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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
CHAIRMAN

BOB STUMP
COMMISSIONER

BOB BURNS
COMMISSIONER

TOM FORESE
COMMISSIONER

ANDY TOBIN
COMMISSIONER

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION

DOCKET NO. E-00000J-14-0023

THE ALLIANCE FOR SOLAR CHOICE'S (TASC) NOTICE OF FILING ERRATA OF DIRECT TESTIMONIES OF R. THOMAS BEACH AND WILLIAM A. MONSEN

The Alliance for Solar Choice ("TASC") hereby provides this Notice of Filing Errata of the Direct Testimonies of R. Thomas Beach and William A. Monsen in the above referenced matter. Attached you will find corrections to the aforementioned testimonies.

RESPECTFULLY SUBMITTED this 5th day of May, 2016.

Arizona Corporation Commission
DOCKETED
MAY 05 2016
DOCKETED BY

/s/ Court S. Rich
Court S. Rich
Attorney for The Alliance for Solar Choice

Original and 13 copies filed on this 5th day of May, 2016 with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

I hereby certify that I have this day served the foregoing documents on all parties of record in this proceeding by sending a copy via electronic or regular mail to:

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By: ______________________

EXHIBIT A

Errata corrections to

Direct Testimony of R. Thomas Beach

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	ANDY TOBIN COMMISSIONER	

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION

DOCKET NO. E-00000J-14-0023

ERRATA CORRECTIONS TO DIRECT TESTIMONY OF R. THOMAS BEACH

Errata to Exhibit 2 to Direct Testimony of R. Thomas Beach on behalf of TASC

The Benefits and Costs of Solar Distributed Generation for Arizona Public Service

Page	Original	Corrected
8	With these inputs, our forecast of APS's avoided energy costs for solar DG is a 20-year levelized value of 6.3 cents per kWh, in 2014 dollars.	With these inputs, our forecast of APS's avoided energy costs for solar DG is a 20-year levelized value of 6.2 cents per kWh, in 2016 dollars.
14	The result is a solar DG value for transmission capacity equal to about $14 per kW-year for south-facing systems (i.e. $37 per kW-year x 39% contribution to peak) and $19 per kW-year for west-facing.	The result is a solar DG value for transmission capacity equal to about $16 per kW-year for south-facing systems (i.e. $43 per kW-year x 36% contribution to peak) and $23 per kW-year for west-facing.
14	**Table 5** shows these calculations. The result is avoided transmission capacity costs for solar DG of $8 per MWh (0.8 cents per kWh) for south-facing systems and $13 per MWh (1.3 cents per kWh) for west-facing systems.	**Table 5** shows these calculations. The result is avoided transmission capacity costs for solar DG of $9 per MWh (0.9 cents per kWh) for south-facing systems and $16 per MWh (1.6 cents per kWh) for west-facing systems.

EXHIBIT B

Errata corrections to
Direct Testimony of William A. Monsen

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
CHAIRMAN

BOB STUMP
COMMISSIONER

BOB BURNS
COMMISSIONER

TOM FORESE
COMMISSIONER

ANDY TOBIN
COMMISSIONER

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	**DOCKET NO. E-00000J-14-0023**

ERRATA CORRECTIONS TO DIRECT TESTIMONY OF WILLIAM A. MONSEN

The attached includes a complete set of exhibits to Mr. Monsen's testimony that fully incorporate the specific corrections identified below:

- Exhibit WAM-2, p. 2 (APS's Response to TASC's Data Request 1.15): Replaces original page with APS's Supplemental Response to Data Request 1.15 which should have been attached originally.

- Exhibit WAM-2, pp. 7-8 (APS's Response to TASC's Data Request 2.1): This data request response was inadvertently omitted from Mr. Monsen's testimony and is attached hereto.

- Exhibit WAM-3, p 2 (APS Response to Vote Solar' Data Request 1.1) This data request response was inadvertently omitted from Mr. Monsen's testimony and is attached hereto.

- Exhibit WAM-9 was replaced in its entirety by the new Exhibit WAM-9 (PG&E 2014 GRC Phase II Prepared Testimony, p. 2-8). The Settlement Document was inadvertently included instead of the Testimony attached hereto.

Table of Exhibits

Exhibit WAM-1: Resume of William A. Monsen

RESUME FOR WILLIAM ALAN MONSEN

PROFESSIONAL EXPERIENCE

Principal
MRW & Associates, LLC
(1989 - Present)

Specialist in electric utility generation planning, resource auctions, demand-side management (DSM) policy, power market simulation, power project evaluation, and evaluation of customer energy cost control options. Typical assignments include: analysis, testimony preparation and strategy development in large, complex regulatory intervention efforts regarding the economic benefits of utility mergers and QF participation in California's biennial resource acquisition process, analysis of markets for non-utility generator power in the western US, China, and Korea, evaluate the cost-effectiveness of onsite power generation options, sponsor testimony regarding the value of a major new transmission project in California, analyze the value of incentives and regulatory mechanisms in encouraging utility-sponsored DSM, negotiating non-utility generator power sales contract terms with utilities, and utility ratemaking.

Energy Economist
Pacific Gas & Electric Company
(1981 - 1989)

Responsible for analysis of utility and non-utility investment opportunities using PG&E's Strategic Analysis Model. Performed technical analysis supporting PG&E's Long Term Planning efforts. Performed Monte Carlo analysis of electric supply and demand uncertainty to quantify the value of resource flexibility. Developed DSM forecasting models used for long-term planning studies. Created an engineering-econometric modeling system to estimate impacts of DSM programs. Responsible for PG&E's initial efforts to quantify the benefits of DSM using production cost models.

Academic Staff
University of Wisconsin-Madison Solar Energy Laboratory
(1980 - 1981)

Developed simplified methods to analyze efficiency of passive solar energy systems. Performed computer simulation of passive solar energy systems as part of Department of Energy's System Simulation and Economic Analysis working group.

EDUCATION

M.S., Mechanical Engineering, University of Wisconsin-Madison, 1980.

B.S., Engineering Physics, University of California, Berkeley, 1977.

William A. Monsen

Prepared Testimony and Expert Reports

1. California Public Utilities Commission (California PUC) Applications 90-08-066, 90-08-067, 90-09-001
   Prepared Testimony with Aldyn W. Hoekstra regarding the California-Oregon Transmission Project for Toward Utility Rate Normalization (TURN). November 29, 1990.

2. California PUC Application 90-10-003
   Prepared Testimony with Mark A. Bachels regarding the Value of Qualifying Facilities and the Determination of Avoided Costs for the San Diego Gas & Electric Company for the Kelco Division of Merck & Company, Inc. December 21, 1990.

3. California Energy Commission Docket No. 93-ER-94
   Rebuttal Testimony regarding the Preparation of the 1994 Electricity Report for the Independent Energy Producers Association. December 10, 1993.

4. California PUC Rulemaking 94-04-031 and Investigation 94-04-032
   Prepared Testimony Regarding Transition Costs for The Independent Energy Producers. December 5, 1994.

5. Massachusetts Department of Telecommunications and Energy DTE 97-120
   Direct Testimony regarding Nuclear Cost Recovery for The Commonwealth of Massachusetts Division of Energy Resources. October 23, 1998.

6. California PUC Application 97-12-039
   Prepared Direct Testimony Evaluating an Auction Proposal by SDG&E on Behalf of The California Cogeneration Council. June 15, 1999.

7. California PUC Application 99-09-053
   Prepared Direct Testimony of William A. Monsen on Behalf of The Independent Energy Producers Association. March 2, 2000.

8. California PUC Application 99-09-053
   Prepared Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association. March 16, 2000.

9. California PUC Rulemaking 99-10-025
   Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. July 3, 2000.

10. California PUC Application 99-03-014
Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. September 29, 2000.

11. California PUC Rulemaking 99-11-022
Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 7, 2001.

12. California PUC Rulemaking 99-11-022
Rebuttal Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 30, 2001.

13. California PUC Application 01-08-020
Direct Testimony on Behalf of Bear Mountain, Inc. in the Matter of Southern California Water Company's Application to Increase Rates for Electric Service in the Bear Valley Electric Customer Service Area. December 20, 2001.

14. California PUC Application 00-10-045; 01-01-044
Direct Testimony on Behalf of the City of San Diego. May 29, 2002.

15. California PUC Rulemaking 01-10-024
Prepared Direct Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. May 31, 2002.

16. California PUC Rulemaking 01-10-024
Rebuttal Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. June 5, 2002.

17. Arizona Docket Numbers E-00000A-02-0051, E-01345A-01-0822, E-0000A-01-0630, E-01933A-98-0471, E01933A-02-0069
Rebuttal Testimony on Behalf of AES NewEnergy, Inc. and Strategic Energy L.L.C.: Track A Issues. June 11, 2002.

18. California PUC Application 00-11-038
Testimony on Behalf of the Alliance for Retail Energy Markets in the Bond Charge Phase of the Rate Stabilization Proceeding. July 17, 2002.

19. California PUC Rulemaking 01-10-024
Prepared Testimony in the Renewable Portfolio Standard Phase on Behalf of Center for Energy Efficiency and Renewable Technologies. April 1, 2003.

20. California PUC Rulemaking 01-10-024
Direct testimony of William A. Monsen Regarding Long-Term Resource Planning Issues On Behalf of the City of San Diego. June 23, 2003.

21. California PUC Application 03-03-029
Testimony of William A. Monsen Regarding Auxiliary Load Power Metering Policy and Standby Rates on Behalf of Duke Energy North America. October 3, 2003.

22. California PUC Rulemaking 03-10-003
Opening Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation On Behalf of the Local Government Commission Coalition. April 15, 2004.

23. California PUC Rulemaking 03-10-003
Reply Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation on Behalf of Local Government Commission. May 7, 2004.

24. California PUC Rulemaking 04-04-003
Direct Testimony of William A. Monsen Regarding the 2004 Long-Term Resource Plan of San Diego Gas & Electric Company on Behalf of the City of San Diego. August 6, 2004.

25. Sonoma County Assessment Appeals Board
Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. September 10, 2004.

26. Sonoma County Assessment Appeals Board
Presentation of Results from Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. September 10, 2004.

27. Sonoma County Assessment Appeals Board
Presentation of Rebuttal Testimony and Results of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. October 18, 2004.

28. California PUC Rulemaking 04-03-017
Testimony of William A. Monsen Regarding the Itron Report on Behalf of the City of San Diego. April 13, 2005.

29. California PUC Rulemaking 04-03-017
Rebuttal Testimony of William A. Monsen Regarding the Cost-Effectiveness of Distributed Energy Resources on Behalf of the City of San Diego. April 28, 2005.

30. California PUC Application 05-02-019
Testimony of William A. Monsen SDG&E's 2005 Rate Design Window Application on Behalf of the City of San Diego. June 24, 2005.

31. California PUC Rulemaking 04-01-025, Phase II
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 18, 2005.

32. California PUC Application 04-12-004, Phase I
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 29, 2005.

33. California PUC Application 04-12-004, Phase I
Rebuttal Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. August 26, 2005.

34. California PUC Rulemakings 04-04-003 and 04-04-025
Prepared Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. August 31, 2005.

35. California PUC Application 05-01-016 et al.
Prepared Testimony of William A. Monsen Regarding SDG&E's Critical Peak Pricing Proposal on Behalf of the City of San Diego. October 5, 2005.

36. California PUC Rulemakings 04-04-003 and 04-04-025
Prepared Rebuttal Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. October 28, 2005.

37. Colorado PUC Docket No. 05A-543E
Answer Testimony of William A. Monsen on Behalf of AES Corporation and the Colorado Independent Energy Association. April 18, 2006.

38. California PUC Application 04-12-004
Prepared Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 14, 2006.

39. California PUC Application 04-12-004
Prepared Rebuttal Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 31, 2006.

40. Public Utilities Commission of Nevada Dockets 06-06051 and 06-07010
Testimony of William A. Monsen on Behalf of the Nevada Resort Association Regarding Integrated Resource Planning. September 13, 2006.

41. California PUC Application 07-01-047
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company For Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design. August 10, 2007.

42. Colorado PUC Docket No. 07A-447E
Answer Testimony of William A. Monsen on Behalf of the Colorado Independent Energy Association. April 28, 2008.

43. California PUC Application 08-02-001
Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning The Application of San Diego Gas & Electric Company And Southern California Gas Company For Authority To Revise Their Rates Effective January 1, 2009 In Their Biennial Cost Allocation Proceeding. June 18, 2008.

44. California PUC Application 08-02-001
Rebuttal Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning The Application of San Diego Gas & Electric Company And Southern California Gas Company For Authority To Revise Their Rates Effective January 1, 2009 In Their Biennial Cost Allocation Proceeding. July 10, 2008.

45. California PUC Application 08-06-001 et al.
Prepared Testimony of William A. Monsen On Behalf of The California Demand Response Coalition Concerning Demand Response Cost-Effectiveness And Baseline Issues. November 24, 2008.

46. California PUC Application 08-02-001
Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning Revenue Allocation And Rate Design Issues In The San Diego Gas & Electric Company And Southern California Gas Company Biennial Cost Allocation Proceeding. December 23, 2008.

47. California PUC Application 08-06-034
Testimony of William A. Monsen On Behalf of Snow Summit, Inc. Concerning Cost Allocation And Rate Design. January 9, 2009.

48. California PUC Application 08-02-001
Rebuttal Testimony of William A. Monsen on Behalf of The City of Long Beach Gas & Oil Department Concerning Revenue Allocation and Rate Design Issues in The San Diego Gas & Electric Company and Southern California Gas Company Biennial Cost Allocation Proceeding. January 27, 2009.

49. California PUC Application 08-11-014
Testimony of William A. Monsen on Behalf of The City of San Diego Concerning the Application of San Diego Gas & Electric Company tor Authority to Update Cost Allocation and Electric Rate Design. April 17, 2009.

50. Public Utilities Commission of the State of Colorado 09-AL-299E
Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. – Notice of Confidentiality: A Portion of Document Has Been Filed Under Seal. October 2, 2009.

51. Public Utilities Commission of the State of Colorado 09-AL-299E
Supplemental Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. October 8, 2009.

52. Public Utilities Commission of the State of Colorado Docket No. 09AL-299E
Surrebuttal Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. December 18, 2009.

53. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, "Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana," September 15, 2010.

54. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, "Supplemental Findings and Conclusions Regarding Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana," November 2, 2010.

55. California PUC Application 10-05-006
Testimony of William Monsen on Behalf of the Independent Energy Producers Association in Track III of the Long-Term Procurement Planning Proceeding Concerning Bid Evaluation. August 4, 2011.

56. Public Service Company of Colorado Docket No. 11A-869E
Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. June 4, 2012.

57. California PUC Application 11-10-002
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocations, and Electric Rate Design. June 12, 2012.

58. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Cross Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. July 16, 2012.

59. California PUC Rulemaking 12-03-014
Reply Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track One of the Long-Term Procurement Proceeding. July 23, 2012.

60. California PUC Application 12-03-026
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association concerning Pacific Gas and Electric Company's Proposed Acquisition of the Oakley Project. July 23, 2012.

61. California PUC Application 12-02-013
Testimony of William A. Monsen on Behalf of Snow Summit, Inc. Concerning Revenue Requirement, Marginal Costs, and Revenue Allocation. July 27, 2012.

62. California PUC Application 12-03-026
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Pacific Gas and Electric Company's Proposed Acquisition of the Oakley Project. August 3, 2012.

63. California PUC Application 12-02-013
Rebuttal Testimony of William A. Monsen on Behalf of Snow Summit, Inc. in Response to the Division of Ratepayer Advocates' Opening Testimony. August 27, 2012.

64. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Supplemental Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. September 14, 2012.

65. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Supplemental Cross Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. October 5, 2012.

66. Public Utilities Commission of the State Oregon Docket No UM 1182
Northwest and Intermountain Power Producers Coalition Direct Testimony of William A. Monsen. November 16, 2012.

67. Public Utilities Commission of the State Oregon Docket No UM 1182
Northwest and Intermountain Power Producers Coalition Exhibit 300 Witness Reply Testimony of William A. Monsen. January 14, 2013.

68. California PUC Rulemaking 12-03-014
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track 4 of the Long-Term Procurement Plan Proceeding. September 30, 2013.

69. California PUC Rulemaking 12-03-014
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track 4 of the Long-Term Procurement Plan Proceeding. October 14, 2013.

70. California PUC Application 13-07-021
Response Testimony of William A. Monsen on Behalf of Interwest Energy Alliance Regarding the Proposed Merger of NV Energy, Inc. with Midamerican Energy Holdings Company. October 24, 2013.

71. California PUC Application 13-12-012
Testimony of William A. Monsen on Behalf of Commercial Energy Concerning PG&E's 2015 Gas Transmission and Storage Rate Application. August 11, 2014.

72. Public Utilities Commission of Nevada Docket No. 14-05003
Direct Testimony of William A. Monsen on Behalf of Ormat Nevada Inc. August 25, 2014.

73. California PUC Application 13-12-012/I.14-06-016
Rebuttal Testimony of William A. Monsen on Behalf of Commercial Energy Concerning PG&E's 2015 Gas Transmission & Storage Application. September 15, 2014.

74. California PUC Rulemaking 12-06-013
Testimony of William A. Monsen on Behalf of Vote Solar Concerning Residential Electric Rate Design Reform. September 15, 2014.

75. CPUC Rulemaking 13-12-010
Opening Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Phase1A of the 2014 Long-Term Procurement Planning Proceeding. September 24, 2014.

76. CPUC Application 14-01-027
Testimony of William A. Monsen on Behalf of the City Of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. November 14, 2014.

77. CPUC Application 14-01-027
Rebuttal Testimony of William A. Monsen on Behalf of the City Of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. December 12, 2014.

78. CPUC Rulemaking 13-12-010
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Supplemental Testimony in Phase1A of the 2014 Long-Term Procurement Planning Proceeding. December 18, 2014.

79. CPUC Application 14-06-014
Opening Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Standby Rates in Phase 2 of SCE's 2015 Test Year General Rate Case. March 13, 2015.

80. CPUC Application 14-04-014
Opening Testimony of William A. Monsen on Behalf of ChargePoint, Inc. Regarding SDG&E's Vehicle Grid Integration Pilot Program. March 16, 2015.

81. Public Utilities Commission of the State of Hawaii Docket No. 2015-0022
Direct Testimony on Behalf of AES Hawaii, Inc. July 20, 2015.

82. Federal Energy Regulatory Commission Docket Nos. EL02-60-007 and EL02-62-006 (Consolidated)
Prepared Answering Testimony of William A. Monsen on Behalf of Iberdrola Renewables Regarding Rate Impacts of the Iberdrola Contract. July 21, 2015.

83. Public Utilities Commission of Nevada Docket Nos. 15-07041 and 15-07042
Prepared Direct Testimony of William A. Monsen On Behalf of The Alliance for Solar Choice (TASC). October 27, 2015.

Exhibit WAM-2: APS Responses to TASC Data Requests

This Exhibit includes the following Data Responses: TASC DR 1.15, 4.1, and 4.4 (Note: Response to DR 1.15 includes feeder data that has not been included here. It can be provided on request.

TASC'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
JANUARY 26, 2016

TASC 1.15: Please provide, in Excel format, hourly load data, for the most recent historical year for which data is available, for a representative sample of distribution feeders on the APS system.

Response: APS is gathering this information and will provide a response as soon as possible.

Supplemental Response: Attached as APS15804 (in native Excel format) please find hourly data for eight feeders on the APS system that are geographically representative of feeders with primarily residential load. Please note that the majority of feeders in the APS system are dynamic; that is, customer loads on feeders change due to a number of factors including technology adoption, customer growth, infill construction, mix of customer type and others. These feeders may not constitute a representative sample in the future.

