COMMISSION REPORT

FORMS AND INSTRUCTIONS FOR ELECTRICITY DEMAND FORECASTS

Prepared in Support of the 2011 *Integrated Energy Policy Report*

CALIFORNIA
ENERGY COMMISSION

Arnold Schwarzenegger, Governor

DECEMBER 2010

CEC-200-2010-007-CMF

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ABSTRACT

These electricity demand forms and instructions ask load-serving entities in California to provide information to the California Energy Commission. The information relates to electricity demand forecasts, demand-side management and energy efficiency impacts, private supply impacts, and related information for 2011-2022 and historic years 2000-2010.

Keywords: Electricity demand, consumption, forecast, peak, self-generation, conservation, demand-side, energy, efficiency, price, retail, end use

Please use the following citation for this report:

Fugate, Nick, Tom Gorin, Chris Kavalec. 2010. ***Forms and Instructions for Electricity Demand Forecasts.*** California Energy Commission, Electricity Supply Analysis Division. Publication number: CEC-200-2010-007-CMF.

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General □nstructions for - emand □orecast □ubmittals

□ntroduction

To develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety, the California Energy Commission is directed by Public Resources Code (PRC) Section 25301 to conduct regular assessments of all aspects of energy demand and supply. These assessments serve as the foundation for analysis and policy recommendations to the Governor, Legislature, and other agencies in the *Integrated Energy Policy Report (IEPR)*. To carry out these assessments, "the Energy Commission may require submission of demand forecasts, resource plans, market assessments, and related outlooks from electric and natural gas utilities, transportation fuel and technology suppliers, and other market participant" (PRC Section 25301[a]). The Energy Commission's data collection regulations authorize these forms and instructions to collect data identified in CCR, Title 20, §1345.

The Energy Commission is preparing to undertake assessments for the *2011 IEPR*. The adopted forecast, or range of forecasts, will provide a foundation for the analysis and recommendations of the *2011 IEPR*, including resource assessment and analysis of progress towards energy efficiency, demand response, and renewable energy goals. Energy Commission forecasts are used in the California Public Utilities Commission (CPUC) procurement and resource adequacy proceedings, by the California Independent System Operator (California ISO), and in transmission planning studies. Energy Commission demand and supply assessments are also used in the *California Gas Report*.

To provide the Energy Commission and the public with the opportunity to consider a range of perspectives on demand trends, the Energy Commission is 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 load-serving entities (LSEs) with annual peak demand greater than 200 megawatts (MW). These submittals are to be prepared and documented according to the attached instructions.

Separate documents will direct the contents and format of resource planning information. Each LSE should take care that the assessments submitted on the resource plan forms are consistent with the submitted demand forecast.

Definitions of terms used in these forms and instructions are found at the end of this document.

Questions relating to these forms and instructions should be directed to Nick Fugate of the Demand Analysis Office at (916) 654-4219 or by email at nfugate@energy.state.ca.us.

Who □ust □ile

Data are requested from all load-serving entities whose annual peak demand in the last two years exceeded 200 MW.

Statutes found in the Public Resources Code and supporting regulations give the Energy Commission authority to require forecast submittals from all entities engaged in generating, transmitting, or distributing electric power by any facilities. This includes utility distribution companies (UDCs), energy service providers (ESPs), community choice aggregators (CCAs) permitted to operate under Assembly Bill 117 (Migden, Chapter 838, Statutes of 2002), and all other entities that serve end-use loads, collectively referred to as LSEs. However, according to existing regulations, small LSEs[1] need not comply with the complete reporting requirements but may be required to submit demand forecasts in an alternative abbreviated format established by the Energy Commission. For this specific *IEPR* proceeding, the Energy Commission is not requesting long-term forecast data using these forms from any UDC with peak demand less than 200 MW.

Summary of Requested Data

UDCs are to submit Forms 1 through 6 and 8. ESPs are to submit Forms 7 and 8. A table indicating which forms are to be filled out by various participants is presented in the beginning of the Forms template.

- Form 1. Historical and Forecast Electricity Demand – annual sales and peak demand, private supply, and hourly loads
- Form 2. Forecast Input Assumptions – economic and demographic assumptions and electricity rate forecasts
- Form 3. Demand Side Management (DSM) Program Impacts and Costs (Committed and Uncommitted), including demand response and distributed generation program impacts
- Form 4. Forecast Methodology Documentation
- Form 5. DSM Methodology Documentation (Committed)
- Form 6. DSM Methodology Documentation (Uncommitted)
- Form 7. ESP Load Forecasts
- Form 8. Price and Rate Forms

Changes From Previous IEPR

This data request is largely the same as the *2009 IEPR* demand forecast data request, save for the following notable changes:

1 A small LSE is one that has experienced a peak demand of 200 megawatts or less per year in both of the two calendar years preceding the required data filing date and is owned or operated by a public government entity or regulated by the California Public Utilities Commission.

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?.*)"%&!&2I-"))" / 6!,.).! **without** a request for confidentiality are requested to submit either a compact disk or an electronic file containing the data and documentation:

By electronic mail to:

Docket@energy.state.ca.us

Please include “Docket #11-IEP-1C Electricity Demand Forecast” in the subject line.

Or by mail to:

California Energy Commission

Docket Office / Attn: Docket 11-IEP-1C

1516 Ninth Street, MS-4

Sacramento, CA 95814-5512

□onfidentiality

The forms provided for the 2011 IEPR submissions have been modified to reflect previous Executive Director confidentiality designations. The yellow highlighted portions of the forms are meant to serve as a guide for entities wishing to submit confidentiality requests but are unclear how similar requests have been handled in the past. While this guide is a not a definitive determination, it provides a reference for consideration by applicants.

If you are requesting confidentiality for any part of your submittal, please read and carefully follow the instructions in the Appendix "How to Request Confidentiality."

) rotocols for □ubmitted - emand □orecasts

In general, the demand forecast submitted should be the most likely projection of unmanaged total consumption. Unmanaged consumption means that the forecast should not include uncommitted DSM, and total consumption means that the forecast should include total electricity usage irrespective of the type of LSE, although locally supplied energy is reported separately from sales. Because one use of these forecasts will be to provide a basis for resource assessments, total consumption at the end-user level must be adjusted by losses to reflect total usage at the generation level. Since local private supply reduces system requirements and losses, forecasts of local private supply are also required from distribution utilities.

The primary purpose of most of the data requested is for each UDC to provide its view of demand trends and document the methods and data it uses to develop its forecast. Some data may also be used for development of the staff forecast. The Energy Commission is not requiring the use of specific forecasting methods.

General instructions on how the forecast is to be submitted:

- UDC forecasts are to project expected electricity demand for 2011-2022. Data for 2010 should represent the UDC's best estimates available at the time of filing. ESPs should provide projections for the period through which they have contracted load.
- UDCs are to provide forecasts for both their expected "bundled" customers (customers to whom they provide both generation and distribution services) and for all customers to whom they provide distribution services, including direct access, CCA load, and any other form of LSE providing generation services to end users. Bundled load is reported on Forms 1.1 and 1.3, and total load on Forms 1.2 and 1.4.
- UDCs are to prepare demand forecasts using either:

  (A) Franchise service area defined by applicable state law or regulatory decisions lawfully determined by the CPUC, or (B) A definition of distribution utility service area that has been mutually agreed upon by the distribution utility and Energy Commission staff.
- Impacts of demand-side management (DSM) and demand response programs on energy and peak demand should be provided according to the guidelines below:

Section 1345 of the Energy Commission's regulations (found in Title 20 of the California Code of Regulations) requires that demand forecasts are to account for all conservation "reasonably expected to occur." Since the *1985 Electricity Report*, reasonably-expected-to-occur conservation programs have been split into two types: committed and uncommitted. This demand forecast continues that distinction. Committed programs are defined as programs that have been implemented or for which funding has been approved. While conservation "reasonably expected to occur" includes both committed and uncommitted programs, only the effects of committed programs should be included in the demand forecast.

For the IOUs, committed conservation programs are those programs funded through 2012. Uncommitted effects are defined as the incremental impacts of post-2012 programs, impacts of future unfunded programs, and impacts from expansion of currently funded programs.

For publicly owned utilities, "committed" means the governing board for a municipal utility has authorized spending for at least a preliminary program plan from which impacts can be estimated.

Information about uncommitted programs designed to pursue the goals established for an LSE's energy efficiency or private supply activities by a regulatory agency should be submitted separately and not comingled with the impacts and descriptions of committed programs.

