STAFF PAPER

A Review of Transmission Losses in Planning Studies

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ABSTRACT

California Energy Commission staff analyzed the current state of estimating transmission and distribution loss values in planning studies. In this effort, staff analyzed data, researched literature and proceedings, and interviewed representatives from the utilities, the California Public Utilities Commission, and the California Air Resources Board. California average system losses for transmission and distribution ranged from 5.4 percent to 6.9 percent during 2002 to 2008, based on Energy Commission data. This staff paper identifies data gaps or methodology questions necessary to support a common set of assumptions to be used in various analyses.

Keywords: Transmission, distribution, losses, loss factors, transmission and distribution, subtransmission, primary, secondary, import

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EXECUTIVE SUMMARY

The sources and uses of electricity transmission and distribution system losses (energy consumed during the process of moving power from generation to load) in planning studies are discussed in this paper. While transmission and distribution losses may be a small percentage of total energy use, inaccurate estimates can affect program costs. Inaccurate estimates also can lead to overprocurement or underprocurement of supply. Underestimating the loss factor could lead to underprocurement of energy, while overestimating the loss factor could lead to overprocurement of resources. Comparisons among different generation resource options are hampered by discrepancies in percentages of losses across studies. By reviewing current practice and identifying key issues, staff hopes to spur discussion surrounding an important, but often overlooked issue.

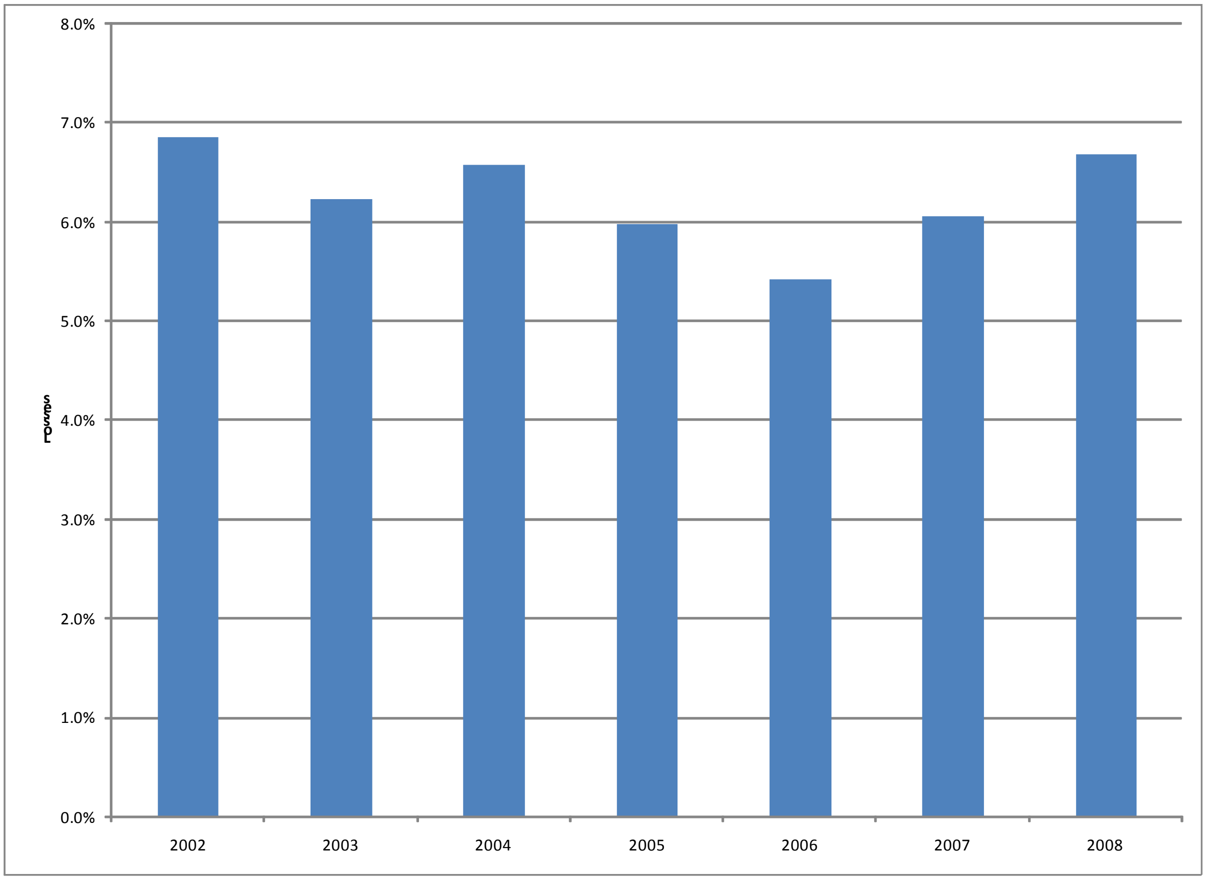
Loss factors are used any time one is studying the amount of generation that will be needed to serve load, or the generation that might be avoided by various types of demand side alternatives. For example, loss factors are used in the California Energy Commission's adopted demand forecast to scale up end-use electricity demand to estimate the amount of generation necessary to serve it (known as net energy for load). Loss factors are also used to evaluate generation needs for resource adequacy at the California Public Utilities Commission; to calculate emission displacement implications (in-state versus imported generation) by the California Air Resources Board; to calculate avoided costs (the cost of the electricity that would have been used) of distributed energy resources, demand response, and energy efficiency by the California Public Utilities Commission; and to scale up marginal energy costs by estimated line losses in general rate cases at the California Public Utilities Commission.

Figure ES-1 presents California average system losses for transmission and distribution, which ranged from 5.4 percent to 6.9 percent during 2002 to 2008 based on California Energy Commission data. A slightly different range from 4.5 to 8.0 percent can be obtained using U.S. Energy Information Administration data. Utility-specific losses will vary based on their individual transmission and distribution system. For example, losses within the Pacific Gas and Electric area tend to be higher because the transmission system is composed of longer and lower-voltage transmission lines, which cause more losses. The location of a generator with respect to the grid and with respect to load (where the energy is consumed) affects the amount of line losses that occur. In addition, average losses may vary from on-peak losses given the location of generation and system operating conditions at the peak hour.

Table ES-1 presents peak and energy loss factors recently used by the three investor-owned utilities in California. Some analyses include peak and energy loss factors, while in other studies only a peak loss factor is used. Furthermore, in some analyses, average values are used while in others, the values vary by program.

Loss factors for Pacific Gas and Electric range from 1.0834 (based on converting 7.7 percent losses to a loss factor) to 1.109 for peak losses. Loss factors for Southern California Edison range from 1.076 to 1.098 for peak losses. Loss factors for San Diego Gas & Electric range from 1.066 to 1.096 for peak losses. The difference between low and high values ranges from 0.02 to 0.03 depending on the utility.

Figure ES-1: California Statewide Average Historical Transmission and Distribution Losses



Source: California Energy Commission.

Table ES-1: Comparison of Loss Factors

	Energy Commission Demand Forecast		CPUC General Rate Case		CPUC Avoided Costs	CPUC Scoping Memo Long-Term Procurement Proceeding (LTPP)		
					Distributed Energy Resources, Demand Response	Energy Efficiency	Demand Response	Combined Heat and Power
	Peak	Energy	Peak	Energy	Peak	Peak	Peak	Peak
PG&E	1.097	1.096	1.101	1.109	1.109	1.097	1.119	1.077
SCE	1.076	1.068	1.098	1.081	1.084	1.076	1.112	1.077
SDG&E	1.096	1.0709	N/A	N/A	1.081	1.096	1.066	1.077

Note: The loss factors for Energy Efficiency and Demand Response in the California Public Utilities Commission *Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo* for Long-Term Procurement Proceeding are loss factors, while the loss factor for Combined Heat and Power represents losses or a loss rate as a percentage of net energy for load. Staff was unable to obtain loss factors from SDG&E General Rate Case.

Sources: California Energy Commission, *California Energy Demand 2010-2020, Adopted Forecast;* Pacific Gas and Electric Company 1993 Test Year General Rate Case, Exhibit (PG&E-16), Chapter 4 Marginal Transmission and Distribution Capacity Costs, page 6-18; Southern California Edison, 2009 General Rate Case Application 08-03-002 (staff was unable to verify the original vintage of the data); CPUC avoided costs for distributed energy resources and demand response available at: [http://www.cpuc.ca.gov/NR/rdonlyres/786A98AC-9F92-4D8D-A071-6A8065944CCE/0/2011IOUDRProgramTotalsFinal728.xls] and [http://www.ethree.com/public_projects/cpucdr.html], see the Avoided Cost Calculator (12/15/2010) under the section, Distributed Generation Cost-effectiveness Framework; and CPUC *Attachment I, Standardized Planning Assumptions (Part 1) for System Resource Plans* R.10-05-006, page 56, available at: [http://docs.cpuc.ca.gov/efile/RULC/127543.pdf].

This staff paper reviews the loss factor estimates being used by different entities, describes the sources of these estimates and how they are used, and identifies data gaps or method questions necessary to support a common set of assumptions to be used in various analyses. There is not a common set of assumptions in use in planning studies. The paper solicits comments from practitioners on what transmission and distribution loss factors sources and data should be used in future studies. Narrowing the differences among studies will improve overall study coordination and analytic efficiency.

CHAPTER 1: Introduction and Overview of Transmission and Distribution Systems

This working paper discusses the sources and uses of transmission and distribution loss values in planning studies. Transmission and distribution losses may be a small percent of total energy use, but inaccurate estimates can affect program costs. Inaccurate estimates also can lead to overprocurement or underprocurement of supply. Underestimating the loss factor could lead to underprocurement of energy, while overestimating the loss factor could lead to overprocurement of resources. Discrepancies among studies can result in inaccurate comparisons among resource options. By taking the time to review current practice and identify issues, staff hopes to spur discussion surrounding an important, but often overlooked issue.

