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Distributed Energy Resources in Practice: A Case Study Analysis and Validation of LBNL's Customer Adoption Model Appendix

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Environmental Energy Technologies Division

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Acronyms and Definitions

AESC	Alternative Energy Systems Consulting Inc.
AGA	American Gas Association
A&P	A&P Waldbaum's Supermarket
BD	BD Biosciences Pharmingen, also referred to as Pharmingen in figures
CDM Energy	a consulting, engineering, constructions and operations firm
CEC	California Energy Commission
CERL	Construction Engineering Research Laboratory
CHP	combined heat and power
CPLEX	a trademark of CPLEX Optimization, Inc
CPUC	California Public Utilities Comission
DEER	Office of Distributed Energy and Electric Reliatiblity, U.S. DOE
DER	distributed energy resources
DER-CAM	Distributed Energy Resources Customer Adoption Model
DG	distributed generation
DHW	domestic hot water
DOD	Department of Defense
DOE	Department of Energy
DOE-2	Building energy simulation software developed by at Berkeley Lab
EBMUD	East Bay Municipal Utility District
ERC	emission reduction credits
FERC	Federal Regulatory Energy Commission
GAMS	General Algebraic Modeling System
GIS	geographic information systems
GSA	U.S. General Services Administration
GSB	Guarantee Savings Building
GTI	Gas Technology Institute
HELCO	Hawaii Electric Light Company Inc.
HHV	higher heating value
HVAC	heating, ventilation, and air conditioning
IC	internal combustion (engine)
IEM	imbalance energy market
LHV	lower heating value
LIPA	Long Island Power Authority
MTH	high pressure (natural gas) microtubine
MTL	low pressure (natural gas) microtubine
NAEA	National Accounts Energy Alliance
NEMS	National Energy Modeling System
NG	natural gas
NPV	net present value
NREL	National Renewable Energy Laboratory
NYSEG	New York State Electric and Gas
NYSERDA	New York State Energy Research and Development Authority
NY PSC	New York State Public Service Commission
ORNL	Oak Ridge National Laboratory

PG&E	Pacific Gas and Electric
PPA	power purchase agreement
PURPA	Public Utility Regulatory Policy Act
PV	photovoltaic
QF	qualifying facility
RG&E	Rochester Gas and Electric
RIA	Rochester (NY) International Airport
SBC	system benefits charge
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
SoCalGas	Southern California Gas Company
USPS	United States Postal Service, San Bernardino facility
UTC	United Technologies Corporation

Appendix A. Tabular Presentation of Results

Results for all sites are presented graphically in the main body of this report. The numeric results from which these graphics were generated are presented in this appendix.

A.1 Results for A&P

Table A- 1: Scenario Results for A&P Without Grants

CASE	Technologies Selected	Annual energy cost	Percentage of base case cost	Annual savings over base case	Electricity purchases	Natural gas purchases	Self generation costs
1: No Invest		$245,468			$220,550	$24,918	$ -
2: Unlimited Invest	None	$245,468	100%	$0	$220,550	$24,918	$0
3: Unlimited Investment in Microturbines	None	$245,468	100%	$ -	$220,550	$24,918	$0
4A: Forced Minimun Investment in 60 kW Microturbines (gen. only)	1x60 kW Capstone turbine	$249,783	102%	($4,315)	$210,089	$29,712	$9,982
4B: Forced Minimun Investment in 60 kW Microturbines (with CHP)	1x60 kW Capstone turbine, CHP	$248,501	101%	($3,033)	$195,042	$34,927	$18,532
4C: Forced Minimun Investment in 60 kW Microturbines (with Abs. Cooling)	1x60 kW Capstone turbine, abs. chiller	$253,709	103%	($8,241)	$199,859	$36,770	$17,080
4D: Forced Minimun Investment in 60 kW Microturbines (with CHP and Abs. Cooling)	1x60 kW Capstone turbine, CHP, abs. chiller	$256,917	105%	($11,449)	$186,823	$40,687	$29,407

