Final Report for Assessment of Visibility and Control Options for Distributed Energy Resources

California ISO
Shaping a Renewed Future

Rated: LEED Platinum

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1. Executive Summary

KEMA, Inc, (supported by the National Renewable Energy Laboratory (NREL) and Energy Exemplar LLC (owners of PLEXOS production cost software); hereinafter referred to as the "KEMA Team") provide this report to evaluate the market and operational impacts, and quantify the benefits and cost associated with gaining visibility and control of projected Distributed Energy Resources (DER) in California.

While Distributed Energy Resources provide local power resources, management of load and environmental benefits, DER also creates variability in its offering – both from the nature of the resource and the uncertainty in response to various programs. Variability in distributed energy resources comes from a variety of different sources in distributed resources examined in this report (solar, temperature, load conditions and economics associated with DER). Uncertainty of each distributed resource relates to forecasted responses and is associated with DER monitoring to improve capabilities to forecast DER responses. Indirect control relates only to those distributed energy resources that the ISO (California ISO) provides price instructions and meters responses. Some DER are directly controlled by distribution providers or third parties working with the distribution provider so the ISO receives benefits from efforts by these agents. The KEMA Team only examined the benefits from indirect control of DER in this report.

Operational impacts are addressed by examining the effects of distributed energy resources on reserve requirements as well as technical requirements for monitoring and controlling those resources. To quantify the market impacts[1] from increased DER visibility, the KEMA Team built forecast models for six DER[2] technologies and compared the results with a high and low forecast model errors. We then simulated production costs for California and CAISO members with and without the impacts of forecasting/monitoring DER for the high and low forecast model error cases. We also examined the impacts of indirect control of price responsive demand response.

[1] The benefits refer to the system operational benefits for transmission operator (ISO). Benefits to distribution operations are not analyzed in this study.

[2] Utility, residential, commercial and industrial Photovoltaics (PV), Central Heat and Power (CHP), Self Optimizing Customer bundles of technology (SOC), Plug in Electric Vehicles (PEV), utility, residential, industrial and commercial Distributed Energy Storage and Demand Response Programs.

1.1 Questions Addressed and Conclusions

Given the stated goal of having 12,000 MW of distributed generation resources in California by 2020[3] and efforts to establish a 33% target for procurement of renewable energy including DER[4], it is imperative to understand the operational and market impacts of DER. Specifically, the KEMA Team addressed these impacts:

1. What impact will different penetrations of DER have on the ISO requirements for regulation and load following? The KEMA Team found that high DER penetrations can triple 2020 Load Following reserve requirements over a 2011 Baseline. In our forecast models, we found that the bulk of Load Following Requirements reductions through more accurate forecasts occur in the 10 Minute time frames associated with load following purchases. With conservative assumptions about how much forecasting/monitoring can reduce DER variability, the KEMA Team found that visibility can reduce load following up maximum reserve requirements purchased by as much as 8% in the High DER case, 10% in the Mid DER case and 12% in the Low DER case.

2. What are the technical requirements for increased DER monitoring and control to achieve market and operational benefits? The KEMA Team found that communication architecture from a bundle of different current and emerging networks can provide monitoring and forecast capability. For indirect control of Dispatchable Demand Response, we note that existing communication architectures such as Open Automation of Demand Response (ADR) can increase response efficiency and reduce lags in response. The key technical issues to resolve are security and database consistency, latency and storage requirements to meet IEEE or NERC requirements.

3. What are the expected benefits and cost to increased DER visibility and control?

    a. KEMA found that even with small reductions in forecast error of DER show benefits ranging from $309 million / year to $90 million / year in 2020 for CAISO members, depending upon the penetration of DER expected. The greatest benefit of visibility occurs in the High DER Penetration Case, where production costs of $391 million in 2020 can be saved through reduced load following and

[3] http://www.jerrybrown.org/Jobs for the Future

[4] PUC Section 399 11-399 20. Renewable Portfolio Standards require investor-owned utilities, electric service providers, and community choice aggregators to increase procurement from eligible renewable energy resources to 33% of total procurement by 2020.

regulation reserve requirements. Of the DER profiles examined in the High Case, the greatest benefits occur with PV visibility ($176 Million), followed by Demand Response ($149 million) and then Distributed Storage ($63 Million).

b. The costs of monitoring and control to obtain the benefits are roughly $65 million in capital and $2 million of operating cost in 2020 for CAISO members. The KEMA Team examined several communication and monitoring devices technologies required to monitor distributed energy resources. DER technology communications across six DER profiles total $65 million in capital costs and about $2 million in operating costs per year. PV, Storage, PEV, SOC, CHP DER would likely be controlled through the utility and data for monitoring and forecasting provided to the ISO.

4. How would additional DER visibility and control enhance the ISOs ability to forecast and manage the system and market? We found that increased visibility leads to more efficient procurement of regulating and load following requirements, more efficient database of planned and existing DER projects and grid response programs, more efficient loading of DER and existing grid components, and more efficient voltage management. The KEMA Team examined the benefits of controlling Demand Response DER in the High DER Penetration Case. Controls for Demand Response improved response times and effectiveness of response. For indirect control of Dispatchable Demand Response, KEMA found benefits of $197 million / year in 2020 for high penetrations of CAISO Demand Response[5]. The benefits were estimated to be $197 million. Using existing technology such as the Auto DR communication technology, KEMA estimated capital costs of $28 million and operating costs of $0.7 million per year.

1.2 Next Steps

For stakeholders, the ISO should develop a communication plan to describe the benefits and costs to various stakeholders and the steps each group must follow to capture the benefits noted above. These stakeholders include the California Public Utility Commission, the California Energy Department, Investor Owned Utilities, Municipalities and Irrigation Districts, DER industry groups and Market Participants.

[5] In this study we only evaluated indirect control of Dispatchable Demand Response by sending a price signal and monitoring responses to those signals. We did not evaluate direct load control programs.

Standards will have to be examined. These standards include Visibility as part of DER Interconnection Standards (Rule 21) and for access to Real Time Pricing for various distributed resources. Additional communication impacts involve communication standards such as Smart Inverter Communications Input/Output Standards. Wireless technology life cycles are 2-3 times shorter than DER asset lives. Adoption of any common carrier wireless services saves costs at the risk of early obsolescence. An open Input/Output standard may allow faster adoption of widely available low cost communications.

ISO procedures will need to be developed for creating visibility and control in the distributed resources (including forecasting, scheduling, voltage management and planning requirements). Settlements and charges will have to be developed for the communications costs and/or socialized market benefits are used to cover DER visibility costs that are borne by DER owners / aggregators. Control costs will be part of the overall economics of Demand Response – market payments for Demand Response have to cover the convenience and technology costs.

The ISO will definitely require visibility into what DER is installed and what its characteristics are; additionally real time visibility of DER net generation / load on a take-out point basis would potentially be useful in analyzing “voltage contingencies” associated with DER. Both under and over voltage conditions are potentially problematic.

2. Introduction and Summary

KEMA, Inc, (supported by the National Renewable Energy Laboratory (NREL) and Energy Exemplar LLC (owners of PLEXOS production cost software); hereinafter referred to as the "KEMA Team") provide this report to evaluate the market and operational impacts, and quantify the benefits and cost associated with gaining visibility and control of projected Distributed Energy Resources (DER) in California.

Operational impacts are addressed by examining the effects of distributed energy resources on reserve requirements as well as technical requirements for monitoring and controlling those resources. To quantify the benefits[6] from increased DER visibility, the KEMA Team simulated production costs for California with and without the impacts of monitoring DER. We also examined the impacts of indirect control of price responsive demand response. Costs associated with technologies required to monitor and control were then compared to benefits to obtain the net benefits of monitoring and controlling DER.

While Distributed Energy Resources provide local power resources, management of load and environmental benefits, DER also creates variability in its offering – both from the nature of the resource and the uncertainty in response to various programs. Variability in distributed energy resources comes from a variety of different sources in distributed resources examined in this report (solar, temperature, load conditions and economics associated with DER). Uncertainty of each distributed resource relates to forecasted responses and is associated with DER monitoring to improve capabilities to forecast DER responses. Indirect control relates only to those distributed energy resources that the ISO (California ISO) provides price instructions and meters responses. Some DER are directly controlled by distribution providers or third parties working with the distribution provider so the ISO receives benefits from efforts by these agents. The KEMA Team only examined the benefits from indirect control of DER in this report.

In this Introduction and Summary we describe the target questions for the study in Section 2.1, describe the methodology used to address those questions in Section 2.2; describe the assumptions used in the study in Section 2.3 and discuss results for target questions in Section 2.4. In Section 2.5, we provide a summary of conclusions and next steps.

[6] The benefits refer to the system operational benefits for transmission operator (ISO). Benefits to distribution operations are not analyzed in this study.

2.1 Questions to Address

Given the stated goal of having 12,000 MW of distributed generation resources in California by 2020[7] and efforts to establish a 33% target for procurement of renewable energy including DER[8], it is imperative to understand the operational and market impacts of DER. Specifically, the KEMA Team addressed these impacts:

5. What impact will different penetrations of DER have on the ISO requirements for regulation and load following? The KEMA Team found that high DER penetrations can triple 2020 Load Following reserve requirements over a 2011 Baseline.

6. What are the technical requirements for increased DER monitoring and control to achieve market and operational benefits? The KEMA Team found that communication architecture from a bundle of different current and emerging networks can provide monitoring and forecast capability. For indirect control of Dispatchable Demand Response, we note that existing communication architectures such as Open Automation of Demand Response (ADR) can increase response efficiency and reduce lags in response. The key technical issues to resolve are security and database consistency, latency and storage requirements to meet IEEE or NERC requirements.

7. What are the costs and expected benefits to increased DER visibility and control? For monitoring and forecasting, KEMA found that even with small reductions in forecast error of DER show benefits ranging from $309 million / year to $90 million / year in 2020 for CAISO members, depending upon the penetration of DER expected. For indirect control of Dispatchable Demand Response, KEMA found benefits of $197 million / year in 2020 for high penetrations of CAISO Demand Response[9]. The costs of monitoring and control to obtain the benefits are roughly $65 million in capital and $2 million of operating cost in 2020 for CAISO members.

8. How would additional DER visibility and control enhance the ISOs ability to forecast and manage the system and market? We found that increased visibility leads to more efficient procurement of regulating and load following requirements, more efficient

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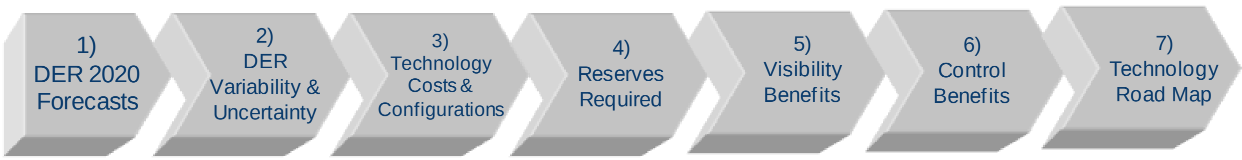
[7] http://www.jerrybrown.org/Jobs for the Future

[8] PUC Section 399 11-399 20. Renewable Portfolio Standards require investor-owned utilities, electric service providers, and community choice aggregators to increase procurement from eligible renewable energy resources to 33% of total procurement by 2020.

[9] In this study we only evaluated indirect control of Dispatchable Demand Response by sending a price signal and monitoring responses to those signals. We did not evaluate direct load control programs.

database of planned and existing DER projects and grid response programs, more efficient loading of DER and existing grid components, and more efficient voltage management.

2.2 Methodology



2.2.1 Distributed Energy Resource (DER) 2020 Forecasts

The KEMA Team forecasted profiles of six Distributed Energy Resources (DERs) including both Distributed Generation, such as photovoltaic (PV), combined heat and power (CHP), Self-Optimizing Customers (SOC), as well as load-impacting technologies which include charging electric vehicles (PEV), distributed storage, and demand response. Self Optimizing Customers manage the energy purchases and sales associated with a variety of energy technologies on their respective campuses.

The KEMA Team worked with the ISO to use PV forecasts based upon the Long Term Procurement Proceeding (LTPP) 33% Environmentally Constrained Case developed under the California Public Utility Commission Scoping Memorandum.[10]

The KEMA Team utilized forecast models developed by KEMA for five DER profiles: Customer PV, Utility Distributed PV, Combined Heat and Power, Self Optimizing Customers, Distributed Storage and Demand Response. The KEMA Team utilized a forecast model developed by NREL to determine penetrations of electric vehicle charging.

For each of the six DER profiles, KEMA developed 2020 forecasts of 1 minute DER profiles to determine variability of the forecast for the target year. The 1 minute profiles were used as inputs to determine Load Following and Regulation Requirements[11].

[10] Track 1 Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator, Rulemaking 10-05-006 and Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, Rulemaking 10-05-006, Amended 12/3/2010.

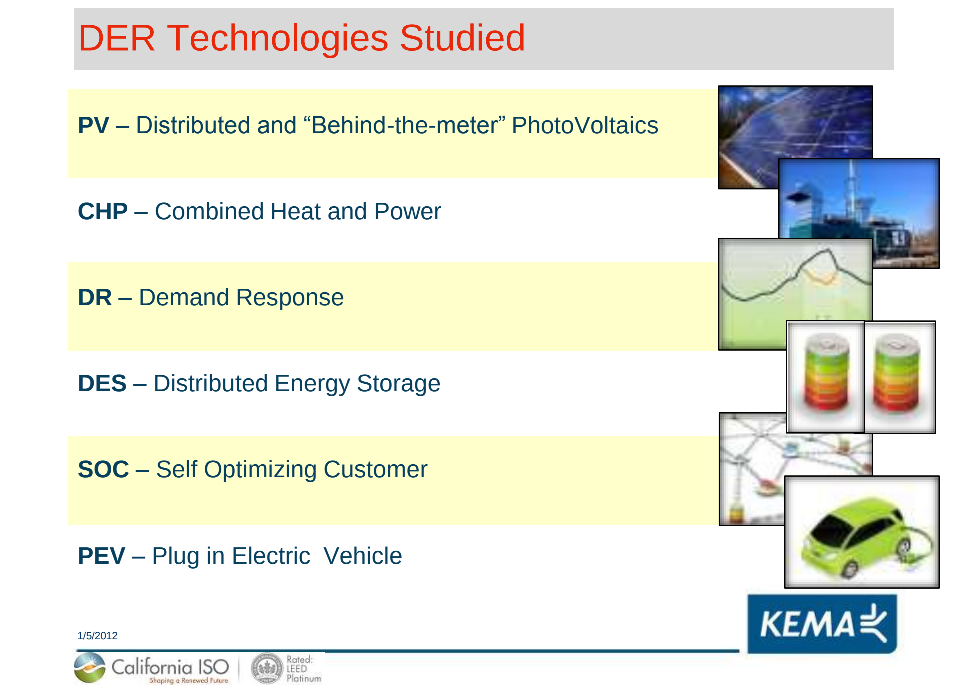


Exhibit 2-1: Nomenclature used to describe the 6 DER profiles

2.2.2 Determine DER Variability and Forecast Error Reductions

With each DER resource, we calculated two different measures: 1) variability without any visibility (monitoring and forecasting) of the distributed resource, and 2) uncertainty error when resources are monitored and forecasted.

For PV, forecast error without any visibility into PV was determined by using existing T-1 persistence forecast (just using the last observation as the forecast for the next observation) developed in earlier work by CAISO[12]. A forecast error was computed [(predicted–actual)/predicted]. To obtain a reduced forecast error due to visibility of PV, we determined a model error in our Commercial, Residential and Distributed Utility PV models [(predicted – actual)/predicted] that can be reduced by forecasting and monitoring PV resources. The

[11] We used the definitions of Load Following and Regulating Reserves based upon NERC rules and found in Integration of Renewable Resources: Technical Appendices for California ISO Renewable Integration Studies, October 11, 2010.

[12] Track 1 Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator, Rulemaking 10-05-006.

benefits of monitoring and forecasting PV is the difference in T-1 persistence forecast error and forecasted model error.

For CHP, SOC, Demand Response and Distributed Storage resource profiles, we used a model error (comparing actual to forecasted values) to determine the reduction in forecast error without any visibility into the resources. To determine the forecast error associated with increased monitoring and forecasting, the KEMA Team reduced each forecast parameter (temperature, prices, etc) by 20% and then calculated a new, reduced forecast error to represent the benefits of visibility and monitoring each DER resource.

For Electric Vehicles, we estimated forecast error with no visibility to be based upon delays in charging time. For PEV visibility, we estimated forecast error reductions based upon improved traffic congestion models[13].

Beginning with the load profile in the 2020 High Load Long Term Procurement Planning scenario[14], we adjusted the California loads for CHP electric load, SOC electric load, Electric Vehicle load, distributed storage load shifted from one time period to another, and demand response components. This adjustment was made to avoid double counting load for these resources. Without visibility, the load forecast error was determined from previous work by the ISO[15]. Forecast error improvement through monitoring/forecasting was calculated by weighting the original load forecast error by each DER load component and then determining a revised forecast error.

2.2.3 Determine Cost of Increased Monitoring and Control

For all six DER profiles, KEMA determined the existing and emerging communication architectures and technologies expected to be in place by the study year of 2020. The technologies included those for both monitoring and control purposes. KEMA estimated the capital cost and operating cost for each technology.

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[13] Tony Markel, Treiu Mai and Michael Kintner-Meyer, Presented at the 25th World Battery, Hybrid and Fuel Cell Electric Vehicle Symposium & Exhibition, November 5-9, 2010.

[14] Track 1 Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator, Rulemaking 10-05-006.

[15] Integration of Renewable Resources: Technical Appendices for California ISO Renewable Integration Studies, October 11, 2010.

2.2.4 Determine Load Following and Regulation Requirements: With and Without Visibility and Control

By reducing uncertainty in DER forecasts, less Load Following and Regulation Reserves are needed. Load following and regulation requirements were determined by using CAISO's Pacific Northwest National Laboratories' (PNNL's) statistical analysis software. For each scenario, we calculated load following and regulation requirements with visibility and without visibility using PNNL's model. For each case, lower load following and regulation requirements will quantify how much reserves are reduced. In the next step, we quantify the market impacts.

2.2.5 Simulate Production Cost Savings to Determine Benefits of Visibility

To quantify the production cost benefits of increased DER visibility, the KEMA Team used load following and regulation requirements from the PNNL tool in Step 1.2.4 as inputs to the PLEXOS production simulation software. We simulated 2020 CAISO, California and WECC market conditions for a variety of scenarios.

2.2.6 Determine Benefits of Controlling DER

Of the six DER profiles examined, Demand Response had the highest potential for indirect control. Simulating the benefits of control of the resource, KEMA noted improvements in effective response and reductions in response lags for Demand Response programs under indirect control. Demand Response parameters include response to signals (effectiveness) as well as delays in response to signals. KEMA then estimated how those Demand Response parameters change under indirect control and then estimated the production cost savings. KEMA then estimated the cost of communications, devices and database/forecasts for the control of the resource.

2.2.7 Technology Roadmap

Summarizing conclusions reached, KEMA proposed a timeline and next steps for capturing the benefits from increased DER visibility and control.

2.3 Assumptions

To develop DER penetration and variability, uncertainty and forecast errors, KEMA used models which depend upon various parameters:

- Forecasted penetration based on economics, demographics, and current utility profiles

- Variability drivers include temperature, price reactions and conforming load profiles

KEMA used the 1 Minute PV profiles used in the CAISO LTPP 2020 Environmentally Constrained Case. For simulations and impacts assessments the KEMA Team used the CPUC Scoping Memo and CAISO LTPP 2020 scenarios as starting point and made adjustments based upon DER Profile Forecasts.

KEMA assumed that by 2020 PV, distributed storage, Self Optimizing Customers, Combined Heat/Power customers and electric vehicle charging would be controlled by balancing areas directly with the customer or through third parties who aggregate and control customer responses. Dispatchable Demand Response programs are already indirectly controlled by the ISO.

For the Technology cost estimates and Technology Roadmap, the KEMA Team used various engineering studies and the experience of consultants to select technologies and cost estimates based upon current DER profiles.

Key assumptions in our simulations and analysis are various operational assumptions about forecasting to reduce uncertainty and projected requirements for load following and regulation. With different ramp times for distributed energy resources, much of the load following and regulation requirements are procured in the Integrated Forward Market prior to the operating day. The ISO procures Regulation Up, Regulation Down, Spinning and Non-Spinning Reserves in this manner. The ISO then conducts the Residual Unit Commitment to adjust any commitments based upon short term forecasts.

Most of the wind and solar resources schedule in real time; creating a lack of visibility of those resources when load following and regulation are usually scheduled. Aside from the uncertainty associated with these resources, the real time schedules can create a situation where fossil units are “over-committed” to deal with uncertain resources. Below, we analyze how increased visibility can contribute to more efficient use of load following and regulating reserves.

2.4 Results

Results of the study are summarized below in response to each question raised in the objectives.

2.4.1 Q1: What impact will different penetrations and variability of DER have on the ISO requirements for regulation and load following?

To address this question, KEMA forecasted 2020 DER penetrations from models, determined variability in the DER profile, determined uncertainty reduced through increased visibility and control by the ISO or balancing authorities in the ISO and then simulated the impacts on load following and regulation requirements.

Penetration and Forecast Error

The profiles for the high, mid and low cases are described in Exhibit 2.2. Further, we provide a brief description of penetration assumptions, variability drivers, estimate of variability and a reduction in variability through monitoring and control.

The variability of each DER profile is split into the components mentioned below:

- Total underlying profile variability
- Profile variability which can be reduced by increased control
- Profile uncertainty (forecasting error) which can be reduced by increased monitoring (what we define as visibility) of the resource.

It is understood that the variability of certain DERs such as Dynamic Pricing Demand Response (DP), Dispatchable Demand Response (DDR) and to an extent distributed PV can be reduced by better control. However, the variability of weather, solar insolation and electric demand distributions are not affected by visibility or control. It is also realized that the error forecasts of DER resources that depend on the above parameters can be reduced by better visibility (monitoring) and control by: 1) reducing the forecast errors of input parameters, 2) reducing the DER profile model errors by updating information to improve the forecast and 3) reducing the forecast error of solar production, which is an input to several DER profile models and 4) reducing the variability of certain DERs such as Dispatchable Demand Response by better control.

Input drivers to the DER models are assumed to be uncorrelated, so the total error of DER forecasts is a weighted sum of the two error sources without accounting for any correlations between temperature, prices and distributed resource profiles. The correlation between the decrease in the forecast error of PV by better visibility and its effect on the error reduction on other DERs such as storage and Self Optimizing Customer has not been yet analyzed and presents substantial scope for further investigations. Going forward, we would want to incorporate these correlations to further reduce forecast error.

DER Profile*[16]	High DER (Max MW)	Mid DER (Max MW)	Low DER (Max MW)	California Penetration Assumptions	Variability Drivers	No Visibility forecast error[17]	Visibility Model Error[18]
PV	7812	4757	1747	Scaled according to ISO scenarios for distributed PV	Clear Sky index and PV Technology. .[19]	Varies by subtype and Clear Sky index: improvement is 20%	
CHP	4468	3092	1732	Based upon CEUS[20]	Prices, temperature, conforming load	6.8%	5.7%
SOC	1277	806	337	Based upon CEUS	Prices, temperature, conforming load	8.4%	7.0%
PEV	-882	-662	-625	Based upon research by NREL	Commute time and traffic congestion	1.5%	1.25%
Distributed Storage	-2808	-1920	-1033	Based upon CEUS	PV smoothing requirements and prices	Varies by subtype and Clear Sky index: improvement is 20%	
Dispatchable Demand Response[21]	-2466	-1926	-1390	Based upon existing utility programs	Prices, load and temperature	6%	4%

Exhibit 2-2: California Penetrations, Assumptions, and Variability Drivers

Differences in Load Following and Regulation Requirements

NERC defines regulation as purchased capacity and energy required continuously to balance generation and load following as the provision of generation capacity "to meet daily and hourly load variations"[22]. Increasing variable resources or resource currently not "visible" creates the need for more Load Following and Regulation to adjust for fluctuating generation or load. Creating a more accurate forecast, monitoring and control, reduces the cost of meeting load

[16] Using the convention that PV, CHP, SOC are distributed generation resources with a positive impact and PEV, DES and Demand Response reduce or shift load with a negative number

[17] Stated as standard deviation ÷ average profile

[18] Percent of Profile variation improved through monitoring and forecasting.

[19] Clearness Index and Solar technologies used are described more fully in Section 1.2. The LTPP High Load Case is described in Track 1 Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator Corporation, R.10-05-006.

[20] California Commercial End Use Survey, California Energy Commission, http://www.energy.ca.gov/ceus/

[21] Note that Dynamic Pricing Demand Response programs are combined with Load. See Section 2.3.

[22] NERC, Interconnected Operations (Ancillary) Services: Workshop on Definitions and Requirements for Managing Unbundled IOS, Palm Beach Gardens, FL, June 19-20.

following and regulating requirements[23]. Why does better monitoring and forecasts of DER improve forecast uncertainty? Better Day-Ahead Load Forecasting can reduce uncertainty about having sufficient generation to meet variability in resources. Monitoring resources improves the system operator knowledge of how those resources react in real time. Controlling DER leads to improvements in responses by those resources.

By monitoring and forecasting each DER profile in the High DER Penetration Case, the KEMA Team notes the following improvements can be made in Load Following and Regulation Requirements as shown in Exhibit 2.3.

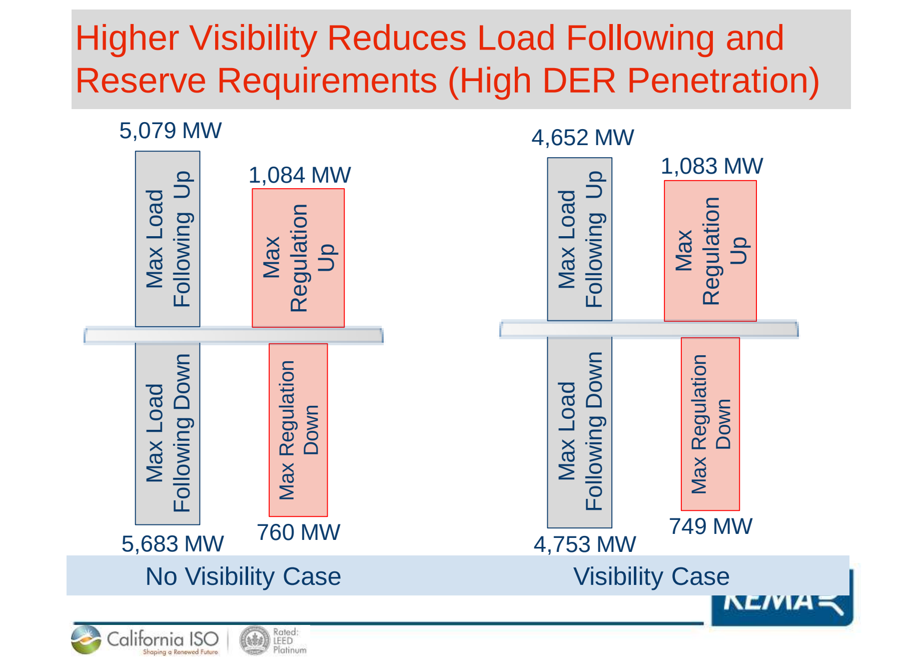

Exhibit 2-3: California Load Following and Regulation Requirements Improvements through Increased Visibility of DER Resources – High DER Penetration Case

[23] Note that the KEMA team did not adjust spinning and non-spinning reserve requirements in this study. These are determined according to NERC principles for the percent of load responsibility or largest credible contingency. Renewable ramping and variability are managed via load following and regulation. The cost of load following and regulation requirement may be more than the purchase price of the requirements. There may be re-dispatch costs that are not directly incorporated in the purchase of the regulation and load following. We use the PLEXOS model to simulate re-dispatch to meet alternate load following and regulation requirements.

The High DER Penetration Case reduces the maximum load following up by 322 MW and the load following down maximum by 930 MW. Smaller reductions occur for regulation requirements.

Why was there more reduction in load following requirements than regulation requirements? The higher load following requirements reductions are due to the frequency of ramps for individual profiles. For example, the adjusted load profile (including load impacts from DER profiles) shows that 99% of the time almost all ramps of 1 MW occur over 10 minutes versus over 5 minutes or less. The longer ramping times would require relatively more load following resources which measures the difference between hourly average net load and 5 minute average net load than regulation resources which measures the difference between 5 minute average net load the 1 minute net load..

The Mid and Low DER Penetration Cases show similar results.

2.4.2 Q2: What are the technical requirements for monitoring and control to achieve market and operational benefits?

To address this question, KEMA first examined existing programs to glean information on configurations which are likely for the study. Using this information, KEMA constructed hypothetical communication architectures which meet the needs for increased DER monitoring and control.

KEMA examined several existing distribute energy resource programs in use by Regional Transmission Operators, Utilities and Third Parties with promise of adoption/expansion. These programs include Open ADR or Auto-DR pilots for Demand Response, Steffys™ water heater for Demand Response; PJM Director for encryption of DER communication profiles; University of Delaware EV pilot for electric vehicles and GM OnStar™ programs for electric vehicles. Many existing and emerging communication technologies can be expected to follow these examples. Several conclusions from these studies were:

- Security and encryption was a key issue in many of the current projects. The Steffys™ hot water heater control uses encrypted DNP3[24] protocols to communicate regulations signals to hot water heaters that are controlled by aggregators. The PJM Director utilized an internet based device with an encryption chip that has been used to demonstrate internet based regulation services to a variety of resources including

[24] DNP3 (Distributed Network Protocol) is a set of communications protocols used between DER components and Distributed Energy Management Systems to control and monitor resources.

batteries and electric vehicles. These two devices are considerably less expensive today than a generator interface device, and costs are expected to drop further. The use of such devices for Dispatchable Demand Response control would provide security at a reasonable cost.

- The Open ADR protocol is in widespread use, can be encrypted for security, and offers low cost Demand Response protocols that will with high probability be adopted by National Institute of Standards and Technology as a Smart Grid standard[25]. Open ADR provides Demand Response monitoring and control capabilities especially for building automation systems. Further Open ADR has been embraced by Building Automation Software suppliers[26].

To enhance visibility, KEMA considered both the density of monitoring points and frequency of data updates for distributed energy resources. Within each DER, several communication architectures were analyzed depending upon whether they are provided by the Utility, Common Carrier or Third Parties. Present and emerging communication architectures analyzed included Utility Supervisory Control and Data Automation (SCADA), Automated Metering Infrastructure (AMI) Mesh Networks, Cellular General Packet Radio Services (GPRS) and Short Message Service (SMS) communication architectures, Wifi, Internet Point of Presence (POP) access points, Ethernet and Building Automation System Networks. Some conclusions:

- For Residential, Commercial and Industrial PV, KEMA identified five communication technologies likely to be used by 2020. These technologies include smart inverters with mesh networks; GPRS radio communications, Wifi and/or cellular backhaul to and from the ISO; and various combinations of licensed and unlicensed frequencies. The combined costs of these likely PV technologies to CAISO members were estimated to be about $30 million in capital expenditures and $0.5 million in operating expenditures.

- For utility scale PV and storage, KEMA estimated existing CAISO utility SCADA communication structure would cost $27.5 million in capital expenditure and 0.6 million in operating expenditure.

- For the Self Optimizing Customer, KEMA estimated that costs for a CAISO customer SOC network in 2020 would be about $2.5 million in capital expenditures and <$0.1 million in operating expenditures.

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[25]NIST Special Publication 118, NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0, page 57.

[26] http://news.yahoo.com/openadr-alliance-experiences-membership-growth-130220353.html

- PEV communication architectures depend heavily on various utility programs and design of building controls for CHP[27]. Because of this and due to relatively low impacts on load following and regulation reserve requirements, KEMA did not estimate costs of these communication architectures.

In addition to the above communication architecture costs to monitor DER, KEMA also examined the incremental cost to control DER Resources.

- DER assets less than 1 kW have a number of control options such as Encrypted wireless (cellular SMS) for rooftop PV, Internet POP for smart Home Automation systems and Building Automation.

- Utility assets (grid connected PV and storage) are assumed to already have monitoring and control via utility distribution SCADA and distribution automation

- No additional hardware or communications costs are assumed to be required for the ISO for aggregating and providing data. No ISO control is required for those resources.

- CAISO Dispatchable Demand Response control also may provide improvements in responses on the order of $197 Million/year. The CAISO costs of controlling Dispatchable Demand Response include Open ADR for commercial buildings, and a variety of demand response electronics, Home Automation Networks and Automated Meters. CAISO capital costs for these controls include $28 Million along with $0.6 million in operating costs.

- Other DER (PV, Self Optimizing customer, utility storage) respond locally to local conditions (PV, voltage) and price. In these cases, the ISO members gain the benefits without the necessity for control.

2.4.3 Q3: What are the costs and expected benefits to increased DER visibility (monitoring and forecasting) as well as control of DER?

- To determine the benefits of increased visibility into DER profiles, the KEMA Team simulated the production cost impacts of higher Load Following and Regulation

[27] For example, PEV programs accommodate single and separate metering requiring different communication needs. Adam Langton, PEV Adoption Rates and Anticipated Grid Impacts, September 2011.

Requirements without visibility (monitoring and forecasting) to lower Load Following and Regulation Requirements with visibility using PLEXOS production costing software.

- Of each of the six DER profiles analyzed above, we analyzed the case of ISO direct control of Dispatchable Demand Response (DDR) resource. We found CAISO net benefits of $197 million to send control signals and monitor performance of that resource. We did not analyze payments to those DDR resources.

After compiling the costs of visibility of the DER resources, the KEMA Team results are presented in Exhibit 2-4:

What are the costs and expected benefits to increased DER visibility and control for CAISO Members?

DER Profiles – Visibility Comparison	Variability	Load Following/ Regulation Increase	Benefit from Visibility/ Control *	Cost of Visibility (Capital Expenditure / Operational Expenditure)***
1) All High DER - all DER profiles	Very High	Very High	$391M	$37M / $1.7M
a) All High DER – Demand Response contribution	High	High	$149 M	Included in 1)g)
b) All High DER – Distributed Energy Storage contribution	High	High	$63 M	$27.5 M/ $0.6 M
c) All High DER - PV contribution	High	High	$176 M	
d) All High DER – Central Heat/Power contribution	Low	Low	$3 M	N/A
e) All High DER – Self Optimizing Customer contribution	Low	Low		$2.5 M/ < $0.1 M
f) All High DER – Plug in Electric Vehicles contribution	Low	Low		N/A
g) Additional benefit from Control of DER	High	NA	$197 M**	$28M / $0.3M
2) All Med DER – all DER profiles	High	High-Med	$159 M	N/A
3) All Low DER – all DER profiles	Medium	Med-Low	$90 M	N/A

* Benefit seen in 2020 based on CAISO DER Monitoring and thus production cost savings in Millions of $/year
** Benefit seen in 2020 as a result of direct control of CAISO DER assets in Millions of $/year
***Communication infrastructure cost estimates are $65M in capital expenditure and $2M operating expenditure(based on approx 1M sample points (High Case) with a variety of technologies.