The term "demand response" encompasses a variety of programs, including traditional direct control (interruptible) programs and new price-responsive demand programs. For this filing, a key distinction is whether the program is dispatchable. Dispatchable programs are defined here as programs with triggering conditions that the customer does not control and cannot anticipate, such as direct control, interruptible tariffs, or demand bidding programs. Programs with triggering conditions are dispatchable whether they are a day-of or day-ahead trigger, and whether the trigger is economic or physical.

LSEs should treat energy or peak load saved from dispatchable programs as a resource and not a reduction to the demand forecast. Nondispatchable programs are not activated using a predetermined threshold condition but allow the customer to make the economic choice whether to modify its usage in response to ongoing price signals. Impacts from committed *nondispatchable* programs should be included in the demand forecast, for example, load reductions at on-peak hours subtracted from the "base" forecast and load building or load shifting in off-peak hours added to the "base" forecast.

To summarize, parties submitting demand forecasts are required to include the energy and peak impacts of all committed conservation and nondispatchable demand response in these demand forecasts. The impacts of uncommitted conservation and nondispatchable demand response programs and committed and uncommitted dispatchable demand response programs are to be excluded from the demand forecasts but reported in Form 3 as appropriate.

- The demand forecast and aggregate forecast of demand response and uncommitted DSM impacts should be consistent with the data submitted in the electricity resource plan forms.

□pecific □nstructions

UDCs are to complete Forms 1 through 6 and 8 only. ESPs complete Forms 7 and 8 only.

□orm 1 Historic and □orecast (lectricity - emand

Several forms request data by sector. Definitions of the sectors used in the Energy Commission forecast models are listed in the Definitions section at the end of this document. However, UDCs that use other sectors or customer classes to develop their forecast should modify forms as needed to report the forecast using their own categories and document their sector or customer class definitions.

□orm 1.1 □etail □ales of (lectricity by □lass or □ector

Form 1.1a is for the entry of total retail sales of electricity to bundled and direct access customers, measured on the customer side of the meter in gigawatt hours (GWh). Each UDC should modify the sectors listed on Form 1.1 template to reflect the sectors or classes by which they forecast.

Form 1.1b is for the entry of total retail sales of electricity to bundled customers only. The distinction between forms 1.1a and 1.1b is meant to streamline potential confidentiality requests for retail sales to bundled customers.

These forms also asks for documentation of the amount of load assumed to be migrating to or from the UDC and load growth associated with previously unserved areas. If the forecast of departing load is based on historical trends, this form should report those historical data.

□orm 1.2 - istribution , rea □et (lectricity or Generation / oad

Form 1.2 is for the entry of electricity deliveries in GWh by type of customer and the addition of losses to calculate utility system energy requirements. Each UDC should report deliveries for the following categories, as applicable:

- Sales to bundled customers (from Form 1.1b)
- Deliveries to direct access customers
- Deliveries to customers of CCAs
- Deliveries to customers of other publicly owned departed or departing load (such as irrigation districts) in the UDC's distribution area

Losses are to be calculated at generation busbar and should represent total transmission and distribution losses, as well as any other unaccounted-for losses in the system.

□orm 1.3) eak - emand by □ector (Bundled □ustomers)

Form 1.3 accounts for coincident peak demand by sector as well as for losses. The coincident peak is the sector peak at the time of the distribution area peak. Reported losses should be calculated at the generation busbar and include distribution, transmission, and unaccounted-for energy. Peak demand for residential and commercial sectors should, if possible, be separated into base load or weather-sensitive peak demand.

UDCs should also show the amount of migrating load assumed in the forecast. IOUs should use this form to show the amount of load expected to be gained in newly developed areas, or lost to municipalized or "newly departed load." Publicly owned utilities (POUs) should identify expected load growth or loss from migrating load or newly developed areas included in their base forecast.

□orm 1.4 - istribution , rea) eak - emand

Form 1.4 is for the entry of peak demand and losses at the time of the distribution system peak by type of customer, where the categories provided are:

- Coincident peak demand and losses of bundled customers (from Form 1.3).
- Coincident peak demand and losses of direct access customers.
- Coincident peak demand and losses of CCA entities.
- Coincident peak demand and losses of other publicly owned departing or departed load (such as irrigation districts) that are still in the distribution area.

Losses entered should represent total transmission and distribution losses at generation, as well as any other unaccounted-for losses in the system.

□orm 1.5) eak - emand Weather □cenarios

This form records distribution area peak demand forecasts under high temperature conditions. The cases, referred to as 1-in-5, 1-in-10, 1-in-20, and 1-in-40, refer to peak demand under temperature conditions that have a 20 percent, 10 percent, 5 percent, and 2.5 percent chance of being met or exceeded, respectively. These conditions should be contrasted with the 1-in-2 baseline temperature condition that has a 50 percent chance of being met or exceeded.

□orm 1.6a-1.6b □ystem Hourly / oads

Form 1.6a reports actual system hourly loads and losses for 2009 and 2010 and forecasted hourly loads for 2011. If complete loads for 2010 are not yet available, filers are asked to submit at least through September 15, 2010. UDCs who have already submitted 2009 or 2010 loads to the Energy Commission through other data requests need not resubmit them.

MW in each hour reflects integrated end-user load and effects of committed demand-side programs and excludes private supply. IOUs are asked to report bundled and unbundled loads and losses separately. For historical years only, also provide the estimated amount of curtailed load resulting from triggering of demand response and interruptible programs. Finally, UDCs are asked for estimates of actual outages in hours with a significant amount of outages, such as during the heat storm of late July 2006. Outage estimates are of the most importance for summer peak periods.

Reporting entities are to report separate hourly loads for each distinct geographic footprint (distribution service area, transmission planning area, control area, where applicable).

Form 1.6b is for reporting hourly loads for the same years as Form 1.6a but at a more disaggregate level of geography. The zones used should be climate zones or other geographic subareas used for transmission planning studies or rate making (if applicable to the respondent).

The template illustrates a preferred data layout; UDCs may submit equivalent data in other text, spreadsheet, or database formats (such as Access).

□orms 1.7a–1.7d) rivate □upply , nnual) eak and (nergy

Forms 1.7a-1.7d allow for the reporting of local private supply by sector or customer class and technology type. Form 1.7a focuses on annual energy, Form 1.7b on annual peak demand coincident with the distribution area peak, Form 1.7c on cumulative installed capacity, and Form 1.7d on uncommitted private supply. Policy decisions to pursue large goals of rooftop photovoltaic or other distributed generation on the customer side of the meter, such as combined heat and power (CHP) or cogeneration, implies greater needs for documentation of these influences on the demand forecast than in previous IEPR cycles. Private supply includes self-generation, distributed generation on the customer side of the meter, "over-the-fence" sales from a CHP facility, or wheeling from a CHP facility to a final user.

Given the wide range of differences in technology, cost, market maturity, and operating mode, Forms 1.7a-1.7d require an explicit breakout by technology type. In addition to photovoltaic technology, other technologies that could be used to meet a portion or all of onsite electricity demand include microturbine, fuel cell, combustion turbine, and internal combustion engine. Each technology in turn can be differentiated by the use of renewable or nonrenewable fuel. CHP is traditionally thought of as the simultaneous production of mechanical energy, which may be used to generate electricity and useful heat. Settings where the self-generator does not make productive use of the recovered waste heat but only uses the technology to generate electricity may be considered as falling under the broader scope of distributed generation. To properly capture such variation in technology use, Forms 1.7a-1.7d require explicit accounting of impacts by technology type. Each form has a section for photovoltaics, CHP for each technology type, and an “other” section for technologies that are not a photovoltaic system or operating as a CHP plant, such as wind turbines. Form filers should create a copy of the “CHP” and “Other” section in Forms 1.7a-1.7d for each technology being reported. Photovoltaic impacts should reflect the system’s CEC AC rating.

Energy and peak load forecasts should reflect how facilities are expected to operate, not simply installed capacity or potential energy. These forms represent the UDC’s estimate of total private supply in the distribution area, including the effects of committed renewable and distributed generation programs reported on Form 3.3.

As with energy efficiency programs, committed and uncommitted program impacts should not be comingled, and uncommitted program impacts should not be included in the demand forecast. Such uncommitted impacts should be reported on Form 1.7d.

LSEs may provide additional forms if they wish to show other categories (for example, fuel type and consumption) of energy, peak demand, or installed capacity in their filing.