Table A- 2: Scenario Results for A&P With Grants

CASE	Technologies Selected	Annual energy cost	Percentage of base case cost	Annual savings over base case	Electricity purchases	Natural gas purchases	Self generation costs
1: No Invest		$ 245,468			$ 220,550	$ 24,918	$ -
2: Unlimited Invest (no grant)	none	$ 245,468	100%	$ -	$ 220,550	$ 24,918	$ -
3: Unlimited Invest in MT's, all units at grant-level price	7x 60 kW Capstone microturbine with CHP	$ 226,111	92%	$ 19,357	$ 134,828	$ 70,572	$ 20,711
3: One 60 kW MT w/ CHP covered by grant, additional units full price	60 kW Capstone with CHP	$ 234,767	96%	$ 10,701	$ 195,042	$ 34,927	$ 4,798
4: Forced minimum investment in 60 kW MT (gen. only)	1x 60 kW Capstone	$ 249,783	102%	$ (4,315)	$ 210,089	$ 29,713	$ 9,981
4: Forced minimum investment in 60 kW MT w/ CHP	1x 60 kW Capstone with CHP	$ 248,501	101%	$ (3,033)	$ 195,042	$ 34,927	$ 18,532
4: Forced minimum investment in 60 kW MT w/ abs. cooling	1x 60 kW Capstone with abs. cooling	$ 253,709	103%	$ (8,241)	$ 199,859	$ 36,771	$ 17,079
4: Forced minimum investment in 60 kW MT w/ CHP and abs. cooling	1x 60 kW Capstone with CHP and abs. cooling	$ 256,917	105%	$(11,449)	$ 186,824	$ 40,688	$ 29,405
4: Forced minimum investment in 60 kW MT w/ CHP (all at grant-reduced cost)	7x 60 kW Capstone microturbine with CHP	$ 226,111	92%	$ 19,357	$ 134,828	$ 70,572	$ 20,711
5: Forced investment in 60 kW MT with CHP	60 kW Capstone with CHP	$ 234,767	96%	$ 10,701	$ 195,042	$ 34,927	$ 4,798

Table A- 3: Standby Sensitivity for A&P

Standby Charge ($/kW)	0	2	2.46	6	10	14	20
Generation Only Installed Capacity (kW)	0	0	0	0	0	0	0
CHP Installed Capacity (kW)	60	60	60	60	60	60	60
Abs. Cooling Installed Capacity (kW)	0	0	0	0	0	0	0
Yearly Energy Costs ($)	232996	234436	234767	237316	240196	243076	247396
Max. Electric Load (kW)	500	500	500	500	500	500	500

Table A- 4: Flat Rate Electricity Sensitivity for A&P

CASE	Technologies Selected	Annual energy cost	Electricity purchases	Natural gas purchases	Self generation costs	Installed Capacity (kW)
2: Unlimited Invest, actual electric rates, grant one unit max	1 x 60 kW Capstone microturbine with CHP	$ 234,767	$ 195,042	$ 34,927	$ 4,798	60
2: Unlimited Invest, flat electric rate ($0.100668/kWh)	60 kW Capstone turbine with CHP	$ 225,531	$ 186,245	$ 34,562	$ 4,724	60

Table A- 5: Spark Spread Sensitivity for A&P

Percent of Natural Gas Prices	50	70	80	90	95	100	105	110	120	140	160	180	200
Generation Only Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP Installed Capacity (kW)	120	60	60	60	60	60	60	60	60	60	60	60	60
Abs. Cooling Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0
Yearly Energy Cost	$210,696	$223,628	$227,828	$231,364	$ 233,065	$ 234,767	$236,468	$238,170	$241,572	$248,375	$255,093	$261,559	$267,209
Max. Electric Load (kW)	500	500	500	500	500	500	500	500	500	500	500	500	500
actual nat. gas price ($/kWh)	0.0144	0.0202	0.0231	0.0259	0.0274	0.0288	0.0303	0.0317	0.0346	0.0404	0.0461	0.0519	0.0577
electricity price (do nothing case) ($/kWh)	0.100668	0.100668	0.100668	0.100668	0.100668	0.100668	0.100668	0.100668	0.100668	0.100668	0.100668	0.100668	0.100668
spark spread	7.0	5.0	4.4	3.9	3.7	3.5	3.3	3.2	2.9	2.5	2.2	1.9	1.7
spark spread (percent of actual NG price)	7.0 (50%)	5.0 (70%)	4.4 (80%)	3.9 (90%)	3.7 (95%)	**3.5 (100%)**	3.3 (105%)	3.2 (110%)	2.9 (120%)	2.5 (140%)	2.2 (160%)	1.9 (180%)	1.7 (200%)