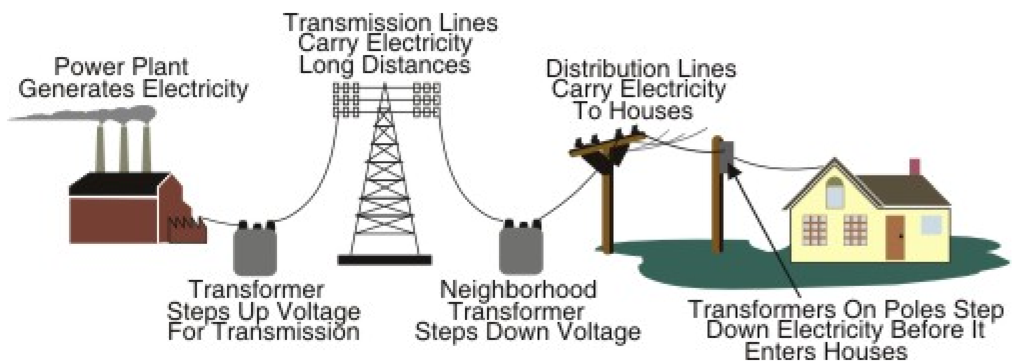
In broad terms, loss factors represent energy consumed during the process of moving the power from generation to load. Because transmission and distribution losses are so widespread and vary depending on distance and grid infrastructure, metered losses are not readily available. Instead they are usually estimated. Loss factors are used any time one is studying the amount of generation that will be needed to serve load, or the generation that might be avoided by various types of demand side alternatives. For example, they are used in the California Energy Commission's adopted demand forecast to scale up end-use electricity demand to estimate the amount of generation necessary to serve it (known as net energy for load). Loss factors are also used to evaluate generation needs for resource adequacy at the California Public Utilities Commission (CPUC); to calculate emission displacement implications by the California Air Resources Board (ARB); to calculate avoided costs of distributed energy resources, demand response, and energy efficiency by the CPUC; and to scale up marginal energy costs by estimated line losses in general rate cases at the CPUC.

California average system losses for transmission and distribution ranged from 5.4 percent to 6.9 percent during 2002 to 2008 based on Energy Commission data. Utility-specific losses will vary based on the individual transmission and distribution system. For example, losses within the Pacific Gas and Electric area tend to be higher since the transmission system is composed of longer and lower-voltage transmission lines, which cause more losses. The location of a generator with respect to the grid and with respect to load (where the energy is consumed) affects the amount of line losses that occur. In addition, average losses may vary from on-peak losses given the location of generation and system operating conditions at the peak hour.

This staff paper reviews the loss factor estimates being used by different entities, describes the sources of these estimates and how they are used, and identifies data gaps or method questions necessary to support a common set of assumptions to be used in various analyses. The paper solicits comments from practitioners on what transmission and distribution loss factor sources and data should be used in future studies. Narrowing the differences among studies will improve overall study coordination and analytic efficiency.

Electricity is generated and delivered via the transmission and distribution system to industrial, commercial, and residential customers. **Figure 1** shows a simplified diagram of the electric power system. The system consists of connected power plants, bulk transmission lines, substations, distribution lines, and customers. Power losses occur during the delivery of electricity along the transmission and distribution system. In general, the difference between what is produced and what is consumed constitutes transmission and distribution losses. For example, if the transmission and distribution system has losses of 7 percent, 100 megawatt hours (MWh) of electricity produced at the power plant would provide only 93 MWh to the customer. Transmission and distribution losses are a real cost because more electricity needs to be generated to compensate for losses and to serve load.

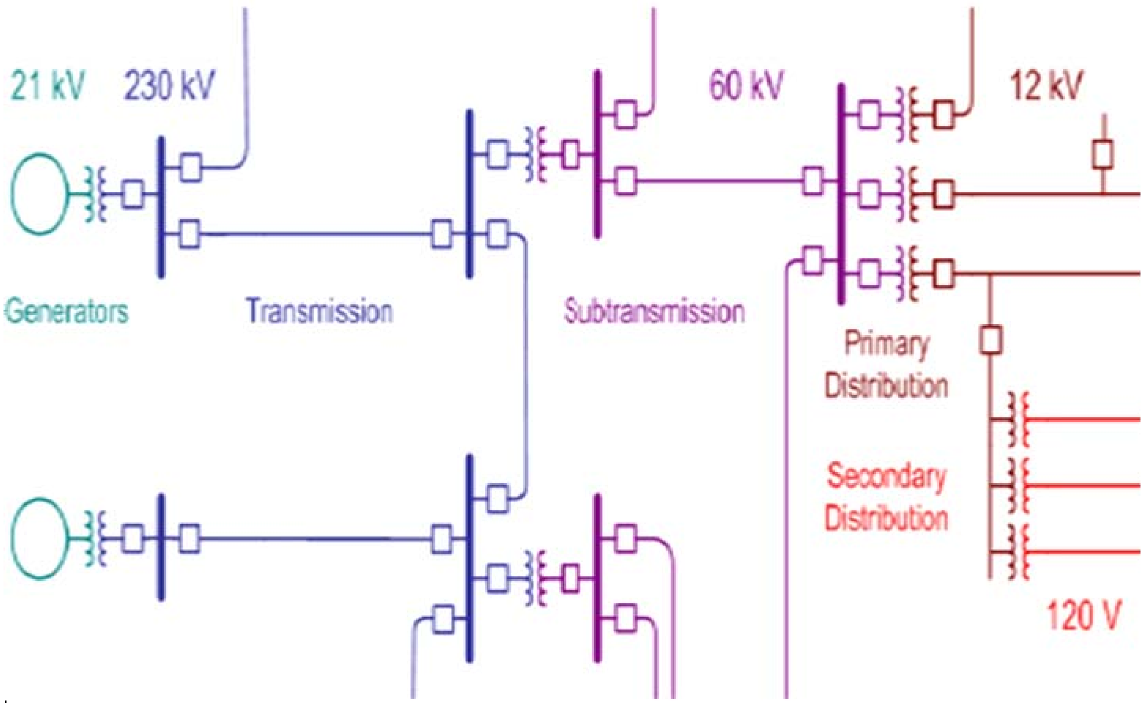
Figure 1: Electric Power Generation, Transmission, and Distribution Diagram



Source: U.S. Energy Information Administration/National Energy Education Development Project.

Transmission losses occur due to of the electricity system's physical characteristics. Underestimating the loss factor could lead to underprocurement of energy, while overestimating the loss factor could lead to overprocurement of resources. **Figure 2** depicts a schematic of the generators, transmission lines, transmission and distribution substations, transformers, and the service connection. This diagram depicts the basic flow of electricity: It is created at power plants and other generating facilities, and is transported across high-voltage transmission and lower-voltage distribution lines to reach homes and businesses. Transformers at substations step the electric voltage up and down to deliver power efficiently to the customers. The transformers are symbolized by the squiggly lines. The distribution substation is a switchyard that connects the transmission system to the distribution system. The transmission system operates at higher voltage levels to minimize power losses in long distance transmission, while the distribution system operates at lower voltage levels to provide safe delivery to the customer.

Figure 2: Power System Structure With Typical Voltage Levels



Source: Dr. Alexandra von Meier (2010). *Demystifying the Electric Grid* (PowerPoint slides), available at California Energy Commission Web site: [http://www.energy.ca.gov/research/notices/2010-10-25_symposium/presentations/1%20Demystifying%20the%20Electric%20Grid.pdf].

In general, the bulk transmission system is defined as the high voltage lines, greater than 100 kilovolts (kV).[1] This network of high voltage transmission lines interconnects generating stations and large substations located close to the customers or load centers by using overhead lines. In some instances, underground transmission lines, such as the Trans-Bay Cable in the San Francisco Bay Area, may be built, but given the high cost of putting transmission lines underground, most high voltage transmission lines are overhead.

1 The North American Electric Reliability Corporation (NERC) definition for the bulk electric system is all transmission and generation elements and facilities operated at voltages of 100 kV or higher necessary to support bulk power system reliability. Elements and facilities operated at 100 kV or higher, including radial transmission systems, may be excluded, and elements and facilities operated below 100 kV may be included through the bulk electric system exemption process.

The subtransmission system is defined as medium voltage in the range of 69 to 138 kV. The subtransmission system can be defined as that part of the grid that interconnects the bulk transmission elements with the distribution elements. The subtransmission system tends to cover shorter distances.

The distribution system begins at the high voltage substation between the subtransmission and primary distribution parts of the system through the lower voltage lines to the retail customer. The primary distribution system operates at voltages in the low tens of kV and may deliver power directly to larger commercial and industrial customers. The secondary distribution system operates at the lowest voltage level of 120 volts and delivers power to residential customers and small commercial customers.

Causes of Transmission Losses

Transmission and distribution losses are the power losses in an electrical system. Transmission losses are caused by:

- The electrical resistance of the conductor lines or power lines.
- Converting the power between high voltages used for long distance transmission and safe low voltages used in most industry and residential homes.

The amount of power transmitted by a power line is measured in watts (W), which also corresponds to amperes multiplied by volts. Current represents a flow rate of charge and is measured in amperes or amps. This flowing electric charge is typically carried by moving electrons in a conductor such as wire. Voltage represents the electrical potential or energy per charge and is measured in volts (V). Standard home wiring is 120 V, and long-distance transmission can be upwards of 500 kV.

Resistance represents friction and inhibits transfer capability and is measured in ohms. Resistance can vary based on temperature, and the resistance of a copper wire increases as it heats up. Resistance along wires increases with length and decreases with cross-sectional area. Larger wires would have lower resistance than smaller wires. Resistance increases as length increases, so the losses will increase along longer distance transmission lines.

When electric current flows through power lines, it creates heat due to some resistance in the lines. The resistive heating along the power lines is lost energy and known as resistive losses.

Transmission losses are proportional to the square of the amount of the current flowing on the wire and of the resistance it encounters. In general, the current on a given transmission line remains a constant, and the loss associated with a single transmission of electricity is primarily a function of the distance the electricity is transmitted.[2]

Losses vary by whether they use alternating or direct current. Bulk transmission lines used to connect more distant power plants to load centers are built at the higher voltage levels of 110 kV or higher to minimize losses. The Western Electricity Coordinating Council (WECC) is one of three synchronous grids (operating at a synchronized frequency) across North America and is an alternating current (AC) system. An AC power system allows stepping up and down voltage levels through the use of a transformer, whereas a direct current (DC) power system does not allow the use of transformers. The advantage of using transformers is the ability to use different voltage levels along the transmission and distribution system.

DC lines can be used in an AC system, such as the Pacific DC Intertie between the Pacific Northwest and Los Angeles. DC lines connect with the AC system through the use of more expensive DC conversion equipment. The advantage of the DC lines is they operate at high voltages, which minimize losses, and they have lower capital costs than AC lines.

