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INITIAL STATEMENT OF REASONS

Proposed Additions to and Modifications of
Regulations Governing Data Collection
and Designation of Confidential Information

California Code of Regulations
Title 20, Sections 1302, 1304, 1306, 1308, 1314, 1344, 1353, & 2505

California Energy Commission
Docket Number 16-OIR-03
August 4, 2017

PROBLEM STATEMENT – Gov. Code § 11346.2(b)(1)

<u>Electric and Gas Monthly Customer Data, Meter Data, Interconnection, Load Shapes</u>

Energy Commission Mandate and California Energy and Environmental Policies

Forecasting: The Legislature has stated that “electrical energy is essential to the health, safety and welfare of the people. . . and to the state economy, and that it is the responsibility of state government to ensure that a reliable supply of electrical energy is maintained at a level consistent with the need for such energy for protection of public health and safety, for promotion of the general welfare, and for environmental quality protection. (Pub. Resources Code §§ 25001 and 25300, subd. (b).) Further, the Legislature has found that “state government requires at all times a complete and thorough understanding of the operation of energy markets” and that “timely reporting, assessments, forecasting, and data collection activities are essential to serve the information and policy development needs of the Governor, the Legislature, public agencies, market participants, and the public.” (Pub. Resources Code § 25300, subds. (c), (d).)

As a result, the Energy Commission is mandated by statute to “conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices.” (Pub. Resources Code § 25301, subd. (a).) These forecasting and assessment activities are developed as part of the Integrated Energy Policy Report (IEPR)[1] that is mandated every two years. (Pub. Resources Code § 25302.) As part of the IEPR process, the Energy Commission adopts a detailed demand forecast that is used by other energy agencies -- including the California Independent System Operator -- to identify resource additions needed to ensure reliability. (Pub. Resources Code § 25302, subd. (f).) In addition, the demand forecast is used “for analyzing the success of and developing policy recommendations for public interest energy strategies." (Pub. Resources Code § 25305.) In sum, the Energy Commission's forecasting activities serve two fundamental purposes: 1) to identify actions needed to ensure the reliable operation of the state's electricity and natural gas supply systems; and 2) to assess progress in and develop recommendations for meeting state energy goals.

Data Collection Authority: In conducting assessments and forecasts for the IEPR, the Energy Commission is authorized to collect data from a broad range of market participants, including generators, gas utilities, and electric utilities. Pursuant to Pub. Resources Code § 25108, the latter group includes utility distribution companies or "UDCs," and load-serving entities or "LSEs." A UDC is an electric utility that physically distributes electricity to end-use customers, whereas an LSE sells electricity to end-use customers. A UDC can be either an investor-owned utility or a local publicly owned electric utility. All UDCs in California are also LSEs, but there are LSEs – such as community choice aggregators -- that rely on a UDC to physically distribute the power the LSE sells. The proposed changes affect regulations governing UDC data reporting requirements and the confidential status of that data.

Greenhouse Gas Emissions Reductions: In 2006, California established a greenhouse gas (GHG) emissions reduction goal, requiring the state to reduce GHG emissions to 1990 levels by 2020. (Health & Saf. Code §§ 38550-38551.) Recently, the state established an aggressive goal of reducing GHG emissions to 40 percent below 1990 levels by 2030. (Health & Saf. Code § 38566). Key strategies adopted by state agencies (including the Energy Commission, the California Air Resources Board and the California Public Utilities Commission (CPUC)) to meet these GHG emissions reduction goals have dramatically altered California's energy mix and affected customers' consumption and generation patterns. Specifically, in an effort to reduce GHG emissions, the state has actively promoted increased use of transportation electrification (electrification of vehicles, freight movement, and ports), the deployment of energy storage systems, the generation and procurement of renewable energy, including rooftop photovoltaic (PV) and other distributed energy resources, and increased development of energy efficiency standards and programs. The state's investor-owned and local publicly owned electric utilities have responsibilities for GHG emissions reduction goals as well. (Pub. Utilities Code §§ 454.52 and 9621.) As discussed in more detail below, the data currently collected by the Energy Commission does not capture the effects of these policies. In order for the Energy Commission to meet its statutory obligations of identifying emerging trends in energy efficiency potential, renewable energy development, and GHG emissions reduction efforts, and to assess the effects of energy efficiency savings on electricity demand on an hourly and seasonal basis, more disaggregated data is now needed. (Pub. Resources Code §§ 25305, 25310.)

Energy Efficiency: From its inception, the Energy Commission has been responsible for identifying and encouraging energy efficiency savings in order to reduce unnecessary consumption of fossil resources and to capture associated economic savings. Now, as a result of the state's GHG emissions reduction goals, programs and policies promoting energy efficiency have become even more important. State law requires the state's investor-owned utilities (IOUs) and local publicly owned electric utilities to "first meet [their] unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible." (Pub. Utilities Code § 9615.) More specifically, legislation enacted in 2015 directs the Energy Commission to "establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings by 2030." (Pub. Resources Code § 25310, subd. (c)(1).) Energy efficiency can reduce both electricity and natural gas consumption and the need for new generation resources.

Renewable Energy: California initially established a Renewables Portfolio Standard (RPS) program in 2002 and both the CPUC and Energy Commission were tasked with implementation responsibilities. Over the years, the renewable energy target has been increased and currently, LSEs are under a legislative mandate to procure renewables for 50 percent of retail sales by 2030. (Pub. Utilities Code §§ 399.11, 399.30.) By 2016, an estimated 27 percent of electricity sold at retail in the state was generated by renewable sources.[2] Of particular significance for this rulemaking is the dramatic increase in rooftop PV, which allows individual customers to generate some or all of their own electricity, which they can use as it is generated or use later if the customers have installed energy storage. Although large industrial customers have had the ability to self-generate significant electricity for a number of years, recent incentives had led to increased deployment of residential and commercial rooftop PV, affecting electricity system load patterns at the local, regional, and statewide level.

Distributed Energy Resources: Distributed energy resources (DER) are another important component of the state's GHG policy. DER refers to generation connected at the distribution level (for example, smaller generation resources such as rooftop PV or small wind farms) and non-generation resources such as energy efficiency or energy storage; in fact, even an electric vehicle (EV) can be a DER. These resources can reduce GHG emissions by minimizing electricity and natural gas consumption and minimizing electric transmission line losses - energy losses that occur when electrical energy is transmitted over high-voltage electrical lines. DER helps ensure local reliability for those areas that have limited electricity and natural gas supply infrastructure.

To facilitate the deployment of these resources, IOUs are required to develop distribution resource plans that identify locations of DER that maximize benefits and minimize costs for electric grid investments. (Pub. Utilities Code § 769.) In 2016, almost

9,400 megawatts (MW) of DER (excluding energy efficiency), enough electricity to supply at least 7 million homes,[3] was operating or installed in California.[4]

Energy Storage: Energy storage systems, which are a type of distributed energy resources, can play a particularly important part of state energy policy.[5] One of the means by which the state plans to meet its GHG emissions reduction goals is through increased use of renewable generation. However, renewable generation is intermittent and often occurs at times when electrical demand or “load” is low.[6] Because electrical loads must be met instantaneously, energy storage allows the renewable generation that is not needed at the time it is generated (and would otherwise need to be curtailed) to be stored and to displace fossil generation at a later time when renewable energy production levels are low. Lack of energy storage could hamper the state’s ability to maximize use of renewable generation, which in turn hinders its ability to meet its GHG emissions reduction goals. Pursuant to Public Utilities Code § 2836, the CPUC established an energy storage procurement target of 1,325 MW for IOUs, with installations required no later than the end of 2024. (<u>See</u>, Rulemaking, 10-12-007, D. 13-10-040.) This section also requires local publicly owned electric utilities to establish energy storage targets. Expansion of energy storage capacity will help optimize grid operations and minimize the need for electric grid investments by maximizing the state’s ability to use electricity generated from intermittent renewable resources at different times of the day.

Transportation Electrification: Increased investments in transportation electrification have also been adopted as a key strategy to meet GHG emissions reduction targets. The state is required to adopt policies, rules, and regulations that achieve GHG emissions reductions through deployment of transportation electrification options, including electrification of cars, trucks, trains, and ports. (Pub. Utilities Code § 740.12, subd. (a)(1)(D), Health & Saf. Code § 44258.5.) However, unmanaged charging of EVs can lead to an increase in peak demand, which is typically met with the higher-emission fossil generation resources that are faster ramping and well-equipped to supply electricity at peak.[7] As a result, state policy encourages EV drivers to charge when electricity demand is low (to avoid adding to peak demand) or when renewable resources are abundant.

GHG Emissions Reduction Efforts Affect Consumption and Generation Patterns: Together, these GHG emissions reduction strategies can have a dramatic impact on how much and when customers will need to rely on an LSE to supply electricity. In fact, aggregated historic customer demand patterns - in which load increased beginning in the morning to a mid-day peak, tapered off until early evening when returning workers increased their electrical demands, and dropped to low levels overnight – are increasingly less representative of actual demand. For example, energy efficiency has lowered the overall electricity demand that an LSE must meet. Demand response programs can shift customer demand from peak to off-peak hours. PV systems generate electricity to meet customer demand and tend to peak when the sun is directly overhead, reducing mid-day demand on utility systems. Similarly, there is a large drop in PV production when the sun sets, shifting the peak demand that the utility must serve and creating a steep upward ramp in demand in the evening. Finally, the timing of EV charging – whether at work or overnight -- can noticeably affect demand patterns. While these changes in demand patterns are more prominent in the electricity system, increases in energy efficiency and other DER as well as renewable generation also affect natural gas demand patterns.

Current Data Collection Doesn't Track New Trends: These examples illustrate that California's new policy and regulatory initiatives require an increased focus on individual consumers, their energy and technology choices, and their particular locational circumstances. It has long been known that energy use varies considerably across households and firms as a function of behavioral, economic, demographic, and geographic factors, even with comparable end-use technology. When factors such as EV ownership or rooftop solar are also present, the variation is even greater. Moreover, this household- and firm-level variation does not "average out" in the aggregate but rather has major effects on aggregate consumption patterns and on the effects of policies and programs that influence energy use and carbon emissions. Information on local, seasonal, and individual consumption patterns is needed.

In addition, the particular locational circumstances of individual customers matter. For example, energy use can vary significantly depending on the climate of a particular geographic area. Energy use patterns in hot, inland areas are different than in coastal areas. Similarly, PV generation varies depending on the amount of solar insolation in a given area, as well as the amount of shading and cloud cover. The Energy Commission demand forecast currently incorporates 20 climate zones with temperature regimes and climatic conditions to ensure climatic variations across California are captured.[8] Additional disaggregation of the forecast to capture sub-areas and more localized variations in climate is necessary to improve forecast quality and to adequately forecast when and where PV generation will occur.

Where demand shows up on the electricity system is also important in assessing whether there is sufficient generation to reliably meet demand. Planning for electricity system infrastructure is increasingly done at a localized level. Disaggregation to local areas and sub-areas is necessary especially in local load pockets (also referred to as local reliability areas), where distributed resources are increasingly deployed to provide reliability and grid support services.[9] Investments in energy efficiency and demand response resources can help defer the need for natural gas-fired generation, thereby reducing GHG emissions. However, if energy efficiency or demand response resources do not materialize at given locations as anticipated, or if PV systems do not perform as expected, gas-fired generators may have to run to preserve reliability. This would impair the state's ability to meet its GHG emissions reduction goals. In addition, there are certain sub-areas of the electricity system – transient in nature and dependent on highly localized demand and supply conditions – that present unique reliability challenges. Understanding how these sub-regions emerge and evolve and how they can be addressed by deploying resources such as renewables, energy efficiency, and demand response requires disaggregated data.

The consumption data collected by the Energy Commission is aggregated to the monthly, county, and customer class level and does not include information about use of EVs, participation in energy efficiency programs, use of generation from rooftop PV and other distributed energy resources, including energy storage systems. This highly aggregated demand and supply information creates two significant problems in meeting statutory mandates. First, the Energy Commission's forecasts are less accurate than they would be with more detailed information. Estimates of peak demand and overall consumption patterns do not reflect local and regional variations. Because the Energy Commission's forecast is used for energy planning, including infrastructure planning by other agencies (e.g., Pub. Resources Code, § 25302, subd. (f)), inaccurate forecasts could result in the deployment of unneeded generation and transmission resources, burdening utility ratepayers with unnecessarily high electricity costs. Inaccurate forecasts could also hamper the state's ability to recognize areas that require additional DER for local reliability purposes as well as missed opportunities to identify where demand-side resources can lead to reductions in peak load in a cost-effective manner.

In addition, inaccurate and aggregated forecasts do not allow for more localized assessments of consumption patterns or peak load. This in turn means that the Energy Commission cannot evaluate the effectiveness of state GHG emissions reduction strategies – such as increasing energy efficiency or EV use - by comparing customers in the same communities who do and do not participate in programs designed to promote those strategies. As a result, the Energy Commission's ability to develop recommendations for actions to achieve state energy policies and to evaluate the effect of existing actions on state energy policy is hampered. For example, in assessing the most cost-effective means of reducing GHG emissions, it is important to know whether customers reduce their consumption of utility-delivered energy by participating in energy efficiency programs, or by use of PV generation. Similarly, tracking the effect of EV deployment on electricity consumption requires cross-referencing EV ownership (information obtained by the Energy Commission from the California Department of Motor Vehicles) with the electricity consumption patterns of EV owners.

Finally, evaluations of billing data have shown that the electric and natural gas utilities have difficulty assigning accurate North American Industrial Classification System (NAICS) codes (standard classifications of economic activity of businesses or industry developed by the federal government) to their customers, leading to direct negative impacts on the forecast quality. For example, a number of LSEs assign a significant amount of their sales as “unclassified” sales – consumption that the Energy Commission cannot map to a specific type of business or industry. In fact, unclassified sales are the fastest growing category of energy consumptions reported to the Energy Commission.[10] As different types of businesses and industries can have different energy consumption patterns, the lack of accurate NAICS codes means that the Energy Commission cannot accurately assess or track trends in consumption by economic sectors and activities.

Proposed Modifications: Fortunately, as new energy generation and consumption patterns have developed, so has information technology. Data tracking capability that wasn’t available ten years ago is now widely used by larger gas and electric utilities for their business purposes. For example, most large UDCs use “smart meters” at homes and businesses - meters that record and transmit consumption data at frequent intervals, such as 15 minutes or one hour. Billing data is also maintained electronically and easily accessed. The Energy Commission proposes to take advantage of this technological evolution to address the problems identified above. In fact, much of the new data identified in the proposed regulations consists of files that the gas and electric utilities keep in the ordinary course of business. Little or no data processing is required and the reporting entities will simply submit the files as they keep them to the Energy Commission. This minimizes regulatory costs and burdens.

Specifically, the Energy Commission is proposing to modify its data collection regulations to require the provision of energy-related data at disaggregated or “high resolution” levels. Proposed regulatory language requires the submission of individual gas and electric customer billing data, including electric interval meter data, additional information from UDC interconnection agreements about small generation and energy storage systems connected to the electric grid, as well as the results of analytical efforts by UDCs to estimate generation and consumption activities that affect the completeness of information provided by UDC interval meters. The specific data to be required, how it is used, and an explanation of why the Energy Commission proposes to address the problems with these changes to data collection is found in discussions addressing Sections 1302, 1304, 1306, 1308, 1344, and 1353 below. The confidentiality of customer billing data is addressed in a proposed change to Section 2505.

<u>Natural Gas Pipeline System</u>

In addition to the problems faced by the Energy Commission described above, recent shortages of natural gas needed to maintain reliable operation of the electric grid have highlighted the problem of inadequate information for assessing the functioning of the natural gas system. The Energy Commission has broad authority to evaluate supply uncertainties and the sufficiency of natural gas supplies and infrastructure to ensure electric system reliability. (Pub. Resources Code § 25303, subds. (a)(3) & (4).) And, as noted above, the Energy Commission is mandated to develop assessments and forecasts for analyzing the success of and developing policy recommendations for public interest energy strategies, such as renewable energy deployment. (Pub. Resources Code, § 25301, subd. (a).)

The natural gas system in California requires the use of supplies delivered into its transmission pipelines and supplies drawn from storage to meet demand. In fact, California produces little of its own natural gas and relies heavily on imports. Shortages in natural gas supply for certain power plants can cause electricity shortages that can lead to curtailments of customers or outages. When there are natural gas shortages at the natural gas-fired power plants that support intermittent renewable generation, older and less flexible natural gas units are dispatched instead and renewable production is curtailed. This hampers the state's ability to meet its renewable and GHG emissions reduction targets.

In recent years, the state's natural gas system and the electricity system have become increasing interdependent. The state's natural gas system is designed for seasonal swings in residential and commercial demand – characterized by high demand in winter and low demand in summer. However, in recent years, swings in demand are seen on a daily and hourly basis, as natural gas plants are called upon to accommodate the much more variable generation patterns of an electricity system more dependent upon intermittent renewable resources.

This interdependence was clearly seen when a major natural gas leak occurred at the Aliso Canyon Natural Gas Storage Facility on October 23, 2015. Aliso Canyon provides natural gas to natural gas-fired power plants that play a central role in meeting regional electrical demand. As such, the facility (as well as other natural gas storage facilities) is critical to meet peak natural gas demand in winter months and help to meet peak electrical demands during the summer months.[11] Analyses performed in response to the leak indicate that if Aliso Canyon were unavailable or not permitted to operate in winter, or if pipeline supplies did not materialize because of conditions east of California,[12] Southern California Gas Company would be unable to meet its 1-in-10 year cold day reliability planning criteria and would require electric generator curtailment. Additionally, without the complete curtailment of all noncore customers, core reliability would be in jeopardy during a 1-in-35 year peak day event. ("Core" customers are primarily residential and small commercial customers, accounting for approximately 32 percent of the natural gas delivered by California utilities in 2012. "Noncore" customers are large consumers, such as electric generators and industrial customers and account for approximately 68 percent of the natural gas delivered by California utilities in 2012.[13]) A risk assessment of 2016 summer conditions assuming no withdrawals from Aliso

Canyon estimated 16 days of possible natural gas curtailments in the Los Angeles Basin, depending on weather and other contingencies. These analyses demonstrate the crucial role that the natural gas system plays in electrical system reliability.

In addition, natural gas-fired generation supports the increasing levels of intermittent renewable resources that are being developed to meet the state's RPS. (Pub. Utilities Code §§ 399.15 & 399.30.) The specific natural gas-fired generation resources that are needed to integrate these intermittent resources have fast ramping capabilities, such as shorter start times and the ability to rapidly increase or decrease generation to match system needs. The timely delivery of natural gas to these plants is a prerequisite to maximizing renewable generation and achieving GHG emissions reduction goals while maintaining electric system reliability.

To ensure the Energy Commission has the necessary information to enable it to address these problems, the Energy Commission is proposing regulations that will require the state's three largest gas utilities to submit data needed to better monitor, model, and analyze the interaction of California's electricity and natural gas systems for grid reliability. The specific data to be required, how it is used, and an explanation of why the Energy Commission proposes to address the problems with these data collection changes are discussed below. The proposed language is found in Section 1314.

<u>Minor Clarifying Changes</u>

The Energy Commission proposes to adopt three sets of minor clarifying changes addressing: 1) cogeneration data, 2) natural gas infrastructure data, and 3) automatic designation of confidential data proposed to be collected.

Cogeneration Data: Current data submission requirements for owners of cogeneration facilities, contained in Section 1304, only require the reporting of electrical sales, and not the amount of thermal production that is used for commercial or industrial processes. As a result, the Energy Commission is precluded from identifying actual cogeneration facility emissions intensities and efficiencies. The state has identified the deployment of cogeneration facilities as an important tool in meeting GHG emissions reduction goals. (*2015 Integrated Energy Policy Report*, p. 151, Pub. Utilities Code § 2840 et seq.) Data about the actual performance of cogeneration facilities will help the Energy Commission evaluate the extent to which these facilities in fact achieve the benefits that are the basis of the state policy. In addition to the changes proposed for Section 1304, subdivision (a), three definitional changes related to Section 1304 are proposed for Section 1302.

Natural Gas Infrastructure Data: In Section 1308, several names associated with the state's gas infrastructure are incorrect or need to be added as a result of new construction. This problem is addressed with the proposed amendments to Section 1308, which identifies data requirements associated with those facilities, and is discussed in more detail below.

Automatic Designation: The Energy Commission's regulations implementing the California Public Records Act (PRA), found at Government Code section 6250 et seq., generally require a third party to submit an application for confidential designation if he or she believes the information he or she is submitting is exempt from the disclosure requirements of the PRA. However, because certain types of information collected by the Energy Commission are so clearly confidential that an application would be pointless, the Energy Commission has designated certain information as "automatically confidential" and requires no application for confidential designation. These categories are identified in Section 2505, subdivisions (a)(5)(B)1. – 8., and the Energy Commission proposes to add individual customer billing data and natural gas infrastructure information to that list in a new subdivision (a)(5)(B)9. Further discussion is provided below.