A.2 Results for Guaranteed Savings Building

Table A- 6: Scenario Results for Guaranteed Savings Building Without Grants

CASE	Technologies Selected	Annual energy cost	Percentage of base case cost	Annual savings over base case	Electricity purchases	Natural gas purchases	Self generation costs
1:No Investment		$ 489,524			$462,806	$26,718	$0
2: Unlimited Investment	500 kW natural gas engine, 1 x 55 kW natural gas engines with CHP	$ 429,977	88%	$ 59,547	$147,505	$176,286	$106,186
3: Unlimited Investment in PAFC	No installation of DER	$ 489,524	100%	$ -	$462,806	$26,718	$0
4: Forced Minimun Investment in PAFC	200 kW PAFC with CHP and absorption chiller	$ 576,618	118%	$ (87,094)	$273,101	$96,643	$206,874
5: PAFC 600 kW with Abs Cooling and CHP	3 x 200 kW PAFC with CHP and absorption chiller	$ 835,910	171%	$ (346,386)	$65,912	$168,724	$601,274

Table A- 7: Scenario Results for Guaranteed Savings Building With Grants

CASE	Technologies Selected	Annual energy cost	Percentage of base case cost	Annual savings over base case	Electricity purchases	Natural gas purchases	Self generation costs
1: No Invest		$ 489,524			$ 462,806	$ 26,718	$ -
2: Unlimited Invest	1 x 100 kW PV 3 x 55 kW natural gas engines with CHP 1 x 500 kW natural gas engine with absorption chiller	$ 402,756	82%	$ 86,768	$ 43,217	$ 198,280	$ 161,259
3: Unlimited Invest in PAFCs	200 kW PAFC with CHP	$ 471,495	96%	$ 18,029	$ 283,230	$ 97,271	$ 90,994
4: Forced minimum investment in 200 kW PAFC with CHP and Abs. Chiller	200 kW PAFC with CHP	$ 488,341	100%	$ 1,183	$ 273,101	$ 96,643	$ 118,597
5: Forced duplication of site decision: 3x 200 kW PAFC with CHP and Abs. Chiller	3x 200 kW PAFC with CHP and abs. chiller	$ 571,078	117%	$ (81,554)	$ 65,912	$ 178,724	$ 326,442

Table A- 8: Standby Sensitivity for Guaranteed Savings Building

Standby Charge ($/kW)	0	1	2.167	3	4	6	8	10
Generation Only Installed Capacity (kW)	0	0	0	0	0	0	0	0
CHP Installed Capacity (kW)	200	200	200	200	200	200	200	0
Abs. Cooling Installed Capacity (kW)	0	0	0	0	0	0	0	0
Yearly Energy Costs ($)	$ 466,293	$ 468,693	$ 471,495	$ 473,493	$ 475,893	$ 480,693	$ 485,493	$ 489,524
Max. Electric Load (kW)	600	600	600	600	600	600	600	600

Table A- 9: Flat Electricity Rate Sensitivity for Guaranteed Savings Building

CASE	Technologies Selected	Annual energy cost	Electricity purchases	Natural gas purchases	Self generation costs	Installed Capacity (kW)
2: Unlimited Invest, actual electric rates	1 x 100 kW PV 3 x 55 kW natural gas engines with CHP 1 x 500 kW natural gas engine with absorption chiller	$ 402,756	$ 43,217	$ 198,280	$ 161,259	765
2: Unlimited Invest, flat electric rate ($0.143/kWh)	1 x 50 kW PV 1 x 100 kW PV 1 x 500 kW natural gas engine with CHP	$ 388,797	$ 59,821	$ 185,434	$ 143,542	650

