation Resource Integrated Database
EIA	U.S. Energy Information Administration
EM&V	Evaluation, Measurement, & Verification
EPA	Environmental Protection Agency
EPACT	Energy Policy Act
EPCA	Energy Policy Conservation Act
EWG	Exempt Wholesale Generators
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas

GW	Giga-watt
GWh	Giga-watt hour
GWP	Global Warming Potential
IEA	International Energy Agency
IOU	Investor Owned Utility
IPCC	Intergovernmental Panel on Climate Change
IPMVP	International Performance Measurement and Verification Protocol
ISO	Independent Systems Operator
KW	Kilo-watt
KWh	Kilo-watt hour
LADWP	Los Angeles Department of Water and Power
LDC	Load Duration Curve
MMBtu	"One thousand" British Thermal Units
MW	Mega-watt
MWh	Mega-watt hour
N_20	Nitrous Oxide
NAECA	National Appliance Energy Conservation Act
NAPEE	National Action Plan for Energy Efficiency
NARUC	National Association of Regulatory Utility Commissioners
NEA	National Energy Act
NECPA	National Energy Conservation Act
NERC	North American Reliability Corporation
NDC	Net Dependable Capacity
NIST	National Institute of Standards and Technology
OASIS	Open Access Same-time Information System
OM	Operating Margin
MGS	Mohave Generating Station
PGC	Public Goods Charge
POU	Publically Owned Utility
PG&E	Pacific Gas and Electric Company
PUCHA	Public Utility Holding Company Act
PURPA	Public Utilities Regulatory Act
PVNGS	Palo Verde Nuclear Generating Station
PX	Power Exchange
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organizations
QEF	Qualified Energy Facility
QFER	Quarterly Fuel and Energy Report
SRP	Salt River Project
SONGS	San Onofre Nuclear Generating Station
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SMUD	Sacramento Municipal Utility District
SPR	Strategic Petroleum Reserve

T&D	Transmission and Distribution
TEPCO	Tucson Electric Power Company
UN FCC	United Nations Framework for Climate Change
WECC	Western Electricity Coordinating Council
WRI	World Resources Institute

CHAPTER 1: INTRODUCTION

OVERVIEW

The role of Greenhouse Gas (GHG) emissions in global climate change, particularly those resulting from the combustion of fossil fuels for the purpose of electricity generation, has been well documented (IPCC 2001). Owing to a number of factors, the State of California has long been considered a leader in efforts to mitigate anthropogenic impacts on the environment. Within the last decade, this sensitivity has been channeled toward developing policies designed to reduce GHG emissions through market based mechanisms. Prior, and concurrent, to the passage of AB32, California regulators have adopted policies indirectly designed to reduce GHG emissions through the more efficient use of electric energy, particularly through energy conservation and demand side management (DSM) activities. As electricity imports from neighboring states significantly increased following California electric utility restructuring in the late 1990s, and the ensuing electricity crises in 2000, California regulators placed an increased emphasis on DSM as a mechanism both as a way to manage load growth and to reduce dependence on electricity imports (Sweeney 2002).

Since the 1970s, utilities in California have promoted energy conservation through consumer education and direct financial incentives as a mechanism to control load growth. A recently added benefit of utility DSM activities is that they tie into the state's over-arching focus on GHG emission reductions. During the 2010 through 2012 Program Cycle, the California Public Utilities Commission (CPUC) authorized the state's three electric Investor Owned Utilities Pacific Gas and Electric (PG&E), Southern

California Edison (SCE), and San Diego Gas and Electric (SDG&E), to invest over $3.1 billion in rate-payer funds toward electricity and natural gas DSM programs. For these three years alone, this investment is expected to translate to over 3,800 gigawatt-hours (GWh) of saved electricity (CPUC 2013), and, by the estimates provided in the results of study, over 296,000 metric tons of "carbon dioxide equivalents" (CO_2e) in avoided emissions. Carbon dioxide equivalents is used to describe an aggregate total of all greenhouse gas emissions according to their respective 100-year global warming potentials (GWP) compared to an equal weight of carbon dioxide are carbon dioxide (CO_2). For instance, methane (CH_4) has a GWP 25 times more than CO_2. Similarly, nitrous oxide (N_2O) has a GWP 298 times more GWP than CO_2. [1]

However, given the state's reliance in electricity imports from areas throughout the Western United States, it only stands to reason that some of such reduced GHG emissions can be attributed to lower demand for electric generators located in states from which it imports electricity, particularly Arizona. Though many entities, such as the California Climate Action Reserve (CCAR), the California Air Resources Board (CARB), as well as the California Energy Commission (CEC), have all been actively involved in developing GHG emission factors, inventories, and calculators specific to California utilities since the late 1990s, these organizations have not adequately developed a methodology to assess the "spill-over effect" of avoided emissions in neighboring states as a result of California utility demand side management activities.

[1] For additional GWP information, please reference; Intergovernmental Panel on Climate Change (IPCC), Fourth Assessment Report (AR4), Working Group 1 (WG1), Chapter 2, *Changes in Atmospheric Constituents and in Radiative Forcing*, Table 2.14, page 212

Indeed, the current course of academic inquiry regarding utility DSM has been generally limited to basic assessments of avoided emissions specific to one geographical region (Hall et al. 1995), the cost-effectiveness of DSM programs (Loughran and Kulick 2004), or broad life-cycle assessments (Weisser 2007).

OBJECTIVE

The objective of this study is to quantify the reduction of CO2e that are attributed to lowered demand from Arizona-based resources by California IOUs as a result of their DSM activity during the 2010 through 2012 DSM program cycle. Through this analysis, the study hopes to shed light on the spill-over effect of environmental regulation between grid-connected states, as well as serve as a foundation for future academic inquiry into effective strategies to track, monitor, and model avoided emissions from grid-based utility resources.

RESEARCH QUESTION

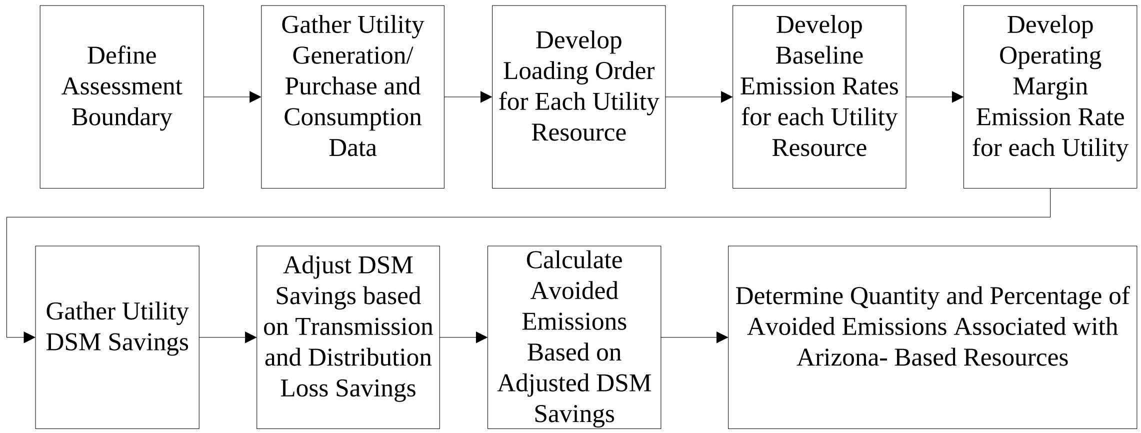
This study answers the research question: What quantity of CO2e are attributed to lowered demand from Arizona-based resources by California IOUs as a result of their DSM activity during the 2010 through 2012 DSM program cycle?

STRUCTURE OF THE STUDY

This study has five distinct sections. The first section provides historical context and background information regarding the structure and nature of California’s electric system, with the purpose of identifying major pieces of recent federal and state legislation, including electric industry restructuring and demand side management policies which had significant impacts on the recent development of California's electric system. The second section briefly describes the evolution of GHG emissions assessments specific to California, including GHG emission factors developed by the California Climate Action Reserve (CCAR), inventory and reporting tools developed by CARB, as well as the GHG calculator developed by the CEC and in use by PG&E, SCE, and SDGE. Next, the study describes the methodology outlined in the United Nations Framework for Climate Change (UN FCC), adopted by the World Resources Institute (WRI) for carbon offset projects, and subsequently modified for use in assessing avoided emissions resulting from demand side management on a utility grid network. Last, the study present the results of this assessment; describe the relative strengths, weaknesses, and difficulties of this approach; as well as suggestions for further research aimed at improving the accuracy of the model and expanding the spatial context of this analysis. Figure 1 illustrates the methodological framework employed in this study:

Figure 1:

Methodological Framework



CHAPTER 2: THE CALIFORNIA ELECTIC SYSTEM

BACKGROUND

Despite a large installed base of domestic generation capacity, California utilities have increasingly relied on electricity imports to meet their consumer demand, primarily from hydroelectric generators located in the Pacific Northwest and coal and nuclear generators in Arizona, Utah, and New Mexico. The passage of the Electric Utility Industry Restructuring Act (Assembly Bill 1890 or AB 1890) by the California legislature in 1996 directly and indirectly promoted increases in electricity imports from neighboring states (Blumstein et al. 2002). Assembly Bill 1890 required the state's IOU's to divest their generating and transmission assets and allow other power marketers access to their distribution system (AB 1890). What ensued was a major boom in wholesale merchant power plant construction across the border in neighboring Arizona, where environmental permitting requirements remained relatively simple and existing electric transmission lines were able to quickly meet the needs of additional generators. Despite an abundant supply of renewable energy resources, as well as access to natural gas, the California electric system seems to have abruptly migrated into Arizona and other neighboring states. The following section provides a brief overview of the evolution of California electric energy system culminating in the passage of AB 1890, the ensuing growth of wholesale merchant generation in Arizona is designed primarily to meet the needs of California utilities, and the current focus on DSM management as a way to meet future resource needs.

HISTORICAL GROWTH AND DEVELOPMENT

Throughout the late-1800s, hydroelectric generators were constructed to provide reliable and inexpensive power to small, but burgeoning communities in California (Williams 1997). These small hydroelectric generators paved the way for the construction of much larger generators throughout the state, mainly the east side of the state's Sierra Nevada and Southern Cascade Mountain ranges (Hubbard 2006). The availability of water, gently sloping rivers, and large drainage basins, as well as their proximity to growing population centers, agricultural areas, and timber operations provided steady demand for these hydroelectric generators. Dams were soon constructed in several areas of the state to store winter precipitation and thus provide reliable year-round generation. Hydroelectric generators provided almost all of California's electric generation needs for the first half of the twentieth century up until World War II (CEC 2012a). Much of the state's remaining hydroelectric generators provide base-load or intermittent power depending on the availability of adequate precipitation to replenish associated reservoirs.

Industrial expansion during World War II promoted the construction of several, large oil-fired generators along the coast near Los Angeles and San Francisco to supplement existing hydroelectric generation. Given the proximity of these generators to major waterways, ocean-going tankers were easily able to supplement domestic oil supplies to ensure that the state's utilities could provide reliable electricity even during dry seasons, when hydroelectric generators often failed to meet demand. Additionally, their proximity to the coast meant that seawater could be used for cooling and their proximity to major urban areas. Despite these advantages, the era of oil-fired generation was short-lived. Stringent air quality rules in the 1970s led to the conversion of nearly all of these oil-fired boilers to natural gas-fired facilities. One small oil-fired power plant remains in operation in the San Francisco area, though this plant is expected to cease operations in the near future (CEPA 2006).

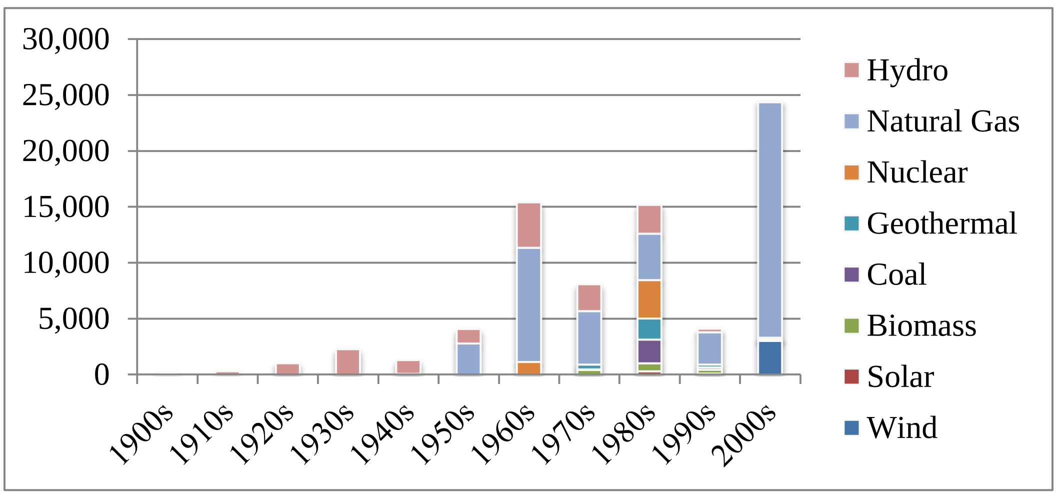
Significant technological advances in the 1960s fostered the growth of two very large commercial grade nuclear power plants, which were subsequently expanded through the 1980s. Initial construction of the San Onofre Nuclear Generating Station (SONGS) located in the northwestern corner of San Diego County along the Pacific coast began in 1968 with additional units added in 1983 and 1984 (Los Angeles Times 2012a). The facility is jointly operated by SCE (78.2 percent ownership), SDG&E (20 percent), the City of Riverside California Utilities Department (1.8%), and has a rated capacity of about 2,200 megawatts (MW) though the plant has been shut down following the accidental release of radioactive steam in January 2012 (Los Angeles Times 2012b). Pacific Gas and Electric Company constructed a 2,200 MW nuclear generation facility near San Luis Obispo County in 1968. Diablo Canyon, as it is called, has also raised public fears of safety issues when a major geologic fault was discovered beneath the plant (NRC 2011). When combined, SONGS and Diablo Canyon generate roughly the same amount of electricity as all of the state’s hydroelectric generators combined (36,666 GWh in 2011) (CEC 2012a). The California legislature passed a moratorium on the construction of new nuclear generation facilities in 1976, new nuclear generators in the state are unlikely (Wellock 1998).

Coal generated electricity currently comprises only two percent of in-state generation (3,120 GWh in 2011) (CEC 2012a). In place of coal, the state has been aggressively promoting the development of renewable energy resources. California Senate Bill 1078, passed in 2002, and subsequently modified in 2006 (Senate Bill 107 and 2011 (Senate Bill 2) requires investor and publically owned utilities in the state to increase procurement of electricity from renewable energy resources to 33 percent of total resource use by 2020 (CPUC 2012a). Despite drastic increases in renewable electricity consumption as a percent of total sales PG&E (19 percent), SCE (20.6 percent), and SDG&E (20.3 percent) has increased, in-state generators only account for a small percentage of total installed capacity. Renewable energy resources account for only eleven percent of the state's total installed generation capacity (Solar – 1,058 GWh, Wind – 7,594 GWh in 2011, Biomass – 5,777 GWh (CEC 2012a). The remaining balance of renewable electric generation is imported from neighboring states.

Despite future projected growth in renewable electricity energy supply, natural gas-fired combustion turbine and combined-cycle facilities comprise the vast majority of the state's installed base of electric generators. Advances in the efficiency of combined-cycle technology, increased and cheaper supplies, stringent air quality regulations, and ease of operations and maintenance all contributed the rapid growth in natural gas-fired generators during the state's electricity restructuring in the late 1990s. Prior to electricity restructuring, between 1978 and 1998, the California Energy Commission (CEC), which is the agency responsible for licensing thermal power plants greater than 50 MW, approved forty-seven total natural-gas fired electricity production projects with an installed capacity of 5,589 MW (CEC 2012a). Following the enactment of AB 1890 the CEC approved sixty-six electricity generation projects with an installed capacity of 25,789 MW (CEC 2012a). Thirty-nine of these natural gas generators with an installed capacity of 13,180 MW had been ultimately constructed by 2008, nearly doubling the total installed capacity of generation from all sources of electricity from previous decades (see Figure 2).

Figure 2:

California Installed Capacity Additions by Fuel Type and Decade (1890-2010) (MW)



Source: CEC QFER Database 2012

Notwithstanding the rapid construction of natural gas generators in the late 1990s, the state's total installed capacity is only able to meet 70 percent of domestic consumption needs. The installed nameplate capacity of all 1,146 generators greater than 0.1 MW in operation in 2011 totaled 71,341 MW, though net dependable summer capacity of in-state generation is much lower at 58,458 MW (CEC 2012a, CAISO 2011). Net dependable capacity (NDC) refers to the maximum capacity at which a generator can be depended upon to supply dispatchable load based on seasonal limitations (particularly for hydroelectric generators dependent upon rainfall), forced outages, and operation and maintenance requirements, and required reserve margin requirements (CAISO 2011). California utilities distribute approximately 285,000 GWh of electricity annually. Approximately 33 percent (94,000 GWh) of this electricity is distributed by publically owned utility (POU) customers, the largest of which are Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD). Investor owned utility electricity distribution is nearly double that of POU distribution. Combined, customers from the state's three major IOUs, PG&E (85,000 GWh), SCE (84,000 GWh), and SDG&E (17,500 GWh) account for nearly all (98 percent) of the total electricity consumed in the state annually (186,000 GWh) (CEC 2012b). Almost 30 percent of this electricity must be imported from generators located in neighboring states in the Pacific Northwest (10 percent- 27,718 GWh) and Desert Southwest (20 percent - 56,821 GWh) (CEC 2012a). [2]

[2] The California Energy Commission's definition of the Pacific Northwest includes the states of Idaho, Montana, Oregon, South Dakota, Washington, and Wyoming, as well as the Canadian provinces of Alberta and British Columbia; whereas the Desert Southwest refers to the states of Arizona, Colorado, New Mexico, Nevada, Utah, and the western-most part of the Texas pan-handle.

ELECTRICITY IMPORTS

Since the construction of the Bonneville (1937), Hoover (1935), Grand Coulee (1942), and Glen Canyon (1963) dams, California has relied on electricity imports to meet its consumption needs (Williams 1997). The California-Oregon AC-Intertie, Pacific DC Intertie, Intermountain DC Tie, and several Desert Southwest (Arizona/Colorado and Arizona) high voltage transmission intertie projects in the 1970s allowed electricity generated from newly constructed coal and nuclear generation facilities to supply California consumers. Several California utilities took advantage of these new high capacity lines by either directly financing or, later purchasing utility generators located throughout Arizona, New Mexico, Nevada, and Utah (see Table 1). Nearly all of these generators continue to supply electric power to California consumers except for the coal-fired, 1,580 MW Mohave Generating Station (MGS) in Nevada, owned by SCE (56 percent) and LADWP (10 percent). Mohave was retired in 2005 due to the costs associated with the installation of new pollution control equipment, as well as the inability of SCE to negotiate water rights to operate the coal slurry line which transported fuel to the facility (SCE 2012). Following the passage of AB 1890, electricity imports significantly increased primarily from wholesale natural-gas fired merchant generators in the Desert Southwest.

Table 1

California Utility Ownership in Out-of State Electricity Generating Facilities (2012)

Plant Name	Fuel- Type	Operating Company	Comissioning Date	Total Nameplate Capacity	Generating Unit	Installed Unit-Level Capacity	California Ownership	Percent Owned By California Utility	Capacity Owned by California Utiity
Four Corners Power Plant, New Mexico	Coal	Arizona Public Service Company	1969	2,070 MW	4	818.1	Southern California Edison	48%	393
			1970		5	818.1	Southern California Edison	48	393
San Juan Generating Station, New Mexico	Coal	Public Service Company of New Mexico	1973 (Unit 3 & 4 purchased by Southern California Public Power Authority (SCPPA) in 1993)	1,848 MW	3	555	City of Azusa	6.15%	34
					3	555	City of Colton	6.15%	34
					3	555	City of Glendale	4.10%	23
					3	555	City of Banning	4.10%	23
					3	555	Imperial Irrigation District	21.30%	118
					4	555	City of Anaheim	10.04%	56
					4	555	MSR Public Power Agency	28.71%	159
Navajo Generating Station, Arizona	Coal	Salt River Project	1974	2,409 MW	NAV1	803.1	Los Angeles Dept Water & Power	21.20%	170
			1975		NAV2	803.1	Los Angeles Dept Water & Power	21.20%	170
			1976		NAV3	803.1	Los Angeles Dept Water & Power	21.20%	170
Reid Gardner Generating Plant, Nevada	Coal	Nevada Power Company	1983	612 MW	4	270	California Dept of Water Resources	67.80%	183
Intermountain Power Plant, Utah	Coal	Los Angeles Department of Water and Power	1986	1,640 MW	1	900	Intermountain Power Agency	96%	787
					2	855	Intermountain Power Agency	96%	787
Palo Verde Nuclear Generating Station, Arizona	Nuclear	Arizona Public Service Company	1988	3,937 MW	Unit 1	1,311	Southern California Edison (15.8%) Southern California Public Power Authority (5.9%) Los Angeles Department of Water and Power (5.7%)		
					Unit 2	1,314			
					Unit 3	1,312			

Source: California Energy Commission California Utility Ownership in Out of State Generation (CEC 2012c)

ELECTRIC INDUSTRY RESTRUCTURING

Prior to AB1890 California's electric system operated in a simple, predictable manner based on the pretext of efficiency through economies of scale. Each of the state's IOUs were granted exclusive franchise rights by the CPUC to serve all retail customers within a designated geographical service territory in exchange for government oversight of the rates, finances, and quality of service. As in other areas of the county, these IOUs operated as vertically integrated monopolies, directly financing, constructing, and operating vast generation, transmission and distribution networks. The role of the

CPUC was to ensure public oversight of these IOUs on par with other municipal POUs, which were regulated by their own respective municipal boards,[3] to ensure that consumers were being charged fair market rates for electric consumption. The CPUC used an administrative law process, known as a “rate case” to balance consumer interest (service quality, pricing, service access, and environmental considerations) with the ability of the utility to earn a fair profit for their investors (Phillips 1993).