As mentioned earlier, transmission losses also occur from converting power between high voltages and low voltages through the use of transformers. Transformer heating causes some power to dissipate in the form of heat. A transformer consists of two conductor coils that are connected through a magnetic field. Copper losses occur in the conductor windings because of electrical resistance. Iron losses occur in the transformer core due to of resistance or friction of iron particles. Loss factors can vary by season and time of day due to ambient conditions such as temperature, wind, and rain. In general, losses are higher in the summer than they are in the winter.

2 Sithe/Independence Power Partners, L.P. v. FERC, 285 F.3d 1, 2 (D.C. Cir. 2002).

CHAPTER 2: Historical Overview of Transmission Loss Values

Before discussing losses used in various studies, it is first necessary to work through some nomenclature. Values are reported as either *losses* or *loss factors*, which are two distinct metrics. Loss factors also may be referred to as *gross-up values*. Terminology and clear definition are lacking. Inconsistent use of terminology among the various forums creates confusion when comparing numbers.

In this paper, *losses* reported as a percentage refer to a percentage of net energy for load that is attributed to losses. Losses may be referred to as *loss percentage* or *loss rate*. References to California losses in the 5.4 to 6.9 percent range mean losses as a percentage of net energy for load. *Net energy for load* is defined as net generation excluding self-generation plus imports less exports.

Table 1 illustrates how transmission losses can be represented and what they mean. For example, if losses are 7 percent then 100 megawatt hours of electricity needs to be produced at the power plant (net energy for load) to deliver 93 MWh to the customer (retail sales). *Retail sales* are defined as consumption excluding self-generation. Seven MWh of power losses are attributed to transmission and distribution losses.

Loss factor refers to a factor used to scale end-use demand or retail sales to produce net energy for load. A loss factor is used to calculate how much more energy needs to be produced to account for losses and meet load. Multiplying the loss factor by the amount of energy actually delivered (usually retail sales) produces an estimate of how much energy must be produced by the generator (net energy for load). The loss factor in this example is 1.075269 (that is, 1.00/1.00 minus 0.07). Retail sales multiplied by the loss factor equals net energy for load, or 93 MWh multiplied by 1.075269 equals 100.0 MWh.

Table 1: Losses Example

1	Generation, or Net Energy for Load (MWh)	100
2	Losses (%) or Loss Rate (%)	7%
3	Losses (MWh)	7
4	Retail Sales (MWh)	93
5	Loss Factor – [1.0/(1.0 – 7%]	1.075269

Source: California Energy Commission.

The loss factor is similar to a *gross-up*[3] factor that can be applied to a program to calculate avoided energy including losses. For example, a demand response program may displace 93 MWh of retail load. Accounting for losses of 7 percent, a gross-up factor of 1.075269 is multiplied by the program savings of 93 MWh to get the total avoided energy of 100 MWh including losses. The demand response program saves the utility from having to procure 100 MWh of resources to meet 93 MWh of load.

To convert from loss rate to loss factor:

$$\text{Loss factor} = \frac{1}{(1\text{-loss rate})}$$

$$\text{Loss factor} = \frac{1}{(1\text{-}0.07)}$$

$$\text{Loss factor} = 1.075269$$

To convert from loss factor to loss rate:

$$\text{Losses (\%)} = 1 - \frac{1}{\text{loss factor}}$$

$$\text{Losses (\%)} = 1 - \frac{1}{1.075269}$$

$$\text{Losses (\%)} = 7.0\%$$

Losses can be calculated for either a single hour (typically a peak demand hour) or for a longer aggregate period. The mathematical calculation of loss factors remains the same. The key difference is that the data used in estimation of aggregate losses over a period will obscure short periods of extreme loss conditions and provide only an "average" loss factor. As described earlier, the actual losses depend on a number of physical, system, and environmental factors. The result is that loss factors are often presented for both collective "energy" losses as well as losses during "peak" demand periods when the system is likely to be stressed and every MW may be considered essential.

California statewide average transmission and distribution losses can be calculated using different sources of data and under slightly different methods. The two main sources of data are Energy Commission data and U.S. Energy Information Administration data. The method may vary slightly whether losses are a known quantity or calculated as the

3 The term *gross-up* refers to a method to scale up an item, such as resources or marginal energy costs. Gross-up factor refers to the factor that is multiplied by the item.

difference between generation and retail sales. Calculating transmission and distribution losses using the two different data sources yields different estimates of losses.

California Statewide Average Historical Transmission and Distribution Loss Calculations

Two Energy Commission sources of data used to calculate historical statewide losses are the *California Energy Demand 2010-2020 Adopted Forecast* and California Energy Almanac, *Electricity Generation by Resource Type 1997-2009*.[4] The data source for both demand and supply is information provided by utilities and balancing authorities through the Quarterly Fuel and Energy Reports that are compiled and published by Energy Commission staff.

California Energy Demand 2010-2020 Adopted Forecast provides historical retail sales data, and *Electricity Generation by Resource Type 1997-2009* provides historical data on California electrical energy generation. Adjustments were made to retail sales to add in small utility load that is not subject to reporting requirements and to generation data to subtract out self-generation. Self-generation is energy consumed onsite or by the entity that produced it, and this generation does not contribute to losses. **Table 2** provides an overview of average statewide historical losses between 2002 through 2008. Using this method and data, average statewide losses range from 5.4 percent to 6.9 percent.

The data on California electrical energy generation includes specified imports and unspecified imports. Specified imports are reported as California utilities' prorata share of the generation, so this amount includes losses. Unspecified imports are recorded by the four balancing authorities – California Independent System Operator (California ISO), Los Angeles Department of Water and Power (LADWP), Imperial Irrigation District (IID), and Sacramento Municipal Utility District (SMUD). The historical loss calculation includes some losses on imports, but as unspecified generation increases between 2002 and 2008, the inclusion of these losses on imports declines because unspecified imports exclude losses from the out-of-state generator to the border. By 2008, historical losses are primarily representative of losses within California.

Year-to-year losses vary with year-to-year generation services. In wetter years, California hydropower generation may account for a larger source of generation while out-of-state

4 Kavalec, Chris and Tom Gorin, 2009. *California Energy Demand 2010-2020, Adopted Forecast*. California Energy Commission. CEC-200-2009-012-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html]. The California Energy Almanac, *Electricity Generation by Resource Type 1997-2009* (Excel file), available at: [http://www.energyalmanac.ca.gov/electricity/index.html#table].

generation and other in-state fossil units may account for less, so losses would be generally lower in wetter years. Staff looked at historical California hydro generation between 2002 and 2008 and normalized the data by calculating the hydro generation as a percentage of the median hydro generation between 1970 and 2009. There is a negative correlation of about -0.77 (with 1.0 being perfect correlation) between this factor and losses. As hydro generation increases, losses decrease. This simple correlation is based only on seven years of data, so this is a rough estimation.

Table 2: California Historical Losses

Row	Item	2002	2003	2004	2005	2006	2007	2008
	Total Retail Sales (GWh)							
1	Total Retail Sales	243,826	249,677	259,013	259,525	268,009	273,431	274,746
2	Plus: Small CA load	1,700	1,700	1,700	1,700	1,700	1,700	1,700
3	Adjusted Total Retail Sales (Row 1+2)	245,526	251,377	260,713	261,225	269,709	275,131	276,446
4	**Total CA Generation Plus Net Imports (GWh)**							
5	Total CA Generation Plus Net Imports	274,101	279,571	289,682	288,806	297,022	304,148	306,813
6	Less: Self-Gen	10,509	11,483	10,594	10,970	11,853	11,266	10,576
7	Adjusted Total CA Generation (Row 5-6)	263,591	268,088	279,088	277,836	285,168	292,883	296,237
8	**Transmission and Distribution Losses**							
9	Losses (GWh)- (Row 7-3)	18,065	16,711	18,375	16,611	15,459	17,751	19,791
10	Losses (%)-(Row 9/7)	6.9%	6.2%	6.6%	6.0%	5.4%	6.1%	6.7%

Sources: Retail Sales is based on the *California Energy Demand 2010-2020 Adopted Forecast*, and generation data is based on the California Energy Almanac, *Electricity Generation by Resource Type 1997-2009*.

U.S. Energy Information Administration Historical Transmission and Distribution Losses

Each year, the U.S. Energy Information Administration (EIA) publishes a report, *The State Electricity Profiles 2008*, which presents a summary of state statistics. Data published in the *State Electricity Profiles* are compiled from five forms filed annually by electric utilities and other electric power producers.[5] In Table 10 of this report, "Supply and Disposition of

5 The five forms are: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor forms. U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report." U.S. Energy Information Administration, Form EIA-861, "Annual

Electricity, 1998 and 2002 Through 2008," EIA provides statistics for each state. The "Supply and Disposition of Electricity" includes information on losses, and EIA provided information on how to calculate losses based on these data. Staff used this information to calculate losses, which are presented in **Table 3**.

Table 3: EIA Data on Historical California Losses

	Million Kilowatt-hours	1998	2002	2003	2004	2005	2006	2007	2008
1	Total Disposition, Inc. Losses	268,285	261,557	279,680	286,525	284,599	298,510	302,067	310,311
2	Direct Use (Self-Gen.)	13,871	14,993	15,183	15,199	11,673	14,030	16,818	21,916
3	Net Energy For Load (Row 1-Row 2)	254,414	246,564	264,497	271,326	272,926	284,480	285,249	288,395
4	Losses	16,011	11,154	21,253	19,251	18,574	20,957	20,721	19,681
5	Losses (%) (Row 4/Row 3)	6.3%	4.5%	8.0%	7.1%	6.8%	7.4%	7.3%	6.8%

Note: Total disposition is composed of retail sales including direct use and losses. Estimated losses are reported at the utility level and then allocated to states based on the utility`s retail sales by state. Reported losses may include electricity unaccounted for by the utility. Direct use is commercial or industrial use of electricity that (1) is self-generated (2) is produced by either the same entity that consumes the power or an affiliate, and (3) is used in direct support of a service or industrial process located within the same facility or group of facilities that houses the generating equipment. Direct use is exclusive of station use.

Source: EIA, *The State Electricity Profiles 2008*, available at: [http://www.eia.doe.gov/cneaf/electricity/st_profiles/sep2008.pdf].