□orm 2 (lectricity □orecast □nput □ssumptions

Electricity demand forecasts are based in part on projections of economic and demographic variables. Document these projections on Forms 2.1 through 2.4. UDCs may provide these variables in their own format as long as the equivalent information is provided and the variables are clearly labeled. The deflator series used to convert variables from nominal to real values should be provided in these forms. If different deflators are used for different variables, each deflator series should be provided.

UDCs should document the methods used to develop the economic and demographic projections, including historical data sources, projected data sources, appropriateness of source for forecast and a discussion of the plausibility of those projections in the Form 4 methodology report.

□orm 2.1 (conomic and - emographic Variables

Form 2.1 documents economic and demographic variables that are used directly in an LSE's energy demand forecast models. Examples include employment and output by industry, local population, and population by age groups, households and / or housing by type, and taxable sales.

Only those variables actually used to develop the forecast need be reported. UDCs, particularly those with large geographic planning / service areas, should provide any subutility regional breakdowns of population and income projections used in the development of the economic, demographic, or energy forecasts. Subutility regions may be individual counties, groups of counties, and / or weather zones.

It must be emphasized that variables need to be precisely defined. For example, population estimates should be accompanied by an identification of the source of the estimates and whether the estimates are midyear or end of year and whether the estimates are for total population, civilian population, household population, or other subgroups.

□orm 2.2 (lectricity □ate □orecast

Form 2.2 allows for the reporting of projected electricity prices for the sectors or classes used to develop the forecast. The price forecasts should be reported using the same customer sectors or classes as Form 1.1. Prices should not include city taxes. Electricity prices are to be presented in 2009 cents per kilowatt hour (kWh). Provide the deflator series used to convert nominal to real prices or real to nominal prices. Where the electricity price projections are derived from a specific resource supply plan, those plans should be documented or referenced.

□orm 2.3 □ustomer □ounts and □ther □nputs

Form 2.3 provides recorded and projected customers counts by major customer sector as used to develop the forecast. These customer counts should reflect end users with whom the UDC has a generation services relationship. For example, an IOU should not report all customers in its service area, but only the bundled service customers. The most convenient and consistent series is acceptable, but a narrative should explain the units reported (for example, number of customers or number of accounts), and whether the annual values are derived from a specific point in time, a specific month, an average of months across the year, or another method.

/ oad □igration - rivers and □ther , ssumptions

Economic, demographic, and energy price projections may not exhaust all variables used by the participant to "drive" the energy demand forecast model(s). In particular, UDCs should identify the data used to project expected load migration. Some utilities may evaluate such factors as the amount and zoning of undeveloped land within the boundaries of the utility district; local residential, commercial, and industrial development policies; local population and income trends; annexation policies; and the general plan of the municipality. If other input assumptions affect the forecast, it is critical that they be documented. Provide narrative and spreadsheets as appropriate.

□orm 3 - emand □ide □anagement (- □□)) rogram □mpacts

This section of the forms and instructions summarizes the format requirements for reporting:

- Historical and forecasted energy and coincident peak impacts of conservation, load shifting, demand response, and distributed generation and renewable programs, both committed and uncommitted.
- Costs of DSM programs.

Peak impacts should represent the expected impact at the time of distribution area peak. Alternatively, UDCs may report average impacts during their peak period. Each UDC should document what the peak impacts represent and which hours it considers its peak period.

As indicated on the forms, reported DSM program impacts should be reported both at the gross and net levels. Net savings are defined as the change in load attributed to the program adjusted to exclude the effects of free drivers, free riders, state or federal conservation standards, changes in the level of energy service, and natural change effects.

These forms request data by market sector, such as residential, commercial, industrial, and agricultural. UDCs may modify the sectors used as needed to be consistent with the UDC analysis and forecasting methods.

Documentation of the method used to estimate impacts for each program should accompany these and are to be presented in Form 5.

□orms 3.1a – 3.1c and □orm 3.2 (nergy (fficiency □osts and □mpacts

These forms record the costs and impacts of energy efficiency programs. Each program entry should specify whether the program is committed or uncommitted. Uncommitted program impacts should not be included in the demand forecast. Forms 3.1a and 3.1b are for first-year gross and net impacts, respectively, by program category and sector. Form 3.1c reports program costs for each program by cost category. The following categories are requested for program costs: Administrative, Incentives, Measurement and Evaluation, and Participant cost.

Form 3.2 is for reporting of cumulative impacts by program and sector through 2022. Cumulative savings refers to all savings that can be attributed to a program in a given year.

Cumulative savings is equal to current first-year savings plus residual savings from previous-year impacts.

On Forms 3.1a – 3.1c and 3.2, IOUs should also provide the estimated total impacts associated with bundled customers only. To the extent IOUs wish to provide backup information about program impacts that covers both bundled and direct access customers, this is acceptable as long as there is a supplement explaining the adjustment to identify the portion of impacts that is expected for bundled service customers.

□orm 3.3 □enewable and - istributed Generation) rograms

Form 3.3 reports the costs and expected energy and coincident peak impacts of customer-side-of-the-meter renewable and distributed generation programs, including cogeneration through the use of technologies such as internal combustion engine, turbine, microturbine, photovoltaic, wind, and fuel cell. This should include any program that results in displaced utility sales to the end user through self-generation or distributed generation, but not all distributed generation. Self-generation that adds power to the grid should be reported in resource plans.

In particular, IOUs should report projected impacts of the Self-Generation Incentive Program and the California Solar Initiative. Public utilities should include impacts of current solar and other renewable programs and planned programs to comply with Senate Bill 1 (Murray, 2006, Chapter 132, Statutes of 2006). Public utilities should also include impacts of current and planned programs to promote renewable and nonrenewable self-generation including cogeneration.

Energy and peak impacts should be reported as distributed generation facilities are expected to operate, not based on installed capacity or potential energy. Thus, there is an interaction with retail electricity rates, fuel prices, and how end users choose to operate these facilities.

□orm 3.4 - emand □esponse) rogram □osts and □mpacts

Form 3.4 should report costs and expected coincident peak impacts for each demand response and interruptible program. Programs should be identified as committed or uncommitted, and dispatchable or nondispatchable, as discussed in Item 4 in the section on Protocols for Submitted Demand Forecasts.

□orm 4 - emand □orecast □ethods and □odels

Each LSE shall document the electricity demand forecast methods and models used to develop the submitted forecast and shall include a discussion of the following topics.

- emand □orecast □ethods

Explain the conceptual basis of the forecast:

- The energy and peak modeling approaches
- The definition of customer classes, including which rate classes are included in the categories for which forecasts are submitted
- Economic and demographic data

- Data sources

Define the area for which the forecast is developed. Identify isolated loads and resale customers and describe how they are included or excluded.

Describe model capabilities in forecasting electricity demand components (such as end uses, fuel types, or structure types) and key forecast model structural equations (econometric relations, other behavioral equations, and identities). Algebraic variables and computer mnemonics should be defined. For sector models developed using aggregate econometric methods, provide data for the independent and all dependent variables for the entire estimation period. Report all standard statistical parameters for econometric models. LSEs may include existing forecast model reports as an appendix to this form if this report includes a brief summary.

Since the emphasis in the *2011 IEPR* cycle for demand forecasts is on gaining improved knowledge about energy efficiency and other demand-side measures included in demand forecasts, the methodology section should explicitly discuss how such impacts are incorporated into the final forecast for each sector. Methods might include:

- Direct inclusion of use of end-use models and appropriate inputs characterizing the impacts of standards or programs.
- Calculation of the difference from an unmitigated forecast without program savings in the historic or forecast period and a forecast with both historic and forecast program savings included.
- Separately computed savings for programs from other analytic techniques with some or all of these savings subtracted from a "raw model output" to produce the final forecast.
- Other techniques.

The description of how this is accomplished should be explicit for each sectoral energy model and for peak demand. Savings estimates used in the historical period to adjust sales by sector should be provided as well as estimates used for the forecast period.

Discuss how the submitted forecast is reasonable in light of economic, demographic, price, demand-side management, and state policy trends. Discuss the reasonableness of differences between historical and forecasted growth patterns.

Describe the methods and data used to develop the historical and projected peak loads of sectors or customer classes reported in Form 1.3.

Historical □orecast) erformance

Report and discuss the past performance of the forecasting method, including comparison of previous forecasts to actual annual weather-adjusted peak and energy demand.

(stimates of - irect , ccess, □ommunity □hoice , ggregation, and □ther - eparted / oad

Distribution utilities should describe the methods, assumptions, and data used to forecast direct access, community choice aggregation, and other departed load reported in Forms 1.2 and 1.4. This should include a list of current and projected ESP and CCA entities in the distribution utility's planning area.