During rate cases, utilities would generally propose rates and underlying assumptions regarding operating costs. In turn, the CPUC would accept, reject, or ask the utility to modify the proposed rates based on their own understanding of a fair rate of return on capital for private investment needed to finance the construction of a wide range of power plant, transmission, and distribution projects. Even though rate cases made IOUs beholden to public oversight, they served as a reliable funding mechanism to increase generating capacity while almost guaranteeing a return on investment for utility investors (Joskow 1989). This system worked well through the 1960s. In California, like many other states the CPUC worked with utility companies to activity promote the expansion of electricity throughout the state. With regulatory support, PG&E, SCE, and SDG&E were able to rapidly finance, site, and construct several hundred electric generators and thousands of miles of transmission lines, including associated substations and switchyards (Eto 1996). Utilities flourished as they were quickly able to achieve economies of scale through the construction of additional generators, advances in

[3] California’s other two large utilities – Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD) – are publically owned utilities (POU), and, in such, are not regulated by the CPUC.

technology, and reducing operating costs protected from competition by their monopoly franchise rights. Consumers also reaped the benefits of expanded electric service and steadily declining electric rates (EIA 2000). In many respects, the 1950s and 1960s were a "Golden Age" of public and private cooperation in California benefitting private industry, electric utilities, and consumers.

Though the rapid growth and expansion of the state's electric industry was not without its problems. New federal air quality regulations, dramatic increases in the price of oil, environmental concerns over oil and gas exploration, and the introduction of capital intensive generating technologies, namely nuclear power, coupled with ever-increasing interest rates placed pressure on utilities to increase rates. After decades of ever-increasing growth, the once harmonious relationship between utility companies and state regulators had come to an end due to public concerns regarding the environmental consequences of energy production (Hyman 1994). The Clean Air Act (CAA) of 1970 required utilities to reduce emissions resulting from the combustion of fossil fuels (EPA 2012). The Arab Oil embargo of 1973-74, and the Iranian oil embargo of 1979 dramatically increased the cost of fossil fuels. As well, the accident at Three Mile Island in 1979 raised costs of constructing nuclear power plants due to new environmental concerns and increased scrutiny by federal regulators. These factors, combined with skyrocketing interest rates, placed utility companies increasingly at odds with state regulators as attempts to recover through the traditional rate case process became more and more difficult (Kahn 1988). The CPUC, facing political pressures of its own, utilized the rate case process to ensure utility compliance with federal and state environmental mandates, which severely hampered the construction of new power plants needed to meet the ever increasing demands for electricity by California consumers.

In response to increasing tension between state regulators and utility companies in California (as well as other states) the U.S. Congress passed several pieces of legislation designed to reduce U.S. dependence on foreign sources of energy through both demand-side and supply- side strategies. Among these acts were the Energy Policy and Conservation Act (1975) (EPCA), Energy Conservation and Production Act (1976) (ECPA), Public Utilities Regulatory Policies Act of 1978 (PURPA), and National Energy Conservation Policy Act (1978) (NECPA), consolidated under the umbrella National Energy Act (NEA)(1978), which laid the foundations for the structure of California's utility industry. The ECPA authorized the creation of the Strategic Petroleum Reserve (SPR), extended oil price controls, mandated minimum efficiency standards for automobiles, and directed the establishment of minimum energy efficiency standards for new residential and commercial buildings, as well as the creation of incentives for energy conservation and state weatherization programs (ECPA 1976). Similarly, the EPCA directed the National Institute of Standards and Technology (NIST) to develop standard procedures for measuring the energy efficiency of common household appliances (EPCA 1975). These standard efficiency ratings were later codified in the National Appliance Energy Conservation Act 1975, amended in 1987 (NAECA 1987). The NAECA created uniform federal energy efficiency standards for many common household appliances, including refrigerators, freezers, kitchens ranges and hoods, single room air conditioners, direct heating equipment, water heaters, pool heaters, central air conditioners, central heat pumps, furnaces, and boilers (IEA 2000). Energy Efficiency standards developed through EPCA (and later NAECA) and EPCA were later consolidated and codified into the Energy Policy Act of 1992 (EPACT), and subsequently amended by the Energy Policy Act of 2005.

Whereas ECPA and EPCA focused primarily on measures designed to shaping consumer energy demand, the role of PURPA was to promote efficiency in utility supply by fostering market competition and the construction of non-utility electric generators. PURPA required utilities to purchase power from more efficient non-utility generators if the cost of that generation was less than the utility's own "avoided cost" of constructing new generating capacity (PURPA 1978). The intent of this legislation was to foster market competition by decoupling the cost of generation from utility service for new power generation, while maintaining the service monopolies of existing utility companies. This act went so far as to require utilities to set up transmission lines to and purchase electricity directly from non-utility generators (known as qualifying facilities (QF)) even, in some cases, if the utility already had sufficient generating capacity to meet demand.[4] Though the interpretation and implementation of the provisions of this act were generally left to individual states, the CPUC aggressively used PURPA to support the growth of non-utility generation in the California, and laid the foundations for later electric industry restructuring under AB 1890 passed almost two decades later.

[4] PURPA outlines a number of provisions for qualifying facilities including size and ownership restrictions.

Though not as profound as PURPA, the NECPA was the first attempt to codify demand-side management as a resource option on par with the construction of new generation assets. This act required utilities to offer on-site energy audits, acknowledging that the cost of demand side management, in some cases, could prove to be lower than the cost of new generation. While utility companies, on one hand, fought against PURPA given that it threatened the existing returns on investment from the construction of new generating facilities, NECPA was initially viewed as more of a benign law (Eto 1996). The only hard requirement of NECPA was that utilities were now required to educate consumers regarding the potential benefits of energy conservation, though these programs seemed to have limited effect (Stern, Berry, and Hirst 1985). NECPA was preceded in California by the Warren-Alquist Energy Conservation and Development Act (1974), which authorized the creation of the CEC and set minimum energy efficiency standards for consumer appliances in California (Martin 1997, Borenstein et al. 1999, Joskow 1989).

The strict enforcement of PURPA and NECPA in California, as well as the addition of new federal rules governing the use of natural gas and oil in new generating facilities, led to delays in the ability of the CPUC to oversee IOU rate case applications, as the agency coped with integrating federal policy into state regulations. This further strained relations between utilities and state regulators (Moskovitz 1989, Wiel 1989). As mentioned earlier, California's strict interpretation of PURPA required utilities to purchase power from independent power producers. While this led to significant growth in the construction of non-utility generation, many IOU generation assets remained idle as supply from these assets could no longer be used to meet demand (Reid 1988). In the past, the cost of idle generation would have been passed onto consumers through the standard rate case process over an extended period of time. Stranded utility investment in excess generating capacity, particularly at nuclear generating facilities, mandates to purchase electricity from expensive non-utility generators, and other costly environmental regulations forced utility companies to rapidly increase electricity rates through the 1980s and into the early 1990s (Joskow 2001, Sweeney 2002). The CPUC, however, faced pressure to resist any rate increases designed to allow utilities to recover the "stranded costs" of idle generation given that electric rates were steadily increasing along with the cost of fuel. Neither PURPA, nor the CPUC's interpretation of PURPA, include provisions for utilities to recover stranded cost of idle generation capacity. The solution was the development of a semi-public utility resource planning process which later became known as the "least cost utility planning" process (Goldman, Hirst, and Krause 1989).

Though the CPUC retained the rate case process, it adopted the practices of the least cost utility planning process to better balance the interests of utilities and consumers. California, along with Washington, New Jersey, Rhode Island, Maine, Massachusetts, Minnesota, and Oregon were among the first states to adopt least cost utility planning practices (Nadel and Kushler 2000). The least cost utility planning process, otherwise known as integrated resource planning, served to shift the focus of utility regulation from purely supply-side policies toward a balanced assessment of both supply and demand-side options which would provide the best economic *and* social benefit (Cavanagh 1986, Hirst 1988, NARUC 1988). Under the traditional rate case process, utility companies planned, constructed, and operated power generation facilities without much public input, then approached the CPUC to recover the construction of their investment (Krause and Eto 1988). The assumption of both the utility companies and utility commission was that ever increasing economies of scale and increasing electric consumption would always be available to cover the cost of construction (Kahn 1991). Through the least cost utility planning processes utilities were now forced to consider alternatives to new power plant construction to cost effectively meet consumer's electricity needs (Cavanagh 1986). In such, utility companies were required to develop alternative forecasts of future electric loads, then assess those load requirements against an array of pricing, generation, consumption, transmission, and distribution alternatives. Utilities would then present a series of alternatives to the CPUC under the rate case process and discuss the most appropriate combination of resources, including demand side management activities. These discussions resulted in a wide range of assessments comparing different assumptions, such as economic growth, fossil fuel prices, and environmental externalities (Krause and Eto 1998). Once utilities and the CPUC came to an agreement upon the recommended resource allocation, the CPUC would then authorize a rate for the utility and monitor its progress until the next rate case (Hirst 1988). Though not perfect, the least cost utility planning process provided a forum for utilities to lay out the basic assumptions underlying their operations, which could subsequently be modified based on input from the public (Schweitzer, et al. 1991, Eto 1996).

In addition to updating nearly every major piece of energy related legislation, the Energy Policy Act of 1992 (EPACT) helped to promote the practice of the integrated resource planning process to other states. The act also created a new class of non-utility generator known as “exempt wholesale generators” (EWGs). These EWGs were exempt from corporate or geographic restrictions and would be allowed to sell wholesale electricity across borders at market rates unrestricted by the Federal Energy Regulatory Commission (FERC). It amended the Public Utility Holding Company Act (PUCHA) (1935), which regulated the interstate sale of electricity, to direct FERC to order utilities to provide EWGs with open access to their transmission infrastructure. This caused significant problems for many utilities, which, despite the open access requirements of PURPA, had failed to invest enough in expanding their transmission infrastructure. Fearing that they would be forced to compete with EWGs, utilities dragged their feet in constructing new transmission and distribution lines, thus favoring their own generators which were located along existing transmission networks, despite the lower cost of electricity purchases from many non-utility generators (Eto, Soft, and Belden 1994).

In order to rectify this situation, FERC issued Order 888 in April 1996 to compel utility companies to provide open transmission access at a reasonable “tariff” operated by Regional Transmission Organizations (RTOs)[5], such as CAISO, as well as Order 889 which created a wholesale electricity trading system, known as Open Access Same-time Information System (OASIS) for utilities to reserve and dispatch wholesale electricity

[5] Though Order 888 did not explicitly call for the creation of RTOs, some states, such as California had already moved to create ISOs. FERC passed Order 2000 in 1999 to provide structure to regional transmission organizations.

(Brennan 1998). The provisions of EPACT, along with FERC orders 888 and 889 once again set the stage for sweeping changes in the electric industry, which later became known as “electricity deregulation”, or “electricity restructuring” (Joskow 1996). The push to deregulate the electric industry followed previous efforts of other industries. The railroad, airline, banking, and telecommunication industries had all already undergone significant deregulation during the late 1980s and early 1990s (Hirsh 1999). It was the hope that in light of technological innovations, primarily in the form of new efficient combined-cycle natural gas fired generation, which could be supply both base-load and peaking power at a significantly reduced cost than traditional base-load coal and nuclear plants, that deregulation would also help transform the U.S. electric industry thus leading to lower consumer costs (Kuhn et al. 1996).

The thinking at the time was that PURPA would provide consumers benefit from even greater competition between wholesale several smaller, less expensive wholesale generators, rather than a few large capital intensive base-load coal or nuclear power plants (Joskow 2001). FERC Orders 888 and 889 were intended to facilitate these wholesale power transactions by decoupling the transmission and generation of electricity from retail distribution, which were already regulated by state utility commissions eventually leading to lower retail rates (Chao and Peck 1996). Even prior to the FERC Orders 888 and 889, faced with increasing pressure from utilities to recover stranded costs, the CPUC had already taken steps to restructure its electric industry (Kuhn 1996).

In 1992, the CPUC issued a directive to explore methods to reform the state’s regulatory environment to provide more retail competition (CPUC 1992). The resulting

“Yellow Book” thus named for the color of the report’s cover, published in 1993 called for unbundling electricity generation from transmission, and retail sales in order to allow market forces to drive more competitive retail electric rates (CPUC 1993). The Yellow Book was followed two years later by “Blue Book” which laid out the regulatory framework for electric industry restructuring in California (CPUC 1994). The Blue Book proposed phasing in retail electric competition in the state by providing consumers with direct access to wholesale electricity and replacing the current cost of service rate structure with a performance-based approach. The issue of stranded utility investments would be mitigated through a limited “competitive transition charge” requiring each retail customer to pay for the privilege of open market access, while also allowing IOUs to recover the cost of investment in idle generation capacity. In order to ensure fair transmission and distribution of wholesale electricity, the CPUC issued a directive in 1995 creating a separate Independent Systems Operator (ISO) to manage the state’s transmission network, and Power Exchange (PX) to act as a wholesale electricity clearinghouse (CPUC 1995).

The California legislature codified these decisions through the passage of the Electricity Industry Restructuring Act (Assembly Bill 1890) in 1996, which effectively legally separated electricity generation, transmission, and distribution in California without fundamentally altering private utility ownership, quality of service or reliability standards. While IOUs could still own some generation, transmission, and distribution assets, they would be forced to hand over coordination of transmission activities to CAISO and were forced to purchase even self-generated wholesale electricity through the

PX. Under electric industry restructuring PG&E and SCE divested 50 percent of their generating assets and SDG&E divested all of its fossil fuel generation as a condition of a previously approved merger between Enova and Pacific Enterprises (EIA 1999).

Prior to AB 1890, the energy efficiency and conservation programs were under the direct control of the CPUC, while the CEC maintained responsibility for renewable energy research. In less than a year after AB 1890 became law, PG&E, SCE, and SDG&E worked with FERC to create the structure and operating rules for CAISO and PX to provide for open access to other retail providers as called for in AB 1890 (FERC 1997). While AB 1890 itself seemed to be a fair compromise between the interests of utility companies, consumers, and state and federal regulators, in promoting effective retail competition, its implementation, as well as the enactment of subsequent legislation designed to clarify operational procedures of electric restructuring, ultimately led to the demise of retail competition itself. The first of these bills, AB 360 (1997), allowed IOUs to issue bonds to recoup some of its stranded generation investments.[6] An additional provision of AB 1890 called for a 10 percent reduction in retail electric rates and for those rates to be frozen until March 2002 or until such time that stranded costs could be recovered through competitive transition charges.

Despite these bonds and the competitive transition charge, nearly all of the state's IOUs began to divest at least some of their generating assets. In 1998, PG&E announced its intent to sell 13 natural gas-fired plants and one geothermal facility to recoup stranded

[6] The amount authorized by AB 360 was $7.3 million.

investments. SCE and SDG&E also made plans to sell generating assets to newly formed generating holding companies. While retail prices remained fixed, once CAISO and PX went online in March 1998, wholesale prices were allowed to fluctuate. In the summer of 1999, SDG&E began to experience price volatility in its service territory as wholesale prices surpassed retail price caps and after divesting some its generating assets earlier than expected, subsequently petitioned the CPUC to end the freeze on its retail rates (Sweeney 2002).

ELECTRICITY CRISIS

In early 2000, PG&E and SCE began to experience similar price volatility as wholesale electricity marketers, the most famous of which being Enron, began to monopolize available power during high peak periods leading to a spike in wholesale electric prices (Egan 2005). In the midst of a very hot summer of 2000 several areas in California experienced rolling blackouts as wholesale electricity prices far exceeded authorized retail electric rates, causing a shortage in the available cost-effective power utilities could provide (Joskow and Kahn 2002). The ensuing electricity crisis of 2000-2001 nearly bankrupted all three of the state's IOUs as they were forced to purchase wholesale electricity well above what they could recover (Sweeny 2002). By December 2000, it was estimated that the state's IOUs were losing up to $50 million a day, leaving both PG&E and SCE financially insolvent by January 2001 (Joskow 2002). While the CPUC initially resisted calls to cease wholesale electricity sales, the California legislature passed Assembly Bill 970 (AB 970) in a futile attempt to keep ahead of the crisis by reducing the power plant permitting process from one year to six months.[7] These efforts fell short as new generation facilities were not available soon enough to provide adequate additional wholesale electricity to the market. Eventually FERC intervened in the crises by investigating the manipulation of wholesale prices by power marketing company Enron. Eventually, wholesale electricity prices returned to normal by the summer of 2001. Subsequent lawsuits by SCE forced the CPUC to declare an effective end to retail electric competition in the state in October 2001 (Sweeney 2002). While electric industry restructuring was ineffective in transitioning California toward full retail competition, it did significantly impact the electricity landscapes of California and neighboring Arizona.

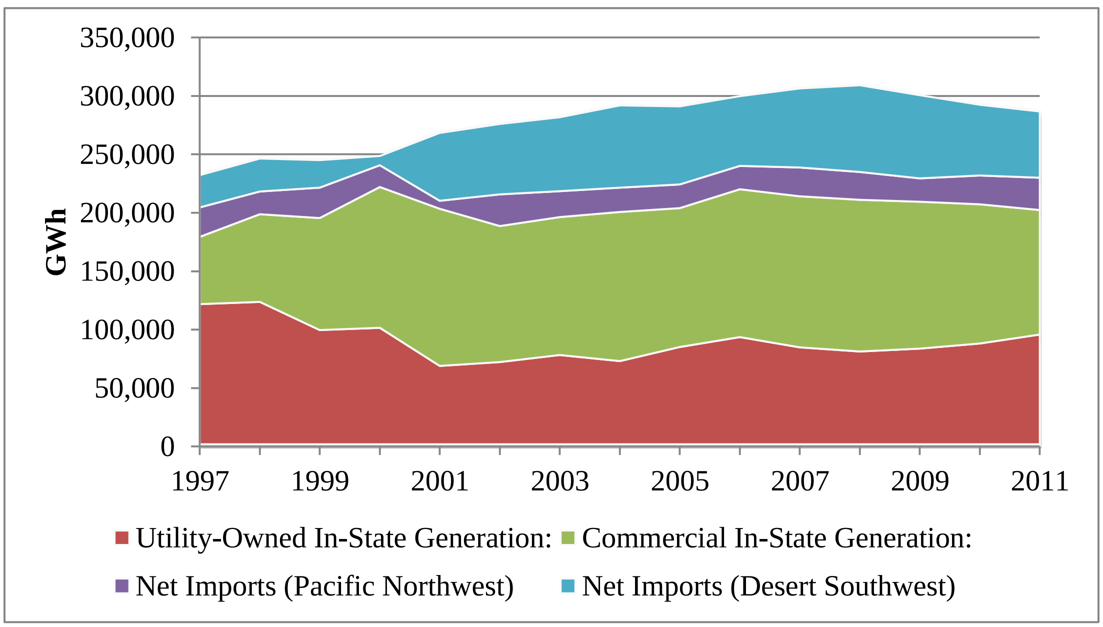
The divestiture of the majority of California IOU generating assets increased utility reliance on non-utility commercial generation as well as additional electricity imports from the Pacific Northwest and Desert Southwest (Figure 3). Between 1997 and 2011, California's total electricity consumption increased by 19 percent from 230,243 GWh in 1997 to 284,953 GWh in 2011. Concurrently, electricity imports, as a percent of total electricity consumption, increased by over 38 percent during the same period of time, from 52,720 GWh in 1997, to 84,539 GWh in 2011 (CEC 2012d). The vast majority of these additional electricity imports were supplied by generators located in the Desert Southwest, primarily Arizona. Electricity imports from the Desert Southwest more than doubled from 27,517 GWh in 1997 to 56,821 GWh in 2011, while electricity imported from generators located in the Pacific Northwest increased by only a modest

[7] The intent of Assembly Bill 970 was to reduce power plant licensing process from 12 months to 6 months and was scheduled to go into effect in January 1, 2004.

nine percent from 25,204 GWh in 1997 to 27,718 GWh in 2011 (CEC 2012d). Much of the increase in electricity imports from the Desert Southwest can be explained by the fact that electricity supplied by generators in the Pacific Northwest is primarily from hydroelectric resources. Given that hydroelectric facilities have generally limited capacity for expansion, California utilities were forced to look east towards wholesale merchant power plants in Arizona for additional sources of supply.

Figure 3

California Electric Supply by Generation Source (1997-2011) (GWh)



Source: CEC Electricity Consumption Database (CEC 2012d).

Merchant power plants are private electricity generators specifically designed to sell wholesale power to any retail operators. Many of these power plants effectively fall into the EPACT category defined as EWG. Many of the in-state generating assets divested by PG&E, SCE, and SDG&E following AB 1890 were purchased by EWG, such as AES Corporation, Duke Energy, NRG, Mirant, Dynegy, and Reliant and others. Though merchant generators, given their EWG status are not required to supply electricity to a specific geographic service territory and are free to sell wholesale electricity to any entity in the market based on hourly, daily, or other spot market mechanisms in practice these merchant operators, in reality most, if not all of these new domestic merchant generators almost immediately entered into long-term power contracts to supply base load power to the IOUs from which they were purchased assets (CEC 2011). With additional domestic wholesale merchant resources unavailable, and hydroelectric supplies from the Pacific Northwest at, or near, capacity, California utilities turned to an emerging wholesale merchant generation market in Arizona to meet its additional resource requirements.