The method to calculate losses using EIA data is slightly different than the approach staff used to calculate California historical losses. In the EIA data, losses are a known, reported quantity, while losses are calculated as the difference between generation and retail sales data using Energy Commission data for retail sales and generation data. Losses can be defined either as (1) losses divided by total generation plus net interchange[6]; or (2) losses

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Electric Power Industry Report." DOE, Office of Electricity Delivery and Energy Reliability, Form OE-781R, "Annual Report of International Electric Export/Import Data," predecessor forms, and National Energy Board of Canada, and Federal Energy Regulatory Commission, FERC Form 423, "Monthly Cost and Quality of Fuels for Electric Plants."

6 Net interchange represents the power that is transferred between balancing authority areas and is defined as the difference of imports minus exports.

divided by total net energy for load. The EIA definition for net energy for load is defined as generation excluding self-generation, plus imports less exports. Net energy for load also can be a derived number from retail sales plus losses. The key point is that losses are included in the denominator in the calculation of losses. The denominator should represent the total amount of energy including losses needed to serve load.

Average statewide losses range from 4.5 percent to 8.0 percent using EIA's data and method. The historical losses for 2008 are similar between staff-calculated historical losses of 6.7 percent and EIA data of 6.8 percent. There are more variations between staff calculated losses and EIA data in other years. Data reporting issues could be driving some of these differences. For example, the losses in **Table 10** of the EIA report were revised for 2003, 2004, and 2005. The losses for 2002 appear low and could contain an error, but these losses were not revised. Furthermore, definitions of direct use or self-generation seem to vary between EIA data and the Energy Almanac. Staff did not attempt to reconcile these potential differences.

CHAPTER 3: Summary of Loss Values Used in Different Analyses

This chapter presents the wide range of loss factors that have been used in various California utility forums. **Table 4** presents peak and energy loss factors recently used for averages and by specific programs, such as energy efficiency, by the three investor-owned utilities (IOU) in California. Actual loss factors may vary by program, like in the *CPUC Scoping Memo Long-Term Procurement Proceeding*, but an average across all programs may be used like in the Energy Commission demand forecast. Some analyses include peak and energy loss factors while in other studies only a peak loss factor is used. Furthermore, average loss values are used in some analyses, while the values vary by program in others.

Table 4: Comparison of Loss Factors

	Energy Commission Demand Forecast		CPUC General Rate Case		CPUC Avoided Costs	CPUC Scoping Memo Long-Term Procurement Proceeding (LTPP)		
					Distributed Energy Resources, Demand Response	Energy Efficiency	Demand Response	Combined Heat and Power
	Peak	Energy	Peak	Energy	Peak	Peak	Peak	Peak
PG&E	1.097	1.096	1.101	1.109	1.109	1.097	1.119	1.077
SCE	1.076	1.068	1.098	1.081	1.084	1.076	1.112	1.077
SDG&E	1.096	1.0709	N/A	N/A	1.081	1.096	1.066	1.077

Sources: California Energy Commission, *California Energy Demand 2010-2020, Adopted Forecast;* Pacific Gas and Electric Company 1993 Test Year General Rate Case, Exhibit (PG&E-16), Chapter 4 Marginal Transmission and Distribution Capacity Costs, page 6-18; Southern California Edison, 2009 General Rate Case Application 08-03-002 (staff was unable to verify the original vintage of the data); CPUC avoided costs for distributed energy resources and demand response available at: [http://www.cpuc.ca.gov/NR/rdonlyres/786A98AC-9F92-4D8D-A071-6A8065944CCE/0/2011IOUDRProgramTotalsFinal728.xls] and [http://www.ethree.com/public_projects/cpucdr.html], see the Avoided Cost Calculator (10/18/2010) under the section, Distributed Generation Cost-Effectiveness Framework; and CPUC *Attachment I, Standardized Planning Assumptions (Part 1) for System Resource Plans* R.10-05-006, page 56, available at: [http://docs.cpuc.ca.gov/efile/RULC/127543.pdf].

The loss factor for combined heat and power in the CPUC's *Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling* for the 2011 Long-Term

Procurement Proceeding[7] is a California statewide average, and this loss factor for CHP represents losses as percentage of net energy for load, rather than a loss factor or "gross-up" factor. The loss factor for energy efficiency and demand response represent program gross - up factors.

Loss factors for PG&E range from 1.0834 (based on converting 7.7 percent losses to a loss factor) to 1.109 for peak losses. Loss factors for Southern California Edison range from 1.076 to 1.098 for peak losses. Loss factors for San Diego Gas & Electric range from 1.066 to 1.096 for peak losses. The difference between low and high values ranges from 0.02 to 0.03 depending on the utility.

The maximum peak loss factor by utility represents the maximum losses experienced by a utility during their peak hour. There is a presumption that during the peak hour a utility needs resources beyond its local resources to serve load, and the farther the distance the resource is from load, the higher the losses.

Loss factors vary across utilities because their infrastructure differs. Some loss factors may be used for shorter terms while others may be used for longer terms up to 10 years forward. Depending on the purpose, time of day, or season, loss factors may be used rather than a single peak and energy loss factor. This is especially true for the loss factors used in avoided costs. The specific programs will displace electricity, but the benefit of avoiding losses may vary depending on the time and location of program delivery to the grid. In other cases, the reasons for variations in loss factors are less clear. There may be a vintage issue based on the time loss factors are filed in one forum versus another forum. Further details of the losses used in each of the analyses and their applications are presented in the next section.

California Energy Commission Demand Forecast

The Energy Commission produces a 10-year California energy demand forecast in support of the biennial *Integrated Energy Policy Report* (*IEPR*). The forecast covers electricity and peak demand forecasts for each utility planning area in California and for the state as a whole. The Energy Commission uses an end-use model to produce its forecast of electricity consumption, which excludes transmission and distribution losses. In an effort to support systems analysis studies, the Energy Commission also produces net energy for load forecasts, which include these losses. The Energy Commission uses a loss factor to gross up its forecast of electricity consumption to produce net energy for load. The loss factors used

7 California Public Utilities Commission, *Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling*, Rulemaking 10-05-006, May 2010, available at: [http://docs.cpuc.ca.gov/efile/RULC/127542.pdf].

in the demand forecast could be viewed as forecast loss factors because they will be used to project demand. **Table 5** presents the loss factors and losses by utility service area used in the *2009 California Energy Demand 2010-2020, Adopted Forecast*.

Table 5: Forecast Loss Values

	Loss Factor		Losses	
	Peak	**Energy**	**Peak**	**Energy**
PG&E	1.097	1.096	8.84%	8.76%
SMUD	1.077	1.064	7.15%	6.02%
SCE	1.076	1.068	7.06%	6.37%
LADWP	1.112	1.135	10.07%	11.89%
SDG&E	1.096	1.0709	8.76%	6.62%
Burbank, Glendale, Pasadena	1.051	1.064	4.85%	6.02%
IID	1.060	1.128	5.66%	11.35%
Department of Water Resources	1.060	1.038	5.66%	3.66%

Source: California Energy Commission, *California Energy Demand 2010-2020, Adopted Forecast*.

These loss factors represent losses within the planning area, including unaccounted-for energy (UFE). In general, the losses from an out-of-state generator to the border of the planning area are not captured in this demand forecast. LADWP's balancing authority area is unique because its transmission system is far-reaching with 81 percent of its transmission assets outside the Los Angeles basin.[8] LADWP's loss factor tends to be higher than the others based on several factors: (1) its control area function of operating the Pacific DC Intertie between the Nevada-Oregon border and the Sylmar Converter station;[9] (2) it transforms its energy to 34.5 KV and 4.8 kV, which is lower than other utilities; (3) its

8 Los Angeles Department of Water and Power, *2010 Power Integrated Resource Plan, Appendix I, Transmission System.*

9 LADWP's control area is unique in that its boundary includes a fictitious point in the middle of the Pacific DC Intertie (PDCI), called the Nevada-Oregon Border (NOB). Normally there is a meter at every control area tie point with another control area. When the PDCI transmission line was built back in the early 1970s, LADWP and Bonneville Power Administration decided to make the control area boundary between the two utilities at this fictitious point. Since there are no meters at this point, LADWP estimates the DC losses between the Sylmar Converter station and NOB. They add these calculated PDCI losses to the Sylmar meters to transpose the interchange point from Sylmar to NOB.

balancing authority area includes several ties outside of California located in Utah, Arizona, Nevada, and at the Nevada-Oregon Border; and (4) losses from Intermountain Power generating station in Utah are included because it is within its balancing authority area.

UFE results when the sum of the loads within a given utility distribution company service territory does not equal the total energy supplied to that territory, after adjusting for imports, exports, and physical line losses in the distribution and transmission systems. UFE is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical load profile errors, and distribution loss deviations. Various types of errors can result in positive or negative UFE for any given hour.

These loss factors are based on older utility studies and have not been updated recently. The Energy Commission reviews the losses that the utilities file in their *IEPR* demand filings to support continued use of these loss factors, but in the next California Energy Demand forecast, Energy Commission staff plans to work with the utilities to update these loss factors. At the October 14, 2010, Staff Workshop on Electricity Demand Forecast Data Collection and Analysis, Energy Commission staff informed the utilities that staff would be looking at the loss factors in this next forecast and requested that the utilities provide detailed information on their loss method calculations. In addition, this issue was raised at the Demand Analysis Working Group at the CPUC on November 9, 2010. Utilities have begun to respond to the request for more information on the calculation of loss factors.

California Public Utilities Commission General Rate Cases

The general rate cases filed by the utilities at the CPUC include estimates for transmission and distribution loss factors. In general, the IOUs submit loss factors from each of several locations on the transmission and distribution grid in the rate cases. Utilities incur costs from transmission and distribution losses and expect to recover these costs. Customers are provided service at different points on the distribution system, which will correspond to different losses. Utilities may record and estimate losses at four levels of service: (1) transmission, (2) subtransmission, (3) primary distribution, and (4) secondary distribution. The diagram in **Figure 2** shows where these levels of service occur along the transmission and distribution system.