TASC'S FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET E-00000J-14-0023 MARCH 14, 2016

TASC 4.1: Please provide hourly loads for all of APS's residential customers for 2014 and 2015 in Excel format. In addition, please provide hourly loads for the following subsets of residential customers:

a. Customers participating in APS's energy efficiency programs;

b. Customers participating in APS's demand response programs;

c. Customers located in the city limits of Phoenix;

d. Customers located in the Phoenix metropolitan area;

e. Customers with rooftop solar;

f. Customers that do not have central air conditioning;

g. Customers that have swimming pools;

h. Customers that have setback thermostats that control their air conditioners;

i. Customers that are dual fuel customers (as discussed on page 26 of Mr. Snook's testimony);

j. Customers living in apartments (as discussed on page 25 of Mr. Snook's testimony);

k. Customers that are "empty nesters" (as discussed on page 25-26 of Mr. Snook's testimony).

For each set of hourly loads, please indicate the average number of customers included in each set.

Response: Hourly loads for each of APS's 1.1 million residential customers would consist of over 9.5 million data points annually, and is too voluminous to provide. However, APS is providing as APS15876 the total hourly load for 2014 for customers on each residential rate APS offers. These loads are disaggregated by each load type used by APS in the 2014 Cost of Service Study as discussed in APS Witness Snook's direct testimony. APS15876 also provides customer counts for each of the load types. Additionally, please see APS15871, provided in the Company's response to TASC Question 3.2, for average hourly loads for dual fuel, winter visitor, and apartment customers for 2014 as discussed in Mr. Snook's testimony. If average per customer loads are desired, please divide the total hourly loads by the customer count provided.

TASC'S FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET E-00000J-14-0023
MARCH 14, 2016

TASC 4.1 Supplemental Response:

a - b. APS does not possess hourly load data for energy efficiency and demand response participants as the Company's customer information system (CIS) does not track these customers.

c – d. APS objects to this request as unduly burdensome and seeking irrelevant information that is not likely to lead to the discovery of admissible evidence. Further, no documents exist with this information. Although APS's customer information system does contain the zip codes in which customers live, any document showing this information would have to be created through targeted queries to its database, compilation of data, and organization and labeling of data into an understandable Excel format.

e. Please see APS15876 for total hourly loads and customer counts of customers with rooftop solar, from which an average hourly load can be easily derived.

f – h. APS does not possess hourly load data for central air conditioning, swimming pools, or setback thermostat customers as the Company's CIS does not track these customers.

i – j. Please see APS15878, provided in the Company's second supplemental response to TASC Question 3.2, for average hourly loads for dual fuel customers and apartment dwellers.

k. APS does not possess hourly load data for "empty nesters", as CIS does not track these customers.

TASC'S FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET E-00000J-14-0023 MARCH 14, 2016

TASC 4.4: Is APS aware of any instances in which power flows from residential NEM systems interconnected at the secondary distribution voltage level have resulted in power being backfed onto APS's transmission system? If your response is anything except for an unqualified "no," please provide data indicating precisely when such backfeeding occurred and the costs incurred by APS as a result of that backfeeding.

Response: APS is not currently aware of any power backfed into APS's transmission system solely from residential NEM systems; however, APS is aware of several distribution feeders that have experienced reverse flow directly due to residential NEM systems.

Attached as APS15879 is a table showing APS's top 25 distribution feeders by interconnected residential NEM systems and the number of NEM systems connected to each. The eleven feeders that experienced reverse power flow in 2015 are designated in yellow.

To date, APS has not incurred equipment or system costs directly attributable to these reverse power flows. Given the increasing penetration of rooftop solar, however, APS anticipates that the severity of reverse power flows will only increase.

Reverse Power Flows in 2015 – Highest System Count NEM Distribution Feeders				
Feeder	**NEM System Count**	**Lowest 15 Min**	**Lowest 15 Min 2015 (MWs)**	**Total Hours of Reverse Flow**
1	848	5/8 @ 12:45	-0.9368	328.75
2	702	1/16 @ 13:15	0.0005	
3	689	5/9 @ 12:45	-2.0783	935.50
4	467	4/16 @ 13:00	-0.6794	133.25
5	451	5/8 @ 12:45	-0.5829	49.75
6	409	5/8 @ 12:45	-0.4658	184.50
7	402	3/15 @ 12:30	1.1599	
8	353	4/16 @ 10:30	0.0203	
9	338	8/7 @ 19:45	-0.0008	18.00
10	331	9/29 @ 10:15	-0.0011	2.25
11	324	10/8 @ 13:15	1.2314	
12	322	5/8 @ 13:30	-0.1282	15.75
13	284	11/17 @ 13:00	0.8633	
14	274	11/6 @ 13:30	0.8384	
15	268	4/16 @ 12:30	0.4930	
16	260	4/16 @ 12:30	0.6152	
17	258	11/5 @ 12:15	0.7298	
18	253	5/8 @ 13:45	-0.1101	29.00
19	229	4/27 @ 11:15	-0.0020	0.50
20	228	6/10 @ 9:15	0.0008	
21	224	4/16 @ 12:30	0.1960	
22	208	11/9 @ 10:15	1.0964	
23	202	9/2 @ 3:30	4.5452	
24	194	9/23 @ 3:00	2.2743	
25	189	3/9 @ 13:15	-0.0927	1.50

TASC'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET E-00000J-14-0023 FEBRUARY 3, 2016

TASC 2.1: Please provide the following data from APS's 2014 Integrated Resource Plan (IRP), in Excel format.

a. The output data (including hourly production and emission costs in $/MWh) from the PROMOD IV runs for the four major IRP scenarios, as cited in the IR, pp. 55 and 97.

b. The data for the key inputs for the IRP PROMOD runs, including:

1. Natural gas price forecast (IRP Figure 11);
2. Carbon costs (IRP Figure 12);
3. Loads;
4. New resources; and
5. Assumed retirements.

c. Unredacted Tables 19, 20, and 26.

d. Please provide any calculation that APS has performed of the additional up- or down-ramp costs associated with increasing amounts of solar generation, as discussed on page 43 of the IRP.

e. Please provide a quantitative example of how "as a matter of practice, APS routinely includes estimates of grid integration costs into its planning analytics," as stated on page 44 of the IRP.

f. Please provide unredacted Attachments C, D, and F (including all subparts) to the IRP in Excel format.

g. Please provide the details of APS's imputed debt calculations in Attachment D.10 of the IRP.

h. Please provide the data in Attachment D.10 for all four of the portfolios *Base Enhanced Renewables, Coal Reduction, Coal-to-Gas) modeled in the IRP.

i. Please provide the annual transmission capital additions from 2014-2029 in each of the four primary IRP scenarios.

j. Please provide the assumptions used in APS's application of the Societal Cost Test for the energy efficiency programs included in Tables 34 and 35 of the IRP. Include all avoided cost assumptions included in the Societal Benefits, in all years, for (1) energy, (2) generation capacity, (3) avoided line losses, (4) avoided T&D capacity, (5) avoided carbon and/or environmental costs, and (6) any other avoided "societal" costs.

k. Please provide any calculations that APS has performed quantifying any of the four Distributed Energy risks discussed on page 17 of the IRP, for any of the IRP scenarios.

l. Please provide the capital costs and annual first-year revenue requirements associated with the future transmission projects listed on page 79 of the IRP.

Response: APS's response to these questions provides native Excel files only in those instances where a native file contains calculations (other than sums of columns) showing the derivation of the file content or where a printout of the content would be voluminous.

a. APS objects to this question for the following reasons: PROMOD hourly outputs in the IRP scenarios are not extracted in the normal course of modeling the APS system and would require additional model runs to retrieve the data. Moreover, retrieving this data would result in tens of thousands of documents in a document format unique to PROMOD. And, hourly PROMOD outputs contain system and unit-specific competitively confidential data.

b. The data for the key inputs for the IRP PROMOD runs are provided in the following files:

   1. APS15808, Natural Gas Price Forecast (IRP Figure 11);
   2. APS15809, Carbon costs (IRP Figure 12);
   3. APS15810, Loads;
   4. New resource assumptions are outlined in APS15820, provided in response to TASC Data Request 2.1(f); and
   5. All cases in the IRP assume retirements of 220 MW of steam generation at Ocotillo on 9/30/2017. The coal reduction portfolio assumes retirement of Cholla 2 on 4/1/2016, and Cholla units 1 and 3 on 12/31/2024.

c. Table 19 (APS15811) and Table 26 (APS15812) are provided in unredacted form. Table 20 was provided in unredacted form in TASC Data Request 1.4.

d. APS utilized PROMOD to evaluate portfolio requirements under alternative scenarios. The cost of meeting ramping requirements is embedded in the 2014 portfolio costs from the model and is not separately identified. In addition, please see

Exhibit WAM-3: APS Responses to Vote Solar Data Requests

This Exhibit includes the following Data Responses: Vote Solar DR 1.1, 2.1, 2.3, and 2.4

ARIZONA CORPORATION COMMISSION
VOTE SOLAR'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
DECEMBER 14, 2015

Vote Solar 1.1: In an October 8, 2015 letter filed in Docket No. E-01345A-13-0248, APS stated that it has completed a cost of service study regarding solar customers. Please provide a copy of the cost of service study and supporting workpapers in executable Excel format with formulas and links intact.

Response: Attached are the following workpapers that support the cost of service study summary APS filed on October 8, 2015.

- The cost of service study (APS15744)
- The revenue requirement report (APS15745)
- The allocation factor workbook (APS15746)
- The 2014 load data (APS15747)
- The cost of service working model (APS15748) - please note this model is only provided in excel and is not part of the PDF package.

2014 Allocation Factor Input Page

Line No.	Customer Class	# of Customers	Energy Consumption (MWH)	Delivery Level %	CP (kW)	4CP (kW)	12CP (kW)	NCP (kW)	Ind. Max (kW)	Delivery Level %	Line No.
	Residential										
0	Residential - Solar Site (Energy Rates)	27,078	369,769		122,495	112,553	73,588	122,816	198,649		0
0	Residential - Solar Site (Demand Rates)	1,176	25,432		7,536	6,954	4,696	7,568	11,693		0
1	E-12 (No Solar)	468,372	3,579,549		947,566	865,097	647,709	1,106,357	2,137,411		1
2	ET-1 (No Solar)	140,698	2,328,525		706,794	637,055	439,842	802,832	1,170,152		2
3	ECT-1R (No Solar)	27,488	726,448		199,141	179,779	127,494	212,342	309,249		3
4	ET-2 (No Solar) w/ET-SP	288,729	4,030,856		1,172,586	1,080,109	751,280	1,341,792	2,168,198		4
5	ECT-2 (No Solar)	91,248	2,020,487		552,582	510,485	353,463	606,438	907,202		5
6	**Total Residential**	**1,044,789**	**13,081,066**		**3,708,700**	**3,392,032**	**2,398,072**	**4,202,145**	**6,908,554**		**6**
	General Service										
7	**E-20**	409	38,842		11,200	8,900	6,517	22,943	28,136		7
8	E-30,E-32 0-20kW	106,780	1,432,985		270,400	262,350	239,683	341,726	548,276		8
9	E-32 21-100kW	14,494	2,572,375		538,400	508,725	399,317	636,796	847,773		9
10	Total E-30, E-32 0-100kW	121,274	4,005,360		808,800	771,075	639,000	978,522	1,396,049		10
11	Total E-30, E-32 0-100kW @ Dist. Primary	53		0.001700					2,351	0.001684	11
12	Total E-30, E-32 0-100kW @ Secondary Txf	121,221		0.998300					1,393,698	0.998316	12
13	Total E-32 101-400kW	4,252	3,188,803		550,900	509,900	440,242	628,994	814,527		13
14	Total E-32 101-400kW @ Dist. Primary	35		0.012000					12,873	0.015804	14
15	Total E-32 101-400kW @ Secondary Txf	4,217		0.988000					801,654	0.984196	15
16	Total E-32 401-999kW	694	1,699,183		261,900	239,900	226,667	298,642	353,653		16
17	Total E-32 1,000+kW	101	1,188,116		184,000	158,750	123,558	195,966	244,300		17
18	Total E-32 401+kW	795	2,887,299	-	445,900	398,650	350,225	494,608	597,953		18
19	Total E-32 401+kW @ Transmission Level	5		0.005000					3,745	0.006263	19
20	Total E-32 401+kW @ Dist. Primary	57		0.132800					100,227	0.167617	20
21	Total E-32 401+kW @ Secondary Txf	733		0.862200					493,981	0.826120	21
22	**Total E-30,E-32**	126,321	10,081,462		1,805,600	1,679,625	1,429,467	2,102,124	2,808,529		22
23	E-32 TOU 0-20kW	204	3,519		500	500	583	837	1,384		23
24	E-32 TOU 21-100kW	132	34,740		5,000	4,550	4,133	5,788	8,100		24
25	Total E-32 TOU 0-100kW	336	38,259		5,500	5,050	4,716	6,625	9,484		25
26	Total E-32 TOU 0-100kW @ Dist. Primary	1		0.003200					50	0.005272	26
27	Total E-32 TOU 0-100kW @ Secondary Txf	335		0.996800					9,434	0.994728	27
28	E-32 TOU 101-400kW	73	70,694		10,800	10,200	9,000	11,666	15,770		28
	Total E-32 TOU 101-400kW @ Dist. Primary			0.114800					2,729	0.173050	
	Total E-32 TOU 101-400kW @ Secondary Txf			0.885200					13,041	0.826950	
29	E-32 TOU 401-999kW	43	132,818		18,500	16,200	14,992	19,860	24,674		29
30	E-32 TOU 1000+kW	14	131,780		15,200	16,525	15,467	23,900	30,200		30
31	Total E-32 TOU 401+kW	57	264,598		33,700	32,725	30,459	43,760	54,874		31
32	Total E-32 TOU 401+kW @ Dist. Primary	10		0.192100					9,110	0.166017	32
33	Total E-32 TOU 401+kW @ Secondary Txf	47		0.807900					45,764	0.833983	33
34	**Total E-32 TOU**	466	373,551		50,000	47,975	44,175	62,051	80,128		34
35	**General Service School TOU**	116	110,696		15,200	16,150	14,808	36,939	40,172		35
36	**Total E-34**	30	881,656		143,500	137,475	117,150	152,848	171,923		36
37	Total E-34 @ Transmission Level	3		0.138300					21,468	0.124870	37
38	Total E-34 @ Dist. Substation	-		0.000000					-	0.000000	38
39	Total E-34 @ Dist. Primary	18		0.652700					101,289	0.589153	39
40	Total E-34 @ Secondary Txf	9		0.209000					49,166	0.285977	40
41	**Total E-35**	37	2,127,615		256,500	255,400	245,900	288,761	336,110		41
42	Total E-35 @ Transmission Level	3		0.084300					20,189	0.060067	42
43	Total E-35 @ Dist. Substation	-		0.000000					-	0.000000	43
44	Total E-35 @ Dist. Primary	13		0.423200					101,332	0.301485	44
45	Total E-35 @ Secondary Txf	21		0.492500					214,589	0.638449	45
46	**Total General Service**	**127,379**	**13,613,822**		**2,281,000**	**2,145,525**	**1,858,017**	**2,665,666**	**3,464,998**		**46**
47	E-221	1,467	346,679		42,500	40,175	36,475	73,365	123,951		47
48	STREETLIGHTS	1,023	142,665		-	-	8,250	33,000	33,000		48
49	DUSK TO DAWN	8,319	22,969		-	-	1,325	5,300	5,300		49
50	**Total ACC**	**1,182,977**	**27,207,201**		**6,032,200**	**5,577,732**	**4,302,139**	**6,979,476**	**10,535,803**		**50**

2014 Allocation Factor Input Page

ENERGY

Line Loss Values

1.01300	(3) to (4)
1.00900	(4) to (5)
1.01800	(5) to (6)
1.00200	(6) to (7)
1.00906	(7) to (8)
1.02503	(8) to (9)
1.07837	

DEMAND

Line Loss Values

1.01900	(3) to (4)
1.01300	(4) to (5)
1.02600	(5) to (6)
1.00300	(6) to (7)
1.01201	(7) to (8)
1.01888	(8) to (9)
1.09532	

Revenue Credit Customers							
BHP MINERAL	1	49,918	9,800	5,225	5,942	15,200	15,200
MEXICO TAP BOSE	1	26,014	4,400	4,325	3,317	4,700	4,700
MEXICO TAP DEMDA	1	1,025	100	150	117	700	700
MEXICO TAP MECOX	1	1,344	300	250	200	500	500
MEXICO TAP PAULSON	1	4,594	900	900	667	1,300	1,300
SOLANA PLANT	1	34,343	-	-	2,958	20,100	20,100
DUKE ARLINGTON	1	16,331	-	-	183	17,000	17,000
HARQUAHALA PLANT	1	16,340	-	-	1,542	11,200	11,200
MESQUITE PLANT	1	2,658	-	-	158	9,600	9,600
PANDA PLANT	1	24,853	-	-	500	18,100	18,100
Total Revenue Credit Customers	10	177,420	15,500	10,850	15,584	98,400	98,400
	1,182,987	27,384,621	6,047,700	5,588,582	4,317,723	7,077,876	10,634,203
Residential - E-12 Solar Delivered	10,305	72,787	26,734	22,478	15,974	32,422	54,700
Residential - ET-1 Solar Delivered	5,119	61,194	21,906	18,645	12,800	25,898	39,869
Residential - ET-2 Solar Delivered	11,654	133,231	46,214	40,016	27,395	56,417	85,326
Residential - Solar Delivered (Energy Rates)	27,078	267,212	94,854	81,139	56,169	114,737	179,895
Residential - E-12 Solar Net	10,305	10,781	24,553	18,850	13,240	32,422	54,700
Residential - ET-1 Solar Net	5,119	29,873	21,273	17,434	11,808	25,898	39,869
Residential - ET-2 Solar Net	11,654	70,642	44,913	37,487	25,338	56,417	85,326
Residential - Solar Net (Energy Rates)	27,078	111,296	90,739	73,771	50,386	114,737	179,895
Residential - ECT-1 Solar Delivered	355	6,917	2,259	1,921	1,364	2,575	3,831
Residential - ECT-2 Solar Delivered	821	12,775	3,918	3,465	2,437	4,799	7,083
Residential - Solar Delivered (Demand Rates)	1,176	19,692	6,177	5,386	3,801	7,374	10,914
Residential - ECT-1 Solar Net	355	4,827	2,235	1,866	1,318	2,575	3,831
Residential - ECT-2 Solar Net	821	8,766	3,851	3,324	2,318	4,798	7,083
Residential - Solar Net (Demand Rates)	1,176	13,593	6,086	5,190	3,636	7,373	10,914
Residential - E-12 Solar Received	-	62,006	2,181	3,628	2,734	-	-
Residential - ET-1 Solar Received	-	31,321	633	1,211	992	-	-
Residential - ET-2 Solar Received	-	62,589	1,301	2,529	2,057	-	-
Residential - Solar Received (Energy Rates)	-	155,916	4,115	7,368	5,783	-	-
Residential - ECT-1 Solar Received	-	2,090	24	55	46	-	-
Residential - ECT-2 Solar Received	-	4,009	67	141	119	1	-
Residential - Solar Received (Demand Rates)	-	6,099	91	196	165	1	-
Residential - E-12 Solar Site	10,305	105,638	35,929	32,860	21,683	35,929	61,904
Residential - ET-1 Solar Site	5,119	82,880	27,748	25,227	16,476	27,748	43,617
Residential - ET-2 Solar Site	11,654	181,251	58,818	54,466	35,429	59,139	93,128
Residential - Solar Site (Energy Rates)	27,078	369,769	122,495	112,553	73,588	122,816	198,649
Residential - E-12 Solar Delivered	10,305	72,787	26,734	22,478	15,974	32,422	54,700
Residential - ET-1 Solar Delivered	5,119	61,194	21,906	18,645	12,800	25,898	39,869
Residential - ET-2 Solar Delivered	11,654	133,231	46,214	40,016	27,395	56,417	85,326
Residential - Solar Delivered (Energy Rates)	27,078	267,212	94,854	81,139	56,169	114,737	179,895
Residential - ECT-1 Solar Site	355	8,649	2,651	2,376	1,623	2,658	4,046
Residential - ECT-2 Solar Site	821	16,783	4,885	4,578	3,073	4,910	7,647
Residential - Solar Site (Demand Rates)	1,176	25,432	7,536	6,954	4,696	7,568	11,693
Residential - ECT-1 Solar Delivered	355	6,917	2,259	1,921	1,364	2,575	3,831
Residential - ECT-2 Solar Delivered	821	12,775	3,918	3,465	2,437	4,799	7,083
Residential - Solar Delivered (Demand Rates)	1,176	19,692	6,177	5,386	3,801	7,374	10,914
Residential - E-12 Solar (Customer Usage)		32,851	9,196	10,382	5,709	3,507	7,204
Residential - ET-1 Solar (Customer Usage)		21,686	5,842	6,582	3,676	1,850	3,748
Residential - ET-2 Solar (Customer Usage)		48,020	12,604	14,450	8,034	2,722	7,802
Residential - Solar (Customer Usage)(Energy Rates)		102,557	27,641	31,414	17,419	8,079	18,754
Residential - ECT-1 Solar (Customer Usage)		1,732	392	455	259	83	215
Residential - ECT-2 Solar (Customer Usage)		4,008	967	1,113	636	111	564
Residential - Solar (Customer Usage)(Demand Rates)		5,740	1,359	1,568	895	194	779
Residential - E-12 Total Solar Generation		94,857	11,376	14,010	8,443	3,507	7,204
Residential - ET-1 Solar Generation		53,007	6,475	7,793	4,668	1,850	3,748
Residential - ET-2 Solar Generation		110,609	13,905	16,979	10,091	2,722	7,802
Residential - Solar Generation (Energy Rates)		258,473	31,756	38,782	23,202	8,079	18,754
Residential - ECT-1 Solar Generation		3,822	416	510	305	83	215
Residential - ECT-2 Solar Generation		8,017	1,034	1,254	755	112	564
Residential - Solar Generation (Demand Rates)		11,839	1,450	1,764	1,060	195	779