ELECTRIC RESTRUCTURING IN ARIZONA

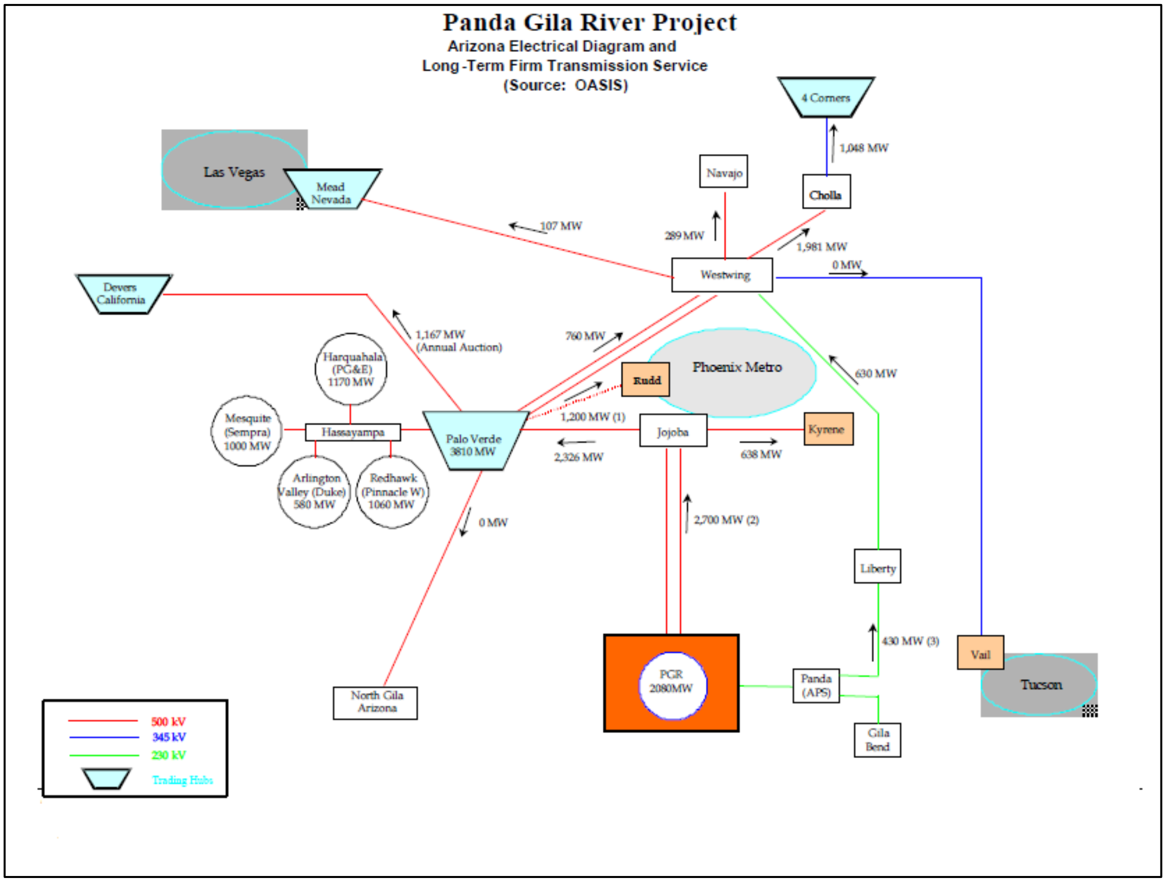
The State of Arizona has long been a major supplier of electricity to California. Southern California Edison already holds an ownership stake in Arizona's largest power plant, the massive 3,875 MW Palo Verde Nuclear Generating Station (PVNGS) and much of the supply from this power plant is used to supply SCE customers. Electric restructuring in Arizona stimulated the construction of additional wholesale merchant generators, which could also be called upon to provide additional supplies to SCE, as well as PG&E and SDG&E, both utilities which also share connections to the Palo Verde transmission hub. In December 1996, only months after similar AB 1890 was passed in California, the Arizona Corporation Commission (ACC) passed the "Retail Electric Competition Rule." Similar to AB 1890, this "Rule" authorized retail competition in Arizona, permitted utility companies to recover stranded costs, and allowed consumers to choose between retail electric providers (Walls 2000). This paved the way for the construction of several new merchant generators in Arizona to take advantage of new market opportunities in within Arizona as well as in newly opened markets in California.

Between June of 1998 and June of 2000, several private merchant electricity generation companies petitioned the ACC to allow the construction of up to 13 merchant power plants, primarily in the western portion of the state (Hedler 2000). In order to provide some perspective, prior to 1998, there were only 34 power plants of any type in Arizona (EIA 2012a). By December 2002, in its Second Biennial Transmission Assessment, the ACC estimated that it would need to significantly upgrade the state's existing transmission network to accommodate up to 21 new electricity generation facilities totaling over 11,817 MW in additional installed capacity between 2001 and 2005 (EIA 2012a). A total of 16,583.9 MW of electric generation capacity had been installed in Arizona from 1926 to 2000, including massive energy projects such as the Glen Canyon Dam (1,155 MW) in 1963, the coal-fired Navajo Generating Station (2,409.3 MW) from 1974-1976, as well as Palo Verde (EIA 2012a).

The pace of construction of natural-gas fired generating plants in Arizona during a span of four years, far outstripped any previous energy projects in the state and far exceed the future projected resources needed by Arizona utilities, even taking into account double digit population growth (ACC 2002). An alternative explanation for the construction of these plants was to serve newly opened markets in California. Merchant power companies took advantage of deregulation efforts in Arizona with the ultimate intent of selling excess wholesale capacity to California. Indeed, several of these merchant generators were constructed near Hassayampa and Jojoba switchyard which provide easy access to the high voltage transmission lines of the Palo Verde bus bar, about 40 miles southwest of Phoenix. In 2002 alone, five new merchant generators, with a combined capacity of 6,010 MW began transmitting electricity across the Palo Verde distribution system, including Redhawk Units 1 and 2 (1,060 MW) , Arlington Valley Unit 1 (580 MW), Mesquite (1,250 MW), Harquahala (1,040 MW) and Panda Gila River (2,080) (ACC 2004). Figure 4 illustrates the Palo Verde transmission system in 2004, while merchant generation applications in Arizona as represented in ACC biennial transmission assessments and EIA-860 Annual Operator Reports are represented in Table 2.

Figure 4

Schematic of Generation Additions in Arizona (2002)



Source: Arizona Corporation Commission Second Biennial Transmission Assessment (ACC 2002)

Table 2

Arizona Natural Gas Generation Projects (2000-2006)

Facility Name	Commercial Online Date	Technology	Fuel Type	Installed Capacity (MW)	Project Developer	Location	Merchant/ Utility
Desert Basin Generating Station	6/1/2001	Combined Cycle	Natural Gas	520	Salt River Project (Purchased from Reliant Resources, Inc.)	Casa Grande, AZ	Utility
South Point Energy Center	6/1/2001	Combined Cycle	Gas	540	Calpine	Mohave, AZ	Merchant
West Phoenix (Phase 1)	8/1/2001	Combined Cycle	Gas	120	Pinnacle West Energy (APS)	Phoenix, AZ	Utility
West Phoenix (Phase 2)	8/4/2003	Combined Cycle	Gas	530	Pinnacle West Energy (APS)	Phoenix, AZ	Utility
Griffith Energy Project	1/11/2002	Combined Cycle	Gas	650	Griffith Energy (PPL & Duke Energy)	Kingman, AZ	Merchant
Sundance Energy Project 1	7/19/2002	Combined Cycle	Gas	450	Pinnacle West Energy (APS; purchased from PPL Generation)	Coolidge, AZ	Utility
Arlington Valley I	8/1/2002	Combustion Turbine	Gas	580	Duke Energy NA (StarWest)	Arlington, AZ	Merchant
Kyrene Generating Station	9/1/2002	Combined Cycle	Gas	250	Salt River Project	Tempe, AZ	Utility
Redhawk 1	9/1/2002	Combined Cycle	Gas	530	Pinnacle West Energy (APS)	Arlington, AZ	Utility
Redhawk 2	9/1/2002	Combined Cycle	Gas	530	Pinnacle West Energy (APS)	Arlington, AZ	Utility
Saguaro	9/1/2002	Combustion Turbine	Gas	80	Pinnacle West Energy (APS)	Red Rock, AZ	Utility
Mesquite Power I	6/1/2003	Combined Cycle	Gas	625	Sempra Generation	Arlington, AZ	Merchant
Mesquite Power II	11/12/2003	Combined Cycle	Gas	625	Sempra Generation	Arlington, AZ	Merchant
Gila River I	5/31/2003	Combined Cycle	Gas	580	Entergra Power Group	Gila Bend, AZ	Merchant
Gila River II	6/19/2003	Combined Cycle	Gas	580	Entergra Power Group	Gila Bend, AZ	Merchant
Gila River III	7/21/2003	Combined Cycle	Gas	580	Entergra Power Group	Gila Bend, AZ	Merchant
Gila River IV	7/21/2003	Combined Cycle	Gas	580	Entergra Power Group	Gila Bend, AZ	Merchant
Harquahala Generating Station	5/1/2004	Combined Cycle	Gas	1170	Societe Generale (from PG&E NEG)	Tonopah, AZ	Merchant
Santan (I)	4/20/2005	Combined Cycle	Gas	550	Salt River Project	Gilbert, AZ	Utility
Santan (II)	6/1/2006	Combined Cycle	Gas	275	Salt River Project	Gilbert, AZ	Utility

Source: Arizona Corporation Commission Second and Third Biennial Transmission Assessment (ACC 2002; ACC 2004

In April 2003, Arizona Public Service Company (APS), the largest utility in the state, issued a report stating: "For residential and smaller commercial customers, transaction costs of retail choice have been more significant than first believed…APS does not believe that the Retail Electric Competition Rules should be continued in their present form (APS 2003)." The following year, the Arizona Court of Appeals declared the ACC decision requiring utilities to divest their generation assets was unconstitutional given that the agency did not provide an adequate explanation as to how these divestitures would help to control electric rates (ACA 2004). Following the Court of Appeals decisions, the ACC took no significant additional action to promote retail competition leading to a de facto suspension of electric industry restructuring in the state.

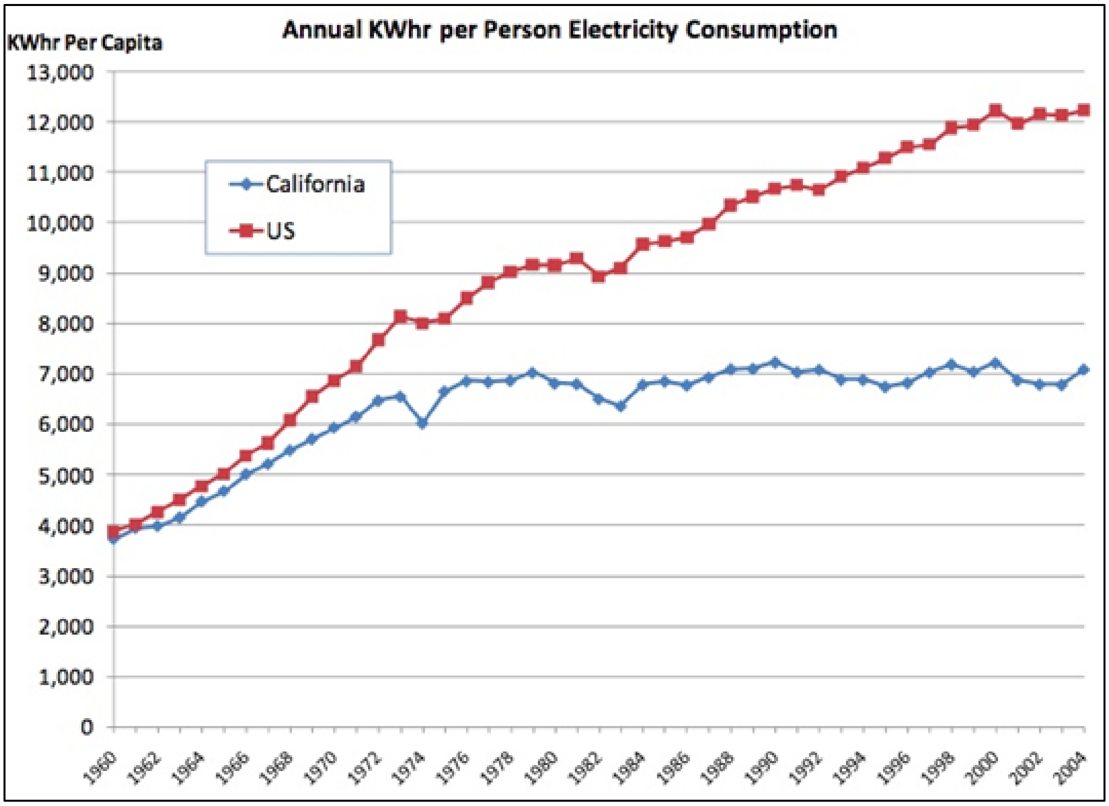
Following the suspension of retail price competition in Arizona in 2004, many of these merchant power plants were subsequently purchased by APS, Salt River Project (SRP), and Tucson Electric Power Company (TEPCO). Nonetheless, given the tremendous additional generating capacity afforded by these new merchant operators, Arizona generators were able to increase electricity exports by 60 percent from 23,144 GWh in 2000 to 34,447 GWh in 2010. These electricity exports represented nearly one-third of state's total electricity supply (112,000 GWh in 2010) (EIA 2012b). Based on estimates in Pasqualetti and Kelley (2008), approximately one half of these total exports in 2010 (14,928.91 GWh) were supplied directly to California utilities. Based on the estimates contained in this study, we were able to confirm that at least 30 percent (4,520 GWh) of these total exports are supplied by merchant generators to California IOUs on an annual basis. This additional wholesale merchant generation is generally more expensive that domestic electricity supply and is primarily used to supply peaking power only.

DEMAND SIDE MANAGEMENT

As an alternative to increased electricity imports, California utilities are also pursuing extremely aggressive demand side management activities. Since the 1970s, California has led the nation in the developing and promoting demand side management programs (Nadel and Geller 1996). The purpose of utility DSM programs is to reduce electricity consumption and peak load demand through a mixture of consumer education and financial incentives. The California State and Consumer Services Agency (CSCSA) estimates that between 1975 and 2000, California energy efficiency programs have offset the need to construct roughly 10,000 MW of electrical generation capacity (CSCSA 2002). In fact, per capita electricity consumption has remained relatively flat in California over the last thirty years as compared to the rest of the U.S. (see Figure 5). This phenomenon is known as the “Rosenfeld Curve” after retired California Energy Commissioner Dr. Arthur Rosenfeld (Cavanagh 2009). While some of this reduced consumption can be attributed to changes in the composition of the state’s industrial base, smaller average household sizes, and other factors, utility administered DSM programs have undoubtedly contributed to electricity reductions (Sudarshan and Sweeney 2008).

Figure 5

“Rosenfeld Curve” -- Per Capita Electricity Consumption Change in California (1960-2004)



Source: California Energy Commission Energy Consumption Database (CEC 2012b)

Under the least cost utility planning process, utility DSM in California was considered a viable resource option on par with supply-side generation additions. California IOUs actively invested in DSM, particularly in high load growth areas as a cost-effective means to mitigate transmission constraints, as well as manage the commissioning of new generation capacity. During the 1980s and 1990s, the CPUC regulated utility energy efficiency programs as a resource on par with new generation capacity. The CPUC set energy efficiency goals for each of the state's IOUs, which, in turn, would administer the programs and earning incentives through a share-holder incentive mechanism based on the achieving savings goals, based on "ex post" measurement of energy savings. Even though these programs were designed to maximize ratepayer and utility benefit (avoided costs), they were not directly tied to a specific kilowatt hour (KWh) or Kilowatt (KW) savings goal.

The use of public benefit funds to finance demand side management activities had become commonplace following deregulation as they were considered generation neutral and were relatively small (Nadel and Kushler 2000). In that sense, given that utilities had little ability to coordinate generation, transmission, and distribution under the terms of AB 1890, PG&E, SCE, and SDG&E essentially became temporary DSM program administrators. From 1997 through 2001,[8] the CPUC provided only short term extensions to utility energy efficiency (EE) programs on a yearly basis. During this time period, incentives paid to utilities based on milestone achievements (number of audits performed, measurement of market effects, number of appliances recycled, etc.), rather than a resource- benefit basis with only a small portion paid through ex ante verified savings (CPUC 2005).

The divestiture of generating assets, price controls, and other cost cutting measures under electric industry restructuring significantly dis-incentivized utility DSM investment and made voluntary DSM an undesirable resource planning option for utilities

[8] AB 1890 only provided funding for EE programs through 2002.

(Gillingham et al. 2004). In light of this fact, the CPUC required the IOUs to collect a public goods charge (PGC) equivalent to one percent of their utility bills to finance demand side management activities, a practice which had become commonplace in other states following electric industry restructuring (Nadel and Kushler 2000, Kushler and Witte 2001). Within the provisions of AB 1890, these funds would be used to finance cost-effective energy efficiency and conservation, low-income energy assistance, public interest research and development, and renewable energy technologies.[9] Still, utility investment in DSM activity remained rather flat as they struggled to control internal costs in the wake of divesting their generating assets.

Immediately following the California Energy Crisis of 2000-2001 and the subsequent suspension of electric restructuring in the state, the CPUC moved quickly to reinstate integrated supply and demand side management, though the focus and goals of these programs were to be directed toward short-term energy efficiency measures and peak load reduction to mitigate against potential future crises (Goldman et al. 2002). The commission continued funding energy efficiency programs on a yearly basis from 1998 through 2003, and a two year "bridge period" for 2004 and 2005 based (CPUC 2004a). During this timeframe (1998-2005), PG&E, SCE, and SDG&E customers had contributed a total of $1.8 billion toward energy efficiency programs through the public goods charge (PGC) (CPUC 2004b). This funding was roughly equal to 1.5 percent of annual IOU retail sales resulting in roughly 1,400 GWh and 300 MW in energy savings

[9] AB 1890; In 2000, the California legislature passed AB 995 and AB 1194 which extended PGC funding for ten additional years (AB95, AB 1194).

over a span of seven years. This amounted to only roughly one percent of combined annual retail electric sales (CPUC 2004b). In 2005, the CEC published a study which determined that demand side management program funding proved to be more cost effective than any other form of supply-side options (CEC 2003). During 2004, base load generation cost roughly 5.8 cents per kWh, shoulder load 11.8 cents per kWh, and especially peak load generation at 16.7 cents per kWh, making demand side management clearly the most cost effective resource option.[10] In 2000, the average cost of DSM programs amounted to 3.7 cents per kWh saved through energy efficiency programs. By 2004, the cost of saved energy dropped dramatically to an average of 1.1 cents per kWh saved (CEC 2005). In comparison, the average retail residential cost of electricity in 2004 averaged approximately 11.78 cents per kWh across all three IOUs (CEC 2005).

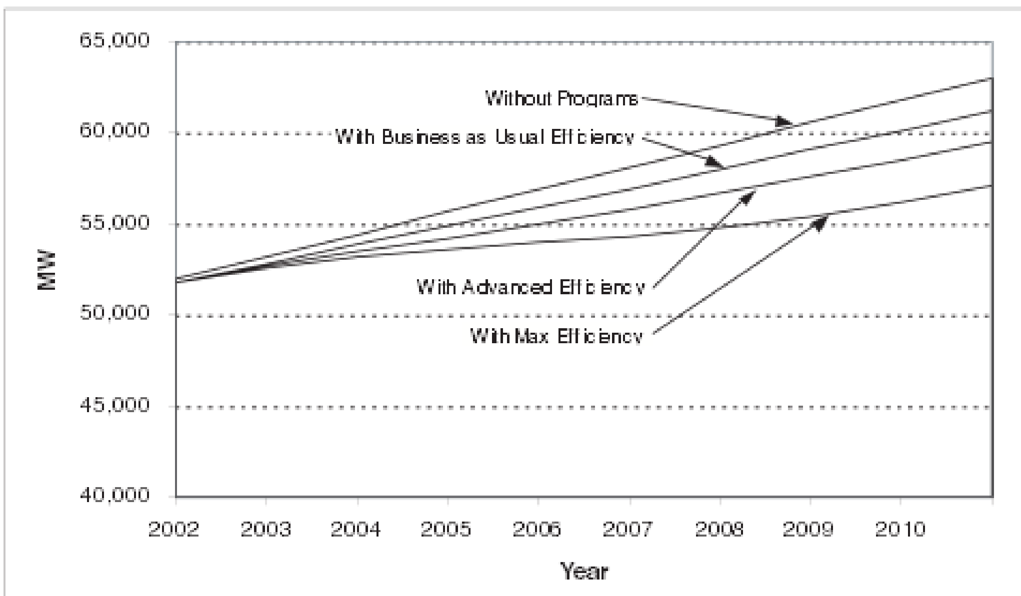
The findings confirmed an earlier study released in 2002 commissioned by the independent Energy Foundation and Hewlett Foundation by Xenergy, Inc. entitled, "*California's Secret Energy Surplus: The Potential for Energy Efficiency* "(Rufo and Coito 2002). This study, which largely shaped DSM policy in the ensuing years, analyzed consumer behavior and electricity use patterns in the wake of the electricity crisis with the goal of determining potential achievable energy efficiency savings. The study concluded that peak energy demand growth, which was expected to grow from 53,000 MW in 2001 to 63,000 MW in 2011, and could be effectively curtailed by up to 50

[10] Base load generation refers to the minimum amount of generation which is always available; usually base load electricity is generally provided by coal or nuclear-fired generators; shoulder load refers to the early morning when commercial and industrial operations begin (8 AM- 1 PM), and in the evening when residential consumption is highest (7 PM - 9PM).

percent through significant investment in utility DSM program (See Figure 6). Using existing DSM funding levels equating to $2 billion over the course of the next 10 years, the study found that IOUs would receive nearly $5.5 billion in net benefits (avoided generation, transmission, and distribution costs), and that incremental increases in energy efficiency investment above those levels would result in exponentially greater net benefits (Rufo and Coito 2002).