BENEFITS

The primary benefits of the proposed new reporting requirements will be that the Energy Commission will be able to more accurately depict when, where, and for what purpose energy is used and to more accurately identify the specific effect of various energy programs and policies on electricity and natural gas consumption patterns. This will improve electricity forecasts geographically, by sector, and by end-use, and will allow for better tracking and targeting of policies designed to promote state energy goals.

Natural gas modeling will provide the benefit of allowing the state the analytical capability to run the Synergi gas model,[14] a model allowing assessments of gas transmission and distribution operational capabilities, and assess the results of a range of natural gas demand and supply scenarios. In light of the close interrelationship between the natural gas supply system and the reliability of the electricity system discussed above, these efforts will allow for the Energy Commission to make recommendations to ensure that the state has a reliable supply of natural gas. (Pub. Resources Code § 25303, subds. (a)(3) & (4), § 25303.5, subd. (b)(6).)

The corrections to the identification of natural gas infrastructure in Section 1308, and two new categories of automatically confidential information ensure accurate regulations and regulations that identify a streamlined process for confidential treatment of data that the Energy Commission already determines to be confidential.

PURPOSE AND NECESSITY

1302 – Rules of Construction and Definitions.

Subdivision (b)(2)

Purpose: The purpose of subdivision (b)(2) is to modify the existing definition of "Cogenerator."

Necessity: It is necessary to modify the definition of "Cogenerator" because the Energy Commission is changing the phrase "useful thermal energy" – which is used in the current definition -- to "useful thermal output" in Section 1304, which imposes specific data reporting requirements on owners of cogeneration facilities. The phrase in the existing regulations - "useful thermal energy" – is not defined, and the Energy Commission has decided to change the term to match the term used by the U.S. Energy Information Administration (EIA) – "useful thermal output." The definition of "useful thermal output" and the reason for its use are found in the discussion of Section 1304, subdivision (a)(1)(G), (a)(2)(A)4., 6., 7. – 9., (a)(2)(B)4., 6., 7. – 9., and (a)(2)(C)4., 7. – 10., below.

Subdivision (b)(18)

Purpose: The purpose of subdivision (b)(18) is to add a definition of "Energy storage system," a term that is used in proposed Section 1353.

Necessity: Energy storage systems are capable of absorbing and storing energy and later discharging it. Use of energy storage systems by customers can affect energy consumption patterns and peak electricity demand. As discussed above, energy storage is an important component in the state's plan to reduce GHG emissions through increased use of renewable energy resources. UDCs must approve interconnection of an energy storage system to the electric grid. The Energy Commission is proposing to include energy storage systems in the information UDCs would be required to report pursuant to existing Section 1304 and new Section 1353. Therefore, it is necessary to add a definition of energy storage system. Public Utilities Code section 2835 contains the only statutory definition of energy storage system in the California codes, and the Energy Commission proposes to use the first sentence of this definition for the data collection requirements in Section 1304 and 1353. The remainder of the definition in that statute identifies the characteristics of those energy storage systems to be included in regulatory procurement targets and is not relevant to the basic definition of an energy storage system.

Subdivision (b)(35)

Purpose: The purpose of subdivision (b)(35) is to add a definition of “Interval meter.”

Necessity: Interval meters are devices that can record and transmit data about energy consumption and generation at intervals of one hour or less. In Section 1353, the Energy Commission proposes to require the submission of interval meter data. Therefore, a definition of an interval meter is necessary. This definition reflects the ability of a meter to accurately collect data in increments of time and transmit that information for tracking and billing.

Subdivision (b)(36)

Purpose: The purpose of subdivision (b)(36) is to add a definition of “Interval meter data.”

Necessity: As noted for subdivision (b)(35), the Energy Commission proposes to require the submission of interval meter data in Section 1353. Therefore, a definition of interval meter data is necessary. The definition provided identifies the energy demand information that is captured by an interval meter.

Subdivision (b)(41)

Purpose: The purpose of subdivision (b)(41) is to add a definition of “Meter identification number.”

Necessity: All metered LSE customers have specific meters associated with the customer and the specific service being provided in order to provide billing and for tracking consumption. (Some of these meters are interval meters but many are not.) LSEs assign each meter a unique number to correlate metering information with an account or agreement. In order for Energy Commission staff to match customer information with meters, it is necessary for the Energy Commission to identify and use the phrase “meter identification number.”

Subdivision (b)(48)

Purpose: The purpose of the modifications to subdivision (b)(48) – which provides the definition of “North American Industry Classification System” or “NAICS” - is to rely on the updated language used by the federal Office of Management and Budget to designate various industrial classifications.

Necessity: The federal Office of Management and Budget maintains a database of various industrial classifications. NAICS is the standard used by federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy. The current regulations reference an outdated manual of NAICS classifications. As NAICS classifications are updated regularly, the Energy Commission needs to change the language in its regulations to reference the current NAICS publication. This is a status-conferred situation, and requiring the use of any updates to NAICS adopted by the Office of Management and Budget will ensure consistency with other governmental analytical efforts.

Subdivision (b)(51)

Purpose: The purpose of the modifications to subdivision (b)(51) is to expand the definition of "Peak demand" to include time periods other than an hour.

Necessity: The modification to this definition is needed to allow for the reporting of data at time periods or intervals other than hours as proposed in Section 1353. Data will be provided at the interval over which the consumption is collected and the corresponding peak data will need to be for the same interval.

Subdivision (b)(56)

Purpose: The purpose of subdivision (56) is to add a definition of "Premise identification number."

Necessity: This definition is needed because the phrase "premise identification number" is used in proposed Section 1353. The definition captures the unique alphanumerical value corresponding to the location at which service is provided to the customer by the LSE. Since meters can change over time due to reasons such as damage or upgrade, an identifier which specifies static location of the metering at the service address is needed to consistently track consumption.

Subdivision (b)(58)

Purpose: The purpose of subdivision (b)(58) is to add a definition of "PV."

Necessity: A definition of PV is needed because the Energy Commission is proposing to collect information from LSEs about PVs as part of this rulemaking. The definition is identical to that adopted by the Energy Commission in 2011 in Title 20, Cal. Code Regs., § 2701, subd. (p) for the Solar Offset Program, which ensures consistency across programs.

Subdivision (b)(59)

Purpose: The purpose of subdivision (b)(59) is to add a definition of "Rate schedule."

Necessity: This definition is needed because the phrase "rate schedule" is used in proposed Section 1353. The term "rate schedule" captures all service related to billing information and is specific to the type of service being provided. LSEs adopt various rate schedules, which are available to different customer classes.

Subdivision (b)(60)

Purpose: The purpose of subdivision (b)(60) is to provide a definition of "Secure electronic method."

Necessity: This definition is needed because the phrase "secure electronic method" is used in proposed Sections 1314 and 1353. The term is used to specify the level of protection needed to transfer confidential data between third parties and the Energy Commission. End-to-end encryption will ensure the data is protected; the definition of "end-to-end encryption" comes from the State Administrative Manual § 5300: Information Technology - Office of Information Security. (https://cdt.ca.gov/security/technical-definitions).

Subdivision (b)(61)

Purpose: The purpose of subdivision (b)(61) is to add a definition of "Service account number."

Necessity: This definition is needed because "service account number" is one of the primary methods used by utilities to identify and track utility services to specific customers and is a required field in Section 1353. The "service account number" is a unique identification number assigned by the utility to an account to track energy demand, provide billing services, and specify the service agreement between the utility and the customer.

Subdivision (b)(64)

Purpose: The purpose of subdivision (b)(64) is to add a definition of "Therm."

Necessity: This definition is needed because the therm unit is used in Sections 1308, 1314, and 1353 as the unit for the amount of natural gas deliveries and as the basis of a reporting threshold.

Subdivision (b)(66)

Purpose: The purpose of subdivision (b)(66) is to provide a definition of "Useful thermal output."

Necessity: This definition is needed because the Energy Commission is proposing to change a phrase in Section 1304 to require owners of cogeneration facilities to provide information about "useful thermal output." Currently, owners of cogeneration facilities are required to provide information about "useful thermal energy," a term which is not defined. The Energy Commission proposes to change this term to match that used by the EIA and to use the EIA definition, found in 18 C.F.R. § 292.202, subd. (h). See the discussion below for Section 1304, subdivisions (a)(1)(G), (a)(2)(A)4., 6., 7. – 9., (a)(2)(B)4., 6., 7. – 9., and (a)(2)(C)4., 7. – 10. for a more detailed discussion of necessity.

Subdivision (b)(68)

Purpose: The purpose of subdivision (b)(68) is to provide a definition of "Waste heat."

Necessity: It is necessary to add this definition because the Energy Commission is proposing to require owners of cogeneration facilities to provide information about waste heat as a result of changes to Section 1304. Waste heat is the amount of thermal energy produced by a cogeneration plant that is not useful thermal output. The percentage of thermal energy that is not waste heat (for example, that is useful thermal energy) affects the efficiency and emission intensity of cogeneration facilities, and with this information, the Energy Commission will be able to evaluate the extent to which cogeneration facilities are in fact providing the benefits that are the basis of the state's cogeneration policy. See the discussion below for Section 1304, subdivisions (a)(1)(G), (a)(2)(A)4., 6., 7. – 9., (a)(2)(B)4., 6., 7. – 9., and (a)(2)(C)4., 7. – 10. for a more detailed discussion of necessity.

Renumbering – The addition of new definitions to subdivision (b) required renumbering; the renumbering reflects the fact that all of the definitions are provided in alphabetical order.

References – three new sections are included as references: Pub. Resources Code §§ 25305, 25305.1, and 25310. The latter two are statutes enacted since this Section was last amended that govern data analysis and the first statute was inadvertently omitted during the previous rulemaking; it too references the Energy Commission's analytical responsibilities.

1304 – Power Plant Reports

Subdivision (a)

With one exception, the changes in subdivision (a) address the need of the Energy Commission to obtain more detailed information from cogeneration facilities in order to assess fuel efficiency and emission intensity factors. The exception is a proposed grammatical correction; changing "an" to "a" in the last sentence of subdivision (a).

Subdivisions (a)(1)(G), (a)(2)(A)4., 6., 7. – 9., (a)(2)(B)4., 6., 7. – 9., (a)(2)(C)4., 7. – 10.

Purpose: Currently, the owner of a owner of a cogeneration facility is only required to report the electricity sales from the facility. The purpose of these changes is to add the requirement that the cogeneration facility owner report the amount of thermal energy provided for commercial or industrial purposes and reports the amount of thermal energy that is wasted.

Necessity: The changes to these sections are necessary to allow the Energy Commission to understand the relative efficiency of cogeneration facilities. Cogeneration facilities produce electricity and useful thermal energy. However, not all thermal energy is used for industrial or commercial processes; some is wasted. The state has identified increased deployment of cogeneration (also referred to as combined heat and power) facilities as a means of meeting the state's GHG emissions reduction goals. However, the current language of the regulation only requires the provision of sales data, and doesn't require the owner of the cogeneration facility to provide any information about the thermal output. Without information about the percentages of thermal energy that are used in another industrial or commercial process (useful thermal energy) and that are wasted, the Energy Commission cannot assess the efficacy of cogeneration in furthering the state's GHG emissions reduction goals. For example, if two identical cogeneration facilities each produce 1,000 million British thermal units (MMBtu) per hour of excess heat, and one captures and uses 800 MMBtu of that heat for an industrial process, while the other only captures and uses 200 MMBtu for the same process, then the first plant is clearly much more efficient and has fewer emissions associated with the industrial process than the second. However, with our current data collection it is impossible to tell the difference between these two plants or to compare them to the impacts (fuel-efficiency, GHG emissions, etc.) of other energy sources. Consequently, this limits the Energy Commission's ability to provide sound policy analysis and recommendations regarding the emission intensity and efficiency of cogeneration facilities.

Subdivision (a)(1)(G), requiring the submittal of the Customer Classification Code of the recipient of "waste heat", is removed as waste heat doesn't have recipients; this is an error from the previous rulemaking.

In subdivisions (a)(2)(A)4. and 7., (a)(2)(B) 4. and 7., and (a)(2)(C)4. and 7., the phrase "useful thermal energy" is replaced with "useful thermal output." As noted above, the definition of "useful thermal output" is identical to that found in 18 C.F.R. § 292.202, subd. (h). Provision of this information will allow analysis of cogeneration plant performance for policy analysis.

New subdivisions (a)(2)(A) 8., (a)(2)(B)8., and (a)(2)(C)8. are added to require owners of cogeneration facilities to provide the amount of useful thermal output provided to each recipient and the customer classification code of each recipient. As noted above, this is needed to assess the efficiencies of cogeneration facilities.

Finally, new subdivisions (a)(2)(A)9., (a)(2)(B)9., and (a)(2)(C)9. are added to require owners of cogeneration facilities to provide the amount of waste heat produced by the power plant. The waste heat information – in conjunction with the information about useful thermal output – will allow analysis of cogeneration plant performance for policy analysis.

Renumbering and Typographical Errors – The addition of new subdivision (a)(2)(C)8.and 9. required renumbering of the remained of subdivision (a)(2)(C). The phrase “end users” is changed to “end-users” in subdivisions (a)(2)(A)(7), (a)(2)(B)(7), and (a)(2)(C)(7) for consistency with the rest of the Section. Finally, an extra “r” is removed, changing “primer mover” to “prime mover” in subdivision (a)(1)(J)7, correcting a typographical error.

Subdivision (b)

Purpose: The purpose of these amendments is threefold: 1) to require that UDCs include energy storage systems in the reporting of devices interconnected to the electric grid (subdivisions (b), (b)(4), (b)(5), (b)(6), (b)(13), (b)(14)); 2) to eliminate the size threshold for reporting of devices interconnected to the grid (subdivision (b)); and 3) to require additional information about the location and date of each device’s interconnection with or removal from the electric grid (subdivisions (b)(12) - (14)). Additionally, three minor changes are also proposed for the purpose of clarification: the capacity denomination is changed from megawatts to kilowatts in subdivision (b)(3); “expressed to the nearest degree” (relating to latitude and longitude) is proposed to be deleted from subdivision (b)(7); and an “and” is proposed to be deleted in subdivision (b)(10).

Necessity: Currently, UDCs are required to provide information about power plants with a capacity of 100 kilowatts (kW) that are interconnected to the electrical grid in their service territories. Broadening the reporting requirements to include energy storage systems as well as smaller power plants is necessary to better understand the types of generation available to electricity customers as well as to track progress and make recommendations for policy goals favoring installation of small renewable energy generation systems and energy storage systems. Knowing whether the device is installed “behind the meter” (connected to the customer’s side of the electrical system rather than the UDC’s), the rate schedule associated with behind-the-meter installations, the date of interconnection approval, and whether an interconnected power plant or energy storage system has been disconnected is necessary for the same reason. Megawatts is changed to kilowatts in subdivision (b)(3) to reflect the fact that UDCs will be reporting for many smaller power plants and energy storage systems. "[E]xpressed to the nearest degree," relating to latitude and longitude in subdivision (b)(7) is removed because providing the data at the nearest degree is less precise than the zip code, and is hence unnecessary. An "and" is deleted from subdivision (b)(10) to reflect the fact that the list of required informational items is longer.

Storage: Energy storage is necessary for the state to maximize its renewable generation and to meet its GHG emissions reduction goals.[15] [16] By adding energy storage systems to the list of devises for which information must be provided pursuant to subdivision (b), the Energy Commission will be able to track the deployment of energy storage. In conjunction with information about whether energy storage is installed behind the meter (Subdivision (b)(14)), load shape information (Section 1344), and billing and meter data (Section 1353), the Energy Commission will be able to identify and track trends in energy storage system installation by quantity and by location, as well as to correlate energy storage system installations with other factors affecting consumption patterns such as PV installations and EV ownership. This, in turn, will assist the Energy Commission in identifying any additional actions that may be needed for the state to achieve its energy storage goals. (Pub. Resources Code section 25305.)

Size threshold: The Energy Commission also needs information from installations currently excluded from the reporting requirements – those of 100 kW or less in capacity - to ensure trends are captured and to allow for program and policy evaluation. For example, the number of IOU installations captured by the 100 kW threshold is less than 1 percent of the total installations.[17] In recent years, there has been a significant increase in small electrical generation systems, many of which are installed by customers to provide generation for their own use. Currently about 93 percent of the IOU installations are at or below 10 kW. Across the three largest IOUs the number of interconnected installations has increased from 264 with a total capacity of less than 1 MW in 2000.[18] In 2016, across all utilities there were approximately 560,000 PV installations totaling 4,407 MW of total capacity.[19] Examples of customer-installed generation include PV, fuel cells, reciprocating engines, gas turbines, and microturbines.[20] While the Energy Commission does receive information about the total amount of electricity sold, there is an increasing gap between generation and sales data due to the fact that the generation – or even the existence – of these smaller units is not required to be reported. Since the last data collection regulations in the early 2000s, there has been a significant change in the number and capacity of interconnected resources. The Energy Commission needs to know how much generation comes from each of these small installations to accurately estimate demand at regional levels and to evaluate the success of state policies designed to promote installation of these types of generation. Therefore, the size threshold is proposed to be eliminated.

In conjunction with information about whether these energy sources are installed behind the meter (Subdivision (b)(14)), load shape information (Section 1344), billing and meter data (Section 1353), and information gained by deleting the 100 kW threshold in subdivision (b) will allow the Energy Commission to identify and track trends in small generation installation by quantity and by location, as well as to correlate small generation installations with other factors affecting consumption patterns such as PV installations and EV ownership.

Additional Information: The regulation is proposed to be modified to require the reporting of additional details about the power plant or energy storage system. Specifically, subdivision (b)(14) requires the UDC to indicate whether the power plant or energy storage system is a “customer-side installation” or, as it is more commonly phrased, “behind the meter.” When generation is connected behind the UDC meter, its generation shows up as a reduction in demand at the meter. Similarly, an energy storage system connected behind the meter consumes and discharges electricity in a way that is not captured at the UDC meter. In order to accurately estimate local and regional demand, the Energy Commission must know how much small generation and energy storage is installed behind the meter.

Additionally, in order to link the data appropriately across databases and to track the interconnected resources impact on the demand, the specific location and meter data are needed. The service account number, premise identification number, and meter identification number provide the needed information to correlate demand and location with the interconnected resource. (Subdivision (b)(14).) This information will allow the development of representative characteristics for those locations with and without interconnected resources and inform the impacts of distributed resource policies on energy demand.

The name of the rate schedule (Subdivision (b)(14)) is also needed because customer consumption is directly related to the price charged and often the resources are being used explicitly to lower energy costs in accordance with a rate schedule. Understanding the use of interconnected resources under various rate schedules directly influences potential policy development and achieving state energy goals.

Finally, the date of interconnection approval (Subdivision (b)(12)) and the date that any interconnected system is no longer (Subdivision (b)(13)) interconnected is needed to understand the period of time that all power plants and energy storage systems are available to generate and to ensure that the Energy Commission’s estimates of installed capacity are accurate.

References – three new sections are included as references: Pub. Resources Code §§ 25305, 25305.1, and 25310. The latter two are statutes enacted since this Section was last amended that govern data analysis and the first statute was inadvertently omitted during the previous rulemaking; it too references the Energy Commission's analytical responsibilities.

1306 – LSE and UDC Reports, and Customer Classification Reports

Subdivision (a)(5)

Purpose: The purpose of the proposed change in subdivision (a)(5) is to exempt UDCs filing data pursuant to Section 1353 from the requirement to file pursuant to this section after January 1, 2019.

Necessity: Currently, all UDCs provide aggregated monthly customer data, including the number of customers, revenue, and volume by bundled and unbundled customers pursuant to this section. This data forms the basis of long-term trend analyses, demand forecasting, and understanding changes to energy consumption. Proposed Section 1353, subdivision (b) would require large UDCs to provide customer-specific information, including energy, price, and volume. This customer-specific data can be aggregated to the monthly level currently collected in Section 1306, thereby eliminating the need for Section 1306 data from those UDCS that will report under new Section 1353. As with any new data process, there may be issues with reproducing existing Section 1306 data from the new customer-level data identified in Section 1353. Reproducing the Section 1306 data is important to accommodate existing forecast model input requirements. The 2019 implementation date will allow the Energy Commission the time to resolve any issues with reproducing currently collected data and ensure a continual and consistent data set.

1308 - Quarterly Gas Utility and Electric Generator Tolling Agreement Reports

Subdivision (a)

Purpose: The purpose of the proposed changes to subdivision (a) is to reflect changes to the natural gas pipeline infrastructure as well as corrections to the names of various natural gas infrastructure components. Pipelines that no longer transport natural gas are deleted, new pipelines are identified, and one incorrect name is corrected.

Necessity: The change to subdivision (a)(2)(A)(4) is necessary because the name of the pipeline "PG&E Gas Transmission - Northwest at Malin" has changed to "Gas Transmission – Northwest at Malin." The addition of subdivision (a)(2)(A)(5) is necessary because "Ruby Pipeline at Malin" is a new pipeline at the California border placed in service in 2014. The remainder of subdivision (a)(2)(A) is renumbered to reflect the insertion of the new subsection.