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
JANUARY 4, 2016

Vote Solar 2.1: Regarding APS's October 8, 2015 Cost of Service letter filed in Docket No. E-01345A-13-0248:

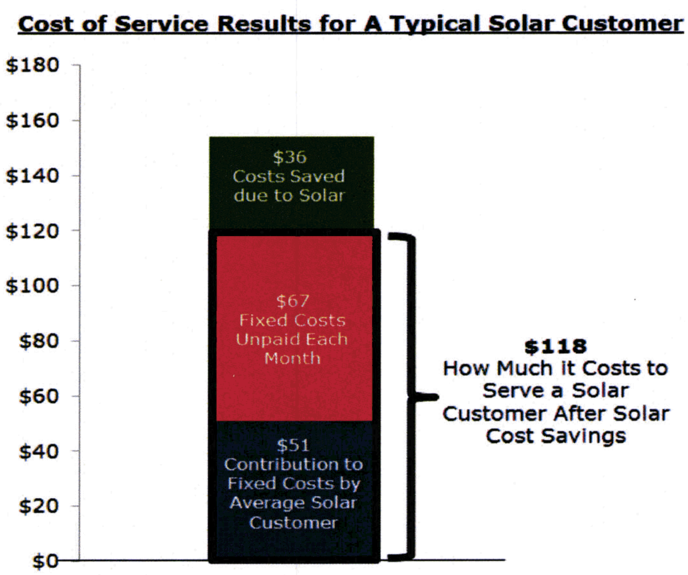
On page 2 of APS's October 8, 2015 Cost of Service letter, the Company provided a chart depicting the "Cost of Service Results for A Typical Solar Customer." Please provide all workpapers supporting this chart, including linked references to the Cost of Service Working Model provided by APS in response to VS 1.1.

Response: See attached as APS15767 for the workpapers supporting this chart.

Back-Up for Chart:

	(A)		(B)	(C)	(D)
	Total Monthly Cost to Serve Typical Solar Customer		What Solar Customers Should Pay	What Solar Customers are Actually Paying	Unrecovered Amount (Column B-C)
Base Cost to Serve a Customer	$136		$104	$44	$61
Adjustors	$18		$14	$8	$6
Total	$154		$118	$51	$67

Costs Saved due to Solar	$36



Residential Solar @ Actual ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement after Energy and Demand Credits

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802	$0	$6,216,972	$26,756,298	$20,811,249	$0	$4,840,752	$0	$0	$3,019,457	$114,452,899
2)	Customer Accounts							$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				(42,827)	(184,236)	(143,295)						(370,358)
5)	Customer Advances	(15,924)			(71,725)	(308,550)	(239,982)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,420	$26,263,512	$20,427,972	$2,374,732	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Actual Earned ROR @ -5.36%												
8)	Return on Rate Base (Line 6 * Line 7)	($2,759,039)	($72,780)	$0	($327,339)	($1,408,796)	($1,095,773)	($127,383)	($259,662)	($5,787)	($6,536)	($161,966)	($6,225,060)
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	($2,603,557)	($68,679)	$0	($308,892)	($1,329,405)	($1,034,022)	($120,204)	($245,029)	($5,460)	($6,167)	($152,839)	($5,874,254)
	Expenses												
12)	Expenses	$8,029,855	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$0	$1,337,751	$0	$0	$1,208,737	$29,172,005
13)	Customer Accounts	$0	$0	$0	$0	$0	$0	$1,533,621	$0	$304,642	$115,894	$0	$1,954,157
14)	Cust. Service & Info and Sales Expense	$0	$0	$0	$0	$0	$0	$700,635	$0	$0	$0	$0	$700,635
15)	Total Expenses	$8,029,855	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,257	$1,337,751	$304,642	$115,894	$1,208,737	$31,826,798
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$2,667,259	$9,496,171	$3,561,494	($68,947)	$52,906	($91,648)	$1,986,670	$833,061	$293,395	$103,191	$893,932	$19,727,483
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584	$9,763	$22,010	$0	$0	$0	$5,574,020
18)	**REVENUE REQUIREMENT @-5.36%**	**$1,068,886**	**$6,762,177**	**$2,714,428**	**($104,347)**	**($148,925)**	**($217,232)**	**$1,976,907**	**$811,050**	**$293,395**	**$103,191**	**$893,932**	**$14,153,463**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0040**	**0.0253**	**0.0102**	**-0.0004**	**-0.0006**	**-0.0008**	**0.0074**	**0.0030**	**0.0011**	**0.0004**	**0.0033**	**0.0530**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$3.29**	**$20.81**	**$8.35**	**-$0.32**	**-$0.46**	**-$0.67**	**$6.08**	**$2.50**	**$0.90**	**$0.32**	**$2.75**	**$43.56**

Residential Solar @ Targeted ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement after Energy and Demand Credits

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802	$0	$6,216,972	$26,756,298	$20,811,249		$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							1,794,234		107,877	121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				(42,827)	(184,236)	(143,295)						(370,358)
5)	Customer Advances	(15,924)			(71,725)	(308,550)	(239,982)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,420	$26,263,512	$20,427,972	$2,374,732	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Targeted ROR @ 4.99%												
8)	Return on Rate Base (Line 6 * Line 7)	$2,566,629	$67,704	$0	$304,511	$1,310,549	$1,019,356	$118,499	$241,554	$5,383	$6,080	$150,671	$5,790,935
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	$828,727	$21,861	$0	$98,322	$423,157	$329,135	$38,262	$77,994	$1,738	$1,963	$48,649	$1,869,809
	Expenses												
12)	Expenses	8,029,855	9,637,630	3,561,494	567,284	2,791,108	2,038,147		$1,337,751			$1,208,737	$29,172,005
13)	Customer Accounts							1,533,621		304,642	115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$8,029,855	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,257	$1,337,751	$304,642	$115,894	$1,208,737	$31,826,798
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$11,425,211	$9,727,195	$3,561,494	$970,116	$4,524,814	$3,386,638	$2,391,017	$1,657,299	$311,763	$123,937	$1,408,057	$39,487,542
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584	$9,763	$22,010	$0	$0	$0	$5,574,020
18)	**REVENUE REQUIREMENT @4.99%**	**$9,826,838**	**$6,993,201**	**$2,714,428**	**$934,717**	**$4,322,984**	**$3,261,054**	**$2,381,255**	**$1,635,289**	**$311,763**	**$123,937**	**$1,408,057**	**$33,913,522**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0368**	**0.0262**	**0.0102**	**0.0035**	**0.0162**	**0.0122**	**0.0089**	**0.0061**	**0.0012**	**0.0005**	**0.0053**	**0.1269**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$30.24**	**$21.51**	**$8.35**	**$2.88**	**$13.30**	**$10.04**	**$7.33**	**$5.03**	**$0.96**	**$0.38**	**$4.33**	**$104.36**
23)	**Under Recovery (Targeted less Actual)($/Cust/Month)**	**$26.95**	**$0.70**	**$0.00**	**$3.20**	**$13.76**	**$10.70**	**$1.24**	**$2.54**	**$0.06**	**$0.06**	**$1.58**	**$60.80**

Residential Targeted ROR	Weighted Residential ROR
Rate Base	$ [illegible]
Operating Income	[illegible]
Current Rate of Return	[illegible]

Residential Solar @ Actual ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement before Energy Credits

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249	$0	$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				($42,810)	($184,243)	($143,305)						(370,358)
5)	Customer Advances	($15,924)			($71,696)	($308,560)	($240,001)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Actual Earned ROR @ -10.77%												
8)	Return on Rate Base (Line 6 * Line 7)	($5,539,575)	($146,127)	$0	($657,233)	($2,828,567)	($2,200,080)	($256,757)	($521,347)	($11,618)	($13,122)	($325,194)	($12,498,621)
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	($4,395,555)	($115,949)	$0	($521,503)	($2,244,418)	($1,745,725)	($202,939)	($413,680)	($9,219)	($10,412)	($258,036)	($9,917,435)
	Expenses												
12)	Expenses	10,277,250	17,706,894	3,561,494	$567,284	$2,791,108	$2,038,147		$1,337,751			$1,208,737	$39,488,665
13)	Customer Accounts							$1,533,621		$304,642	$115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$10,277,250	$17,706,894	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$42,143,457
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$342,121	$17,444,818	$3,561,494	($611,452)	($2,281,877)	($1,907,658)	$1,775,559	$402,725	$283,805	$92,359	$625,507	$19,727,401
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584	$9,763	$22,010	$0	$0	$0	$5,574,021
18)	**REVENUE REQUIREMENT @-10.77%**	**($1,256,252)**	**$14,710,824**	**$2,714,428**	**($646,852)**	**($2,483,706)**	**($2,033,242)**	**$1,765,796**	**$380,715**	**$283,805**	**$92,359**	**$625,507**	**$14,153,380**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**-0.0047**	**0.0551**	**0.0102**	**-0.0024**	**-0.0093**	**-0.0076**	**0.0066**	**0.0014**	**0.0011**	**0.0003**	**0.0023**	**0.0530**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**-$3.87**	**$45.27**	**$8.35**	**-$1.99**	**-$7.64**	**-$6.26**	**$5.43**	**$1.17**	**$0.87**	**$0.28**	**$1.93**	**$43.56**

Residential Solar @ Targeted ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249		$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							1,794,234		107,877	121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				(42,810)	(184,243)	(143,305)						(370,358)
5)	Customer Advances	(15,924)			(71,696)	(308,560)	(240,001)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Targeted ROR @ 4.99%												
8)	Return on Rate Base (Line 6 * Line 7)	$2,566,629	$67,704	$0	$304,513	$1,310,548	$1,019,354	$118,499	$241,554	$5,383	$6,080	$150,671	$5,790,935
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	$828,727	$21,861	$0	$98,323	$423,157	$329,135	$38,262	$77,994	$1,738	$1,963	$48,649	$1,869,809
	Expenses												
12)	Expenses	10,277,250	17,706,894	3,561,494	567,284	2,791,108	2,038,147		$1,337,751			$1,208,737	$39,488,665
13)	Customer Accounts							1,533,621		304,642	115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$10,277,250	$17,706,894	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$42,143,457
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$13,672,606	$17,796,459	$3,561,494	$970,120	$4,524,814	$3,386,636	$2,391,017	$1,657,299	$311,763	$123,937	$1,408,057	$49,804,202
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584	$9,763	$22,010	$0	$0	$0	$5,574,021
18)	**REVENUE REQUIREMENT @4.99%**	**$12,074,233**	**$15,062,465**	**$2,714,428**	**$934,720**	**$4,322,983**	**$3,261,052**	**$2,381,254**	**$1,635,289**	**$311,763**	**$123,937**	**$1,408,057**	**$44,230,181**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0452**	**0.0564**	**0.0102**	**0.0035**	**0.0162**	**0.0122**	**0.0089**	**0.0061**	**0.0012**	**0.0005**	**0.0053**	**0.1655**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$37.16**	**$46.35**	**$8.35**	**$2.88**	**$13.30**	**$10.04**	**$7.33**	**$5.03**	**$0.96**	**$0.38**	**$4.33**	**$136.11**
23)	**Under Recovery (Targeted less Actual)[$/Cust/Month]**	**$41.02**	**$1.07**	**$0.00**	**$4.87**	**$20.95**	**$16.29**	**$1.89**	**$3.86**	**$0.09**	**$0.10**	**$2.41**	**$92.55**

Note: The target ROR of 4.99% is the average residential non-solar ROR.

	Demand Credit	Energy Credit
Line 12 before credits	**$10,277,250**	**$17,706,894**
Line 12 after credits	**$8,029,855**	**$9,637,630**
Difference is the credits	**($2,247,395)**	**($8,069,264)**

	Weighted Residential ROR
Residential Targeted ROR	
Rate Base	$ 3,856,521,439
Operating Income	192,497,895
Current Rate of Return	4.99%

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
JANUARY 4, 2016

Vote Solar 2.3: Regarding APS's October 8, 2015 Cost of Service letter filed in Docket No. E-01345A-13-0248:

On page 2 of APS's October 8, 2015 Cost of Service letter, the Company stated that its cost of service study "incorporates and credits to solar customers the measurable costs that APS avoids when a customer installs rooftop solar."

a) Please list the categories of avoided costs that APS incorporated into its cost of service study.

b) Please describe the methodology APS used to calculate each category of avoided costs listed in response to subquestion (a).

c) For each category of avoided costs listed in response to subquestion (a), please describe where the Cost of Service Working Model provided in response to VS 1.1 calculates each avoided cost.

Response: a & b. In the cost of service study, the avoided costs for which APS credited solar customers are:

- A "Production Demand Credit" which provides the solar customers with a credit for their reduced demand on APS's system. This was calculated by taking the total megawatts APS delivers to the customer as a percent of the customer's total site load (see APS's response to VS 2.4.c 'Solar Site' for a description of this term) for both non-coincident and coincident peak during the 4 system peak months of the year (June-September). This is consistent with the "average and excess" method of allocating production demand cost required by the ACC. This then derived a blended average that credits the solar customers for offsetting a portion of APS's peak load. The total amount credited for solar energy customers was $2.2M (or a reduction of 18.66% in their production demand cost) and for solar demand customers it was $109k (or a reduction of 14.64% in their production demand cost). See APS15768.

- An "Energy Fuel Credit" which provides the solar customers with a credit for the energy they actually produce. This is calculated by first grossing up their total energy production to recognize the line loss benefit. Then APS applied the EPR-6 excess generation rate (see APS15773 for a copy of the EPR-6 tariff) to the grossed up amount of energy produced to calculate the Energy Fuel Credit. This amount is then credited to the solar energy customers. The total amount credited for solar energy customers was $8M and for solar demand customers it was $370k. See APS15768.

- An explicit "Transmission Credit" was not developed in this study. However, transmission costs were allocated on a delivered energy basis. This is conservative and over-credits solar energy customers for avoided transmission. A more precise method would be to allocate cost at the 4 system coincident peak months and credit the difference based on the delivered data.

- A "Distribution Credit" was not applied since the non-coincident peak occurred at nearly the same time for both site and delivered data, thus indicating no significant avoided distribution costs.

No other avoided costs existed as a results of rooftop solar generation.

c. The credits are inputs into the working model, but attached as APS15768 are the workpapers that calculate each avoided cost mentioned above. The calculation is done as a separate analysis using load data and information from the cost of service and then the credits are applied in the O&M report in the cost of service, which reduces the overall cost to serve those customers.