Exhibit 2-4: Net Benefits to Visibility of DER Resources

In Scenario 1 we considered high DER penetration for all six DER profiles which exhibited very high variability and uncertainty due to forecast errors for all six profiles combined. This high variability and uncertainty leads to increased load following and regulation requirements. By monitoring all high DER profiles lower production costs of $391 million / year for 2020 are projected. The cost of monitoring communications for these profiles is only $65 million a year in capital over the life of the project with an annual operating budget of $2 million / year.

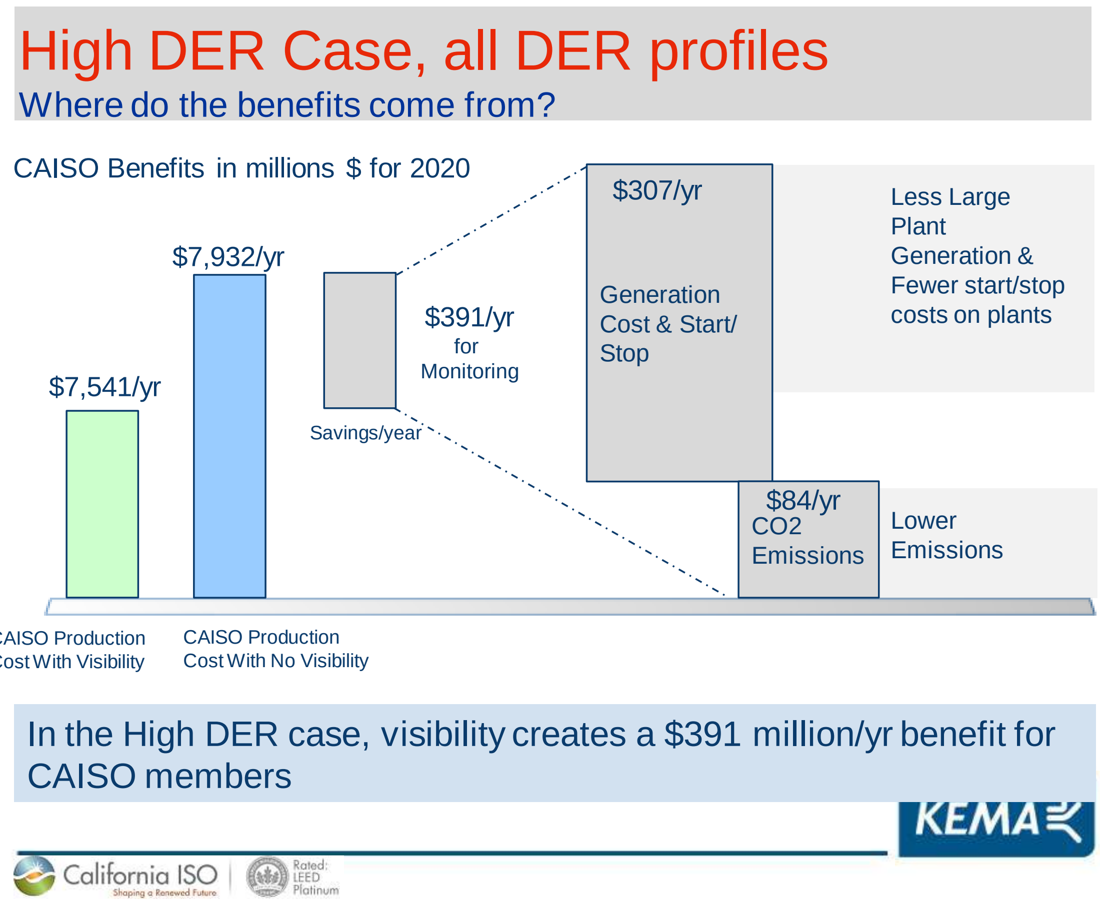

Exhibit 2-5: High DER Case: Where do the benefits come from?

As shown in Exhibit 2.5, the benefits are defined as production cost reductions from monitoring [28]. The $391 million / year in CAISO benefits include reductions in large plant generation and fewer starting/stopping of those units which were supplemented by Distributed Generation

[28] We found that DER generation *reduces* central station power plant generation (and starting/stopping costs), *increases* energy export to non-CAISO members such as irrigation districts and municipalities and *reduces* the need for imports, freeing up internal resources to meet energy (load) instead of higher cost imports. After isolating the benefits of increased net exports accruing to non-CAISO members, the net savings in generation to CAISO members is $307 million / year in 2020.

($307 million a year). Because much of the DER generation comes from renewable sources, CO2 emissions and costs to obtain permits is reduced ($84 million / year).

DER profiles with the highest impact are those with the largest potential to vary in total, which is a combination of the inherent variability of a given resource, the degree to which aggregate resource behavior is correlated in time; and the penetration of the resource type. Monitoring the resource can improve the uncertainty and reduce the amount of load following and regulation requirements. Controlling the resource can reduce this variability. Using a similar methodology, the KEMA Team found that PV (Scenario 1c, Exhibit 2.4), Distributed Energy Storage (Scenario 1b, Exhibit 2.4) and Demand Response (Scenario 1a, Exhibit 2.4) are the largest contributors to net benefits from monitoring.

Other contributors include Combined Heat and Power (Scenario 1d, Exhibit 2.4), Self Optimizing Customer configurations (Scenario 1e, Exhibit 2.4), and Plug-in Electric Vehicles (Scenario 1f, Exhibit 2.4).

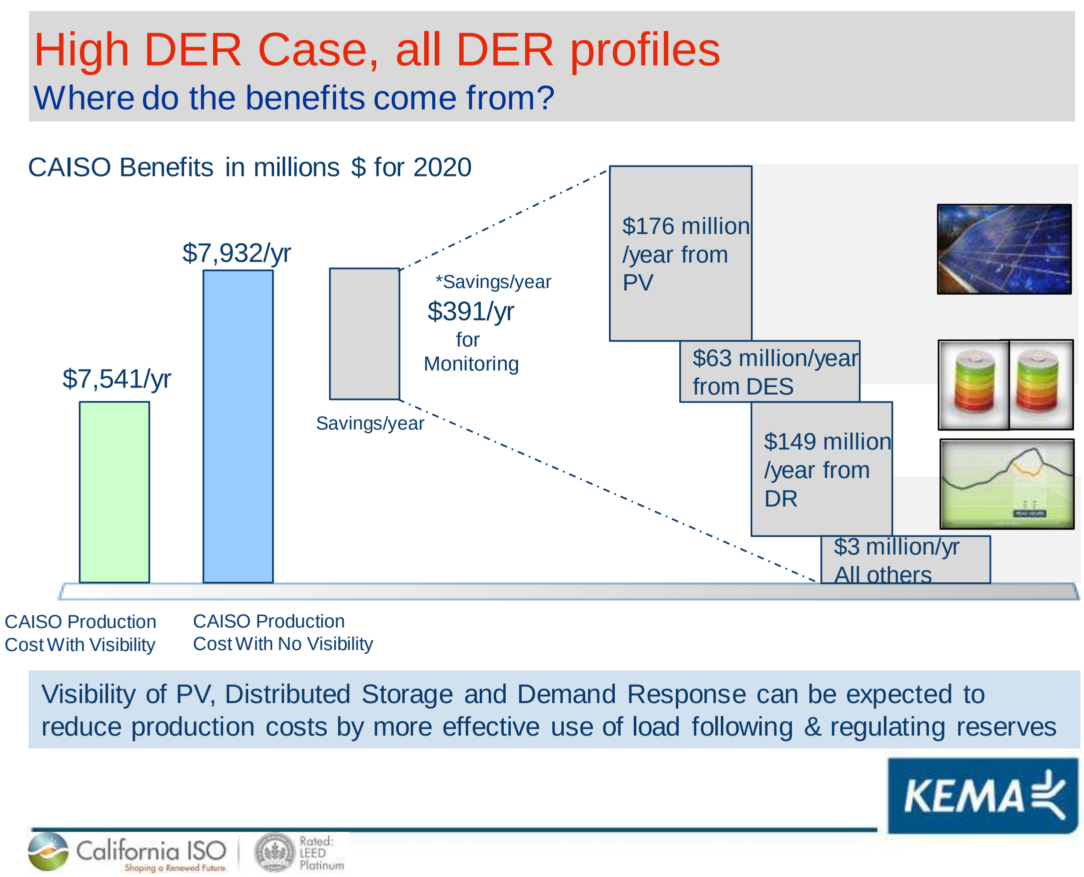

Exhibit 2-6: Which DER assets contribute the most benefits?

As shown in Exhibit 2-5, Distributed Energy Storage contributes about $63 million per year by 2020 by smoothing PV profiles and time shifting various load/resources. This is because PV has the largest contribution to supply relative to other DER and PV displaces more expensive generation alternatives. Demand Response contributes $149 million / year in cost savings by reducing load. PV has the bulk of the contribution to production cost savings ($176 million / year). CHP, SOC and PEV resources cost savings contribute to the remainder of the savings.

Because the level of penetration can vary, the KEMA Team also developed a Medium (Scenario 2, Exhibit 2.4) and Low Scenario (Scenario 3, Exhibit 2.4) with all DER penetrations. For the Low Scenario case the net benefits of improved visibility for all DER are projected to be $90 to $159 million / year.

In addition to the $149 million/year savings from forecasting Dynamic Pricing Demand Response, simulated benefits of Dispatchable Demand Response control was estimated to be about $197 million per year. These savings were due to increased “realization” or response of the total MW in the DDR program and less lag time in response to telemetry both at the start and at the end of the program.

2.4.4 Q4: How would additional DER visibility enhance the ISOs ability to forecast and manage the system and markets?

Benefits to the ISO through forecasting and system management include:

- More efficient procurement of regulating and load following requirements.
- More efficient database of planned and existing DER projects and grid response
- More efficient loading of DER and existing grid components
- More efficient voltage management

DER visibility provides these benefits by enabling the ISO to validate and enhance models of DER behavior using actual data. All forecasting of DER response will be model-based to some extent, as were the profiles developed for this study. Those models will be inaccurate to varying degrees and must be continuously improved. There are two sources of data for this continuous improvement: historical data from utility AMI systems capable of recording interval data; and direct monitoring of the DER resources themselves. Use of AMI data requires that statistical methods be employed as DER behavior will be hidden inside aggregate customer load. Direct monitoring is not subject to this difficulty. Also, when knowledge of what a DER resource is doing “now” helps to model what it will do in the near and medium term, that visibility can directly improve forecasting.

Better visibility also allows the ISO to forecast reactive power requirements to manage voltage response during disturbances. DER cannot regulate bulk power voltage (under IEEE 1547 interconnection standards) unless interconnected at a secondary level. Further, DER may displace generation which has the capability of voltage regulation, increasing the need for visibility.

2.5 Conclusions and Next Steps

The ability to monitor and forecast Distributed Energy Resources has the following impacts on load following and regulation reserves required to manage the system effectively:

- With conservative assumptions about how much forecasting/monitoring can reduce DER variability, the KEMA Team found that visibility can reduce load following up maximum reserve requirements purchased by as much as 8% in the High DER case, 10% in the Mid DER case and 12% in the Low DER case.
- The bulk of Load Following Requirements reductions occur in the 10 Minute time frames.

The KEMA Team examined several communication and monitoring devices technologies required to monitor distributed energy resources.

- DER technology communications across six DER profiles total $65 million in capital costs and about $2 million in operating costs per year.
- We measured benefits from increased Dispatchable Demand Response effectiveness and reduced response delays. KEMA estimate a net benefit of $DDD million in 2020 versus a capital cost of about $28 million and operating expense of $0.6 million.
- PV, Storage, PEV, SOC, CHP DER would likely be controlled through the utility and data for monitoring and forecasting provided to the ISO.

The benefits of DER visibility were estimated through several 2020 simulations of production costs for different levels of DER penetration and to isolate the net benefits for each type of DER penetration. Costs of proposed communication architectures and monitoring devices were then compared to the benefits to determine:

- The greatest benefit of visibility occurs in the High DER Penetration Case, where production costs of $391 million in 2020 can be saved through reduced load following and regulation reserve requirements. Of the DER profiles examined in the High Case, the greatest benefits occur with PV visibility ($176 Million), followed by Demand Response ($149 million) and then Distributed Storage ($63 Million).
- For the Low Scenario case the benefits of improved visibility for all DER are projected to be $90 Million. For the Medium penetration Scenario, net benefits of improved visibility for all DER are projected to be $159 Million.
- Costs of communications architectures to improve visibility range from $37 million capital costs and $1.3 million operating expenditure in the High DER penetration case.

The KEMA Team examined the benefits of controlling Demand Response DER in the High DER Penetration Case. Controls for Demand Response improved response times and effectiveness of response. The benefits were estimated to be $197 million. Using existing technology such as the Auto DR communication technology, KEMA estimated capital costs of $28 million and operating costs of $0.7 million per year.

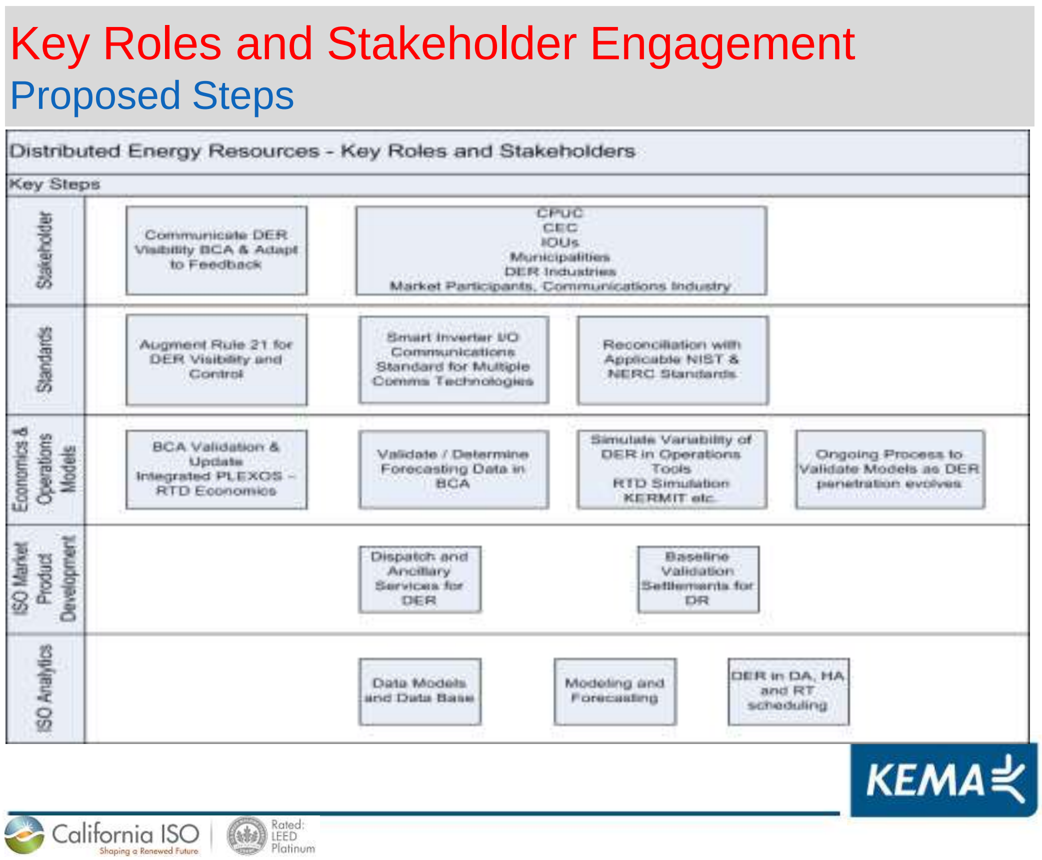

Exhibit 2-7: Draft Implementation Next Steps

To pursue the benefits of higher visibility of DER and control of Dispatchable Demand Response, KEMA proposes the following next steps as shown in Exhibit 2-7.

For stakeholders, the ISO should develop a communication plan to describe the benefits and costs to various stakeholders and the steps each group must follow to capture the benefits noted above. These stakeholders include the California Public Utility Commission, the California Energy Department, Investor Owned Utilities, Municipalities and Irrigation Districts, DER industry groups and Market Participants.

Standards will have to be examined. These standards include Visibility as part of DER Interconnection Standards (Rule 21) and for access to Real Time Pricing for various distributed resources. Additional communication impacts involve communication standards such as Smart Inverter Communications Input/Output Standards. Wireless technology life cycles are 2-3 times shorter than DER asset lives. Adoption of any common carrier wireless services saves costs at the risk of early obsolescence. An open Input/Output standard may allow faster adoption of widely available low cost communications.

ISO procedures will need to be developed for creating visibility and control in the distributed resources (including forecasting, scheduling, voltage management and planning requirements). Settlements and charges will have to be developed for the communications costs and/or socialized market benefits are used to cover DER visibility costs that are borne by DER owners / aggregators. Control costs will be part of the overall economics of Demand Response – market payments for Demand Response have to cover the convenience and technology costs.

The ISO will definitely require visibility into what DER is installed and what its characteristics are; additionally real time visibility of DER net generation / load on a take-out point basis would potentially be useful in analyzing "voltage contingencies" associated with DER. Both under and over voltage conditions are potentially problematic.

3. Phase 1: Estimating DER Penetration, Variability and Forecast Uncertainty

In the first phase of the study, the KEMA Team forecasted the penetration, variability and uncertainty of various Distributed Energy Resources regionally and for the state of California. Based upon various data sources, KEMA first based the penetration of each Distributed Energy Resource upon existing local, state and national programs, economic and demographic trends, and various policies, regulations and technology based upon the consultant's experience.

Note that this study focuses solely upon distributed energy resource technologies and market impacts. Many of the same technologies presented are also used for various wholesale market applications which are not modeled below.

The variability of each profile is split into the components mentioned below:

- Total underlying profile variability
- Profile variability which can be reduced by increased control
- Profile uncertainty (forecasting error) which can be reduced by increased monitoring (what we define as visibility) of the resource.

In general, each of the distributed energy resources has intrinsic variability. The errors in the forecasts of the variability can be divided into the following components:

- Forecast errors in input parameters of DER profiles – These are the forecast errors in temperature, energy cost, conforming load and solar PV production.

- Errors in DER profile models – The DER profile models define the relationships between the input parameters and the outputs of the DERs.

It is understood that the variability of certain DERs such as DP, DDR and to an extent distributed PV can be reduced by better control. However, the variability of weather, solar insolation and electric demand distributions are not affected by visibility or control. It is also realized that the error forecasts of DER resources that depend on the above parameters can be reduced by better visibility (monitoring) and control by: 1) reducing the forecast errors of input parameters, 2) reducing the DER profile model errors 3) reducing the forecast error of solar production, which is an input to several DER profile models and 4) reducing the variability of certain DERs such as DDR and DP by better control.

At this stage of analysis, the input drivers to the DER models are assumed to be uncorrelated, so the total error of DER forecasts is a weighted sum of the two error sources. The correlation between the decrease in the forecast error of PV by better visibility and its effect on the error reduction on other DERs such as storage and SOC has not been yet analyzed and presents substantial scope for further investigations.

In Section 3.1, distributed Photovoltaic (PV) facility assumptions and variability are discussed. In Section 3.2, Combined Heat/Power (CHP) facility assumptions, variability and distributed energy resource profile adjustments to load are described. In Section 3.3, Demand Response assumptions, variability and distributed energy resource profile adjustments to load are described. In Section 3.4, Distributed Energy Storage facility assumptions, variability and distributed energy resource profile adjustments to load are described. In Section 3.5, Self Optimizing Customers (SOC) facility assumptions, variability and distributed energy resource profile adjustments to load are described. In Section 3.6, Electric Vehicle assumptions, variability and distributed energy resource profile adjustments to load are described. In Section 3.7, Load assumptions, variability and distributed energy resource profile adjustments to load are discussed[29].

3.1 Distributed Utility and Customer PV

3.1.1 PV Technologies

Flat-plate Photovoltaic (FPV) modules common to distributed energy resources are commercially available worldwide. These PV modules can be mounted on fixed tilt structures or on one or two axis tracking devices. As of December 2007, the market share of fixed arrays was 73% of the total installed capacity in large-scale PV installations; only 27% were tracking systems[30]. However in situations with a high proportion of direct normal insolation[31], such as in California, the one-axis tracking system could increase the sunlight capture by up to 25% over traditional fixed-tilt systems, while significantly reducing land use requirements.

By the end of 2007, the cumulative installed capacity of distributed solar PV systems around the world had reached more than 9,200 MW. This compares with a figure of 1,200 MW at the end of

[29] Wind generation was not analyzed as part of this study.

[30] Source: ibid

[31] Insolation measures the amount of solar radiation energy received on a given surface area in a given time. For PV it is commonly measured as kWh/(kWp·y) (kilowatt hours per year per kilowatt peak rating).

2000. Installations of PV cells and modules around the world have been growing at an average annual rate of more than 35% since 1998.

There are almost 880 photovoltaic power plants (put into service in 2007 or earlier), each with peak power of 200 kiloWattpeak (kWp) or more, are listed. Cumulative power of all these photovoltaic power plants is about 955 MegaWattpeak (MWp) and average plant power output is slightly more than 1.24 MWp. More than 390 large-scale photovoltaic plants are located in Germany, 225 in USA and more than 130 in Spain[32].

Note that larger scale PV penetrations (such as thermal PV generation units) are not modeled here. Nor is any benefits associate with wholesale markets.

3.1.2 Penetration and Variability Assumptions

We assumed distributed PV capital costs ranging from $1200 to $2000/kW installation cost[33] depending upon the scenario examined. For the low penetration of DER scenario, the $2000/kW PV capital costs reduced to economics of PV penetration; for the high DER penetration scenario, lower PV capital costs of $1200/kW increased penetration.

Assumptions used for forecasts**:**

- Continue existing net metering favorable to customers
- Continuation of U.S. Investment Tax Credit past 2012

3.1.3 Model Description and Logic

This study considers photovoltaic (PV) generation that is operated by utilities at distributed locations and by customers. The latter category refers to customers that use on-site PV generation to offset load levels. All the PV data that this study uses are from the previously completed 33% Renewable Profiles Study (RPS). The basic process to develop the profiles in RPS study was as follows:

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[32] Source: KEMA, CEC Cost of Generation Study. California Energy Commission Staff Workshop Present and Future Central Station Renewable Plant Costs April 16, 2009.
[33] In 2009 dollars. Source: KEMA, CEC Cost of Generation Study. California Energy Commission Staff Workshop Present and Future Central Station Renewable Plant Costs April 16, 2009.

1. Define geographic regions throughout the state that generalize small, distributed generation. Generalizing enables treating a collection of resources as a single plant.

2. Develop irradiance profiles for each of the generalized geographies. These irradiance profiles refer strictly to the energy generation due to the position of the sun. The profiles are at one minute resolution.

3. Add variability due to atmospheric conditions through clear sky index[34] calculations on large scale plants. The clear sky variability for the distributed resources mirrors that of larger scale PV production plants in similar locations. Thus, the distributed resource patterns match those observed for larger plants.

The results of this process were statewide 1-minute PV planning profiles. For the purpose of this project, the data needed to be at generalized ISO utility areas. KEMA disaggregated the profiles, maintaining the statewide shape while respecting hourly distributed PV generation energy levels at the utility area level.

[34] The clear sky index is a ratio of direct solar radiation to total direct and indirect solar radiation. On sunny days, high direct solar radiation occurs and the ratio approaches 1. On cloudy days, there is more indirect radiation and the ratio may approach 0. Common ranges for the US are between 0.8 and 0.2. Variations in PV output are different for each solar index. Reference NOAA.

3.1.4 Variability in Profile

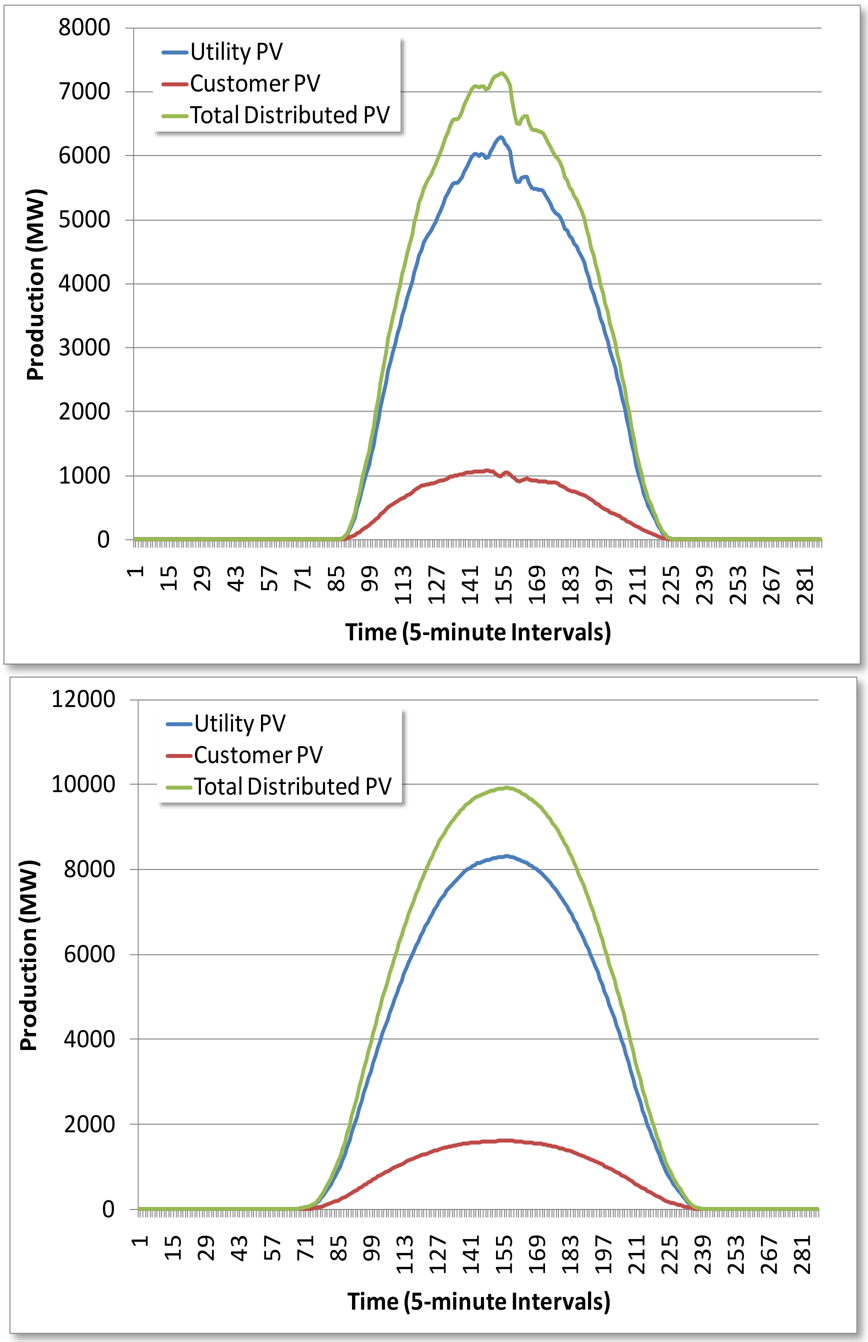


Exhibit 3-1: PV variability and peak production differ across days: Two Examples.

1) The variability in PV, in part, drives variability for other DERs

2) Both utility and customer-side PV are used as input data streams for the other distributed energy profiles

3.1.5 PV Variability and Forecast Error

Total PV variability is described by standard deviation in profiles. KEMA analyzed the variability for the 1 Minute, 5 Minute and hourly profiles and presents volatility (standard deviation divided by average) as shown in Exhibit 3.2[35].

Metric	1 Minute Profile	5 Minute Profile	Hourly Profile
Customer PV (Residential & Commercial “Rooftop” PV; size of 0-1 MW)			
Volatility or Standard Deviation/Average	146%	143%	143%
Maximum Value	705 MW		
Minimum Value	0 MW		
Utility PV (Larger distributed PV; size 1-20 MW)			
Volatility or Standard Deviation/Average	142%	142%	141%
Maximum Value	7,107 MW		
Minimum Value	0 MW		

Exhibit 3-2 High DER Penetration PV Profile Variability Descriptions

A portion of this total profile variability can be reduced by monitoring and forecasting PV performance. The KEMA team worked with CAISO staff to develop the forecast uncertainty associated with the PV profile. For the No Visibility case, we measure the forecast uncertainty by measuring the actual 2005 PV generation against a T-1 “persistence” forecast[36]. Forecast error represents the uncertainty that can be reduced from forecasting PV and is shown in Exhibit 3.3.[37] The PV forecast error was computed based upon a Clear Sky Index, measuring

[35] 1 Minute, 5 Minute and Hourly Profiles used in the LTPP Environmental Case. 1 Minute PV profiles were provided by Nexant.

[36] (Actual less projected error)/actual error. T-1 persistence forecasts the next time increment based on the prior time increment.

[37] See Integration of Renewable Resources: Technical Appendices for California ISO Renewable Integration Studies, October 11, 2010.

the amount of irradiance for different cloud cover.[38] Lastly, we split the PV profile into a different customer and distributed utility portion because the uses and forecasts had different drivers. Customer PV is defined as small residential, commercial and industrial fixed pivot PV installations ranging from 0.1 to 1 MW. Distributed Utility PV installations are larger installations ranging from 1 to 20 MW.

For the visibility case, we used a model error to calculate the forecast error reductions that could be achieved with increased monitoring and a forecast model. The KEMA team determined the variability of each forecast parameter and weighted it by the "importance" or first derivative of each parameter with respect to the output.[39] The no visibility forecast error and visibility forecast error by Customer PV and Distributed Utility PV are provided in Exhibit 3.3.

Metric	$0 \le CI \le 0.2$	$0.2 \le CI \le 0.5$	$0.5 \le CI \le 0.8$	$0.8 \le CI \le 1$
Customer PV, Forecast Error as Percent of Maximum, *No Visibility*	0.6%	2.6%	3.6%	2.2%
Customer PV, Forecast Error as Percent of Maximum, *Visibility*	0.5%	2.2%	3.0%	1.9%
Distributed Utility PV, Forecast Error as Percent of Maximum, *No Visibility*	1.5%	5.1%	6.1%	3.6%
Distributed Utility PV, Forecast Error as Percent of Maximum, *Visibility*	1.2%	4.3%	5.1%	3.0%

Exhibit 3-3: PV Profile Variability Descriptions

When compared with volatility, forecast error is a small percent. In Phase 2, the forecast error is then used to calculate Load Following and Regulation Reserve Requirements both with and without visibility.

[38] Ibid.

[39] See Appendix A for a derivation of the model error.

3.2 Combined Heating/Power (CHP)

3.2.1 CHP Technologies

Combined Heating/Power (CHP) refers to a group of proven technologies that operate together for the concurrent generation of electricity and useful heat in a process that is more energy-efficient than the separate generation of electricity and useful heat. There are numerous commercial and emerging technologies that can be used for CHP. In most cases, small power generation consists of a heat engine, or prime mover that creates shaft power that, in turn, drives an electric generator. In a CHP application, the heat from the prime mover is recovered to provide steam, hot water, or chilled water to meet on-site needs. By combining the electrical and thermal energy generation in one process, CHP can have an overall efficiency of 70-80 percent compared with 30-33 percent for simple-cycle electric generation.

CHP technologies include reciprocating engines, gas turbines, microturbines, steam turbines, and fuel cells. These technologies can run on a variety of fuels such as natural gas, coal, oil, propane, biogas, and biomass. However, the vast majority of cogenerated electricity in the U.S. is powered by natural gas. About 35 GW of new CHP capacity has been installed in the U.S. since 1995, with just over 4 GW of capacity retired. Further, natural gas represents roughly 85 percent of the primary fuel across U.S. CHP applications. Sizes of CHP technologies by industry grouping are shown in Exhibit 3-4.

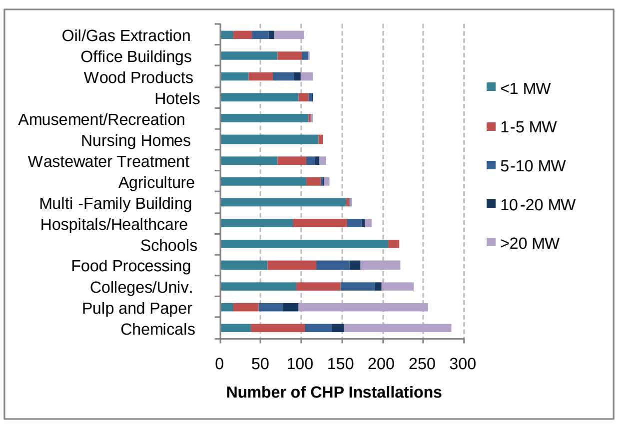


Exhibit 3-4: Combined Heating and Power Information Abstracts, After DOE/EIA

3.2.2 CHP Profile and Model

While there is a potential for CHP to participate in wholesale markets, we do not forecast penetration of CHP wholesale market impacts. In our study, the distributed CHP resources responds to internal load demands first and then may provide net generation or net load resources to the grid.

CHP penetration scenarios were developed by KEMA based on the recently completed ICF report for CEC[40] assessing CHP potential. CHP was assumed to be a base load resource with characteristics based on ambient temperature.

A set of assumptions are researched to estimate the installed capacity of CHP across all regions. Assumed CHP is sized to meet 80% maximum heating needs. Other CHP characteristics such as power to heat ratio and efficiency for different types of CHP are specified in the assumptions in Exhibit 3-5.

As shown in Exhibit 3-6, total CHP projected capacity for 2020 is projected by size of the facility. Beyond 5 MW, lower power to treat ratios and efficiencies are observed due to changes in configurations.

[40] *Combined Heat and Power Market Assessment*, Prepared by ICF International, Inc., for California Energy Commission, April 2010, *CEC-500-2009-094-F*

High DER Penetration Facility Size in kW	Nameplate Capacity	Power to Heat Ratio Assumed[41]	Electric Efficiency[42]
50 – 500 kW	428 MW	0.7	32.5%
500 – 1,000 kW	319 MW	0.9	37%
1-5 MW	985 MW	1.18	41%
5-20 MW	622 MW	0.84	29.7%
>20 MW	2761 MW	1.18	39.7%
Total/ Average	5115 MW Total	0.99 Average	36.2% Average

Exhibit 3-5: CHP installed capacity assumptions

High DER Penetration Facility Size	IID (MW)	LADWP (MW)	PGE Bay (MW)	PGE Valley (MW)	SCE (MW)	SDGE (MW)	SMUD (MW)	TID (MW)	Total (MW)
50 – 500 kW	13	12	58	91	193	54	3	4	428
500 – 1,000 kW	11	16	40	64	141	37	5	5	319
1-5 MW	36	47	146	232	389	98	22	15	985
5-20 MW	24	27	95	149	220	70	21	16	622
>20 MW	0	305	644	1020	663	36	12	81	2761
Total (MW)	84	407	983	1556	1606	295	63	121	5115

Exhibit 3-6: 2020 CHP Installed Capacity by California state regions[43] calculated by KEMA

The CHP model accounts for four categories of installation – 1) Price responsive and less than 20 MW, 2) Price responsive and greater than 20 MW, 3) Non-price responsive and less than 20 MW, 4) Non-price responsive and greater than 20 MW. Heating and electric load (determined by temperature and economic conditions) and electricity Day-Ahead price adjusted for tariffs and

[41] Power to Heat ratios measure the output of electricity relative to steam output for the facility. Source: CEUS and KEMA.