Figure 6

California Secret Energy Surplus Study DSM Potential Forecast (2002-2012)



Source: California's Secret Energy Surplus: The Potential for Energy Efficiency, 2002

This study came to be one of the most cited documents in CPUC and CEC reports regarding utility DSM and laid the foundation for the California's first Energy Action Plan released in 2003 (EAP 2003). The stated goal of EAP 2003 was to: "Ensure that adequate, reliable, and reasonably-priced electrical power and natural gas supplies, including prudent reserves, are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers." In order to meet this goal, the report defined a specific ranking of "preferred" energy resources. This ranking, which eventually become known as a "loading order" included six key broad areas of importance to energy policy in the state: (1) optimize energy conservation and resource efficiency, (2) accelerate the state's goal for renewable generation, (3) ensure reliable, affordable electricity generation, (4) upgrade and expand the electricity transmission and distribution infrastructure, (5) promote consumer and utility owned distributed generation, and, (6) ensure reliable supply of reasonably priced natural gas (EAP 2003).[11] While only nine pages long, this document succinctly outlined a series of actionable steps to achieve the state's energy goals.

With respect to DSM program activities, EAP 2003 defined several action items intended to minimize the need for additional generation capacity, as well as link environmental concerns (namely GHG emission reductions), improved electric reliability, and price stabilization. Specific steps included in the policy statement were to: (1) implement a voluntary dynamic pricing system to reduce peak demand by as much as

[11] Although the term "loading order" cannot be found in EAP 2003, it has since become a common reference used to describe resource preference.

1,500 to 2,000 MW by 2007 [12], (2) improve new and remodeled building efficiency by five percent[13], (3) improve air conditioner efficiency by 10 percent above federally mandated standard[14], (4) make every new state building a model of energy efficiency[15], (5) create customer incentive for aggressive energy reduction, (6) provide utilities with demand response and energy efficiency investment rewards comparable to the return on investment in new power and transmission projects, (7) increase local government conservation and energy efficiency programs, (8) incorporate, as per Public Resources Code section 25402, distributed generation or renewable technologies into energy efficiency standards for new building construction, and, [16] (9) encourage companies that invest into energy conservation and resource efficiency to register with the state's Climate Change Registry (EAP 2005). Nearly all of these action items were integrated into the CPUC Decision D. 04-09-060 released in 2004, but intended for energy efficiency program cycles for 2006 and beyond (CPUC 2004). This decision also

[12] The CPUC had already implemented policy directive R-02-02-001 in 2002 to evaluate and implement these pricing systems.

[13] In 2003, the CEC had already released a draft version of proposed building standards (which were to go into effect in 2005) designed to attain this energy reduction goal.

[14] Recently released federal appliance standards were expected to result in a 20 percent increase in energy efficiency; additional efficiency standards in California over and above federal standards were expected to garner a further 10 percent increase incremental efficiency.

[15] No specific direction was provided in the document as to neither how this goal would be attained nor what metric by which it would be measured.

[16] CPRC section 25402 was a legislated action directing the CPUC to reduce unnecessary consumption of energy

identified the achievable energy efficiency goals outlined in the Secret Energy Surplus Study as the baseline "stretch goals" for attainable IOU energy savings, and ordered state IOUs to integrate these energy efficiency goals into resource acquisition and procurement plans (CPUC 2004).

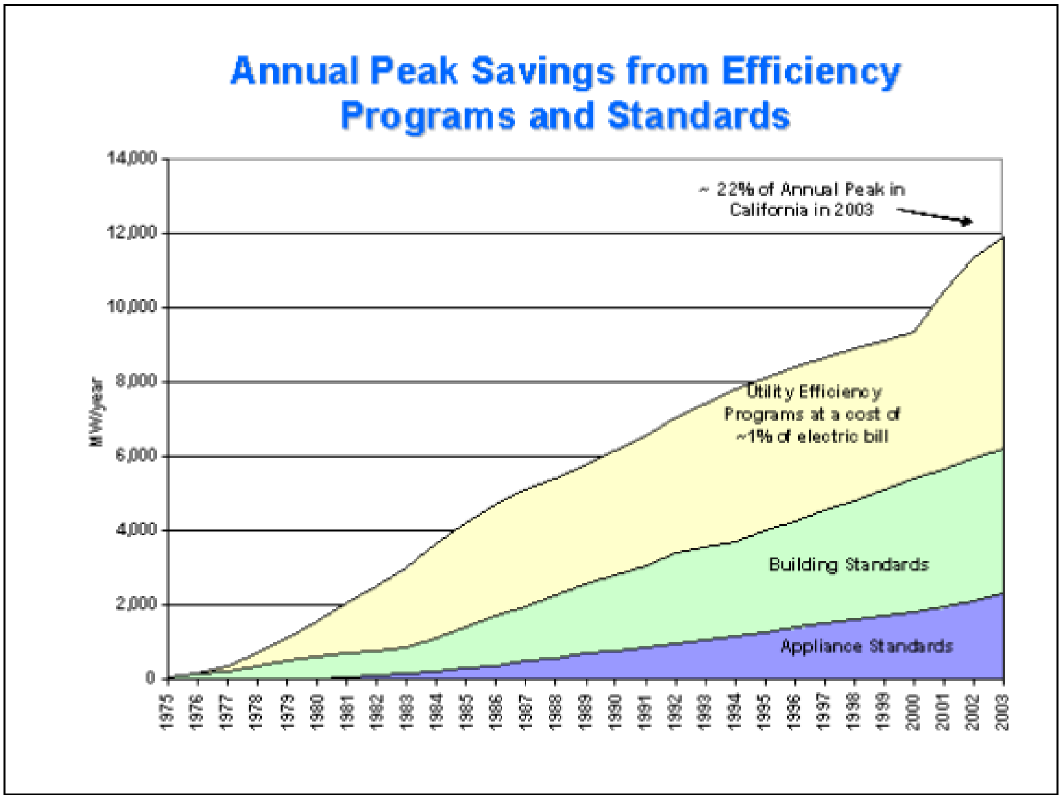
In 2005, the CPUC and CEC, along with input from CAISO, released Energy Action Plan (EAP 2005), as an update to EAP 2003 integrating various state executive orders, CEC integrated planning reports, CPUC decisions, and legislative initiatives.[17] EAP 2005 reaffirmed the policy statements of EAP 2003 and included additional provisions to address the emerging issue of climate change, transportation-related energy activities, and several research and development initiatives (EAP 2005). This document also affirmed the state's commitment that "cost effective energy efficiency is the resource of first choice for meeting California's energy needs" while also providing the first cohesive set of historical energy efficiency investment data, including budgets through 2013 (See Figures 7 and 8).[18] This data described key phases of energy efficiency with the state over the past 30 years from the implementation of appliance standards, through the development of utility incentive mechanisms, electric industry restructuring, the subsequent energy crisis, and projected investment in energy efficiency through integrated resource planning.

[17] By this point in time, the Consumer Power and Conservation Financing Authority had ceased operations and consequently was no longer included in energy policy planning.

[18] EAP 2005 section 2; many references commonly misrepresent EAP 2003 as the basis for energy efficiency being the first in the state's loading order; however, it is only in EAP 2005 that the position of energy efficiency is affirmed as being the "first choice" energy resource.

Figure 7

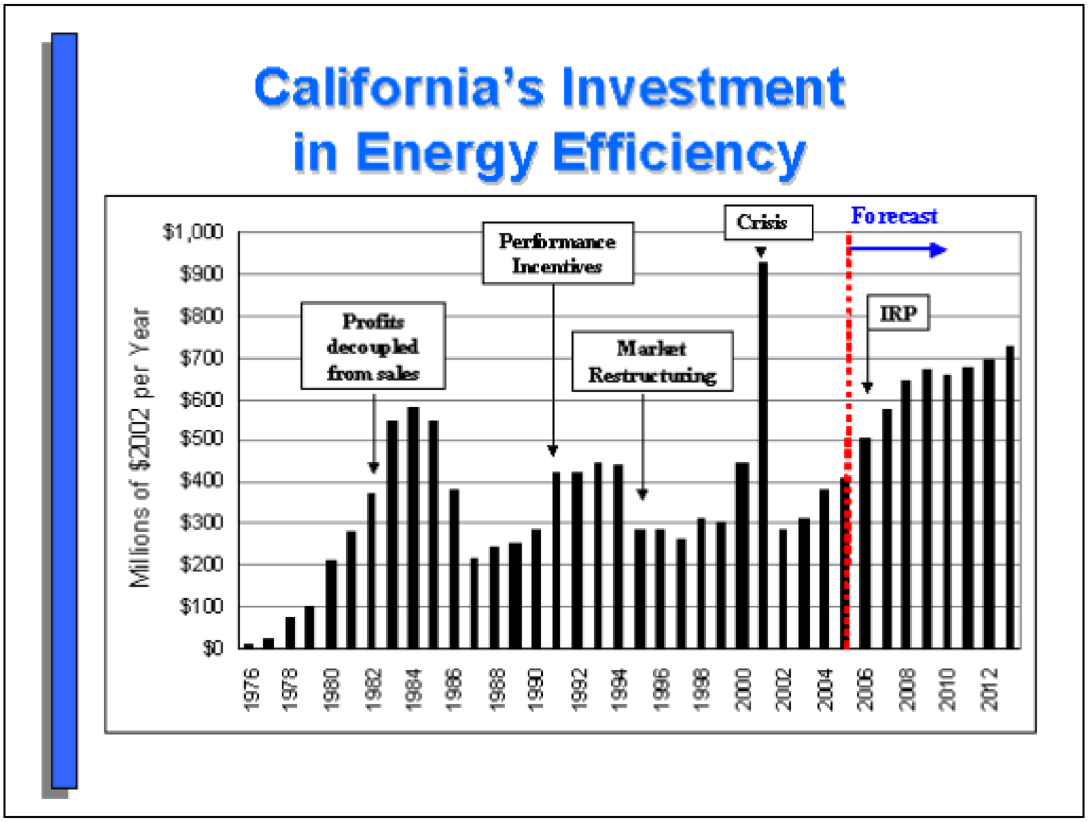
Historical Peak Energy Savings from Energy Efficiency Program and Standards Data (1975-2003)



Source: Energy Action Plan 2005

Figure 8

Historical and Projected California Investment in Energy Efficiency



Source: Energy Action Plan 2005

Energy Action Plan 2005 also expanded on the actionable steps included in EAP 2003 in order to increase "non-resource" energy efficiency efforts through public outreach and education, energy efficiency research, demonstration projects, and improved *post ante* evaluation, measurement and verification efforts (which to this point had been cursory at best) which were to be integrated into the IOUs 2006-2008 energy efficiency program cycle. Key actions outlined in EAP 2005 included: (1) requiring that cost-effective demand-side energy efficiency options be integrated into IOU resource plans on par with new supply-side generation requirements, (2) that the CPUC adopt 2006-2008 energy efficiency program portfolios and finalize funding levels for these programs no later than 2005, (3) creating additional “non-resource” energy efficiency marketing, education and outreach program during the next program cycle[19], (4) creating a balanced portfolio of base load and peak load electricity reductions while maintaining long term reliability, (5) integrating demand response (emergency peak load reduction) with energy efficiency, (6) improving building performance standards in government buildings to reduce electricity purchased by 20 percent by 2015, (7) assisting IOUs in building business cases for energy efficiency programs, (8) adopting new efficient appliance standards, (9) adopting new building standards to include demand response and solar photovoltaic technologies, (10) increasing the availability of state-backed low interest loans for energy efficiency and distributed generation technologies, (11) improving energy efficiency programs for low income and “hard to reach” market sections, (12) adopting a performance based incentive structure in 2006 to encourage IOU energy efficiency investment, (13) updating evaluation, measurement, and verification protocols to include associated environmental benefits, particularly emissions reductions, in future resource plans, (14) identifying opportunities to increase water system optimization as a vehicle for reduced peak energy consumption and, finally, (15) supporting

[19] Traditional energy efficiency retrofits and measure installation, including appliance recycling efforts have been considered “resource’ program. Up to that point, with the exception of buildings and standards, there was very little coordination between public outreach through “non-resource” programs outside of compliance with federal public awareness mandates in place since the late 1970s.

recommendations for building system retrofits in state buildings as required by Assembly Bill 549 (CPUC 2003). These actions, as outlined in EAP 2005 set the stage for the first truly integrated energy efficiency program cycle, which was set to begin in 2006 and end in 2008.

Based on the policy decisions set forth in EAP 2005, the CPUC released an interim opinion outlining energy efficiency portfolio plans and program levels for the next three years Decision 05-09-043, released in September 2005, authorized PG&E, SCE, and SDG&E to develop specific types of energy efficiency programs under the umbrella of a unified program portfolio with the intent that these activities should be sufficient to meet up to 50% utility resource needs for the next ten years (CPUC 2005). This was a departure from previous energy efficiency program cycles which afforded individual utilities with very little autonomy in program administration. The decision provided guidance to utilities that their programs should be both cost effective, meaning the value of the energy savings should be greater than the cost of measures,[20] as well as the cost of utility program administration and shareholder incentives. Preceding utility energy efficiency program filings estimated that the 2006-2008 program cycle would save an estimated 500 MW of generation capacity over the course of the three year cycle at a cost of $800 million per year (including associated post ante program evaluation, measurement, & verification (EM&V) costs).

[20] The term “measure” is used to describe not only the physical energy efficiency technology installed, but also the cost of energy efficiency installation and associated project costs incurred.

The Decision identified general “statewide” programs in which all utilities would participate, as well specific program administered by each utility, but operated through a competitive third party solicitation process. These incentive programs included both “upstream” incentives in which the utility buys works with manufacturers to buy down the cost of energy efficient technologies so they can be sold at stores below retail price, and “downstream” rebates, in which customers are reimbursed for a least portion of the cost measure installation. All three IOUs coordinated their activities to develop “statewide” rules and incentives structures for both upstream and downstream programs, the most popular of which become known as “Express Efficiency” and “Standard Performance Contract.” Express Efficiency allowed customers to purchase energy efficient technologies and received a fixed rebate per measure installed, whereas rebates for Standard Performance Contracts were based on the verifiable electricity saving and the technology installed.

Both of these programs have continued into subsequent program cycles though they are known by different names. In addition to statewide programs, all three IOUs developed a portfolio of targeted programs for “hard- to reach” customer segments. The target market approach was designed to provide select customer segments with a tailored energy efficiency, financing, incentives, retro-commissioning, design assistance, and rebates to maximize customer savings over time, such as agriculture, schools, large retail, industrial, healthcare, lodging, data centers, and new construction segments. All three IOUs were also required to coordinate activities for the assessment of emerging technologies, codes and standards efforts (collectively known as Title 24), and engineering assessments within their own authorized budgets. Within the guise of the "Flex Your Power" campaign, all utilities were required to coordinate energy efficiency marketing activities across all media including: television, radio and newspaper ads, printed educational materials, events, a comprehensive website resource serving all parties statewide, a biweekly electronic newsletter, forums and workshops, and partnerships with businesses, local governments, water agencies, non-profits and others, including the state and federal government agencies responsible for energy and water efficiency. Finally, each utility was required to develop local government partnerships to provide marketing, education, and outreach, facilities retrofits, construction and rebate assistance, as well as emerging technologies demonstrations within their authorized budgets.

Following a bridge period in 2009, the CPUC authorized $3.1 billion in rate-payer funds to finance the 2010 through 2012 IOU program cycle. Many of the programs developed during the 2006 through 2008 program cycle were continued as mechanisms to effectively reduce the need for new power plant construction as well as achieve the "complimentary policy" goals of carbon reduction described in the CARB AB32 Scoping Plan. In addition, each of the state's IOUs have made significant strides in improving program performance and processes, including engineering assessments, incentive applications, customer outreach and marketing. The energy savings achieved during the 2010-2012 program, release in February 2013 totaled over 7,672.45 GWh in electricity savings and 1,397.64 MW in peak demand reduction (CEC 2013).

SUMMARY

The California electricity system has undergone significant structural change over the course of the last fifty years culminating in a fundamental restructuring of its electric industry and increased electricity imports from neighboring states, namely Arizona. This section provided a brief overview of some of the more pertinent issues facing the state's electric industry with added emphasis on the evolution of the industry, GHG emissions reductions goals, and utility administered DSM programs. The next section describes the evolution of GHG emission assessments specific to California with added emphasis on GHG emission factors, inventories, and current efforts by IOUs to estimate avoided emission reductions as a result of DSM activity.

CHAPTER 3: REVIEW OF LITERATURE

INTRODUCTION

Emission factors and emission inventories are fundamental tools of GHG emissions estimates (Southerland 1982). They provide a basic framework for analyzing relative source emission estimate for all GHG assessment, mitigation, and management activities. The following section describes the evolution of emission factors and emission inventories, with particular attention to the way in which these analytical tools are used to estimate emission, or in the case of this study, "avoided" emission estimates. Particular attention will also be given to how emission estimates and emission inventories have been used in assessing emissions estimates with respect to electrical generation in California. In that respect, this study will touch upon emission factors developed by the California Climate Action Registry (CCAR), emissions inventories developed by CARB, and, finally, the CPUC "E3" calculator used currently by the state's IOUs to assess emissions based on in-state generation activity.

EMISSION FACTORS

The genesis of emission factors lay with the Clean Air Act (CAA) of 1963, which required the EPA to develop a national standard for several atmospheric pollutants, including carbon monoxide, nitrogen dioxide, sulfur dioxide, particulate matter, hydrocarbons, and photochemical oxidants (CAA 1963). After several additional intermediate amendments, the 1990 CAA expanded the list of pollutants to 189, including those most commonly associated with electrical production, which are believed to be responsible for between 30 and 40 percent of total anthropogenic atmospheric pollution. The primary pollutants emitted as a result of fossil-fuel based fuel combustion are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_20). The EPA has recently been given the regulatory authority to regulate these emissions under the authority of the CAA in January 2011 (EPA 2012).

In order to quantify, track, and inventory these pollutants, the EPA initially relied on a compilation of emission factors published by the U.S. Public Health Service in 1968, which were later revised in 1972 and 1985. These emission factors were intended to represent a relative quantity of pollutants expressed in terms of the weight of the pollutant divided by the distance, duration, heat rate, or production of the polluting activity (e.g. lbs. of CO per mile driven, grams of CH_4 per MMBtu, or kg of CO_2 per MWh electricity generated (EPA 2010a). The most common measure of general GHG emissions from electricity generation is known as “Carbon Dioxide Equivalency” (CO_2e), which describe the equivalent mixture of a number of greenhouse gases in terms of the amount of CO_2 with the same global warming potential (GWP). As a baseline, CO_2 has a GWP of exactly one, whereas methane and nitrous oxide have global warming potential of twenty five and two hundred eighty six respectively, meaning that one kilogram of methane has a global warming potential twenty five times greater than one kg of carbon dioxide, and one kilogram of nitrous oxide has a global warming potential equal to two hundred eighty six times that of one kilogram of carbon dioxide.

These factors are widely used to facilitate the estimation of representative averages of available data regarding the relative amount of pollutants emits from various sources of per unit of activity (EPA 1999). The U.S. Department of Energy (DOE) uses these established emission factors to estimate emissions for fossil fuel based electricity generation sources on an annual basis (DOE 2000). The DOE then aggregates these generator emission factors to develop average emission factors for various regions within the U.S (U.S. DOE 2001). The equations for estimating emissions and emission reduction activity using emission factors are described in Equations 1 and 2, respectively:

Equation 1

Estimating Emissions Using Emission Factors

$$E = A \times EF$$

Where:

- E represents emissions, in terms of the weight of the pollutant (e.g. kilograms, pounds, metric tons, etc.)
- A represents the rate of activity (e.g. miles, MMBtu, MW, etc.)
- EF represents the emission factor, in terms of weight of the pollutant per rate of activity.

Equation 2

Estimating Emission Reduction Activity Using Emission Factors

$$E = A \times EF \times (1-ER/100)$$

Where:

- E represents emissions, in terms of the weight of the pollutant (e.g. kilograms, pounds, metric tons, etc.)
- A represents the rate of activity (e.g. miles, MMBtu, MW, etc.)

- *EF* represents the emission factor, in terms of weight of the pollutant per rate of activity.
- *ER* represents the efficiency of emission reduction controls applied in terms of percentage efficiency.

Given that the basic research question of this study (*What quantity of CO2e are attributed to lowered demand from Arizona-based resources by California IOUs as a result of their DSM activity during the 2010 through 2012 DSM program cycle?*) involves estimating avoided emissions as a result of electricity reduction activity, it would be accurate to say that this study simply involved solving for “ER.” While true, the method by which to derive ER is no easy task. Estimating emission reductions, or in this case “avoided emissions” involves a deep understanding of the dynamic between electric generation, transmission, and consumption. Complicating matters further is the fact that the electricity California consumers rely upon is generated by a diverse mix of electric generations based on different fuels, each with its own respective unique emission factors. While some of these fuel types produce no emissions, such as hydroelectric or solar electric generators, others, namely natural gas, coal, and biomass.

Adding to the complexity of the study is the fact that these generation resources are operated, or dispatched at various times of day and year in different sequences, known as dispatch orders or loading orders. Once this electricity is produced, it is then transmitted over several hundred miles where some of it is lost due to radiative forcing, until it is finally distributed to utility customers. At this point in time, there seems to be no practical method to truly trace electricity directly from primary generator along a single transmission path and to the final consumer, much less determine what emissions were "avoided" as a result of one, or many of those consumers reducing their electricity usage. The purpose of this study is to *almost* do just that…but before moving to the methodology employed in this study, it is important to consider some of the preliminary work of others entities involved in GHG emission estimates in California, such as CCAR, CARB, and the CPUC.

CALIFORNIA CLIMATE ACTION REGISTRY

The California Climate Action Registry was established in 2000 as a voluntary GHG emission registry by which entities could report their annual direct GHG emissions and have those emissions estimates verified by an independent auditing firm accredited in the organizations reporting protocols. While the CCAR protocols are very rigorous and employ methods similar to those employed by national and international standards organizations, such as the American National Standards Institute (ANSI), they do not fully account for total utility emissions (Little 2002). Instead of total emissions, these reports include only "directly" emitted utility emissions as a result of utility controlled generation activity. These do not include estimates of electricity imported, then sold to consumers per se (CCAR 2002). This makes it extremely difficult to develop a complete emission factor from which to derive emission reduction activity without taking into account sources of over 30 percent of total electricity consumption, namely imported electricity. Without information regarding exact sources of electricity imports, CCAR, instead, focused on establishing an aggregate baseline emission factors for each utility's respective GHG generation mix based on generation originating from within California, and under utility control only, though the organization later weighted some of these emission factors based on published utility power supply labels required under Senate Bill 1305. Nonetheless, CCAR emission reports were important components of developing a standardize and verifiable method to compare the relative pollution emitted per unit generated across utilities within the state and it was an important first step in assisting CARB in eventually developing a complete emissions inventory for the state.