The deletion of subdivision (a)(2)(B)(1) is needed to reflect the fact that the pipeline "Kern River Gas Transmission/Mojave Pipeline at Kern River Station" doesn't connect to an interstate pipeline and never should have been included in the regulation. A new pipeline – Questar Pipeline at Essex - is added to the subdivision so that the Energy Commission has a complete data set of natural gas receipts at instate locations. Finally, the proposed change in subdivision (a)(2)(B)(4) is needed to reflect the correct name of the pipeline identified; it is "PG&E at Kern River Station" not "PG&E at Wheeler Ridge."

Subdivision (b)

Purpose: The purpose of the proposed changes to subdivision (b) is to reflect changes to the natural gas pipeline infrastructure and to correct a mistake in the current regulations.

Necessity: Subdivision (b)(4)(A) is deleted because, as noted above, Kern River Station is not connected to an interstate pipeline and should never have been included in the regulation. Instead, a new delivery point, Freemont Peak, is substituted so that the Energy Commission has a complete data set for deliveries to interstate pipelines.

Subdivision (c)

Purpose: The purpose of the proposed addition of subdivision (c)(3) is to exempt natural gas utilities filing data pursuant to Section 1353 from the requirement to file pursuant to this section.

Necessity: Currently, all natural gas utilities report aggregated data on sales and transport by NAICS codes and county. However, proposed Section 1353, subdivision (b) would require that large natural gas utilities provide disaggregated customer information, including the revenue, volume, and address, along with other customer-specific data. As a result, the more aggregated data described in this section is superfluous for the natural gas utilities subject to reporting requirements in Section 1353 and it is necessary to relieve them from the obligation to file the data identified in this section.

1314 Natural Gas System Analysis

Purpose: The purpose of new subdivision (a) is to require that large natural gas utilities provide the modeling files used for conducting hydraulic modeling of their systems.

Necessity: The information described in this subdivision is needed for the Energy Commission to be able to do the hydraulic modeling of the natural gas system and monitor and analyze the interaction of California's electricity and natural gas systems for grid reliability.

Reporting Entities: The regulations apply to the three largest natural gas utilities in the state, one of which serves customers in northern California, the other two of which serves southern California customers. According to data provided by natural gas utilities pursuant to the current data collection regulations, these three entities supply approximately 94 percent of the natural gas delivered to retail customers. (See the Energy Commission on-line database for electricity and natural gas consumption data at http://ecdms.energy.ca.gov/.) As a result, information from the three largest gas utilities is sufficient to assess gas reliability issues statewide.[21]

Modeling Files: Currently, staff assesses the natural gas pipeline and delivery system by examining monthly data on natural gas delivered from interstate natural gas pipelines to receipt points in California, to other pipelines, power plants and deliveries to natural gas utilities. Staff examines monthly deliveries from interstate pipelines to natural gas utility receipt locations and natural gas delivered to end-use customers and storage facilities. Staff assesses whether the natural gas utilities have sufficient pipeline capacity to meet natural gas demand on a monthly basis. Staff also uses the existing data in natural gas modeling to forecast the price of natural gas, which is done on an average annual basis. The monthly pipeline data that is currently collected is insufficient to examine the operations of the utilities natural gas systems (on a daily and hourly basis) to determine whether they can reliably meet customer demand over a range of conditions such as when natural gas demand is high during winter for heating and in summer for electric generation. Monthly data on pipeline receipts and deliveries are also not sufficient to assess the adequacy of and need for storage to meet daily customer demand.

The natural gas modeling tools currently used by staff, including the North American Gas Trade Model (NAMGas), do not model the hydraulics (the physical conveyance of liquids through pipes and other infrastructure) in natural gas systems needed to simulate physical operations or evaluate facility additions or changes. Rather NAMGas balances supply and demand at each node of a system based on economics and given the maximum flow capability of a particular pipe or generic path. This economic and linear programming model simulates the economic behavior of natural gas markets and can estimate the market impacts of pipeline additions to help project when market prices between two locations might be large enough to support new pipeline investment, but does not address the physical capabilities of pipelines and other facilities.

Hydraulic models using daily and hourly data, on the other hand, provide a dynamic tool for assessing the physical operational capabilities of natural gas transmission and distribution systems. They are widely used in the natural gas industry. In particular, hydraulic models show how physical flows of natural gas and line pressures change as demand and supply conditions alter operating pressures on the network.[22] The models apply standard engineering pressure flow equations to simulate the flow of compressible substances in a pipeline network. Among other things, natural gas utilities use the models to assess how to size a pipeline in order to achieve a particular flow rate, the pressure required to transport a given volume of gas and the compression horsepower required. In the context of variable natural gas requirements caused by the intermittency of renewables, a hydraulic model allows both natural gas utilities and regulators to examine how a system would react should one or more generators suddenly need to ramp up or off at a given moment.[23] Hydraulic modeling is the only way the Energy Commission can evaluate natural gas and electric reliability concerns associated with natural gas availability and deliverability under different possible supply, demand, and natural gas storage scenarios.

The natural gas utilities subject to reporting requirements under proposed Section 1314 use a hydraulic model called Synergi Gas, developed by the large international company DNV GL, which has specialization in oil, gas, and energy industries, for performing the evaluations discussed above. It is a widely used software model for simulating the operation of natural gas supply systems, and in response to the shutdown of Aliso Canyon discussed above, the Energy Commission has acquired a license for the same model.

In order to run the Synergi Gas model and assess the results of a range of natural gas supply scenarios, the Energy Commission needs detailed information about each natural gas utility's natural gas system. Because all three natural gas utilities subject to reporting requirements under this proposed section run the same model, the Energy Commission proposes to require that each utility provide the data inputs that the utilities themselves use to populate and run the model. Even though the three natural gas utilities may characterize their systems differently and run the model differently, the Energy Commission can use the utilities' own files to run a range of scenarios and obtain greater insight into the workings of the California natural gas system, as well as identify particular scenarios that shed light on potential reliability and renewable integration issues. Under the proposed section, the natural gas utilities would be required to provide the files they used during the previous calendar year on an annual basis.

Delivery Method: Section 1314 requires the delivery of confidential data that would be transferred via a secure electronic method needed to ensure security throughout the entire transfer process from origin to destination.

1344 Load Metering Reports

Subdivision (f)

Purpose: The Energy Commission proposes to add a new subdivision (f) to identify a requirement that large UDCs provide any analysis and supporting data used to characterize, assess, and forecast behind-the-meter load impacts including PV generation, EV charging, and energy storage system use.

Necessity: Load shapes are representations of the variation in electrical demand over time. Load shapes can be created for customer classes (e.g., residential or commercial), for specific areas (a zip code or utility service area), for specific end uses (e.g., air conditioning or EV charging), and any other number of factors that influence consumption. Load shapes can vary according to the class of customer, the type of end use, the location of consumption, and weather, as well as other factors.

In response to state policy goals for reducing GHG emissions, consumers have increasingly taken actions that affect generation and consumption that occur "behind the meter" – installations on the customers' property that only appear in aggregate at the UDC meter. For example, traditional generation occurs at large power plants, which are separately metered. Residential behind-the-meter PV, on the other hand, is netted out before it reaches the UDC meter, making it difficult to predict what percentage of the load at the UDC meter has been met by the PV installation and over what period of time. Accurate information about behind the meter load shapes for PV, energy storage systems, and EV charging is necessary to allow the Energy Commission to accurately forecast or assess future consumption patterns and evaluate the impact of programs promoting the use of these technologies as a means of meeting state policy goals favoring GHG emissions reductions. (e.g., Pub. Resources Code §§ 25305, 25310).

Reporting Entities: The proposed language would apply to the five largest UDCs in the state, which serve approximately 88 percent of the state's electrical load.[24]

Required Information – Load Shape Analyses and Supporting Data: The information identified in the proposed express terms consists of estimated load shapes the UDCs have developed for behind-the-meter load for PV generation, EV charging, and energy storage system use, along with supporting data. The UDCs are responsible for ensuring that their customers have a reliable electrical supply and for those purposes, need to understand behind-the-meter activity that affects this responsibility. The Energy Commission is aware that several UDCs develop such load shape estimates for their own planning purposes; for example, some IOUs submeter electric vehicle charging[25] and SDG&E is conducting load research on a longitudinal group of PV customers. The Energy Commission proposes to collect UDC load research studies to ensure more accurate regional forecasts and evaluate the impact of programs promoting state policy goals.

References – three new sections are included as references: Pub. Resources Code §§ 25305, 25305.1, and 25310. The latter two are statutes enacted since this Section was last amended that govern data analysis and the first statute was inadvertently omitted during the previous rulemaking; it too references the Energy Commission's analytical responsibilities.

1353 Disaggregated Demand Data

As discussed above, the Energy Commission needs to prepare more disaggregated demand forecasts and to monitor the impacts of GHG emissions reduction policies such as deployment of EVs, increased installations of renewable and other distributed generation resources and energy storage systems, and doubling energy efficiency savings. Along with much of the other data already discussed, the electric and gas customer billing data and electric meter data identified in this proposed new section is needed to better meet the disaggregated forecast and GHG emissions reduction obligations. Specifically, the Energy Commission will use this data to correlate consumption patterns with a number of variables, such as behind-the-meter PV, participation in energy efficiency programs, and location. This in turn will allow the Energy Commission to develop policy recommendations for meeting the state's ambitious energy goals in light of the dramatic changes in generation and consumption patterns that have been seen in recent years.

In addition, the information required pursuant to this section will improve the accuracy of how electricity and natural gas customers are classified. The Energy Commission's energy forecasting is by end-use — in other words, by the type of equipment consuming the energy in various customer sectors. The Energy Commission uses NAICS Codes (see discussion under Section 1302(b)(48)) to determine the end uses. However, the aggregated data currently provided by electric and natural gas utilities often contains errors in classifying customers – assigning them to the appropriate type of business or industry. For example, a manufacturer may be classified as a warehouse or a school may be classified as an office building. These errors reduce the accuracy of the load shapes and energy patterns for the different customer classifications in end-use forecasting. The data collected under this new regulation would allow the Energy Commission to check and correct customer classifications provided by electric and natural gas utilities, allowing better identification of trends and more accurate forecasts by end use and by location.

Subdivision (a)

Purpose: The purpose of subdivision (a) is to identify the method and requirements associated with filing the customer billing and meter data. The subdivision requires secure electronic transfer for filing and establishes general filing requirements by reference to Section 1342.

Necessity: This section is needed to ensure that the general requirements identified in Section 1342 are applicable to this section as well, and obviates the need to write additional regulatory language governing extensions, delegation, and other general matters. It is also needed to ensure that the data – which the Energy Commission proposes in a separate section to make automatically confidential – is securely transferred to the Energy Commission. "Secure electronic method" is defined in Section 1302(60); see the discussion of that section for an explanation of how this method was selected.

Subdivision (a)(1) – (4)

Purpose: The purpose of these subdivisions is to provide a reporting schedule, confirm that the regulation only applies to information already regularly collected by the UDC or natural gas utility and at the level collected, and to require an explanation of estimates used by the UDC or natural gas utility for data regularly collected but missing or misread.

Necessity: Subdivision (a)(1) is necessary to identify which UDCs and gas utilities are required to provide the information identified, to specify when they must file and to explain the data that is estimated. The larger gas utilities and UDCS to whom this section applies already make quarterly filings on the same schedule identified in this Section (see Section 1303, subdivision (d)) so using the same schedule will reduce the burden associated with separate filings. Quarterly submittals are needed to track any large-scale trends as soon as they begin to appear. Subdivision (a)(2) – (3) are needed to make explicit that the Energy Commission is identifying only that information the UDC or gas utility regularly collects and – for interval meter data – at the interval the UDC collects the data. Subdivision (a)(4) is needed so that the Energy Commission understands the methods that a UDC or gas utility uses to estimate missing and misread data. Meters can malfunction and all UDCs and gas utilities use methods for estimating data that is missed or misread; as a result, the Energy Commission needs this information to both distinguish the estimated data from actual data and to better understand the implications of the full data set provided pursuant to subdivisions (b) and (c).

Subdivision (b)(1)

Purpose: The purpose of subdivision (b) is to identify which UDCs are subject to the reporting requirements of the section and the reporting schedule.

Necessity: Imposing additional reporting requirements in subdivision (b) on the 5 UDCs with peak demand of 1000 MW or more in the previous two years is necessary because the five UDCs that meet this 1000 MW requirement deliver electricity to 91 percent[26] of the state's customers. The remaining UDCs are quite small and information from the largest five is the minimum needed to create the more detailed, accurate, and disaggregated load forecasts discussed above, as well as to track and support achieving the state's energy policy goals. Quarterly data is needed to be able to track trends that may happen quickly, such as in response to a natural disaster or failure of infrastructure.

Subdivision (b)(1)(A) - (M)

Purpose: The purpose of subdivision (b)(1) is to identify the electricity customer billing data to be filed that is associated with those UDC meters that are not interval meters. (The informational requirements applicable to UDCs are divided into categories that vary depending on whether the consumption information is collected from a non-interval meter, an interval meter, or estimated, as the amount of information from each source will vary.)

Necessity: The specific informational requirements of subdivision (b)(1) to allow the Energy Commission to correlate electricity consumption patterns with other information about end uses such as household appliances and industrial machinery, locations of customers, and the costs of providing electricity services to California customers. By holding all other factors (or set of factors) constant, this information allows the Energy Commission to determine how each of the factors (or groups of factors) change customer consumption behavior. This allows for more accurate local and regional forecasts. In addition, tracking the individual factors affecting consumption is needed for the Energy Commission to better meet its obligations to analyze the success of and develop policy recommendations for public interest energy strategies. (Pub. Resources Code § 25305.) And, as noted above, this information can be used to check and correct customer classifications provided by UDCs, allowing better identification of trends and more accurate forecasts by end use and by location.

SERVICE ADDRESS – the address required in subdivision (b)(1) is necessary because the Energy Commission needs to identify individual customers who have behind-the-meter PV or energy storage systems, charge electric vehicles, or participate in energy efficiency programs in order to better understand locational load shapes for purposes of assessing and tracking the actual impacts of those activities on electricity consumption.

Only an address will allow the Energy Commission to track each of these characteristics with individual customers.

SERVICE ACCOUNT NUMBER – the service account number is needed to ensure consumption and account data is properly correlated to the service being provided at a specific location.

PREMISE IDENTIFICATION NUMBER – the premise identification number is needed because UDC meters are associated in customer billing files with specific premise identification numbers. Having the premise identification number allows the Energy Commission to ensure that consumption and other account information is properly correlated with the correct service location since meters can change over time, due to reasons such as damage or upgrade. An identifier which specifies static location of the metering at the service address is needed to consistently track consumption.

MONTHLY CHARGE (DOLLARS) – monthly charge is needed so that the Energy Commission can correlate energy costs with other variable factors, such as use of behind–the-meter PV or energy storage systems, EV ownership, participation in energy efficiency programs, and rate schedule or tariff. These correlations are necessary to understand the inter-relationship of the various factors that affect energy consumption.

START OF BILLING CYCLE – the start date of the billing cycle is needed to understand over what days consumption is occurring and to understand in what month consumption is occurring. This data can be correlated with weather and other temporal factors that can affect consumption.

NUMBER OF DAYS IN BILLING CYCLE – the number of days in the billing cycle are needed to understand how many days the monthly charges are being calculated for and to better characterize different consumption patterns, including weekend and weekday differences.

CUSTOMER PARTICIPATION IN UDC ENERGY EFFICIENCY PROGRAM – this information is needed to correlate energy consumption patterns with program participation, which in turn, allows the Energy Commission to provide recommendations and an update on progress toward achieving a doubling of energy efficiency savings by January 1, 2030, and assess the effect of energy efficiency savings on electricity demand statewide, in local service territories, and on a seasonal basis. (Pub. Resources Code § 25310, subd. (e.))

RATE SCHEDULE – a rate schedule or tariff is needed so that the Energy Commission can analyze how rates and rate structure can affect consumption in light of the other factors affecting consumption, such as location or participation in an energy efficiency program.

NAICS CODE - the NAICS code (defined in Section 1302(b)(48)) is a standardized way of identifying the type of entity that is purchasing the electricity. This information is needed so that the Energy Commission can determine what types of end uses are likely responsible for electricity consumed by the consumer, such as residential uses, streetlighting, or various commercial and industrial activities. Together with information about the other factors identified, it will allow the Energy Commission to forecast end uses more accurately as well as to make recommendations about deployment and tracking of programs designed to promote state energy policy goals by sector (such as commercial or industrial).

PV OR ENERGY STORAGE SYSTEM INTERCONNECTION - this information about on-site PV and energy storage system installations is needed so that the Energy Commission can determine whether the quantity of electricity delivered by the UDC is the total amount consumed by the customer and to track trends in consumption patterns as the number of PV and energy storage system installations increases across the state.

METER IDENTIFICATION NUMBER – the meter identification number is necessary to connect meters to a premise identification number. New legislation requires the Energy Commission to report energy efficiency savings and demand reductions using normalized metered electricity measurements. (Pub. Resources Code § 25310, subd. (c)(5).)

VOLUME – this information is needed for the Energy Commission to correlate any of the other variables – for example, location, participation in an energy efficiency program, use of behind-the-meter PV – with consumption.

Subdivision (b)(2)(A) - (E)

Purpose: The purpose of subdivisions (b)(2)(A) – (E) is to identify the customer data from UDC interval meters.

Necessity: See discussion above for subdivisions (b)(1)(A) – (L). Other informational items required by this section are addressed below.

START OF INTERVAL – this information is needed to know when the interval of electricity consumption began, to track the overall interval consumption, and to ensure all consumption is accurately reported.

DURATION OF INTERVAL – this information is needed to know the amount of time the consumption is being reported to track consumption trends and ensure consumption data accuracy and quality.

VOLUME OF ELECTRICITY - this information is needed for the Energy Commission to correlate any of the other variables – for example, location, participation in an energy efficiency program, use of behind the meter PV – with consumption.

INTERVAL PEAK DEMAND – this information is needed for the Energy Commission to know how the electricity demand influences local infrastructure, correlate the impacts to peak demand of other resources, evaluate the impacts of policy changes, and develop new policies to mitigate fluctuations in peak demand.

Subdivision (b)(3)(A) – (C)

Purpose: The purpose of subdivision (b)(3)(A)-(C) is to identify the customer data that is associated with UDC-delivered electricity that is not individually metered.

Necessity: This section is necessary for the Energy Commission to disaggregate the forecast, characterize consumption across California regions, better monitor and track energy consumption trends, and to directly inform the evaluation and development of energy policy.

ESTIMATE OF VOLUME OF ELECTRICITY - this information is needed for the Energy Commission to account for all electricity consumption across the state, even consumption not metered.

ESTIMATE OF PEAK DEMAND – this information is needed for the Energy Commission to know how the electricity demand influences local infrastructure, correlate the impacts to peak demand of other resources, evaluate the impacts of policy changes, and develop new policies to mitigate fluctuations in peak demand.

Subdivision (c)

Purpose: The purpose of subdivision (c) is to identify natural gas customer billing data that is to be filed.

Necessity: The specific informational requirements of subdivision (b)(1) to allow the Energy Commission to correlate natural gas consumption patterns with other information about end uses such as household appliances and industrial machinery, locations of customers, and the costs of providing natural gas services to California customers. By holding all other factors (or set of factors) constant, this information allows the Energy Commission to determine how each of the factors (or groups of factors) change customer consumption behavior. This allows for more accurate local and regional forecasts. In addition, tracking the individual factors affecting consumption is needed for the Energy Commission to better meet its obligations to analyze the success of and develop policy recommendations for public interest energy strategies. (Pub. Resources Code § 25305.) And, as noted above, this information can be used to check and correct customer classification provided by natural gas utilities, allowing better identification of trends and more accurate forecasts by end use and by location.

Regulated Entities: The regulations apply to the three largest natural gas utilities in the state, one of which serves customers in northern California, the other two of which serves southern California customers. According to data provided by gas utilities pursuant to these data collection regulations, these three entities supply approximately 94 percent of the natural gas delivered to retail customers. (See the Energy Commission on-line database for electricity and natural gas consumption data at http://ecdms.energy.ca.gov/.) As a result, information from the largest gas utilities is sufficient to assess gas reliability issues statewide.

Specific Informational Items for Subdivision (c)

SERVICE ADDRESS - the service address required in subdivision (c)(1) is needed to identify individual customers who participate in energy efficiency programs by location in order to better understand locational load shapes for purposes of assessing and tracking the actual impacts on natural gas consumption.

PREMISE IDENTIFICATION NUMBER – the premise identification number is needed because gas utility meters are associated in customer billing files with specific premise identification numbers. Having the premise identification number allows the Energy Commission to ensure that consumption and other account information is properly correlated with the correct service location since meters can change over time, due to reasons such as damage or upgrade. An identifier which specifies static location of the metering at the service address is needed to consistently track consumption.