PG&E described how it uses line loss factors in computing its marginal energy costs (MEC) in its general rate case: [10]

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10 Pacific Gas and Electric Company, *2011 General Rate Case Phase 2 June 30, 2010 Update to Prepared Testimony and Revisions for Testimony Moved to 2011 GRC Phase 3 Exhibit (PG&E-9) Marginal Cost*, A.10-

PG&E estimated the MEC at each voltage level for each TOU [Time Of Use] *period by using the simple average of the hourly MECs during that period, grossed up by a factor that accounted for expected electricity line losses. The line loss adjustment is necessary because the total amount of energy that PG&E procures must be equal to the sum of (1) the marginal energy demanded by customers, plus (2) the amount of energy that will normally be lost in the system due to line losses.*

Table 6 and **Table 7** summarize the loss factors from the utility general rate cases for PG&E and SCE, respectively.

Table 6: PG&E 1993 General Rate Case Application Loss Adjustment Factors

(Cumulative)	Capacity	Energy					
		Summer Peak	Summer Shoulder	Summer Off-Peak	Winter Shoulder	Winter Off-Peak	Annual
Transmission Loss Factor	1.038	1.024	1.010	1.012	1.012	1.017	1.014
Primary Loss Factor	1.08	1.058	1.043	1.037	1.039	1.040	1.041
Secondary Loss Factor	1.101	1.109	1.073	1.057	1.089	1.060	1.07

Note: Fewer time-of-day periods are reported during the winter because there is less hourly variation than during the summer.
Definition of Time Periods: SUMMER Period A (Service from May 1 through October 31):
Summer Peak: 12:00 noon to 6:00 p.m. Monday through Friday (except holidays)
Summer Partial peak: 8:30 a.m. to 12:00 noon Monday through AND 6:00 p.m. to 9:30 p.m. Friday (except holidays)
Summer Off peak: 9:30 p.m. to 8:30 a.m. Monday through Friday, All day Saturday, Sunday, and holidays
WINTER Period B (service from November 1 through April 30):
Winter Partial Peak: 8:30 a.m. to 9:30 p.m. Monday through Friday (except holidays)
Winter Off Peak: 9:30 p.m. to 8:30 a.m. Monday through Friday (except holidays), All day Saturday, Sunday, and holidays.
HOLIDAYS: Holidays for the purposes of this rate schedule are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

Source: *Pacific Gas and Electric Company 1993 Test Year General Rate Case Workpapers Application Exhibit (PG&E-16), Chapter 4 Marginal Transmission and Distribution Capacity Costs*, page 6-18. This document was provided by PG&E and is the original source of loss factors referenced in subsequent General Rate Cases.

03-014, available at: [https://www.pge.com/regulation/GRC2011-Ph-II/Testimony/PGE/2010/GRC2011-Ph-II_Test_PGE_20100813_197769.pdf].

Table 7: SCE General Rate Case, Time-of-Use Loss Factors Energy (cumulative)

Season	Time of Use Period	Number of Hours	Transmission	Subtransmission	Primary	Secondary
Annual	All	8760	1.01707	1.02738	1.05667	1.08055
	On-Peak	498	1.01885	1.03065	1.06664	1.09029
	Mid-Peak	2957	1.01754	1.02841	1.05951	1.08297
	Off-Peak	5305	1.01643	1.02638	1.05342	1.07719
Summer	All	2856	1.01777	1.02855	1.06023	1.08440
	On-Peak	498	1.01885	1.03065	1.06664	1.09029
	Mid-Peak	747	1.01816	1.02946	1.06282	1.08641
	Off-Peak	1611	1.01701	1.02733	1.05624	1.08042
Winter	ALL	5904	1.01666	1.02678	1.05471	1.07817
	MID-PEAK	2210	1.01730	1.02804	1.05829	1.08156
	OFF-PEAK	3694	1.01613	1.02594	1.05202	1.07547

Note: Staff was unable to verify the original vintage of the data. Staff believes the original source of the data may be from loss studies done in the early 1990's. Staff was able to verify that the annual values for all hours for energy and demand are the same values reported in the 2009 General Rate Case.

Source: Southern California Edison, 2009 General Rate Case, Application 08-03-002.

Table 7: (Continued) Demand (Cumulative)

Season	Time of Use Period	Number of Hours	Transmission	Subtransmission	Primary	Secondary
Annual	All	8760	1.02004	1.03282	1.07445	1.09788
	On-Peak	498	1.02004	1.03282	1.07445	1.09788
	Mid-Peak	2957	1.01988	1.03253	1.07345	1.09687
	Off-Peak	5305	1.01986	1.03252	1.07310	1.09651
Summer	All	2856	1.02004	1.03282	1.07445	1.09788
	On-Peak	498	1.02004	1.03282	1.07445	1.09788
	Mid-Peak	747	1.01988	1.03253	1.07345	1.09687
	Off-Peak	1611	1.01986	1.03252	1.07310	1.09651
Winter	ALL	5904	1.01880	1.03067	1.06669	1.09000
	MID-PEAK	2210	1.01880	1.03067	1.06654	1.08985
	OFF-PEAK	3694	1.01878	1.03063	1.06669	1.09000

Note: Staff was unable to verify the original vintage of the data. Staff believes the original source of the data may be from loss studies done in the early 1990s. Staff was able to verify that the annual values for all hours for energy and demand are the same values reported in the 2009 General Rate Case.

Source: Southern California Edison, 2009 General Rate Case, Application 08-03-002.

California Air Resources Board

In the California Air Resources Board (ARB) *Climate Change Scoping Plan*[11], the definition for statewide greenhouse gas emissions "means the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in California, accounting for transmission and distribution line losses, whether the electricity is generated in state or imported. Statewide emissions shall be expressed in tons of carbon dioxide equivalents." ARB evaluated the potential costs and emissions reductions from meeting the recommended targets and the expanded targets.

11 California Air Resources Board, *Climate Change Scoping Plan* and *Climate Change Scoping Plan Appendices*, December 2008, available at: [http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm].

In calculating the emission reductions, ARB accounts for the avoided line losses by assuming a 7.8 percent avoided line loss for in-state electricity saved. This line loss is used in calculating the additional savings associated with programs through the avoided line losses for CHP, photovoltaic solar, energy efficiency, and the renewables programs.[12] ARB uses the following formula to calculate avoided line losses:

$$\text{Avoided Line Loss} = \frac{X}{1-0.078} - X\text{, Where } X \text{ is the Reduced Grid Demand}$$

This formula uses the same method presented earlier to convert losses into a loss factor and then estimate the additional energy that would have been needed to overcome line losses. Using the formula to convert loss rate into a loss factor, losses of 7.8 percent equals a loss factor of 1.08460.

The source of ARB's assumption is the Energy Commission *California Energy Demand 2008-2018 Staff Revised Forecast.*[13] ARB staff used Form 1.2 Statewide California Energy Demand 2008-2018 of this forecast to calculate in-state California losses. Staff members used 7.8 percent since losses were 7.8 percent between 1990-2018 except for four years where it was 7.9 percent (1991, 1993, 1995, and 1998). The focus of the *Climate Change Scoping Plan* was on the baseline years of 2002-2004 and the future of 2020. The losses were 7.8 percent in those years with 2018 being used as a proxy for 2020.

ARB staff had to estimate the losses associated with unspecified imported power for its historical inventory accounting. The imports are counted on an "as received" basis to the balancing authority, which would exclude the line losses from the out-of-state generator to the border. A line loss factor is used to determine the generated power at the source plant required to deliver that amount of power to the border. As described in the next paragraph, ARB assumed an additional 7.5 percent line loss from the point of generation to the state line. As a result, unspecified imports were assigned a total of about 15.3 percent losses from the point of generation to the point of final end use in the state. For specified imports, ARB used the actual plant generation and utility ownership share in its inventory accounting, so an incremental line loss is not used for specified imports.

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12 Though ARB indicates in Footnote 37 that 7 percent avoided line losses are applied to CHP, ARB actually used 7.8 percent to account for avoided line losses from electricity savings. The detailed savings are defined in Appendices Volume 2 on page I-28 of the *Climate Change Scoping Plan*, which confirm losses of 7.8 percent.

13 Marshall, Lynn and Tom Gorin, 2007. *California Energy Demand 2008-2018, Staff Revised Forecast*. California Energy Commission. CEC-200-2007-015-SF2, available at: [http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF].

Import losses are based on the distance from an out-of-state generator to the border. ARB staff had data for three specified out-of-state coal plants. Colstrip in Montana and Hunter in Utah both reported line losses of 7.5 percent from the generator to the border, and Bonanza in Utah reported at 3 percent. ARB used these out-of-state generators as a basis for its estimate of 7.5 percent.[14]

ARB adopted regulations for mandatory reporting stating that the regulations must account for greenhouse emissions from all electricity consumed in the state, including transmission and distribution line losses from electricity generated within the state or imported from outside the state. Utility contracts with out-of-state generators may require firm delivery to the border, which means the sellers are responsible for the power losses from the generator to the border. However, under the Global Warming Solutions Act of 2006, Assembly Bill 32, (Núñez, Chapter 488, Statutes of 2006) guidelines, the emissions associated with these losses are the responsibility of the California utility that imported the power. Importers are required to report their line losses in the 2009 update of the mandatory reporting to ARB and for all years after that.

California Public Utilities Commission Resource Adequacy Proceeding

In Decision 10-06-036, the CPUC adopted a method to gross up the qualifying capacity of dispatchable demand response (DR) resources for avoided line losses.[15] All parties agreed that the load forecast used in resource adequacy (RA) includes transmission and distribution (T&D) losses. The CPUC agreed with SCE and The Utility Reform Network in that DR resources provide a means of balancing supply and demand without accruing line losses because the resource is supplied at the customer meter level. The adopted formula is:

DR RA Value = 1.15 * DR Load Impact * (1.00/(1.00 – T&D Line Loss Rate))
where, T&D Line Loss Rate = 3% + IOU-specific Distribution Loss Rate and
where Distribution Loss Rate = $\dfrac{\text{Transmission Loss Factor}}{\text{Secondary Distribution Loss Factor}}$

14 The information on the losses used in the ARB *Climate Change Scoping Plan* and inventory reporting is based on information provided by Larry Hunsaker of ARB on November 8-9, 2010.

15 CPUC, *Decision Adopting Local Procurement Obligations for 2011 and Further Refining the Resource Adequacy Program*, D. 10-06-036, Section 4.2.5.2, page 38, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/119856.htm].

The ratio of the transmission loss factor to the secondary distribution loss factor yields the loss rate for subtransmission and distribution, which is called the distribution loss rate.