Table A- 10: Spark Spread Sensitivity for Guaranteed Savings Building

Percent of Natural Gas Prices	50	70	80	90	95	100	105	110	120	140	160	180	200
Generation Only Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP Installed Capacity (kW)	400	400	200	200	200	200	200	200	200	0	0	0	0
Abs. Cooling Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0
Yearly Energy Cost	$ 413,298	$ 441,827	$ 452,066	$ 461,784	$ 466,640	$ 471,495	$ 476,351	$ 481,203	$ 490,804	$ 500,147	$ 505,459	$ 510,770	$ 516,081
Max. Electric Load (kW)	600	600	600	600	600	600	600	600	600	600	600	600	600
actual nat. gas price ($/kWh)	0.0125	0.0175	0.0200	0.0225	0.0237	0.0249	0.0262	0.0274	0.0299	0.0349	0.0399	0.0449	0.0499
electricity price (do nothing case) ($/kWh)	0.1312	0.1312	0.1312	0.1312	0.1312	0.1312	0.1312	0.1312	0.1312	0.1312	0.1312	0.1312	0.1312
spark spread	10.5	7.5	6.6	5.8	5.5	5.3	5.0	4.8	4.4	3.8	3.3	2.9	2.6
spark spread (percent of actual NG price)	10.5 (50%)	7.5 (70%)	6.6 (80%)	5.8 (90%)	5.5 (95%)	**5.3 (100%)**	5.0 (105%)	4.8 (110%)	4.4 (120%)	3.8 (140%)	3.3 (160%)	2.9 (180%)	2.6 (200%)

A.3 Results for The Orchid

Table A- 11: Scenario Results for The Orchid

CASE	Technologies Selected	Annual energy cost	Percentage of base case cost	Annual savings over base case	Electricity purchases	Propane purchases	Self generation costs
1: No Invest		$ 1,474,339			$ 1,304,144	$ 170,195	$ -
2: Unlimited Invest	2x 200 kW converted propane engine with CHP, 1 x 500 kW converted propane engine with abs. cooling	$ 1,253,405	85%	$ 220,934	$ 101,333	$ 801,459	$ 350,613
3: Unlimited Invest in converted propane engines	2x 200 kW converted propane engine with CHP, 1 x 500 kW converted propane engine with abs. cooling	$ 1,253,405	85%	$ 220,934	$ 101,333	$ 801,459	$ 350,613
4: Forced minimum investment in 200 kW converted propane engines with CHP and 200 kW converted propane engines with abs. cooling	3x 200 kW converted propane engine with CHP, 1x 200 kW converted propane engine with abs. cooling	$ 1,273,867	86%	$ 200,472	$ 203,546	$ 737,867	$ 332,454
5: Forced duplication of site decision (2 x 200 kW engine w/ CHP, 2x 200 kW w/ abs. cooling)	2x 200 kW converted propane engine with CHP, 2x 200 kW converted propane engine with abs. cooling	$ 1,277,673	87%	$ 196,666	$ 179,675	$ 755,513	$ 342,485
5: Forced duplication of site decision (1 x 200 kW engine w/ CHP, 3x 200 kW w/ abs. cooling)	1x 200 kW converted propane engine with CHP, 3x 200 kW converted propane engine with abs. cooling	$ 1,310,159	89%	$ 164,180	$ 156,713	$ 800,930	$ 352,516
5: Forced duplication of site decision (3 x 200 kW engine w/ CHP, 1x 200 kW w/ abs. cooling)	3x 200 kW converted propane engine with CHP, 1x 200 kW converted propane engine with abs. cooling	$ 1,273,867	86%	$ 200,472	$ 203,546	$ 737,867	$ 332,454

Table A- 12: Flat Rate Electricity Sensitivity for The Orchid

CASE	Technologies Selected	Annual energy cost	Electricity purchases	Propane purchases	Self generation costs	Installed Capacity (kW)
3: Unlimited Invest, actual electric rates	2x 200 kW propane engine with CHP, 1x 500 kW propane engine with abs. cooling	$ 1,253,405	$ 101,333	$ 801,459	$ 350,613	900
3: Unlimited Invest, flat electric rate ($0.177/kWh)	2x 200 kW propane engine with CHP, 1x 500 kW propane engine with abs. cooling	$ 1,192,569	$ 65,963	$ 776,002	$ 350,604	900

Table A- 13: Standby Charge Sensitivity for The Orchid

Standby Charge ($/kW)	0	2	4	6	8	10	11.4	12	14	16	18	20	24	28	32	36	44	52
Generation Only Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP Installed Capacity (kW)	500	500	500	400	400	400	400	400	400	400	400	300	600	500	400	400	200	0
Abs. Cooling Installed Capacity (kW)	500	500	500	500	500	500	500	500	500	500	500	500	0	0	0	0	0	0
Goal Function ($)	$1,125,472	$1,149,472	$1,173,472	$1,185,085	$1,216,685	$1,238,285	$1,253,405	$1,259,885	$1,281,485	$1,303,085	$1,324,685	$1,344,901	$1,374,988	$1,399,807	$1,419,138	$1,438,338	$1,463,061	$1,474,339
Max. Electric Load (kW)	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350