METER IDENTIFICATION NUMBER – the meter identification number is necessary to connect natural gas meters to a premise identification number. New legislation requires the Energy Commission to report energy efficiency savings and demand reductions using normalized metered natural gas measurements. (Pub. Resources Code § 25310, subd. (c)(5).)

VOLUME – this information is needed for the Energy Commission to correlate any of the other variables – for example, location, participation in an energy efficiency program – with consumption.

MONTHLY CHARGE (DOLLARS) - Monthly bill is needed so that the Energy Commission can correlate bills with other variable factors, such as participation in energy efficiency programs and rate schedules or tariff. These correlations will help the Energy Commission better understand the inter-relationship of the various factors that affect energy consumption including fuel switching.

NAICS CODE – the NAICS code (defined in Section 1302(b)(48)) is a standardized way of identifying the type of entity that is purchasing the electricity. This information is needed so that the Energy Commission can determine what types of end uses are likely responsible for electricity consumed by the consumer, such as residential uses, streetlighting, or various commercial and industrial activities. Together with information about the other factors identified, it will allow the Energy Commission to forecast end uses more accurately as well as to make recommendations about deployment and tracking of programs designed to promote state energy policy goals by sector (such as small commercial or multifamily housing).

CUSTOMER PARTICIPATION IN ENERGY EFFICIENCY PROGRAM – this information is needed to correlate energy consumption patterns with program participation, which in turn, allows the Energy Commission to provide recommendations and an update on progress toward achieving a doubling of energy efficiency savings by January 1, 2030, and assess the effect of energy efficiency savings on electricity demand statewide, in local service territories, and on a seasonal basis. (Pub. Resources Code § 25310, subd. (e).)

RATE SCHEDULE – a rate schedule or tariff is needed so that the Energy Commission can analyze how rates and rate structure can affect consumption in light of the other factors affecting consumption, such as location or participation in an energy efficiency program.

Section 2505 – Designation of Confidential Records

Subdivisions (a)(5)(B)9.

<u>Purpose</u>: The purpose of adding new subdivision (a)(5)(B)9. is to include the information required pursuant to proposed Sections 1314 and 1353 to the list of data that is entitled to an automatic confidentiality designation.

<u>Necessity</u>: The changes to subdivision (a)(5) amend language concerning the “automatically confidential” categories of data for which no application or certification is required. One new subdivision – (a)(5)(B)9. would be added. The first set of data consists of the information provided by gas utilities to run hydraulic modeling for their natural gas supply systems pursuant to proposed Section 1314. This information is proprietary and also provides details about critical gas supply system infrastructure, whose release could create significant security risks.

The second data set is required under proposed Section 1353 and consists of detailed information about individual gas utility and UDC customers, and is protected under the Information Practices Act (Civ. Code § 1798 et seq.) Existing subdivision (a)(5)(B)1. and

2. already provide confidential designation of similar information. Moreover, the Executive Director has granted confidentiality for these types of data in the past.

The Energy Commission believes that proposed data to be collected under subdivisions (a)(5)(B)9. and (a)(5)(B)10. are so clearly entitled to confidential treatment that applications or certifications should not be required. Requests for release and release of any information deemed automatically confidential will be addressed as they are now, in accordance with Sections 2506 and 2507.

ECONOMIC IMPACT ASSESSMENT Gov. Code § 11346.2(b)(2)(A)

The economic impact assessment was performed pursuant to Gov. Code § 11346.2(b)(2)(A) and is incorporated as Attachment A.

DOCUMENTS RELIED UPON – Gov. Code § 113462(b)(3)

2016 Integrated Energy Policy Report Update. California Energy Commission, 2016. Publication Number: CEC-100-2016-003-CMF., pp. 6, 22. http://www.energy.ca.gov/2016_energypolicy/index.html.

2015 Integrated Energy Policy Report. California Energy Commission, 2015. Publication Number: CEC-100-2015-001-CMF., pp. 64-66, 151. http://www.energy.ca.gov/2015_energypolicy/index.html.

Final 2016 Environmental Performance Report of California's Electrical Generation System. California Energy Commission, 2016. Publication Number: CEC-700-2016-005-SF. http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-03/TN214098_20161018T145845_Staff_Report_Final_2016_Environmental_Performance_Report_of_Cal.pdf

California Energy Demand 2008-2018 Staff Revised Forecast. California Energy Commission, 2007. Publication Number: CEC 200-2007-015-SF2., p 34. http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF.

California Public Utilities Commission Decision D.13-10-040 https://www.sce.com/wps/wcm/connect/435ea164-60d5-433f-90bc-b76119ede661/R1012007_StorageOIR_D1310040_AdoptingEnergyStorageProcurementFrameworkandDesignProgram.pdf?MOD=AJPERES

U.S. Energy Information Administration (EIA) On-line Glossary – "useful thermal output." https://www.eia.gov/tools/glossary/?id=electricity

Office of Management and Budget, North American Industry Classification System, 2017. https://www.census.gov/eos/www/naics/2017NAICS/2017_NAICS_Manual.pdf

Energy Commission On-line Consumption Database. http://ecdms.energy.ca.gov/

California Energy Commission – Tracking Progress. Renewable Energy, Dec. 22, 2016. http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf

California ISO On-line Glossary. http://www.energy.ca.gov/glossary/ISO_GLOSSARY.PDF

Thermal Efficiency of Gas-Fired Generation in California: 2015 Update. California Energy Commission, 2016. Publication Number: CEC 200-2016-002. http://www.energy.ca.gov/2016publications/CEC-200-2016-002/CEC-200-2016-002.pdf

California Energy Demand 2016-2026, Revised Electricity Forecast. California Energy Commission, 2016. Publication Number: CEC-200-2016-001-V1. p. 21, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf.

Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin, prepared by the Staff of the California Public Utilities Commission, California Energy Commission, the California Independent System Operator, and the Los Angeles Department of Water and Power, April 6, 2016. http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN210958_20160406T135321_Aliso_Canyon_Action_Plan_to_Preserve_Gas_and_Electric_Reliabili.pdf

California Public Utilities Commission: Natural Gas and California website. (http://www.cpuc.ca.gov/natural_gas/)

The Value of Energy Storage and Demand Response for Renewable Integration in California. Lawrence Livermore National Laboratory, 2017. California Energy Commission, 2017. Publication Number: CEC-500-2017-014. http://www.energy.ca.gov/2017publications/CEC-500-2017-014/CEC-500-2017-014.pdf

California Distributed Generation Statistics, NEM Currently Interconnected Data Set. http://www.californiadgstats.ca.gov

U.S. Energy Information Administration, California Natural Gas Consumption by End Use, https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCA_a.htm.

2016 California Gas Report, Southern California Gas Company and Pacific Gas and Electric Company total gas consumption (2011-2015). https://www.socalgas.com/regulatory/documents/cgr/2016-cgr.pdf.

Scope of Additional Model Platforms Needed to Assess Impact on Natural Gas System from Renewable Intermittency and Deliverability to Power Plants, Aspen Environmental Group, 2011.

California Public Utilities Commission: Plug-in Electric Vehicle (PEV) Submetering website. http://www.cpuc.ca.gov/general.aspx?id=5938.

Department of General Services, Procurement Division. Master Service Agreements, MSA 5137002. List of Contractors, Classifications and Rates. http://www.dgs.ca.gov/Portals/9/Documents/MAU%201/ITMSA/Contractorslist.xlsx

Energy Information Administration. Number of Customers, Annual. Form-826, Table 10. https://www.eia.gov/electricity/sales_revenue_price/xls/table10.xlsx

Amazon Web Services, S3 Storage Pricing. https://aws.amazon.com/s3/pricing/

California State Civil Service Pay Scales, Salaries of Civil Service Classifications. http://www.calhr.ca.gov/Pay%20Scales%20Library/PS_Sec_15.pdf

State Administrative Manual § 5300: Information Technology Office – Office of Information Security Definitions. https://cdt.ca.gov/security/technical-definitions.

REASONABLE ALTERNATIVES - Gov. Code § 11346.2(b)(4)(A)

Pursuant to the requirements of Government Code section 11346.2(b)(4)(A), this section of the ISOR contains “[a] description of reasonable alternatives to the regulation and the agency's reasons for rejecting those alternatives.”

During the initial, informal stage of the rulemaking process, the Commission conducted a public process, considered suggestions from stakeholders about (1) alternatives that could improve the feasibility of the Commission’s preliminary versions of the proposed regulations or could reduce their adverse impacts; (2) the technical and cost-effectiveness analyses of those preliminary proposals; and (3) the language in those proposals.

In 2016, the Energy Commission held meetings with electricity and natural gas industry stakeholders to vet potential code updates, identify concerns, and resolve issues. The Energy Commission held a pre-rulemaking public workshop for all interested parties to build upon and continue this process. The proposed additions to and modifications of regulations governing data collection in California Code of Regulations Title 20, Sections 1302, 1304, 1306, 1308, 1314, 1344, 1353 were included in these workshops and discussions. During the pre-rulemaking workshop the Commission received a large number of comments. After consideration of all comments the Commission developed, “Proposed Language for Discussion at the November 16, 2016 Commissioner

Workshop" and held a comprehensive pre-rulemaking public workshop on to obtain public comment on the proposed additions and modification of regulations. Following the workshop, many more comments were received and in response to them the Commission produced the proposed regulations that accompany this ISOR.

Thus in the pre-rulemaking process there has already been detailed consideration of suggested alternatives, many of which have been incorporated into the proposed amendments. The following material summarizes the major suggestions and the Commission's responses.

As an alternative to the proposed regulation under Section 1314 to collect necessary natural gas data for hydraulic modeling, the Energy Commission considered basing their analysis of the gas utilities' own modeling. However, the Energy Commission determined that depending on the natural gas utilities modeling efforts would limit the Energy Commission's effort to consider independent scenarios when monitoring, modeling, and analyzing the interaction of California's electricity and natural gas systems for grid reliability.

As an alternative to the proposed regulation under Section 1353 to collect necessary electricity and natural gas information to support a disaggregated forecast, the Energy Commission considered collecting aggregated customer billing and meter data instead of the disaggregated data identified in Section 1353. However, the Energy Commission determined that individual customer data is needed to be able to differentiate between different types of effects caused by factors such as location, rate, EV ownership, participation in an energy efficiency program, etc. This differentiation allows the Energy Commission to assess the effects of programs on a local level, as well as to refine its demand forecast. Moreover, because the information is electronically stored, it is actually more work for the LSE to aggregate the data than it is to just transmit the file. Therefore, the Energy Commission determined that this alternative will not provide information the Energy Commission needs to meet its statutory obligations as effectively as the proposed regulation.

REASONABLE ALTERNATIVES - SMALL BUSINESS Gov. Code § 11346.2(b)(4)(B)

The definition of "small business" in Gov. Code § 11342.610 (b)(8) excludes utilities that generate and transmit more than 4.5 million kilowatts hours annually. All of the UDCs and LSEs affected by the proposed changes to these regulations transmit more than 4.5 million kilowatts hours annually. Of the power plant owners impacted by proposed changes to Section 1304, only three fall below the annual 4.5 million kilowatt hours generation threshold. One of these owners is a municipality and the other is a subsidiary of a large international company. Only one appears to be a small manufacturer with fewer than 250 employees.

One potential alternative would be to exclude the single entity from reporting the specific clarifying information proposed in the regulations. Since the entity is already reporting cogeneration data to the Energy Commission and the proposed information merely clarifies the existing data submitted, the state rejects the alternative of not reporting the data. The burden is small for the single entity and excluding the data from this owner of a cogeneration facility would lead to a knowledge gap that limits the development of policies potentially beneficial to similar entities.

FACTS RELIED UPON RE BUSINESS IMPACT – Gov. Code § 11346.2(b)(5)(A)

The following summarizes the detailed methods found in the economic impact assessment that was performed pursuant to Gov. Code § 11346.2(b)(2)(A) and is included in this Initial Statement of Reasons as Appendix A.

The number of obligated parties was estimated using the Energy Commission's historic generation, sales, and delivery data already tracked through existing data collection regulations.

Section 1304 (a) Combined Heat and Power Data – Using an understanding of current reporting practices and the time necessary to fill out existing forms, staff estimated the time necessary for all existing reporting entities to complete the extra data fields.

Section 1304 (b) Interconnection Data – Staff identified the fields used for interconnection applications across a survey of utilities in California, evaluated past interconnection data collected for other purposes, and developed an estimate of the time necessary to complete the data forms.

Section 1306 (a) Quarterly UDC Reports – A survey of time necessary to complete, manage, and resolve data issues with the existing reporting was performed to estimate the benefit of no longer reporting the data required under this section.

Section 1308 (a) and (b) Monthly Natural Gas Data – There were no costs associated with the proposed clarifying changes to this section which merely identifies the proper name for natural gas distribution locations. Energy Commission staff worked with obligated parties to clarify the proper references for this section.

Section 1308 (c) Monthly Natural Gas Deliveries - A survey of time necessary to complete, manage, and resolve data issues with the existing reporting was performed to estimate the benefit of no longer reporting the data required under this section.

Section 1314 Natural Gas Modeling Data – The Commission held stakeholder meetings with obligated parties, contacted modeling software vendors, and is explicitly requiring data which is currently utilized by the utilities for hydraulic modeling. The effort required of obligated parties will be primarily be in transferring the information which is exported from the existing utility models.

Section 1344 (f) Behind-the-meter Load Impacts – The Commission had multiple stakeholder meetings and discussions on behind-the-meter load research and has asked the obligated parties to provide existing load research information, the cost of which would be primarily associated with collecting and transferring the information.

Section 1353 (a) Disaggregated Data Reporting – All but one of the requirements are administrative in nature and only the section requiring a description of methodologies would result in a cost. Staff has estimated times based upon existing data reporting processes and procedures.

Section 1353 (b) Monthly and Interval Meter Electricity Data – Staff has consulted with utilities regarding interval meter data, clarified the requirements, and worked with the information technology specialists to estimate the needed time, cost, and infrastructure to appropriately manage, utilize, store, and analyze the interval meter data.

Section 1353 (c) Monthly Natural Gas Customer Data - Using an understanding of current reporting practices, the scope of the data collection, staff estimated the time necessary for all existing reporting entities to complete the extra data fields.

SPECIFIC TECHNOLOGIES - Gov. Code §§ 11346.2(b)(4)(A), 11346.2(b)(1)

The proposed changes to these regulations do not require the use of specific technologies or equipment.

EFFORTS TO AVOID UNECESSATY DUPLICATION OR CONFLICT WITH FEDERAL REGULATIONS – Gov. Code § 11346.2(b)(6)(B)

Several federal agencies require the submission of energy data. For example, the Unites States Energy Information Agency collects and publishes a broad range of energy statistics and analysis and the Federal Energy Regulatory Commission collects information for its market oversight functions. Much of this information is publicly available. However, the data that would be required to be reported as a result of the proposed express terms is either different information or submitted on a different schedule than the information submitted to the federal agencies. If federal law is changed and requires the submission of the specific data required under the proposed express terms, Sections 1303 and 1342 of the Energy Commission's regulations allows the filer to apply for approval from the Commission's Executive Director to submit the federal filing in lieu of one meeting the formatting and submission requirements found in the Commission's regulations. If the request is approved, no further permission is needed for the submission of the alternative data. (Cal. Codes Regs. Tit. 20 sections 1303, subd. (i),1343, subd. (g).)

ACRONYMS

CPUC	California Public Utilities Commission
DER	distributed energy resources
EIA	U.S. Energy Information Administration
EV	electric vehicle
GHG	greenhouse gas
IEPR	Integrated Energy Policy Report
IOU	investor-owned utility
kW	kilowatt
LSE	load serving entity
MMBtu	one million British thermal units
MW	megawatt
NAICS	North American Industrial Classification System
NAMGas	North American Gas Trade Model
PG&E	Pacific Gas and Electric Company
PRA	California Public Records Act
PV	photovoltaic
RPS	Renewables Portfolio Standard
SDG&E	San Diego Gas & Electric
UDC	utility distribution company

END NOTES

[1] List of acronyms available at the end of this document, p. 43.

[2] California Energy Commission – Tracking Progress. Renewable Energy. December 22, 2016. http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

[3] Based on an estimate that 1 MW can power 750 homes The number of homes powered by a megawatt fluctuates because electrical demand changes based on the season, the time of day, and other factors www.energy.ca.gov/glossary/ISO_GLOSSARY.PDF.

[4] California Energy Commission – Tracking Progress. Renewable Energy. December 22, 2016. p. 14, Table 4: Renewable Distributed Generation Resources, On-Line, and Pending Projects. http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

[5] California Energy Commission Staff. 2016. *2016 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2016-003-CMF. pp. 6, 22. http://www.energy.ca.gov/2016_energypolicy/index.html.

[6] California Energy Commission. 2015. *2015 Integrated Energy Policy Report*. Publication Number: CEC-100-2015-001-CMF. pp. 64-66. http://www.energy.ca.gov/2015_energypolicy/index.html.

[7] For example, in 2014 the thermal efficiency (measured as the heat rate in British thermal units per Kilowatt-hour) for peaking generators was 10,415 Btu/Kwh, while combined cycle power plants was 7,329 Btu/Kwh. The heat rate of a generator correlates directly with the amount of emissions: the higher the heat rate, the dirtier the plant. *Thermal Efficiency of Gas-Fired Generation in California: 2015 Update*. California Energy Commission, 2016. Publication Number: CEC 200-2016-002. http://www.energy.ca.gov/2016publications/CEC-200-2016-002/CEC-200-2016-002.pdf

[8] 2016. *California Energy Demand 2016-2026, Revised Electricity Forecast*. California Energy Commission, 2016. Publication Number: CEC-200-2016-001-V1. p. 21, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf.

[9] Local reliability areas are transmission constrained portions of the electric grid where sufficient local generating resources must be provided to ensure reliable electricity service.

[10] *California Energy Demand 2008-2018 Staff Revised Forecast*. California Energy Commission, 2007. Publication Number: CEC 200-2007-015-SF2 .p 34 http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF.

[11] *Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin*, prepared by the Staff of the California Public Utilities Commission, California Energy Commission, the California Independent System Operator, and the Los Angeles Department of Water and Power, April 6, 2016.

[12] The majority of the natural gas that flows into the Southern California Gas Company System comes from locations east of California, which can be limited when demand in regions outside California are high, when prices are high or when well freeze-off limit supplies due to extremely cold weather in the natural gas production basins.

[13] http://www.cpuc.ca.gov/natural_gas/

[14] Synergi gas network modelling is custom software developed by DNV GL. The software is capable of identifying and addressing natural gas system operational challenges. Synergi gas model has been customized to be used for the natural gas system in California.

[15] *The Value of Energy Storage and Demand Response for Renewable Integration in California*. Lawrence Livermore National Laboratory, 2017. California Energy Commission. Publication Number: CEC-500-2017-014.

[16] Public Utilities Code sections 2835 - 2837.

[17] California Distributed Generation Statistics, http://www.californiadgstats.ca.gov/downloads/, NEM Currently Interconnected Data Set.

[18] *Ibid*.

[19] *Final 2016 Environmental Performance Report of California's Electrical Generation System*. California Energy Commission, 2016. Publication Number: CEC-700-2016-005-SF. p. 41, http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-03/TN214098_20161018T145845_Staff_Report_Final_2016_Environmental_Performance_Report_of_Cal.pdf.

[20] *2016 Integrated Energy Policy Report Update*. California Energy Commission, 2016. Publication Number: CEC-100-2016-003-CMF. pp9, 53-59. http://www.energy.ca.gov/2016_energypolicy/index.html.

[21] Source for California total gas consumption (2011-2015). U.S. Energy Information Administration, https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCA_a.htm. Source for Southern California Gas Company and Pacific Gas and Electric Company total gas consumption (2011-2015). 2016 California Gas Report. https://www.socalgas.com/regulatory/documents/cgr/2016-cgr.pdf.

[22] *Scope of Additional Model Platforms Needed to Assess Impact on Natural Gas System from Renewable Intermittency and Deliverability to Power Plants*, Aspen Environmental Group, performed under California Energy Commission Work Authorization 1910.002, Subtask 5 Deliverable, September 9, 2011.

[23] *Ibid*.

[24] Calculated for 2014 using the following file: http://www.energy.ca.gov/almanac/electricity_data/2012_LSE_peak_loads_GWh_requirements.xlsx.

[25] California Public Utilities Commission, Plug-in Electric Vehicle Submetering. http://www.cpuc.ca.gov/general.aspx?id=5938.

[26] Energy Information Administration. Number of Customers, Annual. Form-826, Table 10. https://www.eia.gov/electricity/sales_revenue_price/xls/table10.xlsx

ATTACHMENT A
Economic Impact Assessment for Title 20 Data Collection Regulation Modifications

July 18, 2017

Summary of Cost Impacts

The following table summarizes the costs for all modifications proposed for the Title 20 data collection regulations for the first three fiscal years of the data collection implementation.