D.06-07-031[16] adopted a simplifying 3 percent transmission loss factor and D.05-10-042[17] adopted utility-specific distribution loss factors. Resources located out-of-state and in-state near the load avoid the same amount of transmission losses of 3 percent according to this simplifying assumption. The CPUC adopted the simplifying assumption of 3 percent because of the administrative complexity of adopting an alternate method to evaluate losses for each resource. The demand response capacity is further scaled up by 15 percent to capture the avoided planning reserve requirement. As demand-side resources, DR reduces peak loads and planning reserves requirements such that the reduction of a single kilowatt (kW) during peak results in a reduction in net supply requirements of 1.15 kW.

Further clarification is made to the formula regarding the IOU-specific distribution loss factors. SCE and SDG&E file cumulative average loss factors, while PG&E files non-cumulative marginal loss factors for primary and secondary distribution levels. This makes the formula for calculating the distribution loss factors slightly different between the utilities.

Table 8 shows the estimated T&D loss factors calculated by CPUC staff per D.10-06-036:

Table 8: Estimated Loss Factors to Gross-Up Demand Response in Resource Adequacy

	On-Peak T&D Losses	On-Peak T&D Loss Factor
SCE	10.1%	1.112
SDG&E	6.2%	1.066
PG&E	10.6%	1.119

Source: CPUC worksheet to gross up demand response values for resource adequacy, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/786A98AC-9F92-4D8D-A071-6A8065944CCE/0/2011IOUDRProgramTotalsFinal728.xls].

CPUC staff calculated the on-peak T&D gross-up factor, and Energy Commission staff converted that data into an on-peak T&D loss rate using the conversion formula presented earlier. A loss rate of 10.1 percent used in the formula for calculating the final qualifying

16 CPUC, *Opinion on Remaining Phase 1 Issues,* D.06-07-031, July 2006, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/58320.htm].

17 CPUC, *Opinion on Resource Adequacy Requirements*, D.05-10-042, October 2005, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/50731.htm].

capacity of demand response produces a gross-up factor of 1.112 (that is, 1.112 = 1/(1 - 10.1 percent). This gross-up factor is multiplied by the average *ex ante* load impact to get the total impact from the program including losses.

California Public Utilities Commission Program Cost-Effectiveness

The CPUC developed cost-effectiveness protocols to evaluate utility distributed energy resource programs, such as the California Solar Initiative, distributed generation, demand response, and energy efficiency. One of the protocols is the avoided cost calculation, which calculates the cost of the electricity that would have been used without the program. One of the input assumptions in the avoided cost calculation is transmission and distribution loss factors. The loss factor used in the avoided cost calculation is a scaling factor used to scale the value of generation energy and capacity and emission costs to account for avoided losses. The loss factor used in this context is similar to the loss factor used by PG&E in its general rate case to scale marginal energy costs.

The avoided cost for distributed generation adopted by the CPUC in D. 09-08-026 is calculated as the sum of six components, presented in **Table 9**. The utility avoided cost value is calculated as the sum in each hour of these six components.

Table 9: Avoided Cost Components

Component	Description
Generation Energy	Estimate of hourly wholesale value of energy measured at the point of wholesale energy transaction.
System Capacity	The costs of building new generation capacity to meet system peak loads.
Ancillary Services	The marginal costs of providing system operations and reserves for electricity grid reliability.
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads.
Environment	The cost of carbon dioxide emissions (CO^2) associated with the marginal generating resource electricity generation.
Avoided Renewables Portfolio Standard	The avoided net cost of purchasing procuring renewable resources to meet an RPS Portfolio that is a percentage of total retail sales due to a reduction in retail loads.

Source: E3, *Appendix A: Methodology for Determining Utility Avoided Cost* in D.09-08-026, available at: [http://www.ethree.com/public_projects/cpucdr.html].

Though this decision broadly applies to distributed generation, the focus of the decision was on the California Solar Initiative and the Self-Generation Incentive Program. Loss factors are used in the calculation of generation energy, system capacity, T&D capacity, and environment components. No losses are included in the ancillary services or avoided renewable portfolio standard components.

E3 developed a calculator to calculate the avoided costs for distributed generation.[18] The avoided cost method captures time- and location-based variations in the value of electricity production. **Table 10** provides the input assumptions for the marginal energy loss factors by time of use, season, and utility. These loss factors represent energy losses from the generator to the retail delivery point, including transmission and distribution losses. These energy losses are used in the generation energy, system capacity, and environment components of the avoided cost calculation.

Table 10: Distributed Energy Resources Marginal Energy Loss Factors by Time-of-Use Period and Utility

Time of Use	Description	PG&E	SCE	SDG&E
1	Summer Peak	1.109	1.084	1.081
2	Summer Shoulder	1.073	1.080	1.077
3	Summer Off-Peak	1.057	1.073	1.068
4	Winter Peak	-	-	1.083
5	Winter Shoulder	1.090	1.077	1.076
6	Winter Off-Peak	1.061	1.070	1.068

Source: E3, available at: [http://www.ethree.com/public_projects/cpucdr.html], see the Avoided Cost Calculator (12/15/2010) under the section, Distributed Generation Cost-effectiveness Framework.

Table 11 presents the loss factors used in the T&D capacity component of the avoided cost calculation. The demand response capacity effect at the customer meter is scaled up by the transmission and distribution peak loss factor to represent the load reduction at the transmission level. Transmission peak and distribution peak are input as cumulative loss factors from the designated level to the customer. Transmission peak represent losses from transmission and distribution voltage levels to the retail delivery point, and distribution includes only distribution losses.

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18 E3, available at: [http://www.ethree.com/public_projects/cpucdr.html], see the Avoided Cost Calculator (12/15/2010) under the section, Distributed Generation Cost-Effectiveness Framework. E3 has indicated that the loss factors were obtained from: PG&E 1996 General Rate Case, SCE 1995 General Rate Case, and SDG&E 2004 Rate Design Window.

Table 11: Distributed Energy Resources Loss Factors for Transmission and Distribution Capacity

Description	PG&E	SCE	SDG&E
Transmission Peak	1.083	1.054	1.071
Distribution Peak	1.048	1.022	1.043

Source: E3, *Appendix A: Methodology for Determining Utility Avoided Cost* in D.09-08-026, available at: [http://www.ethree.com/public_projects/cpucdr.html], see revised DG cost effectiveness framework avoided cost methodology description under the section, Distributed Generation Cost Effectiveness Framework.

Demand Response

On November 2, 2010, the CPUC held a workshop to discuss the cost-effectiveness protocols for demand response (R.07-01-014). E3 worked with the CPUC to develop a standardized demand response template to calculate the avoided costs of demand response. This template is largely based on prior work of E3 in developing avoided cost calculators.[19] The line losses represent the additional costs resulting from line losses between the point of generation and the point of retail delivery at the system peak. The loss factors that pertain to demand response are on-peak loss factors since demand response primarily affects the peak periods. The utility-provided input assumptions for the loss factors defined in this template are presented in **Table 12**. The demand response-avoided cost-loss factors are the same as those used in the cost-effectiveness calculation for distributed energy resources.

Table 12: Demand Response Avoided Cost Loss Factors

	On-Peak Avoided Cost Loss Factor		
	Generation	Transmission & Distribution	Distribution
PG&E	1.109	1.083	1.048
SCE	1.084	1.054	1.022
SDG&E	1.081	1.071	1.043

Note: The demand response template has input for losses, and staff converted the losses into loss factors for comparison.

Source: CPUC, demand response reporting template May 2011, available at: [http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm].

19 E3's cost-effectiveness framework has been used to evaluate distributed energy resources, like the California Solar Initiative and Self-Generation Incentive Program, adopted by the CPUC in D.09-08-026. A similar framework is also being considered in evaluating the cost-effectiveness of demand response in R.07-01-014 and in evaluating the cost-effectiveness of permanent load shifting.

California Public Utilities Commission Scoping Memo for 2011 Long-Term Procurement Proceeding

The CPUC *Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling* (*Scoping Memo*) for the 2011 Long-Term Procurement Proceeding (LTPP) provides a set of guidelines that the IOUs should follow in preparing their LTPP plans. The CPUC's goal is to ensure a reliable and cost-effective electricity supply in California through integration and refinement of a comprehensive set of procurement policies, practices, and procedures underlying long-term procurement proceedings, and to provide the appropriate forum in which to consider the CPUC's electric resource procurement policies and programs and how to implement them.

The *Scoping Memo* includes a set of line loss factors that should be used to gross up program savings for avoided line losses. **Table 13** presents the line loss factors in the *Scoping Memo* for energy efficiency, demand response, and CHP. Different loss factors are used for each program with different sources of data.

Table 13: CPUC Scoping Memo, Line Loss Factors

	Line Loss Factors		
	Energy Efficiency	**Demand Response**	**CHP**
North	9.7%	11.9%	7.7%
South	7.6%	11.2%	7.7%
San Diego	9.6%	6.6%	7.7%

Source: CPUC *Attachment I, Standardized Planning Assumptions (Part 1) for System Resource Plans* R.10-05-006, page 56, available at: [http://docs.cpuc.ca.gov/efile/RULC/127543.pdf].
Original source of data: Energy Efficiency – *California Energy Demand 2010-2020*, page 50. Demand Response – [http://www.cpuc.ca.gov/NR/rdonlyres/786A98AC-9F92-4D8D-A071-6A8065944CCE/0/2011IOUDRProgramTotalsFinal728.xls], CHP - ARB *Climate Change Scoping Plan*, December 2008, footnote 37, available at: [http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm].

The basis for the energy efficiency loss factors is the Energy Commission demand forecast. The basis for the demand response loss factors is CPUC resource adequacy, D.10-06-036. The basis for the CHP loss factors is ARB's *Climate Change Scoping Plan*, which is based on the Energy Commission *California Energy Demand 2008-2018 Staff Revised Forecast*. The loss factors for energy efficiency and demand response are gross-up factors, but the loss factor for CHP is losses (loss rate) as a percentage of net energy for load. As defined earlier in this paper, losses (loss rate) and loss factor are different metrics.