[42] Electrical efficiency is measured as the ratio of BTU outputs to inputs. Source: CEUS and KEMA.

[43] **Regions**

IID – Imperial Irrigation

LADWP – Los Angeles Department of Water Power

PGE – Pacific Gas & Electric (Bay and Valley Regions)

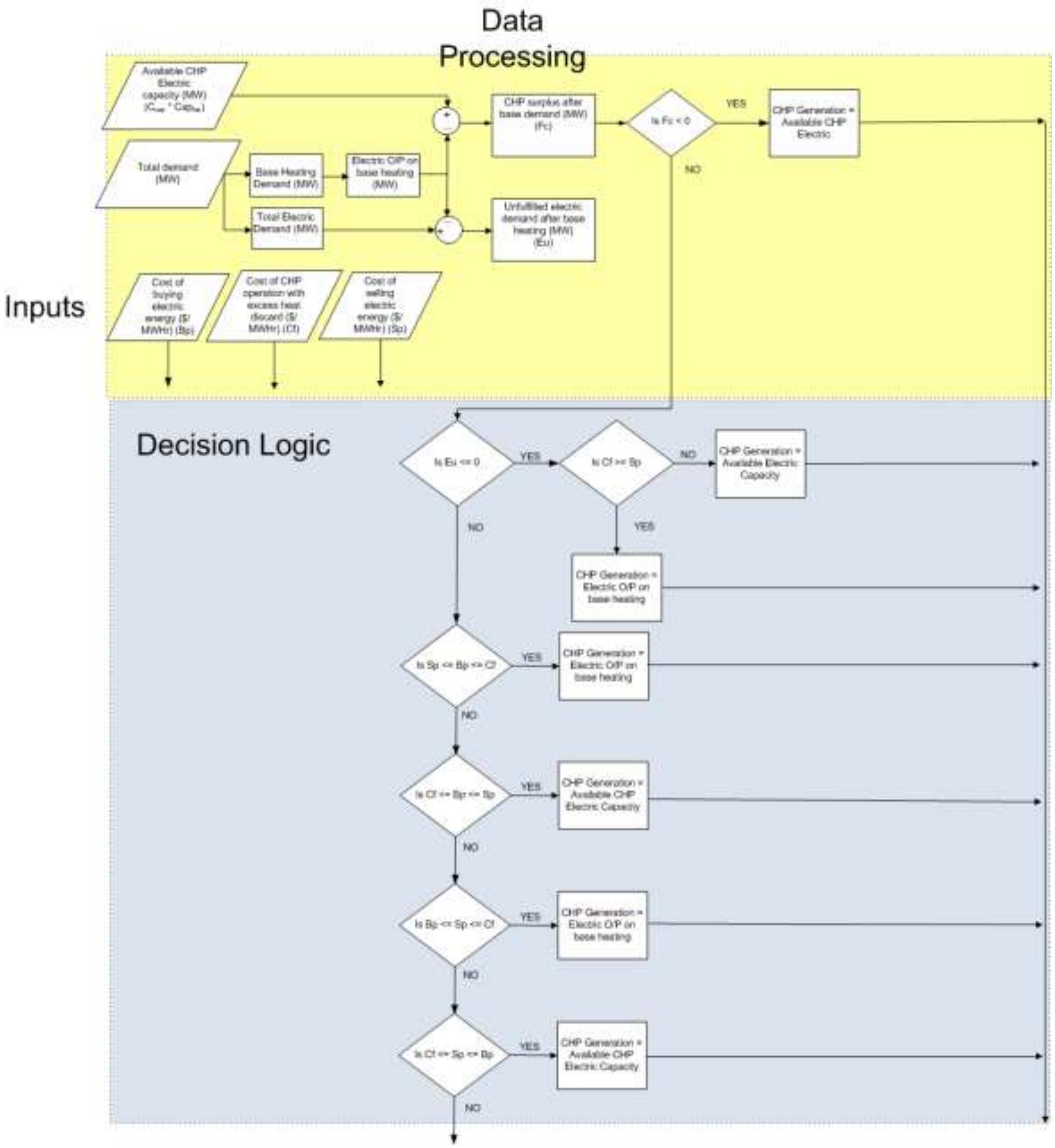
SCE – Southern California Edison

SDGE – San Diego Gas and Electric

SMUD – Sacramento Municipal Utility District

TID – Turlock Irrigation District

distribution charges as well as electricity sell-back prices are key inputs to CHP module which create the minute by minute variations in the profile. Additional inputs include gas prices and incentive/costs to run CHP configurations. The prior application associated with CHP is to serve the base thermal load. Exhibit 3-7 shows the calculations and decision logic for the CHP profile.



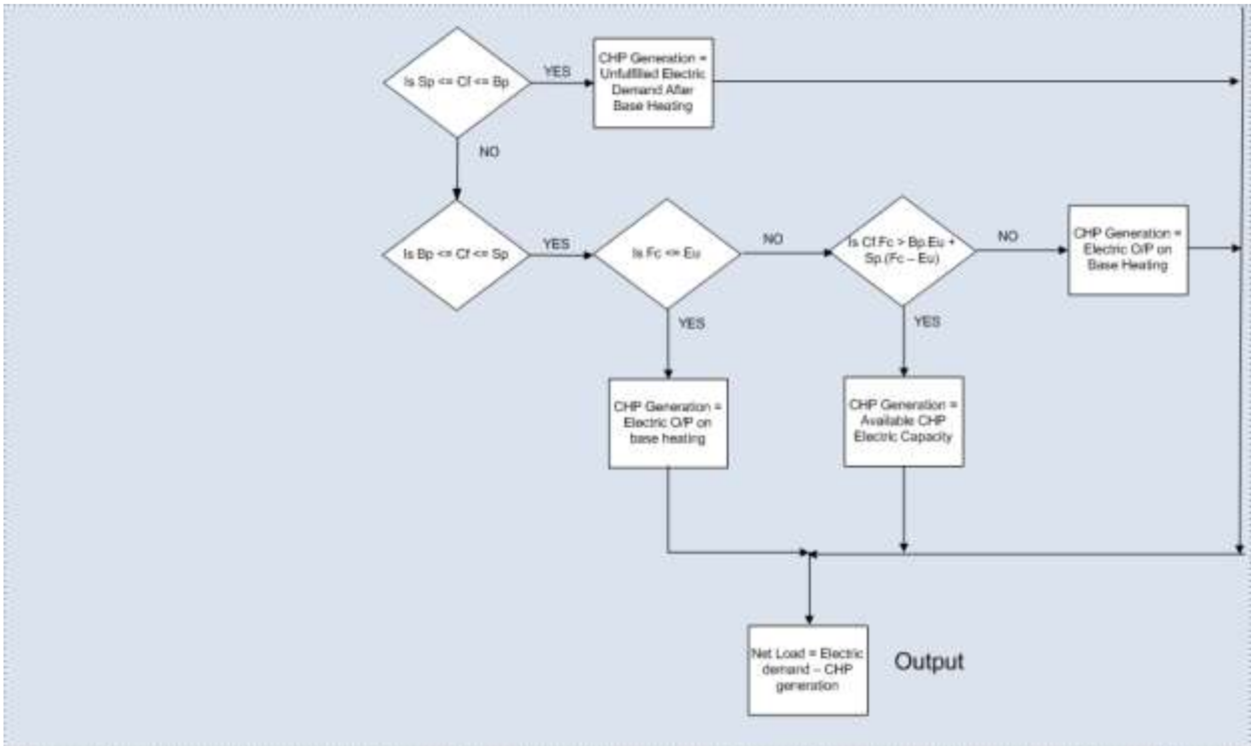


Exhibit 3-7: Flowchart of Data Logic in CHP Model

Depending on factors such as demand and tariff structure, CHP can meet or exceed thermal needs, and produces if economically rational. The price responsive category receives a fixed fee for selling power to the grid. It is generally not worth the cost for this category to increase generation beyond thermal profile to sell to the grid unless for industrial customers who will still sell to the grid because they would have produced that much anyway to meet thermal needs. The non-price responsive category is paid based on a fraction of market price. Therefore, during high price periods, they may increase their production beyond meeting their thermal needs in order to sell when the cost of extra production and buying price is less than revenue from selling price and incentives[44]. To illustrate how CHP generation reduces the net load on a July day, refer to Exhibit 3-8.

[44] Price responsive CHP are those CHP facilities which alter generation supplied to the grid depending upon electricity price observed. We assumed that 50% of industrial CHP capacity is price responsive and 25% of commercial CHP capacity is price responsive.

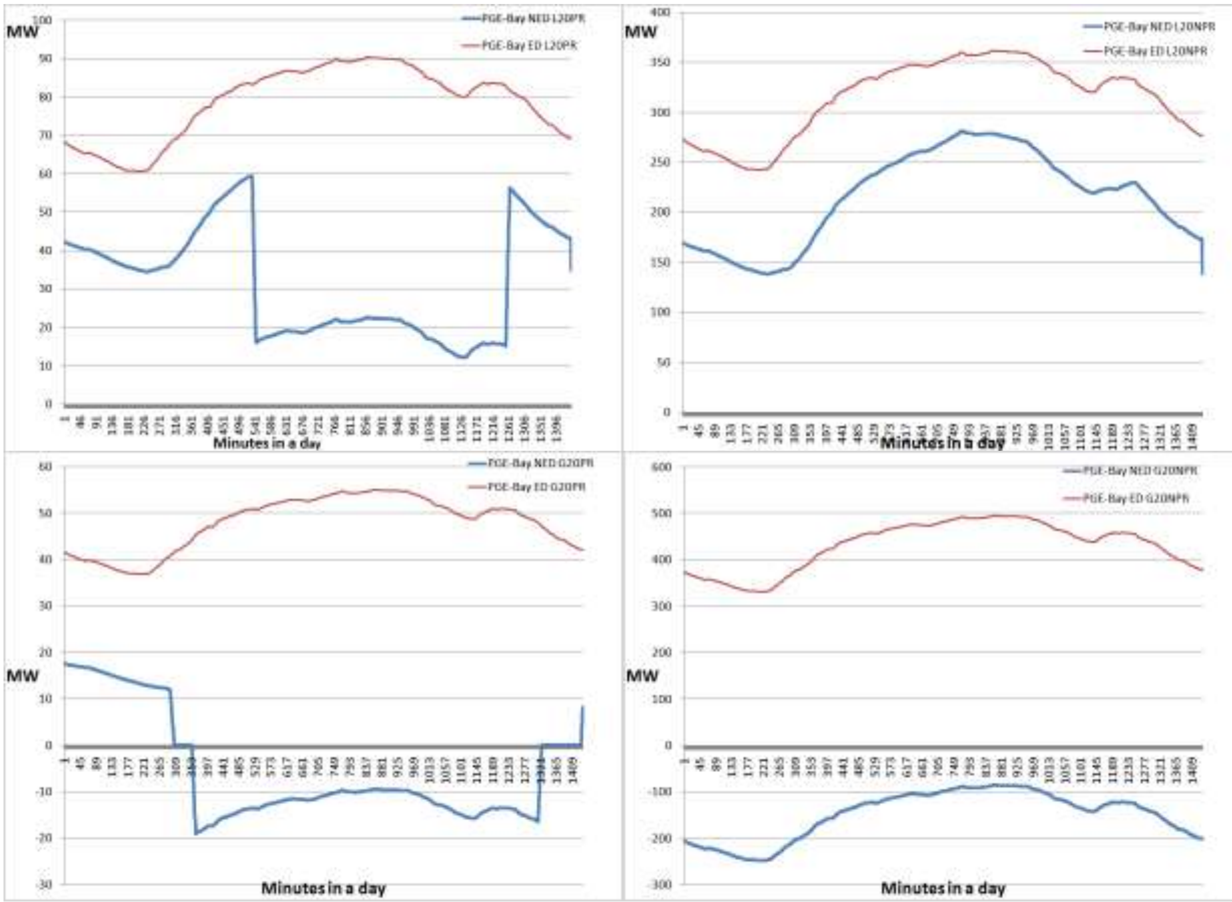


Exhibit 3-8: CHP Variability for Select Days

Exhibit 3-8 shows CHP electric demand (red) and CHP net electric demand (blue) for the day of July 22 for the region PGE-Bay. Clockwise from the left, the figures represent the following model categories: 1) Less than 20 MW, non price responsive; 2) less than 20 MW, price responsive; 3) greater than 20 MW, non price responsive; 4) greater than 20 MW, price responsive. It is noticeable that the electric generation by the price responsive model categories react can exceed the electric demand corresponding to supplying base thermal load if the price of energy sell-back is favorable compared to the cost of generation. Moreover, the net electric demand can be negative, which means a net energy injection into the utility grid for the time-interval when sell-back is favorable.

We assume that the CHP customer has access to hourly prices for energy, specifically the wholesale market price marked up by delivery tariffs and other rate based components. The price of energy and the normal variability of conforming load in the commercial / industrial sector are the variability drivers for this customer segment. (Large customers who also might have PV or storage or DR participation are included in the Self Optimizing Customer class)

3.2.3 Variability in CHP Profile

CHP variability depends upon a number of factors. Natural Gas price is assumed to be known day ahead and does not introduce intra-day variability in the CHP profile but it does affect profiles across the year. Variability in inputs, namely Day-Ahead electricity price and load profile drives the variability in CHP profile. Developing the ISO ability to forecast CHP behavior with respect to natural gas prices is the same model refinement problem as is CHP electric price elasticity.

Total variation of CHP generation is measured by volatility measures the total fluctuation in CHP projected 2020 resource, assuming each input parameter is forecasted from 2020 values. KEMA analyzed the variability for the 1 Minute, 5 Minute and hourly profiles as shown in Exhibit 3-9[45].

Metric	1 Minute Profile	5 Minute Profile	Hourly Profile
Volatility or Standard Deviation/Average	12%	20%	20%
Maximum Value	4,468 MW		
Minimum Value	2,528 MW		

Exhibit 3-9: CHP Profile Variability Descriptions

The KEMA team developed the forecast uncertainty associated with the CHP profile by comparing actual to forecasted values for the latest year that data was available[46]. In the no visibility case, the forecast error is based upon a persistence forecast, or the last observation is the forecast for the next observation. For the visibility case, we measured model error to represent forecast, or actual to projected forecast value. The CHP profile was split into an electric load component and generation component. CHP generation does not vary appreciably by clearness index because the portion of PV related to this profile is fairly small.

[45] 1 Minute, 5 Minute and Hourly Profiles used in the 2020 High DER Penetration

[46] Based upon CEUS data published in 2006.

Metric	Forecast Error
CHP Generation Forecast Error Percent of Maximum, *No Visibility case*	6.8%
CHP Generation Forecast Error Percent of Maximum, *Visibility Case*	5.7%

Exhibit 3-10: CHP Profile Variability Descriptions

When compared with volatility, forecast error is a small percent. In Phase 2, the generation forecast error is then used to calculate Load Following and Regulation Reserve Requirements both with and without visibility (Exhibit 3-10). The CHP load is an adjustment to the load profile with and without visibility.

3.3 Demand Response (DR) Profiles

3.3.1 DR Trends

Demand Response has reduced peak Load in U.S. ISO/RTO markets ranges from 3% to 9% of system peak[47]. The National Energy Regulatory Commission (NERC) estimates the 2009 US System Peak Demand at 810 GW in 2009, with an annual growth of 1.7%, reaching 898 GW in 2015 in peak load reduction potential[48]. NERC projects peak demand from all US ISO/utility DR programs would decline between 38 GW due to DR by 2015 (4.4% of system peak) up to 78 GW (8.7% of system peak)[49].

3.3.2 DR Model

There are multiple ways in which demand side resources can interact with the market. Below, we model an autonomous response to a market price signal, or "Dynamic Pricing" (DP). Several appliance makers are developing smart appliances that can accept an energy price signal and control their on/off status or starting time accordingly. More complex local controls could include a Home Automation System that manages thermostat settings, air conditioner controls, and other loads against energy prices. In such schemes one question is "which price"

[47] Source KEMA.
[48] NERC, Long Term Resource Adequacy, 2010. http://www.nerc.com/files/2010_LTRA_v2-.pdf
[49] ibid

do the resources follow – the Day-Ahead (DA), Hour-Ahead (HA), or intra-hour (Real Time or RT) prices? Anticipating the dynamic response of such autonomous price sensitive load becomes a new dimension in load forecasting for market operators. Estimating potential demand elasticity has been of great interest in recent years as smart grid projects and technologies are anticipated.

A second way of interaction is for Demand Response to occur in response to control / dispatch signals from the market and system operator, or ISO. This kind of “Dispatchable Demand Response” or DDR makes DR look like a resource akin to conventional generation – it has to participate in accessible energy and ancillary markets and is paid a market price for responding to dispatch. FERC has recently issued Order 745 which spells out some principles of compensating Demand Response providers in the markets.

Demand Response penetrations were developed from the Dispatchable Demand Response potential in California[50]. That is, scenarios will be developed that are “within” the potentials identified in that report and the technical performance of DR resources will be modeled based on the characteristics identified in that report. DR characteristics will be considered based on the significant end use applications – commercial and residential Air Conditioning load, hot water heaters; commercial refrigeration, commercial lighting, and so on. Thermal storage as a way to shift Air Conditioning load will also be considered.

One consideration for Dynamic Pricing is determining the portion of Industrial Dynamic Pricing (DP) which is projected to be real time price reactive. It was decided for this study to treat industrial (and commercial) customers as reacting to day-ahead prices. This is the behavioral component that most affects variability. More reactive real time pricing would create fluctuations in the one to five minute range which would suggest a higher proportion of regulating reserves; more reactive hourly pricing would create more fluctuations in the hourly time frame which would deploy higher portions of load following reserves. Those large customers with the ability to react to real time prices in the future would (a) most likely to be large enough to justify real time interval metering and (b) in any case the same modeling and forecasting impacts of visibility would apply. Response to real time prices would increase variability and depending upon the response time of the customer (presumably only those customers able to adjust demand on a cycle consistent with real time price periods would participate) might have variability or load following requirement burden mitigation effect due to price elasticity. However, the ISO would, as with day-ahead price reactive customers, need to be able to forecast that price elasticity response.

[50] KEMA, Demand Response Potential, Report to the California Energy Commission.

Another modeling issue is whether DP would eventually “crowd out” Dispatchable Demand Response (DDR). This effect was not modeled. While policies and economic assessments of the interaction of DDR and DP are not settled today, it is clear that a customer who is implementing Demand Response under a market agreement as a participant would also expect to pay the applicable hourly (or real time, possibly) wholesale price for actual energy used – indeed, it is hard to imagine any other possibility (note that residential customers providing DR would still be on an energy tariff) It is possible that some DDR providers would have reduced their load in response to prices in any case, thus benefiting both from DDR payments as well as from reduced energy costs for remaining load. However, there is no practical way to avoid this phenomenon.

Another important assumption in Demand Response projections is that we assume time of use rates and for commercial true wholesale price pass through. Time of use rates provide incentives for residential customers to react to pricing more readily. Further, commercial price pass through allows immediate economic decisions regarding reactions to price changes.

Demand is dispatched by the DDR module. DDR ‘profile’ will be based on enrollment amounts on that day as well as an estimated realization rate. Enrollment is derived from the forecasts. The low scenario is the Investor Owned Utility forecast and the high scenario is derived from Federal Energy Regulatory and Lawrence Berkeley National Laboratory analyses[51]. Key inputs to the realization are end-use type, sector type and load profiles of each per day type. The following Exhibit 3-11 shows the assumptions for enrollment amounts for the High DER Penetration case:

[51] 2010 Assessment of Demand Response and Advanced Metering, FERC Staff Report, February 2010. Lawrence Berkeley Laboratory Demand Response Research Center, Fast Automated Demand Response to Enable the Integration of Renewable Resources, September 28, 2011 Presentation to CAISO.

Type of Demand Response	California (Max MW available)
Dispatchable Demand Response (High DER Penetration Case)	2,116 MW
Dynamic Price Demand Response (High DER Penetration Case)[52]	9,959 MW

Exhibit 3-11: Dispatchable and Dynamic Price Demand Response Capability

A key assumption in the Dispatchable Demand Response forecast is the threshold price for dispatching demand response and the minimum price at which Dispatchable Demand Response can be invoked. These vary by region[53] and are shown in Exhibit 3-12.

	IID	LADWP	PGE_Bay	PGE_Vly	SCE	SDG&E	SMUD	TIDC
Percentage of Prevailing Price Observed at which Dispatchable Demand Response is exercised	18%	12%	10%	10%	10%	10%	13%	18%
Minimum Peak Price Threshold to exercise Dispatchable Demand Response	$30/ MWh	$40/ MWh	$40/ MWh	$40/ MWh	$40/ MWh	$40/ MWh	$50/ MWh	$50/ MWh

Exhibit 3-12: Dispatchable Demand Response Price Response

An observed phenomenon is a spike in demand after Dispatchable Demand Response programs have ended, called “Kick-back”. A certain portion of the demand reduced due to DDR will be shifted to the next hours. The portion depends on the end-use type such as ventilation, cooling, space heating and day type contributing to DDR. Exhibit 3-13 lists the estimated load allocation based on end-use type along with their kick-back percentages:

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[52] Note that Dynamic Pricing Demand Response is included as part of the load profile and is invoked when pricing conditions justify; Dispatchable Demand Response is a separate resource.

[53] IID is the Imperial Irrigation District; LADWP is the Los Angeles Department of Water Power; PGE_Bay and PGE_Vly are two regions in PGE’s distribution area; SCE refers to Southern California Edison; SDGE is San Diego Gas and Electric; SMUD is Sacramento Municipal Utility District and TIDC is the Turlock Irrigation District Control Area.

End Use Category	[1] Percent of Total Residential and Commercial End Use	[2] Estimated Share of Potential Kickback	[3] = [1]*[2] Estimated Potential Kickback percent of total
Cooling	14.9%	40%	5.96
Space Heating	1.6%	40%	0.64
Air Compressors	1%	20%	0.2
Cooking	4.2%	20%	0.84
Water Heat	0.9%	40%	0.36
Refrigeration	13.4%	20%	2.68
Remainder	55.9%	None	None

Exhibit 3-13: Kickback Response Assumptions

Exhibit 3-14 lists the assumptions for DDR realization rate, DDR realization duration, kickback percentage, kickback duration. Realization rate measures the actual participation volume compared to the expected volume of DDR called. If the ISO requests 100 MW of DDR for 100 minutes, with a realization rate of 63%, the ISO will receive 63MW of actual DDR response for 100 minutes. Further, if the time for full realization of DDR is 30%, then it will take 30 minutes to reach that full realization of 63 MW. Time for load restoration of 10% implies in our example, that when the DDR is complete, it will take the load 10 minutes (10% of 100 minutes of DDR duration) to return to normal. Kickback percent of total DDR called upon measures the portion of total DDR which can be expected to be *increased* (11% of 100 MW or 11 MW in our example). The kickback duration percent of total DDR Duration measures the percent of time that kickback occurs after the DDR call is complete (33% X 100 minutes or 33 minutes in our example). Kickback dissipation percent of kickback measure the percent of time that kickback actually occurs (in our example of 100 minutes of DDR call, 20% or 20 minutes is required before kickback is complete. The dynamics of DDR realization and kickback over the given durations is modeled by a cubic polynomial fit.

DDR Characteristics	
Realization Rate	63%
Percent of Time for full realization as percent of DDR call duration	30%
Percent of Time for load restoration as percent of DDR call duration	10%
Percent Time for full kickback as percent of Kickback duration	20%
Kickback percent of total DDR called upon	11%
Kickback Duration percent of DDR Duration	33%
Time for kickback dissipation as percent of kickback duration	20%

Exhibit 3-14: DDR Response Assumptions

Exhibit 3.15 illustrates an example of various DDR actual and expected profiles over time.

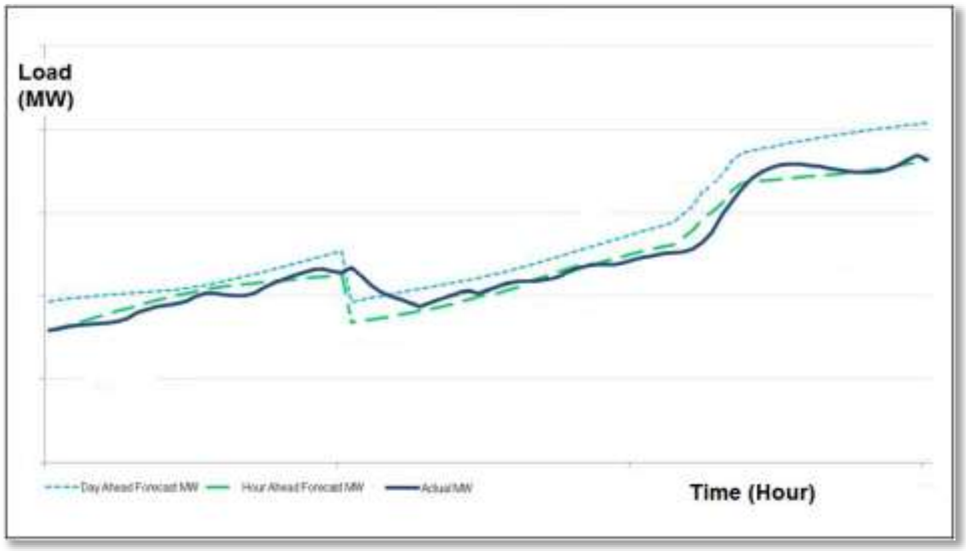


Exhibit 3-15: Kickback example illustrated

In the hypothetical example, Day-Ahead forecasted MW and Hour-Ahead forecasted MW are shown with 20 MW of DDR called upon by the ISO. Actual MW metered shows a DDR reaction time and kickback beyond the forecast schedule. The realization rate and kick-back effects are variability drivers in the overall profiles. Kickback occurs because a significant percentage of DDR load will be load representing energy usage that is deferred somehow. When any thermal load (HVAC or hot water heating or refrigeration) is turned off for a period of time, there will be some thermal recovery needed when it is turned back on. This means that individual end elements will cycle "on" for longer periods once power is restored so that aggregate load increases. This is a well known phenomenon. Other types of DDR resources such as lighting are pure avoidance and not subject to kickback. Kickback does not add to the variability of DDR because DDR only occurs when the ISO calls for it and can be forecast. But kickback will add to load following as when the DDR duration is over it adds to the ramping up of the DDR profile.

3.3.3 Demand Response Variability and Forecast Uncertainty

Because DR is activated at the ISO's instructions, it does not add to load following or regulation requirements but can serve to help meet them.

Because the ISO knows when it has dispatched DDR there is not a forecasting issue other than that associated with actual realization and kick back. These are of a lesser magnitude than the forecasting errors inherent in DER types that respond autonomously to external variability drivers.

3.4 Distributed Storage Models

Electricity storage penetrations as grid connected and distributed resources emerge are an important distributed resource. KEMA developed, with ISO review, scenarios for electricity storage penetrations based on very high level; forward technology and cost forecasts and assumptions around likely policy issues affecting storage development such as the US Senate Wyden bill for storage investment tax credit and the FERC Order 755 on pay for performance. Additionally, assumptions on the use of storage in daily scheduling and in renewable firming were developed and then embedded in the PLEXOS model. While the KEMA Team has modeled storage in PLEXOS[54] some simplifications are necessary in order to guarantee solutions. Distributed storage under two main operations is considered, namely, under utility operations (Community Energy Storage) and behind the meter (Customer Storage). The latter is further divided into residential customers and commercial and industrial (C&I) customers. Not considered in this study is Grid connected (large scale) storage which can be self-scheduled or co-optimized for energy arbitrage. These are not distributed resources and are not considered for this study. The technologies used for grid connected include pumped hydro and Compressed Air Energy Storage will be assumed to be co-optimized in the energy markets as today. Large advanced battery devices will be self-scheduled as merchant operations. These technologies are assumed to primarily be developed to provide wholesale market services such as ancillary services and not part of distributed energy resources. Community storage and customer storage systems will most likely be high efficiency electrochemistries that do not require advanced heating or cooling systems and which are inherently safe chemically (Li Ion) or well accepted (advanced Lead Acid). Efficiencies for these technologies and their inverters range from 70 – 85% and low end efficiencies will be used to be conservative. This is appropriate given that for the distributed storage applications the upfront cost will be a major factor in determining penetration and the trade-offs will favor lower initial costs.

3.4.1.1 Community Energy Storage

Distributed storage under utility operations (Community Energy Storage) is primarily developed to defer capital/ improve reliability at the feeder/substation level. Moreover, storage is used by the utility to smooth the renewable variability (here customer PV production). Once the net load is dropped suddenly beyond a certain threshold due to the increase in customer PV production,

[54] KEMA, European Union ongoing modeling efforts for the year 2050. Still ongoing.

charging from storage takes place to make up for this undesired fluctuation. A number of assumptions are used to specify the storage forecasted capacity, its efficiency and operational constraints and also to set the thresholds (control characteristics) that trigger the storage charge/discharge as shown in Exhibit 3.17. Exhibit 2.16 shows the distribution of utility installed storage in terms of installed capacity for the eight regions in California.

	IID	LADWP	PGE Bay	PGE Vly	SCE	SDGE	SMUD	TIDC	Total
Total Utility PV (max MW output)		178.4	349.9	552.2	480	160	27.3		1747.8
Utility Storage (MW capacity)	24.8	139.5	189.1	299.1	536.2	103.4	103.4	15.4	1411
Peak Load (MW)	1237	6938.3	9396.7	14866	26650	5138.4	5140	764	70131

Exhibit 3-16: Utility Storage Penetration Assumptions

Efficiency (%)	Duration (hrs)	Minimum State of Charge (%)	Peak Shave Level (% of annual peak)	Maximum Ramping Rate (%)
70%	4	10%	80%	20%

Exhibit 3-17: Utility Storage Characteristics and Control Criteria

The application of storage for capacity deferral is represented by peak shaving on utility feeders. The peak shave level specifies the load above which storage discharge is activated. Smoothing of real power and hence frequency on the utility feeder is dictated by the ramping rate threshold, which is defined as the absolute difference in MW, between two time instants of simulation. Any fluctuation in the feeder demand greater than the ramping rate, caused primarily by customer DERs activates appropriate charging or discharging action by the storage module.

The following flow chart gives a high-level view of the steps associated with preparation of input data as well as the decision logic of the Utility Storage model. The customer net load (i.e., net load after customer PV load reduction) is fed into CES module. Desired maximum demand is obtained using the capacity deferral level percentage from the assumptions multiplied by annual peak. Desired minimum demand is the threshold to control the downward load fluctuations based on minimum allowable ramping rate per hour.

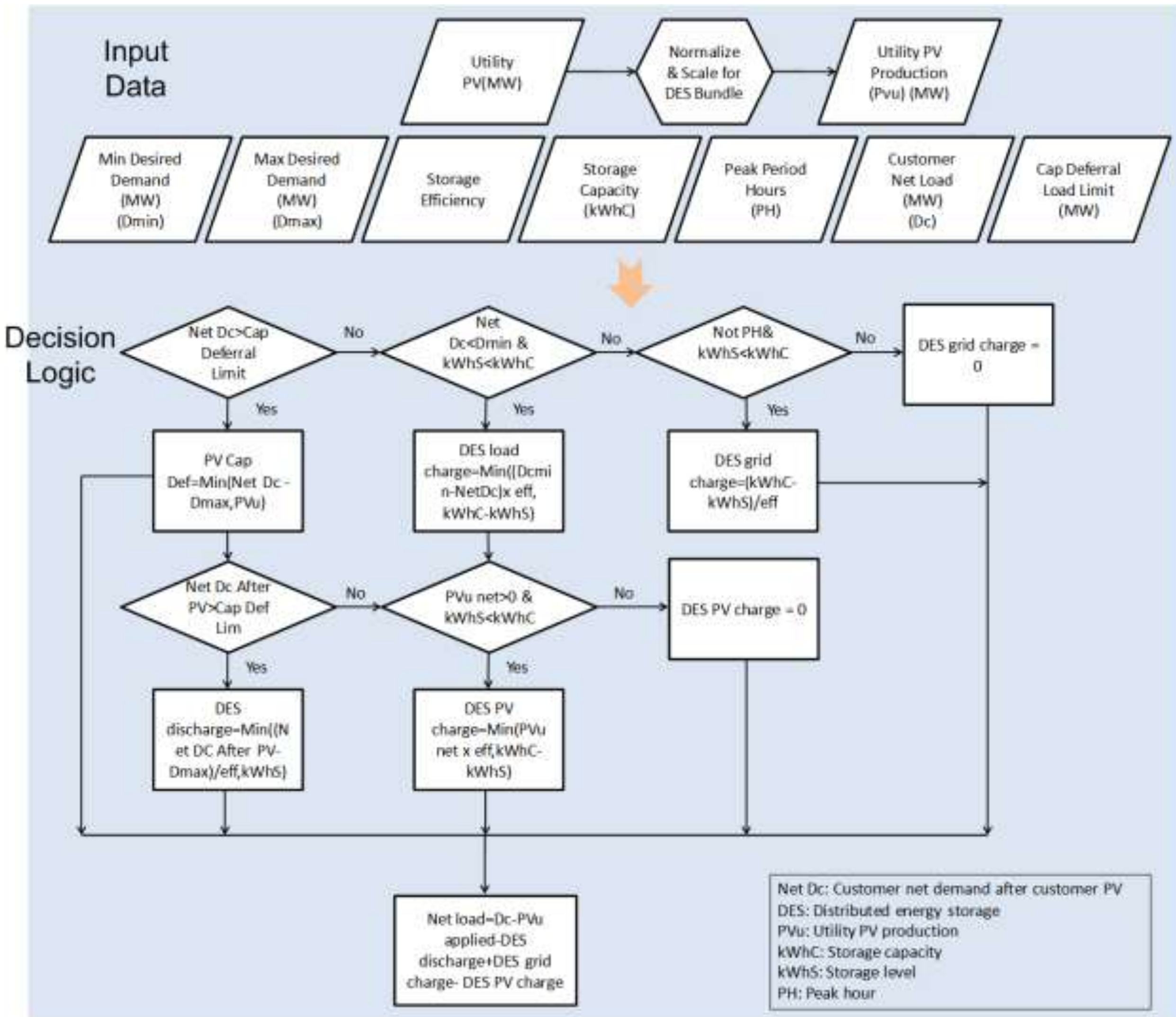


Exhibit 3-18: Utility Storage Model Inputs and Decision Logic

The priority is given to storage discharge for capacity deferral. Once the rate of net load reduction exceeds the allowable ramping down threshold and no storage discharge is taking place, the energy from storage is injected to smooth the downward fluctuation (this could be seen as voltage smoothing for renewable fluctuation). Furthermore, if capacity deferral is not required and there is utility PV production available, PV production is used to charge the storage. Finally, storage charging from the grid occurs during midnight (off-peak). Of course, maximum/minimum storage energy level constraints as well as limits for storage charge/discharge rates are considered during all charge/discharge operations.