CALIFORNIA AIR RESOURCES BOARD

The California Air Resources Board (CARB) is tasked with implementing the California Global Warming Solutions Act of 2006 (AB32) which seeks to “identify, quantify, and set value to carbon emissions with the overarching goal of promoting more efficient electrical generation, through the use of primarily low-carbon and non-carbon based energy resources (CARB 2008).   Approximately one year after AB32 took effect, CARB identified approximately 800 entities across the states that individually emit an excess of 25,000 metric tons of CO_2e annually. By CARB’s estimates, these electric generating facilities, electric retail providers, power marketers, oil refineries, hydrogen plants, cement plants, cogeneration facilities, and industrial furnaces represented over 95 percent of GHG emissions emitted from stationary combustion sources throughout the state. Beginning in 2009, these facilities were required to annually report their emissions to the CARB and have these reports independently verified to serve as the baseline for future market-based emission reduction compliance mechanisms, with the stated goal of administering the first statewide emissions trading program in the western hemisphere.

Within these reporting requirements the CARB required utilities to disaggregate emissions electricity generated from those purchased from other entities. Though the CARB methodology was is vast improvement over the previous CCAR method, the majority of wholesale electricity transactions are still aggregated based on statewide average emission factors for unspecified electricity imports. In other words, the inherent weakness of the CARB approach is that it does not provide the granularity needed to accurately assess the emissions associated with individual utility imports. But that is not really the intention of AB32. The primary purpose of the CARB's mandatory reporting requirement is to develop an emissions trading market. Under CARB's recently released cap and trade rules, in order for a GHG offset project to qualify for an emissions credit it must reduce emissions beyond "business as usual (CCAT 2006). Under this policy interpretation, CARB does not allow utility demand side management activity to qualify for emissions credits, given that these activities are already mandated by law and funded through the ratepayer PGC funds. If the CARB estimates are not useful in determining offsets from DSM activities, how then, do utilities estimate GHG emission reductions for the purposes of reporting to the CPUC?

UTILITY GHG CALCULATIONS

Given the importance of climate change in California, surely there must already be some method PG&E, SCE, and SDG&E use estimate avoided emissions as a result of reductions in electrical use aside from the inventories developed by CCAR and CARB? Indeed, all three IOUs utilize an extremely esoteric tool developed by the CPUC, known as the "E3" GHG Calculator (E3 2010). The primary purposes of the E3 GHG calculator are to assess: (1) the impact of implementing AB32 GHG reduction strategies on utility customers, (2) the sensitivity of utility operations to these reduction strategies due to changes in market forces, such as gas prices, load growth, and energy efficiency costs, and (3) influence of additional regulation (e.g. cap and trade, renewable portfolio standard, etc.) It is important to understand that the utility industry is a business and that all of its operations, including its GHG reduction strategies must operate on the premise of the most cost-effective allocation of rate-payer resources. In the sense that the primary purpose of the calculator is to measure the cost effectiveness, therefore avoided emissions estimates are only a secondary result of the GHG calculator.

The GHG calculator relies on the outputs of an extremely complex electricity dispatch production model known as PLEXOS.[21] PLEXOS is an hourly electricity dispatch model similar to the U.S. EPA Emissions and Generation Resource Integrated Database (eGRID) platform designed specifically to model electricity flows within the Western Electricity Coordinating Council (WECC) region (EPA 2010b). The PLEXOS model utilizes a mixed integer algorithm to simulate how the operations of generators in the western U.S. would adjust to meet load requirements under specific conditions, such as fuel prices, power plant capacity, and power plant operations. Hourly PLEXOS data are summarized into four time periods: summer high load, summer low-load, winter high load, and winter low load. The results are used as an input into the GHG calculator, which in turn, calculates electricity costs and GHG emission rates based on a variety of

[21] The PLEXOS model is based on the Ph.D. work of Glenn Drayton (G.R. Drayton. Coordinating Energy and Reserves in a Wholesale Electricity Market. University of Canterbury, New Zealand, 1997.)

different scenarios including variations in fuel prices, power plant capacity factors, and other key variables. This method was utilized to develop GHG emission estimates for the current GHG Calculator used by California IOUs to estimate baseline GHG emission estimates in 2008 and calculate subsequent avoided emissions estimates for demand side management activity during the 2010-2012 IOU DSM program cycle.

While the estimates in this model have been deemed relatively accurate and credible, the PLEXOS/GHG Calculator combination has many drawbacks. First and foremost is the expense and time associated with gathering reliable information for model inputs. Secondly, PLEXOS is proprietary software which operates at a range of load level tolerances that makes widely ranging assumptions regarding the relationship between load and the market prices of electricity and assumes almost perfect competition amongst electricity generators and consumers throughout the western U.S. without exploring existing contractual relationships between electricity generators and suppliers. The third drawback to this system are the multitude of variables associated with the GHG calculator, which also includes a number of inputs that may or may not prove to be reasonable assumptions in future estimates. Amongst these inputs are various assumptions regarding energy efficiency (EE), demand response (DR), California Solar Initiative (CSI), Combined Heat and Power (CHP), and Renewable Portfolio Standard (RPS) utility adoption rates (CPUC 2008). As well, the calculator allows utilities to change resource assumptions based on the potential future market price for carbon emissions. Finally, the GHG calculator makes several assumptions regarding each group of retail providers including power plant ownership, electricity contracts, load growth, system efficiency, and transmission rates that are accurate only enough to develop average emission factors across all fuel types. In reality, the majority of demand side management activities tend to reduce peak load demand to a greater extent that base-load demand. Given the peculiarities of the resource mix of certain utilities, this could lead to a serious overstatement of emission reductions. Furthermore, the tool provides no spatial context as to where the emissions were likely reduced.

Though the CPUC GHG is an extremely useful tool in modeling the potential impact of various GHG reduction strategies for various groupings of California retail electricity providers, it does not provide enough granularity or sufficiently disaggregated information for individual utilities to utilize the tool for resource planning, or, in our case, to analyze the spatial context of avoided emission efforts. It also does not take into account individual resource plans or the construction or early retirement of new generators within the western U.S. Additionally, though many of the variables can be modified by users to account to develop scenario-based analyses, much of the default information contained within the model are based on data collected prior to 2008 which are extremely dated in the context of analyzing the avoided emissions resulting from the 2010-2012 program cycle. In essence, the GHG Calculator, though a very useful scenario analysis tool, it has only cursory efficacy when applied demand side management avoided emission estimates.

SUMMARY

This section of the study provided an overview of the current state of emissions assessment activity from the perspective of private registries, air pollution control management authorities, as well as the tool employed by the utilities themselves to estimate avoided emissions. It included a brief discussion of the underlying purpose of each assessment methodology, as well as their relative strengths and weaknesses. In the next section, I will describe the methodology ultimately used to derive a fairly accurate avoided emissions estimate based on an expansion of the World Resources Institute (WRI) emissions offset approach. Though imperfect in its own respect, this methodology provides a fairly rigorous estimate that can be built upon to improve accuracy in future models.

CHAPTER 4: EMISSIONS ESTIMATION METHODOLOGY

MODIFIED WRI METHOD

In an attempt to provide more granular emission estimates than those used by the CPUC E3 calculator, this study expanded the WRI "*Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects as a supplement to general Greenhouse Gas Protocol for Project Account* (WRI 2007). Similar to the CCAR protocols, these guidelines define a generally accepted framework that can be used to first quantify, then estimate avoided emissions resulting demand side management activities. The primary difficulty with these guidelines lay in the fact that they were developed for small developing countries which may have only one or two primary sources of electricity and are data intensive, though they produce a rather exact and robust result (Lazarus and Oven 2001). This section describes the WRI methodology and the various modifications employed in this study used to adapt it to estimate avoided emissions as a result of DSM activity, with the end result of calculating avoided emissions from a specific source and source location.

DEFINING ASSESSMENT BOUNDARY

The first step in this emissions assessment was to succinctly define the spatial and temporal boundaries of the study area (Murtoshaw et al. 2006). While utilities generally track directly avoided emissions, or those emissions resulting from changes in consumption through the installation of energy efficiency measures at customer locations, the focus of this study is to quantify those avoided emissions while determining the source of the avoided electricity generation. In this study, the emission assessment boundary is defined as those emissions avoided from electrical generation activity as a result of California IOU DSM program activity from 2010 through 2012. This includes all sources of electrical generation, both domestically and imported sources of electrical generation in operation during this time period that produced electricity which, in turn, was ultimately sold to electricity consumers within each respective IOU's service territory. In such, the first task in this study was to gather detailed records regarding electricity consumption as well as purchases by each of these IOUs for the specified time period by generation source, fuel type, and location (Bosi 2001).

IOU ELECTRICITY PURCHASES AND CONSUMPTION

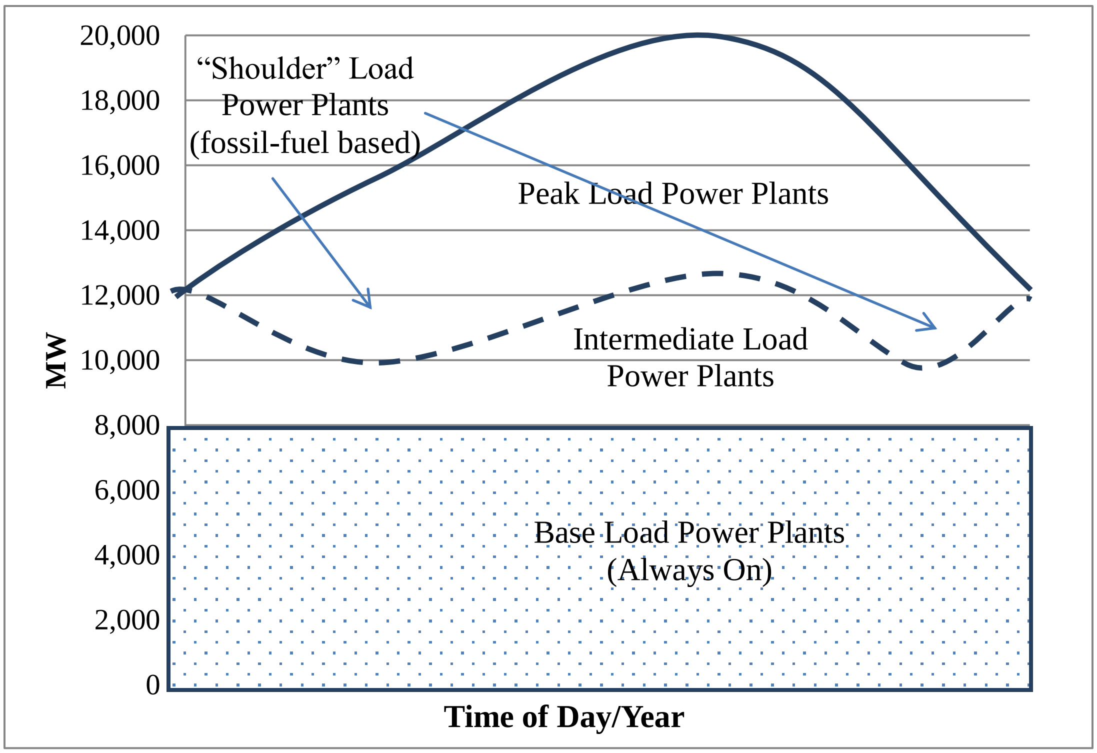
Each California IOU generates, purchases, transmits, and distributes electricity to consumers over a vast transmission and distribution network comprised of various interconnected power plants, each with their own unique operational and emission characteristics. Each of these plants are operated according to each of their unique technical and economic advantages, regulatory and system constraints, as well as ultimate consumer demand. Generally though, the dispatch of electricity from individual power plants can be predicted based on the marginal cost of generation over defined periods of electrical demand. Thus, each type of power plant on the grid can be generally viewed as either serving either a "base-load," "intermediate load," or "peak load" demand for electricity.

"Base-load" refers to the minimum amount of electrical load a utility must supply in order to meet consumer demand. Coal, nuclear, or large hydroelectric power plants, which are able to produce the lowest marginal cost electricity, while also providing electricity at a constant rate are typically used to supply base load power. In California a large portion of base-load demand is met by electricity generated from base-load combined cycle natural gas plants. Conversely, “Peak load” refers to periods of peak electrical demand, usually early afternoon when the demand of electricity to operate air conditioning places reaches its peak. Unlike base-load plants, which operate at a constant rate, peaking power plants are operated only during peak periods of electrical demand. Merchant power plants are generally peaking plants, which can readily supply power to the electrically grid, though the electricity supplied from these plants have the highest marginal cost within the electrical grid.

Between periods of “base-load” and “peak load” demand are periods of “Intermediate load.” During periods of intermediate load, utilities typically utilize intermediate load power plants to meet electrical demand without having to resort to expensive peak load generation capacity. Intermediate load power plants also refer to non-dispatchable renewable sources of electricity in which the utility must utilize all available power. Examples of intermediate load power plants include a mixture of non-base load natural gas plants and “must-take” renewable power plants, such as small hydroelectric, wind, or solar power plants. The operation of these power plants vary by demand type over time (hourly, daily, seasonally) and space according to both the various technological and economic advantages of certain sources of electrical generation as well as transmission constraints, contractually relationships between utilities and generators, and regulatory influences. In most cases, intermediate load resources are coupled with must-take “shoulder load’ (generally fossil-fuel based) generation to make up for these fluctuations in load from renewable resources, and they generally operate in similar fashion as base-load generators (Kartha et al. 2002) (see Figure 9).

Figure 9

Generalized Utility Load Profile



BASELINE EMISSION ESTIMATES

Once data regarding electrical generation and consumption have been gathered, the next step is to develop a "baseline" emissions estimate for each utility. The baseline emission estimate will be used compare emissions occurring prior to demand side management activities, or a "baseline scenario," to emissions occurring after the implementation of each utility's demand side management activities, or a "post-case" scenario." In such, estimates of avoided emissions as a result of demand side management activities will be inferred based on an assessment of reported electricity reduction as a result of these activities as well as an allocation of these savings across the electrical generation and purchases for each individual utility. This study goes further by extrapolating the proportion of those emission reductions which can allocated to reduction in electric demand that can be directly tied to sources of generation located in Arizona.

Baseline emissions estimates in this study were calculated by determining the emissions from each individual source of electricity for each IOU based on the generation and electricity purchase data gathered in the previous step. With respect to electricity reduction activities, these baseline emissions can be broken down into two distinct components – "Operating Margin" (OM) emissions," and "Build Margin" (BM) emissions. Operating Margin emissions represent those emissions which result from electricity used to serve incremental increases in electricity demand (Beiwald 2005). As utility demand increases and additional generation resources are brought online, or additional electricity is purchased, these resources emit an emissions signature which is different from the total utility generation mix as a whole. Operating Marginal emissions are those emissions which are most effected by demand side management activity, given that these activities, on a whole are generally designed to reduce peak load demand. Conversely, Build Margin emissions represent emissions that result from base-load generation which do not fluctuate according to inter-daily or inter-seasonal demand for electricity.[22] Build Marginal emission rates can also be used to represent the anticipated emissions resulting from additional resources coming online, though we are not concerned with additional resources in the scope of this study. Therefore, baseline emissions can be estimated by determining both the OM emission rate and the BM emission rate for each resource within the utility generation mix. The equation for estimating the baseline emission for each utility is as follows (see Equation 3):

Equation 3

Calculating Baseline Emission Rates

$$EF_{\text{baseline } t} = wBM + (1-w)\,(OM)t$$

Where:

- $EF_{baseline\ t}$ represents the baseline emission factor for each utility, (e.g. tons of CO_2e per MWh) for time period *t*
- *BM* represents the build margin emission factor. This variable does not vary over time.
- *OM* represents the operating margin emission factor for time period *t*
- *w* represents the weight between 0 and 1 assigned to the build margin, a build margin of “0” represents a no additional generation or no effect of the activity in reducing emissions.

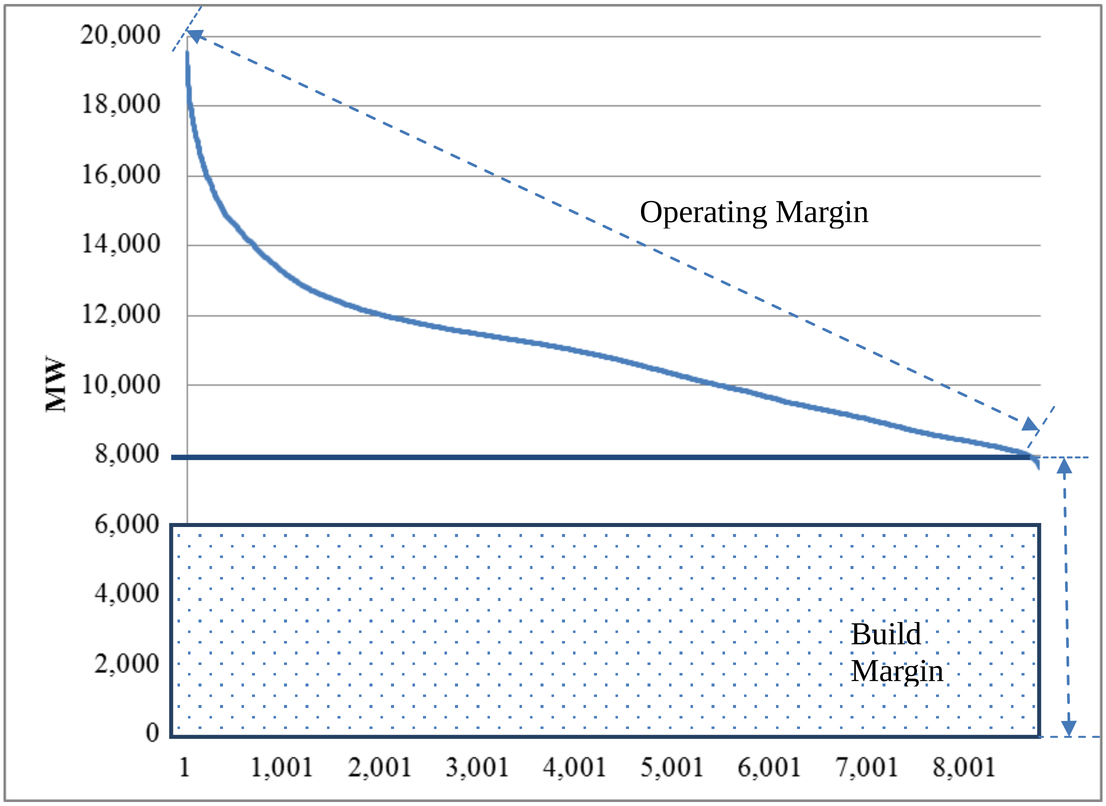
[22] The term “build’ in build margin is an artifact of utility parlance used to describe additional baseline generation which would normally have been constructed to serve base-load demand.

OPERATING MARGIN ESTIMATES

In theory, Operating Marginal emissions should precisely match the electrical generation and electricity purchases brought online during periods of high demand. In practice, however, it is quite a daunting (if not impossible) task to precisely trace each electron from the point of generation to its ultimate consumer (ISO New England 2004). Instead, an OM emission rate was developed by averaging the emission rates of each source of electrical generation weighted according to the length of time individual resources operated "on the margin" during times of peak demand. Without access to propriety utility data, usually in the form of hundreds of thousands of individual North American Electric Reliability Corporation (NERC) e-tags which account for each electricity transaction in the utility network, the length of time that each resource operated was estimated through the use of "Load Duration Curve" analysis. Load Duration Curve (LDC) analysis assists in estimating the generation resource required to meet peak (marginal) system loads over the course of one year. An LDC for each utility was constructed by obtaining the total grid electricity demand (load) for each hour of one year and then ranking the load in descending order from the highest hour of demand to the lowest hours of demand for each of the 8,760 hours in a year (see Figure 10).