Footnote 37 in the ARB *Climate Change Scoping Plan* states avoided transmission line losses of 7 percent are applied to CHP. A line loss of 7 percent equals a loss factor of 1.075269. A loss factor of 1.075269 applied to the program savings will give the total savings including line losses. As mentioned earlier, Footnote 37 contains an error, and ARB used 7.8 percent line losses. The detailed calculations in Appendices Volume 2, page I28, show that line losses of 7.8 percent are used to calculate avoided line losses. A line loss of 7.8 percent equals a loss factor of 1.084599 (or 8.4599 percent). The loss factor for CHP in the CPUC *Scoping Memo* represents losses or loss rate as a fraction of net energy for load and not a gross-up factor.

Western Climate Initiative

The Western Climate Initiative (WCI) is a collaboration of independent jurisdictions who commit to work together to identify, evaluate, and implement policies to tackle climate change at a regional level. Other U.S. states, Canadian provinces, Mexican states, and tribes that are interested in collaborating to combat climate change at a regional level are encouraged to participate in the WCI as either members or observers. One of WCI's goals is to create a greenhouse gas emissions market within a job-creating green economy among the partner states and provinces, built on a strong foundation of reported emissions data. In October 2010, the WCI published updated default emission calculators for 2006, 2007, and 2008. The final calculators are available for download from the WCI website (www.westernclimateinitiative.org) and are intended for use by jurisdictions in attributing emissions to unspecified electricity imports.

In these calculators, the user can change the transmission loss factor, but the default setting is 2 percent. This variable represents the assumed transmission loss rate between the point of generation and the point of receipt where the first jurisdictional deliverer receives electricity. In the calculator, the variable is called the transmission loss factor, but it represents losses as a percentage of net energy.[20] There is no citable source for the default transmission loss factor, but it was based on discussions between staff at the Energy Commission and CPUC Energy Division, and stakeholders at a WCI Electricity Team meeting.

ARB has worked closely with WCI, and the WCI calculator is referenced in ARB's *Staff Report: Initial Statement of Reasons for Rulemaking Revisions to the Regulation for Mandatory Reporting of Greenhouse Gas Emissions Pursuant to the California Global Warming Solutions Act of 2006 Assembly Bill 32*, October 2010.[21] In this staff report, ARB presents proposed revisions to the California regulation for the mandatory reporting of greenhouse gas (GHG) emissions. The proposed revision to the regulation is necessary to support a California GHG cap-and-

20 In the WCI calculator, the emission factor is scaled up by transmission losses. The transmission loss of 2 percent converts to a transmission loss factor of 1.020408 or 1.020 if rounded to three significant digits. The emission factor is multiplied by 1/(1-0.02) or 1.020408 to include losses.

21Available at: [http://www.arb.ca.gov/regact/2010/ghg2010/ghgisor.pdf].

trade program and to harmonize with the U.S. Environmental Protection Agency federal mandatory GHG reporting requirements. ARB staff indicated that it collaborated with colleagues in other states and provinces participating in the WCI, to carefully review the U.S. EPA regulation and develop harmonized calculation and reporting requirements. These proposed requirements include targeted modifications and enhancements to the U.S. EPA rule that are necessary to fully support a cap-and-trade program.

The WCI calculator will be used to calculate GHG emissions from unspecified sources of imported electricity. A 2 percent transmission loss factor is established to meet the requirement in AB 32 to include line losses when they are not already included in reported deliveries or made up from generation sources located in California. Transmission losses are used in the default emission factor to scale up the emission factor by losses. Transmission losses of 2 percent are used to calculate GHG emissions from unspecified sources. The default emission factor for electricity from unspecified sources will be recalculated using the Final WCI Default Emission Factor Calculator created by CPUC staff, vetted through the WCI Electricity Team, and adopted by the WCI Partners.

Other

The Energy Commission collects data on electricity resource plans and supply data from load-serving entities to support the *IEPR*. Load-serving entities in California are asked to submit plans showing how demand for energy and annual peak load will be met by specific supply resources. To support the *2007 IEPR*, the City of Vernon Light and Power Department submitted its demand forecast for 2007, planning reserve margin and qualifying capacity criteria. In its filing, Item 6 in the Section on Qualifying Capacity states:

> *System Resources (imports) and other sources of generation outside of Vernon's MSS [Metered Subsystem Area]*[22] *area that are scheduled to meet Vernon's load incur losses. To reflect and account for the losses outside of Vernon's MSS area the Qualifying Capacity shall be reduced by the following amount in contribution of the losses that are experienced outside of Vernon's MSS.*

- *3.8% for Hoover*

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22 A metered subsystem area (MSS) is a geographically contiguous system located within a zone that has been operating as an electric utility within the California ISO Control Area. It is encompassed by California ISO-certified revenue quality meters at each interface point with the California ISO-Controlled Grid and has California ISO-certified revenue quality meters on all generating units, or, if aggregated, each resource and participating load internal to the system. The metered subsystem operates in accordance with an MSS Agreement.

- *3.7% for Palo Verde*
- *3.75% for all other imports*
- *2% for any other Qualifying Capacity outside of Vernon's MSS area.*

Such reductions for imports shall not be applied to any Qualifying Capacity scheduled to be delivered to the point of interconnection with Vernon's MSS area on a firm basis.

Vernon's filing explicitly included loss estimates for imports from the out-of-state generator to its MSS area that should be used in the qualifying capacity calculation. This section is to reduce qualifying capacity outside Vernon's area to account for losses. This item specifically addresses contracts for imports at the generator busbar. The qualifying capacity of the generator is reduced by the losses from the generator busbar to the MSS area. If the contract for imports requires firm delivery to Vernon's MSS area, then the import is not reduced by losses. A generic loss of 3.75 percent applies to out-of-state imports other than Hoover and Palo Verde, and a generic loss of 2 percent applies to capacity outside Vernon's MSS area but within the California ISO footprint. The difference of 1.75 percent between these two loss estimates can be viewed as an estimate of losses from the out-of-state generator to the California ISO border.

CHAPTER 4: Data Issues

Lack of Data on Import Losses

Public sources of load data include the Energy Commission demand forecast and Federal Energy Regulatory Commission (FERC) Form 714 load data. The load data includes losses, but only within the balancing authorities. In general, losses related to power imported from outside the balancing authority, from the point of the out-of-state generator to the border, are not included. If the balancing authority has physical control of an out-of-state generator, then its generation and losses are included within the filings.

In support of the *2011 IEPR*, the Energy Commission collects data requesting electricity demand forecasts, demand-side management impacts, as well as energy efficiency and private supply impacts from uncommitted new or expanded programs to achieve broad goals established by regulatory agencies, and related information from all California load-serving entities with annual peak demand greater than 200 megawatts. The data collected by the Energy Commission includes losses. The Energy Commission forecasts retail sales and then applies a loss factor to gross up retail sales to net energy for load. One use of these forecasts will be to provide a basis for resource assessments, so total consumption at the end-user level must be adjusted by losses to reflect total usage at the generation level. The loss factor represents losses within the utility distribution company's service territory and excludes the losses outside its territory.

The Energy Commission forecast of net energy for load excludes losses on imported power from the out-of-state generator to the border, except it includes losses on imported power for LADWP. LADWP's loss factor includes losses on the Pacific DC Intertie between the Pacific Northwest and LADWP, losses from Intermountain Power Project, losses from their out-of-state interties in Utah, Arizona, Nevada, and the Nevada-Oregon border.

The FERC Form 714 collects information from electric utility balancing authority and planning areas in the United States. The data is used to obtain a broad picture of interconnected balancing authority area operations including comprehensive information of balancing authority area generation, actual and scheduled interbalancing authority area power transfers, and load. The data is also used to prepare status reports on the electric utility industry, including review of inter-balancing authority area bulk power trade information.[23]

23 FERC Form 714 instructions.

FERC Form 714 load data is a public data source that covers the other areas within the WECC, outside of California. This data is similar to the Energy Commission demand forecast in that losses only within the utility balancing authority are reported. Losses on imported power from the out-of-state generator to the border are not captured. Energy Commission staff contacted FERC staff to find out how losses on imports are handled, and FERC staff indicated that there seem to be many different ways this is handled by all of the different regions across the country. FERC provided information on how losses are handled within the California ISO balancing authority.

Losses associated with California ISO grid use, occurring within their balancing authority area metered perimeter, are financially settled in their market settlement and handled with locational marginal pricing, which includes a component for marginal losses. Losses from an import to or an export from the California ISO, incurred by *purchasing-selling entities*[24] using an external transmission operator's transmission system along the electronic tags; (e-tags)[25] physical path, are repaid using tagged transactions between the two parties, the purchasing selling entity and the transmission operator, independent of the California ISO import or export tag or interchange schedule. Losses are generally "scheduled back" on independent e-tags between the purchasing selling entity and transmission operator in the West. California ISO tracks imports to and exports from its balancing authority area metered perimeter, but it does not track the losses associated with these imports or exports because the losses occurred outside their system. The losses on these imports and exports are handled as a bilateral agreement between the purchasing selling entity and transmission operator, and how losses are handled may be prescribed in the contractual agreement between the parties.

WECC tagging protocols indicate that physical losses within WECC are tagged on a separate e-tag and that tag creation for losses will be the responsibility of the transmission contract holder. E-tags may provide a source for losses, but the information is confidential. The CPUC and WCI obtained data on e-tags to determine the source of power to California. It seems that a similar effort can be made to determine the losses on these imports to California. However, there is some concern about the reporting of the data on the e-tags. Some parties may include the losses along with the energy on one tag, rather than a separate tag for losses. There is not a mechanism to track the losses scheduled back to ensure that

24 A purchasing-selling entity is an entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-selling entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.

25 NERC electronic tagging was implemented in September 1999 to promote increased volumes of wholesale power transactions and to track the physical exchange of power from source to sink.

they match the actual losses. This could cause some accounting issues for calculating losses. Another concern is that the data is confidential.

Power Purchase Agreements

Line losses may or may not be available in power purchase agreements. The power purchase agreements between the out-of-state generator and a California utility may contain provisions to deal with losses, and many of these contracts may call for firm delivery to the border. The utilities may buy supply from an out-of-state generator, where the generation is delivered and the net flow metered at the control area/California ISO area boundary. As a result, the out-of-state generator absorbs the losses to get the generation from the source to the border. The California utility may not know what the actual losses are because the contract calls for firm delivery to the border.