ARIZONA PUBLIC SERVICE COMPANY
Solar Cost of Service Study
Production Energy Credit
Test Year Ending 12/31/2014

	Customer Class	MWhs @ Customer Level	MWhs @ Generation Level	EPR-6 Fuel Rate (cents/kWh)	2014 Solar Fuel Credit
1.	Residential - Solar Generation (Energy Rates)	258,473	278,731	2.895	$8,069,264
2.	Residential - Solar Generation (Demand Rates)	11,839	12,767	2.895	$369,612
3.	Total	270,312	291,498		$8,438,876

ARIZONA PUBLIC SERVICE COMPANY
Solar Cost of Service Study
Production Demand Credit
Test Year Ending 12/31/2014

	Customer Class	Coincident Peak (MW) Delivered	Coincident Peak (MW) Site	Class NCP [On-Peak] (MW) Delivered	Class NCP [On-Peak] (MW) Site
1.	Residential - Solar Generation (Energy Rates)				
	June	76.5	104.1	93.4	104.8
	July	94.9	122.5	111.3	122.5
	August	93.2	119.8	94.2	105.1
	September	60.0	103.8	99.2	107.1
	Average	81.2	112.6	99.5	109.9
	Relationship - Delivery versus Site		27.90%		9.42%
	Peak 2 Point Average				**18.66%**

	Customer Class	Coincident Peak (MW) Delivered	Coincident Peak (MW) Site	Class NCP [On-Peak] (MW) Delivered	Class NCP [On-Peak] (MW) Site
2.	Residential - Solar Generation (Demand Rates)				
	June	5.1	6.5	6.1	6.6
	July	6.2	7.5	7.1	7.5
	August	6.2	7.5	6.0	6.5
	September	4.0	6.3	6.2	6.6
	Average	5.4	7.0	6.4	6.8
	Relationship - Delivery versus Site		22.66%		6.62%
	Peak 2 Point Average				**14.64%**

Calculation of Demand Credit - Residential - Solar Generation (Energy Rates)

	Revenue Requirement @ -6.54% (Before Demand Credit)	**Targeted Revenue Requirement @ Avg Residential ROR 4.99%**
Total Rate Base	$51,435,445	$51,435,445
Return on Rate Base	($3,363,878)	$2,566,629
Taxes	($3,023,197)	$798,893
Expense	$10,277,250	$10,277,250
Revenue Credits	($1,598,373)	($1,598,373)
Revenue Requirement @ -6.54% (before Demand Credit)	$2,291,802	$12,044,399
% Difference in Delivery vs. Site		**18.66%**
Solar Demand Credit		**$2,247,395**

Residential - Solar Generation (Demand Rates)

	Revenue Requirement @ .79% (Before Demand Credit)	**Targeted Revenue Requirement @ Avg Residential ROR 4.99%**
Total Rate Base	$3,289,477	$3,289,477
Return on Rate Base	$25,987	$164,145
Taxes	($37,948)	$51,092
Expense	$651,121	$651,121
Revenue Credits	($119,754)	($119,754)
Revenue Requirement @ -6.54% (before Demand Credit)	$519,406	$746,604
% Difference in Delivery vs. Site		**14.64%**
Solar Demand Credit		**$109,301**

ARIZONA PUBLIC SERVICE
FUNCTIONALIZED REVENUE REQUIREMENT
TEST YEAR ENDING 12/31/2014

Residential Solar @ Actual ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement

Rate Base	Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
1) Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249	$0	$4,840,752			$3,019,457	$114,452,899
2) Customer Accounts							$1,794,234		$107,877	$121,842		$2,023,953
3) Cust. Service & Info and Sales Expense							$580,497					$580,497
4) Customer Deposits				($42,810)	($184,243)	($143,305)						(370,358)
5) Customer Advances	($15,924)			($71,696)	($308,560)	($240,001)						($636,181)
6) Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7) Actual Earned ROR @ -6.54%												
8) Return on Rate Base (Line 6 * Line 7)	($3,363,878)	($88,735)	$0	($399,101)	($1,717,633)	($1,335,987)	($155,307)	($316,585)	($7,055)	($7,968)	($197,472)	($7,589,723)
Computation of Income Taxes												
9) Weighted Cost of Long Term Debt @ 2.58%												
10) Tax Rate @ 39.19%												
11) Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	($3,023,197)	($79,748)	$0	($358,682)	($1,543,677)	($1,200,684)	($139,578)	($284,523)	($6,341)	($7,161)	($177,473)	($6,821,064)
Expenses												
12) Expenses	$10,277,250	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147		$1,337,751			$1,208,737	$31,419,401
13) Customer Accounts							$1,533,621		$304,642	$115,894		$1,954,157
14) Cust. Service & Info and Sales Expense							$700,635					$700,635
15) Total Expenses	$10,277,250	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$34,074,193
Revenue Requirement												
16) Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$3,890,175	$9,469,147	$3,561,494	($190,499)	($470,202)	($498,524)	$1,939,370	$736,643	$291,246	$100,764	$833,791	$19,663,406
17) Less: Revenue Credits	($1,598,373)	($2,733,994)	($847,066)	($35,400)	($201,831)	($125,584)	($9,763)	($22,010)	$0	$0	$0	($5,574,021)
18) REVENUE REQUIREMENT @-6.54%	**$2,291,802**	**$6,735,153**	**$2,714,428**	**($225,899)**	**($672,033)**	**($624,108)**	**$1,929,607**	**$714,633**	**$291,246**	**$100,764**	**$833,791**	**$14,089,385**
19) Energy Consumption (MWh)	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20) Functional Unit Costs (cents/kWh)	**0.0086**	**0.0252**	**0.0102**	**-0.0008**	**-0.0025**	**-0.0023**	**0.0072**	**0.0027**	**0.0011**	**0.0004**	**0.0031**	**0.0527**
21) Number of Customers	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22) Functional Unit Costs ($/Customer/month)	**$7.05**	**$20.73**	**$8.35**	**-$0.70**	**-$2.07**	**-$1.92**	**$5.94**	**$2.20**	**$0.90**	**$0.31**	**$2.57**	**$43.36**

Residential Solar @ Targeted ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement

Rate Base	Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
1) Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249		$4,840,752			$3,019,457	$114,452,899
2) Customer Accounts							1,794,234		107,877	121,842		$2,023,953
3) Cust. Service & Info and Sales Expense							$580,497					$580,497
4) Customer Deposits				(42,810)	(184,243)	(143,305)						(370,358)
5) Customer Advances	(15,924)			(71,696)	(308,560)	(240,001)						($636,181)
6) Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7) Targeted ROR @ 4.99%												
8) Return on Rate Base (Line 6 * Line 7)	$2,566,629	$67,704	$0	$304,513	$1,310,548	$1,019,354	$118,499	$241,554	$5,383	$6,080	$150,671	$5,790,935
Computation of Income Taxes												
9) Weighted Cost of Long Term Debt @ 2.58%												
10) Tax Rate @ 39.19%												
11) Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	$798,893	$21,074	$0	$94,783	$407,923	$317,286	$36,884	$75,186	$1,676	$1,892	$46,898	$1,802,496
Expenses												
12) Expenses	10,277,250	9,637,630	3,561,494	567,284	2,791,108	2,038,147		$1,337,751			$1,208,737	$31,419,401
13) Customer Accounts							1,533,621		304,642	115,894		$1,954,157
14) Cust. Service & Info and Sales Expense							$700,635					$700,635
15) Total Expenses	$10,277,250	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$34,074,193
Revenue Requirement												
16) Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$13,642,772	$9,726,408	$3,561,494	$966,580	$4,509,580	$3,374,787	$2,389,639	$1,654,491	$311,701	$123,866	$1,406,306	$41,667,625
17) Less: Revenue Credits	($1,598,373)	($2,733,994)	($847,066)	($35,400)	($201,831)	($125,584)	($9,763)	($22,010)	$0	$0	$0	($5,574,021)
18) REVENUE REQUIREMENT @4.99%	**$12,044,399**	**$6,992,414**	**$2,714,428**	**$931,180**	**$4,307,749**	**$3,249,203**	**$2,379,876**	**$1,632,481**	**$311,701**	**$123,866**	**$1,406,306**	**$36,093,604**
19) Energy Consumption (MWh)	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20) Functional Unit Costs (cents/kWh)	**0.0451**	**0.0262**	**0.0102**	**0.0035**	**0.0161**	**0.0122**	**0.0089**	**0.0061**	**0.0012**	**0.0005**	**0.0053**	**0.1351**
21) Number of Customers	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22) Functional Unit Costs ($/Customer/month)	**$37.07**	**$21.51**	**$8.35**	**$2.87**	**$13.26**	**$10.00**	**$7.32**	**$5.02**	**$0.96**	**$0.38**	**$4.33**	**$111.07**
23) Under Recovery (Targeted less Actual)[$/Cust/Month]	**$30.01**	**$0.78**	**$0.00**	**$3.56**	**$15.33**	**$11.92**	**$1.39**	**$2.82**	**$0.06**	**$0.07**	**$1.76**	**$67.71**

ARIZONA PUBLIC SERVICE
FUNCTIONALIZED REVENUE REQUIREMENT
TEST YEAR ENDING 12/31/2014

Residential Solar @ Actual ROR (Demand Rates - SITE) — Unbundled Functional Revenue Requirement

	Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
Rate Base												
1) Rate Base (excluding Cust. Advances & Deposits)	$3,290,495	$93,321		$383,085	$1,648,723	$1,164,809	$0	$210,234			$207,678	$6,998,345
2) Customer Accounts							$77,924		$4,685	$5,292		$87,901
3) Cust. Service & Info and Sales Expense							$25,211					$25,211
4) Customer Deposits				($5,961)	($25,655)	($18,125)						(49,741)
5) Customer Advances	($1,018)			($9,983)	($42,966)	($30,355)						($84,322)
6) Total Rate Base	$3,289,477	$93,321	$0	$367,141	$1,580,102	$1,116,329	$103,135	$210,234	$4,685	$5,292	$207,678	$6,977,394
7) Actual Earned ROR @ 0.79%												
8) Return on Rate Base (Line 6 * Line 7)	$25,987	$737	$0	$2,900	$12,483	$8,819	$815	$1,661	$37	$42	$1,641	$55,121
Computation of Income Taxes												
9) Weighted Cost of Long Term Debt @ 2.58%												
10) Tax Rate @ 39.19%												
11) Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	($37,948)	($1,077)	$0	($4,235)	($18,228)	($12,878)	($1,190)	($2,425)	($54)	($61)	($2,396)	($80,493)
Expenses												
12) Expenses	$651,121	$876,242	$241,673	$41,673	$171,988	$113,594		$58,099			$83,137	$2,237,527
13) Customer Accounts							$66,605		$13,231	$5,033		$84,869
14) Cust. Service & Info and Sales Expense							$47,078					$47,078
15) Total Expenses	$651,121	$876,242	$241,673	$41,673	$171,988	$113,594	$113,683	$58,099	$13,231	$5,033	$83,137	$2,369,474
Revenue Requirement												
16) Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$639,160	$875,903	$241,673	$40,338	$166,242	$109,535	$113,308	$57,335	$13,214	$5,014	$82,382	$2,344,103
17) Less: Revenue Credits	($119,754)	($202,970)	($97,447)	$0	($2,181)	($12,437)	($7,030)	($3,655)	($956)	$0	$0	($446,430)
18) REVENUE REQUIREMENT @0.79%	**$519,406**	**$672,933**	**$144,226**	**$40,338**	**$164,061**	**$97,098**	**$106,278**	**$53,680**	**$12,258**	**$5,014**	**$82,382**	**$1,897,673**
19) Energy Consumption (MWh)	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**
20) Functional Unit Costs (cents/kWh)	**0.0264**	**0.0342**	**0.0073**	**0.0020**	**0.0083**	**0.0049**	**0.0054**	**0.0027**	**0.0006**	**0.0003**	**0.0042**	**0.0964**
21) Number of Customers	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**
22) Functional Unit Costs ($/Customer/month)	**$36.81**	**$47.70**	**$10.22**	**$2.86**	**$11.63**	**$6.88**	**$7.53**	**$3.80**	**$0.87**	**$0.36**	**$5.84**	**$134.48**

Residential Solar @ Targeted ROR (Demand Rates - SITE) — Unbundled Functional Revenue Requirement

	Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
Rate Base												
1) Rate Base (excluding Cust. Advances & Deposits)	$3,290,495	$93,321		$383,085	$1,648,723	$1,164,809		$210,234			$207,678	$6,998,345
2) Customer Accounts							77,924		4,685	5,292		$87,901
3) Cust. Service & Info and Sales Expense							$25,211					$25,211
4) Customer Deposits				(5,961)	(25,655)	(18,125)						(49,741)
5) Customer Advances	(1,018)			(9,983)	(42,966)	(30,355)						($84,322)
6) Total Rate Base	$3,289,477	$93,321	$0	$367,141	$1,580,102	$1,116,329	$103,135	$210,234	$4,685	$5,292	$207,678	$6,977,394
7) Targeted ROR @ 4.99%												
8) Return on Rate Base (Line 6 * Line 7)	$164,145	$4,657	$0	$18,320	$78,847	$55,705	$5,146	$10,491	$234	$264	$10,363	$348,172
Computation of Income Taxes												
9) Weighted Cost of Long Term Debt @ 2.58%												
10) Tax Rate @ 39.19%												
11) Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	$51,092	$1,449	$0	$5,702	$24,542	$17,339	$1,602	$3,265	$73	$82	$3,226	$108,373
Expenses												
12) Expenses	651,121	876,242	241,673	41,673	171,988	113,594		$58,099			$83,137	$2,237,527
13) Customer Accounts							66,605		13,231	5,033		$84,869
14) Cust. Service & Info and Sales Expense							$47,078					$47,078
15) Total Expenses	$651,121	$876,242	$241,673	$41,673	$171,988	$113,594	$113,683	$58,099	$13,231	$5,033	$83,137	$2,369,474
Revenue Requirement												
16) Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$866,358	$882,348	$241,673	$65,696	$275,377	$186,638	$120,431	$71,855	$13,538	$5,379	$96,726	$2,826,019
17) Less: Revenue Credits	($119,754)	($202,970)	($97,447)	$0	($2,181)	($12,437)	($7,030)	($3,655)	($956)	$0	$0	($446,430)
18) REVENUE REQUIREMENT @4.99%	**$746,604**	**$679,378**	**$144,226**	**$65,696**	**$273,196**	**$174,201**	**$113,401**	**$68,200**	**$12,582**	**$5,379**	**$96,726**	**$2,379,589**
19) Energy Consumption (MWh)	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**
20) Functional Unit Costs (cents/kWh)	**0.0379**	**0.0345**	**0.0073**	**0.0033**	**0.0139**	**0.0088**	**0.0058**	**0.0035**	**0.0006**	**0.0003**	**0.0049**	**0.1208**
21) Number of Customers	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**
22) Functional Unit Costs ($/Customer/month)	**$52.91**	**$48.13**	**$10.22**	**$4.66**	**$19.36**	**$12.34**	**$8.04**	**$4.83**	**$0.89**	**$0.38**	**$6.85**	**$168.61**
23) Under Recovery (Targeted less Actual)[$/Cust/Month]	**$16.10**	**$0.44**	**$0.00**	**$1.80**	**$7.73**	**$5.46**	**$0.50**	**$1.03**	**$0.02**	**$0.03**	**$1.02**	**$34.13**

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
JANUARY 4, 2016

Vote Solar 2.4: Regarding APS's Response to VS 1.1:

Please provide the following information regarding VS 1.1_2014 COS Load Data_APS15747.xlsm.

a) Please describe the methodology APS used for the load data analysis.

b) Please indicate whether the load data shown for solar customers is the result of a statistical sampling of a subset of actual APS solar customers. If so, please describe the sampling methodology and indicate what proportion of APS solar customers were included in the sample. If not, please describe the derivation of the solar customer load data.

c) Please describe the meaning of the following terms as used in the titles of the spreadsheet tabs: "No Solar," "Solar Delivered," "Solar Site," "Solar Del," and "Solar Net."

Response:

a.) APS queries its energy data "warehouse" for all Residential AMI interval data. The AMI data is then sorted into the corresponding rates and categories (i.e. "No Solar", "Solar Delivered", "Solar Site", and "Solar Net"). A mean-per-unit analysis technique is then used to obtain the peak values for the report.

b.) APS's load data shown for solar customers is based on all solar customers' interval data.

c.) Term Definitions are as follows:

- *No Solar* – measured energy delivered from APS to customers who are not on a solar rate.
- *Solar Del / Solar Delivered* – measured energy delivered from APS to customers on a solar rate.
- *Solar Site* – the energy used by a customer based on the following formula: [Delivered Electricity + (Produced Electricity – Received Electricity)], where Delivered Electricity means energy delivered from APS to the customer and Received Electricity means energy delivered from the customer to APS.
- *Solar Net* – the energy used by a customer based on the following formula: [Delivered Electricity – Received Electricity].

Exhibit WAM-4: Excerpt from
"Effects of Home Energy Management Systems on Distribution Utilities and Feeders Under Various Market Structures," National Renewable Energy Laboratory, presented in the 23rd International Conference on Electricity Distribution, Lyon, France, June 15-18, 2015

Effects of Home Energy Management Systems on Distribution Utilities and Feeders under Various Market Structures

Preprint

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National Renewable Energy Laboratory

Presented at the 23rd International Conference on Electricity Distribution
Lyon, France
June 15–18, 2015

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

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July 2015

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controllers and custom reduced-order building models [10]. The model predictive controllers were also only run once per day, and a real-time price was provided as an input, based on historical CAISO prices and weather.

In this paper, we describe the IESM's structure. We then define the scenario used in the analysis; report results on the impact of HEMS technology on a feeder; and provide conclusions and propose future work.

INTEGRATED ENERGY SYSTEM MODEL

The Integrated Energy System Model (IESM) is being developed to analyze interactions between multiple technologies within various market and control structures, and to identify financial and physical impacts on both utilities and consumers. Physical impacts include both consumer comfort (e.g., difference between actual and desired temperature) and distribution feeder operations including voltage profiles and equipment loading. In addition, the IESM will be dynamically integrated into hardware in the loop (HIL) testing of technologies in the National Renewable Energy Laboratory's (NREL's) Energy Systems Integration Facility (ESIF) by providing market signals to technologies and equipment.

To meet these objectives, the IESM is being designed to perform simulations of a distribution feeder, end-use technologies deployed on it, and a retail market or tariff structure. The IESM uses co-simulation, wherein multiple simulators with specific modeling capabilities co-operate towards a common objective of bringing the capabilities together in a shared execution environment, and manages time and data exchange between component models. The co-simulation execution is performed on a high-performance computer (HPC).

In the current version, GridLAB-D, which performs distribution feeder, household, and market simulations, is co-simulated with Pyomo [11], which implements a HEMS for each household. GridLAB-D is an agent-based, open source power system simulation tool developed by the Pacific Northwest National Laboratory. It performs quasi-steady state simulations for distribution feeders, including end-use loads such as heating-cooling systems, water heaters and electric vehicles. It also manages retail markets and responses to market signals [8]. Similar to [10], the wholesale market is not included.

The IESM can include both price responsive thermostats, responding to the current price, and model predictive controllers which can be run several times during the day, which models the operation of such devices more realistically. In the reported case, the IESM utilizes HEMS, implemented in Pyomo, minimizes its house's cooling cost using a model predictive control approach and sets the cooling setpoint to a calculated optimal value while constrained by an envelope around the desired temperature [12]. No custom HVAC model was developed for the HEMS, instead, through the IESM's co-simulation structure, models available in existing software simulation packages are accessed.

Ultimately, the IESM will utilize an internal discrete event coordinator that operates on abstract time and an enterprise message bus as shown in Figure 1. The scheduler is expected to manage GridLAB-D's simulation of distribution feeders; actual or simulated loads and DER either in experimental hardware, GridLAB-D, or another simulation package such as Energy Plus [13]; and simulation of technologies, such as HEMS, markets, and consumers. Component libraries allow the creation of comprehensive scenarios, including different types of houses and market structures in a plug-and-play component-based manner.

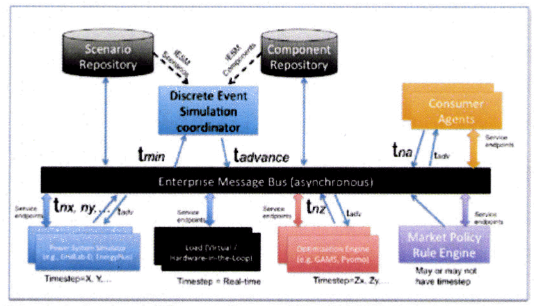

Figure 1. Integrated Energy System Model (IESM) architecture

SCENARIO DEFINITION

A scenario was created for a distribution feeder in the state of North Carolina in the Southeast of the United States in the summer for the month of July when air conditioning use is high. A distribution feeder based on the IEEE 13-node test feeder is used and about 3% of the load is replaced with houses in order to provide a price-responsive, varying load component [14].

The feeder is populated with 20 well-insulated houses with identical parameters, which are connected through four 25 kVA single-phase, center-tapped transformers – each serving 5 houses. The air conditioner in the house is modeled explicitly, and the rest of the household loads are modelled as a lumped ZIP load with a time-varying base power profile. The desired cooling temperature profile is motivated by EPA's Energy Star Recommendations [15]. The desired profile for each house is different, as shown in Figure 2. Each house has a desired daytime temperature between 72° and□77° F (22.2-25.0°C) that is set at uniformly distributed random time between 4:00 AM and 8:00 AM. The desired daytime temperature is constant for 16 hours and is set back by 3°F (1.7°C) at night for 8 hours. Each household's ZIP load base power profile has the same shift in time as the desired temperature.