Figure 10

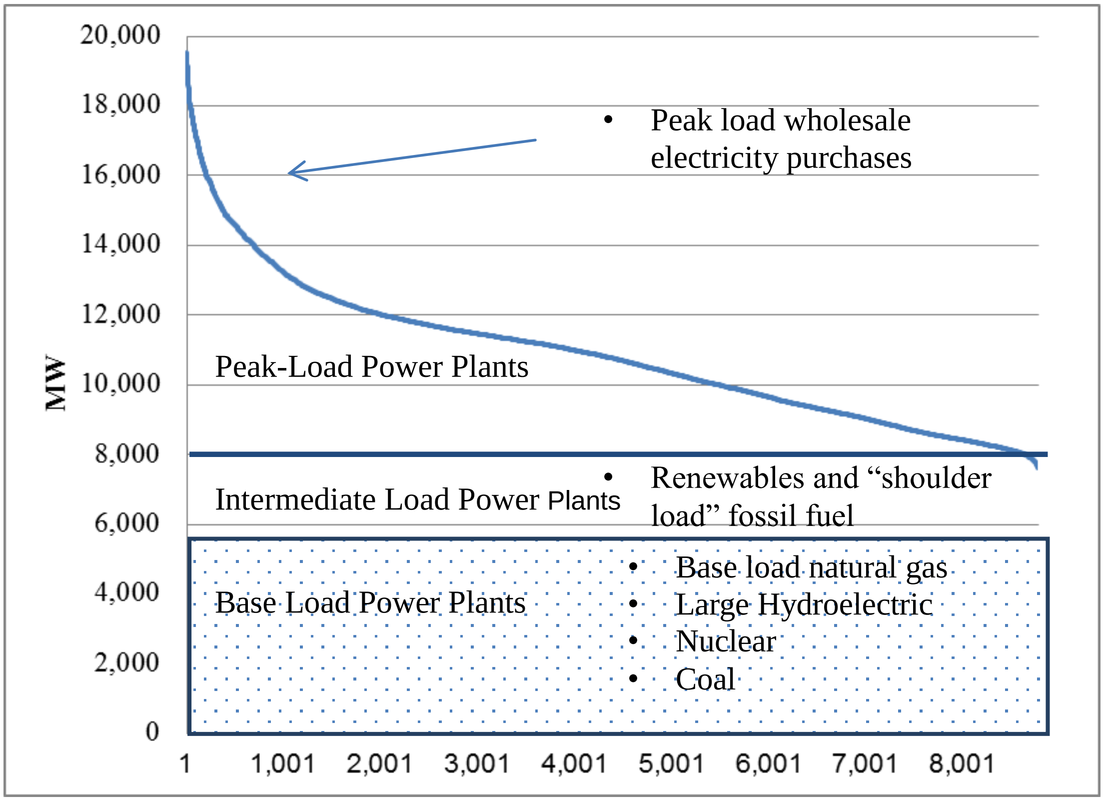
Generalized Utility Load Duration Curve Profile with OM and BM



After developing an LDC for each utility, the next step in determining the appropriate OM and BM margins for each utility by allocating generation and electricity purchases to a portion a specific segment of the LDC curve. The stacking of resources is known as the loading order. The loading order of generation resources, from lowest margin cost of generation at the bottom to highest cost of generation at the top for any particular source of electricity is meant to reflect the marginal cost of electricity while also meeting the operational needs of (e.g. reliability, quality of service, etc.) of any given utility. The marginal cost of electricity is a key component of determining which generation unit is operated (or "dispatched") to meet the demand for electricity at any given time (Conkling 1999). All things equal, the power plants with the lowest marginal cost of electricity production, such as coal, nuclear, or large hydroelectric plants, are dispatched first and therefore are located near the bottom of the loading order. Whereas plants with higher marginal operating costs, such as peak-load serving wholesale electricity purchases, and brought on line as electricity demand increases and are located at the top of the loading order. Other factors that affected the loading order for each utility included must-take renewable energy portfolio resources and Qualified Energy Facilities (QEF), which tend to maximize the use of resources from these facilities despite their average cost. Therefore, all renewable energy and QEF purchases were allocated to the intermediate spectrum of the loading order. This assisted in the development of a standard LDC with Loading Order for each IOU as illustrated in Figure 11.

Figure 11

Generalized Utility Load Duration Curve Profile with Loading Order



The loading order for each utility resource was then matched to the LDC by using an integral function to match the amount of electricity generated by each resource (MWh) calculate the area under the load duration curve which it displaces. Aside from describing the maximum average load (MW) for each resource, this also assists in estimating the total number of hours that each particular resource can be considered "on the margin." This information was used to estimate the percentage of each resource that comprises the operation margin. Based on this percentage, an average marginal emission factor for each resource type was estimated based on individual emission rate for each resource that intersects with the operating margin (see equation 4). Once the emission rates for each resource operating on the margin were calculated, the OM emission factor, for all resources operating “on the margin, was estimated based on a time-weighted average of all the emission rates (see equation 5 below).

Equation 4

Calculating Emission Rates for Each Generation Resources

$$ER_{r,t} = \mathrm{GEN}_{r,t} \text{ x } \mathrm{EF}_r$$

Where:

- $ER_{r,t}$ represents the total emissions for resource type r, for time period t
- $GEN_{r,t}$ represents the total power generated in MWh for resource type r, over time period t
- $EF_{r,t}$ represents the average emission factor for resource type r, for time period t

Equation 5

Calculating Average OM Emission Rates

$$OM_t = \sum (TM_{r,t} \text{ x } ER_{r,t}) / HRS_t$$

Where:

- OM_t represents the OM emission factor for time period, t
- $TM_{r,t}$ represents the number of hours that resource type r, was “on the margin” for time period, t.
- $ER_{r,t}$ represents the average emission factor for resource type r, for time period t.
- HRS_t represents the total number of hours in time period t (8760)

BUILD MARGIN ESTIMATES

The procedure for calculating the BM for each base-load or new generation resource is similar to that used to calculate the OM emissions rate, though instead of calculating the total hours of the LDC in which the resource is utilized, the only information needed is the total electricity generated and the emission factor for each individual resource. For every base-load generation resource, the following equation is used to estimate the BM emissions (see equation 6).

Equation 6

Calculating Average BM Emission Rates

$$BM_t = \sum (ER_{jt} \text{ x } Q_{jt})$$

Where:

- BM_t represents the *BM* emission factor for time period, *t*
- ER_j represents the emission rate of resource *j*, over time period *t*
- Q_j represents the generation (e.g. MWh) or resource *j*, over time period *t*

The associated weight (*w*) corresponding to BM in the initial equation represents the category of electricity offset by the demand side management if those activities had not occurred. A weight closer to “1” indicates that the displaced electricity would have been produced from new generation capacity, whereas a weight between “0” and “1” indicated that the displaced electricity would have been partially been produced by new generation capacity. Alternatively, a weight of “0” indicates that displaced electricity would have been provided by existing generation and/or available additional wholesale electricity purchases. Given that the purpose of demand side management activity is to displace existing resources, a weight of “0” was assigned to “*w”* in the initial equation.

AVOIDED EMISSION ESTIMATES

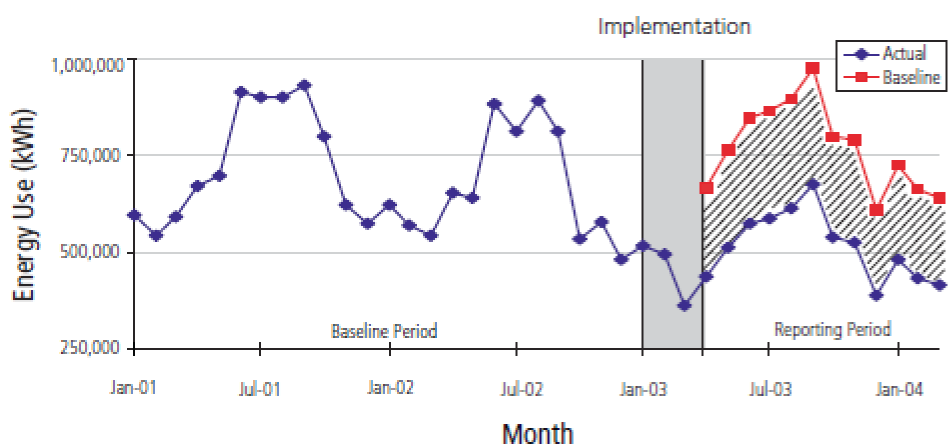
The basic approach to estimating avoided emissions as a result of demand side management activity is to first assess the magnitude of the avoided generation activity for each utility network, then adjust these savings based on electricity transmission and distribution savings as a result of improved system efficiency (Meyers et al 2000). Just as avoided emission estimates involve complex assumptions regarding utility supply, estimates of electricity saving as a result of demand side management involve several assumptions regarding “verifiable” electricity savings. As described in the first chapter of this study, utility DSM programs are coordinated efforts activities designed to reduce customer electricity consumption. These activities include information and educational campaigns, as well as “upstream” incentives designed to both lower the cost and increased the supply of energy efficient technology and “downstream” rebates payable to customers for installing specific technologies designed to reduce electricity consumption. There are several methods to determine electricity savings (and, in turn, associated avoided emissions) depending of the efficacy of the project.

Similar to avoided emission estimates, electricity savings are estimated by comparing post-case actual energy consumption with an estimated “adjusted” baseline of electricity consumption. Usually the measurement and verification of electricity savings are estimated using standard widely accepted protocols, such as the International

Performance Measurement and Verification Protocol (IPMVP) (EVO 2007) or the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) Guideline 14-2 (ASHRAE 2002). Both of these protocols contain detailed methodologies designed to estimate electricity savings, taking into account market effects such as free-ridership, savings about standard building codes, and the effective useful life of the installed electricity saving technology. Each utility is generally required to have reported electricity savings verified by independent third party utilizing the applicable IPMVP or ASHRAE guidelines, or in the case of publically owned utilities the California Evaluation Framework (CPUC 2006).

Figure 12

Electricity Savings Estimate Pre- and Post- Implementation of Demand Side Management Activity



Source: National Action Plan for Energy Efficiency (2007)

Before estimating avoided emissions using these electricity savings estimates, it is important to take into account the associated electricity savings as a result of reduced electricity use within each utility's electrical transmission and distribution network. A small percentage of electrical power is lost within each utility's network as electricity is transmitted and distributed due to electricity resistance, radiant heat, and other forms of dissipation. This causes a small difference in the amount of electricity produced at power plants and electricity ultimately consumed by utility customers. In other words, 1 MWh of reduced electricity consumption can be translated into slightly higher than 1 MWh in electricity generation reduction. These transmission loss estimates must be added to electricity reduction estimates to account for total electricity reductions. Equation 7 describes the method used to calculate adjusted electricity reductions for each utility:

Equation 7

Adjusted Avoided Electricity Reductions as a Result of Demand Side Management Activity accounting for Transmission and Distribution Savings

$$GEN_{dsm\ t} = S_t / (1-L)$$

Where:

- $GEN_{dsm\ t}$ represents the total utility generation avoided by demand side management activity for time period t
- S represents the total reported electricity savings for time period t
- L represents the average percentage electricity lost due to fluctuations in transmission and distribution activity.

These adjusted electricity savings are then used to determine the total avoided emissions as a result of utility DSM activity by multiplying the baseline emission factor derived using the previous equations by adjusted electricity savings for each utility. The formula for this method can be described using the formula found in Equation 8.

Equation 8:

Estimating Avoided Emissions as a Result of DSM Activity

$$EA_t = EF_{baseline\ t} \times GEN_{dsm\ t}$$

Where

- EA_t represents that total avoided emissions over time period t
- $EF_{baseline\ t}$ represents the baseline emission rate for time period t
- $GEN_{dsm\ t}$ represents the electricity avoided, adjusted for transmission and distribution savings over time period t

ESTIMATING AVOIDED EMISSION FROM ARIZONA BASED RESOURCES

The last step in this study is to quantify the amount of these avoided emissions which would have been generated by generators located in Arizona. In order to accomplish this task, these resources disaggregated from total utility resources by each fuel type. For instance, electricity derived from natural gas, as well as nuclear power, or coal fired-based generators were considered separate resource types for the purpose of this study. These fuel types were considered separate resource types for the sake of deriving both OM and BM emission rates.

SUMMARY

This section described the methodology employed in estimating the baseline emission rate, and total avoided emissions for each IOU with the ultimate goal of determining what percentage of these emissions were derived from Arizona-based electricity generation resources. The accuracy of the estimation method described lay in both the granularity and availability of adequate data regarding utility generations, purchases and consumption, as well as estimates of electricity demand side management savings for the 2010 through 2012 program cycle and the transmission and distribution loss factors for each utility. The next section will present the data used in this study along with other underlying assumptions used to justify these emission estimates.

CHAPTER 5: ASSESSMENT DATA

DATA AVAILABLITY, ACCURACY, AND UNCERTAINTY

The most time consuming portion of this study involving gathering, accounting for and organizing information regarding utility generation and consumption. Though many of the generation resources used by each utility are widely known, accounting for the actual electricity used by each utility for each year within the study period proved extremely difficult and time consuming. This section will describe the associated challenges with obtaining this data, as well as other data used in the study. It will also describe levels of uncertainty associated with various pieces of data as well as data substitution methods employed. In such, it will identify suggested areas to improved future research in order to develop more accurate and dynamic estimates of avoided emissions resulting from utility DSM activity.

IOU ELCTRICITY GENERATION AND PURCHASES

By far, the most tedious and time consuming activity of this research involved compiling, quantifying, and accounting for electricity generation and purchases for each IOU for each year during the study period. While a nearly complete set of consumption, and generation/purchase data was compiled for 2010 for each IOU, data for 2011 and 2012 were not available during the study period. Complicating matters further was the outage at San Onofre Nuclear Generating Station, which has been out of operation since January 2011 and comprises a large percentage of base-load generation for both SCE and SDG&E. While it is likely that additional electricity supplied by natural gas facilities was likely used as a substitute, it was impossible to determine this information with certainty in time for publication of this study. In lieu of this information, and given that the missing information affected only the BM, and not the OM estimates which are ultimately tied to DSM activity, 2010 data was used as a surrogate for 2011 as well as 2012. While this was not an optimal solution, it afforded the best opportunity to present reasonably quantifiable results.

Electricity consumption, generation, and purchases used in this study were compiled from several different sources, including CEC S-2: Supply Form and CEC S-5: Electricity Resource Planning Form. The S-2 and S-5 forms are reports each California utility is required to file with the CEC on a semi-annual basis. The S-2 Supply Form contained aggregated data by resource type, whereas the S-5 form contains information regarding each long-term bilateral contract between each utility and its sources of supply and supply type (base-load, peaking, intermediate, must-take, etc.). Additional information was obtained from Annual Company Filing, the U.S. DOE Energy Information Agency EIA-860 and EIA-861 annual operator reports, and well as other CPUC rate case filings.

The information contained in these reports was then compared to original calculation reports submitted to the CEC under the SB1305 electricity power labeling requirement. Even after these comparison, several holes in the data remained. These data gaps were defined as “unspecified” sources of generation within this analysis. In cases where the geographic point of origin could be determined, these were noted and labeled accordingly, California (unspecified), Desert Southwest (unspecified), and Pacific

Northwest (unspecified). Every effort was also made to discount electricity purchased by each IOU, then wheeled through the utility transmission network or resold to other third party entities other than its own customers. The data compiled for each IOU for 2010 are listed on tables 3, 4, and 5.

Table 3

PG&E Electricity Supply for Ultimate Consumption by PG&E Customers (2010)

PG&E Electricity Supply (2010 Base Year)	Fuel Type	Generation Type	Generation (GWh)
Utility-Owned Fossil Energy Supply			
PGE Base-load (Colusa, Gateway, Humboldt, Radback)	Natural Gas	Base-load	3,677
Mobile GT	Fuel Oil	Base-load	4
Utility-Owned Nuclear Energy Supply			
Diablo Canyon	Nuclear	Base-load	18,431
Utility-Owned Hydroelectric Supply			
Hydroelectric plants > 30 MW	Large Hydro	Base-load	12,028
Hydroelectric plants < 30 MW	Large Hydro	Base-load	1,268
Utility Controlled Renewable Supply			
Rooftop solar	Solar	Intermittent	5
DWR Contract* Supply			
Natural Gas	Natural Gas	Base-load	2,640
Natural Gas	Natural Gas	Peaking	1,899
Renewable (Non-Biogenic) (Intermittent)	Wind	Intermittent	93
In-state Qualifying Facility Contract Supply			
Biomass	Biomass	Intermittent	2,660
Geothermal	Geothermal	Intermittent	5
Small Hydro	Small Hydro	Intermittent	569
Solar	Solar	Intermittent	-
Wind	Wind	Intermittent	659
Natural Gas	Natural Gas	Intermittent	9,047
Other	Unspecified	Intermittent	1,707
Direct Contract Renewable Supply			
Biomass	Biomass	Intermittent	598
Geothermal	Geothermal	Intermittent	3,761
Small Hydro	Small Hydro	Intermittent	420
Solar	Solar	Intermittent	58
Wind	Wind	Intermittent	3,485
Other	Unspecified	Intermittent	2
Other Bilateral Contracts			
Natural Gas	Natural Gas	Base-load	392
Natural Gas	Natural Gas	Peaking	87
Renewable (Non-Biogenic)	Wind	Intermittent	392
Short Term and Spot Market Purchases			
California (Unspecified)	Unspecified	Peaking	10,536
Pacfic Northwest (Unspecified)	Unspecified	Peaking	5,268
Desert Southwest (Unspecified)**	Unspecified	Peaking	2,107
Arizona Natural Gas	Natural Gas	Peaking	3,161

Table 4

SCE Electricity Supply for Ultimate Consumption by SCE Customers (2010)

SCE Electricity Supply (2010 Base Year)	Fuel Type	Generation Type	Generation (GWh)
Utility-Owned Fossil Energy Supply			
Four Corners (New Mexico)	Coal (Bitumous)	Base-load	4,738
Mountain View	Natural Gas	Base-load	6,052
SCE Peakers (Barre, Center, Grape, Mira, Oxnard)	Natural Gas	Peaking	21
Utility-Owned Nuclear Energy Supply			
Palo Verde (Arizona)	Nuclear	Base-load	4,930
San Onofre	Nuclear	Base-load	10,770
Utility-Owned Hydroelectric Supply			
Hydroelectric plants > 30 MW	Large Hydro	Base-load	3,794
Hydroelectric plants < 30 MW	Large Hydro	Base-load	534
Utility Controlled Renewable Supply			
Rooftop solar	Solar	Intermittent	-
DWR Contract* Supply			
Natural Gas	Natural Gas	Base-load	12,535
Natural Gas	Natural Gas	Peaking	9,016
Renewable (Non-Biogenic) (Intermittent)	Wind	Intermittent	440
In-state Qualifying Facility Contract Supply			
Biomass	Biomass	Intermittent	1,107
Geothermal	Geothermal	Intermittent	5,028
Small Hydro	Small Hydro	Intermittent	141
Solar	Solar	Intermittent	879
Wind	Wind	Intermittent	2,291
Natural Gas	Natural Gas	Intermittent	10,425
Other	Unspecified	Intermittent	107
Direct Contract Renewable Supply			
Biomass	Biomass	Intermittent	146
Geothermal	Geothermal	Intermittent	2720
Small Hydro	Small Hydro	Intermittent	79
Solar	Solar	Intermittent	50
Wind	Wind	Intermittent	1733
Other	Unspecified	Intermittent	0
Other Bilateral Contracts			
Natural Gas	Natural Gas	Base-load	2,408
Natural Gas	Natural Gas	Peaking	1,204
Renewable (Non-Biogenic)	Hydro	Intermittent	401
Short Term and Spot Market Purchases			
California (Unspecified)	Unspecified	Peaking	680
Pacfic Northwest (Unspecified)	Unspecified	Peaking	291
Desert Southwest (Unspecified)**	Unspecified	Peaking	194
Arizona Natural Gas	Natural Gas	Peaking	1,165

Table 5

SDG&E Electricity Supply for Ultimate Consumption by SDG&E Customers (2010)

SDG&E Electricity Supply (2010 Base Year)	Fuel Type	Generation Type	Generation (GWh)
Utility-Owned Fossil Energy Supply			
SDG&E Baseload (El Cajon, El Dorado, Miramar) Palomar)	Natural Gas	Base-load	3,285
Utility-Owned Nuclear Energy Supply			
San Onofre	Nuclear	Base-load	2,754
Utility-Owned Hydroelectric Supply			
Hydroelectric plants > 30 MW	Large Hydro	Base-load	0
Hydroelectric plants < 30 MW	Large Hydro	Base-load	0
Utility Controlled Renewable Supply			
Rooftop solar	Solar	Intermittent	3
DWR Contract* Supply			
Natural Gas	Natural Gas	Base-load	2,950
Natural Gas	Natural Gas	Peaking	2,122
Renewable (Non-Biogenic) (Intermittent)	Wind	Intermittent	104
In-state Qualifying Facility Contract Supply			
Biomass	Biomass	Intermittent	29
Geothermal	Geothermal	Intermittent	0
Small Hydro	Small Hydro	Intermittent	2
Solar	Solar	Intermittent	0
Wind	Wind	Intermittent	0
Natural Gas	Natural Gas	Intermittent	1,186
Other	Unspecified	Intermittent	0
Direct Contract Renewable Supply			
Biomass	Biomass	Intermittent	522
Geothermal	Geothermal	Intermittent	183
Small Hydro	Small Hydro	Intermittent	20
Solar	Solar	Intermittent	0
Wind	Wind	Intermittent	724
Other	Unspecified	Intermittent	0
Other Bilateral Contracts			
Natural Gas	Natural Gas	Base-load	421
Natural Gas	Natural Gas	Peaking	2,162
Portland General Boardman (Coal)	Coal	Base-load	604
Renewable (Non-Biogenic)	Unspecified	Intermittent	-
Short Term and Spot Market Purchases			
California (Unspecified)	Unspecified	Peaking	130
Pacfic Northwest (Unspecified)	Unspecified	Peaking	43
Desert Southwest (Unspecified)**	Unspecified	Peaking	65
Arizona Natural Gas	Natural Gas	Peaking	194

IOU ELECTRICITY COMNSUMPTION

The total electricity generation and purchases ultimately consumed by associated customers from each IOU for 2010 calculated in using the methodology described earlier were as follows PG&E – 84,958 Giga-watt hours (GWh), SCE – 83,881 GWh, and SDG&E, 17,503 GWh. This consumption data were compared again hourly dynamic load profiles. Dynamic load profiles are publically available data sources and contain hourly consumption information across multiple customer classes and rate structure (e.g. agricultural, municipal, residential, commercial, industrial, etc.). These data, when totaled for each IOU, came within five percent margin of error from the previously estimated generation and purchase data. This can be explained by transmission and distribution losses and losses due to utility consumption of some of the generated or purchased electricity. These dynamic (near-real time) hourly load data were used, in turn, to develop LDCs for each utility. Figure 13 illustrates "raw" untransformed, aggregate hourly load across all customer classes for SDG&E. Figures 14, 15, and 16 illustrate "transformed" LDC for SD&E, PG&E, SCE, respectively from ranked from highest hour of load to lowest hour of load.