POUs that anticipate load growth from newly acquired load should identify the areas in which they are acquiring load and describe the data sources used to account for that load growth. IOUs should describe the methods and data used to account for expected migrating municipal load in their forecasts. Data used to account for migrating or newly departed municipal load should be reported in Form 1 or 2 as appropriate.

/ ocal) rivate □upply (stimates

Describe fully the methods, assumptions, and data sources used to develop both historical estimates and future projections of committed program impacts in Forms 1.7a - 1.7c. Report uncommitted program impacts in Form 1.7d. These are identified as potential impacts that might be achieved by one or more programs in pursuit of goals established by regulatory agencies, but which have not yet been funded or for which final program design details established. Because these are expected energy and on-peak effects, they require estimates of how facilities will actually be operated. Indicate the degree to which conservation efforts, financial incentives, and interruptible programs and negotiated rates have been incorporated into the self-generation forecast. Separate reports may be attached as long as these demand forms include a brief summary.

Weather , djustment) rocedures

Describe the meteorological parameters used for adjusting the forecast to normal weather conditions and the sources of the meteorological data, including:

- Names and locations of the weather stations used.
- Weights used for each weather station.
- Temperature variables used, such as daily maximum, heating and cooling degree days, or apparent temperature values used.
- Base values of the temperature variables used and annual data used in the adjustment process.

UDCs should also describe the methods and assumptions used to develop the high temperature cases (1-in-5, 1-in-10, 1-in-20, and 1-in-40) reported in Form 1.5. Provide a narrative discussion of the baseline peak temperature assumptions, how the high temperature scenarios were developed, sources for the weather data, and the methods used to develop the temperature probability distributions.

□orecast □alibration) rocedures

Most forecasts are calibrated to historical energy consumption and peak demand to "scale" the backcast to more closely coincide with historical data. Provide a comprehensive description of the method of forecast calibration.

The *Quarterly Fuel and Energy Report* (QFER) system is the principal source of data on historical sales of electricity by economic sector for the Energy Commission staff's demand forecast calibration procedure. In December 2010, Energy Commission staff will provide each participating LSE with a copy of its QFER sales data on file by sector code for 2000 through 2009 for review.

(nergy and) eak / oss (stimates

Forms 1.2, 1.3, and 1.4 include estimates of losses. Describe fully the method and data sources used to develop historic and forecast energy and peak losses. If the method uses a loss factor, specify what that factor is and discuss if that factor varies by year or by customer sector.

Hourly / oads by □ubarea

Provide definitions of the subareas for which hourly loads in Form 1.6b are provided. Attach a file with geographic identifiers, such as zip codes, that define the region covered by each zone. Also, describe the source of the data, if from metered load, or the methods used to develop the subarea loads, as applicable.

(conomic and - emographic) rojections

UDCs are required to provide documentation of the methods used to develop the economic and demographic projections reported in Form 2 and a discussion of the plausibility of those projections. They may include an economic and demographic methodology report as an appendix to this form. Documentation should include historical data sources, projected data sources, and appropriateness of source for forecast.

□orm 5 □ommitted - emand-□ide) rogram □ethodology

(fficiency) rogram □osts and □mpacts

Work papers should be provided to document the estimated load impacts provided. Describe how the peak and energy impacts are calculated. Describe the basis or method used to estimate how first-year impacts might change over time. Document the net-to-gross ratios used to convert gross measure or program impacts into net impacts. Describe how the per-measure impact estimates are aggregated and how any interactive effects between the measures are estimated or accounted for. List any studies or sources relied on to support these assumptions.

Discuss and document the different funding sources used and how funds are allocated to programs.

- emand □esponse) rogram □osts and □mpacts

Discuss how the estimates of peak impacts for each program are derived. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections. Describe the method used to develop estimates of nondispatchable program impacts and the extent to which the forecast is consistent with recent program performance. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak. For example, will the dispatch signal be sent each year to all or most customers, or only during emergencies, or on days when peak load passes a critical value?

□enewable and - istributed Generation) rogram □osts and □mpacts

Discuss how the estimates of energy and peak impacts for each program are derived, for both uncommitted and committed programs. In particular, describe in detail the method and data used to project impacts of solar programs. Describe assumptions about eligible population, participation rates, price elasticities, fuel prices, wholesale market conditions, and prices used to develop the projections. Describe what criteria are used in deciding how to model customer decisions to use these facilities in peak shaving or baseload modes.

□orm 6 □ncommitted - emand-□ide) rogram □ethodology

(fficiency) rogram □osts and □mpacts

Work papers should be provided to document the estimated load impacts provided for uncommitted energy efficiency programs. Describe how the peak and energy impacts are calculated. Describe the basis or method used to estimate how first-year impacts might change over time. Document the net-to-gross ratios used to convert gross measure or program impacts into net impacts. Describe how the per-measure impact estimates are aggregated and how any interactive effects between the measures are estimated or accounted for. List any studies or sources used to support these assumptions.

Discuss and document the different funding sources used and how funds are allocated to programs.

Discuss the current status of programs included in the uncommitted forecast. Describe the process that will lead to change in status from uncommitted to committed, and whether this status change is under the control of the LSE or imposed through regulatory requirements.

- emand □esponse) rogram □osts and □mpacts

Discuss how the estimates of peak impacts for each uncommitted program were derived. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections. Describe the method used to develop estimates of nondispatchable program impacts and the extent to which the forecast is consistent with recent program performance. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak. For example, will the dispatch signal be sent each year to all or most customers, or only during emergencies, or on days when peak load passes a critical value?

Discuss and document the different funding sources used and how funds are allocated to programs.

Discuss the current status of programs included in the uncommitted forecast. Describe the process that will lead to change in status from uncommitted to committed, and whether this status change is under the control of the LSE or imposed through regulatory requirements.

□enewable and - istributed Generation) rogram □osts and □mpacts

Discuss how the estimates of energy and peak impacts for each uncommitted program were derived, for both uncommitted and committed programs. In particular, describe in detail the method and data used to project impacts of solar programs. Describe assumptions about eligible population, participation rates, price elasticities, fuel prices, wholesale market conditions, and prices used to develop the projections. Describe what criteria are used in deciding how to model customer decisions to use these facilities in peak shaving or baseload modes.

Discuss and document the different funding sources used and how funds are allocated to programs.

Discuss the current status of programs included in the uncommitted forecast. Describe the process that will lead to change in status from uncommitted to committed, and whether this status change is under the control of the LSE or imposed through regulatory requirements.

□orm 7 (□) - emand □orecast

For each utility distribution area in which it serves load, each ESP should provide a projection of annual sales and peak demand for load currently under contract, for as many years as they have any contracted load. The variables to be reported, by utility distribution area, are:

- Annual Metered Sales: Projected annual sales for customers under contract, before any losses, in megawatt-hours (MWh).
- Annual Peak Demand in MW. This should include distribution losses, comparable to settlement data.
- Customer Counts – Residential and Nonresidential. Note whether the units reported are number of customers or number of accounts, and whether the annual values represent a specific point in time, a specific month, or an average of months across the year.

The submitted load forecast should correspond to the loads the ESP will report on the forthcoming resource plan data request. ESPs may also choose, but are not required, to provide a forecast of expected load if that approach will be more consistent with the submitted resource information. Forecasts should not include reserve margins.

Form 8 Retail Price and Rate Forms

General Instructions

- Provide all financial data in nominal (current-year) dollars for historical data through 2010. Forecast data (2011-2022) should be provided in real 2009 dollars.
- For many electric utilities, some categories of financial data will amount to millions of dollars each year. Round off all financial data to the nearest thousands of dollars. For example, $15,000,000 would be reported as $15,000.
- All forms request only annual data. Some electric utilities maintain their financial records using a fiscal-year accounting system (for example, July 1 to June 30), while others use the calendar year (January through December). Each utility or ESP may use either fiscal year or calendar year data to report (or project) annual data, depending on which accounting system it normally uses to report financial data. For utilities or ESPs that report based on a fiscal-year, the "year" is the starting year of the fiscal year.

Form 8.1a Revenue Requirements by Major Cost Categories/Unbundled Rate Component

Form 8.1a contains three separate forms—Form 8.1a (IOU), Form 8.1a (POU), and Form 8.1a (ESP). Each reporting entity must complete the form corresponding to its filing status. Investor-owned utilities are to complete Form 8.1a (IOU), publicly owned utilities are to complete Form 8.1a (POU), and energy service providers are to complete Form 8.1a (ESP).