Two retail electricity tariff structures that are currently in place for households in North Carolina are used. The first has a flat structure with a constant electricity price of \$0.093587/kWh and a monthly service fee of \$11.80 [16]. The TOU rate structure is shown in Figure 3. It has a varying electricity price with peak, shoulder, and off-peak rates and a monthly service fee of \$14.13. The peak, shoulder, and off-peak rates are \$0.2368/kWh,

$0.11961/kWh, and $0.06936/kWh, respectively. Summer peak hours are 1:00 PM to 6:00 PM, Monday through Friday and shoulder rates are in effect during the two hours before and after the peak hours [17]. All weekend hours are off-peak. Vertical shaded areas in this and other figures indicate peak and should pricing time periods.

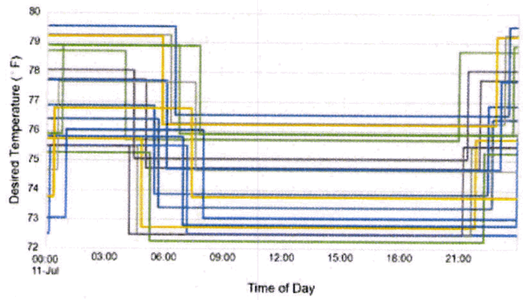

Figure 2. Desired temperature profile for each of the houses in the simulation. Daytime temperatures are randomly distributed between 72 and □(22.2-25.0°C), set at a random time between 4:00 and 8:00 AM. After 16 hours, the desired temperature increases by 3°F (1.7°C).

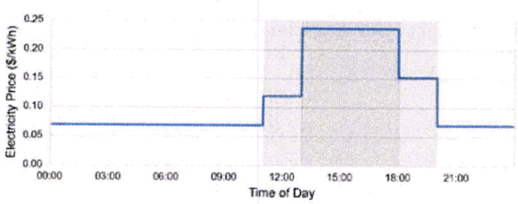

Figure 3. Time-of-use pricing profile for weekdays. All weekend hours are off-peak and have the lowest price

Three HEMS penetrations (0%, 50%, and 100%) are simulated to show how IESM can be used to evaluate the physical and financial impacts of distributed technologies, such as HEMS, in the presence of different markets or tariffs, on the system. Each house's HEMS uses model predictive control to adjust the cooling setpoint from the desired temperature to minimize cost. The HEMS does not allow the setpoint to be above the desired temperature, but does allow it to be down to 5°F (2.8°C) below the desired temperature so that the house can be precooled before peak electricity prices.

RESULTS

Figure 4 shows the range of electricity expenses for the households in the population. Those expenses vary because of variations in desired temperatures and their profiles between houses. For the time period analyzed, the uniform tariff has a lower cost than TOU due to high demand for cooling and other loads during peak hours. Presumably, that load will not be as large at other times of the year and bills under TOU tariffs will be lower during those seasons. Under TOU tariffs, bills are about 5% lower when HEMS are used to manage cooling.

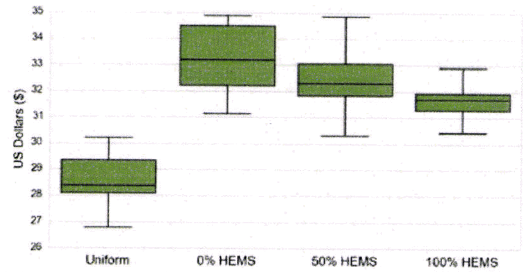

Figure 4. Box plot of the population's electricity bills over the time period from July 7-17, 2012. Use of HEMS reduces each household's bill by about 5%.

Cost savings are driven by the use of power during off-peak and shoulder times for precooling the houses. Figure 5 displays the total cooling power of all the houses over each day with vertically shaded bars indicating peak-price hours and shoulders. The solid lines display the mean total cooling loads over all 11 days, and the shaded areas indicates a 95% confidence interval. Results for the uniform price distribution are identical to the scenario with 0% HEMS penetrations.

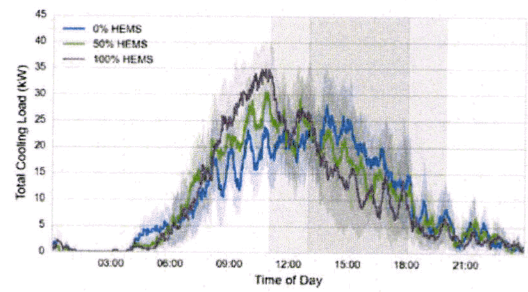

Figure 5. Daily profile of total cooling power load at several levels of HEMS penetrations. When HEMS are present, power use is shifted from peak hours to earlier times when it is less expensive.

When HEMS are present, power use is shifted from times when cost is higher (peak-price periods from 1:00 PM to 6:00 PM) to earlier hours when it is not as expensive. In addition, with the HEMS penetration levels simulated here, the peak is higher during the time period before prices increase than at any time without HEMS. The HEMS used in this study does not adjust any other household loads so they are not shifted due to pricing.

Figure 6 shows the total load on the distribution transformers. The solid line shows the mean and the shaded area shows a 95% confidence interval. The peak load during peak pricing is reduced with the HEMS penetration levels simulated here, but a new, higher peak load is created during the time period before peak pricing. Because the peak load is just shifted, the distribution feeder still experiences peak stress even though the TOU rate structure was likely designed to reduce the peak load.

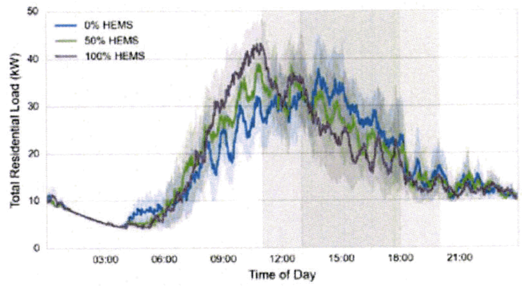

Figure 6. Daily profile of the total distribution transformer load with several HEMS penetrations. Presence of HEMS reduces the peak load during peak pricing but creates a new peak load in the time period before peak pricing is in effect.

Using power to precool intrinsically indicates that the house's temperature setpoint is lower than desired for a time before the peak pricing period. Figure 7 shows the daily profile of the population's average temperature over all days with and without HEMS. The solid line shows the mean and the shaded area shows a 95% confidence interval. The average of the population with HEMS precools by almost 2°F (1.2°C) as compared to the population without HEMS (i.e., without cost optimization). Note that the starting time for cooling is consistent because the two populations have the same time for the initial house's change in desired temperature and, during that time, the setpoint for both is the desired temperature.

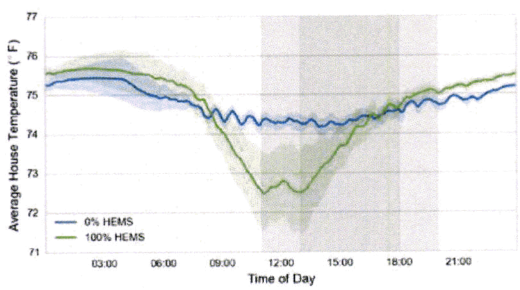

Figure 7. Daily profile of mean household temperature for the population with and without HEMS. HEMS minimize cost by precooling by about 2°F (1.1°C) before peak pricing is in place.

Figure 8 shows the daily profile of the primary voltage of the distribution transformer at node 652. It serves five houses. The solid lines display the mean and the shaded area indicates a 95% confidence interval. With HEMS, the lowest voltage is experienced at an earlier time in the day, coinciding with the peak transformer load moving earlier due to precooling. The minimum voltage is lower in this case, due to the fact that the peak transformer load is higher with HEMS than without. Overall the voltage variation is small due to the fact that only a small percentage of the load at this node is replaced with houses that provide a time-varying load component.

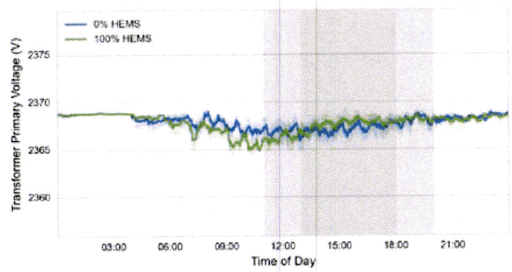

Figure 8. Daily profile of primary voltage of the transformer at node 652 and serving five houses. Use of HEMS shifts time of low voltage to coincide with new peak introduced by HEMS.

Utility net revenue is calculated as the difference between income from the household electricity bills reported above and the wholesale cost of the electricity provided. The wholesale cost of the electricity is calculated as the product of the total electricity demand for the feeder and the Midcontinent Independent Service Operations hourly real-time locational marginal prices for a hub in North Carolina (price node 746136) and are assumed to be unaffected by the modelled changes in the load.

Table 1: Comparison of household expenditures and utility net revenue between scenarios

	Sum of household expenditures	Utility net revenue
Uniform rate	$573	$470
TOU rate – 0% HEMS	$665	$562
TOU rate – 50% HEMS	$650	$547
TOU rate – 100% HEMS	$632	$530

Table 1 shows the utility net revenue and the total household expenditure for the four scenarios. Utilizing HEMS reduces the sum of household expenditures by $33 in the time period analyzed, but only reduces the utility net revenue by $32. Where bulk power prices are unaffected by load, utility net revenue is reduced by approximately the same amount as household expenditure reductions; thus, indicating that the TOU rate structure provides similar net revenue at all times.

CONCLUSIONS AND FUTURE WORK

This paper presented results from a specific scenario simulated using a co-simulation platform, the Integrated Energy System Model (IESM), under development to study the physical and economic impact of distributed technologies under different markets or tariff structures.

The results reported here show that the combination of time-of-use (TOU) pricing and Home Energy Management Systems (HEMS) controlling residential cooling systems reduces peak load during high price hours but moves the load peak to hours with off-peak and shoulder prices. This situation would be further exacerbated with HEMS that are able to shift the operation of multiple loads within a household in

Exhibit WAM-5: Excerpt from
"Energy Star: Program Requirements for Programmable Thermostats,"

ENERGY STAR® Program Requirements for Programmable Thermostats

Partner Commitments
DRAFT 1

Commitment

The following are the terms of the ENERGY STAR Partnership Agreement as it pertains to the manufacturing of ENERGY STAR qualified programmable thermostats. The ENERGY STAR Partner must adhere to the following program requirements:

- comply with current ENERGY STAR Eligibility Criteria, defining the performance criteria that must be met for use of the ENERGY STAR certification mark on programmable thermostats and specifying the testing criteria for programmable thermostats. EPA may, at its discretion, conduct tests on products that are referred to as ENERGY STAR qualified. These products may be obtained on the open market, or voluntarily supplied by Partner at EPA's request;

- comply with current ENERGY STAR Identity Guidelines, describing how the ENERGY STAR marks and name may be used. Partner is responsible for adhering to these guidelines and for ensuring that its authorized representatives, such as advertising agencies, dealers, and distributors, are also in compliance;

- qualify at least one ENERGY STAR qualified programmable thermostat model within one year of activating the programmable thermostat portion of the agreement. When Partner qualifies the product, it must meet the specification (e.g., Tier 1 or 2) in effect at that time;

- provide clear and consistent labeling of ENERGY STAR qualified programmable thermostats. The ENERGY STAR mark must be clearly displayed on the front/inside of the product, on the product packaging, in product literature (i.e., user manuals, spec sheets, etc.), and on the manufacturer's Internet site where information about ENERGY STAR qualified models is displayed;

> **Note:** EPA requires the labeling of all ENERGY STAR qualified products according to one or more of the following options, depending on product design and visibility at both the time of sale and over the use of the product: on the product; in product literature; and on the manufacturer's Internet site. The ENERGY STAR mark is well known by consumers and large purchasers as the symbol for energy efficiency. The ENERGY STAR mark should be placed in an area of high visibility, preferably on front of the product, so that the purchaser and end users can see that by purchasing and using an ENERGY STAR qualified programmable thermostat, they are helping to reduce air pollution and greenhouse gases through energy efficiency. EPA is open to discussing additional placement options.

- provide to EPA, on an annual basis, an updated list of ENERGY STAR qualifying programmable thermostat models. Once the Partner submits its first list of ENERGY STAR qualified programmable thermostat models, the Partner will be listed as an ENERGY STAR Partner. Partner must provide annual updates in order to remain on the list of participating product manufacturers;

- provide to EPA, on an annual basis, unit shipment data or other market indicators to assist in determining the market penetration of ENERGY STAR. Specifically, Partner must submit the total number of ENERGY STAR qualified programmable thermostats shipped (in units by model) or an

1. **Default Program**. The setbacks and setups periods are required to be a **minimum of** 8 hours, but may exceed 8 hours. Partners must have four events on the weekday and two on the weekend, partners may choose to add additional setbacks and/or setups as long as the setback/setup period is at least eight-hours long. Listed below are the suggested events along with setbacks/setups and appropriate temperatures (Tables 1-3).

Table 1: Programmable Thermostat Setpoint Temperatures

Events	**Setpoint Temperature (Heat)**	**Setpoint Temperature (Cool)**
Morning	≤70°F (≤21.1°C)	≥75°F (≤25.6°C)
Day	setback at least 8°F (4.4°C)	setup at least 8°F (3.8°C)
Evening	≤70°F (≤21.1°C)	≥75°F (≤25.6°C)
Night	setback at least 8°F (4.4°C)	setup at least 3°F (2.2°C)

Table 2: Acceptable Weekday Setpoint Times and Temperature Settings

Events	**Time**	**Setpoint Temperature (Heat)**	**Setpoint Temperature (Cool)**
Morning	6 a.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Day	8 a.m.	≤62°F (≤16.71°C)	≥83°F (≤29.4°C)
Evening	6 p.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Night	10 p.m.	≤62°F (≤16.71°C)	≥78°F (≤25.6°C)

Table 3: Acceptable Weekend Setpoint Times and Temperature Settings

Events	**Time**	**Setpoint Temperature (Heat)**	**Setpoint Temperature (Cool)**
Morning	8 a.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Day	10 a.m.	≤62°F (≤16.71°C)	≥83°F (≤29.4°C)
Evening	6 p.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Night	11 p.m.	≤62°F (≤16.71°C)	≥78°F (≤25.6°C)

Exhibit WAM-6: Excerpt from

Qinran Hu, and Fangxing Li. “Hardware Design of Smart Home Energy Management System With Dynamic Price Response.” IEEE Transactions on Smart Grid 4, no. 4 (December 2013)

Hardware Design of Smart Home Energy Management System With Dynamic Price Response

Qinran Hu, *Student Member, IEEE*, and Fangxing Li, *Senior Member, IEEE*

***Abstract*—The smart grid initiative and electricity market operation drive the development known as demand-side management or controllable load. Home energy management has received increasing interest due to the significant amount of loads in the residential sector. This paper presents a hardware design of smart home energy management system (SHEMS) with the applications of communication, sensing technology, and machine learning algorithm. With the proposed design, consumers can easily achieve a real-time, price-responsive control strategy for residential home loads such as electrical water heater (EWH), heating, ventilation, and air conditioning (HVAC), electrical vehicle (EV), dishwasher, washing machine, and dryer. Also, consumers may interact with suppliers or load serving entities (LSEs) to facilitate the load management at the supplier side. Further, SHEMS is designed with sensors to detect human activities and then a machine learning algorithm is applied to intelligently help consumers reduce total payment on electricity without or with little consumer involvement. Finally, simulation and experiment results are presented based on an actual SHEMS prototype to verify the hardware system.**

***Index Terms*—Controllable load, demand response, dynamic pricing, embedded system, machine learning, optimal control strategies, peak shaving, remote operation, smart home energy management system (SHEMS).**

NOMENCLATURE

F_i	Signals from sensors.
C	User's activity.
$X_T(t)$	Temperature in electrical water heater at time t, °C.
$X_a(t)$	Ambient temperature at time t, °C.
a	Thermal resistance of tank walls, W/°C.
$A(t)$	Rate of energy extraction when water is in demand at time t.
$q(t)$	Status of the hot water demand at time t, ON/OFF.
P_{EWH}	Power rating of the heating element, W.
P_{EV}	Power rating of charging station, W.
P_H	Power rating of dishwasher, washing machine, or dryer, W.
$m(t)$	Thermostat binary state at time t, ON/OFF.
$RTP(t)$	Real time price at time t, \$/MWh.
$S_{EV}(t)$	Status of charging station, ON/OFF.
TF_{EV}	The time EV needs to get fully charged (hour).
R_{EV}	Desired percentage of battery being charged.
T_{start}	The time when EV is connected to charging station.
T_{end}	The time when the user needs to drive EV.
T_{hstart}	The time when dishwasher, washing machine, or dryer starts to work.
T_{huse}	Time duration for dishwasher, washing machine, and dryer to complete the work once started.
T_{hready}	The time when dishwasher, washing machine, and dryer is ready to use.
T_{hend}	The time when the user needs to pick up things from the dishwasher, the washing machine or the dryer.

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Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

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I. INTRODUCTION

THE electricity prices in a competitive power market are closely related to the consumers' demand. However, the lack of real-time pricing (RTP) technologies presents challenges to electricity market operators to optimally signal and respond to scarcity, because electricity cannot be stored economically [1]. In the past a few years, the deployment of advanced metering infrastructures (AMI) and communication technologies make RTP technically feasible [2]. RTP, generally speaking, reflects the present supply-demand ratio and provides a means for load-serving entities (LSEs) and independent system operators (ISOs) to solve issues related to demand side management such as peak-load shaving. Applications of RTP enable consumers and suppliers to interact with each other, which also creates an opportunity for consumers to play an increasingly active role in the present electricity market with optimal control strategies at the demand side.

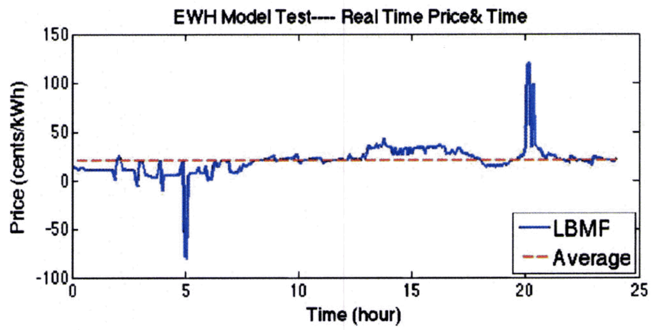


Fig. 11. Real time price curve for 24 hours.

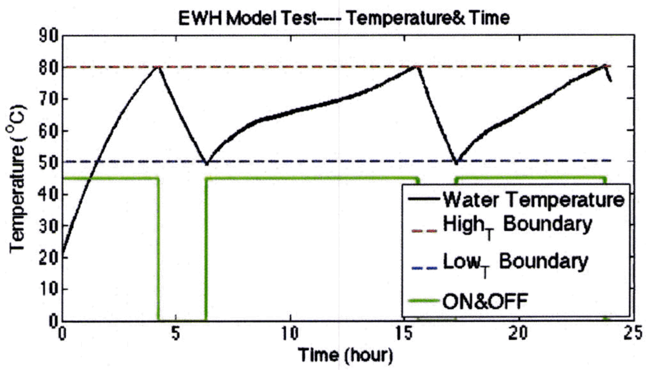


Fig. 12. Typical EWH strategy [26].