Exhibit 3-19 is a sample Utility Storage profile for 07/22/2020 for the region PGE-Bay. The load profile without PV and Storage is shown in blue. Utility storage shaves peak for capacity deferral and voltage control. It charges during downward fluctuations in net customer load (customer PV + load shown in green in Exhibit 3-19) and therefore addresses fluctuations in customer PV. In Exhibit 3-19, Off-peak storage charging from the grid increases the net electricity demand on the grid.

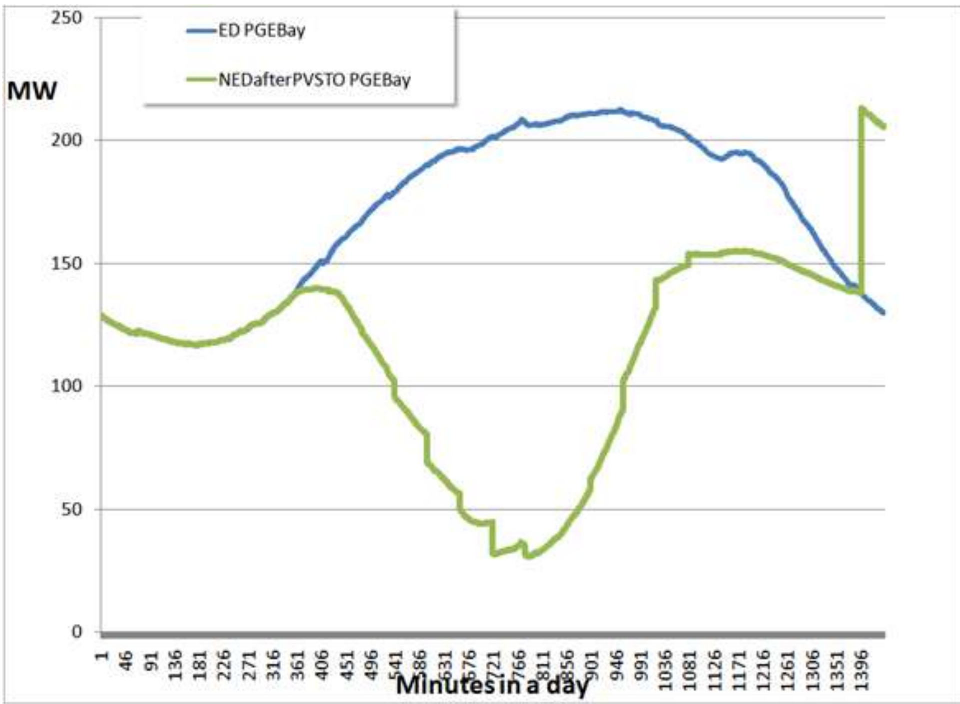


Exhibit 3-19: Utility Storage Profile for 07/22/2020, PGE-Bay

The variablity in the profile would be due to the variability in the input stream. Variations in customer and utility PV production as well as variations in load will be the sources for CES profile variations.

3.4.1.2 Customer Storage

Behind the meter storage will be assumed to be associated with capturing PV production on peak and storing it for off peak usage (such as EV charging or evening AC load. It will therefore be (different from the CES) treated as a load shifting application; again independent of energy markets. Customer storage would consist of two major sectors; residential and commercial and industrial (C&I). Total load profile and customer PV production are normalized and scaled to be allocated between the two sectors.

The storage applications and decisions logic would be different for the two sectors: Residential Storage and C&I Storage.

3.4.1.2.1 Residential Storage

The distribution of installed capacity of residential storage applications and corresponding solar PV installations by region is shown in Exhibit 3-20. Exhibit 3-21 shows the assumed parameters relating to the operation and control of residential storage units.

	IID	LADWP	PGE Bay	PGE Vly	SCE	SDGE	SMUD	TIDC	Total
Residential PV corresponding to storage (MW installed)	4.6	25.63	41.78	66.1	119.21	21.3	29.6	2.82	311
Residential storage (MW installed capacity)	1	5.1	8.4	13.2	23.8	4.3	5.9	0.6	62.2
Peak Residential Load (MW)	474	2656	4330	6850	12353	2207	3066	293	32227

Exhibit 3-20: Residential Storage Forecast by Region

Efficiency (%)	Duration (hrs)	Minimum State of Charge (%)
70%	3	10%

Exhibit 3-21: Residential Storage Characteristics and Control Criteria

The net load profile seen by residential storage will be the reduced load by the residential PV production (scaled customer PV to allocate residential share). Storage discharge is controlled to reduce the peak demand if it exceeds a certain percentage of annual peak demand. The assumptions relating to peak hours are derived from existing tariff rates and the peak shaving percentage reflects the changes in gross demand by month. Exhibit 3-22 lists the peak time data and peak shaving assumptions used for PG&E Bay. The peak hour data are derived from PG&E residential E-6 time-of-use rate schedule.

Month	Weekdays		Weekend		Peak Shaving / Peak Demand
	Start Hour	End Hour	Start Hour	End Hour	
1	17	20	0	0	0.3
2	17	20	0	0	0.3
3	17	20	0	0	0.28
4	17	20	0	0	0.25
5	13	19	0	0	0.25
6	13	19	0	0	0.23
7	13	19	0	0	0.23
8	13	19	0	0	0.25
9	13	19	0	0	0.28
10	13	19	0	0	0.28
11	17	20	0	0	0.3
12	17	20	0	0	0.3

Exhibit 3-22: PGE-Bay Example Residential Storage Peak Shaving Criteria

Storage charging will be from excess PV production and also from the grid during off-peak hours. Exhibit 3-23 demonstrates the decisions logic for residential storage.

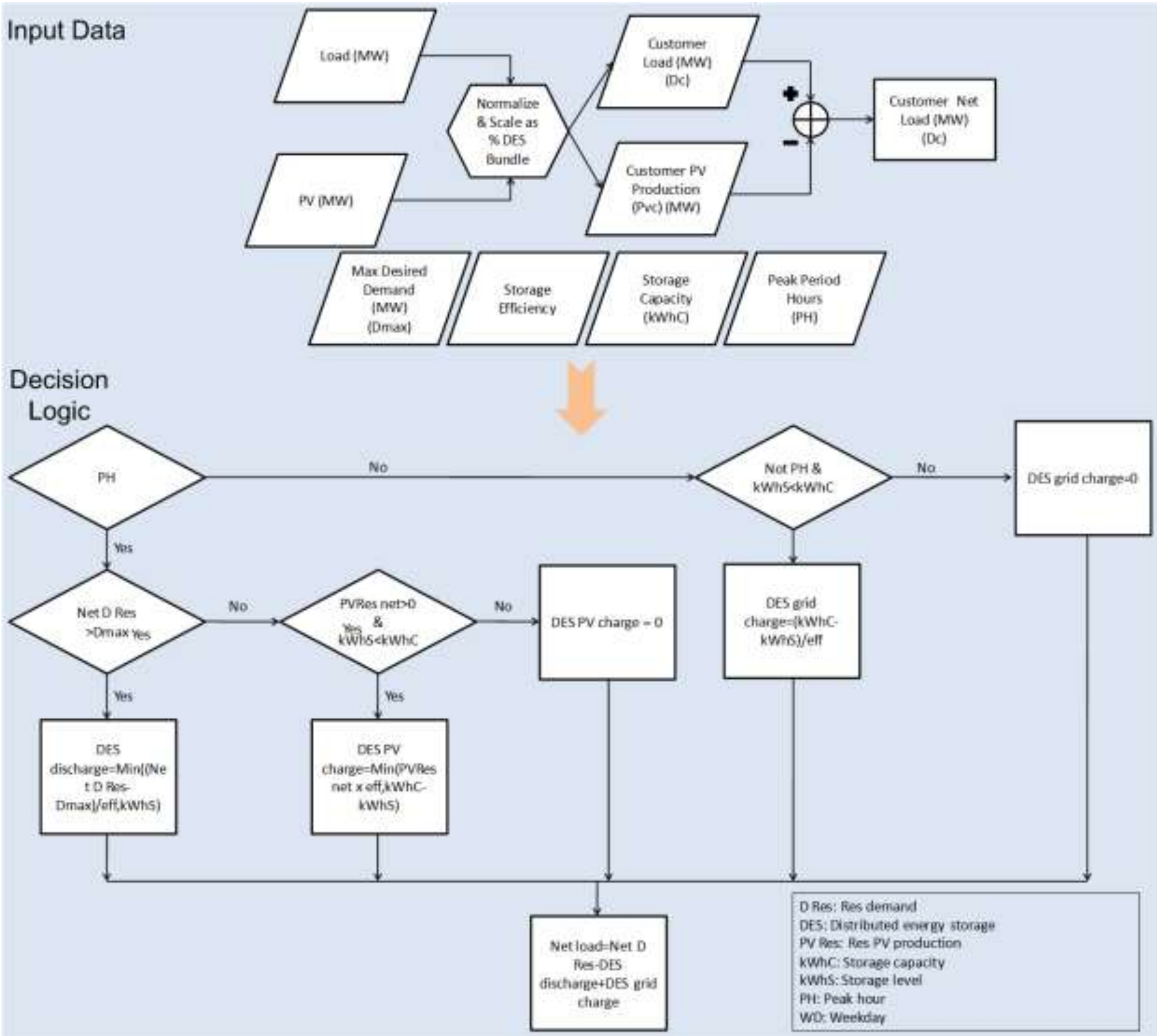


Exhibit 3-23: Residential Storage Model Inputs and Decision Logic

The variablity in the profile would be due to the variability in the input stream. Variations in customer PV production as well as variations in load will be the sources for residential profile variations. Exhibit 3-24 shows an example profile for residential storage net demand and electric demand for July 22, 2020 for the region PGE-Bay. In red, the electric demand for PGE-Bay is shown; in yellow, the same electric demand adjusted for PV is provided and in blue, the net demand adjusted for PV and storage is provided. Solar PV production and storage discharge occurs during peak hours and the corresponding charge is recovered from the grid during off-peak hours. A displacement of demand corresponding to storage operation, from peak to off-peak is demonstrated.

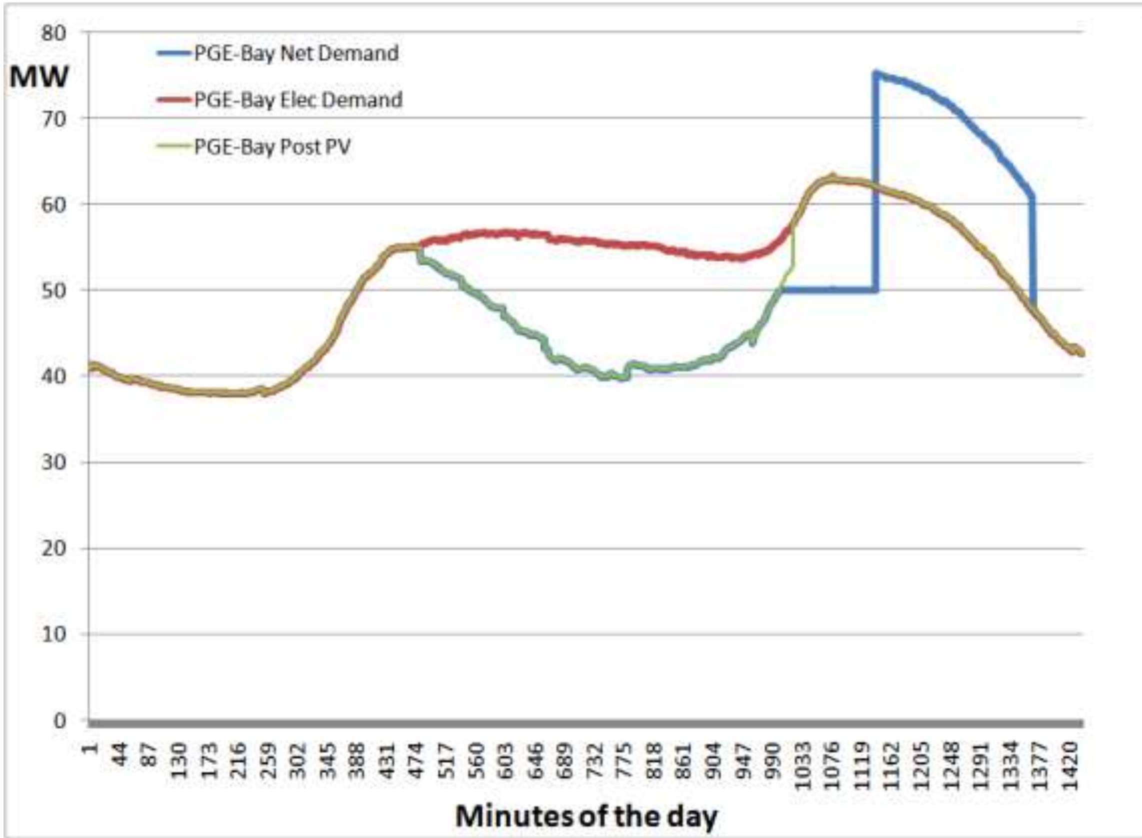


Exhibit 3-24: Residential Storage Profile for 07/22/2020, PGE-Bay

3.4.1.2.2 Commercial and Industrial (C&I) Storage

Exhibit 3-25 shows the distribution of Commercial and Industrial storage installations and corresponding solar PV installation by region. Exhibit 3-26 lists the operation and control parameters of the C&I storage model. Rate of storage charging from the grid during off-peak hours is limited to 30% of annual peak demand.

	IID	LADWP	PGE Bay	PGE Vly	SCE	SDGE	SMUD	TIDC	Total
C&I PV corresponding to storage (MW installed)	5.2	44	39.5	62.4	124.6	30.5	22.4	3.2	332
C&I storage (MW installed capacity)	3.9	33	29.6	46.8	93.4	22.9	16.8	2.4	249

Exhibit 3-25: Commercial and Industrial Storage Forecast by Region

Efficiency (%)	Duration (hrs)	Minimum State of Charge (%)	Maximum Grid Charging Rate (% of annual peak)
70%	4	10%	30%

Exhibit 3-26: Residential Storage Characteristics and Control Criteria

Peak shaving and selling back to the grid using arbitrage are applications associated to C&I storage. Peak hours are determined based on hourly day-ahead electricity prices. If the hourly price exceeds a certain percentage of seasonal peak price on each hour, that hour would be flagged as peak. First, C&I PV production is used for peak shaving requirement and if further peak shaving is still needed, discharge from storage takes place. Excess PV production will be used to charge the storage. Also, storage is charged from the grid over off-peak hours. During weekends, C&I load is served by PV production and storage and then whatever remained from these resources is sold to the grid. Storage charging from the grid is done at midnight during weekends. Exhibit 3-27 lists the above mentioned process.

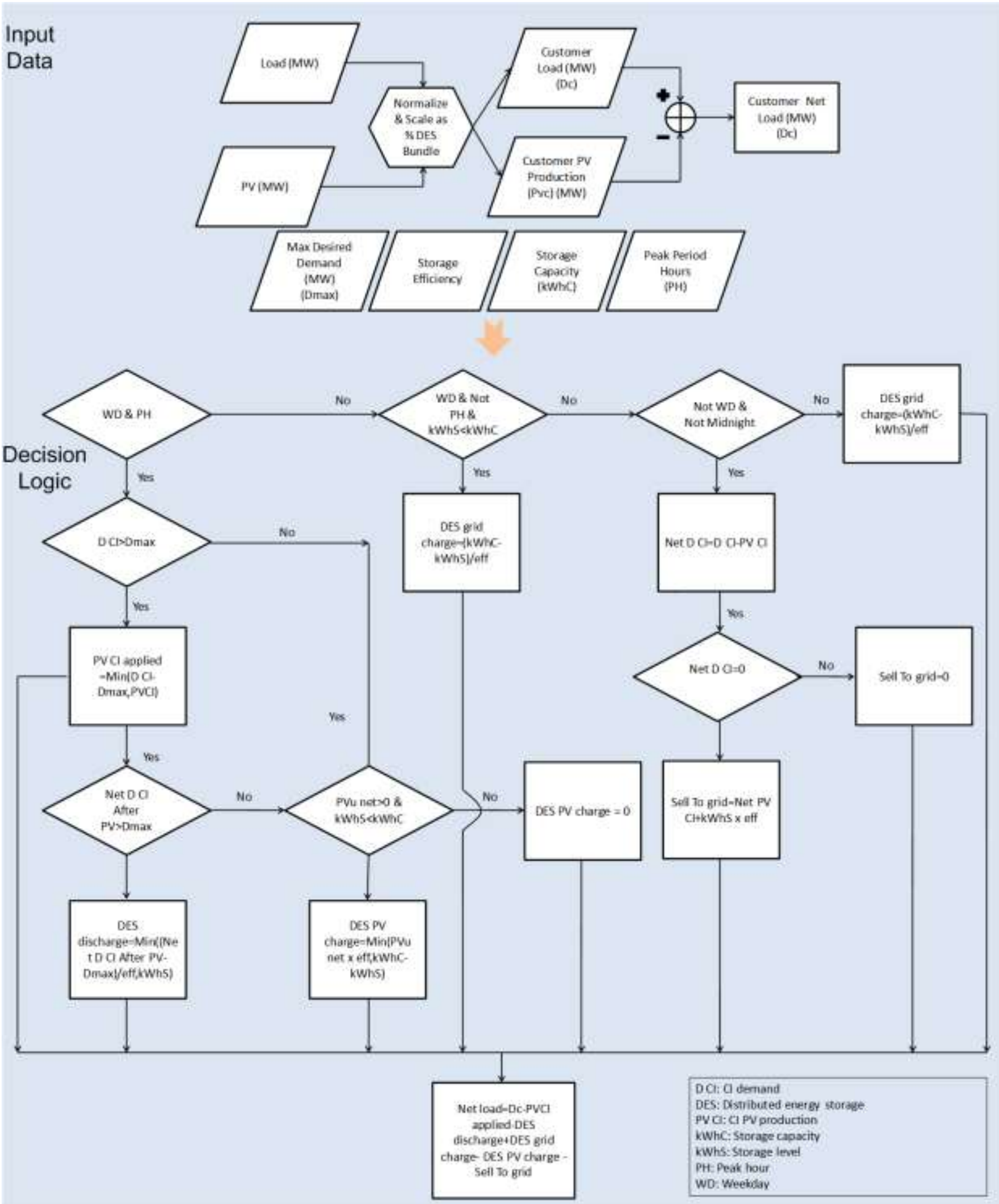


Exhibit 3-27: C&I Storage Model Inputs and Decision Logic

Exhibit 3-28 is a sample C&I profile for a July 22 day for the region PGE-Bay. In red, the electricity demand is represented and in blue, the load net of C&I storage is shown. C&I

storage is used to shave peak load after PV reduction. Evening storage charging from the grid increases the net electricity demand on the grid.

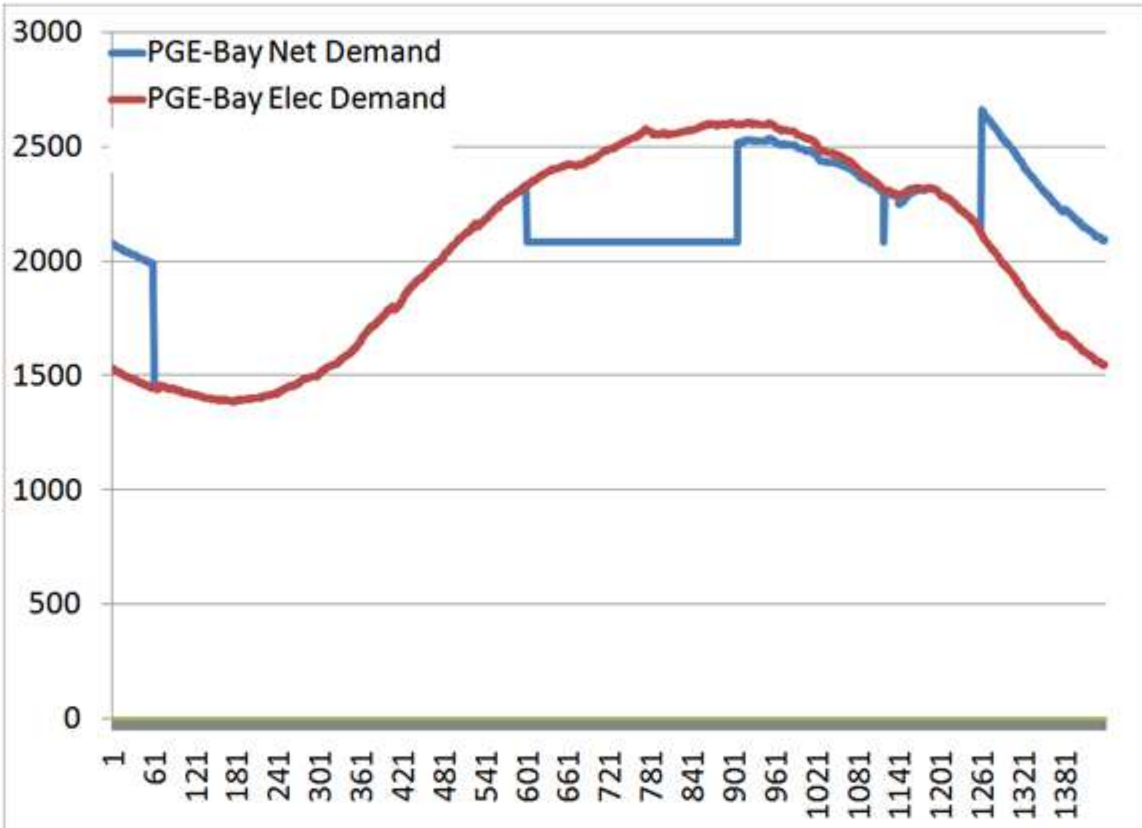


Exhibit 3-28: C&I Storage Profile 07/22/2020, PGE-Bay

3.4.2 Distributed Storage Variability and Forecast Uncertainty

The variablity in the profile would be due to the variability in the input stream. Variations in customer PV production as well as variations in load and hourly electricity price will be the sources for C&I profile variations.

1) We do not model wholesale storage applications such as frequency regulation in distributed storage penetration forecasts.

2) We do not model reliability/backup storage, electric power quality storage as consumer functionality. NOTE: reliability discharging would only occur on an outage so would not affect grid / market operations at all.

Uncertainty for Distributed Storage measures the total fluctuation in net charging/discharging projected for the 2020 resource, assuming each input parameter is forecasted from 2020 values. The net demand of the distributed storage units are added to the demand side to compute the dispatch and commitment requirements and hence the variability of the net demand for the five minute and hourly profiles for the state of California are computed. These are shown in Exhibit 3-29.

Metric	5 Minute Profile	Hourly Profile
Volatility or Standard Deviation / Average	18.3%	18.2%
Maximum Value	2578 MW	2357 MW
Minimum Value	976 MW	917 MW

Exhibit 3-29: Distributed Storage Profile Variability Descriptions

As shown in Exhibit 3-30, the KEMA team developed the forecast uncertainty associated with the Distributed Storage profile by comparing actual to forecasted values for the latest year that data was available. Distributed Storage varies by clearness index because there of the PV associated with this resource.

Metric	0 ≤ CI ≤ 0.2	0.2 ≤ CI ≤ 0.5	0.5 ≤ CI ≤ 0.8	0.8 ≤ CI ≤ 1
Commercial Storage shifted generation Forecast Error Percent of Maximum, *No Visibility Case*	8.8%	11.2%	12.9%	10.5%
Commercial Storage shifted generation Forecast Error Percent of Maximum, *Visibility Case*	7.3%	9.3%	10.8%	8.8%
Distributed Utility Storage shifted generation Forecast Error Percent of Maximum, *No Visibility Case*	0.6%	0.6%	0.6%	0.6%
Distributed Utility Storage shifted generation Forecast Error Percent of Maximum, *Visibility Case*	0.5%	0.5%	0.5%	0.5%

Exhibit 3-30: Distributed Storage Profile Variability Descriptions

When compared with volatility, forecast error is relatively small. In Phase 2, the distributed storage forecast error is then used to calculate Load Following and Regulation Reserve Requirements both with and without visibility.

3.5 Self Optimizing Customer (SOC)

3.5.1 Technologies

When the customer "self optimizes" energy usage over time in response to a schedule of market prices as in the case of day ahead hourly prices we must consider several different technology bundles. This is one expected mode of SOC operation and behavior – the SOC operator or energy manager looks at the published day ahead hourly prices and then schedules the SOC production, storage, and demand resources during the day to optimize the financial outcome. In another variant the SOC operator would bid some of those resources into the market as production or DDR resources as well. Sometimes this interaction is called a "Virtual Power Plant" or VPP; sometimes "SOC" and sometimes "Self Optimizing Customer" or SOC. We will use the last form, "SOC."

3.5.2 SOC Model

In the model below, we present the Self-Optimizing customer model and assumptions.

We assume four different configurations for the self optimizing customer, including:

- Bundle 1: Combined Heat/Power, Electric Storage and Thermal Storage (CHP + ES +TS)
- Bundle 2: Photovoltaic (PV) generation, Electric Storage and Thermal Storage (PV + ES + TS)
- Bundle 3: Photovoltaic (PV) generation, Combined Heat/Power and Thermal Storage (PV + CHP +TS)
- Bundle 4: Photovoltaic (PV) generation, Combined Heat/Power and Electric Storage (PV + CHP + ES)
- Bundle 5: Photovoltaic (PV) generation, Combined Heat/Power, Electric Storage and Thermal Storage (PV + CHP + ES + TS)
- Bundle 6: Photovoltaic (PV) generation and Combined Heat/Power (PV + CHP)

Each of the above bundles was then based upon known technologies:

- PV generation was based upon large scale PV solar facilities currently implemented in California and assumed to be no larger than 75% of total SOC capacity.
- Existing Combined Heat/Power model is used. An additional capability in this model is to use legacy boiler systems and purchase gas from the grid if the price structure disfavors CHP operation.

- The residential battery storage model is used.
- The thermal storage system models building pre-cooling and is dictated by a simplified building entropy constraint. Several other parameters link time interval of pre-cooling as well as the associated energy and power with the ambient temperature, building surface area, time of day and tariff structure.

The distribution of the SOC technologies by the regions or zones in California was compiled based on demand data profiles obtained from CEUS (California Commercial End Use Survey) on building types, fuel types and utility regions. The building types considered relevant to SOC establishment are: 1) Healthcare; 2) Retail; 3) Warehouse; 4) Large Office; 5) Lodging; 6) Military base; 7) University and 8) Small Office. Exhibit 3-31 shows the installed capacities of the technology bundles for the eight regions in California.

	IID	LADWP	PGE Bay	PGE Vly	SCE	SDGE	SMUD	TIDC	Total
CHP + ES + TS	3.8	21.3	21.6	34.2	81.8	25.2	9.7	2.3	200.0
PV + ES + TS	1.3	7.3	8.5	13.5	28.0	4.7	2.5	0.8	66.7
PV + CHP + TS	3.9	22.1	31.7	50.1	84.9	33.3	11.6	2.4	240.0
PV + CHP + ES	7.8	44	64.4	101.9	169.1	70.6	25.2	4.9	488.0
PV + CHP + ES + TS	5.2	29.3	42.9	67.9	112.8	47.1	16.8	3.2	325.3
PV + CHP	0.2	1.3	1.6	2.5	5.1	1.8	0.6	0.1	13.3
Total	23.5	131.9	178.7	282.6	506.7	97.7	97.7	14.5	1333.3

Exhibit 3-31: Installed capacity of SOC bundles for regions (in MW)

The percentage installed capacities of each technology within each bundle varies by the building types, load types and generation source types associated with the bundle. In general, the CHP capacity is associated with the heating demand, the thermal storage capacity is associated with the cooling demand, and electric storage is associated with installed PV capacity, which in turn depends on the total electric demand.

The input time-series data streams for the SOC model are: 1) Heating demand; 2) Cooling demand; 3) Electric demand excluding electric cooling load; 4) Temperature; 5) PV production profile 6) Day ahead energy purchase prices; 7) Price of natural gas and 8) Day-ahead energy sell-back rates. In addition, the following parameters are also taken as inputs: 1) Capacity factor of solar PV production; 2) Power to heat ratio of CHP installation; 3) Electrical efficiency of CHP installation; 4) Total efficiency of CHP installation; 5) Non-fuel operational cost of CHP installation; 6) Duration, efficiency minimum state of charge and maximum ramping rate of battery units; 7) Duration and efficiency of thermal storage systems; 8) Convection coefficient; 9) Boiler efficiency; 10) Maximum ambient temperature above which pre-cooling is not necessary.

SOC module consists of a constrained linear optimization problem to calculate the net load profile of aggregated SOCs based on demand, price and capacity forecasts. The objective would be to minimize the operational cost over time period of optimization, i.e., 24 hours, 8760 hours (for a year), etc. Time intervals for optimization, t, could be chosen to be 1 minute, 1 hour, etc.

PV generation is used to supply electric demand, cooling load and battery charging. CHP generation is used to supply electric demand, cooling demand, battery charging and selling back to the grid on base and non-base heat production. Electric storage (Li-Ion battery banks) is assumed to discharge for cooling load, electric demand and selling back to the grid. Thermal storage discharge is to supply cooling load. Electric energy purchased is to supply electric demand, battery charging and pre-cooling loads. Finally, gas energy purchased is supposed to serve heating load. The centers of energy demand and centers of power generation are shown in the following matrix. In this scenario, no power is sold back to the grid, because the installed capacity is presumed to be less than peak load. Configurations of SOC bundles are shown in Exhibit 3-32.

		Energy Sources					
		PV	CHP	Electric Storage Discharge	Thermal Storage Discharge	Electric Grid Purchase	Gas Purchase
Energy Demand Centers	Electrical Load	✓	✓	✓		✓	
	Heating Load		✓			✓	✓
	Cooling Load	✓	✓	✓	✓	✓	
	Electric Storage Charging	✓	✓			✓	
	Thermal Storage Charging	✓	✓			✓	
	Energy Sellback	✓	✓	✓			

Exhibit 3-32: Energy sources and demand centers in SOC bundles

An example of the mathematical representation of the optimization problem is now shown. The formulation shown does include the variables and constraints related to the purchase of gas from the grid, operation of CHP by rejecting excess heat and the entropy constraints related to thermal charge and discharge. The complete problem formulation is not included here due to space constraints.

Inputs to the model at each instant of time (for all i's ($\forall i = 1,...,T/t$)) are the following:

- D_{Ei}, electric demand (MW);
- D_{Hi}, heating demand (MW);
- D_{Ci}, cooling demand (MW);
- C_{bi}, price of energy purchase ($/MWh);
- C_{si}, price of energy sell-back ($/MWh);
- C_{fi}, operational cost of sources with fuel requirements ($/MWh);
- G_{PVi}, PV generation (MW);
- G_{CHPi}, available CHP capacity (MW);
- P_{BSi}, P_{TSi}, mean power capacity of electrical storage sources and thermal storage sources (MW);
- E_{BSi}, E_{TSi}, mean energy capacity of electrical storage sources and thermal storage sources (MWh);

Decision variables at each time instant ($\forall i = 1,...,T/t$) are:

- g_{PVEi}, PV generation supplying electric load (MW);
- g_{PVCi}, PV generation supplying cooling load (MW);
- g_{PVBSi}, PV generation supplying electric storage charging load (MW);
- g_{CHPEi}, CHP generation supplying electric load (MW);
- g_{CHPHi}, CHP generation supplying heating load (MW);
- g_{CHPCi}, CHP generation supplying cooling load (MW);
- g_{CHPSi}, CHP generation for sell-back to grid (MW);
- g_{BSEi}, electric storage discharge to supply electric load (MW);
- g_{BSCi}, electric storage discharge to supply cooling load (MW);
- g_{BSSi}, electric storage discharge for sell-back to grid (MW);
- g_{TSHi}, thermal storage discharge to supply heating load (MW);
- g_{TSCi}, thermal storage discharge to supply cooling load (MW);

- p_{Ei} , energy purchase from grid to supply electric load (MW);
- p_{Hi} , energy purchase from grid to supply heating load (MW);
- p_{Ci} , energy purchase from grid to supply cooling load (MW);
- p_{BSi} , energy purchase from grid for electric storage charging (MW);
- p_{TSi} , energy purchase from grid for thermal storage charging (MW);
- l_{BSi} , energy within electric storage source at the end of time interval *i* (MWh)
- l_{TSi} , energy within thermal storage source at the end of time interval *i* (MWh)

As mentioned earlier, the problem is a constrained linear programming with a general form of:

$$
\begin{aligned}
&\min_{x} f^T x \\
&\text{such that } Ax \le b \\
&\qquad\qquad A_{eq} x = b_{eq} \\
&\qquad\qquad b_l \le x \le b_h
\end{aligned}
$$

where *x* is the $(m \times 1)$ vector of decision variables

The mathematical form of objective function, f, which is the operational cost minus the revenue of SOC over the optimization horizon, T, is:

$$f = \sum_{i=1}^{T/t} C_{fi}\left(g_{CHPEi} + g_{CHPHi} + g_{CHPCi} + g_{CHPSi}\right) + C_{bi}\left(p_{Ei} + p_{Hi} + p_{Ci} + p_{BSi} + p_{TSi}\right) - C_{si}\left(g_{CHPi} + g_{BSSi}\right)$$

Various constraints are considered to handle the energy balance and technological constraints on the resources:

$$\forall i = 1, \ldots, T/t$$

- Cumulative internal demand is satisfied:

$$
\begin{aligned}
&g_{PVEi} + g_{PVCi} + g_{CHPEi} + g_{CHPHi} + g_{CHPCi} + g_{BSEi} + g_{BSCi} + g_{TSHi} + g_{TSCi} \\
&\qquad + p_{Ei} + p_{Hi} + p_{Ci} \ge D_{Ei} + D_{Hi} + D_{Ci}
\end{aligned}
$$

- Electric demand is satisfied:

$$g_{PVEi} + g_{CHPEi} + g_{BSEi} + p_{Ei} \ge D_{Ei}$$

- Heating demand is satisfied:

$$g_{CHPHi} + g_{TSHi} + p_{Hi} \geq D_{Hi}$$

- Cooling demand is satisfied:

$$g_{PVCi} + g_{CHPCi} + g_{BSCi} + g_{TSCi} + p_{Ci} \geq D_{Ci}$$

- PV constraint: Total power generation = Total PV dispatch:

$$g_{PVEi} + g_{PCi} + g_{PVBSi} = G_{PVi}$$

- CHP capacity constraint: Total CHP generation $\leq$ Total CHP dispatch:

$$g_{CHPEi} + g_{CHPHi} + g_{CHPCi} + g_{CHPSi} = G_{CHPi}$$

- Electric storage flow constraint: Total power flows through electric energy storage sources $\leq$ Mean power capacity of electric energy storage sources:

$$g_{PVBSi} + g_{BSEi} + g_{BSCi} + g_{BSSi} + p_{BSi} \leq P_{BSi}$$

- Thermal storage flow constraint: Total power flows through thermal energy storage sources $\leq$ Mean power capacity of thermal energy storage sources:

$$g_{TSCi} + g_{TSHi} + p_{TSi} \leq P_{TSi}$$

- Electric storage charging constraint: Total electric storage charging during interval *i* $\leq$ Energy within electric storage devices at the end of interval *i* :

$$g_{PVBSi} + p_{BSi} \leq l_{BSi}$$

- Thermal storage charging constraint: Total thermal storage charging during interval *i* $\leq$ Energy within thermal storage devices at the end of interval *I* :

$$p_{TSi} \leq l_{TSi}$$

- Electric storage discharging constraint: Total energy discharged by electric storage during interval *i* $\leq$ Energy within electric storage at the end of interval $(i-1)$:

$$g_{BSEi} + g_{BSCi} + g_{BSSi} \leq l_{BS(i-1)}$$

- Thermal storage discharging constraint: Total energy discharged by thermal storage during the interval

$$g_{TSHi} + g_{TSCi} \leq l_{TS(i-1)}$$

- Electric storage power flow: Energy within electric storage devices at the end of interval *i* = Energy within electrical storage at the end of interval $(i-1)$ + Cumulative charging energy during interval *i* – Cumulative discharging during interval *i* :

$$l_{BSi} - l_{BS(i-1)} = g_{PVBSi} + p_{BSi} - g_{BSEi} - g_{BSHi} - g_{BSCi} - g_{BSSi}$$

- Thermal storage power flow: Energy within thermal storage devices at the end of interval *i* = Energy within thermal storage at the end of interval $(i-1)$ + Cumulative charging energy during interval *i* – Cumulative discharging during interval *i* :

$$l_{TSi} - l_{TS(i-1)} = p_{TSi} - g_{TSHi} - g_{TSCi}$$

- Upper and lower bounds of decision variables

The relative sizes and DER types can strongly affect profiles, including whether or not the SOC produces excess power. The following figures demonstrate the SOC profile for two different configurations. The profile on the left corresponds to the case where CHP capacity is the significant relative to other resources and the one on the right corresponds to the case where PV and electric storage are the significant resources relative to others.