Form 8.1a (IOU)

This form provides each IOU's major costs in the recent past and estimates of major costs over the next 10 years. For 2010 through 2012, IOUs are requested to report their CPUC-authorized revenue requirements, not actual costs.

Form 8.1a (IOU) identifies 10 major revenue-requirement categories, most of which are based on the rate components displayed in IOUs' electricity bills for retail customers. These categories are Generation, Transmission, Distribution, Nuclear Decommissioning, Public Purpose Programs, Department of Water Resources (DWR) Bond Charge, Fixed Transition Amount / Trust Transfer Account, Ongoing Competitive Transition Charge, Regulatory Asset for Energy Recovery Bond (PG&E Only), Taxes and Franchise Fees, and Other Costs Not Already Reported.

The following instructions explain which financial information to report or project under these categories.

Generation Revenue Requirements

The IOUs must base their generation revenue requirements upon the same quantities and types of electricity supply that they reported to the Energy Commission in their electricity-resource-plan submittals. The generation section of Form 8.1a (IOU), therefore, does not ask the IOUs how much electricity they expect to generate or purchase each year.

The Energy Commission staff divided the generation section of Form 8.1a (IOU) into six subcategories: utility-owned / retained generation and five types of purchased power.

Utility-owned / retained generation means generation built or acquired by the IOU that is either placed in the rate base or treated as a cost-based asset for rate recovery purposes. The utility-owned / retained generation section is further subdivided into six types of power plants:

- Nuclear
- Conventional Hydroelectric
- Hydroelectric Pumped Storage
- Natural Gas-Fired Generation
- Coal
- Renewables Portfolio Standard (RPS) "Eligible" Renewables

Conventional hydroelectric generators and hydroelectric pumped storage facilities are defined here as facilities that do not qualify as eligible for California's RPS. This definition avoids double-counting costs for electricity-generating facilities that are both hydroelectric and "RPS 'Eligible' Renewables." Natural gas-fired generation includes all utility-owned / retained steam generation units, combined cycle power plants, combustion turbines, and distributed generation facilities.

RPS "Eligible" Renewables are electricity-generating facilities that use one or more types of renewable energy resources or fuels to operate and that meet the RPS eligibility criteria. IOUs can aggregate revenue requirement dollar amounts for all types of renewable energy facilities.

The IOUs are requested to provide the following cost-related data for each type of utility-owned / retained generating facility: Fuel and Non-Fuel. Fuel-related revenue requirements are the sum of natural gas purchases, gas pipeline transportation, and gas storage. Non-Fuel revenue requirements are the sum of operations and maintenance expenses, depreciation, return on investment, and all other costs.

For conventional hydroelectric generation, projected "fuel" costs are for water rights. "Fuel" costs for hydroelectric pumped storage are the energy costs associated with off-peak pumping.

For utility-owned / retained generation that is natural gas-fired or coal-fired, please provide the average annual fuel price that was used to report and forecast generation-fuel revenue requirements. Report both of these fuel-price data series in dollars per million British thermal units.

The Energy Commission-provided Excel worksheet will subtotal each year's projected costs for each type of utility-owned generation. In addition, it will subtotal the revenue requirement amounts for all types of utility-owned generation.

Form 8.1a (IOU) next asks each IOU to provide financial data on historical, authorized revenue requirements and projected expenses for four categories of purchased power:

- California Department of Water Resources (DWR) contracts

- Supply contracts
- Residual market transactions (that is, short-term and spot market purchases)
- Payments to the California Independent System Operator for market charges

The Energy Commission staff requests a breakout for each of the following types of DWR contracts:

- Must-take
- Capacity-charge / Economic Dispatch
- Renewables

The Energy Commission staff also requests an expense breakout for the following three categories of Supply Contracts:

- Qualifying Facilities (QFs)
- Non-QF Renewables
- All Other Bilateral Contracts

To avoid double-counting, QF contract expenses that are recovered through the Ongoing Competitive Transition Charge (CTC) should not be included in this section of Form 8.1a because a row in the Excel worksheet has been included for "Ongoing CTC" costs, including contract costs. Also, authorized revenue requirements and projected expenses for "Non-QF Renewables" contracts should not include "DWR Renewables" contracts.

The "All Other Bilateral Contracts" category is for reporting authorized revenue requirements and projected expenses for the sum of all other bilateral supply contracts. Examples of the types of bilateral contracts to include are:

- Forward energy
- Capacity
- Tolling agreement
- Physical call or put option

Form 8.1a (IOU) has three final categories of supply contracts:

- Residual market transactions
- Payments to the California Independent System Operator for Market Charges

- Other resources

Under "Residual Market Transactions," the Energy Commission staff requests that IOUs report their authorized revenue requirements and projected expenses for electricity supplies purchased through both short-term contracts (less than three months) and spot-market purchases (for example, forward spot).

Under "Payments to the California ISO for Market Charges," please report authorized revenue requirements and projected expenses for the following:

- Ancillary Services, including spinning reserves, non-spinning reserves, replacement reserves, regulation up, and regulation down
- Market Uplifts, including emissions cost recovery, start up cost recovery
- Energy, including day-ahead, hour-ahead, and real-time

Under "Other Resources," please provide cost projections for future power supplies not already reported in Form 8.1a as "Utility-Owned Generation" or as a type of "Purchased Power" because the ownership of these supplies is unknown by the IOU at this time.

ransmission evenue equirements

This section of Form 8.1a (IOU) is for collecting financial data regarding each IOU's Federal Energy Regulatory Commission (FERC)-jurisdictional transmission assets. Energy Commission staff requests annual transmission-related authorized revenue requirements and cost estimates using the following categories that are based on four FERC-approved rates:

- Base Transmission Revenue Requirement
- Transmission Revenue Balancing Account Adjustment
- Transmission Access Charge Balancing Account
- Reliability Services

"Base Transmission Revenue Requirement" includes transmission system operations and maintenance, depreciation, and return on investment. "Transmission Revenue Balancing Account Adjustment" is an income credit for the California ISO's transmission line operations and includes wheeling, firm transmission rights, and congestion management charge revenues. The "Transmission Access Charge Balancing Account" enables IOUs to collect revenues to recover costs for using others' transmission systems. And the "Reliability Services" rate compensates IOUs for costs to operate reliability must-run generators for local voltage support.

To complete the "Base Transmission Revenue Requirement" row of this form, the IOUs are requested to provide authorized revenue requirements and projected expenses for network improvements (for example, line extensions and reliability upgrades) and large transmission projects it has identified in its five-year transmission plan with the California ISO. Beyond the term of its five-year plan, the IOUs are requested to provide cost estimates only for transmission network improvements.

- istribution □evenue □equirements

This section of Form 8.1a (IOU) reports authorized revenue requirements and projecting expenses for each IOU's CPUC-jurisdictional distribution assets.

Energy Commission staff requests data on the following expense categories be aggregated and reported in the row labeled "base margin":

- Operations and maintenance
- Depreciation and amortization
- Return on investment
- All other costs

"Operations and maintenance" expenses include supervision and engineering labor; load dispatching; substation, transformer, overhead and underground line operations; streetlight and signal operations; customer installation; and miscellaneous expenses.

In the row labeled "Customer Service," please report authorized revenue requirements and projected expenses for the following operating expenses:

- Meter reading and field service
- Customer records, billing, and collections
- Customer service and information
- Telephone center operations
- All other customer-service activities

In addition, the Energy Commission staff requests that IOUs provide information about authorized revenue requirements and projected costs to implement each of the following programs:

- Self-Generation Incentive Program
- Demand Response Program
- Advanced Metering Infrastructure
- California Solar Initiative

&uclear - ecommissioning

IOUs with cost responsibility for decommissioning a nuclear power plant are requested to report authorized revenue requirements and estimated future costs in this section of Form 8.1a (IOU).

) ublic) urpose) rograms

This section of Form 8.1a (IOU) collects annual cost projections for implementing each of the following public purpose programs:

- Low-income programs (including subsidies for medical / life-support equipment users)
- Energy efficiency
- Public interest energy research and development
- Renewable energy

The Energy Commission staff seeks annual cost estimates only for those public-purpose programs that are funded by ratepayers through the electricity Public Goods Charge or Public Purpose Program Charge.

Although cost recovery for “procurement energy efficiency” is through a “Procurement Energy Efficiency Balancing Account” (PEEBA) surcharge, IOUs include the revenue requirement for PEEBA in their Public Purpose Program revenue requirement. Authorized revenue requirements and projected expenses for “energy efficiency” programs, therefore, should include both categories of ratepayer-funded energy efficiency programs.