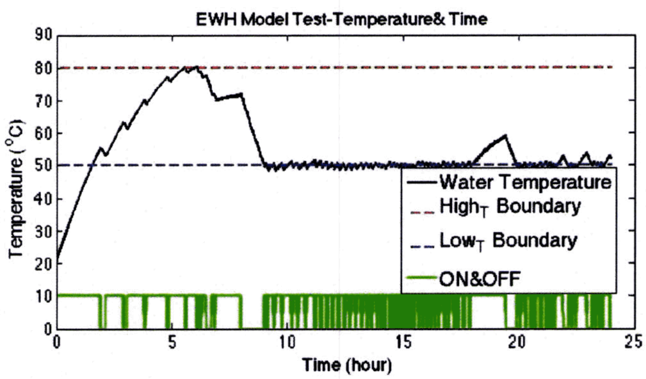


Fig. 13. Optimized EWH strategy.

signal may change as fast as every 5 minutes which is a discrete variable. The model can be described by:

$$\frac{dX_T}{dt} = -a\left(X_T(t) - X_a(t)\right) - A(t)q(t) + P_{EWH} \cdot m(t) \quad (2)$$

Table II shows the specifications of EWH used in the experiment. For testing and simulation purposes, Table III shows some useful information applied here. Also, a typical water usage curve as shown in Fig. 10 is obtained from [25].

In this study, the locational marginal price (LMP) on a randomly selected day from NYISO is used as the real-time price, which is shown in Fig. 11. The result without SHEMS is shown in Fig. 12, and the results after applying an RTP-responsive algorithm to change the ON and OFF strategy of EWH is shown in Fig. 13.

The optimized strategy used in the test can be further improved in future algorithm/software studies, while this paper focuses on the hardware part. Nevertheless, the straightforward algorithm still works greatly. A brief description of the algorithm is presented next.

The principle of the algorithm is to turn EWH on for a while before the dropping temperature reaches the lower bound. Meanwhile, the algorithm also considers whether the EWH can provide comfortable hot water based on the predicted consumer demand of water usage with a look-ahead consideration. For example, the algorithm will preheat the EWH to a higher temperature before the consumer takes a shower. The mathematical description is an optimization model given below.

$$\min \int_0^{24} RTP(t) \cdot m(t) \cdot P_{EWH} \quad (3)$$

$$\text{s.t.}: \quad \text{Eq. (2)}$$

$$T_{low} \le X_T(t) \le T_{high} \quad (4)$$

Since $RTP(t)$ refreshes every 5 minutes, this model given by (2), (3), and (4) is discretized into a time interval of 5 minutes. The genetic algorithm (GA), an intelligent search algorithm using stochastic operations, is customized in this work to solve the model to find the global optimal scheduling for the EWH. With this approach, SHMES can reduce the total payment and energy consumption while meeting the consumer's needs.

The result verifies that SHEMS helps reduce the thermostat ON time by 14%, while reducing the consumer's payment by 60% of the original payment on heating water.

The proposed SHEMS system has been programmed and tested to connect and disconnect a mock EWH load in accordance with Fig. 13.

B. Heating, Ventilation, and Air Conditioning (HVAC)

The American Society of Heating, Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE) has compiled modeling procedures in its Fundamentals Handbook [27]. The Department of Energy has produced the Energy Plus program for computer simulation [28]. Also, the detailed model for simulating HVAC systems is given in [29], [30]. Accurate model for energy consumption needs to consider many factors including weather, season, thermal resistance of rooms, solar heating, cooling effect of the wind, and shading. Unlike EWH which has constant and relatively accurate parameters, those HVAC parameters are difficult to be precisely modeled with the possibility to change over the time due to other factors.

Thus, the testing here is not based on any detailed model but relies on the actual measurement from the experiments performed at the University of Tennessee with the SHEMS prototype and a portable HVAC unit.

In this experiment, the SHEMS optimizes the HVAC based on three parameters: the mock RTP from the prices in a randomly selected day in NYISO used in the previous EWH test, the real-time temperature in the test room, and the temperature setting by the user. Table IV shows the related parameters.

For comparison purpose, a parameter named "Comfort Level" is considered here. In market economics, a consumer has to compromise between quality and price. The introduction of "Comfort Level" is based on similar idea for home energy management. Simply speaking, "Comfort Level" in this case

TABLE IV
HVAC PARAMETERS IN THE TEST

Room Area	800 sq ft
Room Type	Single room
HVAC Power Rate	3.5kW
Room Temperature Setting	73°F (23°C)

TABLE V
HVAC RESULTS WITH SHEMS

	Different Comfort Level		
	+/- 0°C	+/- 3°C (5.8°F)	+/- 5°C (9°F)
Energy Consumption (% w.r.t the case w/o SHEMS)	91%	79%	72%
Payment (% w.r.t the case w/o SHEMS)	86%	73%	64%

means the difference between the actual indoor temperature and the temperature desired by the consumer.

Table V shows the energy consumption and the total payment reduction of the cases under different comfort levels with SHEMS. The results are in percentage with respect to the case without SHEMS. As shown in the table, considerable reduction of energy consumption and payment is achieved. Further, if a consumer can tolerate a higher temperature difference, more payment or credit to HVAC from the supplier can be achieved. This is sensible from the standpoint of market economics.

C. EV, Dishwasher, Washing Machine and Dryer

In order to fully exploit the potential of SHEMS and contribution to the power grid, low cost is an important characteristic of the prototype. Since considering bidirectional power flow will significantly increase the total cost of SHEMS design, the electric vehicle (EV) model in the proposed prototype is to charge a battery. That is, this design of SHEMS does not include the consideration for EV to send power back to grid.

Loads such as charging the battery for an EV are interruptible [15]. It is possible to charge the battery for 1 h, then stop charging for another hour, and then finish the charging after that. In contrast, the loads like dishwasher, washing machine and dryer demonstrate similar features to EV, but differ from EV considerably because they are uninterruptible. That is, as soon as the corresponding appliance starts operation, its operation should continue till completion.

1) Electrical Vehicles: An EV should be fully charged, for example, at 8 A.M. but the EV user does not care when or how the EV battery is charged. Therefore, SHEMS chooses the possible hours with the low electricity price to charge. Meanwhile, SHEMS must make sure EV to be fully charged before being used at 8 A.M..

As an interruptible load, the mathematical expression of the discrete model of EV can be expressed in (5) and (6). Since the real-time price refreshes every 5 minutes, the time interval of discrete model is also set to 5 minutes. Here, $S_{EV}(t)$ is the optimal solution that needs to be generated by SHEMS.

TABLE VI
PARAMETERS OF DISHWASHER, WASHING MACHINE, AND DRYER

	Model	P_H (W)	T_{huse} (min)
Dishwasher	Danby	1000	30
Washing machine	Danby	400	45
Dryer	Whirlpool	3000	40

$$\min \sum_{t=T_{start}}^{T_{end}} P_{EV} \cdot RTP(t) \cdot S_{EV}(t) \qquad (5)$$

$$\text{s.t.}: \frac{1}{12} \cdot \sum_{t=T_{start}}^{T_{end}} S_{EV}(t) = TF_{EV} R_{EV} \qquad (6)$$

2) Dishwasher, Washing Machine, and Dryer: As an uninterruptible load, the mathematical expression of the discrete model of dishwasher, washing machine and dryer can be all expressed in (7), (8), and (9), respectively. The time interval of discrete model is also set to 5 minutes. T_{hstart} is the optimal solution which needs to be generated by SHEMS.

$$\min \sum_{t=T_{hstart}}^{T_{hstart}+T_{huse}} P_H \cdot RTP(t) \qquad (7)$$

$$\text{s.t.}: T_{hready} \leq T_{hstart} \leq T_{hend} \qquad (8)$$

$$T_{hready} \leq (T_{hstart} + T_{huse}) \leq T_{hend} \qquad (9)$$

D. Effects of SHEMS in Load Shifting

Based on the previous analysis on EWH and HVAC, it is rational to conclude that SHEMS can make substantial contribution to reduce home energy consumption from not only EWH and HVAC but also EV, dishwasher, washing machine, dryer, etc. To study the effect of SHEMS in a large-scale system, this section demonstrates a comparison on the load curves with and without SHEMS.

The simulation here is to give a quantified verification that SHEMS will play a critical role in load shifting. The total real-time load curve (including residential, commercial, industrial and other) is selected from NYISO again. The date of the data is the same as the date of the selected RTP.

The EWH and HVAC parameters are the same as from the previous Sections V-B and V-C. The EV parameters are chosen based on Nissan Leaf [31] for this simulation study:

- Charging power rate: approx. 6 kW;
- Battery volume: 24 kWh;
- Time of fully charging: 4 hour; and
- The percentage of EV battery to be charged is set as 100%.

The parameters of dishwasher, washing machine, and dryer are shown in Table VI.

The reduction of energy consumption from individual appliance is scaled up to simulate the optimized residential load consumption. The results are shown in Fig. 14, which illustrates that SHEMS can help with load shifting. In addition, it reduces the loads in peak hours by nearly 10 percent which is significant.

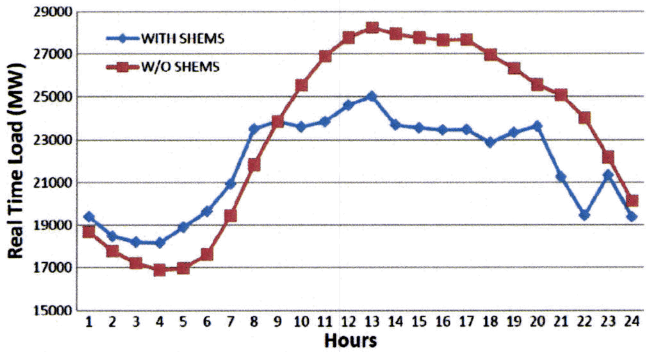


Fig. 14. Load curve comparison with and without SHEMS.

VI. Comparative Analysis and Conclusion

A. Comparative Analysis

As mentioned in the Introduction, there are several companies working on products related to demand response. However, those early products do not take full considerations of all aspects mentioned in this paper. Most of these previous products focus on displaying and monitoring the status of home energy consumption. Some advanced ones may help analyze power usages of different appliances, then offer tips for conserving energy and reducing payment in electricity, which is represented by the "Indirect Feedback" [32], [33]. None of those previous works has reported any real intelligent control down to the appliance level, and users' interaction is needed. However, the proposed design and the actual prototype carried out in our Smart Home lab implements automated, intelligent controls for smart home energy management to the appliance level.

As for the cost, the proposed design typically costs less than \$200 with off-the-shelf retail prices for materials and components. The actual cost also depends on the number of appliances that consumers want to install load interfaces, as well as the number of rooms to be monitored. Here is the cost breakdown in a typical case. The main controller costs around \$80 based on to the off-the-shelf retail price(\$15 for a microcontroller, \$20 for making PCB and accessories, \$15 Wi-Fi module, and \$30 for touch screen). Each load interface and room monitoring unit costs around \$20 (\$15 for Wi-Fi module and \$5 for accessories). With the assumption that a consumer wants to control HVAC and EWH, and has 3$\sim$4 rooms to monitor, the total cost will be around \$200 in this typical setting. In addition, this design is expandable and can be easily upgraded by updating programs running in the processor without any change of existing hardware.

Table VII provides a high-level comparison of the proposed design and 4 SHEMS-like devices from commercial vendors. These 4 devices include Monitor12 by Powerhouse, Home monition and Control by Verizon, Nucleus by GE, and Thermostat controller by NEST. The listed features are monitoring, remote control, real-time price responsive, machine learning, and easy setting. They are randomly named Vendor 1 to 4 without any particular order in Table VII. One of the vendor's cost is the annual service cost, while the device is sold separately. The cost

TABLE VII
Comparison of Existing SHEMS

Name	Appliances	Monitor /Control	Response	Learn	Easy Setting	Cost (\$)
Proposed Design	Extendable	X	X	X	X	~200
Vendor 1	Vendor's own devices	X	X			199
Vendor 2	12 switches	X				1024
Vendor 3	Extendable	X				120/yr
Vendor 4	Thermostat	X		X	X	250

of the system from Vendor 1 is relatively low, but with relatively simple functions. It does not have machine learning algorithm and cannot provide optimized schedule for home appliances. Vendor 4 provides a fancy user interface which is easy and efficient, but cannot control appliances other than HVAC.

Note that the cost of the developed prototype may not be directly comparable with the costs of the four vendors' products since the cost of the developed prototype does not include labor cost and the expected profit. However, on the other hand, the prototype cost is based on retail prices of various materials and components, which are usually higher than wholesale prices under mass production. Nevertheless, the cost information is listed in Table VII for future references.

B. Conclusion

This paper presents a hardware design of a smart home energy management system (SHEMS) with the application of communication, sensing technology, and machine learning algorithm. With the proposed design, consumers can achieve a RTP-responsive control strategy over residential loads including EWHs, HVAC units, EVs, dishwashers, washing machines, and dryers. Also, they may interact with suppliers or load serving entities (LSEs) to facilitate the management at the supplier side. Further, SHEMS is designed with sensors to detect human activities and then apply machine learning algorithm to intelligently help consumers reduce total electricity payment without much involvement of consumers. In order to verify the effort, this paper also includes testing and simulation results which show the validity of the hardware system of the SHEMS prototype. The expandable hardware design makes SHEMS fit to houses regardless of its size or number of appliances. The only modules to extend are the sensors and load interfaces.

Also, if this design can be widely used in the future, the administrator-user structure will provide good potentials for electricity aggregators. Most likely, utilities may not be interested or motivated to administrate all individual, millions of end consumers directly and simultaneously. Therefore, electricity aggregators can play as agents between consumers and utilities. This business mode may facilitate the popularity of SHEMS or similar systems and create win-win results for all players.

Acknowledgment

The authors would like to thank NSF for financial support under Grant ECCS 1001999 to complete this research work. Also, this work made use of Engineering Research Center (ERC) Shared Facilities supported by the CURENT Industry Partnership Program and the CURENT Industry Partnership Program.

Exhibit WAM-7: Excerpt from

California Energy Markets, Issue No. 1379, April 1, 2016

AN INDEPENDENT NEWS SERVICE FROM ENERGY NEWSDATA

CALIFORNIA ENERGY MARKETS

◆ Friday, April 1, 2016 ◆ No. 1379 ◆

BILLBOARD No. 1379

[1] CARB Sets Sights on Including International Offsets in Cap and Trade

The California Air Resources Board is considering whether to allow programs aimed at reducing GHG emissions from tropical deforestation to count as offset credits in the state's cap-and-trade program. Initiatives that prevent deforestation are a critical part of addressing global climate change, and may even provide for direct environmental benefits within California, according to CARB. Energy companies are advocating for additional sources of offsets, saying they are needed for cost containment. ***Sinking carbon at [13].***

Photo: Crustmania, Flickr.com

[2] Cal-ISO: Resources Adequate to Meet Summer Loads

Cal-ISO expects to have adequate resources to meet summer demand. Peak demand should be up slightly in 2016, based on projected economic growth and new behind-the-meter solar installations, while hydroelectric capacity is projected to be near normal for both spring and summer. Cal-ISO did warn, however, of possible natural gas curtailments related to the Aliso Canyon natural gas storage facility. Meanwhile, the growth of rooftop solar helped cancel transmission upgrades planned for the Pacific Gas & Electric service area. ***At [14], generation and transmission.***

[3] CEC to Allow More Time for Puente Review

NRG Energy calls its Puente Power Project, a 262 MW natural gas plant proposed on the Southern California coast at Oxnard, "a bridge to California's energy future." Project opponents this week called for the California Energy Commission to allow more time to evaluate and comment on its environmental review of that "bridge." ***At [11], the CEC says it plans to revise its proposed schedule for Puente.***

[4] Davis, Yolo County to Form JPA for Launch of CCA Program

The City of Davis and Yolo County have agreed to form a joint-powers authority that will administer a community choice aggregation program, with the launch of service expected in 2017. The CCA would serve electricity customers in Davis and unincorporated areas of the county, in competition with incumbent utility Pacific Gas & Electric. The door is open for other cities in Yolo County to join in the aggregation effort down the road. ***At [15], stronger together?***

[14.1] Cal-ISO Board Approves Annual Transmission Plan

Thirteen new transmission projects with an estimated $288 million-dollar price tag were approved for construction by the Cal-ISO Board of Governors to ensure continued grid reliability.

According to the ISO's 2015-2016 Transmission Plan, each of the 13 projects costs less than $50 million and two-thirds are high-voltage upgrades needed to address reliability. None of the projects planned are policy- or economically-driven, which means there will be no need to take projects out for competitive bids, according to Cal-ISO, which approved the plan at its March 25 board meeting.

The transmission plan also called for canceling 13 sub-transmission projects in the Pacific Gas & Electric service area valued at $192 million. Some of these projects were originally approved in 2005. Of these, only two needed board approval—the Monta Vista-Wolfe and Newark-Applied Materials substation upgrades. Both 115 kV substation-upgrade projects were valued at $1 million each. However, Neil Millar, executive director of infrastructure development for Cal-ISO, said it is valuable "to get these cleared out of the way to focus on other projects going forward."

'We really appreciate the reappraisal of those projects.'

In his remarks to the board, Eric Eisenman, director of ISO relations and FERC policy for PG&E, conveyed the utility's support for the plan, including the project cancellations.

"The need for those is just not there anymore," he said. "We really appreciate the reappraisal of those projects." Load forecast has flattened in the service area from a combination of energy efficiency and rooftop solar, which eliminates the need for these upgrades, Eisenman said.

The utility plans to work with Cal-ISO on planning to prevent overbuilding and to ensure customers have affordable services. Future surveys, Eisenman said, would need to consider resources in the Oakland-East Bay area, which has an aging generation plant that may go off line. Roughly two-thirds of PG&E's $1 billion transmission budget is used to address maintenance and replacement of aging infrastructure.

This year's Cal-ISO transmission plan is "light" compared to previous plans, noted Steve Berberich, the grid operator's president and CEO, in his comments to the board. The 2012-2013 and 2013-2014 transmission plans were project-heavy to address issues in the PG&E service area and reliability requirements created by the early retirement of Units 2 and 3 of the San Onofre Nuclear Generating Station.

Among the new reliability projects identified in the 2015-2016 transmission plan are seven different projects, at a projected cost of $202 million, in the PG&E service area, including the reconductoring of the Panoche-Ora Loma 115 kV line and the Wilson 115 kV static VAR compensator (SVC) project.

Five projects are in the San Diego Gas & Electric service area and one is in the Southern California Edison service area. There are no projects planned in the Valley Electric Association service area in this planning cycle.

None of the transmission projects address the 2020 or 2030 renewables portfolio standards; however, Millar says there is a pressing need to better manage generation from renewable sources, which creates wider changes in operating conditions. Ultimately, this will require more voltage support across the system. The system operator is seeing "the impacts in real time" and needs to address these and other voltage-control issues, Millar said.

An upgrade to the Lugo-Victorville 500 kV line is needed, Millar and Berberich said, but Cal-ISO is coordinating with the Los Angeles Department of Water & Power on the project. A detailed cost-benefits analysis is needed because it is an interregional project, which pushes it into the 2016-2017 planning cycle. The needs of the Los Angeles Basin and San Diego areas specific to 230 kV loading in the region will also be addressed in that time frame.

Striving to meet the 50 percent RPS may require looking carefully at transmission needs. "As the system is changing in ways we hadn't historically anticipated," said Berberich, "we're going to have to be agile around re-evaluating the transmission system and what's really needed.

"There are lots of moving parts." *–L. D. P.*

[14.2] Cal-ISO Approves Changes to Commitment Cost-Bidding Process

The Cal-ISO Board of Governors on March 25 approved changes to the commitment cost-bidding process after weighing concerns that the proposal might hinder the use of preferred resources and did not adequately address concerns from demand-response providers.