Table A- 14: Spark Spread Sensitivity for The Orchid

Percent of Natural Gas Prices	50	70	80	90	95	100	105	110	120	140	160	180	200
Generation Only Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP Installed Capacity (kW)	500	400	400	400	400	400	400	400	600	300	200	0	0
Abs. Cooling Installed Capacity (kW)	500	500	500	500	500	500	500	500	0	0	0	0	0
Yearly Energy Cost	$850,080	$1,013,237	$1,093,293	$1,173,349	$ 1,213,377	$1,253,405	$1,293,433	$1,333,461	$1,404,468	$1,495,774	$1,560,080	$1,609,775	$1,643,634
Max. Electric Load (kW)	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550
actual nat. gas price ($/kWh)	0.0179	0.0250	0.0286	0.0322	0.0340	0.0358	0.0376	0.0394	0.0429	0.0501	0.0573	0.0644	0.0716
electricity price (do nothing case) ($/kWh)	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176
spark spread	9.8	7.0	6.1	5.5	5.2	4.9	4.7	4.5	4.1	3.5	3.1	2.7	2.5
spark spread (percent of actual NG price)	9.8 (50%)	7.0 (70%)	6.1 (80%)	5.5 (90%)	5.2 (95%)	**4.9 (100%)**	4.7 (105%)	4.5 (110%)	4.1 (120%)	3.5 (140%)	3.1 (160%)	2.7 (180%)	2.5 (200%)

A.4 Results for BD Biosciences Pharmingen

Table A- 15: Scenario Results for BD Biosciences Pharmingen

CASE	Technologies Selected	Annual energy cost	Percentage of base case cost	Annual savings over base case	Electricity purchases	Natural gas purchases	Self generation costs
1: No Invest		$ 333,733			$ 273,085	$ 60,648	$ 0
2: Unlimited Invest	1x 500 kW nat. gas engine with CHP	$ 233,886	70%	$ 99,847	$ 1,707	$ 160,477	$ 71,702
3: Unlimited Invest in nat. gas engines	1x 500 kW nat. gas engine with CHP	$ 233,886	70%	$ 99,847	$ 1,707	$ 160,477	$ 71,702
4: Forced minimum investment in 150 kW nat. gas engines (gen. only)	3x 150 kW nat. gas engine	$ 275,710	83%	$ 58,023	$ 64,481	$ 144,043	$ 67,186
4: Forced minimum investment in 150 kW nat. gas engines with CHP	3x 150 kW nat gas engine with CHP	$ 258,495	77%	$ 75,238	$ 32,842	$ 160,516	$ 65,137
4: Forced minimum investment in 150 kW nat. gas engines (gen. Only) and 150 kW nat. gas engines with CHP	1x 150 kW nat gas engine, 2x 150 nat. gas engine with CHP	$ 261,109	78%	$ 72,624	$ 32,842	$ 160,521	$ 67,746
5: Forced duplication of site decision: 2x 150 kW nat. gas engines with CHP	2x 150 kW nat gas engines with CHP	$ 266,162	80%	$ 67,571	$ 66,614	$ 150,735	$ 48,813

Table A- 16: Flat Electricity Rate Sensitivity for BD Biosciences Pharmingen

CASE	Technologies Selected	Annual energy cost	Electricity purchases	Natural gas purchases	Self generation costs	Installed Capacity (kW)
2: Unlimited Invest, actual electric rates	1x 500 kW nat. gas engine with CHP	$ 233,887	$ 1,706	$ 160,477	$ 71,704	500
2: Unlimited Invest, flat electric rate ($0.143/kWh)	3x 55 kW nat. gas engine, 3x 55 kW nat. gas engine with CHP	$ 230,457	$ 23,878	$ 153,730	$ 52,849	275

Table A- 17: Standby Sensitivity for BD Biosciences Pharmingen

Standby Charge ($/kW)	0	1	2	2.73	3	4	6	8	10	12	14	16	20	24	28	30
Generation Only Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP Installed Capacity (kW)	500	500	500	500	500	500	385	330	330	330	275	275	220	165	110	0
Abs. Cooling Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Yearly Energy Costs ($)	$233,886	$239,886	$245,886	$250,266	$251,886	$257,269	$266,509	$275,771	$283,691	$291,611	$298,608	$305,208	$316,186	$324,192	$330,973	$333,733
Max. Electric Load (kW)	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600