Figure 13

SDG&E 2010 “Untransformed” Hourly Aggregate Load (2010)

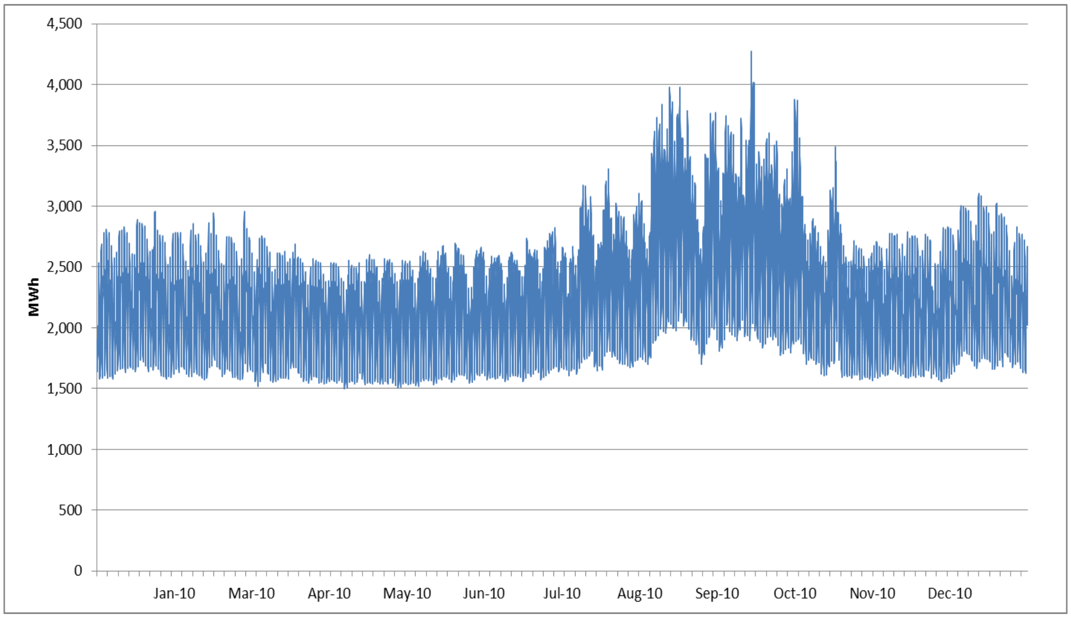


Figure 14

SDG&E 2010 “Transformed” Hourly Aggregate Load (2010)

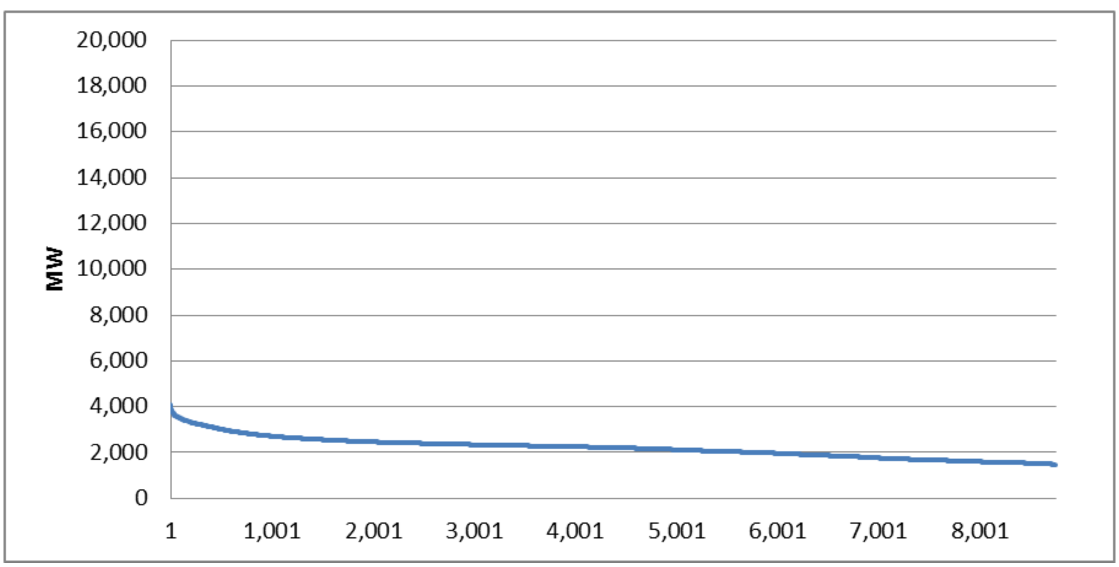


Figure 15

PG&E 2010 "Transformed" Hourly Aggregate Load (2010)

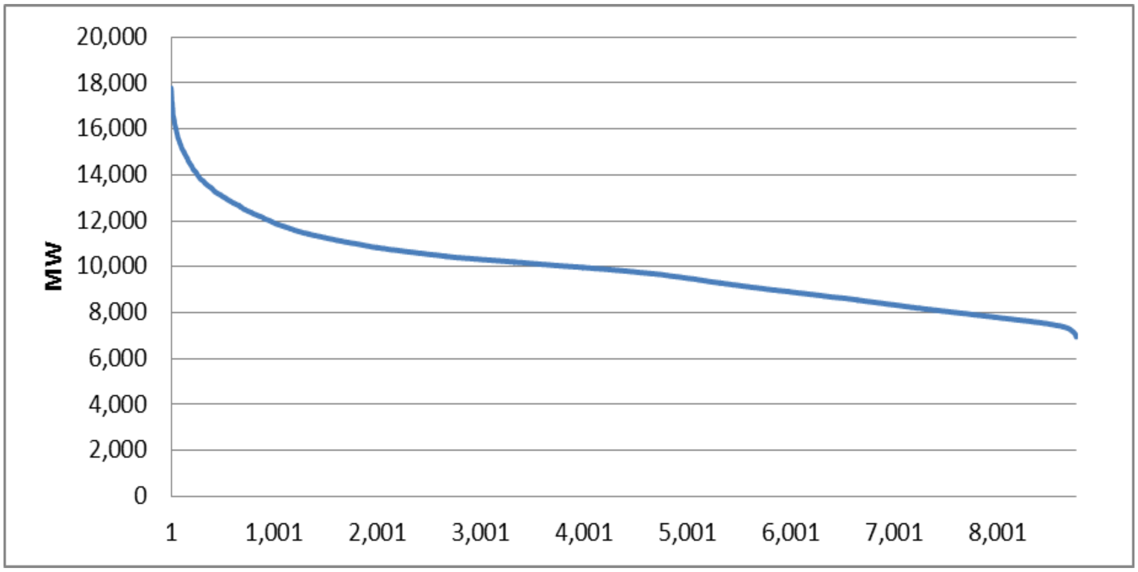
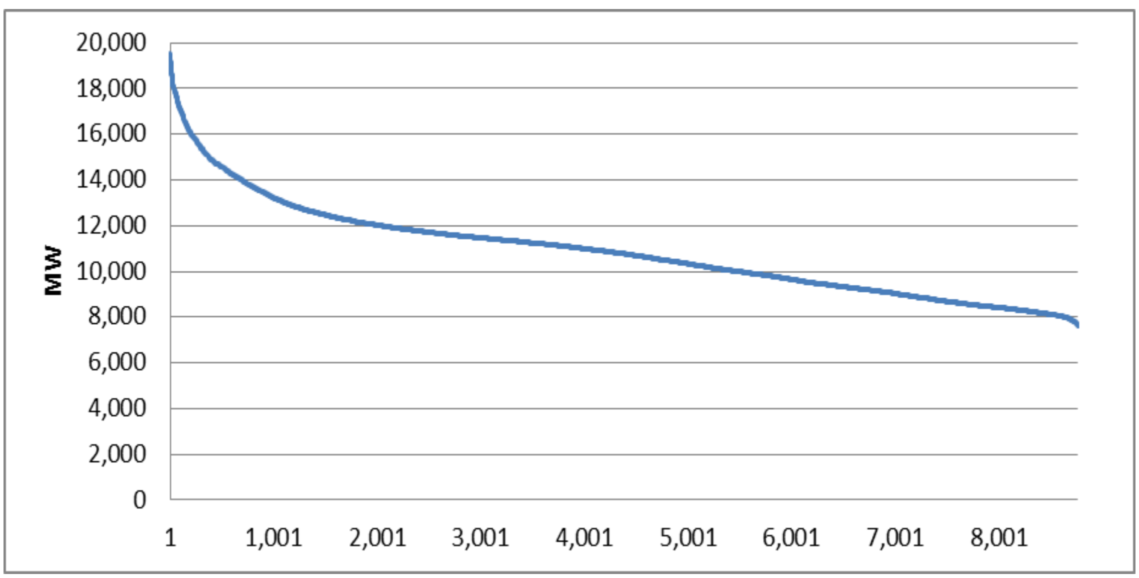


Figure 16

SCE 2010 "Transformed" Hourly Aggregate Load (2010)

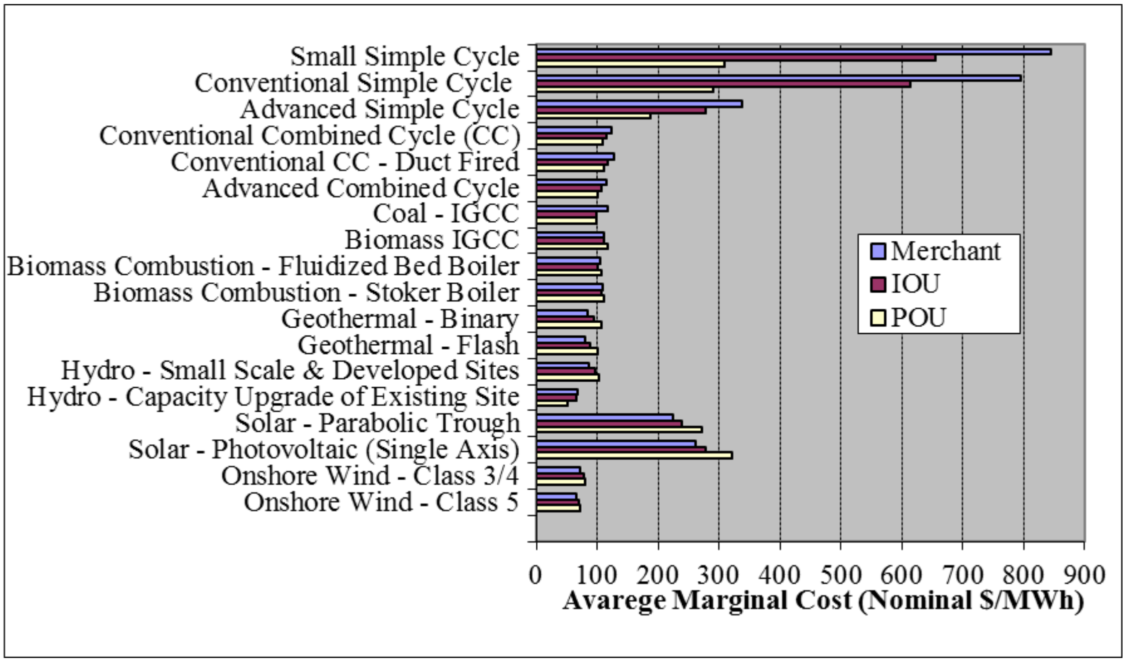


Once an LDC had been developed for each IOU, generation resources and electricity purchases were divided into nineteen combined resources categories and ranked from peak-load through intermediate and base-load generation based on both the marginal cost of generation, as well as regulatory requirements for must-take renewables.[23] Marginal cost of generation data for each resource was obtained from CEC staff. These average marginal cost estimates are illustrated in Figure 17. These stacked loading orders and corresponding LDC allocation are illustrated in Table 6 and Figure 18 (PG&E), Table 7 and Figure 19 (SCE), and Table 8 and Figure 20 (SDG&E) respectively.

[23] "Arizona Natural Gas estimates" that could be directly traced to a source in Arizona are included in "Desert Southwest (Unspecified)" Estimates; Natural Gas "Intermittent" represents natural gas plants used to firm and shape renewable electricity from QF contracts; Coal from SCE contracts are derived from the Four Corners Generating Station in New Mexico;

Figure 17

Average Marginal Cost of Generation for California Merchant, IOU, and POU Generation Sources (2010 Base Year)



Source: CEC Commission Staff (J.Klien)

Table 6

"Stacked" Loading Order for PG&E

Fuel Type	**Generation Type**	**GWh**
AZ Natural Gas	Peaking	3,161
Desert Southwest (Unspecified)	Peaking	2,107
Pacific Northwest (Unspecified)	Peaking	5,268
California (Unspecified)	Peaking	10,536
Natural Gas	Peaking	1,986
Biomass	Intermittent	3,258
Natural Gas	Intermittent	9,047
Geothermal	Intermittent	3,766
Solar	Intermittent	63
Wind	Intermittent	4,629
Small Hydro	Intermittent	989
Large Hydroelectric	Intermittent	13,296
California (Unspecified)	Intermittent	1,709
AZ Coal	Base-load	-
AZ Nuclear	Base-load	-
Natural Gas	Base-load	6,709
Coal	Base-load	-
Fuel Oil	Base-load	4
Nuclear	Base-load	18,431

Figure 18

LDC corresponding to Stacked Loading Order for PG&E

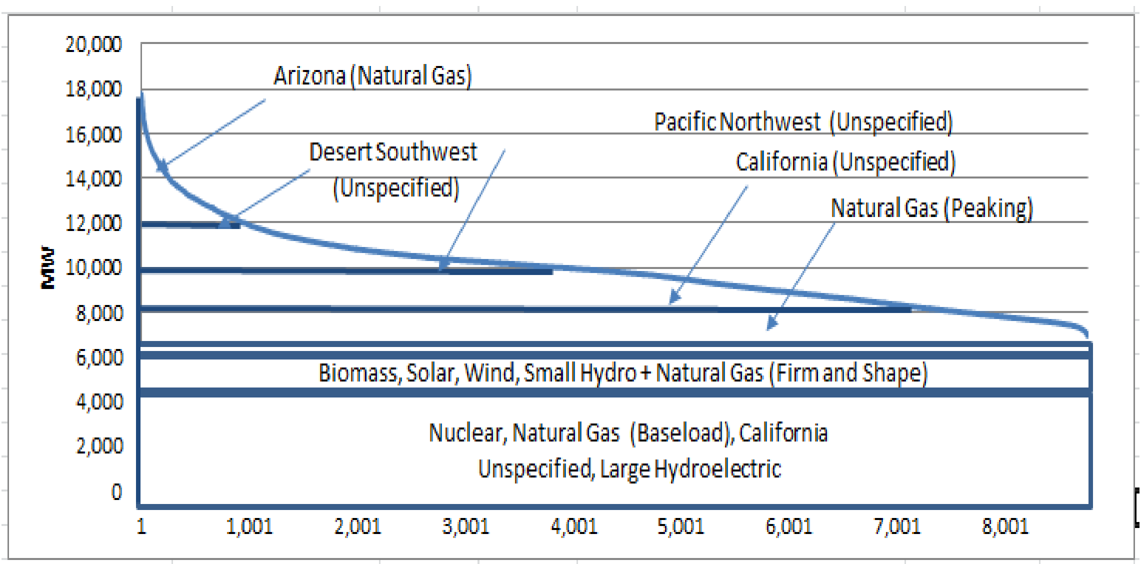


Table 7

"Stacked" Loading Order for SCE

Fuel Type	Generation Type	GWh
AZ Natural Gas	Peaking	1,165
Desert Southwest (Unspecified)	Peaking	194
Pacific Northwest (Unspecified)	Peaking	291
California (Unspecified)	Peaking	680
Natural Gas	Peaking	10,242
Biomass	Intermittent	1,253
Natural Gas	Intermittent	10,425
Geothermal	Intermittent	7,748
Solar	Intermittent	929
Wind	Intermittent	4,464
Small Hydro	Intermittent	220
Large Hydroelectric	Intermittent	4,729
California (Unspecified)	Intermittent	107
AZ Coal	Base-load	-
AZ Nuclear	Base-load	4,930
Natural Gas	Base-load	20,995
Coal	Base-load	4,738
Fuel Oil	Base-load	-
Nuclear	Base-load	10,770

Figure 19

LDC corresponding to Stacked Loading Order for SCE

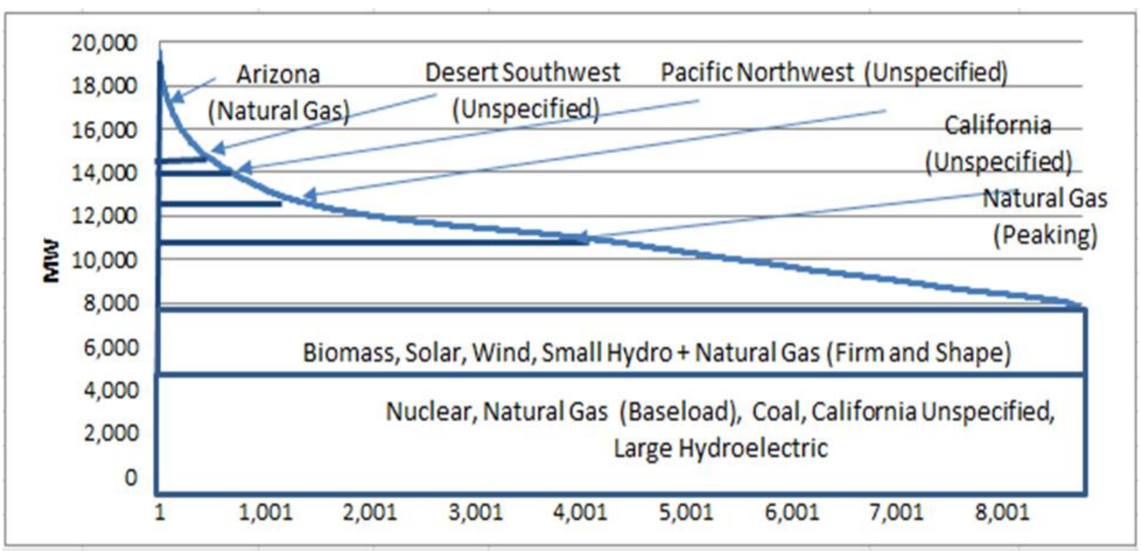


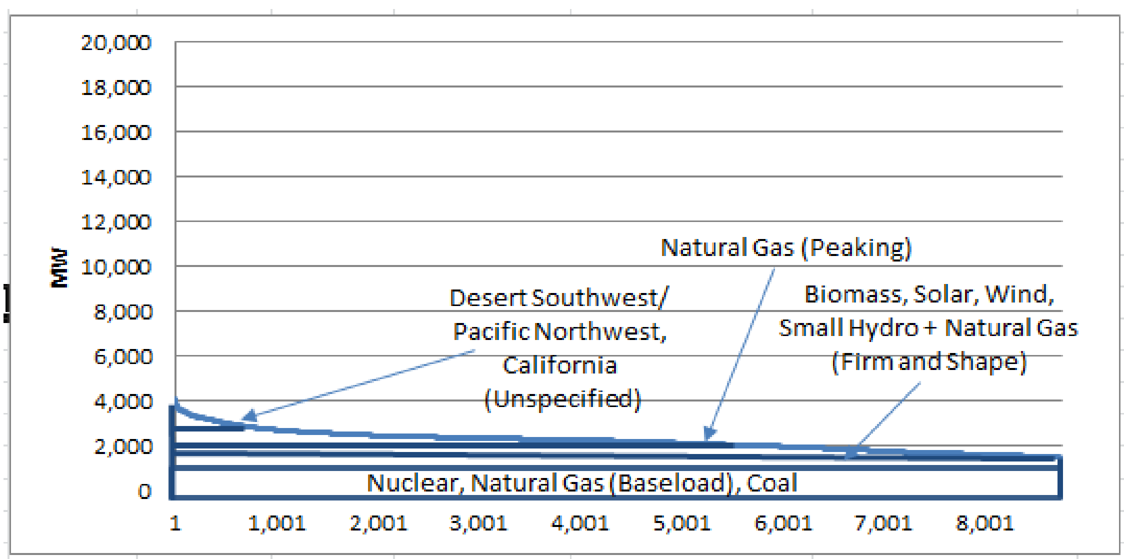
Table 8

“Stacked” Loading Order for SDG&E

Fuel Type	Generation Type	GWh
AZ Natural Gas	Peaking	194
Desert Southwest (Unspecified)	Peaking	65
Pacific Northwest (Unspecified)	Peaking	43
California (Unspecified)	Peaking	130
Natural Gas	Peaking	4,284
Biomass	Intermittent	551
Natural Gas	Intermittent	1,186
Geothermal	Intermittent	183
Solar	Intermittent	3
Wind	Intermittent	828
Small Hydro	Intermittent	22
Large Hydroelectric	Intermittent	-
California (Unspecified)	Intermittent	-
AZ Coal	Base-load	-
AZ Nuclear	Base-load	-
Natural Gas	Base-load	6,656
Coal	Base-load	604
Fuel Oil	Base-load	-
Nuclear	Base-load	2,754

Figure 20

LDC corresponding to Stacked Loading Order for SDG&E



EMISSION FACTORS

Once the utility generation and purchases (supply) have been matched to utility demand along the LDC, the next step in the process is to calculate the emissions for each resource type. Average emission factors for each fuel type were derived from data contained in Appendix B of the U.S. Environmental Protection Agency's Climate Leaders Program for Stationary Combustion Sources (EPA 2008). Emission factors for unspecified sources of electricity were derived based on average regional emission factors for the EPA Arizona- New Mexico Region (Desert Southwest (Unspecified)), California Region (California (Unspecified)), and Pacific Northwest (Pacific Northwest (Unspecified). This data was provided in the form of kilograms of CO_2e per MMBTU (see Table 7). This data was converted to kilograms of CO2e per MWh by using the conversion factor one MMBtu equates to 0.29307107017222 MWh (see Table 8).