The Edison Electric Institute Master Power Purchase Agreement template[26] contains language about transmission and scheduling:

> <u>*Transmission and Scheduling*</u>*: Seller shall arrange and be responsible for transmission service to the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers, as specified by the Parties in the Transaction, or in the absence thereof, in accordance with the practice of Transmission Providers, to deliver the product to the Delivery Point. Buyer shall arrange and be responsible for delivery service at and from the Delivery Point and shall schedule or arrange for Scheduling services with its Transmission Providers to receive the product at the Delivery Point.*

The delivery point is the point at which the product will be delivered and received, which also delineates who absorbs the losses before to the delivery point and after the delivery point. Contracts that call for firm delivery to the California ISO border indicate that the seller will handle and absorb the losses on the imported power. Though the seller may cover the power losses, under AB 32, the California utility procuring the resource is responsible for any greenhouse gasses associated with the losses.

California utilities are entering into power purchase agreements for out-of-state renewables. These contracts must meet certain deliverability requirements to count toward the

26 The Edison Electric Institute Master Power Purchase Agreement template is available at: [http://www.eei.org/ourissues/ElectricityGeneration/Documents/contract0004.pdf].

Renewables Portfolio Standard (RPS). PG&E's contract with Vantage Wind Energy, LLC[27], in the Pacific Northwest calls for delivery at the project busbar. PG&E contracts with a third-party provider, such as Powerex, to provide firming and shaping services for its Northwest RPS busbar transactions, so that the energy will be deliverable and count toward its RPS requirements. The energy PG&E receives at the project busbar will be moved into the Bonneville Power Administration control area, so that the power can then be firmed and shaped. An equivalent amount of firm power will then be delivered to California ISO territory. The firming and shaping contract calls for an equivalent amount of firm power to be delivered to the border. Since an equivalent amount of firm power is to be delivered to the border, this implies that any losses from the project busbar to the border are handled by the provider of the firming and shaping services. Losses will be incurred from the project busbar to the border, so the firming and shaping contract may contain provisions to deal with the losses.

Utility contracts may contain information on losses related to imports, but these contracts are confidential. Even if the seller or a provider of firming and shaping services absorbs the losses, the California utility is still responsible for any GHG associated with the losses. In the future, tracking of losses related to out-of-state power will be important for the utility and for ARB.

27 Information on PG&E's contract with Vantage Wind Energy is available at: [http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_3525-E.pdf] and [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_RESOLUTION/117009.htm].

CHAPTER 5: Next Steps

Energy Commission staff reviewed the transmission and distribution loss values used by the Energy Commission, CPUC, and ARB. The source of some of these values appears to be data that has not been updated in quite some time. The vintage of the loss factors used by the Energy Commission is not known, but they are at least nine years old. The loss factors used in the general rate cases are based on older studies from the 1990s. Staff proposes the following steps to improve consistency of the values in circulation:

- Utilities use common data/loss studies to provide consistent loss factors to the Energy Commission and CPUC.
- Consistency in loss assumptions are used within analyses.
- Energy Commission demand forms and instructions are revised to require utilities to provide separate loss estimates for imports.

Utilities Use Common Data/Loss Studies to Provide Consistent Loss Factors to the Energy Commission and CPUC

Current loss factors in use by the Energy Commission and CPUC appear to be based on older data or studies. The exact factor to use may not be as critical as consistency. The utilities submit losses to the Energy Commission as part of the energy demand forecast forms and instructions, and they provide loss factors as part of their general rate case filings. There should be consistency in the data submitted to the two agencies.

The peak and energy losses submitted by the utilities to the Energy Commission and to the CPUC should be based on common data. The CPUC may require more granularities of losses, such as by time of day or season, than the Energy Commission, but the losses should be based on common data/loss studies.

Consistency in Loss Assumptions Used Within Analyses

The Energy Commission demand forecast contains embedded loss factors in its forecast of net energy for load. These same loss factors should be used to calculate avoided losses for demand-side and other resources, if the Energy Commission demand forecast is used in the analysis. For example, the Energy Commission's Electricity Analysis Office performs WECC system analyses and needs to include avoided losses for energy efficiency, photovoltaic Solar, and combined heat and power. These analyses use the Energy Commission demand forecast and, therefore, should use the loss factors embedded in the demand forecast to calculate the avoided losses. This ensures consistency in loss assumptions.

The CPUC *Scoping Memo* on LTPP provides three sets of loss factors, depending on the program, to use to calculate avoided losses at peak hour. Two of the sets of loss factors are based on the Energy Commission demand forecast, while the third set is based on CPUC D.10-06-036 regarding demand response. One of the common set of assumptions in the LTPP is the Energy Commission demand forecast. Energy Commission staff supports use of the loss factors from the Energy Commission demand forecast to calculate avoided loss savings. This ensures consistency in loss assumptions within the analysis. If a higher loss factor is used for demand response, the program would receive more credit for avoided losses than the losses embedded in the demand forecast.

Energy Commission Demand Forms and Instructions Revised to Require Utilities to Provide Separate Loss Estimates for Imports

The utilities enter into power purchase agreements with out-of-state generators. These power purchase agreements may include information about losses. The power purchase agreements are confidential, but the Energy Commission is interested in the range of and average losses for the utility. The utilities would be most knowledgeable about the losses related to the power they import.

Outstanding Issues

This paper reviews the loss factor estimates in use, describes the sources of these estimates and how they are used, and identifies data gaps. Methodological questions remain that are necessary to answer before a common set of assumptions can be recommended. The paper solicits comments from practitioners on what transmission and distribution loss factors sources and data should be used in future studies. The following provides a list of questions that remain:

- Are updated loss studies needed?
- When is it appropriate to use a statewide loss factor (as used by ARB in its *Climate Change Scoping Plan*) rather than utility-specific loss factors?
- If a statewide historical factor is used as the basis for planning estimates, should a normalized hydro condition be used?
- Should the existing level of self-generation be used when calculating a statewide average historical factor?
- Should a transmission loss factor be added in for unspecified transactions when calculating a statewide average historical factor?

- For statewide studies that are broken down into planning areas, is it necessary to use different transmission and loss factors for the planning areas?
- Should a single factor for distribution be derived and then a planning area transmission loss factor be added, or vice versa?
- How would future changes to the transmission and distribution system affect these loss factors?
- When needed, how should transmission losses be separated into in-state and out-of-state components?
- Should future losses in planning studies be projected based on an average or a trend line, adjusted for in-state hydro?
- What data can be used to estimate import losses?
- Should the data reported under ARB's Mandatory Reporting Requirements be used as the statewide source of line losses for unspecified imports?
- Is there more data which could refine the approximation of unspecified line losses used by ARB in the inventory?

Staff seeks input on these questions to provide information for its analytical and planning activities.

List of Acronyms

Abbreviation	Definition
AC	Alternating current
ARB	California Air Resources Board
CHP	Combined heat and power
CPUC	California Public Utilities Commission
DC	Direct current
DR	Demand response
EIA	U.S. Energy Information Administration
E-tag	Electronic tag
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
GWh	Gigawatt hour
IEPR	*Integrated Energy Policy Report*
IID	Imperial Irrigation District
IOU	Investor-owned utility
ISO	Independent system operator
kV	Kilovolts
kW	Kilowatt
LADWP	Los Angeles Department of Water and Power

Abbreviation	Definition
LTPP	Long-Term Procurement Proceeding
MEC	Marginal energy cost
MWh	Megawatt hour
PG&E	Pacific Gas and Electric
RA	Resource adequacy
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
T & D	Transmission and Distribution
UFE	Unaccounted for Energy
V	Volts
W	Watts
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council

Glossary

Term	Definition
Alternating current	Alternating current is a current that frequently reverses direction. The electric grid across the western United States is an alternating current system.
Balancing Authority Area	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load and resource balance within this area.
Bulk Electric System	Transmission and generation elements and facilities operated at voltages of 100 kV or higher necessary to support bulk power system reliability.
California Solar Initiative	Photovoltaic solar rebate program overseen by the California Public Utilities Commission for California consumers that are customers of the investor-owned utilities – Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric.
Current	Flow rate of charge through transmission and distribution wires, measured in amperes or amps.
Direct current	Direct current is current that always flows in the same direction.
Demand response programs	Programs to manage customer consumption of electricity.
Distributed energy resource	Small-scale power generation technologies (typically <10 MW), located close to where electricity is consumed. The broad definition includes California Solar Initiative, distributed generation, demand response, energy efficiency, and electrical storage.
E-tags	Electronic tagging implemented by NERC in 1999 to track the physical exchange of power from source to sink.
Ex ante	Forecast in advance.
Long-Term Procurement Proceeding	CPUC reviews and approves plans for the utilities to purchase energy. Establishes policies and utility cost recovery for energy purchases. Ensures that the utilities maintain a set amount of energy above what they estimate they will need to serve their customers (called a reserve margin), and implements a long-term energy planning process.
Loss factor	Gross-up or scaling factor defined as (1/(1-losses).
Losses	Transmission and distribution losses as a percentage of net energy for load.
Marginal Energy Costs	Cost to serve the next increment of demand.

Term	Definition
Metered subsystem area	Geographically contiguous system located within a zone that has been operating as an electric utility within the California ISO Control Area.
Net energy for load	Total generation plus energy received from other areas, less energy delivered to other areas through interchange needed to serve load.
Net interchange	Power that is transferred between balancing authority areas and is defined as the difference of imports minus exports
Primary distribution system	The part of the distribution system that operates at voltages in the low tens of kilovolts and may deliver power directly to larger commercial and industrial customers.
Purchasing-selling entity	Purchasing-selling entity is an entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-selling entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Secondary distribution system	The part of the distribution system that operates at the lowest voltage level of 120 volts and delivers power to residential customers and small commercial customers.
Self-Generation Incentive Program	CPUC program that provides rebates for qualifying distributed energy systems installed on the customer's side of the utility meter.
Subtransmission	Medium voltage lines in the range of 69 kilovolts to 138 kilovolts that interconnect the bulk transmission elements with the distribution elements
Transmission system	High-voltage lines, greater than 100 kilovolts (kV). Elements and facilities operated at 100 kV or higher, including radial transmission systems, may be excluded and elements and facilities operated below 100 kV may be included through the bulk electric system exemption process.
Unaccounted for Energy	Quantity of energy that represents the difference between the net energy delivered into a utility distribution company service area and the total net-metered demand, after accounting for the effects of transmission losses within this area. UFE is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical load profile errors, and distribution loss deviations.
Voltage	Electric potential charge that moves electrical current flow, measured in volts.