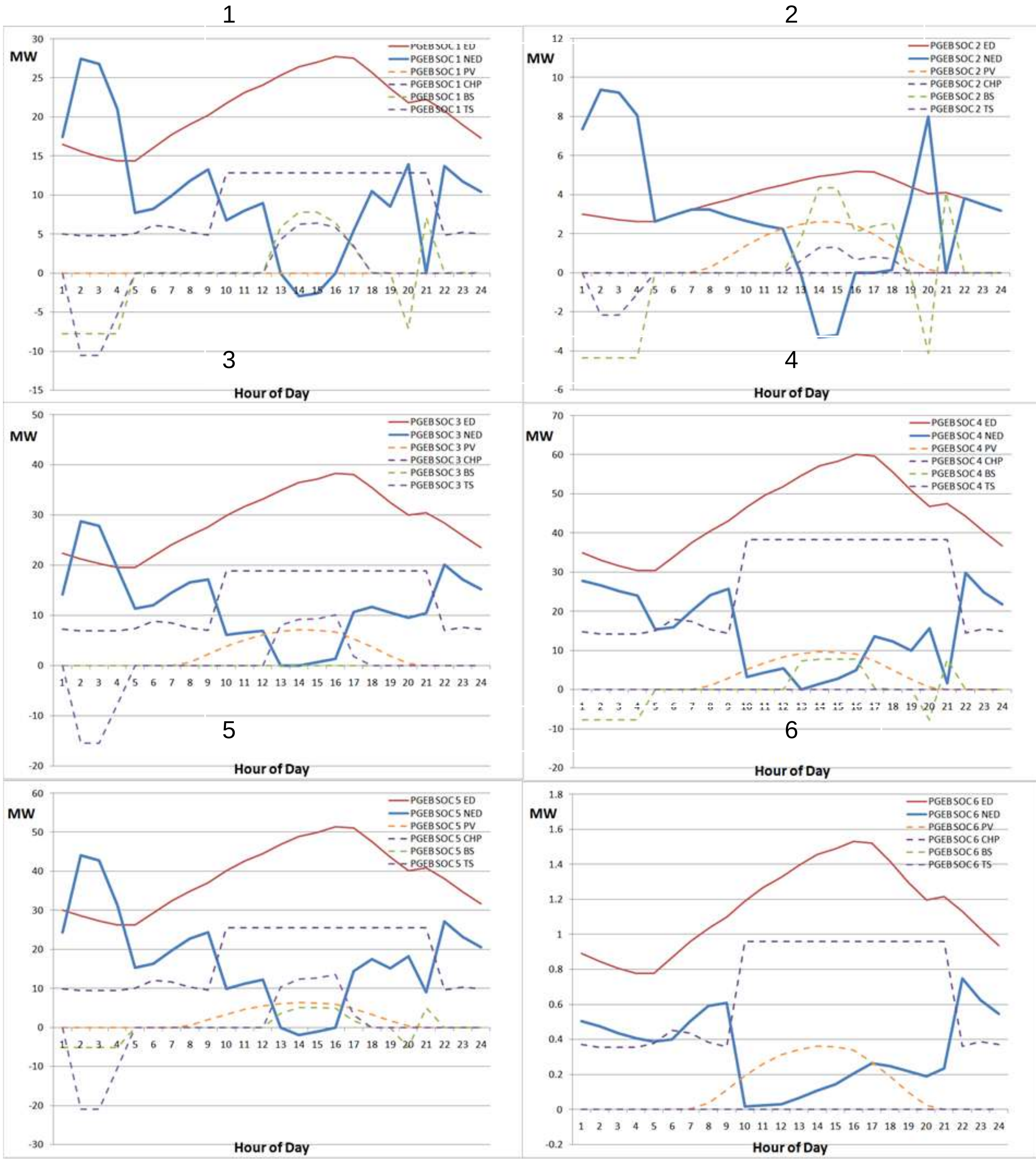


Exhibit 3-33: SOC Profiles for six technology bundles on 07/22/2020, PGE-Bay

Exhibit 3-33 shows the actual electric demand, net electric demand, PV generation, CHP generation and net battery storage and thermal storage outputs for the six technology bundles for PGE-Bay on 7/22/2020. For each diagram, the red line depicts load at each of the SOC configurations, the yellow line shows PV generation; the purple line shows the Central Heat and Power bundle generation; the green line shows the battery storage and the light purple line shows thermal storage. Left to right the technology bundles are: 1) CHP + ES + TS; 2) PV + ES + TS; 3) PV + CHP + TS; 4) PV + CHP + ES; 5) PV + CHP + ES + TS; 6) PV + CHP. Cooling demand is high for the chosen day, and a sharp spike is noticeable during night off peak hours.

3.5.3 SOC Variability

The variability in load profile, electricity price, PV production and temperature introduces variability in SOC profile. Because the SOC model is complex and can act to shift demand / production across hours in response to changes in wholesale prices, it has a large variability in proportion to its absolute size. It also exhibits negative cross correlations across time due to the time shifting nature of its behavior.

Uncertainty for SOC measures the total fluctuation in net charging/discharging projected for the 2020 resource, assuming each input parameter is forecasted from 2020 values. Exhibit 3-34 shows the standard deviation, maximum and minimum of SOC net-demand for the state of California. Since the net demand is negative during net generation, the volatility metric is meaningless and is not shown.

Metric	5 Minute Profile	Hourly Profile
Standard Deviation	307.7 MW	322.8 MW
Maximum Value	1514.4 MW	1514.4 MW
Minimum Value	-417.7 MW	-417.7 MW

Exhibit 3-34: Self Optimizing Customer Generation Profile Variability Descriptions

As shown in Exhibit 3-35, the KEMA team developed the forecast uncertainty associated with the Self Optimizing Customer profile by comparing actual to forecasted values for the latest year that data was available[55]. For regulation purposes, the SOC profiles are split into demand and generation components. For the computation of commitment and dispatch requirements the negative of the SOC net-demand is added to generation. Self Optimizing Customer forecast error does not appear to vary by clearness index because there is a small component of PV compared with other generation and because storage smoothes PV generation associated with this resource.

[55] California Commercial End Use Survey, California Energy Commission, http://www.energy.ca.gov/ceus/

Metric	0 ≤ CI ≤ 0.2	0.2 ≤ CI ≤ 0.5	0.5 ≤ CI ≤ 0.8	0.8 ≤ CI ≤ 1
SOC net generation Forecast Error Percent of Maximum, *No Visibility case*	8.4%	8.4%	8.4%	8.4%
SOC net generation Forecast Error Percent of Maximum, *Visibility Case*	7.0%	7.0%	7.0%	7.0%
SOC net demand Forecast Error Percent of Maximum, *No Visibility case*	11.2%	11.2%	11.2%	11.2%
SOC net demand Forecast Error Percent of Maximum, *Visibility Case*	9.3%	9.3%	9.3%	9.3%

Exhibit 3-35: SOC Profile Forecast Error

When compared with volatility, forecast error is relatively small. In Phase 2, the distributed storage forecast error is then used to calculate Load Following and Regulation Reserve Requirements both with and without visibility.

3.6 Plug-in Electric Vehicle Models

- Custom charging stations offered by several companies include sophisticated technology to implement demand response based on signals from the utility. They also contain technology to allow the EV's to act as distributed storage for the grid. This technology, known as Vehicle to Grid (V2G), could in theory be used to regulate voltage on the grid or to meet peak demand without the need for peaking generators.

- There is uncertainty around the feeder and transformer impacts of PEV charging in target roll-out markets, where PEVs will begin to penetrate the market. Sub-system impacts are of special concern due to expectations about EV clustering.

- Utilities and industry groups are conducting extensive research around customer commuting distances, likely driving and charging patterns, and PEV battery characteristics to predict and address these concerns.

Peak load impacts are contingent on PEV charging times of day and durations. The possibility of concurrent charging and regional clustering of PEVs has given rise to concerns about transformer overloads. In particular, if a transformer is subject to three or four PEVs charging at the same time, it could easily fail. Where the likelihood of charging during peak period increases, the threat of transformer failures increases.

- The PEV market is in an early state of manufacturer design and policy, rate, and infrastructure development and integration.
- Key drivers of commercial viability include: development and price of battery technology, the integration of metering and charging capabilities, and the availability of customer and fleet charging options.
- Federal targets of reaching 1 million PEVs by 2015 could take as long as 2019 to reach, depending on the progress of overcoming price and infrastructure barriers.

The load profiles generated below are an aggregate of the 1-year study conducted by Southern California Association of Governments (SCAG), where 1144 days of GPS drive cycle data was collected. The dataset was split into weekdays and weekends. And the aggregate load profiles were created assuming the 90% power electronics and 90% battery charging efficiencies. The per-PEV load profiles were generated by dividing the total load by the number of PHEVs in the simulation – in aggregate, this per-PEV load profile should be scaled by the assumed number of PEVs.

PEV Load Profiles Sampling Period

Interpolated hourly averages were generated from 1-minute load simulations. Thirty minute and 5-minute averages were also generated to determine how well they fit with the higher-resolution data. The 1-hour averaged load profiles captured the aggregate fleet load magnitude and shape closely. However, significant 5-minute stochastic behavior was present in the data, so random short-duration variability should be added on top of vehicle load. A comparison of filters used for the PEV profiles is provided in Exhibit 3-36. As PEV numbers increase, confidence in the hourly estimate increases, and thus the 5-minute variations (sigma) will become smaller. The most uncertainty in PEV load was found during the lunch hour. In Exhibit 3-37, the standard deviations for travel samples are provided.

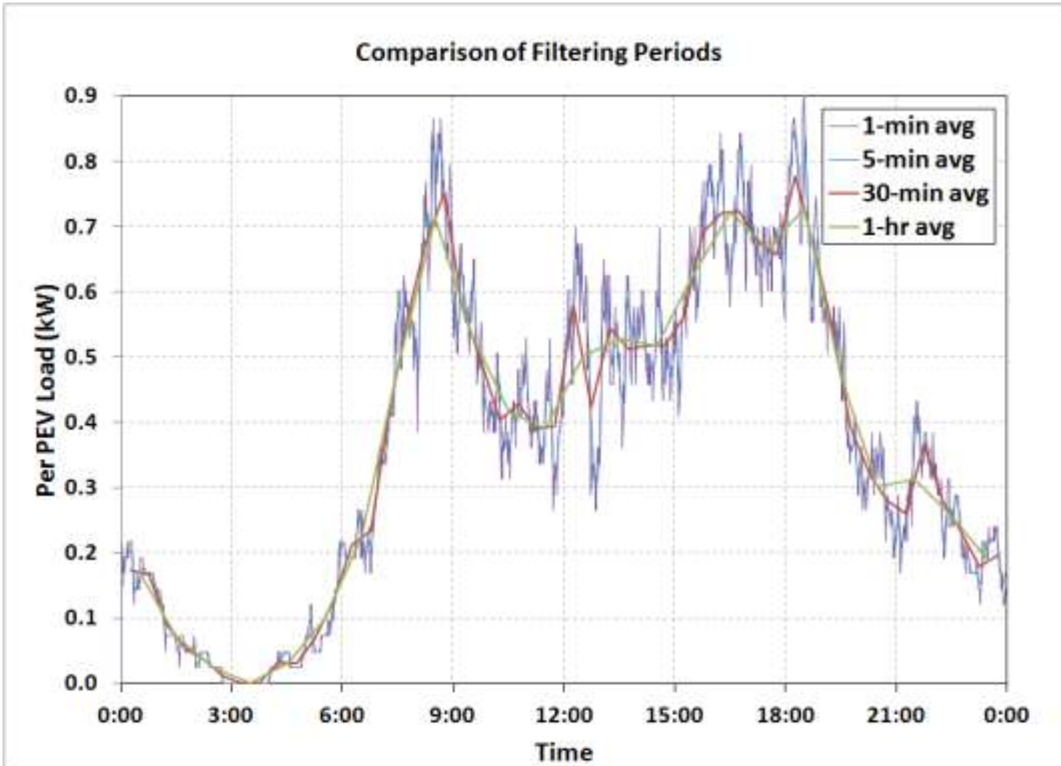


Exhibit 3-36: Comparison of vehicle load profiles when different simulation time steps are used. The 5-minute and 1-minute load profiles match closely.

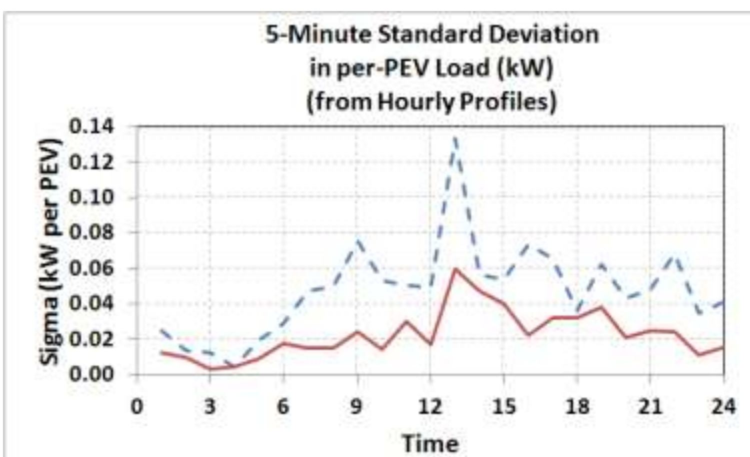


Exhibit 3-37: Standard deviation for GPS travel sample. Per vehicle, the uncertainty in aggregate vehicle load (sigma) decreases as more vehicles load the power grid. 1000-PEV set (solid red), 274-PEV set (dashed blue)

To assess the variation in load caused by vehicle charging power, the charging rates for varied for 3 PEV models – the Chevy Volt, Nissan Leaf, and Plug-In Prius. Under opportunity-charging conditions, load profiles converge for vehicles with battery packs capable of serving 40+ miles. Lower opportunity charging rates decrease extreme load peaks; smaller battery packs, like the 14-mile Prius battery pack, exhibit slightly smaller loads overall. Charging profiles for various automobile types are compared in Exhibit 3-38.

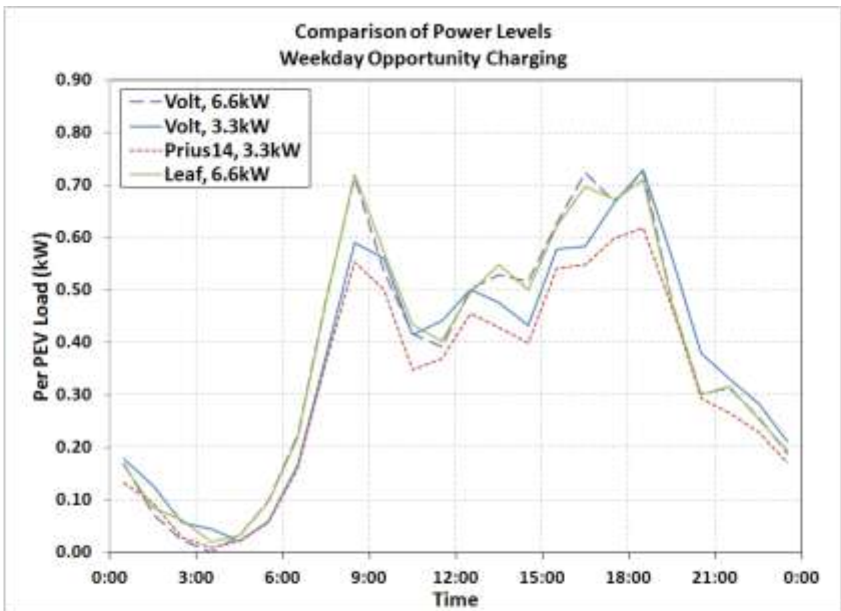


Exhibit 3-38: Comparison of Power Levels

The largest uncertainty in predicting future PEV charging profiles is the percentage of PEVs which opportunity charger versus charge only overnight. Therefore, aggregate load profiles could be modeled as the sum of the 2 distinct load profiles:

$$P = \pi(\alpha,\beta)\sum_{k=1}^{N} \mathrm{P_{opp}}(\mathrm{J,L,u})_\mathrm{k} + (1-\pi(\alpha,\beta))\ \sum_{k=1}^{N} \mathrm{P_{ovn}}(\mathrm{J,L,u})_\mathrm{k}$$

Where P_{opp} and P_{ovn} are the opportunity and overnight load profiles, respectively, both of which are a function of J, the battery capacity, L, the charging power level, and u, utility influences; π is the percentage of PEVs which opportunity charge, and is a function of α, public infrastructure availability (0-100%), and β, behavior of the PEV owner (0-100%); N are the total number of PEVs. A comparison of P_{opp} and P_{ovn} are shown in Exhibit 3-39.

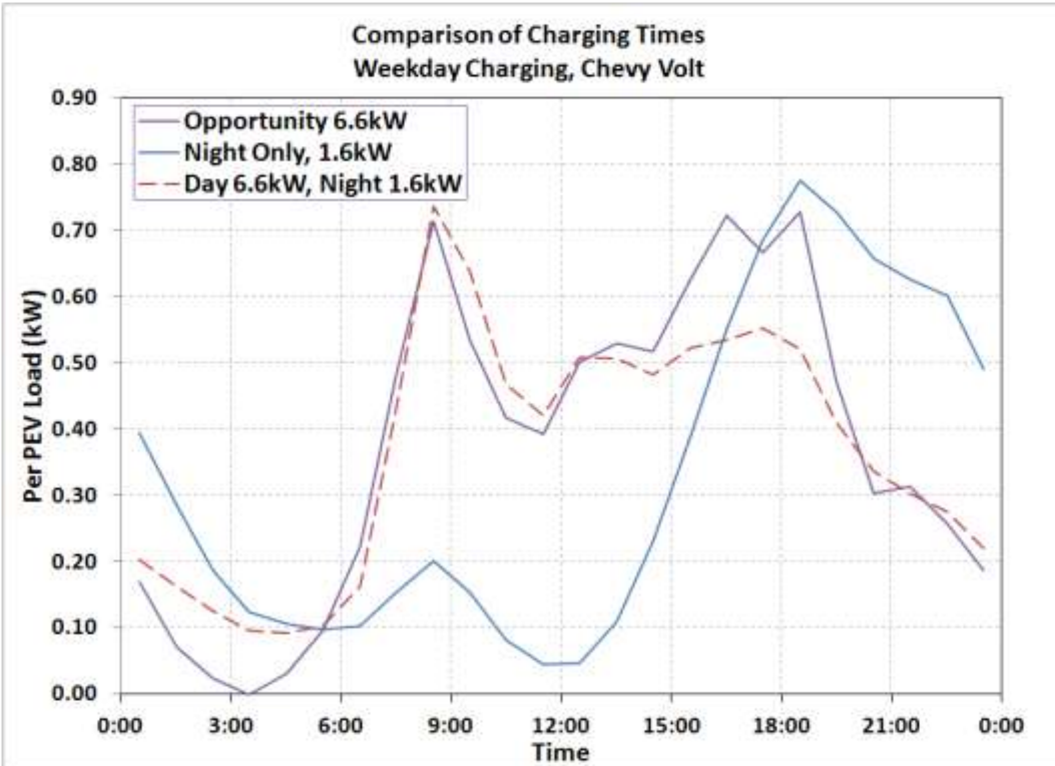


Exhibit 3-39: Comparison of basic P_{opp} and P_{ovn} charging profiles

To illustrate the point that average battery size has a relatively small impact on the overall charging profiles, we ran the same scenario assuming 1.6 kW overnight charging, with Chevy Volts and Plug-In Priuses. As seen in Exhibit 3-40: the duration of overnight charging increases later into the night. Larger battery packs (such as the Nissan Leaf) would likely not increase over the Volt profile, since most drivers would not utilize more battery capacity.

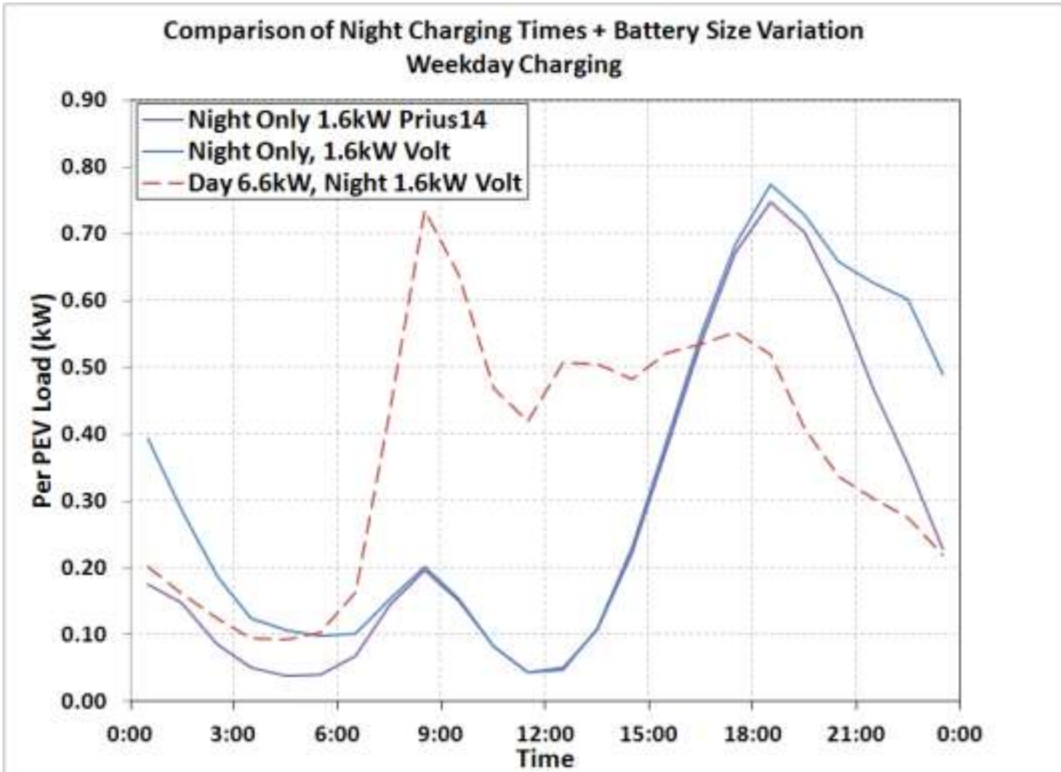


Exhibit 3-40: Comparison of overnight charging profiles for different battery sizes - daytime load shown for comparison to nighttime-only profiles

Weekend profiles were significantly different from their weekday counterparts unless they are charged overnight only. In the overnight-only case, the charging profiles were markedly similar. However, if daytime opportunity charging is available, a unique mid-day peak is observed. The magnitude of the weekend peak is smaller, and the duration of the peak is slightly longer as people enjoy the weekend. This behavior is similar to how utility load profiles vary from weekday to weekend; as shown in Exhibit 3-41.

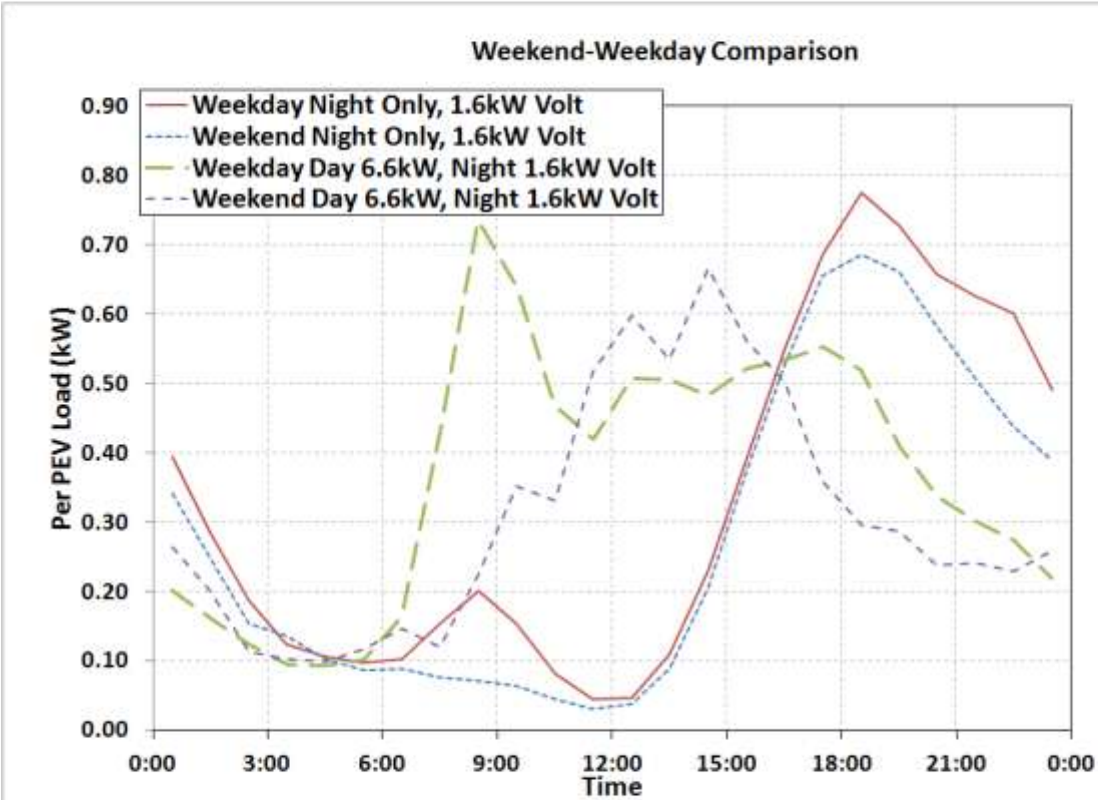


Exhibit 3-41: Comparison of weekend and weekday charging profiles

Parameters that define the weekday load shape are shown in Exhibit 3.42:

1) Morning peak magnitude
2) Evening peak magnitude
3) Evening peak duration
4) Delays due to congestion
5) Early morning magnitude
6) Utility Effects (not shown)

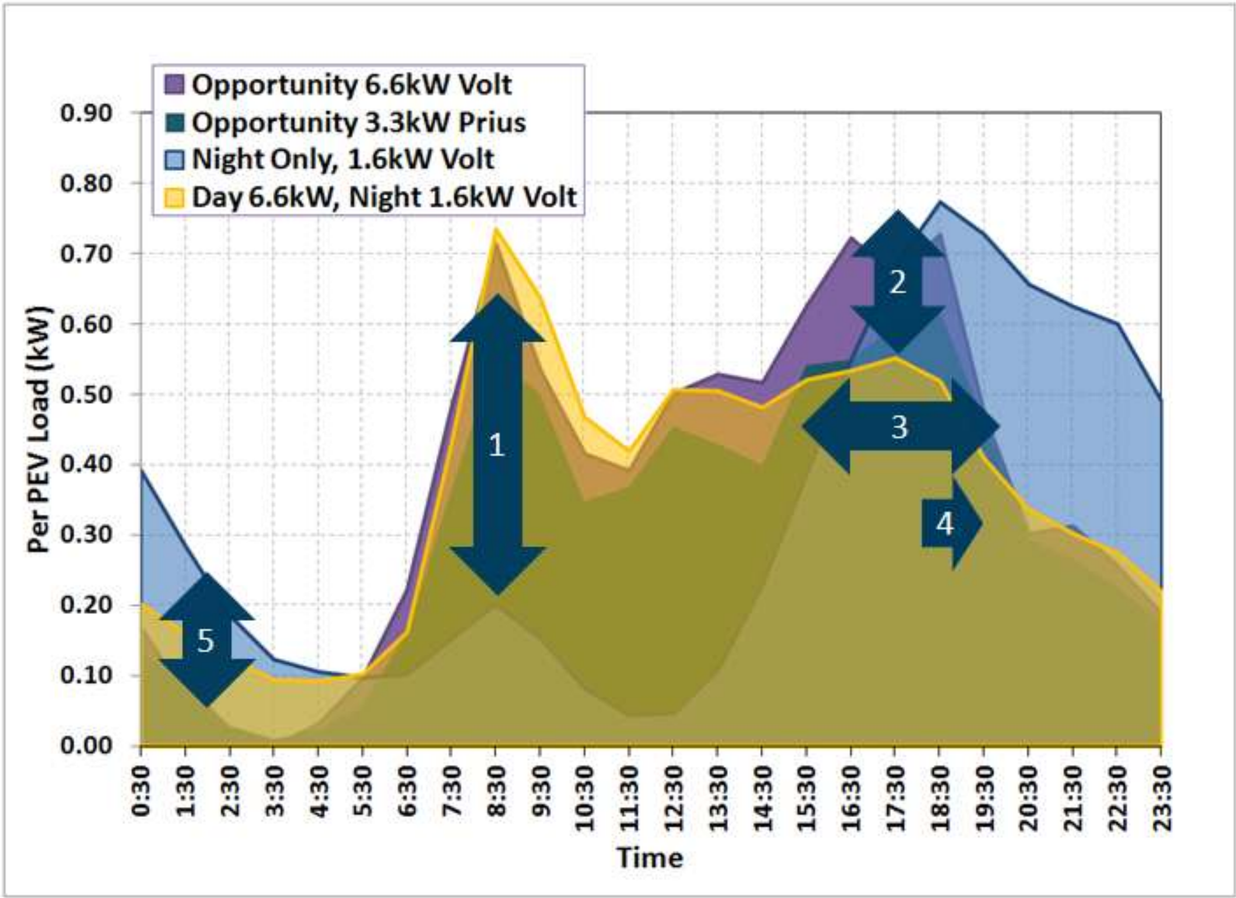


Exhibit 3-42: Illustration of parameters that characterize a daily PEV load profile

Consolidation and Annualization

The PLEXOS modeling requires converting the daily profiles into full annual profiles. There were four steps to this process:

1) *Consolidate to four load profiles by charging strategy*. We consolidated the profiles around the four charging strategies: opportunity, night and day, night only, and time of use. Each of the profiles represents a composite of the EV model specific profiles. Tracking the effects of different types of EVs would add computational complexity without many benefits. The primary difference between the profiles is during off-peak times. The time of use profile is an adjustment to the night only strategy that assumes a time of use rate goes into effect after 9:30 PM.

2) *Create a nominal annual profile.* This step matched the weekend and weekday profile to form a nominal week. The Saturday morning night only charging profile

is a weekday charging pattern. Likewise, the Monday profile reflects a weekend charging pattern. The nominal weekly profiles are projected over the course of a year to create a nominal annual profile.

3) *Add seasonal variation.* Roadways typically have larger traffic volumes in the summer and lower traffic volumes in the winter. The seasonal traffic variation depends largely on the surround land use. Roads near schools, for example, see larger traffic volumes when school is in session. Overall, traffic tends to be heavier in the summer months and lesser during the winter months. We used a sine wave to approximate this effect, letting the summer peak have up to 10% higher demand and the winter have up to 10% lower demand.

4) *Add day of week variation.* Typical traffic patterns show larger traffic volumes during the middle of the week than over the week end. Mondays and Fridays tend to be in between. The assumption here is the same as in the previous step: 10% higher Tuesday through Thursday.

5) *Assume forecast errors using travel time variation.* The principal driver for the start of the charge cycle is the time a vehicle arrives at home and is ready to charge. The variation of when this occurs reflects stochastic changes in travel times. These changes are due to events such as weather, sporting or cultural events, and traffic accidents. Nearly all travel time variations are within 30 minutes. This leads to a 2% forecast error.

The assumptions in points 3), 4), and 5) can be refined using the California Department of Transportation traffic monitoring data. A thorough analysis of these data was not possible within the scope and schedule of this project.

3.6.1 Electric Vehicle Variability and Forecast Uncertainty

Uncertainty for Electricity Vehicle charging measures the total fluctuation in projected load for the 2020 resource, assuming each input parameter is forecasted from 2020 values. The standard deviation, volatility, maximum and minimum of the 5 minute and hourly profile of the net demand profile of EV is shown in Exhibit 3-43.

Metric	5 Minute Profile	Hourly Profile
Standard Deviation	182.14 MW	180.7 MW
Volatility or Standard Deviation/Average	49.8%	49.4%
Maximum Value	882.1 MW	835.2 MW
Minimum Value	61.8 MW	72.9 MW

Exhibit 3-43: Electric Vehicle Variability Descriptions

Electric Vehicle profiles are then netted against load to create an adjusted load profile.