Table 1. Summary of Costs for Proposed Regulations

	Fiscal Year			
Proposed Regulation Sections	**2017/18**	**2018/19**	**2019/20**	**Total**
Section 1302 Definitions	**$0**	**$0**	**$0**	**$0**
Private Obligated Party Costs	$0	$0	$0	$0
Local Public Obligated Party Costs	$0	$0	$0	$0
State Costs	$0	$0	$0	$0
Section 1304 (a) Combined Heat and Power Data	**$169,497**	**$67,695**	**$69,726**	**$307,406**
Private Obligated Party Costs	$119,552	$47,024	$48,435	$215,011
Local Public Obligated Party Costs	$44,070	$17,334	$17,855	$79,259
State Costs	$6,363	$3,336	$3,437	$13,136
Section 1304 (b) Interconnection Data	**$696,570**	**$665,088**	**$682,658**	**$2,044,316**
Private Obligated Party Costs	$58,590	$68,969	$71,038	$198,597
Local Public Obligated Party Costs	$637,980	$574,740	$591,982	$1,804,702
State Costs	$0	$21,379	$19,638	$41,017
Section 1306 (a) Quarterly UDC Reports	**$0**	**$1,896**	**$3,719**	**$5,615**
Private Obligated Party Avoided Costs*	$0	$758	$1,561	$2,319
Local Public Obligated Party Avoided Costs*	$0	$505	$1,041	$1,546
State Avoided Costs*	$0	$633	$1,117	$1,750
Section 1308 (a) and (b) Monthly Natural Gas Data	**$0**	**$0**	**$0**	**$0**
Private Obligated Party Costs	$0	$0	$0	$0
Local Public Obligated Party Costs	$0	$0	$0	$0
State Costs	$0	$0	$0	$0
Section 1308 (c) Monthly Natural Gas Deliveries	**$0**	**$4,438**	**$9,142**	**$13,579**
Private Obligated Party Avoided Costs*	$0	$3,579	$7,373	$10,951
Local Public Obligated Party Avoided Costs*	$0	$0	$0	$0

Proposed Regulation Sections	Fiscal Year 2017/18	2018/19	2019/20	Total
State Avoided Costs*	$0	$859	$1,769	$2,628
Section 1314 Natural Gas Modeling Data	**$10,300**	**$14,482**	**$14,917**	**$39,699**
Private Obligated Party Costs	$6,541	$6,737	$6,939	$20,216
Local Public Obligated Party Costs	$0	$0	$0	$0
State Costs	$3,760	$7,745	$7,978	$19,483
Section 1344 (f) Load Impact Data	**$147,172**	**$46,984**	**$48,394**	**$242,549**
Private Obligated Party Costs	$60,264	$17,242	$17,759	$95,266
Local Public Obligated Party Costs	$40,176	$11,495	$11,840	$63,510
State Costs	$46,732	$18,247	$18,794	$83,773
Section 1353 (a) Disaggregated Data Reporting	**$146,248**	**$35,477**	**$36,542**	**$218,267**
Private Obligated Party Costs	$93,000	$22,990	$23,679	$139,669
Local Public Obligated Party Costs	$46,500	$11,495	$11,840	$69,834
State Costs	$6,748	$993	$1,023	$8,764
Section 1353 (b) Monthly and Interval Meter Data	**$159,173**	**$227,815**	**$155,292**	**$542,280**
Private Obligated Party Costs	$53,568	$64,371	$18,943	$136,882
Local Public Obligated Party Costs	$35,712	$42,914	$12,629	$91,255
State Costs	$69,893	$120,530	$123,720	$314,143
Section 1353 (c) Monthly Natural Gas Customer Data	**$248,587**	**$371,466**	**$226,297**	**$846,349**
Private Obligated Party Costs	$94,860	$80,464	$82,878	$258,201
Local Public Obligated Party Costs	$0	$0	$0	$0
State Costs	$153,727	$291,002	$143,419	$588,148
Section 2505 Designation of Confidential Records	**$0**	**$0**	**$0**	**$0**
Private Obligated Party Costs	$0	$0	$0	$0
Local Public Obligated Party Costs	$0	$0	$0	$0
State Costs	$0	$0	$0	$0
Total Private Obligated Party Costs	$486,374	$307,796	$269,672	**$1,063,842**
Total Local Public Obligated Party Costs	$804,438	$657,978	$646,145	**$2,108,561**
Total State Costs	$287,223	$463,234	$318,008	**$1,068,464**
Total Costs	**$1,578,035**	**$1,429,008**	**$1,233,825**	**$4,240,867**
Private Obligated Party Avoided Costs*	$0	$4,337	$8,934	**$13,271**
Local Public Obligated Party Avoided Costs*	$0	$505	$1,041	**$1,546**
State Avoided Costs*	$0	$1,491	$2,886	**$4,378**
Total Avoided Costs*	**$0**	**$6,334**	**$12,861**	**$19,194**

* The avoided costs derive from the deletion of a requirement to file aggregated data, with some utilities being required to file disaggregated data. These avoided costs, therefore, should be considered in conjunction with the costs associated with the requirement to file disaggregated data, addressed under the discussion for Section 1353.

General Assumptions

The underlying assumptions regarding evaluating the cost impacts of the proposed regulations include assumptions about the implementation date of regulations, the date reporting by obligated parties is first required, the amount of time required of obligated parties to report and of the Energy Commission to process and store the data, salaries and annual increases in salaries of both Energy Commission staff and the staff of employees responsible for filing the information, the availability of Energy Commission data repositories that will be used for data, and modifications of existing data handling procedures and processes that may be required.

The evaluation assumes that the proposed regulations are adopted in 2017 and are effective when approved. The first reporting of data would be in early 2018.

Staffing Resources Assumptions

To estimate the impact of the proposed changes in reporting requirements on staffing resources, the Energy Commission looked at the time associated with the any increased or decreased reporting requirements and the salaries of Energy Commission employees and the employees who would be responsible for filing the information with the Energy Commission. The general cost calculation for the proposed regulations follows the basic formula of:

$$Cost_y = Hourly\ Salary^{(Inflation)^{(y-2017)}} \times Hours \times Parties$$

Where:

$Cost_y$ = Total Fiscal Year cost in year y.

y = the fiscal year in which costs are being evaluated.

$Hourly\ Salary$ = is the annual average hourly rate in 2017 for the work being performed.

$Hours$ = the estimated number of hours needed to perform the activities in a Fiscal Year.

$Inflation$ = the assumed annual salary inflation of three percent.

$Parties$ = the number of obligated parties for the proposed regulations.

Depending on the proposed regulations being evaluated, there may be additional factors included in the calculation such as frequency of reporting or scaling to distribute to private or public obligated parties.

Hourly Salary Assumptions

The private industry 2017 annual average hourly salaries were developed by looking at consultant rates established by the Department of General Services IT Consulting Services Contractor Classifications and Ratesfor contractors eligible to perform programing activities. (See Master Services Agreement for contracts with a value of up to $1.5 million. This list can be found on the DGS website:

http://www.dgs.ca.gov/Portals/9/Documents/MAU%201/ITMSA/Contractorslist.xlsx)

The Energy Commission concluded that a Programmer classification was appropriate for estimating private salaries. The average hourly salary of contractors for the Programmer classification was determined to be $93 per hour in 2017; this hourly salary is used throughout most of the regulation cost estimates.

For Energy Commission employees, the Energy Commission assumed that the workload for one contractor (System Analyst) and three different classifications of state employees (Electric Generation System Specialist I, Energy Commission Specialist II, and Senior Programmer Analyst) would be affected by the proposed regulations. For classifications Electric Generation System Specialist I (EGSS I) and Energy Commission Specialist II (ECS II), the Energy Commission used the highest salary converted to an hourly rate for the purposes of these estimates, $57.84 and $48.20, respectively. For the Senior Programmer Analyst, staff did a survey of the classification and took the highest salary and converted it into an hourly rate. The hourly salary for the state Senior Programmer Analyst is $51.75.

The System Analyst position is a contractor who would be employed by the state and is conservatively assumed to earn the same rate as the Programmer, $93 per hour. The Energy Commission also assumed that analytical activities associated with collection of the new data - developing disaggregated forecasts, tracking the effectiveness of GHG emissions reduction efforts, and making policy recommendations for achieving additional GHG emissions reductions and meeting other important state energy goals - would not require new staff resources. This is due to the fact that staff can use highly automated methodologies for processing the new data; these analytical efforts will replace some of the more labor-intensive efforts that have been used in the past to conduct forecasting activities and develop concomitant policy recommendations.

Over the course of evaluation, all salaries, both consultant and state, are increased by 3 percent annually.

Data Storage Costs

Changes to Sections 1306 and 1308 will result in a reduction of data submitted to the Energy Commission; changes to Sections 1304, 1314, and 1344 will result in additional data that can be accommodated on existing servers. Therefore there are no data storage costs associated with these proposed changes. Section 1353, however, would result in new data storage needs that are addressed below.

The Energy Commission developed an annual data storage cost estimate for proposed Section 1353 (b) and (c). The amount of data to be collected in Section 1353 (b) is estimated by scaling the number of fields currently collected for the Energy Commission's Clean Energy Jobs Act program (under which the Energy Commission receives interval meter data) to the number of fields identified in the proposed regulation. [1] This leads to an estimated size for each customer data record reported of 9.375 megabytes

[1] Existing detailed data used for this evaluation included school consumption data which was compared to other data sets including industrial sector consumption, energy efficiency evaluation data, and discussions with data contractors. The school data was approximately 12.5 MB per record of 21 fields for 15 minute annual data. Since

per year. The number of customers for the five largest utilities was estimated using Energy Information Administration reported values for 2015.[2] Multiplying 13,887,678, the number of customers, by the annual per-customer data record size of 9.375 megabytes yielded an estimated data size of about 130.2 TB of data being collected each year. The cost for storage was then calculated using the commercial prices for Amazon Web Services' (AWS) Standard S3 Storage rates.[3] This resulted in an estimated cost of $39,659 for Fiscal Year 2018/19 and $78,718 for Fiscal Year 2019/20. However, the Energy Commission will likely be using a cheaper service from the Resources Agency which will require a cost of $50,000 in Fiscal Year 2018/19 but should result in lower costs in the long run. To be conservative, the Energy Commission used $50,000 for Fiscal Year 2018/19 and $78,718 for Fiscal year 2019/20. This estimate is for storage of electricity data collected pursuant to Section 1353 only; the amount of natural gas data that will be collected is much smaller. In fact, the Energy Commission estimates that the overall size of the natural gas data would be between 20 GB and just over 1 TB, all of which is easily held on a single hard drive or server. Assuming however, that AWS S3 prices are used for the estimate, the cost of natural gas data storage may be an additional $1 - $28 a year. Because this amount is exceedingly small and speculative, we have not included it in the cost estimate.

Identifying Costs to Private and Public Obligated Parties

The regulations impose new or modified reporting requirements on owners of cogeneration facilities, and natural gas utilities and UDCs, with some of the modifications affecting only the larger of the latter two. Owners of cogeneration facilities can be private (e.g., a small business or an investor-owned utility regulated by the California Public Utilities Commission or CPUC) or public (e.g., a local publicly-owned electric utility). Natural gas utilities are private, while UDCs can be either private (e.g., an investor-owned utility regulated by the CPUC) or public (e.g., a local publicly-owned electric utility). In order to separately identify the costs of private and public obligated parties, the Energy Commission assumed all obligated parties for each proposed section had the same costs for each data requirement and scaled the costs to the number of private and public entities impacted by the proposed regulations. For example, the proposed language in Sections 1344 and 1345 impacts the five largest California UDCs, three of which are private investor-owned utilities and two of which are local publicly-owned electric utilities. Thus, 60 percent of the estimated costs would be borne by investor-owned utilities and the remaining 40 percent would be borne by local publicly-owned electric utilities.

An exception to this approach was used for 1304(a). Of the 349 cogenerationfacilities impacted by Section 1304 (a) changes, 94 are local publicly-owned units and 255 are private. Because costs are established on a per unit basis, 73 percent of the costs are private and 27 percent are public. The proposed changes to Section 1304 (a) only impact cogenerator owners, not the owners of approximately 450 other power plants for which data is reported under Section 1304.

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the regulations involve only 15 fields and may be at 15 minute intervals, the 12.5 MB value was reduced by nearly a quarter and resulted in the 9.375 MB estimate.

[2] https://www.eia.gov/electricity/data.php#sales

[3] https://aws.amazon.com/s3/pricing/

Natural gas utilities are all privately owned so there is no need to differentiate between public and private costs for changes to natural gas data collection requirements.

Estimates for First 3 Fiscal Years

Estimates are provided for fiscal years 2017/18, 2018/19, and 2019/20. Although the regulations are expected to go into effect January 1, 2018, or shortly thereafter, some one-time startup costs may be incurred before the regulations go into effect during the first fiscal year, so we have provided an estimate for fiscal year 2017/18.

Fiscal year 2018/19 is the first year in which compliance with the regulation is required. However, general costs may be higher in fiscal year 2017/18 as new data activities are undertaken.

Fiscal year 2019/20 represents full implementation, representative of the costs associated with the regulations on an ongoing basis.

Section 1302 Definitions

The proposed regulatory changes within Section 1302 focus on clarifying and adding definitions to improve the understanding of the proposed regulations. Since the changes to Section 1302 are administrative in nature and do not independently require reporting, the Energy Commission estimates there would be no cost impacts due to the proposed regulations in this section.

Costs to Obligated Parties

There are no cost impacts to any obligated parties due to clarifying and adding definitions to this section. The proposed language would not result in any changes to reporting processes.

Costs to the State

There are no cost impacts to the state due to clarifying and adding definitions to this section. The proposed language would not result in any changes to reporting processes.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

The proposed regulations within Section 1302 would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform all the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment.

Section 1304 (a)(1) and (2) Cogeneration Data

Changes to these subdivisions require the provision of waste heat and useful thermal output along with customer classification codes of recipients by the 139 owners of 349 cogeneration facilities. These owners already provide detailed energy data about the facilities to the Energy Commission as part of the existing Section 1304 (a)(1) and (2) regulations. Non-cogenerator power plant owners who currently report under Section 1304 will not be impacted by the proposed regulatory changes.

The changes will allow the Energy Commission to collect information needed to estimate cogeneration (also referred to as combined heat and power or CHP) efficiencies by obtaining the useful thermal output. Current regulations focus only on total thermal energy data and do not distinguish between the useful and waste components. Most of the targets/goals for CHP development are based on the idea that they are more fuel-efficient and therefore have lower emissions. Currently CHP facility fuel-efficiency is estimated. The useful thermal output data would provide a solid analytical basis for current and future CHP policy and ensure promoting CHP development is still consistent with state environmental goals.

Costs to Obligated Parties

Obligated parties impacted by the proposed regulations are comprised of 139 power plant owners of an estimated 349 cogeneration facilities; these entities report generation data to the Energy Commission as part of the existing Section 1304 regulations. Non-cogeneration power plant owners will continue to report in accordance with the Section 1304 and will not be impacted by the proposed modifications. Of the 139 owners required to report on cogeneration facilities, 37 are public, and the rest are private. The proposed regulations would require two additional data points for each unit to identify the useful thermal output that is being captured and the customer classification code of the recipient.

There would be no expansion of any industries to comply with the data request. Staff estimates that obligated parties maintain this data for business purposes and would be able to retrieve it from existing datasets. The new requirement may involve the development of an additional process or query to extract the detailed data for reporting. Developing a single initial process for pulling data from an existing system would take, approximately 24 minutes for each facility. Staff estimates it would take about 3.5 hours to test (24 minutes), revise (24 minutes), obtain internal approval on reporting (just under 1.6 hours), and integrate with existing reporting processes (1.2 hours). This leads to a conservative estimate of approximately 4 hours to develop a reporting process for the new data reporting requirement per unit for a one-time effort in the first fiscal year.

Not all obligated parties have staff on hand to perform this work and it may require using a database administer or programmer to perform some of these tasks. Therefore, the Energy Commission has used the average hourly rate of $93 for a Programmer as defined in the California Department of General Services procurement list for IT services.

The described estimates results in a fiscal year 2017/18 cost, including development work, of $119,552 for private cogeneration facility owners, and $44,070 for local public cogeneration facility owners.[4]

Once developed, the recurring reporting will be accomplished through the use of a standard query to collect the data, followed by a creation of a summary, and filing a report. Querying, validating, and

[4] The total costs are allocated equally across all cogeneration facilites with 255 of the 349 units being identified as private. The remaining 94 units are public.

summarizing two additional data points should take no more than 30 minutes (0.25 hours + 0.25 hours) and reporting the data on the Energy Commission's modified forms would take a couple of minutes per unit. Including additional time to confirm the data is entered properly, staff has estimated the reporting to take 7 and half minutes (0.125 hours) per unit. About 69 percent of units (242 units of 349 total units) report quarterly while the remaining unit data is reported annually. In fiscal year 2017/18 only two quarterly reports are assumed to be submitted.

Using the $93 per hour average programmer rate and the fact that 73 percent of units are private, the recurring reporting costs are estimated for fiscal year 2018/19 to be $47,024 for private cogeneration facility owners and $17,334 for local public cogeneration facility owners. For fiscal year 2019/20 costs are estimated at $48,435 for private cogeneration facility owners and $17,855 for local public cogeneration facility owners.

Costs to the State[5]

The proposed section 1304 (a)(1)&(2) would require Energy Commission staff to undertake two categories of activities.

First, in order to facilitate the reporting of the new data Energy Commission staff would need to modify, disseminate, and answer questions regarding updated templates used to collect related data. Additionally, Energy Commission staff responsible for extracting the data would need to be informed about the new data. In total, over the course of modifications, staff estimates this would result in 80 hours of staff time dedicated to the one-time modifications necessary to obtain the data. This work would be completed by an Electric Generation System Specialist I at an hour rate of $57.84 and result in a total one-time cost of $4,628 in fiscal year 2017/18 only.

Second, for each reported value, Energy Commission staff would need to acquire, validate, and review the data submittal. Since this is part of an existing data management process, the staff time to perform these activities would take less than a minute for each data point submitted. As there would be two new data points (useful thermal energy and customer classification code of the recipient) for each of the 349 cogeneration facilities and considering the frequency of reporting, either quarterly or annually based upon total generation capacity by obligated party, there would be approximately 1182 new data points for a half year of reporting and 2150 new data points for a full year of reporting. A conservative estimate would be that this reporting would require 1200 minutes or 20 hours of Energy Commission staff time for a half year of reporting and 2150 minutes or approximately 36 hours for a full years of reporting This work is assumed to be completed by an Electric Generation System Specialist I at a rate of $57.84 per hour and would result in a total annual cost of $1,157 in fiscal year 2017/18, $2,145 in fiscal year

[5] As this data would be collected and managed with other data reported to the Energy Commission, there should be no cost to the state outside of staff time to update the relevant data reporting templates. Staff time consists of entering two additional pieces of data to the updated reporting templates, which should conservatively take approximately 2 minutes. Given that approximately 349 cogeneration facilities have data reported to the Energy Commission, this should result in approximately 35 hours 50 minutes of staff time per year.
(2 staff minutes/facility report) x ((242 facilities) x (4 facility reports/facility/year)+(107 facilities) x (1 facility report/facility/year)) = 2,150 staff minutes per year
= 35 hours 50 minutes of staff time per year.

2018/19 and $2,209 in fiscal year 2019/20. As a conservative estimate, the Energy Commission also assumed a need to resolve data reporting issues with the reporting parties. These efforts are estimated to result in an additional 5 hours of work for each quarter although this may decrease as parties become familiar with the required data. This work is assumed to be completed by an Electric Generation System Specialist I at a rate of $57.84 per hour and would result in a total annual cost of $578 in fiscal year 2017/18, $1,192 in fiscal year 2018/19 and $1,227 in fiscal year 2019/20.

Summing the costs associated with these two categories of activities together, the revisions to section 1304 (a) are estimated to cost the state $6,363 in fiscal year 2017/18, $3,336 in fiscal year 2018/19 and $3,437 in fiscal year 2019/20.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the owners of cogeneration facilities are required to comply with the reporting requirements of this section. For these entities, the costs associated with compliance with the proposed revisions to this section are negligible, and could be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed revisions to Section 1304 (a)(1) and (2) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect facility operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would have indirect benefits, including estimating the efficiency of these facilities and their role in helping the state meets its greenhouse gas emissions reduction goals. These are discussed generally in the Benefits section of the initial statement of reasons (ISOR), and specifically in the explanation of the Purpose and Necessity for this section.

Section 1304 (b) Interconnection Data

The proposed changes in subdivision (b) would require the inclusion of energy storage systems data in reporting interconnections and would eliminate the reporting threshold for interconnected electric generation resources, thereby expanding the interconnected resources required to be reported to the Energy Commission.[6] Utility Distribution Companies (UDCs) would be required to provide interconnection data collected as part of the interconnection application process twice a year. There are 56 California UDCs that will be impacted by this regulation, most of which are smaller local publicly-owned electric utilities, the remainder of which are private investor-owned utilities.[7]

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[6] The term "interconnections" refers to electric generators, including roof top solar, and storage systems interconnections to utility distribution company (UDC) distribution systems.