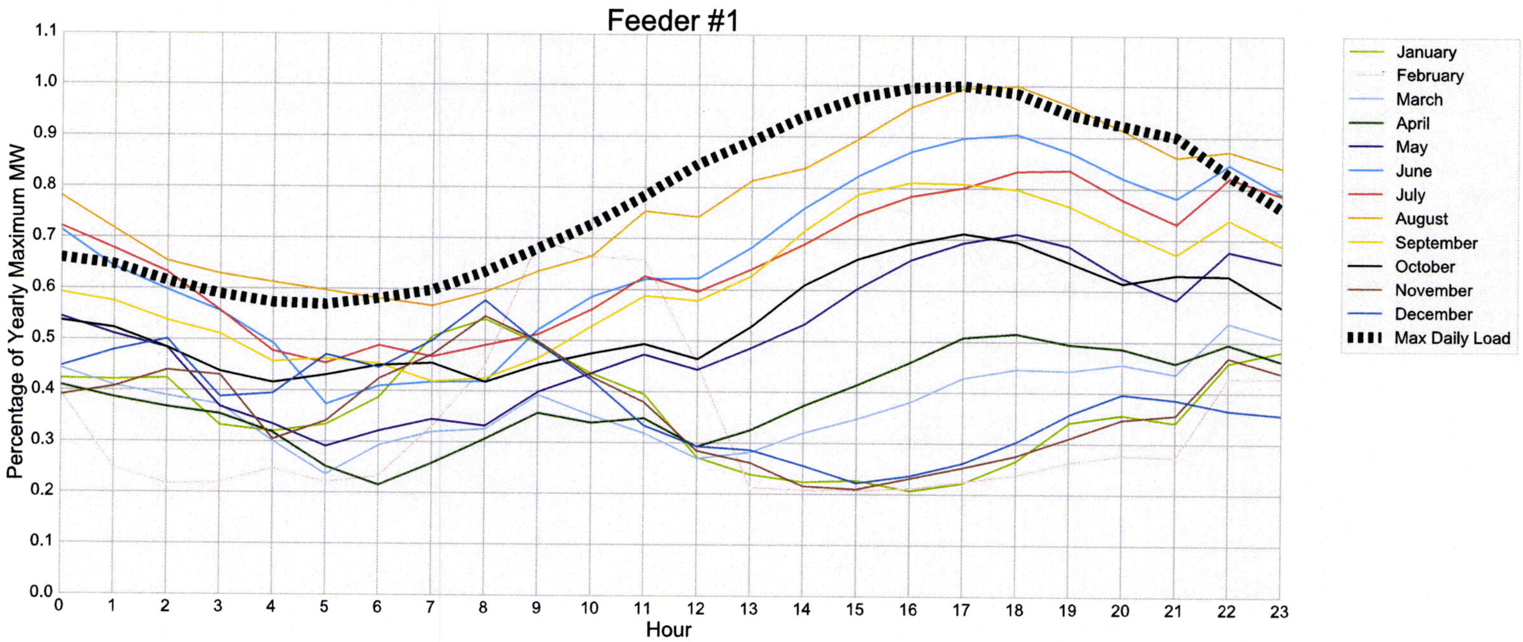
Under the changes, use-limited resources will be eligible for a calculated opportunity cost to include in their daily commitment cost bids, which will allow the market to recognize their use limitations that extend over a longer period of time than the daily markets, such as annual limitations. The move will allow the ISO to eliminate the "registered cost" option for bidding commitment costs, under which a market participant can bid fixed costs for 30 days.

Cal-ISO now has roughly 35,000 MW of use-limited resources available. The goal is to commit these resources when they are of most value to the grid and at maximum profit for the generation owner.

The original language on commitment costs was altered to reflect comments made by CPUC Commissioner Mike Florio.

Florio's changes address concerns related to the use-limited status of preferred resources. This includes giving parties that might be affected—including investor-owned utilities, demand-response and energy-storage providers, and others—more time to better understand and manage the transition to the cost-bidding structure.

Exhibit WAM-8: Normalized Hourly Loading on Representative Feeders Figures



Feeder #1
Percentage of Yearly Maximum MW
Hour
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
1.1
0
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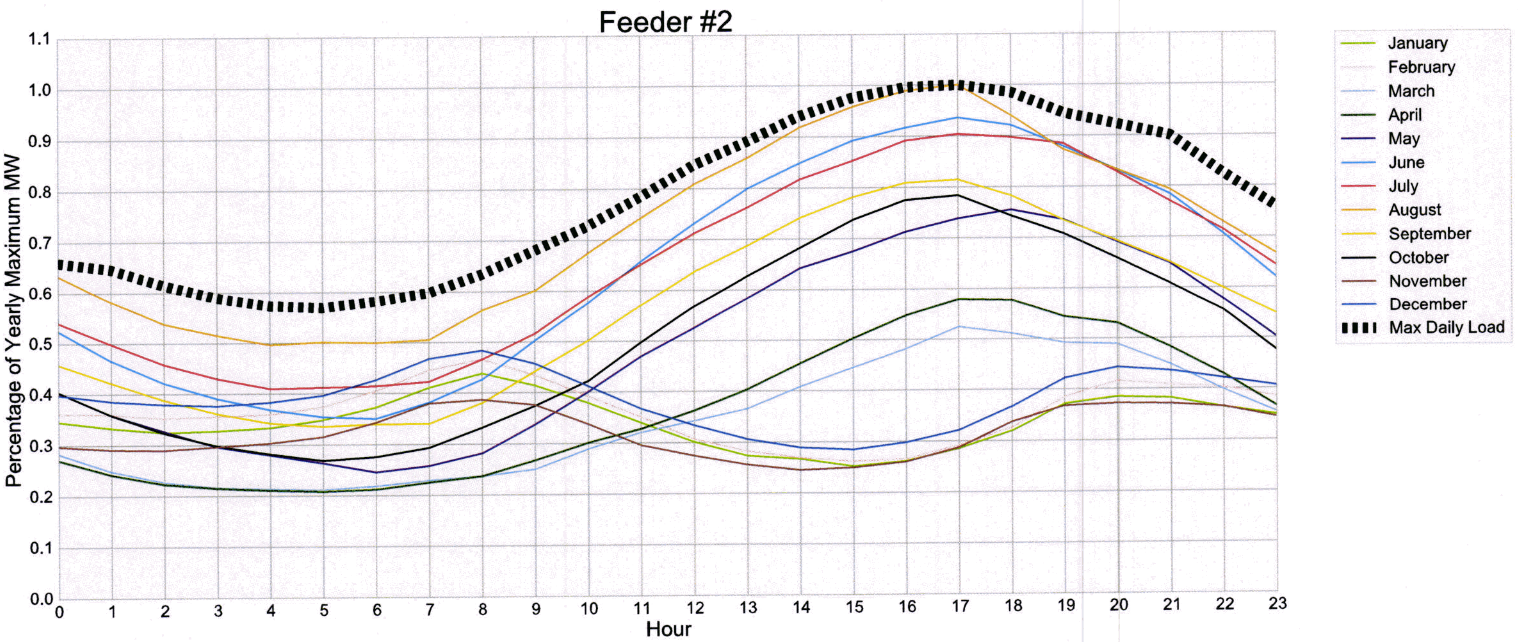
Max Daily Load



Feeder #2
Percentage of Yearly Maximum MW
Hour
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0
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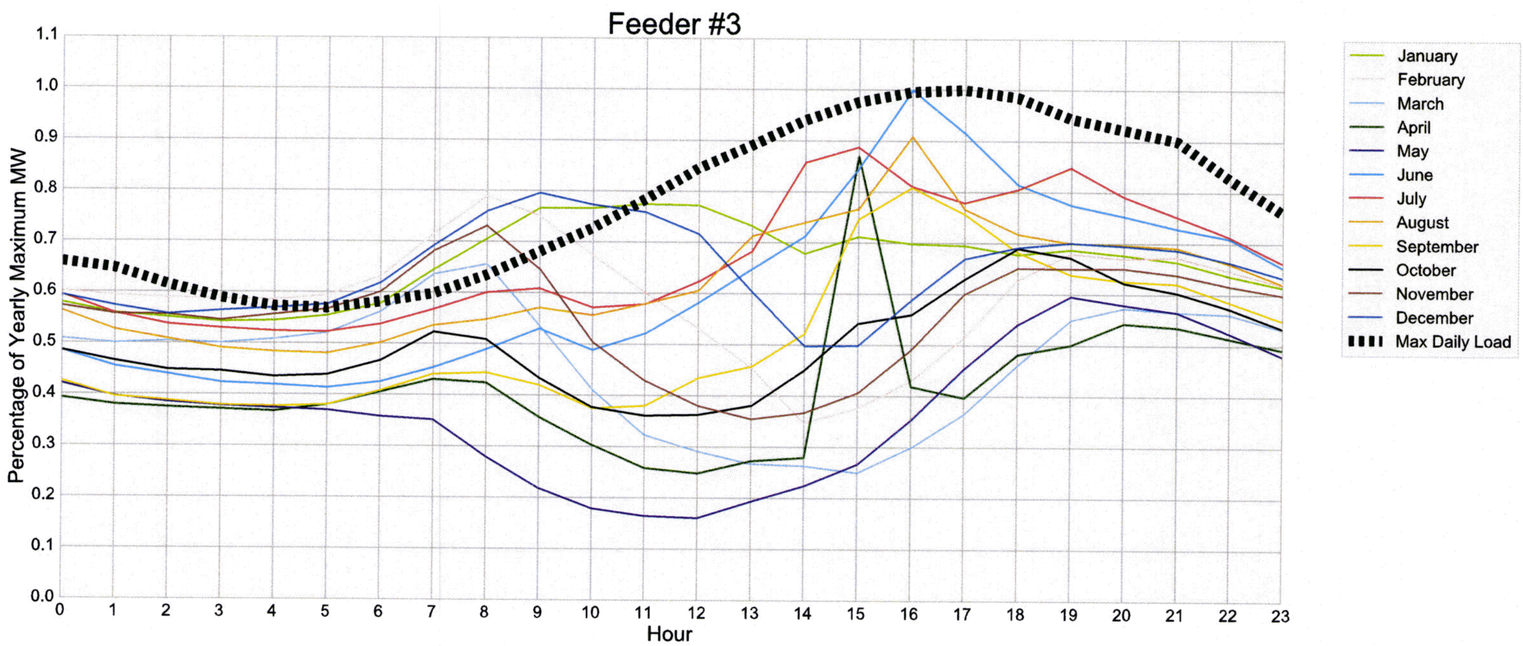
Max Daily Load



Feeder #3
Percentage of Yearly Maximum MW
Hour
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0.7
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0.4
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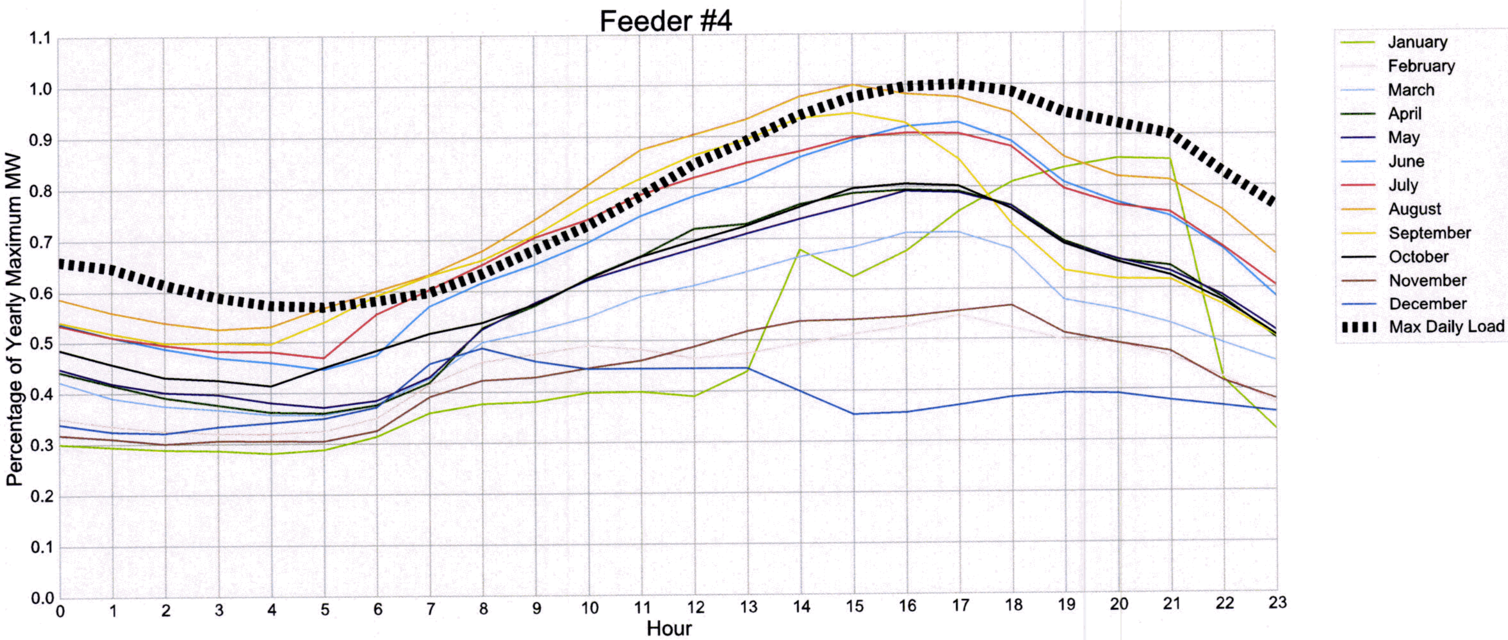
Max Daily Load



Feeder #4
Percentage of Yearly Maximum MW
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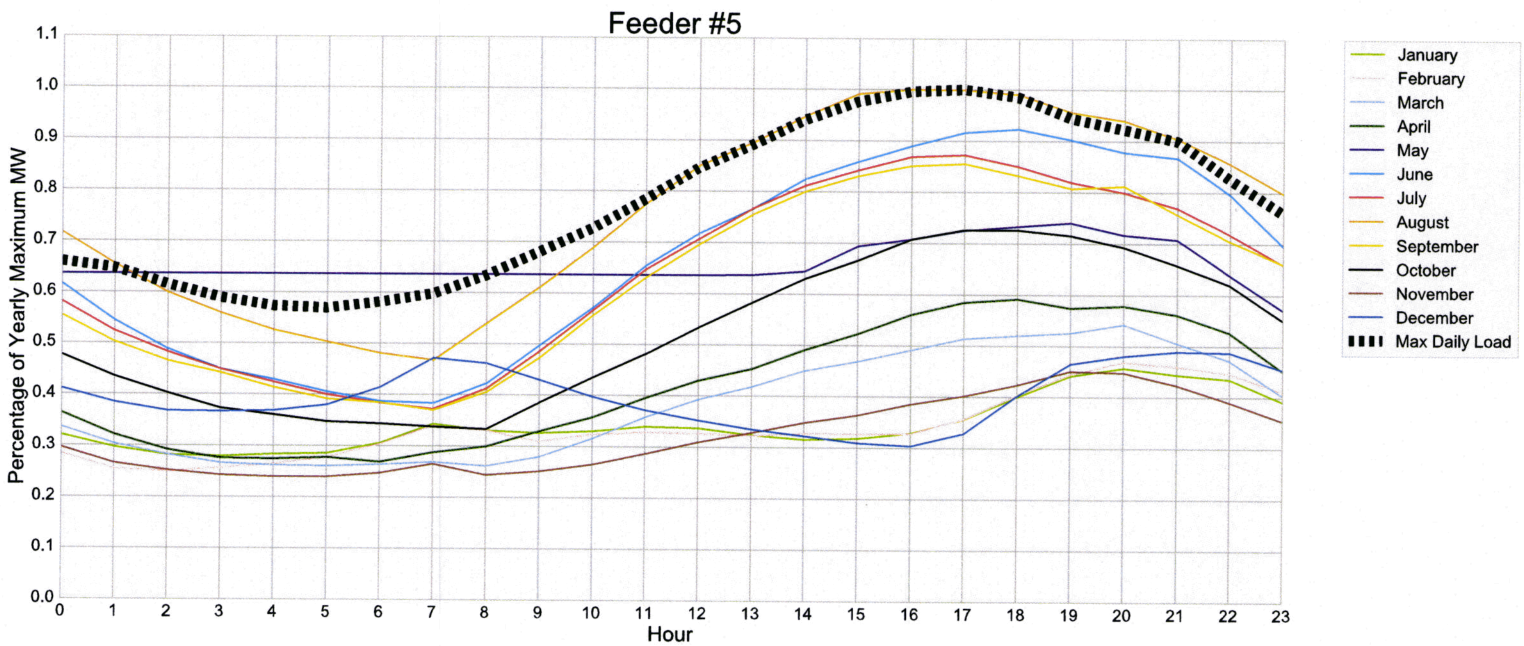
November
December
Max Daily Load



Feeder #5
Percentage of Yearly Maximum MW
Hour
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1.0
0.9
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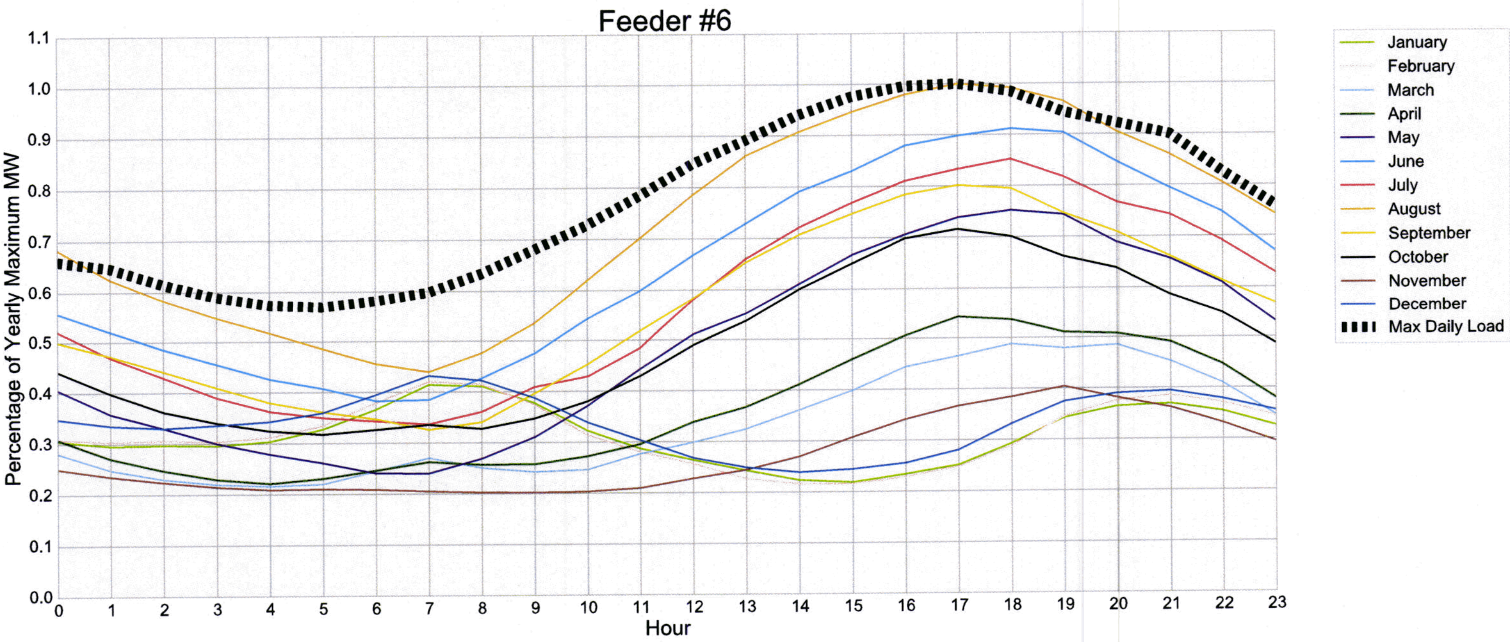
Max Daily Load