3.7 Load Assumptions and Adjustments

Load was assumed to be the same starting point as the 2020 High Load Case used in the LTPP High Load Case. Using the High Load 33% RPS LTPP Scenario as defined in the CPUC Scoping Memo assumptions, KEMA made the following adjustments to High Case DER Penetration Load shown in Exhibit 3-44:

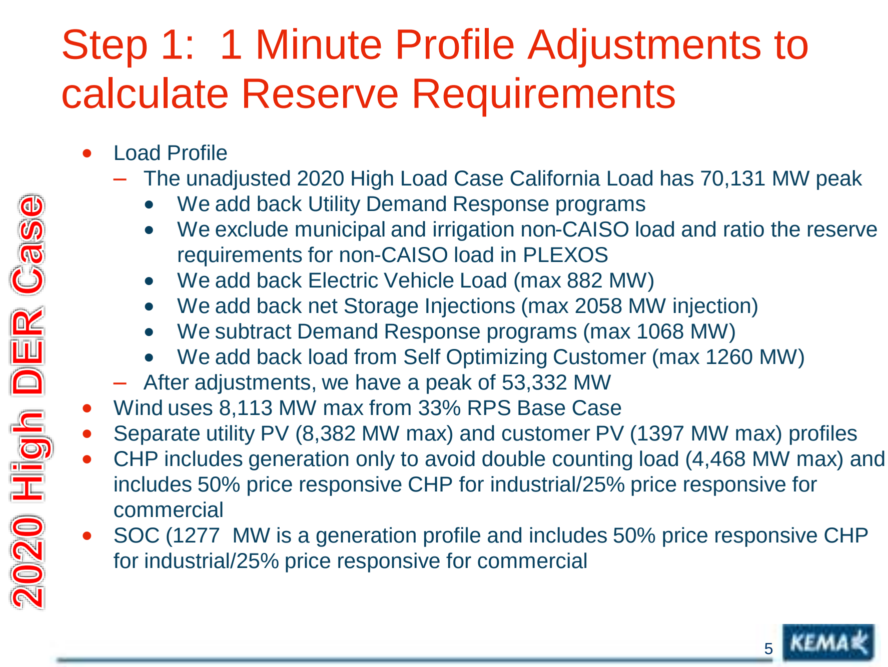


Exhibit 3-44: Adjustments to high load 33% RPS profiles

Similar adjustments were made for each Medium and Low penetration case.

Working with the CAISO, The KEMA team developed the forecast uncertainty associated with the load profile by comparing actual to forecasted values for the latest year that data was available.

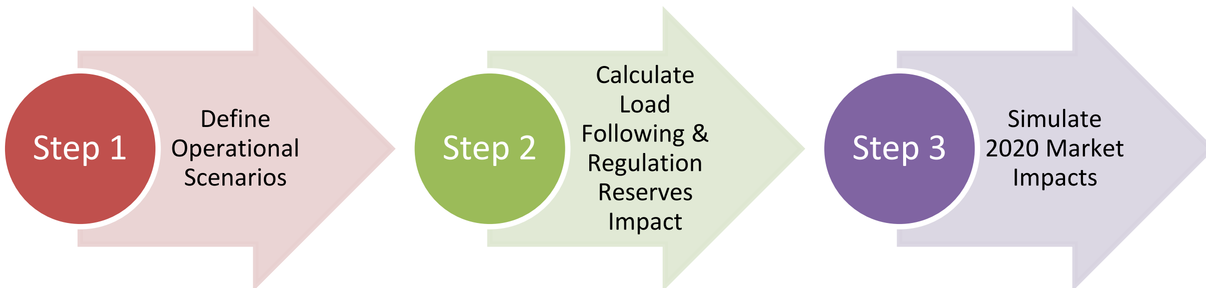
Metric	Spring	Summer	Fall	Winter
Standard Deviation, 5 Minute; visibility & no visibility case	114 MW	114 MW	114 MW	114 MW
5 Minute autocorrelation coefficient, p=1, visibility & no visibility case	0.86	0.92	0.90	0.85
Hourly autocorrelation coefficient, p=1 visibility & no visibility case	0.61	0.70	0.65	0.54
Standard Deviation, Hourly, *No Visibility*	1151 MW	1476 MW	1237 MW	1148 MW
Standard Deviation, Hourly, *Visibility*	1080 MW	1388 MW	1156 MW	1082 MW

Exhibit 3-45: Load Profile Forecast Error

Exhibit 3-45 shows various forecast parameters. When compared with Load volatility, forecast error is relatively small. In Phase 2, the Load forecast error is then used to calculate Load Following and Regulation Reserve Requirements both with and without visibility.

4. Phase 2: Simulate Impacts

To estimate the impact of DER profiles, KEMA focused upon a three-step process:



- In Step 1, KEMA developed operational scenarios as described in Section 4.1
- In Step 2, KEMA used the Pacific Northwest National Laboratories (PNNL) statistical analysis software to determine Load Following and Regulation requirements. The assumptions, methodology and process are described in Section 4.2.
- In Step 3, KEMA used the PLEXOS Solutions production simulation package and also consulted with PLEXOS Solutions to assist in running simulation of markets for the study year. Results are described in Section 4.3.

In Appendix B, we provide a description of the Market Price Referent (MPR) defined in the CPUC Scoping Memo compared to actual 2011 data.

4.1 Step 1: Define Operational Scenarios

The 2020 Study Year was chosen to correspond to the target year for achieving 12,000 MW of Distributed Energy Resources and the target year for achieving 33% of power procurements from renewable resources[56].

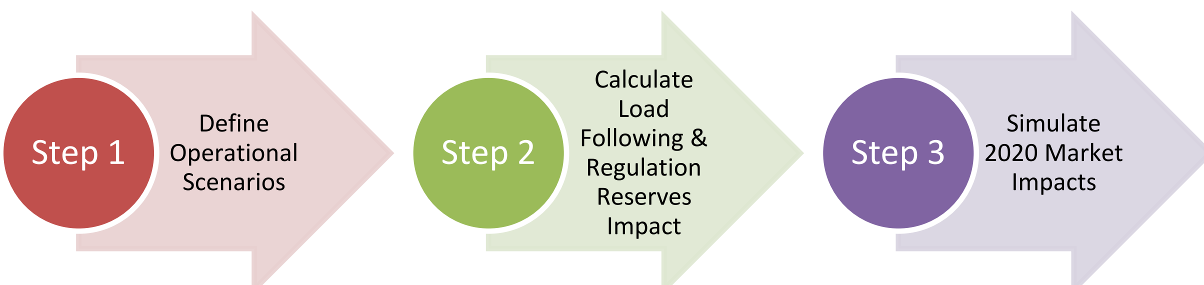
In defining simulation results, there were several areas of investigation:

- What is the load following and regulation requirement impact of increased DER penetration?

[56] http://www.jerrybrown.org/Jobs for the Future and PUC Section 399 11-399 20. Renewable Portfolio Standards require investor-owned utilities, electric service providers, and community choice aggregators to increase procurement from eligible renewable energy resources to 33% of total procurement by 2020.

- What are the production cost benefits of monitoring and forecasting DER uncertainty?
- What are the production cost benefits of direct control of DER variability?
- What is the impact of variability of distributed energy resources on load following and regulation requirement procurement?
- How does increased ability to monitor and forecast load following and regulation requirement impact load following and regulation reserve procurement?
- How is load met with increased DER penetration?
- What is the cost impact to CAISO load?
- How does DER impact the Renewable Portfolio Standard in 2020?

4.2 Step 2: Calculate 2020 Load Following and Regulation Requirements



A key driver in Step 2 is the determination of additional load following and regulation requirements required due to variability controlled by DER and uncertainty reduced by monitoring and forecasting DER. NERC defines regulation as purchased capacity and energy required continuously to balance generation and load following as the provision of generation capacity “to meet daily and hourly load variations”[57]. Increasing variable resources or resource currently not “visible” creates the need for more Load Following and Regulations to adjust for fluctuating generation or load. Creating a more accurate forecast, monitoring and control,

[57] NERC, Interconnected Operations (Ancillary) Services: Workshop on Definitions and Requirements for Managing Unbundled IOS, Palm Beach Gardens, FL, June 19-20.

reduces the cost of meeting load following and regulating requirements[58]. Note that there may be additional re-dispatching which reduces the overall production cost. These are captured in production cost simulations.

In the discussion that follows, we utilize prior work by Pacific Northwest National Laboratories (PNNL) to determine Load Following and Regulation requirements for DER profiles in various combinations[59]. In the sections that follow, KEMA describes the inputs and methodology used for the calculation of load following and regulating reserve requirements in Section 3.1. These inputs include a calculation of forecast error with and without visibility. Focusing on the major contributors to load following and regulating reserves, the KEMA team then examined the impacts of visibility for all DER, PV, Storage and Demand Response.

4.2.1 Load Following and Reserve Requirements Calculations and Methodology

4.2.1.1 Methodology

With each DER resource, we calculated two different measures: 1) variability without any visibility (monitoring and forecasting) of the distributed resource, and 2) uncertainty error when resources are monitored and forecasted. Exhibit 4-1 shows the high, low and mid penetration maximum levels of each DER resource, penetration assumptions, volatility drivers and the forecast error with and without visibility.

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[58] Note that the KEMA team did not adjust spinning and non-spinning reserve requirements in this study. These are determined according to NERC principles for the percent of load responsibility or largest credible contingency. Renewable ramping and variability are managed via load following and regulation. The cost of load following and regulation requirement may be more than the purchase price of the requirements. There may be re-dispatch costs that are not directly incorporated in the purchase of the regulation and load following. We use the PLEXOS model to simulate re-dispatch to meet alternate load following and regulation requirements.

[59] Integration of Renewable Resources: Technical Appendices for California ISO Renewable Integration Studies, October 11, 2010.

DER Profile*[60]	High DER (Max MW)	Mid DER (Max MW)	Low DER (Max MW)	California Penetration Assumptions	Variability Drivers	No Visibility forecast error[61]	Visibility Model Error[62]
PV	7812	4757	1747	Scaled according to ISO scenarios for distributed PV	Clear Sky index and PV Technology.[63]	Varies by subtype and Clear Sky index: improvement is 20%	
CHP	4468	3092	1732	Based upon CEUS[64]	Prices, temperature, conforming load	6.8%	5.7%
SOC	1277	806	337	Based upon CEUS	Prices, temperature, conforming load	8.4%	7.0%
PEV	-882	-662	-625	Based upon research by NREL	Commute time and traffic congestion	1.5%	1.25%
Distributed Storage	-2808	-1920	-1033	Based upon CEUS	PV smoothing requirements and prices	Varies by subtype and Clear Sky index: improvement is 20%	
Demand Response	-2466	-1926	-1390	Based upon existing utility programs	Prices, load and temperature	6%	4%

Exhibit 4-1: California Penetrations, Assumptions, and Variability Drivers

For PV, 1) forecast error without any visibility into PV was determined by using existing T-1 persistence forecast (just using the last observation as the forecast for the next observation) developed in earlier work by CAISO[65]. We used the forecast error [(predicted–actual)/predicted] as a forecast model error. To obtain a reduced forecast error due to visibility

[60] Using the convention that PV, CHP, SOC are distributed generation resources with a positive impact and PEV, DES and Demand Response reduce or shift load with a negative number

[61] Stated as standard deviation ÷ average profile

[62] Percent of Profile variation improved through monitoring and forecasting.

[63] Clearness Index and Solar technologies used are described more fully in Section 1.2. The LTPP High Load Case is described in Track 1 Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator Corporation, R.10-05-006.

[64] California Commercial End Use Survey, California Energy Commission, http://www.energy.ca.gov/ceus/

[65] Track 1 Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator, Rulemaking 10-05-006.

of PV, we determined a model error in our Commercial, Residential and Distributed Utility PV models [(predicted – actual)/predicted] that can be reduced by forecasting and monitoring PV resources. The benefits of monitoring and forecasting PV is the difference in T-1 persistence forecast error and forecasted model error.

For CHP, SOC, Demand Response and Distributed Storage resource profiles, we used a model error (comparing actual to forecasted values) to determine reduction in forecast error without any visibility into the resources. To determine the forecast error associated with increased monitoring and forecasting, the KEMA Team reduced each forecast parameter (temperature, prices, etc) by 20% and then calculated a new, reduced forecast error to represent the benefits of visibility and monitoring each DER resource.

For Electric Vehicles, we estimated forecast error with no visibility to be based upon delays in charging time. For PEV visibility, we estimated forecast error reductions based upon improved traffic congestion models[66].

Beginning with the load profile in the 2020 high load Long Term Procurement Planning scenario[67], we adjusted the California loads for CHP electric load, SOC electric load, Electric Vehicle load, distributed storage load shifted from one time period to another, and demand response components. Without visibility, the load forecast error was determined from previous work by the ISO[68]. Forecast error improvement through monitoring/forecasting was calculated by weighting the original load forecast error by each DER load component and then determining a revised forecast error.

4.2.1.2 PNNL Methodology

KEMA utilized a stochastic process developed by the ISO and Pacific Northwest National Laboratory (PNNL) that employs Monte Carlo simulation to model hourly and sub-hourly ISO operations and markets. This model utilizes interaction of load and DER forecasted errors and

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[66] Tony Markel, Treiu Mai and Michael Kintner-Meyer, Presented at the 25th World Battery, Hybrid and Fuel Cell Electric Vehicle Symposium & Exhibition, November 5-9, 2010.

[67] Track 1 Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator, Rulemaking 10-05-006.

[68] Integration of Renewable Resources: Technical Appendices for California ISO Renewable Integration Studies, October 11, 2010.

variability[69]. From the model, hourly requirements for load following (up and down) as well as regulation (up and down) were used to calculate load following and regulation.

Key to our simulations and analysis are various assumptions operational assumptions about forecasting to reduce uncertainty and projected requirements for load following and regulation. With different ramp times for distributed energy resources, much of the load following and regulation requirements are procured in the Integrated Forward Market prior to the operating day. The ISO procures Regulation Up, Regulation Down, Spinning and Non-Spinning Reserves in this manner. The ISO then conducts the Residual Unit Commitment to adjust any commitments based upon short term forecasts.

Most of the wind and solar resources schedule in real time; creating a lack of visibility of those resources when load following and regulation are usually scheduled. Aside from the uncertainty associated with these resources, the real time schedules can create a situation where fossil units are "over-committed" to deal with uncertain resources. Below, we analyze how increased visibility can contribute to more efficient use of load following and regulating reserves.

[69]ibid

4.2.2 Load Following and Regulation Requirements

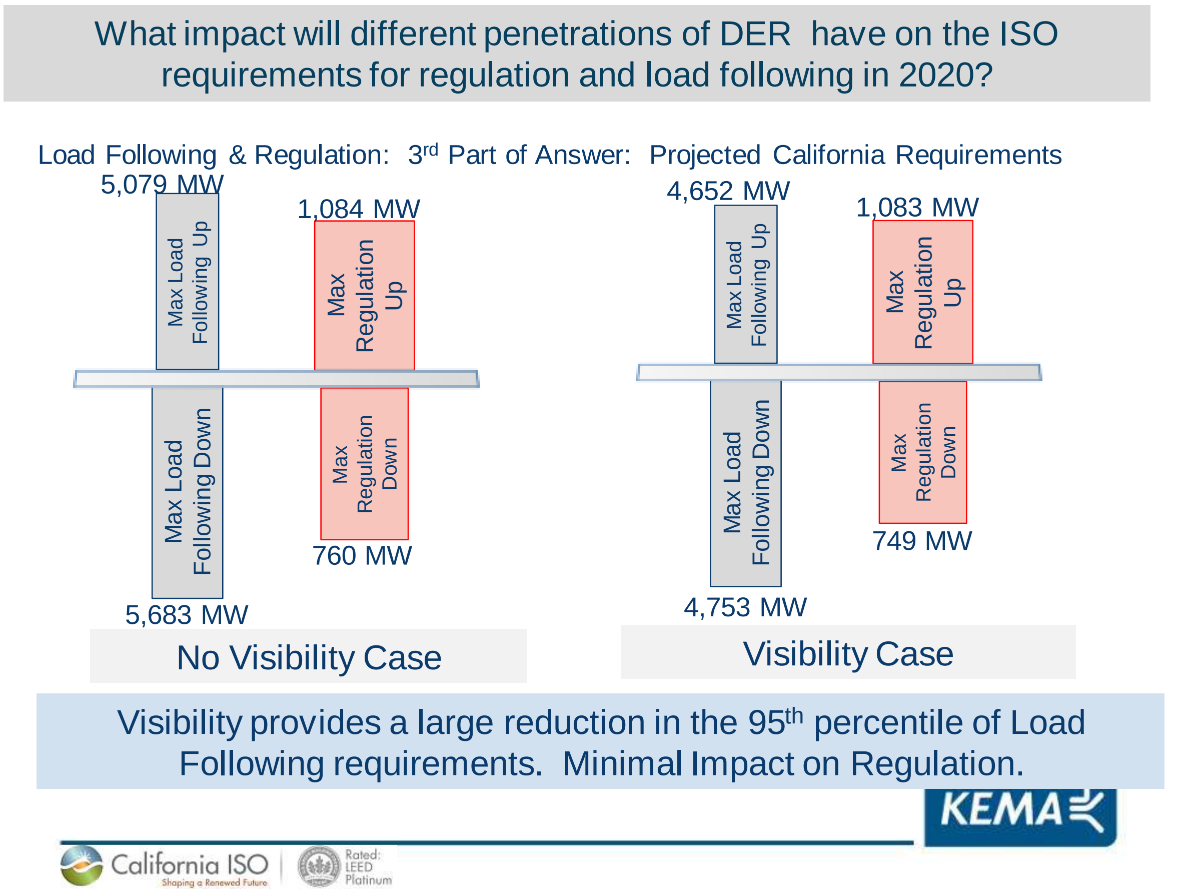


Exhibit 4-2: High DER Penetration: High Visibility Leads to Less Load Following and Regulation

As shown in Exhibit 4-2, note that maximum hourly Load Following Up Capacity requirements show 5,079 MW in the High DER penetration case. By monitoring and forecasting Load Following Up Capacity, a reduction of 427 MW is projected. Similarly, for Load Following down a reduction of 933 MW can be achieved. Regulation requirements had little change.

The Visibility and No Visibility Cases with all DER profiles across high, mid and low DER penetration cases are compared in Exhibit 4-3.

California Load Following and Regulation Requirement	2020 High DER Penetration		2020 Mid DER Penetration		2020 Low DER Penetration	
	Visibility	No Visibility	Visibility	No Visibility	Visibility	No Visibility
Load Following Down (Max MW)	4753	5683	4771	4991	4080	4550
Load Following Up (Max MW)	4652	5079	4672	4896	3875	3998
Regulation Down (Max MW)	749	760	722	724	694	705
Regulation Up (Max MW)	1083	1084	702	704	480	550

Exhibit 4-3: Comparing California Load Following and Regulation Requirements, High, Mid and Low DER Penetration Cases, All DER Profiles

DER profiles have different forecast uncertainty, ranging from a small forecast error for electric vehicle charging to much larger forecast error in PV. We analyzed the contribution of each DER profile with respect to load following and regulation by first analyzing all DER profiles in the High Penetration case and then removing each profile one at a time, and comparing results. The results are tabulated in Exhibit 4-4.

- We found that PV had the highest contribution to both Load Following and Regulation requirements as forecasted by the PNNL tool. The penetration for PV and resulting forecast error was highest for PV.

- Storage (modeled as smoothing PV) had significant contributions to regulation. Note that we only accounted for energy smoothing in our models.

- Demand Response reduced load and had the second most contributions to load following and regulation.

- We found that CHP, SOC and PEV had minimal contributions to increase in load following and regulation.

Profile	Load Following Down		Load Following Up		Regulation Up		Regulation Down	
	Visibility	No Visibility	Visibility	No Visibility	Visibility	No Visibility	Visibility	No Visibility
All DER	4753	5683	4652	5079	749	760	1083	1084
All except PV	4214	4799	4538	4844	549	550	790	791
PV Contribution	539	884	114	235	200	210	293	293
All except Demand Response	4364	5026	4518	5002	749	759	1082	1083
Demand Response Contribution	389	657	134	77	0	1	1	1
All except Distributed Storage	4613	5213	4528	4816	673	673	1040	1040
DES Contribution	140	470	124	263	76	87	43	44
CHP	No Appreciable Differences							
SOC								
PEV								

Exhibit 4-4: Contribution to California Load Following and Regulation Requirements for each DER Profiles, High DER Penetration Case

Comparing the results to prior studies, we note that the DER profiles that we project create more Load Following and less Regulation than in the baseline 2011 study as shown in Exhibit 4-4.

The largest contribution to reserve reductions came from PV; forecasting PV can reduce reserves required. Demand Response forecasting can improve uncertainties surrounding the effectiveness of response. Distributed Energy Storage forecasting can better predict the timing and size of the sharp spikes in net energy consumption expected to occur.

KEMA's profile models use more storage capacity to smooth PV fluctuations, creating less intra-five minute variability forecast error than 20 minute variability. This leads to an increase in Load Following requirements compared to decreases in Regulation Requirements in the High DER penetration case versus the 2011 baseline or LTPP High Load growth case. The variations in KEMA's DER profile modeling relies more on hourly parameters than real time parameters.

As shown in Exhibit 4-5, KEMA examined the ramps for DER profiles combined together to explain why there is a high requirement for load following and relatively low requirements for regulation. For each fluctuation (deviation from average), we measured the fluctuation range (as a percent of average) for 10 minute changes in the resource. Almost 100% of the deviations across 10 minutes occur in the bucket labeled 0-25%. So the size centers around 25% of the average and the frequency of deviations center around 10 minutes. While there were relatively small fluctuations in the 5 minute range, the bulk of fluctuations occur across the 10 minute time frame. Since regulation is used for 5 minute fluctuations, it follows that most of the fluctuations and requirements would require relatively more load following resources.

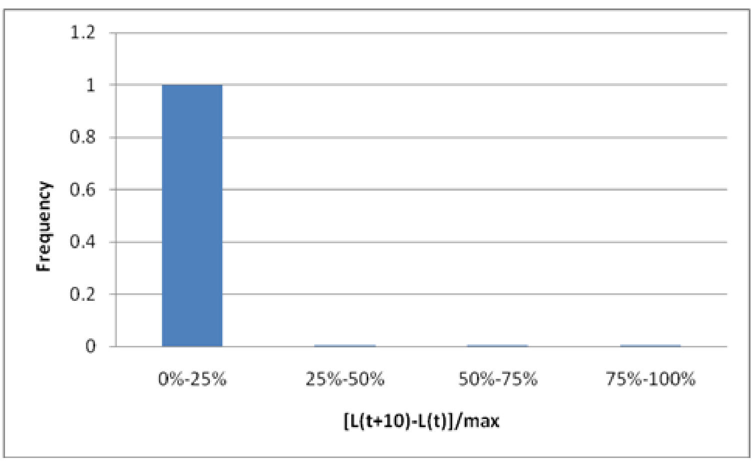
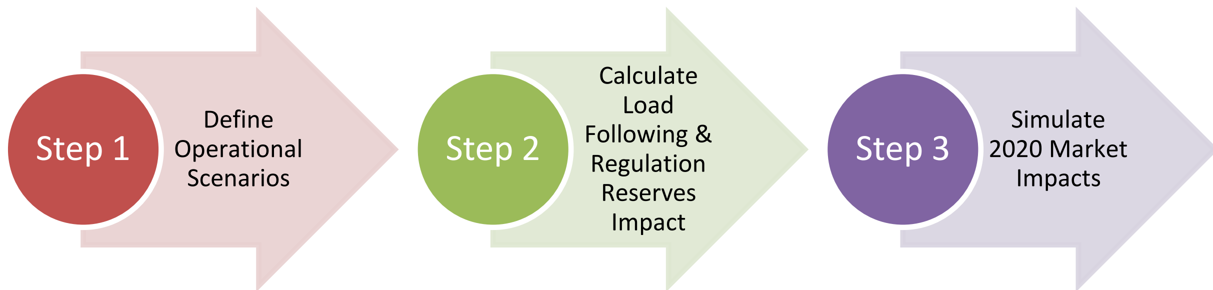


Exhibit 4-5: Profile Variability in Different Cases

Regulation requirements address those balancing needs within 5 minutes. To measure the amount of fluctuation of PV in the 2020 LTPP 33% case, we compared the probability density of the 10 minute fluctuations in profiles. We note that the bulk of the profile changes/variability occur in across 10 minutes, helping to explain why there is higher proportion of load following requirements.

4.3 Step 2: Market Simulation



4.3.1 Adjustments, Full Year and Expected Value Simulations

KEMA worked with Energy Exemplar (PLEXOS) to develop market simulations for the study year of 2020. We started with the High Load case from the 2010 LTPP Scenarios as shown in Exhibit 4-6.

Scenario	Region	Biomass/Biogas	Geothemal	Small Hydro	Solar PV	Distrib. Solar	Solar Thermal	Wind	Total
High Load 33% RPS	CREZ North CA	3	0	0	900	0	0	1205	2108
	CREZ South CA	30	1591	0	2502	0	3069	4245	11437
	Out of State	34	154	16	340	0	400	4149	5093
	Non-CREZ	271	0	0	283	1052	520	0	2126
	Total	338	1745	16	4024	1052	3989	9599	20763

Exhibit 4-6: 2020 LTPP 33% Renewable Generation in MWh before adjustment

From this starting point, KEMA removed the CHP and Small PV and Distributed PV resources, substituting the following distributed energy resource forecasts:

- CHP generation only
- SOC generation only
- Customer PV generation
- Distributed Utility PV generation

To perform market simulations, the KEMA Team conducted a Medium Term Simulation to review input and examine load, renewable profiles, Load Following and Regulation requirements and conformance with Renewable Portfolio Standards. In the second pass, the

KEMA Team conducted a Linear Programming Simulation to check for Load Following and [70]Regulation violations and determine any potential shortfalls of Load Following and Regulations. In the third pass, the KEMA Team did an 8784 hourly production cost using a leap year of 2020 simulation for the High and Low DER penetration cases for all DER profiles:

1) High DER penetration with no visibility into all DER profiles

2) Low DER penetration with no visibility into all DER profiles

To estimate the impacts of PV, Distributed Energy Storage and Demand Response, we set up two sets of simulation runs with and without visibility. For the first group of simulations, we compare all DER profiles but PV with no visibility and then all DER profiles but PV without visibility. Comparing these two sets of simulations will determine the market impact of PV forecasting. Comparing the simulations of all DER profiles with no visibility and the all DER buy PV profiles with no visibility will provide the impact of PV. Similarly, we set up simulations for Distributed Energy Storage and Demand Response. For sensitivity cases selected, the KEMA Team estimated expected production cost scenarios for the following scenarios[71]:

1) High DER penetration with visibility into all DER profiles

2) Low DER penetration with visibility into all DER profiles

3) High DER penetration ***with no visibility*** into all DER profiles but PV

4) High DER penetration ***with no visibility*** into all DER profiles but Distributed Storage

5) High DER penetration ***with no visibility*** into all DER profiles but Demand Response

6) High DER penetration ***with visibility*** into all DER profiles but PV

7) High DER penetration ***with visibility*** into all DER profiles but Distributed Storage

8) High DER penetration ***with visibility*** into all DER profiles but Demand Response

[70] For the cases run, there were no capacity shortfalls for load following and regulation requirements.

9) Mid DER penetration ***with no visibility*** into all DER profiles

10) Mid DER penetration ***with visibility*** into all DER profiles

4.3.2 Expected Production Cost

To estimate market costs, KEMA deployed a common technique to analyze similar days. We took daily loads for 2020 and fitted them to a lognormal probability curve. Then we determined representative days for various probabilities[72]:

- at 99% probability that load would be lower than peak 53,501 (7/22)
- at 75% probability that load would be lower than 41,200 MW (3/26)
- at 50% probability that load would be lower than 37,800 MW (10/18)
- at 25% probability that load would be lower than 34,600 MW (12/25)
- at 1% probability that load would be lower than 28,900 MW (3/26)

[72] As part of the analysis, we assumed no correlation with various weather events. We did not examine how the selected days overlay with days with high solar variability due to cloud cover and how that might impact PV generation.

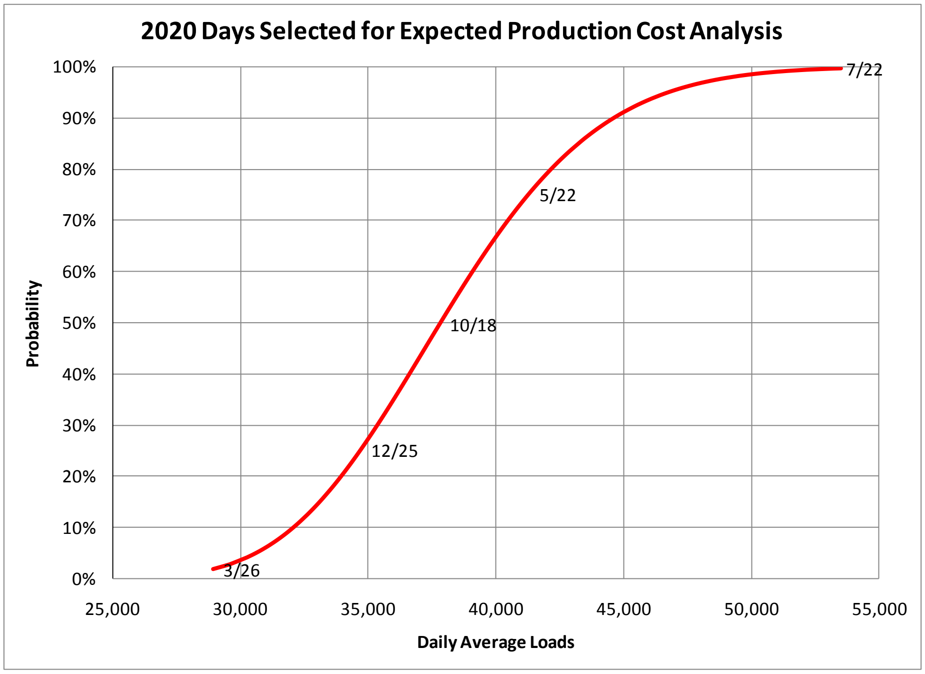


Exhibit 4-7: Days Chosen to Calculate Expected Production Cost Impact

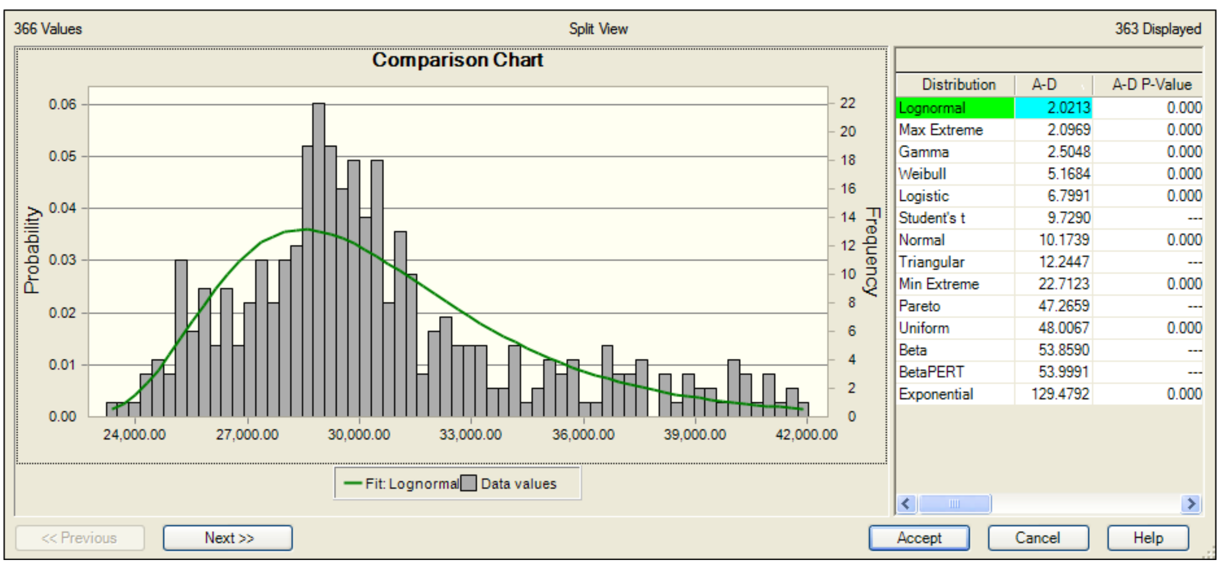


Exhibit 4-8: Fitting 2020 Load Curve to a Lognormal Distribution to Calculate Probability Weighting

As shown in Exhibit 4-8, the fitted lognormal curve had the best fit for load data[73].

4.4 Benefits of DER Visibility

- To determine the benefits of increased visibility into DER profiles, the KEMA Team simulated the production cost impacts of higher Load Following and Regulation Requirements without visibility (monitoring and forecasting) to lower Load Following and Regulation Requirements with visibility using PLEXOS production costing software.

- Of each of the six DER profiles analyzed above, we analyzed the case of ISO direct control of Dispatchable Demand Response (DDR) resource. We found net benefits of $197 million to send control signals and monitor performance of that resource. We did not analyze payments to those DDR resources.

After compiling the costs of visibility of the DER resources, the KEMA Team results are presented in Exhibit 4-9.

[73] Using Anderson Darling goodness of fit test. Stephens, M. A. (1974). EDF Statistics for Goodness of Fit and Some Comparisons, Journal of the American Statistical Association, 69, pp. 730-737.

What are the costs and expected benefits to increased DER visibility and control for CAISO Members?

DER Profiles – Visibility Comparison	Variability	Load Following/ Regulation Increase	Benefit from Visibility/ Control *	Cost of Visibility (Capital Expenditure / Operational Expenditure)***
1) All High DER - all DER profiles	Very High	Very High	$391M	$37M / $1.7M
a) All High DER – Demand Response contribution	High	High	$149 M	Included in 1)g)
b) All High DER – Distributed Energy Storage contribution	High	High	$63 M	$27.5 M/ $0.6 M
c) All High DER - PV contribution	High	High	$176 M	
d) All High DER – Central Heat/Power contribution	Low	Low	$3 M	N/A
e) All High DER – Self Optimizing Customer contribution	Low	Low		$2.5 M/ < $0.1 M
f) All High DER – Plug in Electric Vehicles contribution	Low	Low		N/A
g) Additional benefit from Control of DER	High	NA	$197 M**	$28M / $0.3M
2) All Med DER – all DER profiles	High	High-Med	$159 M	N/A
3) All Low DER – all DER profiles	Medium	Med-Low	$90 M	N/A

* Benefit seen in 2020 based on CAISO DER Monitoring and thus production cost savings in Millions of $/year
** Benefit seen in 2020 as a result of direct control of CAISO DER assets in Millions of $/year
***Communication infrastructure cost estimates are $65M in capital expenditure and $2M operating expenditure(based on approx 1M sample points (High Case) with a variety of technologies.

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Exhibit 4-9: Net Benefits to Visibility of DER Resources

In Scenario 1 we considered high DER penetration for all six DER profiles which exhibited very high variability and uncertainty due to forecast errors for all six profiles combined. This high variability and uncertainty leads to increased load following and regulation requirements. By monitoring all high DER profiles lower production costs of $391 million / year for 2020 are projected. The cost of monitoring communications for these profiles is only $65 million capital over the life of the investment with an annual operating budget of $2 million / year.