[7] http://www.energy.ca.gov/almanac/electricity_data/utilities.html

Costs to Obligated Parties

All UDCs are obligated to provide interconnection data to the Energy Commission under the existing regulation. The modifications would result in the elimination of the size threshold, so that all interconnected facilities would need to be reported by each UDC. In addition, UDCs would be required to report the interconnection of energy storage systems. Of the 56 obligated parties, five UDCs have an electric load greater than 1,000 MW. The three large UDCs that are investor-owned utilities that currently have the obligation to collect and provide some of the interconnection data identified in the proposed modifications to the California Public Utilities Commission, and the additional reporting to the Energy Commission should involve negligible cost. Additionally, the two largest local publicly-owned electric utilities have significant electric generation resources that are tracked in detailed electronic databases. As such, the cost impacts to these five large UDCs for reporting data to the Energy Commission would be small and would primarily involve sending information to the Energy Commission that is already collected in the course of business. Still, these five UDCs may need to revise existing queries to capture the data required in the proposed regulations. This would involve expanding the existing process of gathering interconnection data by revising current queries, testing, resolving issues, and developing reports for the submission to the Energy Commission. Staff estimates this should take 10 hours to complete since much, if not all, of the data is already collected in an electronic format. The recurring costs would involve running the query, summarizing the data appropriately, and sending the data to the Energy Commission and annually would take 60 hours, 40 hours, and 20 hours, respectively.[8]

For the smaller UDCs with electric load that is 1,000 MW and lower, data delivery to the Energy Commission may involve querying existing interconnection agreement data and summarizing into a single data set for delivery to the Energy Commission. The one-time cost of query development is estimated as 80 hours to write the query, test the query, and identify and resolve any issues with the data reporting. Similar to the larger UDCs, the recurring costs would involve running the query, summarizing the data appropriately, and sending the data to the Energy Commission. The smaller UDCs would likely have much lower costs than estimated here due to the smaller number of interconnected resources.[9]

The five largest UDCs would likely employ a programmer to write and implement the queries at an average rate of $93 per hour. As another conservative assumption, $93 per hour is also used to estimate the costs for other obligated parties, although data entry would likely be performed by someone at a

[8] Since fiscal year 2017/18 is only half a year, the costs are estimated as 30 hours for data collection, 20 hours for summarizing, and 10 hours for reporting.

[9] Not all UDCs have fully automated systems to report the information and, in some instances, procedures would need to be implemented for summarizing and reporting the data. In 2014, there were a total of 4,826 interconnections reported to the Energy Commission by the 51 smaller obligated parties. Historically, approximately 17 of these UDCs have identified fewer than 10 total interconnections. Entering the information manually for all 4,826 interconnections into a file from interconnection agreement documents is conservatively estimated to take just over three hours for each obligated party. Staff arrived at the 3 hour estimate by performing its own timed data entry for 18 data elements, as requested in the proposed regulations, and deriving an estimate of just over 3 minutes per entry. Rounding this up to 4 minutes, multiplying by 4,826 for all the interconnections and dividing by 60 minutes per hour, 51 obligated parties, and 2 for each annual reporting event resulted in an estimate of 3 hours and 9 minutes.

lower rate than $93 an hour. Taking into account the difference in costs between large and small UDCs, total costs for fiscal year 2017/18 are $58,590 for investor-owned utilities, and $637,980[10] for local publicly-owned electric utilities. (The costs are greater for local publicly-owned electric utilities both because there are a greater number of them, and because some may lack the automated systems used by the larger UDCs.)

In each of the following years, because the query will already be developed, the estimated costs for all obligated parties would be lower. Costs are estimated to be $68,969 and $574,740 respectively for privately owned and local publicly-owned electric utilities in 2018/19, and $71,038 and $591,982 respectively for privately owned and local publicly-owned electric utilities in 2019/20. These costs increase slightly over time as salaries increase and as the number of interconnections increase although these increases would be mitigated by possible reporting automation.

Costs to the State

In order to facilitate the reporting of the new data, Energy Commission staff would be modifying, disseminating, and answering questions regarding new data requirements. The data provided under Section 1304 (b) isn't standardized; UDCs can use any format they find convenient. This practice would continue under the proposed change to Section 1304 (b). Energy Commission staff responsible for extracting the data would need to be informed about the new data and staff may need to answer questions regarding the new fields. In total, over the course of modifications, staff estimates this would result in 40 hours of staff time dedicated to the one-time modifications necessary to obtain the data. This one time activity would add a cost of $2,314 to the state's costs in fiscal year 2018/19 since data reporting is required semi-annually requiring the first data to be submitted in July of 2018.

Energy Commission staff would also need to acquire, validate, and review the new data submittal. Much of this is handled with automated validation checks of submitted data and would not result in significant additional time. In total additional staff time to manage the new data is estimated at 125 hours to process and validate the data, 30 hours to resolve any data issues, and 5 hours to ensure the data is properly imported for each reporting event. Annually this would result in a total of 320 hours (250 hours to process, 60 hours for data issues, 10 hours for importing) of work being performed since there are two reporting events each year and combined with the one-time development costs (40 hours, costing $2,314) would result in an estimated cost of $21,379[11] in fiscal year 2018/19, and $19,638 in fiscal year 2019/20. Note that state costs are expected to decrease in the final year as staff becomes familiar with data, issues with data reporting are resolved, and data management processes are automated.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

California investor and publicly-owned utilities are required to comply with the reporting requirements of this section. For these utilities, the costs associated with compliance with this section are negligible,

[10] Of the 56 electricity utilities obligated to report under this section, 6 are investor-owned utilities while 50 are publicly-owned utilities. Most of the publicly-owned utilities are smaller and would need to spend more time automating their data collection processes in contrast to the larger utilities whose billing and metering systems are mature and are largely automated.
[11] Assumes the work is performed by an Electric Generation System Specialist at an hourly rate of $57.84.

and can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed revisions to Section 1304 (b) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect UDC operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit to the direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would have indirect benefits, including monitoring the expansion and adoption of interconnected resources, and their role in the state's efforts to achieve greenhouse gas emissions reduction and other energy goals. These are discussed generally in the Benefits section of the ISOR, and specifically in the explanation of the Purpose and Necessity for this section.

Section 1306 (a) Quarterly UDC Reports

The proposed modifications would relieve the five largest utility distribution companies (UDCs) from quarterly reporting of customer data identified in Section 1306 (a) after January 1, 2019. This change would result in a savings to both UDCs and Energy Commission staff for processing, managing, and validating the submitted data. It is important to note that the reduction in reporting under this section is coupled with a new requirement that more customer data be provided by the five UDCs under proposed Section 1353. The costs associated with those reporting requirements are addressed in the discussion of that section, below. The following costs savings are estimated for both obligated parties and state staff due to the reduction in reporting requirements under this section.

Avoided Costs to Obligated Parties

UDCs under the current regulation have to report various types of customer data on a quarterly basis to the Energy Commission. The UDCs that will be relieved of the reporting obligation under this proposed modification have automated much of the reporting process and submit their information via email. The submittal is internally automatically processed at the Energy Commission. If there are specific issues with reporting, Energy Commission staff must resolve the issues by talking with UDC staff. On a quarterly basis, about 30 minutes is estimated to query the data and format, 30 minutes to compose the message to the Energy Commission, attach the data file, and transfer the data. Historically there are a few mistakes in data reporting, which take an estimated 4 hours every quarter to discuss and resolve. The reporting requirement is not eliminated until January 1, 2019; therefore, there is no avoided cost in the first fiscal year. Elimination of the reporting requirement would result in an avoided cost in fiscal year 2018/19 of $758 for the three investor-owned utilities, and $505 for the two local publicly-owned electric utilities. In fiscal year 2019/20, avoided costs are estimated to be $1,561 for investor-owned utilities and $1,041 for local publicly-owned electric utilities).[12]

[12] Assumes the work is performed by a senior engineering utility staff with an hourly rate of $68.13 estimated from a PG&E engineering positions Glassdoor salary survey.

Avoided Costs to the State

The Energy Commission has two staff that manage and work on the electricity data which is submitted through Section 1306 (a). According to estimates from past reporting, staff estimates that they would annually spend 4 hours less on validating and reviewing data, 16 hours less on resolving data issues, and 4 hours less on appending and updating the database. It is assumed this work would be performed by an Energy Commission Specialist I at an hour rate of $43.88. The reporting requirement does not change until January 1, 2019; therefore, there is no avoided cost in fiscal year 2017/18. Estimated savings of $633 begin in fiscal year 2018/19 and $1,117 in the fiscal year 2019/20.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

The proposed regulations within Section 1306 (a) would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment.

Section 1308 (a) and (b) Monthly Natural Gas Data

The proposed regulatory language is a clarification of existing language has been inserted at the request of obligated parties to reflect current conditions within California's natural gas distribution network. No changes to reporting would result from the changing of the proposed location names.

Costs to Obligated Parties

There are no cost impacts to obligated parties due to clarifying distribution location names. The proposed language would not result in any changes to reporting processes.

Costs to the State

There are no cost impacts to obligated parties due to clarifying distribution location names. The proposed language would not result in any changes to reporting processes.

Potential Impacts of Proposed Regulations

The proposed regulations within Section 1308 (a) and (b) would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform all the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment.

Section 1308 (c) Monthly Natural Gas Deliveries

The proposed regulation would relieve the three largest natural gas utilities from quarterly reporting of customer data identified in Section 1308 (c) after January 1, 2019. This change would result in a savings to both natural gas utilities and Energy Commission staff for processing, managing, and validating the submitted data. It is important to note that the reduction in reporting under this section is coupled with a new requirement that more customer data be provided by the natural gas utilities under proposed Section 1353. The costs associated with those reporting requirements are addressed in the discussion of that section, below. The following costs savings are estimated for both obligated parties and state staff from the reduction in reporting requirements under this section.

Avoided Costs to Obligated Parties

Natural gas utilities have to report under the current regulation various types of customer data on a quarterly basis to the Energy Commission. The natural gas utilities that would be relieved of the reporting obligation under this proposed modification have automated much of the reporting process and only have to submit their information in electronic format; this information is then internally automatically processed. If there are specific issues with reporting, Energy Commission staff must resolve the issue by talking with natural gas utilities. On a quarterly basis, about 30 minutes is estimated to query the data and format, 30 minutes to compose the message to the Energy Commission, attach the data file, and transfer the data. There can be a few mistakes that take time to resolve and this is estimated to take about 30 hours every quarter and would involve communicating with Energy Commission staff to resolve. The three natural gas utilities would no longer be required to report after January 1, 2019; therefore, there is no avoided cost in the first fiscal year. For fiscal year 2018/19 estimated savings are $3,579 and fiscal year 2019/20 estimated savings are $7,373.[13]

Avoided Costs to the State

The Energy Commission has staff that manages and works on the natural gas data which is submitted through Section 1308 (c). Based on past experience working with this data, staff estimates that every year they would spend 4 hours fewer on validating and reviewing data, 30 hours fewer on resolving data issues, and 4 hours fewer on appending and updating the database. It is assumed this work would be performed by an Energy Commission Specialist I at an hour rate of $43.88. The reporting requirement does not change until January 1, 2019; therefore, there is no avoided cost in the first fiscal year. In the fiscal year 2018/19 state avoided costs are estimated at $859 and $1,769 for fiscal year 2019/20.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

The proposed regulations within Section 1308 (c) would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform all the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment.

[13] Assumes the work is performed by a senior engineering utility staff with an hourly rate of $68.13 estimated from a PG&E engineering positions Glassdoor salary survey.

Section 1314 Natural Gas Modeling Data

The natural gas utilities are responsible for monitoring and managing the natural gas distribution systems to ensure the safe operation of the distribution system, and to ensure an adequate supply of cost effective resources is available to customers, including electric generators. One important activity natural gas utilities perform to meet these responsibilities is modeling the natural gas distribution system using hydraulic modeling software. The proposed data regulations require the three California natural gas utilities to provide their hydraulic modeling data to the Energy Commission.

Costs to Obligated Parties

Since the modeling work is already performed in the normal course of business for the obligated three largest natural gas utilities, this regulation would not require them to collect additional data. Similarly, the data infrastructure already exists to manage the data and there is no need for additional databases or querying to gather the data. However, there is estimated to be a small cost associated with gathering the data, transferring it to the Energy Commission, and being available to address any questions and resolve data issues. Gathering the data is expected to cost $2,044 and the data transfer is estimated to cost $409 in fiscal year 2017/18 and would involve the delivery of the data via a secure electronic method. Although the natural gas utility staff time to address questions and data issues may change over time, the Energy Commission estimates that on average it would take 20 hours at a total annual cost of $4,088 in the first year of reporting, assuming the work is performed by a Senior Gas Control System Engineer with an hourly rate of $68.13. In summary, the Energy Commission estimates the total costs for all three obligated natural gas utilities to be $6,541 in fiscal year 2017/18, $6,737 in 2018/19, and $6,939 in 2019/20.

Costs to the State

The state has approved one position for the Energy Commission through a Budget Change Proposal (BCP). This position is for an engineer who will perform modeling and assessment of the natural gas sectors to ensure electric service reliability. The Department of Finance 2016-2017 Finance Letter Worksheet (3360-001-0381-2016) indicates a net impact of $579,666 for the one position with salary and wages, staff benefits, and operating expenses. Because this position has already been approved, the costs associated with it are not included in the fiscal impacts associated with the new regulation. No special equipment or infrastructure is required to handle or house the data.

In addition to the approved position, other Energy Commission employees will work with this data. State costs attributable to this work include those associated with data validation and review, resolving any issues, and finalizing data sets for simulation work. Annually the validation, resolving issues, and data finalization work will require 90 hours, 30 hours, and 10 hours, respectively.[14] This work is estimated to total $3,760 in fiscal year 2017/18, $7,745 in fiscal year 2018/19, $7,978 in fiscal year 2019/20.

[14] Reporting will being half way through fiscal year 2017/18 so the costs are estimated at half the total annual costs.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the three largest natural gas utilities are required to comply with the reporting requirements of this section. For these utilities, the costs associated with compliance with this section are negligible and can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed Section 1314 would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect natural gas utility operations, this section would neither create nor eliminate any businesses doing business in California, nor would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would have indirect benefits, including the ability to perform modeling of the natural gas distribution network and develop associated energy policies to address natural gas and electric system reliability and impacts to the environment associated with the state's natural gas and electricity systems. These are discussed generally in the Benefits section of the ISOR, and specifically in the explanation of the Purpose and Necessity for this section

Section 1344 (f) Behind-the-meter Load Impacts

At any given time, the energy demand information collected from customer meters represents only the amount of energy sold to the customer at that time, not the actual amount of energy being consumed by the customer. For example, if the customer owns generation, such as a photovoltaic system or storage, such as a battery system, the amount of energy sold by the UDC to the customer does not necessarily reflect the amount of energy consumed. In addition, the use of electric vehicles can have a profound effect on the grid. Electric vehicles require charging and also have the potential to act as mobile energy storage resources. Much research has been performed to evaluate the process for what is referred to as vehicle-to-grid integration, creating the infrastructure and information to utilize electric vehicles to assist with electric grid management.

These resources and loads modify the consumption measured by the UDC meter. In order to evaluate and understand the magnitude of these resources on the broader energy needs, the rates of adoption, and the operational behaviors, the amount of energy consumed by electric vehicles and the amount generated by PV systems and storage (including EVs) need to be quantified. This requires data on activities that occur 'behind-the-meter,' meaning that the information being collected must come from the location where the activity occurs, and not at the UDC meter, where customer demand and supply are aggregated. This information can be collected by methods such as surveying or monitoring representative populations over time, measuring the demand of specific end-uses or generation (called sub-metering), collecting information from generation sources through smart inverters, or estimating loads by leveraging other studies or research. As part of the operation, planning, and monitoring of the electricity grid, utilities study grid impacts using these methods.

In order to improve the peak demand load forecasts, disaggregate the impacts of these new behind-the-meter resources, track the success or failures of specific policies and programs, and assist with development of new policies, the amendments proposed for this regulation would require the five largest UDCs to provide the detailed load data from their behind-the-meter research targeting three specific potential impacts: photovoltaic installations, energy storage systems, and electric vehicles.

Costs to Obligated Parties

The proposed regulations obligate the five largest UDCs to provide the behind-the-meter impact information to the Energy Commission. Since the regulation is explicitly limited to work being performed by the UDCs, there is only a cost to transmit the information to the Energy Commission. In some cases, there would be minimal coordination required by the UDC staff to gather the information obtained during the load research to provide to the Energy Commission.

There are likely instances where multiple groups within a UDC would lead different areas of load research, which would require some coordination within the UDC to gather the information necessary to comply with the proposed regulations. Most of the cost would involve the initial identification and coordination of the data collection with a much shorter amount of time required afterwards, since key UDC staff would be engaged in the reporting process. The Energy Commission estimates that it would take approximately 160 hours in the first fiscal year to gather the existing data for reporting, which would include identifying and contacting appropriate UDC staff, internally discussing and reviewing information, and collecting the required data. Energy Commission staff estimates it would take 40 hours each subsequent year to complete this work, since it assumed a procedure for communication, identification, and delivery of data would be promulgated.

Once the information is collected, the data would be organized and transferred to the Energy Commission. The Energy Commission estimates that it would take 8 hours to organize and describe the data and another 8 hours to determine appropriate transfer methods and transfer the files to the Energy Commission in fiscal year 2017/18. Once the initial procedures are developed for data transfer, it is estimated to take only 4 hours to transfer the information. Following delivery, clarifying questions regarding the data would need to be addressed and are estimated to initially cumulatively involve 40 hours of UDC staff time for the first data delivery and only 8 hours for future data, since many of the types of questions would have been identified. Using the hourly rate for a Systems Analyst of $93, the total costs for fiscal year 2017/18 are $60,264 for the three investor-owned utilities and are $40,176 for the two local publicly-owned electric utilities. Costs for fiscal year 2018/19 are estimated to be $17,242 and $11,495 respectively for investor-owned utilities and local publicly-owned electric utilities, and for fiscal year 2019/20 are estimated to be $17,759 and $11,840 respectively for investor-owned utilities and local publicly-owned electric utilities.

Costs to the State

The energy load impact research data would need to be reviewed, categorized, and formatted. After the load data is provided to the Energy Commission, the data would need to be evaluated for quality, representativeness, and any missing data. This work is estimated to take Energy Commission staff 40 hours. Energy Commission staff would then need to resolve any issues with the data collaboratively with the obligated utilities. The resolution of issues should be straightforward and would primarily involve obtaining additional descriptive or explanatory information from the utilities. Communicating with UDC staff and clarifying the data is estimated to take 16 hours. Once the data is complete and clearly understood, Energy Commission staff would evaluate the data and format to integrate into the development of regional or local area peak load estimates. The evaluation and formatting of the data is estimated to take 80 hours. This work involves an understanding of both the data and the peak load evaluations and would be performed by a mid-level Energy Commission staff, Energy Commission Specialist II. The fiscal year 2017/18 total annual cost for these activities is estimated at $6,556, for fiscal year 2018/19 the costs are $6,752, and for fiscal year 2019/20 the costs are $6,955.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the five largest UDCs are required to comply with the reporting requirements of this section. For these utilities, the costs associated with compliance with this section are negligible, and can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed Section 1344 (f) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect UDC operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this proposed regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would have indirect benefits by incorporating peak load impacts from emerging behind-the-meter loads into the load data provided using electric meters. These benefits are discussed generally in the Benefits section of the ISOR, and specifically in the ISOR explanation of the Purpose and Necessity for this section.

The proposed regulations within Section 1344 (f) would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform all the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would have indirect benefits, including the development of better electricity demand forecasts and an improved ability to track the role of these specific behind-the-meter activities in meeting the state's greenhouse gas emissions reduction and other energy goals. These are discussed generally in the Benefits section of the ISOR, and specifically in the explanation of the Purpose and Necessity for this section.

Section 1353 Disaggregated Demand Data

The proposed Section 1353 regulation requires each UDC that has either a peak electricity demand of 1,000 megawatts or more or natural gas utility that delivers 200 million therms or more for both of the two preceding calendar years to report detailed customer data to the Energy Commission. This data would include interval meter data when available and would provide the data necessary to support data quality measures, track progress to meet goals, and allow for local forecasting analytics. Similar data is also required from the state's largest three natural gas utilities.

Section 1353 (a) Disaggregated Data Reporting

As the Energy Commission begins collecting more detailed information from the UDCs and natural gas utilities, specific reporting requirements associated with the new detailed information are required to ensure appropriate reporting, transmission, and explanations of the data. The proposed data reporting regulations specify the frequency and scope of the data delivery. In addition, the proposed regulations require the obligated parties to provide explanations of the data provided so the Energy Commission understands what the data represents and can make informed decisions about the appropriateness and uncertainty of the data use for Energy Commission analytical purposes.