- W□ Bond □harge

The Energy Commission staff requests each IOU to provide its forecast of annual costs for DWR revenue bond charges.

□ixed □ransition , mount/□rust □ransfer , ccount

This section of Form 8.1a (IOU) collects each IOU’s annual forecast of costs associated with repaying revenue bonds issued to reduce rates for residential and small commercial customers under California’s electric industry restructuring plan.

PG&E calls its rate reduction bond charge the “Fixed Transition Amount,” while SCE and SDG&E refer to it as the “Trust Transfer Account.”

□ngoing □ompetitive □ransition □harge

Each IOU is requested to project total annual costs to be collected through the ongoing competitive transition charge. Energy Commission staff is not requesting a detailed breakout between generation (for example, CTC-eligible QF costs) and other costs included in this charge.

□egulatory , sset for (nergy □ost □ecovery Bond () G&(□nly)

Energy Commission staff requests that PG&E staff provide data on recent authorized revenue requirements and projected expenses for its energy cost recovery bonds.

□axes and □ranchise □ees

Please provide an annual estimate of future revenue requirements for taxes and franchise fees. Taxes may include federal income, state corporation franchise, property, payroll, business, and Superfund taxes. Franchise fees are those levied by city and county governments.

If an IOU's revenue requirement for "Taxes and Franchise Fees" is collected in another rate component (for example, Distribution) and the dollar amount has been included already in Form 8.1a (IOU) within that rate component, then the IOU need not report its "Taxes and Franchise Fees" expense separately. It should leave the "Taxes and Franchise Fees" row blank and provide a note explaining which rate component includes the "Taxes and Franchise Fees" expense.

□ther □osts &ot , lready □eported

Although the Energy Commission staff attempted to identify all major revenue requirement categories in Form 8.1a (IOU), the IOUs are requested to include a forecast of any other costs not already reported. These "other" costs need not be named.

□otal □evenue □equirements

The Excel worksheet will add up all of the separate costs to produce total revenue requirements. The worksheet also duplicates the annual values for total revenue requirements onto the top rows of Form 8.1b (Bundled) and Form 8.1b (DA).

□orm 8.1a () □.) Budget , ppropriations or , ctual □osts and □ost) rojections by □ajor (xpense □ategories

This form gathers financial data needed for both trend analysis and for forecasting retail electricity prices of California's major POUs.

Through this form, Energy Commission staff seeks to learn each POU's recent historical and projected annual revenue requirements. The form identifies three major cost categories: operating expenses, capital outlay, and debt service, plus appropriations from POU revenues into reserve funds, city general funds, or other municipal accounts.

The following instructions define what financial information to report or project under each cost category. For 2010 through 2012, POU's are requested to report their approved-budget appropriations or actual costs, whichever data is more readily available to the POU.

□perations (xpenses

A POU's operating expenses are its costs to operate and maintain its power generation, transmission, and distribution systems and to provide billing and information services to its customers and others. POUs' governing boards or city councils adopt annual or biennial "operating expense" budgets that appropriate electricity sales revenues (and other income) to pay these expenses. The same costs identified in POUs' operating-expense budgets will be reported and projected in this section of the form.

Form 8.1a (POU) organizes operating expenses into two broad categories: operations and maintenance of power production, transmission, and distribution assets; and customer-related expenses.

) ower) roduction

POUs' power production expenses include costs for labor, materials, fuel, supplies, and services of operating and maintaining utility-owned power plants; and for power purchases. Form 8.1a (POU) divides power-production expenses into two categories:

- Utility-owned generation
- Power purchases

□tility-□wned Generation

Utility-owned generation expenses are costs for operating and maintaining electric generating facilities that were built or acquired by the POU. Power plants built and jointly owned by multiple POUs through joint powers agencies (JPAs) are not included in this section of Form 8.1a (POU). Similarly, if the POU financed power plant construction through a subsidiary financing authority at that financing authority now has a power purchase agreement with the POU, that power plant is not "utility-owned generation."

Through Form 8.1a (POU), the Energy Commission staff requests data on operating and maintenance expenses for utility-owned generation by the following types of fuel or resource:

- Nuclear
- Conventional hydroelectric
- Hydroelectric pumped storage
- Natural gas-fired generation
- Coal
- Generation from renewable resources

POUs may leave blank those rows in Form 8.1a (POU) for which they do not own a specific type of generating facility.

Costs are divided into two subcategories:

- Fuel expenses
- Other operations and maintenance expenses

In addition to the fuel commodity (for example, natural gas), fuel expenses include labor for purchasing and handling fuel, payments for natural gas pipeline use or coal transportation services, payments for fuel-storage facilities, insurance, sales commissions, and residual disposal expenses. For hydroelectric facilities, fuel expenses include water purchases, and payments for licenses or permits for water rights, and payments for riparian rights. For hydroelectric pumped storage facilities, fuel expenses include electricity costs for off-peak pumping.

For both natural gas-fired and coal-fired power plants, the Energy Commission staff also requests each POU to provide its fuel price forecasts in dollars per million British thermal units.

"Other Operations and Maintenance" expenses include labor costs for operating and maintaining the structures and equipment used for electricity generation, and for supplies and operating permits.

) ower) urchases

Power-purchase expenses are costs to the utility for electricity purchased for resale. They include net settlements for exchanges of electricity or power, such as economy energy and for transactions under pooling or interconnection agreements.

Form 8.1a (POU) requests historical and projected cost details for the following categories of purchased power:

- Federal power
- Contracts with JPAs
- Contracts with POU's subsidiaries
- Bilateral contracts

The Energy Commission staff did not ask for cost information about short-term and spot-market power purchases because these purchases are assumed to be a small share of the POUs' supply portfolio and their future costs, unpredictable.

□ederal) ower

POUs are requested to provide cost information for power purchased and to be purchased from the Western Area Power Administration (Western). If a POU also has a contract with the Bonneville Power Administration, those power-purchase costs should be added to its Western supply costs and report as one annual total.

□ontracts With Joint) ower , gencies

California's POUs have co-funded many power plant (and transmission line) projects through many JPAs, including the Northern California Power Agency and the Southern California Public Power Authority. JPAs own these electricity generating facilities, but the participating POUs are obligated to help pay for a project's capital and operating costs and debt service through contracts (that is, power purchase agreements).

Because POUs may have many power purchase agreements with different JPAs, Form 8.1a (POU) asks for power-purchase costs by type of generating facility. The types of generating facilities listed in the form are:

- Nuclear

- Coal
- Conventional Hydroelectric
- Natural Gas-Fired
- Renewable Resources

□ontracts With) □□ □ubsidiaries

POUs may have financed power plant construction through subsidiaries (for example, SMUD Financing Authority) rather than the POU itself issuing a revenue bond or another type of debt instrument. The POU subsidiary owns the electricity generating facility, but the “parent” POU is obligated to help pay for a project’s capital and operating costs and debt service through a contract (that is, a power purchase agreement).

In Form 8.1a (POU), please provide annual costs for purchased power from these subsidiaries. If more than one power purchase agreement exists, please report an aggregated total.

Bilateral □ontracts

Bilateral contracts are legally enforceable agreements between a POU and a supplier (for example, a broker or power plant owner) for electricity deliveries in the future. The terms and conditions of these contracts are set by the two contracting parties, but include the timing and delivery point of specific amounts of energy or capacity and the price (or a price-determining formula). Examples of bilateral contracts include are:

- Forward energy
- Capacity
- Tolling agreement
- Physical call or put option

In Form 8.1a (POU), please divide the sum of all bilateral contracts for power supplies into the following subcategories:

- Renewable resource contracts
- All other bilateral contracts

□ther □esources

Under “Other Resources,” please provide cost projections for future power supplies not already reported in Form 8.1a as "Utility-Owned Generation" or as a type of "Purchased Power," because the ownership of these supplies is unknown by the POU at this time.

□ransmission (xpenses

Form 8.1a (POU) provides three subcategories for reporting transmission expenses:

- Operations and maintenance of utility-owned transmission system
- Payments JPAs for transmission investments / services
- Other transmission-related expenses

Operations and maintenance expenses of the utility-owned transmission system include the POU's cost of labor, materials, and other supplies and services for operating (for example, load dispatching) and maintaining utility-owned transmission facilities. Transmission facilities include substations, switching stations, towers, poles, and overhead and underground lines.

California's POUs have co-funded transmission line projects through JPAs, including the Transmission Agency of Northern California and the Southern California Public Power Authority. JPAs own these transmission facilities, but the participating POUs are obligated to help pay for a project's capital and operating costs and debt service through service agreements. POUs are requested to report their annual payments to JPAs for these transmission investments / services. These expenses represent a POU's share of operating expenses, capital costs, and long-term debt service for JPA-owned transmission projects as well as other services.