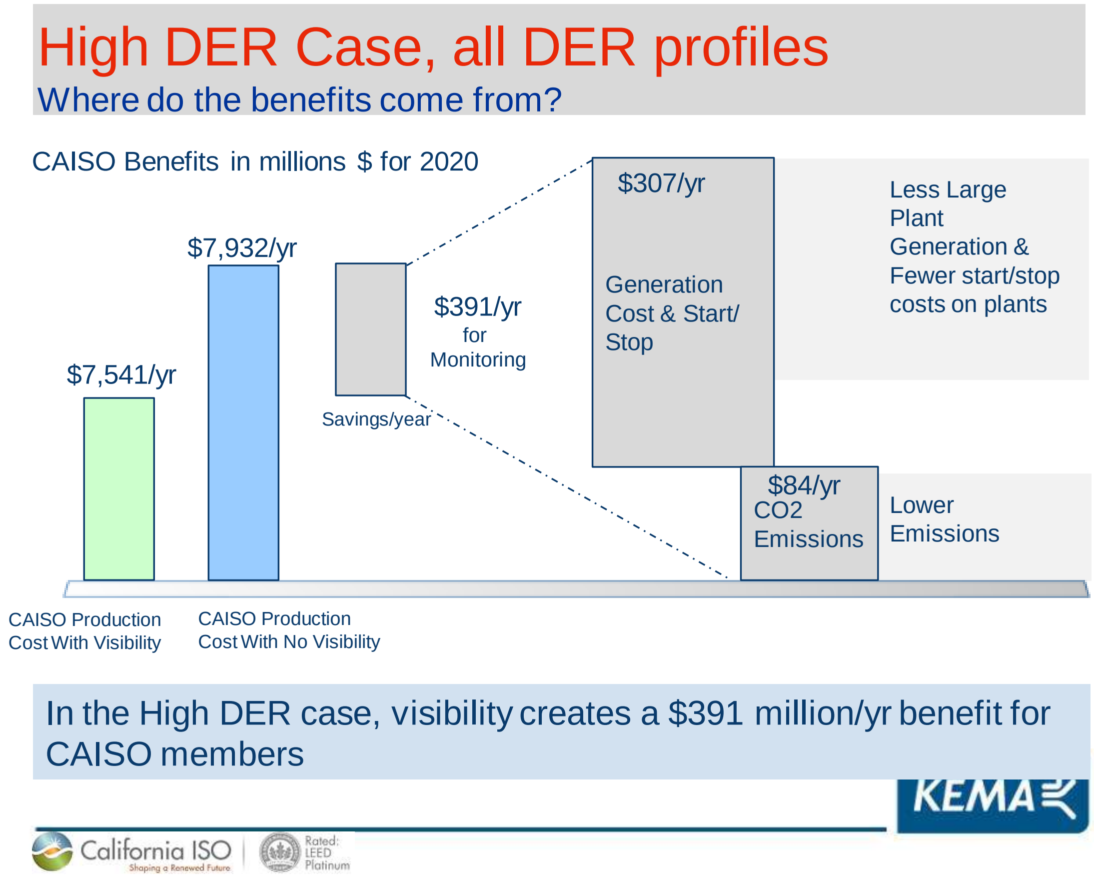

Exhibit 4-10: High DER Case: Where do the benefits come from?

As shown in Exhibit 4-10, the benefits are defined as production cost reductions from monitoring [74]. The $391 million / year in CAISO benefits include reductions in large plant generation and fewer starting/stopping of those units which were supplemented by Distributed Generation ($307 million a year). Because much of the DER generation comes from renewable sources, CO_2 emissions and costs to obtain permits is reduced ($84 million / year).

[74] We found that DER generation *reduces* central station power plant generation (and starting/stopping costs), *increases* energy export to non-CAISO members such as irrigation districts and municipalities and *reduces* the need for imports, freeing up internal resources to meet energy (load) instead of higher cost imports. After isolating the benefits of increased net exports accruing to non-CAISO members, the net savings in generation to CAISO members is $307 million / year in 2020.

DER profiles with the highest impact are those with the largest potential to vary in total, which is a combination of the inherent variability of a given resource, the degree to which aggregate resource behavior is correlated in time; and the penetration of the resource type. Monitoring the resource can improve the uncertainty and reduce the amount of load following and regulation requirements. Controlling the resource can reduce this variability. Using a similar methodology, the KEMA Team found that PV (Scenario 1c, Exhibit 4.4), Distributed Energy Storage (Scenario 1b, Exhibit 4.4) and Demand Response (Scenario 1a, Exhibit 4.4) are the largest contributors to net benefits from monitoring.

Other contributors include Combined Heat and Power (Scenario 1d, Exhibit 4.4), Self Optimizing Customer configurations (Scenario 1e, Exhibit 4.4), and Plug-in Electric Vehicles (Scenario 1f, Exhibit 4.4).

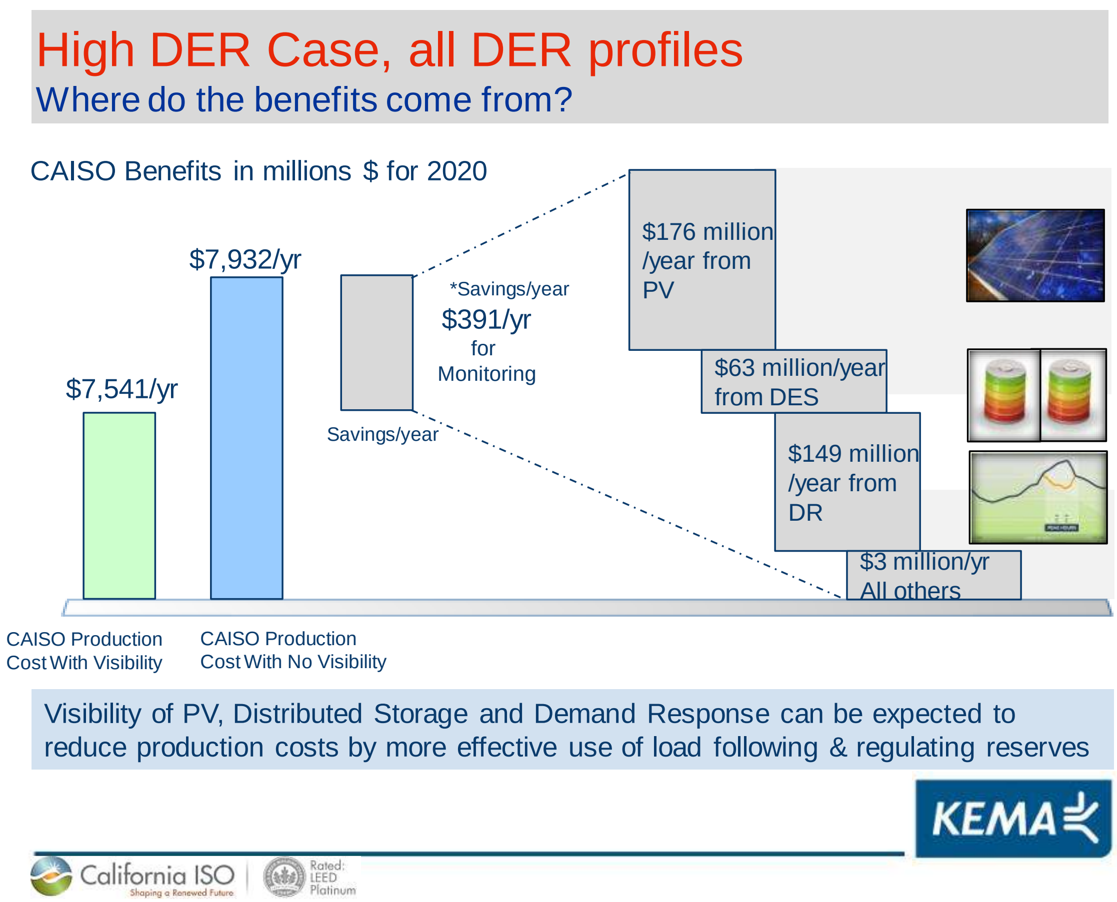

Exhibit 4-11: Which DER assets contribute the most benefits?

As shown in Exhibit 4-11, Distributed Energy Storage contributes about $63 million per year by 2020 by smoothing PV profiles and time shifting various load/resources. This is because PV has the largest contribution to supply relative to other DER and PV displaces more expensive generation alternatives. Demand Response contributes $149 million / year in cost savings by reducing load. PV has the bulk of the contribution to production cost savings ($176 million / year). CHP, SOC and PEV resources cost savings contribute to the remainder of the savings.

Because the level of penetration can vary, the KEMA Team also developed a Medium (Scenario 2, Exhibit 4.4) and Low Scenario (Scenario 3, Exhibit 4.4) with all DER penetrations. For the Low Scenario case the net benefits of improved visibility for all DER are projected to be $90 to $159 million / year.

In addition to the $149 million/year savings from forecasting Dynamic Pricing Demand Response, simulated benefits of Dispatchable Demand Response control was estimated to be about $197 million per year. These savings were due to increased "realization" or response of the total MW in the DDR program and less lag time in response to telemetry both at the start and at the end of the program.

5. Technology Road Map

In this section, KEMA identifies technical options for monitoring and controlling DER. Those technologies that offer adequate capabilities at least cost are assessed and cost estimates for DER monitoring are developed. These costs are the basis of the overall Benefit – Cost comparisons shown in the tables above. As noted in Chapter 4, Demand Response, Storage and PV generation resources provide the bulk of benefits to monitoring. For each of those DER resources, operational requirements are discussed in Section 5.1. In Section 5.2, current and future as well as gaps in Communication Architecture requirements are described. In Section 5.3, we discuss security requirements for DER communications. In Section 5.4, the Technology Road Map is introduced while in Section 5.5 communication cost components are presented and in Section 5.6 various communication configuration costs are estimated. Section 5.7 describes current communication programs for distributed energy resources. Section 5.8 provides a discussion of overall cost/benefits and Section 5.9 provides a description of business process impacts.

While this effort and report focus on the economic impacts of DER and DER visibility on two specific grid and market operations areas – load following and regulation – we qualitatively discuss the impacts of DER and DER visibility on other critical grid operational issues at a high level.

5.1 Operations Requirements for Distributed Resources

Operations requirements will help determine communication requirements for DER. Below we discuss distributed energy and renewable grid operational challenges for grid reliability and security, loading of DER and other grid components, voltage, contingencies, inertial response, market price dynamics and communication notches leading to requirements for communication architecture.

5.1.1 Grid Reliability and Security Related to DER

Small distributed energy resources can usually be served by a single-phase connection to the low-voltage grid without a detailed study. However, larger distributed resources require a three-phase connection, and may require more detailed study.

Currently, the ISO has interconnection requirements for *transmission* connected resources over 0.5 MW or greater size that provides for real time telemetry and if participation in Automatic

Generation Control (AGC) is desired, real time AGC control on a 4 second basis. There are no RTO monitoring requirements in interconnection processes for distributed resources connected to the distribution system (or behind the meter) either by the ISO or by the individual distribution utilities, unless the resources request to participate in wholesale ancillary services market or except under Power Purchase Agreements.

5.1.2 Loading Capability of DER and Existing Grid Components

All components in the medium- and low-voltage grids have to be able to transmit the energy output of distributed generation. That means grid overloads should not occur. In this context, the rated current and consequently the transmission capability of all existing components must not be exceeded if all distributed generating units are feeding into the grid.

Technical investigation of the grid loading and voltage effects is usually performed by the grid operator using network calculation software able to carry out steady-state load-flow (and other network analysis) calculations and simulation of distributed generation properties at the point of common coupling. These network calculations model the existing grid components and their technical properties (i.e., rated current, etc.) as well as the technical data of the conventional and distributed generation plants.

Distribution system operators are concerned with the loading, harmonic content, voltage support effects of distribution connected and behind the meter DER. In addition to plan for circuit capacity requirements, they also need to understand the impacts of DER on circuit voltages and voltage fluctuations, and on fault duties and fault currents, so that protection devices can be set correctly. Additionally, it has become apparent to some Distribution System Operators (DSOs) that have experienced high localized penetration of PV, that the large inverters associated with large PV installations can have adverse effects on circuit voltage between the instance of a fault and the disconnection of the inverter during which time the inverter may actually boost circuit voltage. Traditionally, DSO interconnection requirements provide for rapid disconnection of DER inverters upon detection of no or low voltage so as to avoid circuit energization after a fault clears for safety reasons. In some cases DER may increase fault duty on parts of a feeder circuit necessitating analysis of the need to change fusing and the like.

In order to properly plan for distribution circuit operations under high DER penetrations, DSOs (and, in aggregate, RTOs) will in the future need to know the size, type, characteristics, and location of all DER resources including how they are operated and how their local controls operate. This means that DSOs will need permitting and interconnection standards that provide for collection of relevant data in a standardized structure. DSOs will only require visibility (monitoring) if they implement feeder based control schemes to manage DER operational impacts. Voltage control is the most important among such control schemes today, but in the future adaptive protection setting and other speculative applications may benefit from or require visibility. These activities are strictly in the Research & Development phase at present.

The ISO is responsible for transmission planning and reliability. The ISO routinely performs long term (annual), medium term (next month, next week) and day ahead planning analysis of grid conditions to ensure that loadings, transmission adequacy, and contingency loadings are within norms. It additionally performs additional grid analytics such as transient stability to ensure that grid reliability is adequate during transient conditions post outages.

These studies model the system load at the transmission station level (take out point in ISO lexicon) in varying degrees of detail: as constant (load flow) or as voltage dependent with some transient frequency response associated with rotating load (transient stability). Optimal power flows and other market simulations might additionally model the load as having some price elasticity. Generally speaking, any detailed information on load characteristics around these more complex representations would be provided by the relevant distribution utility and would be based on the relative amount of different load types served (industrial, commercial, residential) at each take out point. For specific and unique large loads (DWR pumping stations, for instance) special representations might be in order especially for transient analyses.

Studies were typically performed using off peak and on peak data points; additional refinements are done based more on major generation patterns and seasonal generation maintenance outages than on subtle changes in local load behavior.

A number of new transmission planning and operations issues are raised by high DER penetrations that challenge today's practices. These are discussed below.

5.1.3 Voltage Support and Voltage Fluctuation on the Transmission Grid

Interconnection requirements provide for voltage support/control capabilities from participating generating units, normally rotating machines with excitation control. These provide leading and lagging power factor reactive power to the grid to help manage transmission voltage levels and reactive flows. Grid connected renewable resources such as wind farms and PV farms are connected via large inverters which until recently did not provide reactive support. DER alters the flow of power on the grid, and thus current and ultimately system voltage. While in general the provision of injected power which reduces (or even in extreme cases negates) load at a takeout point is a positive factor on grid loading, it is the higher variability of DER that can cause voltage fluctuations to occur on the grid. Voltage control apparatus is designed for "normal" operations in response to off peak to on peak load transitions – that is, twice daily transitions at no more than the daily conforming load rate of changes. Abrupt changes caused by major generation outages are not daily events, certainly not in a given location. Transient voltage events caused by faults that are cleared are too fast for voltage apparatus to respond at all (existing voltage control apparatus is largely tap changing transformers and switchable capacitors). The potential for high DER to cause rapid and dramatic changes in local loading leading to rapid voltage fluctuations can change this. The ability of the transmission grid to manage voltage levels under these conditions requires analysis before the need for a means for mitigation can be determined, and in order to do this the extent of DER induced load fluctuation on a localized transmission basis must be understood.

The ISO will definitely require visibility into what DER is installed and what its characteristics are; additionally real time visibility of DER net generation / load on a take-out point basis would potentially be useful in analyzing "voltage contingencies" associated with DER. Both under and over voltage conditions are potentially problematic.

5.1.4 Secondary Contingencies Caused by DER Disconnect

Fault Ride Through (FRT) requirements for conventional generators connected to the transmission system mandate that the generation plants will not disconnect from the grid in the event of voltage sags associated to short-circuits that are correctly interrupted. To reach that standard, the necessary design and control actions will be taken in the generation plants (all their components) for them to withstand three-phase, phase-phase (with and without ground), and phase-ground short circuits without disconnection. The voltage sags (independent of the short circuit type) at the connection point will not result in disconnection as long as the sag is located within a pre-specified range. Although the FRT requirement is independent of the network condition, the steady state voltage and reactive power supply requirements are dependent on network conditions and must be monitored. FRT requirements have been extended to grid connected renewable resources such as wind farms and PV farms.

DER on the other hand are today subject to distribution interconnection requirements developed for back up generation and focused on safety issues around feeder apparatus which is normally expected to be de-energized post fault or as a result of switching for fault isolation or routine maintenance. Consequently, on a transient low voltage condition DER that "sees" the low voltage will be expected to immediately disconnect from the grid. This creates the possibility for a new kind of contingency: when a generator outage, transmission fault (cleared or not cleared) causes a transient dip in voltage, this may propagate to distribution circuits and depending upon the depth and duration of the transient, connected DER on those circuits may disconnect. If this happened at a time, for instance, of maximum PV production in a region, a substantial secondary contingency could occur. The extent to which this issue should be a concern has not been analyzed today in the US and would require integrated transmission – distribution modeling for transient conditions including modeled the detailed behavior of DER inverters and control logic. FTR and Low Voltage Ride Through (LVRT) requirements for DER are not in place today and the quantitative analysis and nature of the requirements, if any, are not well understood. That is to say, a 100 MW secondary contingency in a zone or sub-zone may not be a matter of great concern. On the other hand, a 500 MW or 1000 MW secondary contingency would certainly be a concern, and what is not known is whether these DER interconnection effects fall into the first or second category.

In the event that DER FTR and LVRT behavior and potential secondary contingency analysis becomes significant, visibility will aid the ISO and the transmission utilities in developing validated models of aggregate DER behavior and using these with confidence in planning and operational studies, as well as any potential pre-contingency mitigation routines to be developed.

At a minimum, knowledge of the amount, type, location, and characteristics of significant DER will be required in order to address this problem.

5.1.5 DER inertial and frequency response

The frequency response characteristics of load were in the past considered to be limited to larger rotating machinery (pumping inductive motors, for instance) and were incorporated as a co-efficient in load models in transient stability studies. Most DER, whether load or generation, is not expected to have significant frequency response as it will be inverter connected. The CA ISO has recently released a study of future system inertial and primary frequency response (governor) characteristics under high Renewable Penetration that suggests that sufficient inertial and governor response will remain in the system to maintain stability norms. However, the study did suggest that frequency recovery durations may be extended with higher penetrations of renewable generation[75]. In addition the study indicated that the ISO may be challenged to meet frequency response responsibility with higher penetrations of renewable resources. Thus DER inertial and frequency response is considered a critical problem today. It is conceivable that some DER (especially storage and managed EV charging) could provide a synthetic frequency response if the inverters were so designed. Various academic studies[76] investigated and supported the development of autonomous load frequency response as a desirable augmentation to system regulation and governor response. Some schemes even advocated the control and use of system frequency as a means to communicate marginal pricing and influence load response.

Sizable inverter based DERs such as distribution connected storage, EV charging, and feeder connected PV installations could all provide some degree of autonomous frequency response (even as feeder storage units would provide autonomous voltage response)[77]. The incremental cost to develop this resource would not be that great and is worth consideration. Were the ISO to develop and market products in inertial or governor response or were large renewable developers required to provide or acquire such as an interconnection requirement then DER developers would welcome the opportunity to participate. This is a topic for future consideration.

Visibility into DER responses would not be necessary for routine ISO market or reliability operations; but some degree of at least historical visibility would be required for settlements validation and certification and as with all the DER issues discussed herein visibility of what is actually installed would be essential.

5.1.6 Harmonics caused by DER

Distributed energy resources can cause harmonics that can influence other customers connected to the grid. In this context, CAISO define limits of harmonic currents that may be generated by the individual generating unit. The permissible harmonic currents are related to the network short-circuit duty at the point of common coupling. Harmonic analysis on the distribution feeder is the province of the DSO. There is no indication today that harmonics from

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[75] IEEE 1547 standards may be impacted.

[76] Serban and C. Marinescu, “Aggregate load-frequency control of a wind-hydro autonomous microgrid”, Renewable Energy, Volume 36, Issue 12, December 2011.

[77] We did not examine the feasibility of these devices.

DER apparatus can propagate to or impact the transmission grid, and voltage transformation inherently acts to reduce harmonic content due to the relative impedances of transformers at higher and higher frequencies.

5.1.7 Market price dynamics caused by DER

Some early research[78] has investigated the interaction of price – elastic demand with sequential periodic supply side market clearings. Plainly stated, this means that the market operator algorithmically clears the supply side of the market taking the current demand (or the current demand plus a short term load forecast) as a fixed quantity to be supplied. This clearing sets the new price. In real time, the current demand plus possibly a short term forecast is used; in hour-ahead market pricing, a forecast adapted to recent hours' load is used; and in day ahead markets a forecast is used. All forecasts rely on historic load behavior and weather forecasts.

Under dynamic pricing regimes, the load reacts to the new market price after it is cleared and published. The next generation market adjustment occurs at the next periodic market cycle which could be an hourly or a real time market or both. In some cases, it is mathematically possible (and demonstrated in simulations of some detail and rigor) that the dynamic behavior of the market prices may be unstable – that is to say, oscillating at large amplitudes. The conditions for this instability are complex and involve the relative time response and elasticity of the supply and demand side.

Whether this market instability effect is a possible concern in the ISO markets is not known – analysis of the time dynamics and relative elasticities of different load elements in more detail than was done for this study, especially the dynamics, would be required and then some detailed real time market simulations that included the time dynamics of generation response as well. What is known from the early research is that if the market operator can accurately estimate demand price elasticity and incorporate this into the market clearing process then the potential problem is eliminated. Note that this would be an issue for commercial and load under true dynamic price response (pass through of wholesale prices) but not for residential load under Time Of Use (TOU) rates – under the latter, day to day behavior would be consistent and would be factored into load forecast processes over time in any case.

[78] KEMA, IEEE Smart Grid Innovative Technologies conference, January 2012, "Markets 3.0"

In order to estimate price elasticity the ISO would require knowledge of what components of load were subject to dynamic pricing on a takeout point basis and then real time (historical) data about load in such time resolution as to permit statistical analysis to estimate elasticity. Better still would be direct visibility of load subject to DP. However, it is likely that only "historical" (meaning day before / month before) data as opposed to "real time" (meaning "now") would be required to support such a modeling process.

5.1.8 Commutation notches

Commutation notches occur with inverter-fed generating units; when a number of devices are connected to the same bus and there is a significant difference in phase voltage in a three phase line[79]. To check commutation notches, detailed data from the individual distributed generating unit are necessary. As with harmonics, we do not believe that feeder connected inverter performance at this level will increase visibility and propagate to transmission levels--creating problems that the CA ISO would need to be aware of or be able to manage.

5.2 Communication Architecture

The telemetry requirements for larger Solar Eligible Intermittent Resources (EIR) are well defined for larger (1MW and 5MW) connected resources in the Eligible Intermittent Resources Protocol (EIRP) document.[80] This generally applies to transmission connected resources. Smaller non-aggregated resources that often are located on the distribution network such as roof-top PV that produce KWs and pole top units that produce 100's of Watts are not well defined. Additionally, some utilities and large commercial operations are installing MW size PV facilities that are connected to the system at feeder voltage levels whether behind a meter (consumer side) or not.

Except for direct access customers already on real time pricing, there are no telemetry / visibility requirements established for other DER classes such as CHP, EV, local or community storage, or future price responsive end element load.

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[79] IEEE Standard 519-1981, IEEE Guide for Harmonic Control and Reactive Compensation of Static Power Converters". 1981

[80] http://www.caiso.com/docs/09003a6080/27/ff/09003a608027ff84.pdf

Normally, larger resources can offset the cost of a Remote Intelligent Gateway (RIG) or similar telemetry and control unit and the communications infrastructure; distributed smaller resources generally do not readily accommodate this burden.

There are several issues to consider in analyzing potential DER communications architectures:

- Geographic density – how many DER monitoring points per square km?
- Co-location to other ISO / DSO communications points of presence (POP)
- Ease of connection (the "final 100 meters") to installations not convenient to POP wiring or wireless connectivity such as rooftop installations, basements, remote on ground installations, garages, and so on.
- Likely existence of communications capability in already present / planned electronics part of the DER installation. (an example includes GPS connectivity in EV or similar communications to provide maintenance operators with facility operational data)
- Data traffic requirements: periodicity, volume, and latency requirements
- Reliability requirements on an individual and on an aggregate basis
- Security requirements both from a grid cyber security and an information privacy protection basis
- And, unique to the DER visibility question, there is a question around what degree of sampling coverage is required for the ISO's purposes – is it necessary to monitor every individual DER or is it acceptable to sample a certain fraction of them. Related to this question is whether there is an element of "uniqueness" associated with communications and visibility as there might be with control or financial transactions.

5.3 Technology Roadmap

This section categorizes potential DER communications providers, architectures and their capabilities:

- 3rd Party Private Networks – Includes private networks owned by other aggregator, merchant generator, building owner/operator, municipality, etc

- Utility Distributed Automation Network – Utility private network used for distribution automation applications or other substation communications using combination of owned hardware and wireless technologies

- Utility Advanced Metering Infrastructure Network – Utility private network using proprietary or standard wireless technology to communicate with meters for reading, pricing tables, or outage information. Such are necessary for validation and remuneration purposes for paid DR resources and for resources that respond to Time of Use (TOU) or dynamic wholesale prices. Utility AMI design is assumed to already have addressed these requirements and the data can be used for model development as well, although the responsibility for that model development between the utility, the ISO, and an aggregator remains an open question. (This issue is discussed separately below.) In the event that DR and DP resources are on real time prices the interval resolution and data retention of the utility AMI systems would require validation for this purpose. We do not suggest using the utility AMI systems for other DER monitoring due to cost and network capacity issues as explained below.

- Customer Internet – Broadband internet connection at DER site provided by public local internet provider. Beyond the internet POP at the customer site, there are various in-facility network architectures wired and wireless that would carry communications to the end element device.

- Public Carrier – Wireless data coverage provided by public carrier (e.g. ATT, Verizon, Sprint)

- Broadcast – One-way radio communication to trigger binary DER action (e.g. first-generation HVAC or agricultural demand response, hot water heater control)

Exhibit 5-1 shows the system polling time requirements plotted against DER density or communication coverage requirements. Starting with the highest frequency of communications required and the lowest density of penetration (the upper left hand corner of Exhibit 5-1), 3rd party or private networks usually provide this communication network. As density increases but the polling time requirements remain fairly high, utility distribution automation then customer internets and finally private carrier networks are communication network solutions. When the DER polling time is less frequent, Utility AMI and Broadcast network solutions are appropriate.

Note that Cyber Security issues are different with any of the above networks.

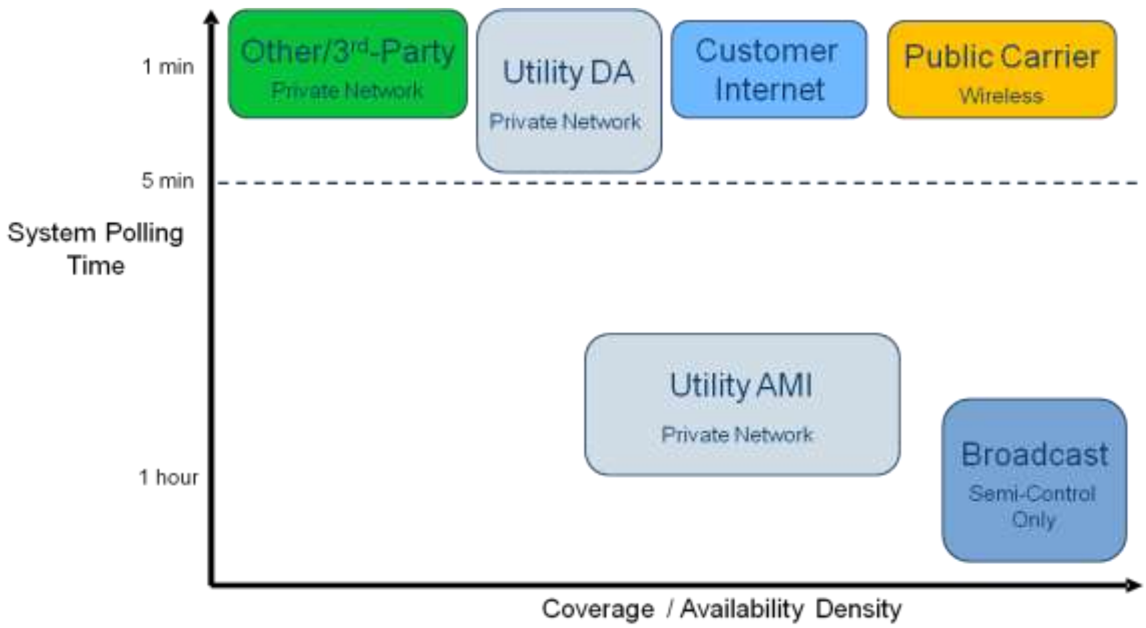

Exhibit 5-1: Communication Architecture for each DER based upon polling time and coverage

5.4 DER Control

From the perspective of the ISO, control requirements are specified primarily for Dispatchable Demand Response. Several DER technologies might participate in DDR – SOC, general residential DR and DP and smart EV charging. Engaging in DDR control requires participation of stakeholders throughout the spectrum – from aggregators to customer facility or end user. Moreover, implementation of DDR control requires additional security beyond DER monitoring – i.e. security protocols for data authentication and validation.

In general, DDR control can be implemented using the set of communications technologies and security guidelines detailed above. The options in communications technologies range through third party private networks, utility distributed automation network, utility AMI network, customer internet, public carrier or simple broadcast.

5.5 Communications Cost Components by Stakeholder

This section identifies potential cost elements by stakeholder of a DER communications network.

Core – The segment includes network and database management and administration. The ISO may need to extend the existing ISO – participant communications network to provide for the additional aggregators and data traffic developed for DER monitoring. DER control requirements fit within the parameters of current ISO – participant control system requirements and the number of aggregators is not expected to be in the thousand's so existing systems may be adequate. DER monitoring requirements are potentially more voluminous. DER historical data can be transmitted to the ISO on a low priority basis where latency is not a concern. However, if real time DER data is used to enhance short term forecasting then 5 minute periodicities are the suggested requirements and this puts DER data traffic at a higher volume/performance level than market and settlements data while lower than Automatic Generator Control data. A rough estimate for this might be: number of DER types multiplied by the number of aggregators multiplied by the number of take out points multiplied by the message length. This may come to hundreds of megabytes of data every 5 minutes which is not an excessive loading. The ISO would not need to retain this on a per aggregator basis across all DER types for modeling and forecasting purposes but would need to retain it on a takeout point basis per DER type as time series for a year in order to support modeling and forecasting work[81]. This is a significant data retention load. Settlements data requirements would only be imposed for paid DR resources and these would be on an aggregator level, so long term settlements retention should not become an issue. Business processes will have to be developed to keep[82] the ISO informed about the numbers, magnitudes, and characteristics of the DER resources under their purview at each take out point. While this is beyond the scope of this study, we surmise that this will be a significant undertaking. Fortunately, ongoing IRC standards work and NIST[83] standards work may address some of these questions and in any case provides a starting platform.

Backhaul – The communications backhaul will function as the backbone of the DER network. Depending on the network architecture, these services and costs are associated with a utility, aggregator, or other network provider/carrier. The costs include installing or upgrading network plant, hardware, software and services needed to carry the DER information. Backhaul costs

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[81] It is assumed that most NERC data requirements for outages will be managed through the balancing authority.

[82] ISO/RTO Council, Briefing Paper on Variable Energy Resources, August 2011.

[83] NISO Framework and Road Map for Smart Grid Interoperability Standards, Publication 108, January 2010.

may be negligible for architectures which leverage existing networks as in the customer-internet architecture.

Field – At a resource or device level, the owners or operators of that resource may incur hardware and services costs to equip resources with communications and to connect these devices to the network.

In many cases, the DER aggregator or other third party (installer / service organization) may already have business reasons to implement backhaul and field communications. Wherever the ISO DER monitoring communications architectures can be aligned with these aggregator / third party objectives the cost savings and acceptance level impacts are obvious and should be embraced. With the exception of DR control communications where cyber security and latency aspects may void this conclusion, this leads to a hierarchy of desirable architectures shown in Exhibit 5-2 as follows:

- Utility owned / operated equipment connected to the feeder – utility Distribution Automation communications are the logical and perhaps only acceptable solution to lower costs and avoid communication integration concerns[84].
- Basis for financial settlements: Utility AMI as a first preference.
- Consumer rooftop PV installations: common carrier wireless to smart inverters
- EV charging: Automotive industry aggregator common carrier wireless to vehicles and charging stations
- Behind the meter price responsive load elements: customer internet to the facility and customer selected in-facility wired or wireless network.
- Industrial / commercial CHP and SOC systems: public internet to in - facility automation systems and proprietary networks beyond to end use elements.

This hierarchy broadly speaking aligns itself with known business models and objectives of the different DER communities today. As one might expect, it also results in the lowest cost / least

[84] Current communications of CHP, SOC, PV, Storage, and PEV are DER that fit into this category.

hassle implementation for the given resource as that is in the interests of the particular community.

Communication Layer / Stakeholder	Core	Backhaul	Field
ISO	• Data Storage and analytics • Security / Encryption • Network Administration and Interoperability		
Utility / Aggregator		• Network capacity and reliability • Data storage and analytics • Security • Servicing and Maintenance	
Site Owner			• End-device connectivity • Public network access charges (ISP)

Exhibit 5-2: Communication Architecture Layers by Core, Backhaul and Field Requirements: Desirable Features

A summary of stakeholder ownerships and time line of communication technologies is shown below in Exhibit 5-3.