Feeder #6
Percentage of Yearly Maximum MW
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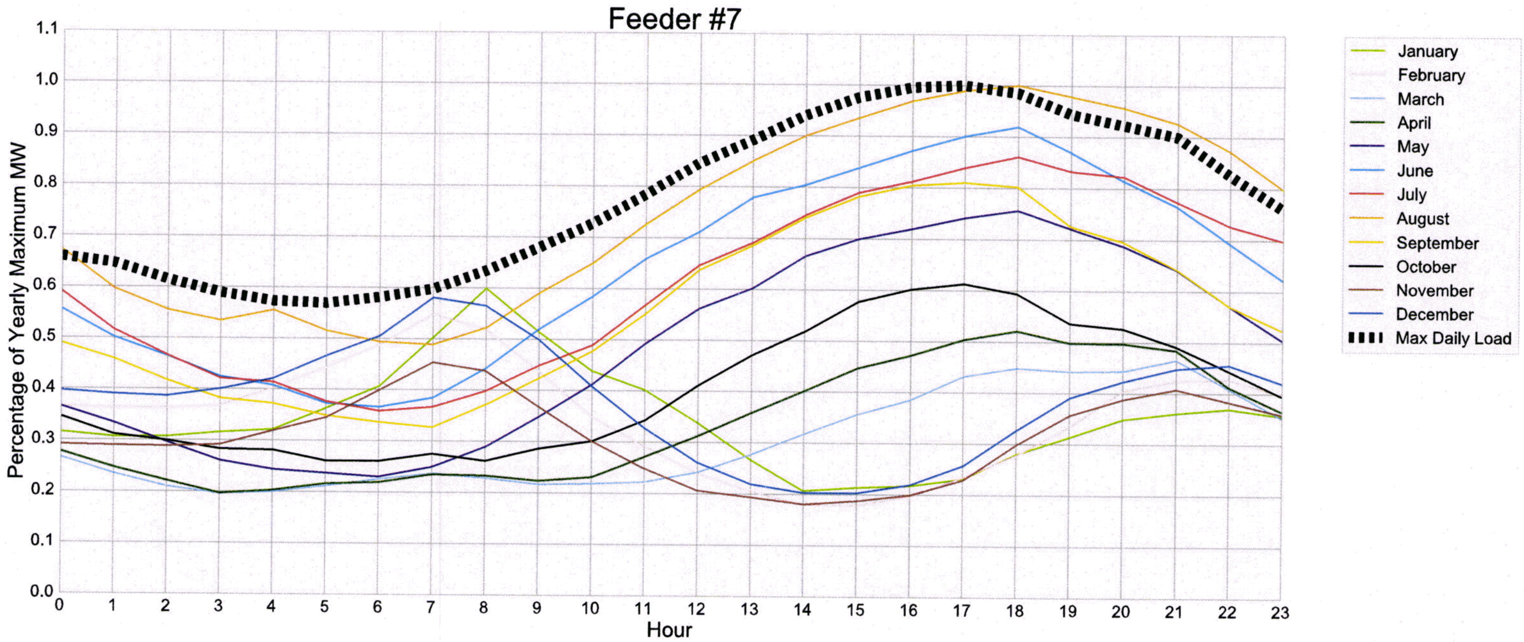
Max Daily Load



Feeder #7
Percentage of Yearly Maximum MW
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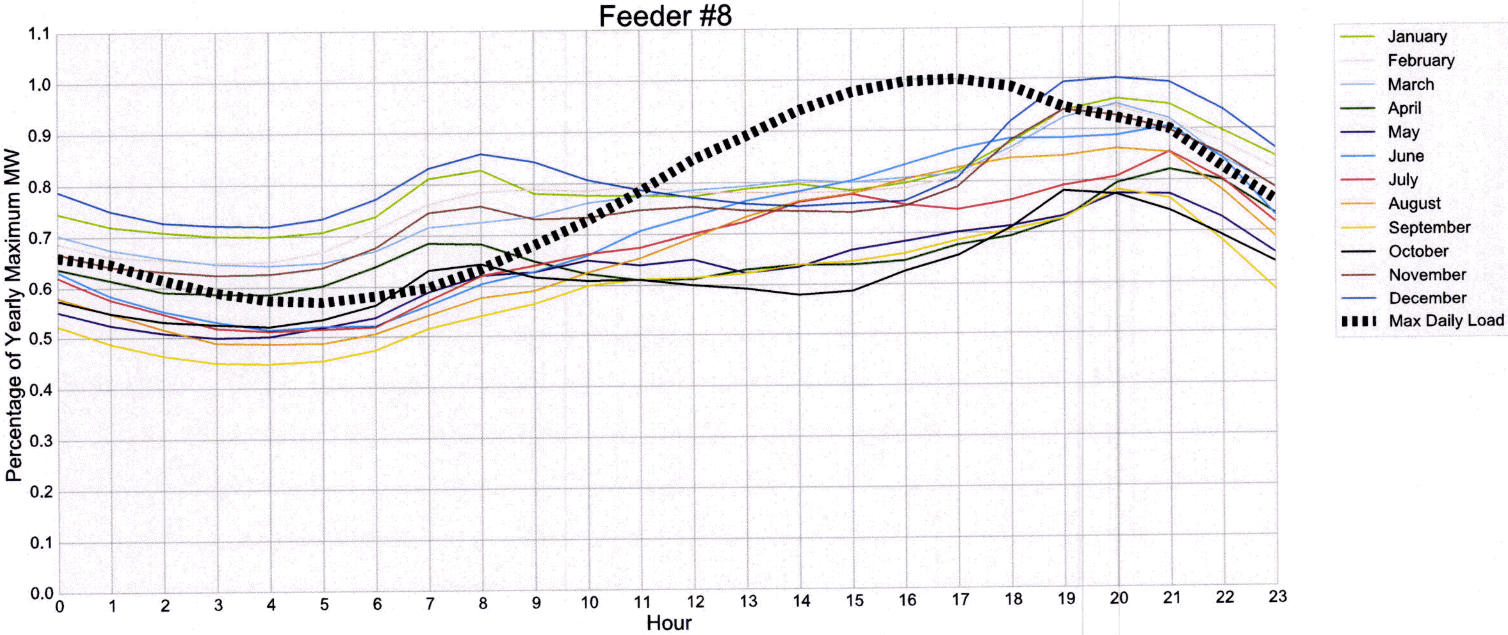

Feeder #8
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0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
Percentage of Yearly Maximum MW
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Max Daily Load

Exhibit WAM-9: Excerpt from
PG&E 2014 General Rate Case Phase II Prepared Testimony, Exhibit (PG&E-1), Volume 1: Revenue Allocation and Rate Design, Application 13-04-012

Application: ____________________
(U 39 M)
Exhibit No.: (PG&E-1)
Date: April 18, 2013
Witness: Various

PACIFIC GAS AND ELECTRIC COMPANY

2014 GENERAL RATE CASE PHASE II

PREPARED TESTIMONY

EXHIBIT (PG&E-1)
VOLUME 1
REVENUE ALLOCATION AND RATE DESIGN

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

REVENUE ALLOCATION PROPOSAL

F. Development of Marginal Cost Revenues

In this section, PG&E presents a description of the development of the marginal cost revenues used in PG&E's proposed EPMC allocation of the distribution and generation functional revenue. Marginal primary and secondary distribution capacity cost revenue and marginal customer access cost revenue are used to calculate EPMC factors and allocate distribution functional revenue. Marginal generation capacity and energy cost revenue are used to calculate EPMC factors and allocate generation functional revenue.

1. Distribution Marginal Cost Revenue

a. Demand-Related Distribution Marginal Cost Revenue

Demand-related distribution marginal costs are estimated for PG&E's primary distribution (between 60 kilovolts (kV) and 4 kV) and secondary distribution (below 4 kV) systems. PG&E uses the appropriate demand measure for each marginal cost to compute the marginal cost revenue. Specifically, PG&E estimates class loads at the substation level using weighting factors called "peak capacity allocation factors" (distribution PCAF)[7] and at the final line transformer (FLT) level.[8]

1) Primary Marginal Cost Revenue

PG&E uses division level distribution PCAF-weighted loads to estimate primary marginal cost revenue. For a given rate schedule and division, the recorded primary marginal cost revenue equals a three-year average of recorded division-level distribution PCAF loads multiplied by the estimated primary marginal cost and the

---

7 Additional information on distribution PCAF loads used in the revenue allocation is provided with PG&E's revenue allocation workpapers. The substation-level PCAF-weighted loads are weather-normalized weighted loads that indicate what contribution a class has made to a substation's peak. These PCAF-weighted loads are then summarized by division for the calculation of primary demand-related marginal cost revenue.

8 Additional information on FLT loads is provided with PG&E's revenue allocation workpapers. FLT loads are either the class' diversified non-coincident demand at the FLT (residential and small commercial classes) or the class' undiversified non-coincident demand at the FLT (all other classes). Non-coincident demand is the class' highest observed demand during the year. As more than one residential or small commercial customer are served by a FLT, the FLT loads for these classes are scaled down (diversified) to reflect the fact that not all the customers served by that transformer will be operating at the time the FLT reaches its peak. For all the other classes, PG&E assumes that there is one customer per FLT.

Exhibit WAM-10: Excerpt from

California Public Utilities Commission, Decision15-08-005

ALJ/DUG/SCR/ek4 **Date of Issuance 8/18/2015**

Decision 15-08-005 August 13, 2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U39M).	Application 13-04-012 (Filed April 18, 2013)

DECISION ADOPTING EIGHT SETTLEMENTS AND RESOLVING CONTESTED ISSUES RELATED TO PACIFIC GAS AND ELECTRIC COMPANY'S ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN

DECISION ADOPTING EIGHT SETTLEMENTS AND RESOLVING CONTESTED ISSUES RELATED TO PACIFIC GAS AND ELECTRIC COMPANY'S ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN

Summary

This decision adopts eight separate settlements as proposed by the settling parties and resolves the remaining outstanding issues based on the merits of the litigated positions. This completes the current review of Pacific Gas and Electric Company's (PG&E) electric marginal costs, revenue allocation, and rate design. Adoption of these new rates will reallocate the existing authorized revenue requirement amongst the various customer classes and within those customer classes. One settlement was partially contested and this decision resolves those contested issues primarily in accordance with the proposed settlements.

Because this proceeding deals with only rate design related questions and not operating or capital costs, or how PG&E operates its electric system, there are no changes to PG&E's overall authorized revenue requirement, although individual customer's bills may change as a result of changes in rate design. Also, there is no impact on employee, customer, or public safety, again because this decision does not change PG&E's revenue requirement or have any direct impact on electric operations.

This proceeding is closed.

1. Procedural History

The proceeding has a complex history, as parties sought and were granted numerous extensions of time to complete settlement negotiations with various sub-groups of interested parties which resulted in eight separate settlements covering all but a few issues that were litigated. All settlement rules were followed and all parties had notice and opportunity to participate. The find that they contain a statement of the factual and legal considerations adequate to advise the Commission of the scope of the settlement and of the grounds for its adoption; that the settlement was limited to the issues in this proceeding; and that the settlement included a comparison indicating the impact of the settlement in relation to the utility's application and contested issues raised by the interested parties in prepared testimony, or that would have been contested in a hearing. These two findings that the settlement complies with Rule 12.1(a), allow us to conclude, pursuant to Rule 12.1(d), that the settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

Based upon our review of the settlement documents we find, pursuant to Rule 12.5, that the proposed settlements would not bind or otherwise impose a precedent in this or any future proceeding. We specifically note, therefore, that neither PG&E nor any party to any of the settlements may presume in any subsequent applications that the Commission would deem the outcome adopted herein to be presumed reasonable and it must, therefore, fully justify every request and ratemaking proposal without reference to, or reliance on, the adoption of these settlements.

7. Summary of Settlements

A copy of all eight of the Settlement Agreements, fully executed by all interested parties, are available at the links below following each settlement. The final language of the settlement controls the terms and conditions of the adopted rates except as specifically modified herein. The proposed settlements are as follows:

1. Settlement Agreement on Marginal Cost and Revenue Allocation Issues, filed July 16, 2014;

http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=99753189;

2. Residential Rate Design Supplemental Settlement Agreement, filed July 24, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=101125976;

3. Large Light and Power Rate Design Settlement Agreement, filed July 25, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=102226995;

4. Streetlight Rate Design Supplemental Settlement Agreement, filed August 29, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=103390568

5. Amended E-Credit Rate Design Supplemental Agreement, filed March 30, 2015;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=151726093;

6. Medium Commercial Rate Design Settlement Agreement, filed September 5, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=105647677;

7. Small Commercial Rate Design Settlement Agreement, filed September, 5, 2014; and

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=107147806

8. Agricultural Rate Design Settlement Agreement, filed December 2, 2014.

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=143515264.

Exhibit WAM-11: Excerpt from

California Public Utilities Commission, A.13-04-012, Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case, Appendix A, July 16, 2014

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 13-04-012 (Filed April 18, 2013)

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2014 GENERAL RATE CASE

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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: July 16, 2014

Pacific Gas and Electric Company
2014 General Rate Case Phase II, A.13-04-012

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION
Appendix A

Marginal Generation Energy Costs:

Table 1 - 2014 Marginal Generation Energy Costs by Time of Use (TOU) Rate Period and Voltage Level (¢/kWh)

Line No.	TOU Rate Period	Voltage Level		
		Transmission	Primary Distribution	Secondary Distribution
1	Summer Peak	5.613	5.718	6.001
2	Summer Partial-Peak	4.791	4.881	5.123
3	Summer Off-Peak	3.654	3.722	3.907
4	Winter Partial-Peak	4.856	4.948	5.192
5	Winter Off-Peak	3.968	4.043	4.243
6	Annual Average	4.266	N.A.	N.A.

Marginal Transmission and Distribution Costs:

Table 2: 2014 Marginal Transmission Capacity Cost ($/kW-Yr)

Line No.	Transmission Capacity
1	34.86

Table 3: 2014 Distribution Marginal Customer Access Costs ($/Customer-Yr)

Line No.	Class	Marginal Customer Access Cost
1	Residential	73.72
2	Agricultural A	321.96
3	Agricultural B	1,457.43
4	Small L & P	323.37
5	A10 Medium L & P Secondary	638.43
6	A10 Medium L & P Primary	1,917.29
7	E19 Secondary	748.05
8	E19 Primary	6,288.92
9	E19 Transmission	6,650.02
10	E20 Secondary	5,559.77
11	E20 Primary	6,688.18
12	E20 Transmission	6,659.54
13	Streetlights	83.05
14	Traffic Control	105.91

Table 4: 2014 Marginal Distribution Capacity Costs by Operating Division

Line No.	Division	Primary Capacity ($/PCAF kW-Yr)	New Business on Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
1	Central Coast	95.45	12.31	4.00
2	De Anza	112.71	22.30	2.45
3	Diablo	52.57	20.78	4.01
4	East Bay	60.29	18.87	1.44
5	Fresno	30.31	8.05	1.61
6	Kern	31.43	7.95	1.97
7	Los Padres	40.87	9.75	2.03
8	Mission	19.87	9.90	1.81
9	North Bay	17.74	12.66	2.13
10	North Coast	42.22	12.65	3.13
11	North Valley	36.06	16.22	3.60
12	Peninsula	38.62	10.46	2.98
13	Sacramento	37.65	13.07	2.21
14	San Francisco	18.33	6.24	1.28
15	San Jose	38.50	12.18	2.79
16	Sierra	29.68	10.15	3.21
17	Stockton	38.26	8.85	2.30
18	Yosemite	45.78	17.54	2.94
19	System	37.33	11.26	2.33

Table 5: 2014 Marginal Distribution Capacity Costs by Distribution Planning Area

Line No.	Division	Distribution Planning Area	Capacity Projects Over $1MM ($/PCAF kW-Yr)	Capacity Projects Under $1MM ($/PCAF kW-Yr)	Total Primary Capacity ($/PCAF kW-Yr)	New Business On Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
1	Central Coast	Carmel Valley 12kV	0.00	31.07	31.07	12.31	4.00
2	Central Coast	Gonzales	0.00	31.07	31.07	12.31	4.00
3	Central Coast	Hollister	16.07	31.07	47.14	12.31	4.00
4	Central Coast	King City	129.50	31.07	160.57	12.31	4.00
5	Central Coast	Monterey 21kV	0.00	31.07	31.07	12.31	4.00
6	Central Coast	Mty_4kV (Monterey Bk#1F	0.00	31.07	31.07	12.31	4.00
7	Central Coast	Oilfields	0.00	31.07	31.07	12.31	4.00
8	Central Coast	Prunedale	0.00	31.07	31.07	12.31	4.00
9	Central Coast	Pt Moretti	0.00	31.07	31.07	12.31	4.00
10	Central Coast	Salinas (4/12 kV)	33.73	31.07	64.80	12.31	4.00
11	Central Coast	Santa Cruz Area	0.00	31.07	31.07	12.31	4.00
12	Central Coast	Seaside 4kV	0.00	31.07	31.07	12.31	4.00
13	Central Coast	Seaside-Marina 12kV	60.75	31.07	91.82	12.31	4.00
14	Central Coast	Soledad	0.00	31.07	31.07	12.31	4.00
15	Central Coast	Watsonvlle (12/21kV)	277.75	31.07	308.82	12.31	4.00
16	Central Coast	Watsonvlle (4kV)	0.00	31.07	31.07	12.31	4.00
17	De Anza	Cupertino	0.00	15.15	15.15	22.30	2.45
18	De Anza	Los Altos (12 kV)	130.97	15.15	146.12	22.30	2.45
19	De Anza	Los Altos (4kV)	0.00	15.15	15.15	22.30	2.45
20	De Anza	Los Gatos	101.47	15.15	116.62	22.30	2.45
21	De Anza	Mountain View	70.62	15.15	85.77	22.30	2.45
22	De Anza	Sunnyvale	108.09	15.15	123.24	22.30	2.45
23	Diablo	Alhambra	0.00	28.54	28.54	20.78	4.01
24	Diablo	Brentwood	0.00	28.54	28.54	20.78	4.01
25	Diablo	Clayton / Willow Pass	0.00	28.54	28.54	20.78	4.01
26	Diablo	Concord	22.24	28.54	50.77	20.78	4.01
27	Diablo	Delta (Split Into Bw And Pitts)	0.00	28.54	28.54	20.78	4.01
28	Diablo	Pittsburg	18.00	28.54	46.54	20.78	4.01
29	Diablo	Walnut Creek 12 kV	24.79	28.54	53.32	20.78	4.01
30	Diablo	Walnut Creek 21 kV	30.60	28.54	59.14	20.78	4.01
31	East Bay	C-D-L	128.09	8.29	136.39	18.87	1.44
32	East Bay	Edes-J	0.00	8.29	8.29	18.87	1.44
33	East Bay	K-X	0.00	8.29	8.29	18.87	1.44
34	East Bay	North	0.00	8.29	8.29	18.87	1.44
35	East Bay	South	60.14	8.29	68.44	18.87	1.44