POUs may use "other transmission-related expenses" to document costs for transmitting POU electricity over transmission facilities owned by others, such as the Western Area Power Administration, IOUs, and other private-sector owners.

- istribution (xpenses

POUs' distribution expenses include the cost of labor, materials, and other supplies and services for operating and maintaining utility-owned distribution facilities. Distribution facilities include substations, line transformers, voltage regulators, poles, overhead and underground lines, utility-owned streetlights and signals, and meters.

Each POU is requested to provide an aggregate of all its distribution-related operations and maintenance expenses (recent historical and projected) in this line of Form 8.1a (POU).

□ustomer-□elated (xpenses

POUs' customer-related expenses include the cost of labor, materials, and other supplies and services for the following activities:

- Meter reading
- Billing and collection
- Service connections and disconnections
- Advertising

In Form 8.1a (POU), please provide an annual sum for all customer-related service expenses. Do not include customer service and information expenses incurred to implement the POU's public benefit programs.

General and , dministrative (xpenses

Form 8.1a (POU) requests recent historical and forecasted financial data regarding each POU's general and administrative expenses. General and administrative expenses include salaries and wages for POU officers and employees who provide services not assignable to a specific utility function (for example, generation, transmission, distribution, customer service). Other general and administrative expenses include property and injury-related liability insurance, employee pensions and benefits, and regulatory commission expenses.

For POUs that are electric departments, general and administrative expenses also include fund transfers for services provides to the electric department by other city departments, such as Finance, Human Resources, Mayor, City Manager, City Council, City Clerk, Administrative Services, Planning and Building Services, and Information Technology.

) ublic Benefit) rograms

POUs are required by state law to fund the following types of public benefits programs with a use-based charge on local distribution service:

- Demand-side management to promote energy efficiency and energy conservation
- Renewable energy resources and technologies
- Research, development, and demonstration programs
- Low-income rate discounts and energy efficiency services

POUs must also fund a solar initiative program that invests in solar energy system installations on residential and commercial buildings.

Form 8.1a (POU) requests each POU to provide recent historical data and a forecast of its operating expenses to implement each of three public benefit programs:

- Low-income
- Energy efficiency (that is, demand-side management)
- California Solar Initiative
- All other public benefit programs

The costs of implementing other public benefit programs should be reported separately in Form 8.1a (POU) as "All other public benefit programs."

(nergy (fficiency (xpenses □rom) rocurement Budget

Expenses for energy efficiency programs paid from the generation or procurement budgets should be reported here.

□perating (xpenses &ot , lready □eported

Form 8.1a (POU) includes this row for POUs to report and forecast all other operating expenses, if any.

□apital □mprovement) lan) rojects

All POUs have long-range plans, usually four to six years, that identify capital projects and equipment purchases. Some capital projects are financed by issuing debt instruments, while others are financed from the POU's annual revenues. A POU's governing board or city council appropriates utility revenues for selected projects through a capital improvement budget.

Form 8.1a (POU) requests annual financial data for capital project expenditures funded by utility revenues rather than debt instruments. Capital project expenditures are divided into the following project categories:

- Generation
- Transmission System
- Distribution System
- Other

Generation

Capital expenditures for utility-owned generation include the cost for land and land rights, structures and improvements, the installed cost of all power plant equipment, and asset retirement costs. Hydroelectric capital expenditures also include the cost of dams, reservoirs, and waterways.

□ransmission

Capital expenditures for the utility-owned transmission system include land and land rights, structures and improvements, and the installed cost of station equipment, towers and fixtures, poles and fixtures, overhead conductors and devices, underground conduit, underground conductors and devices, roads and trails, and asset retirement costs.

- istribution

Capital expenditures for the utility-owned distribution system include land and land rights, structures and improvements, and the installed cost of station equipment, poles, towers and fixtures, overhead conductors and devices, underground conduit, underground conductors and devices, line transformers, meters, street lighting and signal systems, and asset retirement costs.

Form 8.1a (POU) requests financial data on all distribution system capital improvement projects, except deployment of advanced metering systems.

- istribution □ost - etail on , dvanced □ etering □ystem) rojects

Form 8.1a (POU) requests a separate breakout of recent and projected capital expenses to deploy advanced metering systems. POUs would install advanced meters to accomplish one or more of the following objectives:

- Reduce the cost to serve customers (that is, reduce labor costs for on-site meter reading and "back office" customer service).
- Offer time-based electricity pricing and incentives.
- Develop demand-response capability.

- Conduct load research (for example, gather information on time of use and peak load-shed opportunities).
- Enhance customer-communication capability.

, ll □ther □apital □mprovement) rojects

Please report the sum of all other types of capital improvement project expenditures in this section of Form 8.1a. Examples of other capital improvement projects include the following:

- Office furniture and equipment
- Transportation and power-operated equipment
- Stores equipment (that is, equipment used for receiving, shipping, handling and storing materials and supplies)
- Tools, shop and garage equipment
- Communication equipment

POUs should also use this section of Form 8.1a (POU) to report capital improvement expenses associated with their public benefit programs, if applicable. Please add a footnote at the bottom of this form that explains that the reported amount includes capital costs for public benefit-related projects.

- ebt □ervice

Debt service is the sum of a POU's repayments of principal and interest due each year on its outstanding long-term debt (for example, revenue bonds) and commercial paper notes, and trustee fees and debt issuance costs.

□eserve □und □ontributions

POUs make annual contributions to various reserve funds, such as rate stabilization funds, insurance and accident reserve funds, bond payment reserve funds, and credit support collateral reserve funds.

Please provide a total of all contributions to the POU's various reserve funds.

□ransfers to □ity General □und,) ayments in / ieu of □axes, and □ther □ees

When a POU is an enterprise business within a municipal governmental, the city charter may direct the electric utility department to make annual contributions to the city's general fund. Such contributions may also be referred to as "Payments in Lieu of Taxes." POUs may also pay other municipal fees, such as "right of way" fees.

Please provide recent historical and an annual forecast of annual payments to the city general fund and other municipal fees.

For POUs that are electric departments, do not include in this portion of the form fund transfers to other city departments for general and administrative services. Please include such transfers in the general and administrative line of the Operating Expenses section.

□orm 8.1a ((□))

The Energy Commission staff requests each ESP to provide data on its historical and future power-supply costs to serve existing direct access customers. Two power-supply cost categories are provided:

- Bilateral contracts
- Residual market transactions

The Energy Commission staff requests an annual estimate of historical and future costs for all supply contracts, regardless of resource type or ESP-ownership interest. Supply contracts defined as bilateral contracts are contracts for energy and / or capacity entered into before the delivery time. Bilateral contracts include capacity-only contracts to meet resource adequacy requirements.

Residual market transactions are short-term (less than three months) or spot-market purchases of electricity from suppliers other than the California ISO. The Energy Commission staff is not requesting an ESP cost forecast of payments to the California ISO for market charges.

□orm 8.1b (Bundled)

Form 8.1b (Bundled) determines how each respondent will allocate its revenue requirements among its bundled-customer classes.

Form 8.1b (Bundled) focuses on the rate components through which the respondent collects the majority of its revenue requirements: the generation component and the distribution component. Energy Commission staff requests each respondent provide a detailed break-out of its total forecasted revenue requirements for the generation and distribution rate components.

All other revenue requirement categories (for example, transmission, public purpose programs, and so forth) should be aggregated. Please combine all other revenue requirement categories (for example, transmission, nuclear decommissioning, public purpose programs, DWR bond charge, rate reduction bond charge, ongoing CTC charge) in “All Other Revenue Requirements” section of Form 8.1b (Bundled). Each respondent must sum up annual revenue requirements for all of these other categories and then show on Form 8.1b (Bundled) how much of this sum of “other revenue requirements” will be collected annually from each class of bundled customer, as defined below.

Form 8.1b (Bundled) identifies five classes of bundled customers:

- Residential / Domestic
- Commercial
- Industrial
- Agricultural
- All other customer classes (for example, street lighting)

The customer classes listed above match those used by Energy Commission staff to forecast electrical demand; however, they may not match how some utilities define their commercial and industrial customer classes. Some respondents define their commercial and industrial customers by size only (for example, "small," medium," and "large"), based on average monthly consumption and have rate schedules for similar-sized commercial and industrial customers. For example, small commercial and small industrial customers can be on the same rate schedule.