	Utility				Common Carrier				Third Party		
Network	1	2	3	4	1	2	3	4	1	2	3
Present Status	SCADA[85]	AMI Mesh Network[86]	Broadcast Radio		Cellular GPRS SMS[87]		WiFi	Internet POP/ Ethernet/ WiFi[88]		BAS Networks – larger commercial[89]	
Emerging Status	Distribution Automation (DA)	AMI Mesh Networks		700 MHz Band		Cellular LTE[90]	WiFi Public Hot Spots		Electric Vehicle (EV) GPRS Wireless		DER maintenance via cellular / internet
Status by 2020	SCADA/ DA on fiber / 700 MHz	AMI Mesh Networks	Migrated to another spectrum?	Adopted for DA and mobile applications	Not Available	Next Generation ?	Next Evolution?	Pervasive	Next Generation EV	BAS is C&I Standard	Next Generation
Network Advantages	Low Latency levels. NERC CIP compliance	Everywhere. Low Cost Modems	Very Low Cost	Re-allocate spectrum to utility	Everywhere. Low cost.	Everywhere. High Performance. In use for PV	Low modem and data cost	Everywhere. Low Modem Cost	Dependent upon auto makers	Open ADR likely.	Low Cost for monitoring
Network Disadvantages	Expensive. Proprietary	Utility owned. 3rd party access controlled	No access location. One way communications	Utility owned. 3rd party access controlled	Carriers to abandon	High modem costs. High service cost	Security. Not everywhere	Encryption required	Proprietary. Closed Access	Proprietary. Closed Access	Proprietary. Closed Access
Applicable DER Profiles	Utility PV & Storage	Residential PV & Storage	Small scale residential	Unknown	Distributed PV & Storage, Air Cond.	Unknown	DER near internet POP	Any C&I and residential	EV Smart Charging	Commercial DER, SOC, CHP	Distributed PV & Storage

Exhibit 5-3: Communications Ownership and Technology Timeline

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85 Supervisory Control and Data Acquisition networks. NERC definitions, http://www.nerc.com/files/Glossary_12Feb08.pdf

86 Advanced Metering Infrastructure. http://www.ferc.gov/eventcalendar/Files/20070423091846-EPRI%20-%20Advanced%20Metering.pdf

87 General Pack Radio Short Message Service. http://www.activexperts.com/mmserver/cellular/gprsintro/

88 Internet Point of Presence access point and Ethernet transmission. http://www.bitpipe.com/detail/RES/1335535326_774.html

89 Building Automation Systems (BAS)

90 Long Term Evolution is a wireless broadband technology designed to support roaming Internet access via cell phones and handheld devices. http://arstechnica.com/gadgets/2012/05/ltes-future-a-scramble-for-spectrum-and-creative-data-caps/

5.6 DER Communications Costs

This section proposes communication architectures for four DER technologies: Rooftop PV, Community (utility) Storage, EV smart charging, and Demand Response. Price responsive DER elements will receive the ISO day ahead, hour ahead, and real time prices via ISO originated broadcast mechanisms based on publication of those prices on its web site as today so do not require separate communications architecture for control purposes. EV smart charging is also addressed.

DER	Primary Architecture	Secondary Architecture
PV – customer (monitoring) PV – utility scale (feeder connected)	Public Carrier Wireless Utility Private Network	Customer Internet Utility AMI
DR – day ahead / real time	Customer Internet / aggregator VPN	Utility Private Network / broadcast technology
Community (Utility) Storage Consumer storage EV smart charging	Utility Private Network Customer Internet Public Carrier wireless	Public Carrier Wireless Public Carrier Wireless Customer Internet
Owner	**Advantages**	**Disadvantages**
Public Carrier Wireless	Efficiency & Coverage.	Security & Reliability without encryption; suitable for monitoring but not desirable for DR control. Performance for very low latency requirements.
Customer Internet	Cost, and coverage to facilities if not end use.	Security & Reliability without encryption and VPN requirements. Performance for very low latency applications.
Utility Private Network	Security & Reliability.	Cost. Ease of access to non-utility facilities and apparatus remote from the distribution feeder itself.

Exhibit 5-4: Primary and Secondary Communications Architecture by DER and by Owner Type

Public Carrier Wireless

Some DER type communications may be a good fit with public carrier wireless. Their networks have wide coverage in most areas where DER would be located. The traffic profile of DER is also a good fit because the individual DER information packets are small in size and have modest latency requirements. In the aggregate they are small compared to voice or video traffic. This manageable traffic load may allow carriers to offer connectivity through Short Message Service (SMS) which offers substantial cost savings. Provisions can be made, if desirable, to encrypt the data. We do not recommend this for Demand Response control applications but instead for monitoring applications particularly of PV where location and end wiring may be difficult. In the case of PV the installers/ service organizations will already have an incentive to collect some form of this data for performance monitoring.

The large number of potential devices provides the necessary scale for public carriers to offer cost-competitive plans to the ISO, aggregators, or resource owners. A practical benefit of the public wireless solution is that network service costs are aggregated into one fee and are easily transferred and reported between stakeholders.

There are regulatory issues associated with the use of common carrier wireless. A tariff for "utility" (aggregator and utility) data traffic on some basis would have to be established. This can be a win-win for all concerned in terms of added revenue to the carrier at near zero marginal cost; low cost communications for the DER aggregator associated with low cost installation and electronics costs; and thus lowest cost to the consumer. The only likely technology development would be to provide encryption into the smart inverter / GPRS (Standard for General Packet Radio Service) chip if not already available for SMS applications.

Establishing such "smart inverter communications" as a requirement for PV installations, for example, would also require regulatory intervention and leadership. The electric utilities may not see this as their preferred solution since no utility equipment or systems are directly involved, and today they represent the entities with the broadest coverage for the purpose of establishing interconnection standards. The state would of course have some powerful leverage through not only the California Public Utility Commission (CPUC) but possibly through linkage to solar initiative incentives.

Customer Internet

The customer internet architecture leverages an existing internet connection at the DER site. The DER equipment could achieve communication connectivity via local wireless (e.g. Wi-Fi) or wired connections or various Home Automation and Building Automation networks. Although there are encryption technologies and techniques available for tunneling secure connections over the internet, it should be noted that there are significant security challenges when protecting consumer-grade wireless and internet equipment. Therefore in the customer internet architectures, the proper core network protections and decision safeguards are paramount.

Security concerns aside, the customer internet architectures can be cost efficient if the DER owners are willing to supply connectivity. This architecture avoids build out costs associated with new or upgraded private networks and the monthly service fees associated with public carriers. Although beyond the scope of this report, one future consideration of the customer internet architecture should be to review the internet service provider (ISP) agreements in the territory to confirm that customer would not violate any resale restrictions. Customer network architectures are well suited to end use equipment within a facility and where the end use equipment is likely to have local network connectivity for other purposes. Building loads, advanced residential system Air Conditioning, and in the future smart appliances are examples of such. DER monitoring loads would present no challenge to broadband internet performance capabilities and in general the internet reliability is more than adequate for this purpose. Aggregators / servicers would have to meet the security requirements established and obtain certification for ISO purposes.

Private Network (Utility)

In their efforts to deploy Advanced Metering Infrastructure (AMI), Distribution Automation (DA) and other smart grid applications, many utilities are upgrading and expanding their existing private communication networks. In most cases these networks are owned and operated by the utilities to support energy operations, field communications, and corporate data networks. They are generally regarded as more robust and isolated than public carrier networks but have less coverage. In instances where they are supporting demanding energy applications, such as tele-protection, utility private networks offer extremely low latency and highly reliable connections.

On the other hand, some utilities have built out special-purpose private networks for AMI applications that would not meet the continuous 5 minute reporting time required for DER visibility. This is because these networks were designed to do daily meter reads and polling of stored data. In this instance, the private network would need to be upgraded or expanded to meet the DER network requirement. AMI protocols are proprietary and would not lend themselves easily to interconnection to various smart end use or distributed generation assets.

Establishing an additional smart meter at every end use is expensive and would be overkill for this purpose – metering accuracy and data retention is not required.

In most cases the private utility network option will be costly relative to public carrier or customer internet options. Type of equipment and network design vary greatly between private networks.

On the other hand, the utility DA network is probably the only acceptable communications architecture for DER directly connected to the distribution feeder such as community energy storage or large-scale utility PV. The utility would understandably be more comfortable with its own network and would be far more comfortable that present and future cyber security requirements for PV apparatus could be met. Public safety arguments would also make a compelling case for utilizing utility Distribution Automation architectures. Utilities would also demand direct access to utility field equipment without going through third party systems other than a traditional leased line / channel basis as is done for some SCADA applications today. Utilities will already be planning to monitor feeder apparatus and large PV installations and there is zero incremental communications costs associated with getting them to provide the data to the ISO. There will be one time back office applications costs and ongoing software maintenance costs associated with that requirement, but such will be small in the context of utility IT support.

Exhibit 5-5 shows the costs of the communication network for each DER or combinations of DER. For each DER or combination of DER, we determined the monitoring technology, estimated the points to monitor and determined the percent of total locations to monitor. Using industry and KEMA estimates, we then determined capital costs and operating cost for the 2020 Study Year.

DER	Monitoring Technology	Estimated Units/Points to Monitor	Percent Visibility	Total Capital Expenditure	Total Operating Expenditure per year
Distributed PV	Smart Inverters with GPRS radio chip	2,000,000	20%	$8 Million	$0.1 Million
	3G or LTE (700/1800 MHz)			$6 Million	$0.2 Million
	Unlicensed 902-928 MHz or 2.4 GHz WiFi with cellular backhaul to/from TOPs			$1.4 Million	$0.1 Million
	Unlicensed 902-928 MHz or LITE licensed 3.65 GHz			$6 Million	$0.1 Million
	Licensed 700 MHz (D-block) utility owned LTE network			$6 Million	$0.1 Million
	2.4 GHz / 5.8 GHz unlicensed			$2.4 Million	$0.1 Million
Utility Scale PV	Utility SCADA	9,000	100%	$1.4 Million	$0.5 Million
Community Storage		8,000	100%	$1.3 Million	$0.4 Million
Self Optimizing Customer	Customer SOC Network	10,000	100%	$2.5 Million	$0.1 Million
CHP	CHP Building Controls				
Monitoring Sub-total				$37 Million	$1.7 Million
Demand Response	Commercial Building: BAS OpenADR	100,000	100%	$2.8 Million	$0.05 Million
	Commercial End Use: DR Electronics	500,000	100%	$25 Million	$0.25 Million
	Residential: HAN, AMP Post validation and DR electronics				
Control Sub-total				$28 Million	$0.3 Million
Totals				$65 Million	$2 Million

Exhibit 5-5: Communication Network Costs per DER

5.7 Communications for Controlling DER

The sections above discuss different technology roadmaps for monitoring DER. Except in the case of utility owned and operated resources, different non-traditional or non-utility technologies are suggested that utilize one or another common carrier or public network infrastructure for cost and presence reasons. However, these networks may not be acceptable for control purposes due to security concerns. As noted above, there are two DER which will be controlled by aggregators - Dispatchable Demand Response and Smart EV Charging. In both of these cases, there is a concern that a cyber attack could cause large amounts of DR to resume energy consumption simultaneously representing a significant MW contingency. For this reason, additional security provisions may be required. However, using utility Distributed Automation communications for the purpose is prohibitively expensive if the individual resource is not quite large (10's MW). Similarly, using an ISO approved AGC interface device is also too expensive for kW sized resources (and the current CA ISO device requires connectivity to the ISO network).

Two alternative mechanisms are described in the appendix presentations on technology and are worth noting here as acceptable technology solutions for DDR communications for control (and in one case monitoring) purposes. Both make use of the public internet and have been used for price responsive and AGC regulation purposes.

The Steffys hot water heater control uses encrypted DNP3 protocols to communicate regulations signals to hot water heaters that are controlled by aggregators. The PJM utilized Eurotech director is an internet based device with an encryption chip that has been used to demonstrate internet based regulation services to a variety of resources including batteries and electric vehicles. These two devices are considerably less expensive today than a generator interface device, and in volume costs will come down further. The use of such devices for DDR control would provide security at a reasonable cost.

An additional DR technology that should be incorporated in ISO DR Plans is the Open ADR protocol. This is in widespread use, can be encrypted for security, and offers low cost DR protocols that will with high probability be adopted by NIST as a Smart Grid standard. Open ADR provides DR business processes to a variety of end resources; most importantly including building automation systems – it has been embraced by all the leading BAS suppliers.

5.8 Overall Cost Benefit Analysis

The analysis of the impact of DER variability and the benefits of visibility suggest that the visibility of PV production is the single highest priority for the ISO in terms of forecasting and operations. It is the most variable resource and the principal driver of variability in other resources such as SOC and storage. With adequate PV visibility the ISO would have the ability to model and forecast the behavior of utility and customer storage as well. It is not necessary to monitor every PV panel in order to have good local data on PV variability. Based upon prior project experience and depending upon the regional density/occurrence of PV installations (in terms of installations / sq km) sampling down to 10% of installations may be adequate. Practically speaking, it will make sense to require all installations above a threshold (1 kW suggested) to have a smart inverter with wireless SMS or other data communications capability and then to require that aggregators / service operators / utilities sample at a rate sufficient to provide required monitoring accuracy [91]. The estimated per installation electronics cost is on the order of $100 (negligible against the cost of a 5 kW installation, for example) and could become as low as $30. The annual operating cost in terms of payments to the carrier is on the order of $5 – 10 based on conservative estimates of the fees that can be negotiated. The total annualized costs are on the order of $50 M (meaning $7 – 70 M per the chart above) which are small compared to the benefits estimated at high DER penetration.

There are additional reliability and infrastructure benefits that will accrue to the distribution operator from the implementation of this scheme, note.

This is an overall analysis for PV primarily, of course. The second and third most important components to monitor are the SOC and the price responsive customer, in terms of forecasting. As noted above, AMI systems can provide the interval data on an historic basis needed for model development and validation but not the real time data needed for enhanced short term forecasting. Where the installations are large enough to be exposed to dynamic pricing there are likely to be automation systems in place with customer internet communications to service providers and the like. The incremental cost for collecting data from these facilities is limited to the back office costs for the systems used by the aggregators and service providers. As they likely will be collecting similar data for their own business purposes the costs should be limited to the costs of developing applications for interfacing to the ISO. As with other market participant systems the cost of these will be in the range of $1M – 10 M depending upon the

[91] This should be determined in future work.

size and complexity of the participant's business and there will be annual costs for software maintenance and the to be expected periodic changes in market protocols and reporting requirements. Costs will be reduced if the applications can be standardized as discussed below.

It is suggested that EV smart charging will already be monitored by automotive sector 3rd parties via wireless technologies. As such, they should be in a similar situation to the 3rd party SOC and CHP servicers mentioned just above. Additionally, we suggest that the biggest driver in EV charging variability may be traffic congestion data. This is a surmise only as there is no data available to speak of on EV charging today, let alone under a smart charging routine. EV service providers that are promoting smart charging services to EV owners will no doubt also need to forecast EV charging load for their own management purposes and may be able to provide the ISO with updated forecasts at little or no incremental cost to themselves.

5.9 Business Process Issues

The aggregator that has a financial stake in the market outcome around its ability to forecast, schedule, and manage DER resources will naturally invest over time in the most cost effective applications and methods to do that. This implies to the ISO that where aggregators have a financial stake in DER monitoring, control, and forecasting they will take appropriate measures. This is true for DR aggregators and EV smart charging managers. It is unfortunately not the case for PV service providers, for price responsive load acting as a price taker in the markets, or for Self Optimizing Customers that act as price takers in the markets. Absent an aggregator that has a financial interest in forecasting accuracy (i.e. a competitive retailer or outsourced SOC manager) the ISO would therefore be placing a requirement on a 3rd party that had no business reason to do so. This means that lowest cost common applications with minimal innovation would be the norm. This implies that the ISO would have to consider one of several alternative options:

Incent the consumer somehow to provide the ISO with data and forecasts. This would get the ISO into the process of modeling and forecasting individual DER behavior, which has scale and other issues that are not attractive.

Get regulatory support for forcing such customers to deal with aggregators that would have incentives to accurately model and forecast their behavior.

Be prepared to develop modeling and forecasting mathematics and software that can deal with the problem at an aggregated level (take out point basis) somehow using historical data provided by utility AMI systems.

Another critical business process aspect is the collection and transmission to the ISO of the basic “what is there” data around DER location, characteristics, size and so on. This requires development of a standardized reporting format for every DER type sufficient to the ISO modeling (and aggregator) modeling needs; regulatory support for enforcing collection and provision of it via sale, permitting, inspection, and other routine processes; and as with competitive retailing a mechanism for change management as customers switch aggregators and so on. Different channels will have to be exploited for different DER types. In some cases (rooftop PV, EV charging stations) the electrical permitting process and/or the installer business process offer channels. In others (smart appliances; smart residential thermostats) the point of sale is the likely only vehicle for collecting data and even then there will likely be no way to know how the consumer may have programmed the appliance. Some DER end users may end up therefore subject to less informed modeling processes. Note that consumer point of sale information may contain address information but privacy issues will undoubtedly interfere with the ISO getting access to (or, probably, wanting to have) this level of information. Data such as the number of smart clothes dryers sold by reporting area will have to suffice. Adaptive devices such as the NEST thermostat would be more difficult to model. We believe that the ISO will have to account for everything that is explicitly identifiable and attributable to weather drivers such as insolation and temperature, and then will have to deal with price elastic load on a takeout point basis estimating elasticity from net usage data after all the other DER have been accounted for.

As noted above, many of these DER monitoring issues will not fall under traditional electrical permitting or rate / product tariff channels as a way to manage information gathering. Some can be tied to incentives and this may be a more politically attractive and readily implemented channel. The customer as an autonomous price taker is the most challenging in terms of data gathering.

6. Conclusions and Future Considerations

The ability to monitor and forecast Distributed Energy Resources has the following impacts on load following and regulation reserves required to manage the system effectively:

- With conservative assumptions about how much forecasting/monitoring can reduce DER variability, the KEMA Team found that visibility can reduce load following up maximum reserve requirements purchased by as much as 12%.
- The bulk of Load Following Requirements reductions occur in the 10 Minute time frames.

The KEMA Team examined several communication and monitoring devices technologies required to monitor distributed energy resources.

- DER technology communications across six DER profiles total $65 million in capital costs and about $2 million in operating costs per year.
- Most of the control benefits come from increased Dispatchable Demand Response effectiveness and reduced response delays. KEMA estimate a net benefit of $197 million in 2020 versus a capital cost of about $28 million and operating expense of $0.6 million.
- PV, Storage, PEV, SOC, CHP DER would likely be controlled through the utility and data for monitoring and forecasting provided to the ISO.

The benefits of DER visibility were estimated through several 2020 simulations of production costs for different levels of DER penetration and to isolate the net benefits for each type of DER penetration. Costs of proposed communication architectures and monitoring devices were then compared to the benefits to determine:

- The greatest benefit of visibility occurs in the High DER Penetration Case, where production costs of $391 million in 2020 can be saved through reduced load following and regulation reserve requirements. Of the DER profiles examined in the High Case, the greatest benefits occur with PV visibility ($176 Million), followed by Demand Response ($149 million) and then Distributed Storage ($63 Million).

- For the Low Scenario case the benefits of improved visibility for all DER are projected to be $90 Million. For the Medium penetration Scenario, net benefits of improved visibility for all DER are projected to be $159 Million.

- Costs of communications architectures to improve visibility range from $37 million capital costs and $1.3 million operating expenditure in the High DER penetration case.

The KEMA Team examined the benefits of controlling Demand Response DER in the High DER Penetration Case. Controls for Demand Response improved response times and effectiveness of response. The benefits were estimated to be $197 million. Using existing technology such as the Open ADR communication technology, KEMA estimated capital costs of $28 million and operating costs of $0.7 million per year.

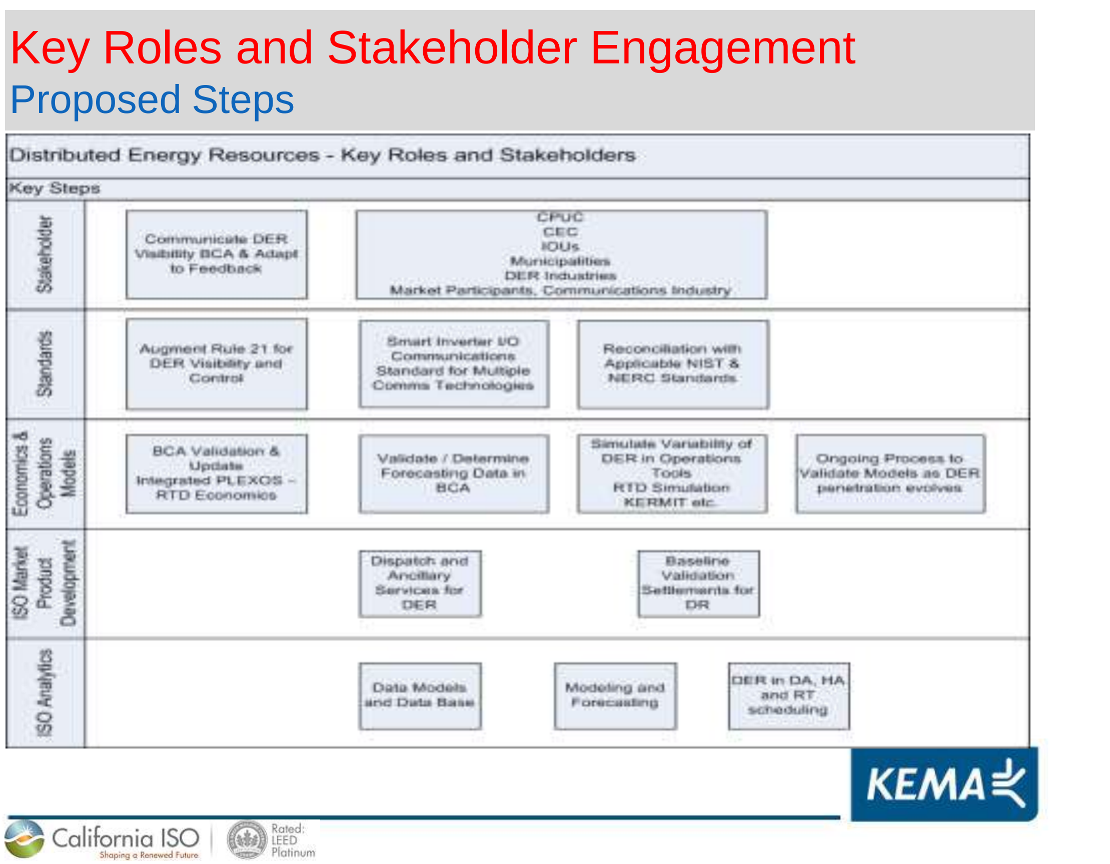

Exhibit 6-1: Draft Implementation Next Steps

To pursue the benefits of higher visibility of DER and control of Dispatchable Demand Response, KEMA proposes the following next steps as shown in Exhibit 6.1.

For stakeholders, the ISO should develop a communication plan to describe the benefits and costs to various stakeholders. These stakeholders include the California Public Utility Commission, the California Energy Department, Investor Owned Utilities, Municipalities and Irrigation Districts, DER industry groups and Market Participants.

Standards will have to be examined. These standards include Visibility as part of DER Interconnection Standards and for Access to Real Time Pricing. Additional communication impacts involve communication standards such as Smart Inverter Communications Input/Output Standards. Wireless technology life cycles are 2-3 times shorter than DER asset lives. Adoption of any common carrier wireless services saves costs at the risk of early obsolescence. An open Input/Output standard is a risk mitigation that allows adoption of widely available low cost communications.

Economic and Operational Models for how DER interacts with current ISO procedures will need to be developed. Settlements and charges will have to be developed for the communications costs and/or socialized market benefits are used to cover DER visibility costs that are borne by DER owners / aggregators. Control costs will be part of the overall economics of Demand Response – market payments for Demand Response have to cover the convenience and technology costs.

Roadmap Conclusions

The ISO will definitely require visibility into what DER is installed and what its characteristics are; additionally real time visibility of DER net generation / load on a take-out point basis would potentially be useful in analyzing "voltage contingencies" associated with DER. Both under and over voltage conditions are potentially problematic.

DER requires significant data retention. Settlements data requirements would only be imposed for paid DR resources and these would be on an aggregator level, so long term settlements retention should not become an issue. Business processes will have to be developed to keep[*2] the ISO informed about the numbers, magnitudes, and characteristics of the DER resources under their purview at each take out point. While this is beyond the scope of this study, we

[*2] ISO/RTO Council, Briefing Paper on Variable Energy Resources, August 2011.

surmise that this will be a significant undertaking. Fortunately, ongoing IRC standards work and NIST[*3] standards work may address some of these questions and in any case provides a starting platform.

[*3] NISO Framework and Road map for Smart Grid Interoperability Standards, Publication 108, January 2010.

A. Deriving Forecast Error

We now begin to describe the process mathematically:

The driving variables of PV, price, temperature, conforming load, and random resource behavior are described as a vector v(t) which is "known" component v0(t) and a vector v(t) which is a random correlated Gaussian variable of covariance R. (We have to allow for correlation of things like temperature and price, or temperature and conforming load, or price and conforming load). For purposes of this exercise, the total driving variables are modeled as a baseline time series or curve plus the random variable component. Thus the price could be given by

Price(t) = p0(t) +vp(t) and so on.

Let the observations of the MW load/production of each resource be given by l(t) (a scalar, clearly, for each resource) where for the real physical resource

l(t+1) = A(l(t), v(t)) meaning that the resource process is nonlinear and possibly has time dynamics. Such a formulation would be mathematically intractable for the problem at hand, so as a simplification we will say that the real process is described as a linear system and observation problem:

l(t+1) = A l(t) + B v(t) and the scalar net load l(t) is given by l(t) = H l(t). We may later assume that we have perfect observations of the net load l(t) but for now let us assume that the observations are subject to noise in the process such that we observe z(t) = l(t) + w(t) where w is a noise scalar with covariance W.

This leads to the Kalman Filter formulation for the best estimate of l(t) . Note that in this formulation the state vector l contains invisible states "behind the meter" that give the scalar net load l(t) its time dynamics.

l(t) = H l(t) and the best estimate for l(t) (denoted as l*(t) is given by l*(t) = H l*(t) and where

l*(t+1) = A l*(t) + BT (BT W-1 B)-1W-1 z(t) this is the normal Kalman Filter formulation.

However, we have a forecast for the driving function v(t) which is v(t+T) where the error in the forecast is given by v(t+T) – v(t+T) and this error has a co-variance R(T). We can allow T = 0 in this to accommodate observations of PV, price, temperature and conforming load in real time. (we will have to be careful in that we may wish to assume that observations of price, temperature, and conforming load are near perfect and this may make the covariance non-invertible).

Thus we have to formulate a Kalman predictor for T time steps in the future. We need more than one time step for the predictor as we may have multiple forecast time steps in the time leading up to the forecast time. (We will want to set T such that the forecast problem is defined as the time period beforehand when Load Following or regulation requirements are set; i.e. one hour in today's paradigm or possibly 15 minutes in some future paradigm).

Discussion: why pursue a time dynamic model? The modeling would be much simpler if we assumed no dynamics in the resource behavior – that is, that the resource load was an instantaneous function of the driving variables. However, this may not be true for some resources which will have some "inertia" to their behavior before they adjust to new PV, temperature, price, and so on. Also, we may have forecasts for some driving variables that are at intermediate time steps between "now" and the forecast period. An example could be that we have short term (i.e. 5 minute) forecasts for PV production as well as forecast period (1 hour) forecasts for PV, temperature, and so on. It is absolutely true that the problem of estimating the variability (i.e. covariance) of forecast DER net load is far simpler without any time dynamics or assumed observation errors; and this may provide an upper bound on the problem. That is, a time dynamic model may afford an opportunity to do a better forecasting job; it may also complicate the problem beyond feasibility or introduce too many unknown parameters to estimate meaningfully.

Simple one time step forecast problem with "stateless" (no dynamics) linear model and perfect observations

In this case the forecast net load l*(t) is given by l*(t) = Bv(t). The apriori covariance of l*(t) is given by

E(l2(t)) = B R BT which simply says that if the net load has an elasticity of bp with respect to price, then the covariance of the load contributed by the price term is bp2 * (covariance of the forecast price rpp).

If the model for l(t) is perfect, then this is the absolute best that can be done in forecasting l*(t). The error in the forecast of the driving variable will carry through to the error in the forecast net DER load.

However, the model is imperfect: we do not know B perfectly. Let us model this imperfection by saying that we are using a model $l(t) = Bm\ v(t)$ where $Bm = B + m$ where the error matrix m has a covariance M.

Then our forecast $l^*(t) = Bm\ v(t) = (B + m)\ v(t)$

And the forecast error $l^*(t) – l(t) = (B + m)\ v(t) – Bv(t)$

Let us reasonably assume that the forecast error and the model error are uncorrelated. Then the new forecast error has a covariance given by:

$E(l^*(t) – l(t))2 = BRBT + mRmT + (mv0(t))2$ where v0(t) is the baseline or "known" component of v.

This means that the model error m introduces an additive random covariance plus a non-zero expected error if there is any underlying trend in the forecast to be amplified by the model error. (absent any visibility, we would not be able to discern that baseline offset)

Depending upon the relative covariances and sensitivities, the statistical terms or the baseline bias term may dominate. That is, if we say that price elasticity is 0.1 MW / $ and the standard deviation of the elasticity error is 0.05 (i.e. +/- 50%) and the price forecast is $50 > the elasticity reference with a standard deviation of $1; then the elasticity error will dominate the process. If the price forecast is at the elasticity reference with a standard deviation of $10, then the statistical term will dominate.

Each DER resource type and driving function pair will have different outcomes in terms of this example.

We can evaluate the linear model B by taking for each driving function the partial derivative of the net load l with respect to that variable. That is,

$Bi = l / vi$

And we estimate m as a per unit error amount in that term.

Discussion: impact of simplifying assumptions

Many of the DER responses will be non-linear in that they will have dead bands, upper limits; and possibly some non-linear continuous or step-wise relationships with the variables. The linear model worst cases the co-variance by ignoring dead bands, and linearity is usually reasonable across an appropriate range. Ignoring the limits on DER response may overstate the co-variances, however; any assessment of the final error standard deviations needs to take this into account. We can approach this by adjusting the standard deviation to be that derived from a limited or truncated normal distribution.

The time dynamics of DER response in theory should allow for more accurate forecasting, provided that the model parameters are known or can be estimated. Each instance of DER behavior will have to be looked at individually to determine if (a) time dynamics are important; (b) there are sufficient observations of driving functions possible to allow estimating the time dynamics; and (c) whether the model becomes identifiable or capable of having the parameters estimated meaningfully.

B. Comparing Market Price Referent (MPR) Fuel Forecasts to Spot Prices

KEMA compared the MPR methodology to spot fuel prices used by generators[92]. The MPR methodology used New York Mercantile Exchange (NYMEX) prices for Henry Hub and basis differentials for various pipeline pooling points. KEMA collected actual data from spot price indexes and compared 2011 spot prices to prices determined by the MPR methodology as shown in Table 2-2.

Because spot prices may vary from future prices, the comparison below notes that there is some differential between actual projected pricing using the MPR methodology.

[92] The MPR methodology is describe in Joint Scoping Memo and Ruling, 10-05-006.

Generator Zone	Hub	Delivery Point	Delivery Charge	Taxes	2011 Baseline	2011 Actual
AESO	Rockies	AECO-C	$ -	$ -	$ 4.368	$ 3.511
APS	SoCal Border	Arizona	$ 0.303	$ 0.225	$ 4.953	$ 4.667
AVA	Sumas	Pacific-NW	$ 0.094	$ -	$ 4.656	$ 4.023
BCTC	Sumas	Sumas	$ -	$ -	$ 4.562	$ 3.929
BPA	Sumas	Pacific-NW	$ 0.094	$ -	$ 4.880	$ 4.023
CFE	SoCal Border	Baja	$ -	$ -	$ 4.953	$ 4.139
EPE	San Juan	San Juan	$ -	$ -	$ 4.489	$ 3.865
IID	SoCal Border	SoCal Burnertip	$ 0.438	$ 0.069	$ 5.119	$ 4.646
LDWP	SoCal Border	SoCal Border	$ -	$ -	$ 4.691	$ 4.139
LDWP 2	SoCal Border	SoCal Burnertip	$ 0.438	$ 0.069	$ 5.119	$ 4.646
NEVP	SoCal Border	SoCal Border	$ -	$ -	$ 4.691	$ 4.139
NWMT	Rockies	Idaho_MT	$ 0.512	$ -	$ 4.368	$ 4.313
PACE-UT	Rockies	Utah	$ 0.271	$ -	$ 4.368	$ 4.072
PACEW	Sumas	Pacific-NW	$ 0.094	$ -	$ 4.562	$ 4.023
PGE-Bay	PG&E Citygate	PGE Citygate BB	$ 0.069	$ 0.040	$ 5.058	$ 4.435
PGE-Bay2	PG&E Citygate	PGE_Citygate LT	$ 0.230	$ 0.041	$ 5.218	$ 4.598
PGE-Valley1	SoCal Border	Kern River	$ 0.359	$ -	$ 4.691	$ 4.498
PGE-Valley 2	PG&E Citygate	PGE Citygate BB	$ 0.069	$ 0.040	$ 5.058	$ 4.435
PGE-Valley 3	PG&E Citygate	PGE_Citygate LT	$ 0.230	$ 0.041	$ 5.218	$ 4.598
PGE-Valley 4	SoCal Border	SoCal Burnertip	$ 0.359	$ -	$ 5.119	$ 4.498
PGN	Sumas	Pacific-NW	$ 0.094	$ -	$ 4.880	$ 4.023
PNM	San Juan	San Juan	$ -	$ -	$ 4.489	$ 3.865
PSC	Rockies	Colorado	$ 0.553	$ -	$ 4.368	$ 4.354
PSE	Sumas	Pacific-NW	$ 0.094	$ -	$ 4.656	$ 4.023
SCE	SoCal Border	SoCal Burnertip	$ 0.438	$ 0.069	$ 5.119	$ 4.646
SDGE	SoCal Border	Baja	$ -		$ 5.119	$ 4.139
SDGE	SoCal Border	SoCal Burnertip	$ 0.438	$ 0.069	$ 5.119	$ 4.646
SMUD	PG&E Citygate	PGE_Citygate BE	$ 0.069	$ 0.040	$ 5.058	$ 4.435
SMUD	PG&E Citygate	PGE_Citygate LT	$ 0.230	$ 0.041	$ 5.218	$ 4.598
SPP	PG&E Citygate	Sierra Pac	$ 0.167	$ -	$ 5.218	$ 4.494
SRP	SoCal Border	Arizona	$ 0.303	$ -	$ 4.691	$ 4.442
TEP	SoCal Border	Arizona	$ 0.303	$ -	$ 4.691	$ 4.442
TIDC	PG&E Citygate	PGE_Citygate_L	$ 0.281	$ 0.041	$ 5.218	$ 4.649
Treas Valley	Rockies	Idaho_MT	$ 0.512	$ -	$ 4.368	$ 4.313
UT S	Rockies	Utah	$ 0.271	$ -	$ 4.368	$ 4.072
WACM	Rockies	Wyoming	$ 0.553	$ -	$ 4.368	$ 4.354
WALC	SoCal Border	SoCal Border	$ -	$ -	$ 4.691	$ 4.139
Coal ($/mmbtu delivered)					$ 1.54	
Average of PRB/Unita (FOB)						$ 2.53
PBR-8.8/0.8%						$ 1.56
Unita-11.7/0.8%						$ 3.50
#2 Oil Used in Study					$ 21.87	
EIA, Spot avg, NYH, $/bbl						$ 21.21
#6 Oil-Low 1%					$ 21.87	
EIA, Spot avg - US Ref Sales Price - Resid/Low Sulf						$ 15.84

Exhibit B-1: Sensitivity to Fuel Price Assumptions

Sources: ICE, published price indexes, DOE coal and oil spot prices. Taxes, Delivery Charges and Hubs were identified in Track 1 Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator Corporation, R.10-05-006