Costs to Obligated Parties

The only costs attributable to subdivision (a) are those associated with the requirement that the obligated parties provide information regarding the methodology and procedures for estimating values would involve work on the part of the utilities to summarize and report to the Energy Commission. On the electric side, UDCs San Diego Gas and Electric Company, Southern California Edison Company, Pacific Gas and Electric Company, Los Angeles Department of Water and Power, and Sacramento Municipal Utility District will report. On the natural gas side, natural gas utilities Southern California Gas Company, San Diego Gas and Electric Company, and Pacific Gas and Electric Company will report. The six electric and natural gas utilities (four investor-owned utilities and two local publicly-owned electric utilities) required to report under Section 1353 (b) and (c) would need to identify and determine all methods used to estimate data that they would be reporting.[15] It is estimated that it would take 160 hours in fiscal year 2017/18 to identify all the appropriate methods and would involve communication within the utilities across staff. The explanation of the methods and procedures would have to be summarized, which is estimated to take 80 hours. Once completed, the report would need to be provided to the Energy Commission and is estimated to take 5 hours each reporting cycle. It is assumed each of the six obligated parties use Systems Analyst staff at a rate of $93 per hour.[16] This results in costs for fiscal year 2017/18 of $93,000 for investor-owned utilities, and $46,500 for local publicly-owned electric utilities.[17] Recurring costs would include packaging and sending the information, estimated at 5 hours for each submittal, and the additional time necessary to update the document if there are any changes to the methods or procedures, estimated at an average of 10 hours for fiscal year 2017/18 and 20 hours for each subsequent fiscal year. Using the $93 per hour rate for UDC staff time, fiscal year 2018/19 costs are

[15] There are six obligated parties for 1353 (a) since it covers both electricity (5) and natural gas (3) with two overlapping obligated parties.

[16] The Energy Commission was unable to find a reference to salaries or rates specifically for a utility Systems Analyst but believes that the average contracted programmer rate of $93 is a conservative estimate of the potential costs for the utilities. The actual rate of a utility analyst would likely be lower.

[17] Of the 6 obligated utilities, 4 are investor-owned utilities while 2 are publicly owned.

$22,990 for investor-owned utilities and $11,495 for local publicly-owned electric utilities, and for fiscal year 2019/20 costs are $23,679 for investor-owned utilities and $11,840 for local publicly-owned electric utilities.

Costs to the State

In order to understand the data provided to the Energy Commission, staff would need to evaluate and understand any estimation methodologies being used to compile the data provided to the Energy Commission. A review and discussion regarding the methodologies of the procedures identified by the utilities is estimated to take 120 hours. It is also estimated that staff would have questions regarding the methods and would need to work with utilities to clarify their understanding of the procedures. The communication and clarification of the methods is initially estimated to take 20 hours. The costs for fiscal year 2017/18 are $6,748, assuming an Energy Commission Specialist II would be responsible for this work. Once the procedures are understood, future changes to the methods and any clarification discussions are estimated to take 20 hours total per year and result in a cost for fiscal year 2018/19 of $993, and a cost for fiscal year 2019/20 of $1,023.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the five largest electricity and three natural gas utilities are required to comply with the reporting requirements of this section. For these utilities, the costs associated with compliance with this section are negligible, and can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed Section 1353 (a) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect UDC or natural gas utility operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit of the data collection to the health and welfare of California residents, to worker safety, or to the state’s environment. However, collecting the estimation methodologies would have indirect benefits, similar to those discussed below for subdivisions (b) and (c).

Section 1353 (b) Monthly and Interval Meter Electricity Data

The proposed data regulations require the largest five UDCs to provide customer-level monthly and interval data, with the interval depending on the metering technology for the customer. This data would be provided quarterly. Current data regulations require the UDCs to provide monthly consumption and revenue information aggregated by county and customer classification code on a quarterly basis. The proposed regulations would instead require the UDCs to replace the aggregated data by providing data by the customer meter.

Costs to Obligated Parties

The utilities are currently required to provide aggregated customer consumption information whereas the proposed regulations would require the UDCs to provide meter level customer data. Since the UDCs have been aggregating this data to report to the Energy Commission, providing the disaggregated information would require a modification of existing queries to their databases. The development of a query of the system to provide the proposed data is estimated to take 160 hours for each UDC over the first two fiscal years, costing approximately $75,000 each year ($74,400 in fiscal year 2017/18 and $76,632 in fiscal year 2018/19) assuming a consultant Systems Analyst rate of $93 per hour.

The collection of the data using the automated reporting process is estimated to take 10 hours for each quarterly report which would include data quality checks and resolving issues with the queried data. The data would need to be briefly summarized with a data dictionary or other explanations and then delivered to the Energy Commission. Summarizing the data is estimated to take 5 hours and reporting should only take an hour for each submitted report. This work would also be performed by a Systems Analyst with an hourly rate of $93 per hour.

This results in costs for fiscal year 2017/18 of $53,568 for investor-owned utilities and $35,712 for local publicly-owned electric utilities.[18] Costs are estimated to be $64,371 and $42,914 respectively for privately owned and local publicly-owned electric utilities in 2018/19, and $18,943 and $12,629 respectively for privately owned and local publicly-owned electric utilities in 2019/20.

Costs to the State

The Energy Commission is implementing a data repository solution that would be capable of managing the monthly and interval meter data proposed for collection in Section 1353 (b). The cost of data storage for this new data is discussed in the "Data Storage Costs" section of this Economic Impact Assessment. Because the Energy Commission's existing framework for data governance and data management processes will apply to this new data there are no governance or management costs associated with the receipt of this new data. As discussed in that section, the Energy Commission estimates costs of $50,000 for Fiscal Year 2018/19 and $78,718 for Fiscal year 2019/20.[19]

The data acquisition staging, testing, validation, and developing access procedures work will take a group of Energy Commission staff comprised of Senior Programmer Analysts and Energy Commission Specialist IIs an estimated 1240 hours to complete these one-time activities across fiscal years 2017/18 and 2018/19.

Ongoing data review and validation work would take about 160 hours each quarter. Resolving data issues is estimated to take 40 hours per quarter. Additionally, data analysis and making the data usable for forecasting staff is estimated to take another 60 hours per quarter. All of this work would be

[18] Of the five obligated UDCs, three are investor-owned utilities while two are local publicly-owned electric utilities. All reporting and data collection costs are assumed to equal across all five utilities.

[19] As discussed in the General Assumption, Data Storage Costs estimation, the AWS S3 cost estimate is at $39,659 for Fiscal Year 2018/19 and $78,718 for Fiscal Year 2019/20. However, to be conservative, the Energy Commission has used $50,000 for Fiscal Year 2018/19 as estimated by the Resources Agency to provide storage services.

performed by Energy Commission Specialist IIs. The data review, data issue, and analysis work would result in fiscal year 2017/18 costs of $15,525, $3,856, and $5,784, respectively. The cost of housing the data is estimated to be $50,000 fiscal year 2018/19. The total costs to the Energy Commission are estimated at $69,893 in fiscal year 2017/18, $120,530 in fiscal year 2018/19, and $123,720 in fiscal year 2019/20.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the five largest UDCs are required to comply with the reporting requirements of this section. For these UDCs, the costs associated with compliance with this section are negligible, and the required reporting can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed revisions to Section 1353 (b) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect UDC operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit to the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would have indirect benefits, including the to the ability to perform regional and local electricity demand forecasts, the ability to perform data quality analyses, and the ability to cross reference data across data sets. These in turn will allow the Energy Commission to track the various factors that affect electricity consumption and the effectiveness of programs and policies designed to assist the state in meeting its reliability, greenhouse gas emissions reduction, and other energy goals. These are discussed generally in the Benefits section of the ISOR, and specifically in the explanation of the Purpose and Necessity for this section.

Section 1353 (c) Monthly Natural Gas Customer Data

The proposed regulations obligate natural gas utilities whose annual natural gas deliveries exceed 200 million therms in the two preceding calendar years (PG&E, SoCalGas, and SDG&E), to provide monthly data for each customer to which service is provided. This is basically the disaggregated data set of what is already provided to the Energy Commission in aggregated form under Section 1308.

Costs to Obligated Parties

In order to provide customer level natural gas data, each of the three obligated parties would need to develop queries of their metering and billing systems. Given the current aggregated reporting requirements, the Energy Commission expects existing queries or methods for reporting could be modified to comply with the proposed customer-level data requirements. The Energy Commission estimates that to develop, test, validate the data collected, and develop reports for data delivery (the initial one-time query development) would take 200 hours in FY 2017/18. Data collection activities, compiling, validating, and summarizing the data is estimate to take a total of 60 hours (30 hours for collection and 30 hours for validation and summarizing) for each quarterly reporting. Once summarized, the data would be transferred to the Energy Commission to be incorporated into the existing data base that houses the current aggregated data. The Energy Commission estimates there to be an additional 10 hours of work for each quarterly reporting to deliver the detailed information. In fiscal year 2017/18, the total cost for obligated parties is estimated at $94,860 and includes the one-time costs. Annual costs in fiscal year 2018/19 are estimated at $80,464 and in fiscal year 2019/20 are estimated at $82,878.

Costs to the State

The Energy Commission would need to modify the existing data collection process to accommodate the new customer level data. This would involve expanding the existing data base, modifying the data acquisition processes, and performing new data quality and validation work on the data. One time development costs are estimated using a consultant programmer at an hourly rate of $93 and Energy Commission Senior Programmer Analysts at an hourly rate of $51.75. Most of this work would be modifying the system to incorporate the new data, to manage a web-based data loading process for reporting, and to test the new system.[20] These costs estimates include contracting for programming services.

The Energy Commission staff time would focus on reviewing, validating the data, and resolving data issues. It is estimated that it would take Energy Commission staff 80 hours to review and validate and an additional 40 hours to resolve any reporting issues for each quarterly reporting. Costs estimates are $153,727 for fiscal year 2017/18, $291,002 for fiscal year 2018/19, and $143,419 in fiscal year 2019/20.

Potential Impacts of Proposed Regulations (Gov. Code § 11346.3, subd.(b).)

Only the three largest natural gas utilities are required to comply with the reporting requirements of this section. For these utilities, the costs associated with compliance with this section are negligible, and can likely be performed by existing staff, without creating new positions. Similarly, the Energy Commission would be able to process this information with existing staff, without creating new positions. Consequently, the proposed revisions to Section 1353 (c) would likely not result in the creation or elimination of any jobs within California. Furthermore, because compliance with this section would not affect natural gas utility operations, this section would neither create nor eliminate any businesses doing business in California, or would it expand any existing businesses in California. Finally, because this regulation only provides for the collection of information by the Energy Commission for analytical purposes, there would be no direct benefit to the data collection to the health and welfare of California residents, to worker safety, or to the state's environment. However, collecting this information would have indirect benefits, including the data needed to perform regional and local forecasts, the ability to perform data quality processes, and the ability to cross reference data across data sets. These are discussed generally in the Benefits section of the ISOR, and specifically in the explanation of the Purpose and Necessity for this section. However, collecting this information would have indirect benefits, including the to the ability to perform regional and local natural gas demand forecasts and the ability to cross reference data across data sets. These in turn will allow the Energy Commission to track the various factors that affect natural gas consumption and the effectiveness of programs and policies designed to assist the state in meeting its reliability, greenhouse gas emissions reduction, and other

[20] The 3 year total hours for state work is 8410 hours of which 7210 is included as one time infrastructure costs.

energy goals. These are discussed generally in the Benefits section of the ISOR, and specifically in the ISOR explanation of the Purpose and Necessity for this section.

Section 2505 Designation of Confidential Records

The proposed regulatory changes within Section 2505 add a subdivision identifying new data collected under sections 1314 and 1353 as automatically confidential. Since the changes are purely administrative in nature and do not independently require additional reporting, the Energy Commission estimates there are no associated cost impacts.

Costs to Obligated Parties

There are no cost impacts to any obligated parties due to automatically designating new data submitted in sections 1314 and 1353 as confidential. The proposed language would not result in any changes to reporting processes.

Costs to the State

There are no cost impacts to the state due to automatically designating new data submitted in sections 1314 and 1353 as confidential. The proposed language would not result in any changes to reporting processes not already captured in other section evaluations.

Potential Impacts of Proposed Regulations

The proposed regulations within Section 2505 would not result in the creation or elimination of any jobs within California. Existing businesses and staff would perform all the work necessary to meet the new obligation. No new businesses would be created and neither would any existing business be eliminated by the new regulations. The proposed regulatory changes would not expand any existing businesses doing business in California and there would be no direct benefits of the data collection to the health and welfare of California residents, to worker safety, or to the state's environment.

Form 399 Methodology Discussion

Economic Impact Statement

A. Estimated Private Sector Cost Impacts

The total economic impact of the proposed regulations is estimated at $4,240,867 for the first three years, which would fall in the "below $10 million" per year category.

The number of total businesses being impacted is the sum of private cogenerator owners and investor-owned utilities. There are 102 private owners of cogeneration facilities and 7 investor-owned utilities for a total number of businesses of 109.

The Energy Commission has identified only a single private owner of a cogeneration facility which could meet the statutory definition of a small business. Given that the total number of businesses impacted is 109, the percent of small businesses impacted is 1 divided by 109 or approximately 0.9 percent.

B. Estimated Costs

Energy Commission estimates the total cost for the first three years of implementation as being $4,240,867. As all reporting obligations would continue as long as the regulations were in place, salaries and state data storage costs would continue to increase, and the number of obligated parties might change, the total lifetime cost would be difficult to capture. Since the Economic and Fiscal Impact State document mentions a three-year time span, and because the regulations will be fully implemented after three years, Energy Commission staff used this as the basis of this total statewide cost estimate.

Table 2. Initial and Annual Ongoing Business Costs

Business	Number of Businesses	2017/18	2018/19	2019/20
Investor Owned Utility	7	$107,433	$73,513	$59,933
Private Cogenerator Owner	102	$1,177	$463	$477
Weighted Average Cost	109	$8,001	$5,154	$4,295

1. a. Small Business Cost Discussion

The small business “initial” cost is the estimated as the amount the small business is likely to pay in the year of implementation, fiscal year 2017/18. The small business is one of the 139 private and public owners of cogeneration facilities in the state and the total cost to these owners is $163,622 ($119,552 + $44,070); therefore, the fiscal year 2017/18 cost would be $1,177 (or (1/139) * $163,622). Similarly, during fiscal year 2018/19 the cost to the small business would be $463 (or (1/139) * $64,359) and $477 (or (1/139) * $66,290) in fiscal year 2019/20 both of which include a 3 percent annual salary increase. The three-year average for the impacted small business is $706.

1. b. Typical Business Cost Discussion

The typical initial costs for all affected businesses represents the cost of compliance with all new reporting requirements for private owners of cogeneration facilities and investor-owned utilities in fiscal year 2017/18, divided by the total number of such entities. The sum of all costs in fiscal year 2017/18 is $1,177 for private owners of cogeneration facilities, and $107,433 for investor-owned utilities. As mentioned above, the number of private owners of cogeneration facilities is 102 while the number of investor-owned utilities is 7. Therefore the weighted average initial cost impact is (($107,433*7)+($1,177*102))/(102+7) which equals $8,001 in fiscal year 2017/18.

By fiscal year 2019/20, the regulations will be fully implemented; therefore, the costs in year three represent the ongoing cost of compliance, or the “typical annual impact” for each type of business affected by the proposed regulations. This represents $477 for private owners of cogeneration facilities owners (including the single small business) and $59,933 for investor-owned utilities, with a weighted average of $4,295.

2. Discussion

The costs for owners of cogenerator facilities is only due to proposed Section 1304 (a) regulations. The total cost over three years for owners of cogeneration facilities is $294,270, the sum of both private and publicly-owned cogenerators three year costs in Table 1 ($215,011 + $79,259). The total three-year local public and private obligated party cost is $3,172,403 (also from Table 1, $1,063,842 + $2,108,561). Therefore the percent of costs for cogeneration facility owners is 9 percent and the percent of utility costs is 91 percent.

C. Estimated Benefits

Over the first three fiscal years the total statewide benefit would be sum of avoided costs to all obligated parties and the state which totals $19,194 as shown at the bottom of Table 1.

Fiscal Impact Statement

A. Fiscal Effect on Local Government

Approximate annual savings is calculated using the total avoided cost for public obligated parties (local publicly-owned electric utilities), $1,546 from Table 1, and dividing by 1.5 since the avoided costs will begin in the middle of fiscal year 2018/19. Therefore the approximate annual savings is $1,031.

B. Fiscal Effect on State Government

The approximate estimated expenditures are for the fiscal year when the regulations are implemented, fiscal year 2017/18. From Table 1 above, the total state costs in fiscal year 2017/18 are $253,795.

	2017/18	2018/19	2019/20	Total Costs for Three Fiscal Years
Section 1304 (a) Combined Heat and Power Data	**$169,985**	**$67,695**	**$69,726**	**$307,406**
Private Obligated Cogenerator Owner Costs	$119,552	$47,024	$48,435	$215,011
Local Public Obligated Owner Costs	$44,070	$17,334	$17,855	$79,259
State Costs	$6,363	$3,336	$3,437	$13,136
Section 1304 (b) Interconnection Data	**$696,570**	**$665,088**	**$682,658**	**$2,044,316**
Private Obligated Party Costs	$58,590	$68,969	$71,038	$198,597
Local Public Obligated Owner Costs	$637,980	$574,740	$591,982	$1,804,702
State Costs	$0	$21,379	$19,638	$41,017
Section 1306 (a) Quarterly UDC Reports	**$0**	**$1,896**	**$3,719**	**$5,615**
Private Obligated Party Avoided Costs	$0	$758	$1,561	$2,319
Local Public Obligated Party Avoided Costs	$0	$505	$1,041	$1,546
State Avoided Costs	$0	$633	$1,117	$1,750
Section 1308 (c) Monthly Natural Gas Deliveries	**$0**	**$4,438**	**$9,142**	**$13,579**
Private Obligated Party Avoided Costs	$0	$3,579	$7,373	$10,951
Local Public Obligated Party Avoided Costs	$0	$0	$0	$0
State Avoided Costs	$0	$859	$1,769	$2,628
Section 1314 Natural Gas Modeling Data	**$10,300**	**$14,482**	**$14,917**	**$39,699**
Private Obligated Party Costs	$6,541	$6,737	$6,939	$20,216
Local Public Obligated Owner Costs	$0	$0	$0	$0
State Costs	$3,760	$7,745	$7,978	$19,483
Section 1344 (f) Load Impact Data	**$106,996**	**$35,489**	**$36,554**	**$179,039**
Private Obligated Party Costs	$60,264	$17,242	$17,759	$95,266
Local Public Obligated Owner Costs	$40,176	$11,495	$11,840	$63,510
State Costs	$6,556	$6,752	$6,955	$20,263
Section 1353 (a) Disaggregated Data Reporting	**$152,997**	**$36,470**	**$37,564**	**$227,032**
Private Obligated Party Costs	$93,000	$22,990	$23,679	$139,669
Local Public Obligated Owner Costs	$46,500	$11,495	$11,840	$69,834
State Costs	$13,497	$1,986	$2,046	$17,528
Section 1353 (b) Monthly and Interval Meter Data	**$159,173**	**$227,815**	**$155,292**	**$542,280**
Private Obligated Party Costs	$53,568	$64,371	$18,943	$136,882
Local Public Obligated Owner Costs	$35,712	$42,914	$12,629	$91,255
State Costs	$69,893	$120,530	$123,720	$314,143
Section 1353 (c) Monthly Natural Gas Customer Data	**$248,587**	**$371,466**	**$226,297**	**$846,349**
Private Obligated Party Costs	$94,860	$80,464	$82,878	$258,201
Local Public Obligated Owner Costs	$0	$0	$0	$0
State Costs	$153,727	$291,002	$143,419	$588,148
Total Private Obligated Party Costs	$486,374	$307,796	$269,672	$1,063,842
Total Local Public Obligated Owner Costs	$804,438	$657,978	$646,145	$2,108,561
Total State Costs	$253,795	$452,732	$307,191	$1,013,718
Total Costs	**$1,544,607**	**$1,418,506**	**$1,223,008**	**$4,186,121**
Private Obligated Party Avoided Costs	$0	$4,337	$8,934	$13,271
Local Public Obligated Party Avoided Costs	$0	$505	$1,041	$1,546
State Avoided Costs	$0	$1,491	$2,886	$4,378
Total Avoided Costs	**$0**	**$6,334**	**$12,861**	**$19,194**

Economic and Fiscal Impact Statement (Form 399)

Economic Impact Statement

A. Estimated Private Sector Cost Impacts

2. The California Energy Commission estimates the economic impact of this regulation (which include fiscal impact) is: **Below $10 Million** $4,186,121

3. Enter the total number of businesses impacted:

Number of Private Cogenerators:	102	102 new estimate, 138 old number
Number of Private Utilities:	7	
Number of Impacted Businesses:	109	
Number of Impacted Small Businesses:	1	
Percentage of Obligated Parties Who are Small Businesses:	0.9%	

B. Estimated Costs

1. What are the total statewide dollar costs that businesses and individuals may incur to comply with this regulation over its lifetime? $4,186,121