Thus, completing Form 8.1b (Bundled) may be a challenge for respondents with size-based systems for classifying commercial and industrial customers because rate schedules (and forecasted sales revenue) are not linked directly to discrete classes of "commercial" and "industrial" customers.

The Energy Commission staff recognizes this problem and recommends the following temporary solution. To overcome potential differences in how the Energy Commission and individual respondents define "commercial" and "industrial" classes, the Energy Commission staff requests that those respondents with size-based rate schedules use the following approach to assign rate schedules to either the commercial or industrial classes:

- Use rate schedules for small and medium-sized customers as the proxy for all "commercial" customers.
- Use rate schedules for large-sized customers as the proxy for "industrial" customers.

□orm 8.1b (- irect , ccess)

Respondents are requested to complete Form 8.1.b (Direct Access) by projecting the annual total of revenue requirements they intend to collect from direct access customers, if applicable. Respondents that do not have direct access customers need not fill out this form. Energy Commission staff is not requesting a detailed breakout of projected costs by revenue-requirement category for this type of electricity customer. For example, the Energy Commission staff is not asking for a separate revenue-requirements forecast for the Direct Access Cost Responsibility Surcharge.

It does, however, request that each respondent separate and report the portion of its annual revenue requirements it intends to collect from the two types of direct access customer: residential and non-residential (all types, that is, of non-residential customer).

□orm 8.2 . tility □esidential (lectricity □ales by Baseline) ercentages

Residential customers from some California utilities buy electricity under a tiered pricing structure. Tiers are defined as percentages of a daily baseline amount, which may vary by geographic region (baseline territory). Respondents whose residential customers do not face a tiered rate structure need not fill out Form 8.2.

Data provided under Form 8.2 will enable Energy Commission staff to study the distribution of electricity-sales by residential customers. Form 8.2 is not intended to determine how many kWh are sold at each tier level.

This data is to be provided for both "all-electric" and "basic-use" customers separately. The Energy Commission staff requests that each respondent complete both versions of Form 8.2 by providing the number of residential customers and their corresponding electricity sales data for 2009 and 2010 in 10 percent increments of baseline quantity by month for each baseline territory (that is, the number of customers in the 0 through 10 percent baseline cell should only include those customers with monthly use not exceeding 10 percent of the allocated baseline quantity and the corresponding energy should be only the energy used by those customers.)

- efinitions

Bundled Customers: Customers who receive both distribution and generation services from the same LSE.

Cogeneration: An arrangement whereby a utility or customer-owned facility sequentially produces thermal energy for process heat or space conditioning use and electrical energy for private use, or for sale to an electric utility, or some combination thereof.

Customer Sectors: Customer sectors used by the Energy Commission are defined using the following North American Industrial Classification (NAICS) categories.

	NAICS
Residential: private households, including single and multiple family dwellings.	RE00-RE39, 001-003, 814
Commercial	115, 2331, 326212, 42, 44-45, 48841, 493, 512, 514, 518-519, 52-55, 561, 61, 62 (excluding 62191), 71, 72, 81 (excluding 81293 and 814), and 92 (excluding 92811)
Industrial	11331, 21 and 23 (excluding 22131); 31-33, 511, and 54171
Agricultural	111, 112, 113, 114
Water Pumping	22131
Transportation, Communication, Utility (TCU)	221, 48, 49, 513, 517, 562, 62191, and 92811
Street Lighting	9225, 9226

Dollar Denomination: Unless otherwise specified, any dollar denominated variable is to be measured in 2009 dollars.

Distributed Generation: Electricity production that is on-site or close to the load center and is interconnected to the utility distribution system. Large generation facilities (such as qualifying facilities) that interconnect to the utility at transmission voltages would not be considered distributed generation.

Utility Distribution Company (UDC): A utility that owns and/or operates an electricity distribution system that interconnects end user loads with a generator serving more than one end user load or the interconnected transmission grid.

Electricity Consumption: The amount of electricity used to provide energy services through both utility sales and local private supply of electricity.

Load-Serving Entity (LSE): An umbrella term encompassing all entities that provide generation services to end-use customers, whether or not it owns or operates a distribution system. Examples are traditional investor-owned utilities, municipal utilities, energy service providers permitted to operate under applicable law, community choice aggregators permitted to operate under AB 117, and all other entities that serve end-use loads.

Local Private Supply: Local private supply is supply from self-generation, customer-owned distributed generation, private sales "over-the-fence" from a cogeneration facility, or wheeling from a cogeneration facility to a final user.

Self-Generation: Any generation of electricity by a final user for his own use, regardless of the technology used. The portion of cogeneration retained for the customer's own use is self-generation even if this is a small portion of overall facility output.

□)) (□- □X □:
How □o □equest □onfidentiality

The Executive Director of the Energy Commission has responsibility for determining what information submitted with an application for confidentiality will be deemed confidential. Parties who seek such a designation for data they submit must make a separate, written request that identifies the specific information and provides a discussion of why the information should be protected from release, the length of time such protection is sought, and whether the information can be released in aggregated form. Certain categories of data provided to the Energy Commission, when submitted with a request for confidentiality, will be automatically designated as confidential and do not require an application. The types of data that are eligible and the process for obtaining this confidential designation are specified in California Code of Regulations, Title 20, Section 2505(a)(5). Note that the Energy Commission has its own regulations distinct from those governing the CPUC, and CPUC determinations on confidentiality are not applicable to data submitted to the Energy Commission.

Data that are not included in these categories but that the filer believes are entitled to confidential treatment should be submitted with an application for confidential designation so that the Executive Director can review the information and make a determination about its confidential status. To do this, please carefully read and follow the instructions below.

The application must include three attributes:

1) A hard copy of the application for confidentiality must be submitted to the Executive Director:

   Melissa Jones, Executive Director

   California Energy Commission

   1516 Ninth Street MS-39

   Sacramento, CA 95814-5504

2) The information being provided to the Energy Commission must be included as an attachment (either hard copy or electronic), marked as Docket #11-IEP-1C, and the confidential data categories must be clearly and properly labeled.

3) A "penalty of perjury certification" must be included. Suggested standard language is as follows:

   I certify under penalty of perjury that the information contained in this application for confidential designation is true, correct, and complete to the best of my knowledge. I also certify that I am authorized to make the application and certification on behalf of (ABC Utility or Corporation).

Applications deemed incomplete in these three respects will **not** be docketed by Energy Commission staff. Applications deemed incomplete will be returned, and the data will be placed in a confidential "suspense" file. The filer will be notified by mail and e-mailed about deficiencies in the application. The applicant has 14 calendar days to correct defects in the application and return an amended application to the Energy Commission. After 14 days, all information associated with an incomplete application for confidentiality (based on the three attributes listed above) will be deemed public and docketed accordingly. In addition, an application may be deemed incomplete and returned to the applicant if it does not contain the following information:

- Identification of the information being submitted, including title, date, size (for example, pages, sheets, MB), and docket number
- Description of the data for which confidentiality is being requested (for example, particular contract categories, specific narratives, and time periods)
- A clear description of the length of time for which confidentiality is being sought, with an appropriate justification, for each confidential data category request
- Applicable provisions of the California Public Records Act (Government Code Section 6250 et seq.), and / or other laws, for each confidential data category request
- A statement attesting that a) the specific records to be withheld from public disclosure are exempt under provisions of the Government Code, or b) the public interest in non-disclosure of these particular facts clearly outweighs the public interest in disclosure
- A statement that describes how each category of confidential data may be aggregated with other data for public disclosure

Parties should be aware that some confidential data may be disclosed after aggregation according to CCR, Title 20, 2507(d). Both historic and forecast energy sales data may be disclosed if reported at the following levels:

- For individual ESPs, data may be aggregated at the statewide level by major customer sector.
- For the sum of all ESPs, data may be aggregated at the service area, planning area, or statewide levels by major customer sector.
- For the total sales of the sum of all electric retailers, data may be aggregated at the county level by major generator, utility, and electric service provider groups as these groups are defined by the U.S. Census Bureau in their North American Industry Classification System (NAICS) tables.

Other aggregations may be considered on a case-by-case basis, but no disclosure of data aggregated in this manner will be released without notice and consultation by the Executive Director.

The Executive Director signs confidentiality determination letters. The applicant has 14 calendar days to appeal this decision.

An applicant can request confidentiality at any time. The Energy Commission strongly encourages filers to provide data and any confidentiality requests concurrently.

More specific questions about confidentiality may be directed to Kerry Willis at kwillis@energy.state.ca.us or (916) 654-3967.