Table 9

Average Emission Factors by Fuel Type/ Region (MMBtu)

Fuel Type	kg CO_2/MMBtu	kg CH_4/MMBtu	kg N_2O/MMBtu	kg CO_2e /MMBtu
Natural Gas	53.0567	0.0052709	0.0001054	53.200036
Fuel Oil (No. 2)	73.15	0.010542	0.000633	73.567457
Biomass	93.8667	0.316256	0.004217	101.815222
Propane	63.0667	0.010542	0.000633	63.484124
Liquid Propane	63.162	0.010542	0.000633	63.579457
Kerosene	72.3067	0.010542	0.000633	72.724124
Fuel Oil (No. 1)	73.15	0.010542	0.000633	73.567457
Fuel Oil (No. 5 & No. 6)	78.7967	0.010542	0.000633	79.214124
Coal (anthracite)	103.62	0.010542	0.001581	104.331575
Coal (bituminous)	93.4633	0.010542	0.001581	94.174908
Coke	113.6667	0.010542	0.001581	114.378242
Fuel Oil (No. 4)	73.15	0.010542	0.000633	73.567457
Diesel	73.15	0.010542	0.000633	73.567457
Desert Southwest (Unspecified)	166.52	0.002500	0.002200	167.250900
Pacific Northwest (Unspecified)	114.16	0.002200	0.001800	114.770900
California (Unspecified)	90.53	0.003800	0.000800	90.865300

Table 10

Average Emission Factors by Fuel Type/ Region (MWh)

Fuel Type	kg CO2/MWh	kg CH4/MWh	kg N2O/MWh	kg CO2e /MWh
Natural Gas	15.550029	0.001545	0.000031	15.592039
Fuel Oil (No. 2)	21.439039	0.003090	0.000185	21.561388
Biomass	27.510756	0.092689	0.001236	29.840335
Propane	18.483792	0.003090	0.000185	18.606132
Liquid Propane	18.511723	0.003090	0.000185	18.634073
Kerosene	21.191882	0.003090	0.000185	21.314222
Fuel Oil (No. 1)	21.439039	0.003090	0.000185	21.561388
Fuel Oil (No. 5 & No. 6)	23.093992	0.003090	0.000185	23.216332
Coal (anthracite)	30.369285	0.003090	0.000463	30.577836
Coal (bituminous)	27.392526	0.003090	0.000463	27.601087
Coke	33.313804	0.003090	0.000463	33.522345
Fuel Oil (No. 4)	21.439039	0.003090	0.000185	21.561388
Diesel	21.439039	0.003090	0.000185	21.561388
Desert Southwest (Unspecified)	48.804220	0.000733	0.000645	49.018435
Pacific Northwest (Unspecified)	33.458382	0.000645	0.000528	33.637427
California (Unspecified)	26.532825	0.001114	0.000234	26.631096

DEMAND SIDE MANAGEMENT ELECTRICITY SAVINGS

Individual utility estimates of gross reported monthly through the California Energy Commission Energy Efficiency Groupware Application (CEC 2013). A complete set of demand side management electricity savings data for each month of the program cycle was made available for the entire 2010-2012 program cycle through this application groupware. This data was aggregated for each utility across the program cycle and averaged across each year in the program. Given that only one baseline year (2010) was used in this study, it was important to normalize the data for one year. Based on this information, emission estimates will be averaged across all program years. It is also important to note that this raw data has yet to be evaluated, measured, or verified (EM&V) using the appropriate EM&V protocol such as IPMVP, ASHRAE, or CEF.

Table 11

California IOU DSM Electricity Savings Estimates (gross GWh)

	PG&E		SCE		SDG&E	
	2010-2012 Cumulative	**Average Annual DSM Savings (2010-2012)**	**2010-2012 Cumulative**	**Average Annual DSM Savings (2010-2012)**	**2010-2012 Cumulative**	**Average Annual DSM Savings (2010-2012)**
Gross Annual Energy Savings (GWh)	5,420.21	1,806.74	4,078.50	1,359.50	892.74	297.58
Aggregate Peak Demand Reduction (MW)	986.36	328.79	773.92	257.97	153.31	51.10

IOU TRANSMISISON AND LOSS FACTORS

An estimate of transmission and distribution (T&D) electricity savings were derived by using the inverse transmission and load loss factors for each IOU based on CEC estimates (Wong 2011). While these T&D loss generally comprise a small portion of the total electricity ultimately consumed, they can significantly affect emissions estimates. Based on a range of T&D load loss estimates, the CEC peak demand load loss forecast estimates were used as a conservative approximation of the modify employed to derive anticipated T&D electricity savings as a result of demand side management activity. The T&D savings multipliers were used to adjust the gross electricity savings estimates as a result of demand side management activity through the program cycle (Table 12).

Table 12

California IOU DSM Electricity Savings Estimates (gross GWh, adjusted for T&D savings)

	PG&E		
	Average Annualized DSM Savings (2010-2012) (MWh)	**Transmission/ Distribustion Load Loss (Savings) Factor**	**Adjusted Average Annualized DSM Savings (2010-2012) (MWh)**
Gross Annual Electricity Consumption (GWh)	1,806.74	0.096	1,998.60
Aggregate Annual Electric Load (MW)	329	NA	
	SCE		
	Average Annualized DSM Savings (2010-2012) (MWh)	**Transmission/ Distribution Load Loss (Savings) Factor**	**Adjusted Average Annualized DSM Savings (2010-2012) (MWh)**
Gross Annual Electricity Consumption (GWh)	1,359.50	0.068	1,458.69
Aggregate Annual Electric Load (MW)	258	NA	
	SDG&E		
	Average Annualized DSM Savings (2010-2012) (MWh)	**Transmission/ Distribution Load Loss (Savings) Factor**	**Adjusted Average Annualized DSM Savings (2010-2012) (MWh)**
Gross Annual Electricity Consumption (GWh)	297.58	0.071	320.32
Aggregate Annual Electric Load (MW)	51	NA	

Source: Wong 2011

CHAPTER 5: RESULTS

BASELINE EMISSION ESTIMATES

Based on the information derived in the preceding sections, several emission estimates were derived for each IOU based on the available information using 2010 base year electricity consumption and generation/purchase data. These data were then used to extrapolate emissions estimates across all program years for each IOU. The first set of emissions estimated were total baseline emissions for each IOU by resource types using the generation by resource type and associated emission factors for each corresponding fuel type. The emission estimates for each fuel types were then aggregated to develop a baseline estimate of total baseline emissions for each IOU (Tables 13, 14, and 15).

Table 13

PG&E Total Baseline Emissions by Resource Type (2010 Base Year)

Fuel Type	**Generation Type**	**GWh**	**Emission Factor (kg CO_2e /MWh)**	**Emissions (kg CO_2e)**	**Emissions (MT CO_2e)**
AZ Natural Gas	Peaking	3,161	15.55002931	49,150,532.64	49,150.53
Desert Southwest (Unspecified)	Peaking	2,107	48.8042204	102,840,253.22	102,840.25
Pacific Northwest (Unspecified)	Peaking	5,268	33.45838218	176,258,757.33	176,258.76
California (Unspecified)	Peaking	10,536	266.3109613	2,805,852,288.39	2,805,852.29
Natural Gas	Peaking	1,986	15.55002931	30,879,403.70	30,879.40
Biomass	Intermittent	3,258	298.403347	972,198,104.56	972,198.10
Natural Gas	Intermittent	9,047	15.55002931	140,681,115.15	140,681.12
Geothermal	Intermittent	3,766	0	-	-
Solar	Intermittent	63	0	-	-
Wind	Intermittent	4,629	0	-	-
Small Hydro	Intermittent	989	0	-	-
Large Hydroelectric	Intermittent	13,296	0	-	-
California (Unspecified)	Intermittent	1,709	26.53282532	45,344,598.48	45,344.60
AZ Coal	Base-load	-	27.39252638	-	-
AZ Nuclear	Base-load	-	0	-	-
Natural Gas	Base-load	6,709	15.55002931	104,319,237.62	104,319.24
Coal (Bitumous)	Base-load	-	27.39252638	-	-
Fuel Oil	Base-load	4	21.43903869	85,756.15	85.76
Nuclear	Base-load	18,431	0	-	-
			Total	*4,427,610,047.25*	*4,427,610.05*

Table 14

SCE Total Baseline Emissions by Resource Type (2010 Base Year)

Fuel Type	Generation Type	GWh	Emission Factor (kg CO_2e /MWh)	Emissions (kg CO_2e)	Emissions (MT CO_2e)
AZ Natural Gas	Peaking	1,165	15.55002931	18,118,894.15	18,118.89
Desert Southwest (Unspecified)*	Peaking	194	48.8042204	9,477,779.60	9,477.78
Pacific Northwest (Unspecified)	Peaking	291	33.45838218	9,746,426.73	9,746.43
California (Unspecified)	Peaking	680	266.3109613	181,091,453.69	181,091.45
Natural Gas	Peaking	10,242	15.55002931	159,255,780.66	159,255.78
Biomass	Intermittent	1,253	298.403347	373,899,393.80	373,899.39
Natural Gas	Intermittent	10,425	15.55002931	162,109,055.54	162,109.06
Geothermal	Intermittent	7,748	0	-	-
Solar	Intermittent	929	0	-	-
Wind	Intermittent	4,464	0	-	-
Small Hydro	Intermittent	220	0	-	-
Large Hydroelectric	Intermittent	4,729	0	-	-
California (Unspecified)	Intermittent	107	26.53282532	2,839,012.31	2,839.01
AZ Coal	Base-load	-	27.39252638	-	-
AZ Nuclear	Base-load	4,930	0	-	-
Natural Gas	Base-load	20,995	15.55002931	326,477,063.84	326,477.06
Coal (Bitumous)	Base-load	4,738	27.39252638	129,785,789.98	129,785.79
Fuel Oil	Base-load	-	21.43903869	-	-
Nuclear	Base-load	10,770	0	-	-
	Total	*83,881*		*1,372,800,650.30*	*1,372,800.65*

Table 15

SDG&E Total Baseline Emissions by Resource Type (2010 Base Year)

Fuel Type	Generation Type	GWh	Emission Factor (kg CO_2e /MWh)	Emissions (kg CO_2e)	Emissions (MT CO_2e)
AZ Natural Gas	Peaking	194	15.55002931	3,016,705.69	3,016.71
Desert Southwest (Unspecified)*	Peaking	65	48.8042204	3,172,274.33	3,172.27
Pacific Northwest (Unspecified)	Peaking	43	33.45838218	1,438,710.43	1,438.71
California (Unspecified)	Peaking	130	266.3109613	34,620,424.97	34,620.42
Natural Gas	Peaking	4,284	15.55002931	66,618,813.56	66,618.81
Biomass	Intermittent	551	298.403347	164,420,244.20	164,420.24
Natural Gas	Intermittent	1,186	15.55002931	18,442,334.76	18,442.33
Geothermal	Intermittent	183	0	-	-
Solar	Intermittent	3	0	-	-
Wind	Intermittent	828	0	-	-
Small Hydro	Intermittent	22	0	-	-
Large Hydroelectric	Intermittent	-	0	-	-
California (Unspecified)	Intermittent	-	26.53282532	-	-
AZ Coal	Base-load	-	27.39252638	-	-
AZ Nuclear	Base-load	-	0	-	-
Natural Gas	Base-load	6,656	15.55002931	103,505,971.09	103,505.97
Coal (Bitumous)	Base-load	604	27.39252638	16,545,085.93	16,545.09
Fuel Oil	Base-load	-	21.43903869	-	-
Nuclear	Base-load	2,754	0	-	-
			Total	411,780,564.96	*411,780.56*

OPERATING MARGIN EMISSION ESTIMATES

Once the baseline emission rate for each resource for each IOU had been calculated, the next step was to estimate margin emission rates from which avoided emissions resulting from IOU DSM activity would be derived. These estimates were derived by calculating the percent of time in terms of load hours in which each given marginal resource intersected with the LDC curve. Using integral analysis defined in the methodology, the number of hours that each resource was "on the margin" was calculated to determine the percentage of time in which that resources would be considered the most prominent load following resource before the next highest cost of generation would have to be put online. The operating marginal emission rate for each fuel type was then used to derive an average total and hourly Operating Margin emission rate for each IOU (see Tables 16 through 18).

Table 16

PG&E Operating Margin Emissions by Resource Type (2010 Base Year)

Fuel Type	**Number of Hours when resource is "on the margin"**	**Percent of LDC/ when resource is "on the margin"**	**Emission Factor**	**Operating Margin Emissions (kg CO_2e/MWh)**
AZ Natural Gas	1,023	14.66%	15.55	15,907,679.98
Desert Southwest (Unspecified)	3,658	52.41%	48.80	178,525,838.22
Pacific Northwest (Unspecified)	2,164	31.00%	33.46	72,403,939.04
California (Unspecified)	105	1.50%	26.53	2,785,946.66
Natural Gas	30	0.43%	15.55	466,500.88
	Total Operating Margin Emission factor			*270,089,904.78*
	Hourly Operating Marginal Emission Factor (/8760)			*30,832.18*

Table 17

SCE Operating Margin Emissions by Resource Type (2010 Base Year)

Fuel Type	Number of Hours when resource is "on the margin"	Percent of LDC/ when resource is "on the margin"	Emission Factor	Operating Margin Emissions (kg CO_2e/MWh)
AZ Natural Gas	879	10.03%	15.55	13,668,475.76
Desert Southwest (Unspecified)	196	2.24%	48.80	9,565,627.20
Pacific Northwest (Unspecified)	528	6.03%	33.46	17,666,025.79
California (Unspecified)	2,954	33.72%	26.53	78,377,966.00
Natural Gas	4,203	47.98%	15.55	65,356,773.18
	Total Operating Margin Emission factor			*184,634,867.94*
	Hourly Operating Marginal Emission Factor (/8760)			*21,077.04*

Table 18

SDG&E Operating Margin Emissions by Resource Type (2010 Base Year)

Fuel Type	Number of Hours when resource is "on the margin"	Percent of LDC/ when resource is "on the margin"	Emission Factor	Operating Margin Emissions (kg CO_2e/MWh)
AZ Natural Gas	789	9.01%	15.55	12,268,973.12
Desert Southwest (Unspecified)	126	1.44%	48.80	6,149,331.77
Pacific Northwest (Unspecified)	112	1.28%	33.46	3,747,338.80
California (Unspecified)	3,030	34.59%	26.53	80,394,460.73
Natural Gas	4,703	53.69%	15.55	73,131,787.84
	Total Operating Margin Emission factor			*175,691,892.26*
	Hourly Operating Marginal Emission Factor (/8760)			*20,056.15*

AVOIDED EMISSION ESTIMATES

Using baseline and operating margin emissions estimates, as well as electricity reduction estimates adjusted for transmission and distribution savings, then normalized for all program years (2010-2012), the total avoided emissions resulting from DSM activity for each individual IOU and aggregated across all IOUs were derived. The resulting avoided emissions estimated as a result of IOU demand side management activity is displayed in Table 19.

Table 19

Total Emission Reductions by IOU (2010-2012 DSM Program Cycle)

	Average Annualized DSM Savings (2010-2012) (GWh)	Transmission/ Distribution Load Loss Factor	Adjusted Average Annualized DSM Savings (2010-2012) (MWh)	Operating Margin Emissions (kg CO_2e/MWh)	Average Annualized Emission Reductions as a Result of DSM Activity (kg CO_2e)	Program Cycle (2010-2012) Emission Reductions Resulting from DSM Activity (MT CO_2e)
PG&E	1,806.74	0.096	1,998.60	30,832.18	61,621,274.08	184,863.82
SCE	1,359.50	0.068	1,458.69	21,077.04	30,744,887.87	92,234.66
SDG&E	297.58	0.071	320.32	20,056.15	6,424,445.36	19,273.34
			Total Emission Reduction As a Result of DSM Activity			*296,371.82*

AVOIDED EMISSION ESTIMATES FROM ARIZONA BASED RESOURCES

Finally, the total avoided emissions from Arizona based resources were derived by using the percent operating margin for Arizona based resources operating on the margin. In this case, the only Arizona based marginal resources generally subject to peak load demand reduction were Arizona-based natural gas resources. This was expected given these resources generally have the highest marginal cost of generation. Additionally other Arizona based resources, such as Arizona nuclear produce no GHG emissions and Arizona-based coal is subject to base load (build-margin) marginal emission rates and would generally not be subject to reductions in peak load demand.

It is important to note that these estimates of Arizona-based GHG reductions are a conservative estimate of total reduction, given that a portion of each IOUs electricity imports from the Desert Southwest could not be specifically traced to Arizona resources, due to a lack of significantly granular data (Table 20). If even fifty percent of the total electricity imports from the Desert Southwest were added to the estimate it could significantly increase these estimates. An interesting facet of this analysis is that avoided emissions from Arizona based resources comprise a slighter higher than average total of other sources of avoided emissions in PG&E and SDG&E's service territories. This could be explained by variations in each utility's fuel mix, though it can likely be best explained by the fact that Arizona resources, specifically natural gas do not operate as long as a marginal ("on the margin") resource in these service territories.

Table 20

Total Emission Reduction from Arizona Resources (Conservative Estimate) as a Result of California IOU DSM 2010-2012 Program Cycle

	Total Arizona NG Operating Margin Emissions (MT CO_2e/MWh)	**Estimated Percent Emissions Avoided (Conservative)**	**Net Reduction in Emissions (2010-2012) (MT CO2e/MWh)**
PG&E	47,723.04	6.00%	2,862.43
SCE	41,005.43	3.53%	1,448.27
SDG&E	36,806.92	2.76%	1,016.42
		Total	*5,327.12*
Percent of Total DSM Emission Reductions (2010-20			*1.7974%*
Percent of Total Emissions (2010-2012)			*0.0286%*

Table 21

Percent Total Emissions Avoided as a Result of 2010-2012 IOU DSM Program Cycle

	Program Cycle Total Emissions (2010-2012 Cycle) (MT CO2e/MWh)	**Program Cycle (2010-2012) DSM Avoided Emissions (MT CO_2e)**	**Percent Emissions Avoided**
PG&E	13,282,830.14	184,863.82	1.39%
SCE	4,118,401.95	92,234.66	2.24%
SDG&E	1,235,341.69	19,273.34	1.56%
Total	*18,636,573.79*	*296,371.82*	*1.59%*

Based on the method described in the previous sections, the answer to the research question: "What is the quantity of GHG emission reductions (in terms of CO2e) that can be attributed to reduced electricity demand from Arizona-based electricity resources as a result of CPUC mandated and rate-payer funded IOU (PG&E, SCE, and SDG&E) DSM activities from 2010 through 2012?," is 5,372 metric tons CO_2e, or approximately 1.8 percent of total avoided emissions can be directly linked to demand reduction for Arizona based generation resources.

POLICY IMPLICATIONS

The immediate policy implications of this research are in assisting both state agencies and utilities in developing credible, accurate, and defensible assessments of avoided emissions estimates. This is extremely relevant given the recently launched "Cap and Trade" program in California. In the future, utilities will receive credits based upon reducing their associated GHG emissions below baseline levels set by CARB. Within the cap and trade scheme utility generation is reported and credited separately from those retail electric operators. While this provides an incentive for utilities to both reduce electric demand and increase purchases from renewable electric generation sources, it also places significantly more importance of the GHG emissions derived from marginal operating sources, such as Arizona-based natural gas despite the added expense of this generation.

Conversely, it is an important tool for Arizona-based operators to use to understand the potential financial implications of the California emissions market as well as reductions in absolute demand from these resources over time. In the broader context of the western electric grid, it serves to further define the market power of GHG emission reductions in the broader context of electricity imports between and among markets. More importantly, through this analysis regarding the spatial context of GHG emission reductions, this study hopes to shed light on the spill-over effect of environmental regulation between states with connected electricity systems, as well as serve as a foundation for future academic inquiry into effective strategies to track, monitor, and model avoided emissions from grid-based utility resources. These improved methods will provide state agencies with objective tools to analyze the long-term implications of GHG mitigation strategies as they are applied to the electric generation sector.

SUGGESTIONS FOR FURTHER RESEARCH

Needless to say, there are significant opportunities to improve this model through the use of more granular data. The most obvious improvement in this regard is to gather additional primary data regarding electrical generation and purchases, the most granular of which are based on North American Electric Reliability Corporation (NERC) e-tags for hourly purchases, though would require sorting and analyzing likely hundreds of thousands of electricity transactions for each IOU across multiple generation types. Though not impossible given that utilities manage and track these data, utilities are not likely to share this information upon request.

In a similar fashion, the model could be significantly improved through the use of an actual loading order for each IOU or, at the very least, improved data regarding the marginal cost of generation for each resource. While utilities are, again, unlikely to share the exact loading order of their generation resources or the marginal cost of generation, more precise loading orders could be determined for each utility based on their own unique generation, transmission, distribution, and consumption profiles. This would also provide improved understanding of each utility's transmission and distribution load loss profile with respect the spatial context of each marginal resource within its electricity mix (e.g. are peak load plants subject to additional load losses given that these resources are located the furthest away from the point of consumption? Or vice versa?).

Finally, the study provides a better understanding of how the load duration curve is affected by electricity reduction as a result of demand side management activity and all demand side management activity was considered as being equal. It would be interesting to estimate how the load duration curve would be affected by changes in load in only portions of a utility service territory, and in turn, how this would affect the marginal emission rate. Further analysis could even be conducted by disaggregating consumption and demand reduction by customer class to derive separate load duration curves. These in turn could be matched individually according the estimated hourly generation resources by customer type to derive even more granular data regarding the impact of demand side management and the emission rate form those specific consumption activities.

CONCLUDING REMARKS

While the primary objective of this research involved quantifying GHG emissions, the research itself lends itself to many other environmental aspects of utility resource planning aside from emissions themselves. The same techniques employed in this study can also be used to measure the effect of other forms of environmental impacts and/or remediation efforts involving grid-based electricity resources. For instance, one could apply the same techniques used in this study to determine the effect of demand side management activities in reducing the use of fresh water for cooling generation. On a micro-level these same techniques can be applied to target demand side management activities within particular areas within a service territory where a mixture of cogeneration, peak load demand shift, and renewable techniques can be used to plan and develop corridors of sustainable electricity development within a given utility service territory. In essence, the efficacy of this research is in how it is applied to other aspects of utility supply and demand side planning to promote cleaner, more efficient electricity production and consumption.

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