	1304			1304 (b)			1314			1344		
Per Obligated Party Cost Estimates	**2017/18**	**2018/19**	**2019/20**	**2017/18**	**2018/19**	**2019/20**	**2017/18**	**2018/19**	**2019/20**	**2017/18**	**2018/19**	**2019/20**
IOU	$0	$0	$0	$12,439	$11,495	$11,840	$2,180	$2,246	$2,313	$20,088	$5,747	$5,920
POU	$0	$0	$0	$12,439	$11,495	$11,840	$0	$0	$0	$20,088	$5,747	$5,920
Cogenerator	$1,177	$463	$477	$0	$0	$0	$0	$0	$0	$0	$0	$0

	1353 (a)			1353 (b)			1353 (c)		
Per Obligated Party Cost Estimates	**2017/18**	**2018/19**	**2019/20**	**2017/18**	**2018/19**	**2019/20**	**2017/18**	**2018/19**	**2019/20**
IOU	$23,250	$5,747	$5,920	$17,856	$21,457	$6,314	$31,620	$26,821	$27,626
POU	$23,250	$5,747	$5,920	$17,856	$21,457	$6,314	$31,620	$26,821	$27,626
Cogenerator	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Highest Possible Total Estimated Costs		
	2017/18	**2018/19**	**2019/20**
IOU	$107,433	$73,513	$59,933
POU	$105,253	$71,268	$57,620
Cogenerator	$1,177	$463	$477
Weighted Average	$8,001	$5,154	$4,295

a. Small business costs

Initial costs for a small business:	$1,177
Annual ongoing costs:	$477
Years:	3

b. typical business costs

Initial costs for a typical business:	$8,001
Annual ongoing costs:	$4,295
Years:	3

2. If multiple industries are impacted, enter the share of total costs for each industry:

Cogenerators:	9%
Electric and Gas Utilities:	91%

C. Estimated Benefits

1. Briefly summarize the benefits of the regulation, which may include among others, the health and welfare of California residents, worker safety and the State's environment: $19,194

3. What are the total statewide benefits from this regulation over its lifetime? $19,194

Fiscal Impact Statement

A. Fiscal Effect on Local Government

3. Annual Savings. (approximate)

Years Overwhich the Avoided Costs are Calculated	1.5
Local Public Obligated Party Annual Avoided Costs	$1,031
State Annual Avoided Costs	$2,918

B. Fiscal Effect on State Government

1. Additional expenditures in the current State Fiscal Year. (Approximate) $253,795

Section 1304 (a) Combined Heat and Power Data

Per Unit Costs for Obligated Parties		Hours Per Unit Per Reporting 2017/18	2018/19	2019/20	Economic Costs (for all obligated parties) 2017	2018	2019
Develop query to extract data from existing data collection efforts		4.0			$129,270		
Collection of new data		0.25	0.25	0.25	$13,741	$25,744	$26,516
Summarizing data		0.25	0.25	0.25	$13,741	$25,744	$26,516
Report new data		0.125	0.125	0.125	$6,870	$12,872	$13,258
				Total Obligated Party Costs	**$163,622**	**$64,359**	**$66,290**

Total Cost First 3 Yr
$294,270

CEC One time Costs (including Infrastructure)		Annual Hours 2017/18	2018/19	2019/20	Fiscal Costs 2017	2018	2019
Update the existing forms to include new data	EGSS I	80			$4,628		
CEC Ongoing Data Management Costs							
CEC Staff validating and reviewing data	EGSS I	20	36	36	$1,157	$2,145	$2,209
Resolve any reporting issues	EGSS I	10	20	20	$578	$1,192	$1,227
					$0	$0	$0
				Total State Costs	**$6,363**	**$3,336**	**$3,437**
	Total Cost of Implementing New Data Regulations				**$169,985**	**$67,695**	**$69,726**

Cost Calculation Assumptions	
Number of Private Obligated Parties	102
Number of Public Obligated Parties	37
Number of Obligated Parties	139
Programmer Rate ($/hour)	$ 93.00
EGSS I	$ 57.84
Annual Salary Increase	3.0%

	Initial Costs 2017/18	2018/19	Ongoing Costs 2019/20	3Yr Average
Per Obligated Party Cost	$1,177	$463	$477	**$706**

Costs by Party	2017/18	2018/19	2019/20	Total
Private[1]	$119,552	$47,024	$48,435	$215,011
Local[1]	$44,070	$17,334	$17,855	$79,259
State	$6,363	$3,336	$3,437	$13,136

Notes:

1. Private and public costs were established by applying the ratio of cogeneration facilities owned by private and public entities to the total economic costs.

Number of Cogenerator Units By Obligated Party and Frequency of Reporting

	Greater than or equal to 50 MW	Between 10 and 50 MW	Between 1 and 10 MW	Total Cogenerator Units
Number of Private Cogenerator Units	126	75	54	255
Number of Public Cogenerator Units	6	35	53	94
Number of Cogenerator Units	132	110	107	**349**
Frequency of Reporting	***Quarterly***	***Quarterly***	***Annually***	

Section 1304 (b) Interconnection Data							
		Annual Hours			Fiscal Costs (for all obligated parties)		
Obligated Party Costs (>1,000 MW)		2017/18	2018/19	2019/20	2017	2018	2019
Develop query to extract data from existing interconnection and account information		10			$4,650		
Collection of inconnection data		30	60	60	$13,950	$28,737	$29,599
Summarizing data		20	40	40	$9,300	$19,158	$19,733
Report new data		10	20	20	$4,650	$9,579	$9,866
Obligated Party Costs (<1,000 MW)							
Develop query to extract data from existing interconnection and account information		80			$379,440		
Collection of interconnection data		30	60	60	$142,290	$293,117	$301,911
Summarizing data		20	40	40	$94,860	$195,412	$201,274
Report new data		10	20	20	$47,430	$97,706	$100,637
				Total Obligated Party Costs	**$696,570**	**$643,709**	**$663,020**
		Annual Hours			Fiscal Costs		
CEC One time Infrastructure Costs		2017/18	2018/19	2019/20	2017	2018	2019
Update the existing form 1306 to include new data	EGSS I		40		$0	$2,314	$0
CEC Ongoing Data Management Costs							
Validate submitted data is complete and valid	EGSS I		250	250		$14,895	$15,342
Resolve any data issues	EGSS I		60	60		$3,575	$3,682
Incorporate submitted data into central database	EGSS I		10	10		$596	$614
				Total State Costs	**$0**	**$21,379**	**$19,638**
	Total Cost of Implementing New Data Regulations				**$696,570**	**$665,088**	**$682,658**

Cost Calculation Assumptions	
Number of Obligated Parties (>1,000 MW)	5
Number of Obligated Parties (<1,000 MW)	51
EGSS I	$ 57.84
Programmer Rate ($/hour)	$ 93.00
Annual Salary Increase	3.0%

	Initial Costs		Ongoing Costs	
	2017/18	**2018/19**	**2019/20**	**3Yr Average**
Per Obligated Party Cost	$12,438.75	$11,494.80	$11,839.64	$11,924

	Costs by Party			
	2017/18	**2018/19**	**2019/20**	**Total**
Private[1]	$58,590	$68,969	$71,038	$198,597
Local[1]	$637,980	$574,740	$591,982	$1,804,702
State	$0	$21,379	$19,638	$41,017
Private and Local	$696,570	$665,088	$682,658	$2,044,316

Notes:

1. Private and public costs were established by applying the ratio of obligated parties by private and public parties to the total economic costs.

Section 1306 Quarterly UDC Reports							
		Annual Hours			Avoided Economic Costs (for all obligated parties)		
Obligated Party Costs		2017/18	2018/19	2019/20	2017	2018	2019
No longer needing to query data			1	2	$0	$351	$723
Not longer needing to transfer data			1	2	$0	$351	$723
No longer resolving data issues			8	16	$0	$561	$1,156
				Total Obligated Party Costs	**$0**	**$1,263**	**$2,602**
		Annual Hours			Avoided Fiscal Costs		
CEC Ongoing Data Management Costs		2017/18	2018/19	2019/20	2017	2018	2019
Staff no longer needing to validate and review data	ECS I		2	4		$90	$186
Staff no longer needing to resolving data issues	ECS I		8	16		$362	$745
No longer appending data to database	ECS I		4	4		$181	$186
				Total State Costs	**$0**	**$633**	**$1,117**
				Total Cost of Implementing New Data Regulations	**$0**	**$1,896**	**$3,719**

Cost Calculation Assumptions	
Number of Obligated Parties	5
ECS I	$ 43.88
Sr Control System Eng, Gas	$ 68.13
Annual Salary Increase	3.0%

	Initial Costs		Ongoing Costs	3Yr
	2017/18	**2018/19**	**2019/20**	**Average**
Per Obligated Party Avoided Cost	$0	$252.63	$520	$258

	Avoided Costs by Party				Annual Average
	2017/18	**2018/19**	**2019/20**	**Total**	**Estimate**
Total Avoided Costs for all 5 Utilities	$0	$1,263	$2,602	$3,865	
Private Avoided Costs[1]	$0	$758	$1,561	$2,319	
POU Avoided Costs[1]	$0	$505	$1,041	$1,546	$1,031
State Avoided Costs	$0	$633	$1,117	$1,750	$1,167

Notes:

1. Private and public avoided costs were established by applying the ratio of obligated parties by private and public parties to the total economic costs.

Section 1308 (c) Monthly Natural Gas Deliveries							
		Annual Hours			Avoided Economic Costs (for all obligated parties)		
Obligated Party Costs		2017/18	2018/19	2019/20	2017	2018	2019
No longer needing to query data			1	2	$0	$211	$434
Not longer needing to transfer data			1	2	$0	$211	$434
No longer resolving data issues			15	30	$0	$3,158	$6,505
				Total Obligated Party Costs	**$0**	**$3,579**	**$7,373**
		Annual Hours			Avoided Fiscal Costs		
CEC Ongoing Data Management Costs		2017/18	2018/19	2019/20	2017	2018	2019
Staff no longer needing to validate and review data	ECS I		2	4		$90	$186
Staff no longer needing to resolving data issues	ECS I		15	30		$678	$1,397
No longer appending data to database	ECS I		2	4		$90	$186
				Total State Costs	**$0**	**$859**	**$1,769**
				Total Cost of Implementing New Data Regulations	**$0**	**$4,438**	**$9,142**

Cost Calculation Assumptions	
Number of Obligated Parties	3
ECS I	$ 43.88
Sr Control System Eng, Gas	$ 68.13
Annual Salary Increase	3.0%

	Initial Costs		Ongoing Costs	3Yr
	2017/18	2018/19	2019/20	Average
Per Obligated Party Avoided Cost	$0	$1,193	$2,458	$1,217

	Avoided Costs by Party				Annual Average Estimate
	2017/18	2018/19	2019/20	Total	
Private	$0	$3,579	$7,373	$10,951	
State	$0	$859	$1,769	$2,628	$1,752
Local	0	0	0	$0	

Section 1314 Natural Gas Hydraulic Modeling Data

		Annual Hours			Fiscal Costs (for all obligated parties)		
Obligated Party Costs		**2017/18**	**2018/19**	**2019/20**	**2017**	**2018**	**2019**
Collection of new data		10	10	10	$2,044	$2,105	$2,168
Report new data (through online form)		2	2	2	$409	$421	$434
Answer questions		20	20	20	$4,088	$4,210	$4,337
				Total Obligated Party Costs	**$6,541**	**$6,737**	**$6,939**
		Annual Hours			Fiscal Costs		
CEC Ongoing Data Management Costs		**2017/18**	**2018/19**	**2019/20**	**2017**	**2018**	**2019**
EC Staff validating and reviewing data	EGSS I	45	90	90	$2,603	$5,362	$5,523
Resolving data issues	EGSS I	15	30	30	$868	$1,787	$1,841
Append data	EGSS I	5	10	10	$289	$596	$614
				Total State Costs	**$3,760**	**$7,745**	**$7,978**
				Total Cost of Implementing New Data Regulations	**$10,300**	**$14,482**	**$14,917**

Cost Calculation Assumptions	
Number of Obligated Parties	3
EGSS I	$ 57.84
Sr Control System Eng, Gas	$ 68.13
Annual Salary Increase	3.0%

	Initial Costs		**Ongoing Costs**	**3Yr**
	2017/18	**2018/19**	**2019/20**	**Average**
Per Obligated Party Avoided Cost	$2,180.18	$2,246	$2,313	$2,246

	Costs by Party			
	2017/18	**2018/19**	**2019/20**	**Total**
Private	$6,541	$6,737	$6,939	$20,216
State	$3,760	$7,745	$7,978	$19,483
Local	$0	$0	$0	$0

Section 1344 (f) Load Impact Data							
		Annual Hours			Fiscal Costs (for all obligated parties)		
Obligated party Costs		**2017/18**	**2018/19**	**2019/20**	**2017**	**2018**	**2019**
Gather existing data for delivery		160	40	40	$74,400	$19,158	$19,733
Draft data descriptions		8	8	8	$3,720	$3,832	$3,947
Transfer data to Energy Commission		8	4	4	$3,720	$1,916	$1,973
Address data questions		40	8	8	$18,600	$3,832	$3,947
				Total Obligated Party Costs	**$100,440**	**$28,737**	**$29,599**
		Annual Hours			Fiscal Costs		
CEC Ongoing Data Management Costs		**2017/18**	**2018/19**	**2019/20**	**2017**	**2018**	**2019**
EC Staff validating and reviewing data	ECS II	40	40	40	$1,928	$1,986	$2,046
Resolve data issues	ECS II	16	16	16	$771	$794	$818
Analyze and transform data for analytical purposes	ECS II	80	80	80	$3,856	$3,972	$4,091
				Total State Costs	**$6,556**	**$6,752**	**$6,955**
				Total Cost of Implementing New Data Regulations	**$106,996**	**$35,489**	**$36,554**

Cost Calculation Assumptions	
Number of Obligated Parties	5
ECS II	$ 48.20
Systems Analyst Rate ($/hour)	$ 93.00
Annual Salary Increase	3.0%

	Initial Costs		Ongoing Costs	3Yr
	2017/18	**2018/19**	**2019/20**	**Average**
Per Obligated Party Avoided Cost	$20,088	$5,747	$5,920	$10,585

	Costs by Party			
	2017/18	**2018/19**	**2019/20**	**Total**
Private	$60,264	$17,242	$17,759	$95,266
Local	$40,176	$11,495	$11,840	$63,510
State	$6,556	$6,752	$6,955	$20,263

Section 1353 (a) Disaggregated Data Reporting

		Annual Hours			Fiscal Costs (for all obligated parties)		
Obligated party Costs		**2017/18**	**2018/19**	**2019/20**	**2017**	**2018**	**2019**
Evaluate and identify methodologies for estimating missread or missing data		160			$89,280	$0	
Summarize data methodologies and procedures		80			$44,640	$0	$0
Update report as necessary			40	40	$0	$22,990	$23,679
Provide report of methodology and procedures		10	20	20	$5,580	$11,495	$11,840
				Total Obligated Party Costs	**$139,500**	**$34,484**	**$35,519**
		Annual Hours			Annual Costs		
CEC Ongoing Data Management Costs		**2017/18**	**2018/19**	**2019/20**	**2017**	**2018**	**2019**
EC Staff validating and reviewing data methodologies and processes	ECS II	120	10	10	$5,784	$496	$511
Clarify data estimation methodologies and procedures	ECS II	20	10	10	$964	$496	$511
Analyze and transform data for analytical purposes	ECS II				$0	$0	$0
				Total State Costs	**$6,748**	**$993**	**$1,023**
				Total Cost of Implementing New Data Regulations	**$152,997**	**$36,470**	**$37,564**

Cost Calculation Assumptions	
Number of Obligated Parties	6
ECS II	$ 48.20
Systems Analyst Rate ($/hour)	$ 93.00
Annual Salary Increase	3.0%

	Initial Costs		**Ongoing Costs**	**3Yr**
	2017/18	**2018/19**	**2019/20**	**Average**
Per Obligated Party Avoided Cost	$23,250	$5,747	$5,920	$11,639

	Costs by Party			
	2017/18	**2018/19**	**2019/20**	**Total**
Private	$93,000	$22,990	$23,679	$139,669
Local	$46,500	$11,495	$11,840	$69,834
State	$13,497	$1,986	$2,046	$17,528

Section 1353 (b) Monthly and Interval Meter Data							
		Annual Hours			Fiscal Costs (for all obligated parties)		
Obligated party Costs		**2017/18**	**2018/19**	**2019/20**	**2017**	**2018**	**2019**
Develop query to extract data from existing data collection efforts		160	160		$74,400	$76,632	
Collection of new data		20	40	40	$9,300	$19,158	$19,733
Summarizing data		10	20	20	$4,650	$9,579	$9,866
Report new data		2	4	4	$930	$1,916	$1,973
				Total Obligated Party Costs	**$89,280**	**$107,285**	**$31,572**
		Annual Hours			Annual Costs		
CEC One time Infrastructure Cost		**2017/18**	**2018/19**	**2019/20**	**2017**	**2018**	**2019**
Plan and develop potential solution	Sr. Programmer Analyst	120			$6,209	$0	
Establish new data as important in data governance processes	ECS II	120	80		$5,784	$3,972	
Implement new data management system for interval meter data	Sr. Programmer Analyst	160	160		$8,279	$8,528	
Design and implement data repository	Sr. Programmer Analyst	320	120		$16,559	$6,396	
Testing data acquisition, staging, validation, and access (ITSB)	Sr. Programmer Analyst	80			$4,140	$0	
Testing data acquisition, staging, validation, and access (Program)	ECS II	80			$3,856	$0	
CEC Ongoing Data Management Costs							
EC Staff validating and reviewing data	ECS II	320	640	480	$15,425	$31,775	$24,546
Resolve data issues and evaluate data gap estimations	ECS II	80	160	160	$3,856	$7,944	$8,182
Analyze and transform data for analytical purposes	ECS II	120	240	240	$5,784	$11,916	$12,273
Annual Data Storage Costs		0	$39,659	$78,718		$50,000	$78,718
				Total State Costs	**$69,893**	**$120,530**	**$123,720**
	Total Cost of Implementing New Data Regulations				**$159,173**	**$227,815**	**$155,292**

Note:

1. AWS S3 cost calculation is $39,659. However, Resources Agency will be providing the data storage at a first year cost of $50,000.

Cost Calculation Assumptions	
Number of Obligated Parties	5
ECS II	$ 48.20
Sr. Programmer Analyst	$ 51.75
Systems Analyst Rate ($/hour)	$ 93.00
Annual Salary Increase	3.0%

	Initial Costs		Ongoing Costs	3Yr
	2017/18	**2018/19**	**2019/20**	**Average**
Per Obligated Party Avoided Cost	$17,856	$21,457	$6,314	$15,209

	Costs by Party			
	2017/18	**2018/19**	**2019/20**	**Total**
Private	$53,568	$64,371	$18,943	$136,882
Local	$35,712	$42,914	$12,629	$91,255
State	$69,893	$120,530	$123,720	$314,143

Section 1353 (c) Monthly Natural Gas Customer Data							
		Annual Hours			Fiscal Costs (for all obligated parties)		
Obligated party Costs		2017/18	2018/19	2019/20	2017	2018	2019
Develop query to extract data from existing data collection efforts		200			$55,800	$0	$0
Collection of new data		60	120	120	$16,740	$34,484	$35,519
Validate and summarizing data		60	120	120	$16,740	$34,484	$35,519
Report new data (through online form)		20	40	40	$5,580	$11,495	$11,840
				Total Obligated Party Costs	**$94,860**	**$80,464**	**$82,878**
		Annual Hours			Fiscal Costs		
CEC One time Infrastructure Cost		2017/18	2018/19	2019/20	2017	2018	2019
Update the existing ECDMS to capture new data	Sr. Programmer Analyst	750	1500		$38,809	$77,618	$0
Implement Phase 3 ECDMS for web-based loading and reporting compliance	Systems Analyst	1000	1760	1000	$93,000	$163,680	$93,000
Testing the new system	Sr. Programmer Analyst		500	500	$0	$25,873	$25,873
Expansion of database to include new data	Sr. Programmer Analyst	200			$10,349	$0	$0
CEC Ongoing Data Management Costs							
EC Staff validating and reviewing data	ECS II	160	320	320	$7,712	$15,888	$16,364
Resolving data issues	ECS II	80	160	160	$3,856	$7,944	$8,182
				Total State Costs	**$153,727**	**$291,002**	**$143,419**
	Total Cost of Implementing New Data Regulations				**$248,587**	**$371,466**	**$226,297**

Cost Calculation Assumptions	
Number of Obligated Parties	3
ECS II	$ 48.20
System Analyst	$ 93.00
Sr. Programmer Analyst	$ 51.75
Programmer Rate ($/hour)	$ 93.00
Annual Salary Increase	3.0%

	Initial Costs		Ongoing Costs	3Yr
	2017/18	2018/19	2019/20	Average
Per Obligated Party Avoided Cost	$31,620	$26,821	$27,626	$28,689

	Costs by Party			
	2017/18	2018/19	2019/20	Total
Private	$94,860	$80,464	$82,878	$258,201
Local	$0	$0	$0	$0
State	$153,727	$291,002	$143,419	$588,148