Table A- 18: Spark Spread Sensitivity for BD Biosciences Pharmingen

Percent of Natural Gas Prices	50	70	80	90	95	100	105	110	120	140	160	180	200
Generation Only Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP Installed Capacity (kW)	500	500	500	500	500	500	500	500	500	500	500	500	500
Abs. Cooling Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0
Yearly Energy Cost	$ 153,640	$ 185,759	$ 201,819	$ 217,878	$ 225,892	$ 233,886	$ 241,854	$ 249,713	$ 264,766	$ 292,786	$ 317,273	$ 339,028	$ 359,471
Max. Electric Load (kW)	600	600	600	600	600	600	600	600	600	600	600	600	600
actual nat. gas price ($/kWh)	0.0093	0.0130	0.0148	0.0167	0.0176	0.0185	0.0195	0.0204	0.0223	0.0260	0.0297	0.0334	0.0371
electricity price (do nothing case) ($/kWh)	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324
spark spread	14.3	10.2	8.9	7.9	7.5	7.1	6.8	6.5	5.9	5.1	4.5	4.0	3.6
spark spread (percent of actual NG price)	14.3(50%)	10.2(70%)	8.9(80%)	7.2(90%)	7.5(95%)	**7.1(100%)**	6.8 (105%)	6.5 (110%)	5.9 (120%)	5.1 (140%)	4.5 (160%)	4.0 (180%)	3.6 (200%)

A.5 Results for San Bernardino United States Postal Service Mail Handling Facility

Table A- 19: Scenario Results for San Bernardino USPS

CASE	Technologies Selected	Annual energy cost	Percentage of base case cost	Annual savings over base case	Electricity purchases	Natural gas purchases	Self generation costs
1: No Invest		$ 1,260,537			$ 1,259,663	$ 874	$ -
2: Unlimited Invest	2x 500 kW nat. gas engine with abs. cooling, 2x 60 kW microturbine with abs. cooling	$ 911,830	72%	$ 348,707	$ 32,078	$ 526,357	$ 353,395
3: Unlimited Invest in natural gas engines	2x 500 kW nat. gas engine with abs. cooling, 2x 55 kW nat. gas engine	$ 916,350	73%	$ 344,187	$ 41,762	$ 531,421	$ 343,167
4: Forced minimum investment in natural gas engines (generation only)	3x 500 kW nat. gas engine	$ 1,011,283	80%	$ 249,254	$ 6,410	$ 578,115	$ 426,758
4: Forced minimum investment in natural gas engines with abs. cooling	2x 500 kW nat. gas engine with abs. Cooling	$ 921,461	73%	$ 339,076	$ 62,276	$ 515,873	$ 343,312
4: Forced minimum investment in natural gas engines with CHP	3x 500 kW nat. gas engine with CHP	$ 1,039,368	82%	$ 221,169	$ 6,411	$ 577,842	$ 455,115
5: Forced duplication of site decision (1x 500 kW nat. gas engine (generation only))	1x 500 kW nat gas engine	$ 1,137,328	90%	$ 123,209	$ 726,156	$ 254,011	$ 157,161
5: Forced duplication of site decision (1x 500 kW nat. gas engine with CHP)	1x 500 kW nat gas engine with CHP	$ 1,146,515	91%	$ 114,022	$ 726,105	$ 253,788	$ 166,622
5: Forced duplication of site decision (1x 500 kW nat. gas engine with abs. cooling)	1x 500 kW nat gas engine with abs. cooling	$ 1,053,810	84%	$ 206,727	$ 587,775	$ 304,481	$ 161,554

Table A- 20: Flat Electricity Rate Sensitivity for San Bernardino USPS

CASE	Technologies Selected	Annual energy cost	Electricity purchases	Natural gas purchases	Self generation costs	Installed Capacity (kW)
2: Unlimited Invest, actual electric rates	2x 500 kW nat. gas engine with abs. cooling, 2x 60 kW microturbine with abs. cooling	$ 911,830	$ 32,078	$ 526,357	$ 353,395	1120
2: Unlimited Invest, flat electric rate ($0.13/kWh)	2x 500 kW nat. gas engine with abs. cooling, 2x 60 kW microturbine with abs. cooling	$ 805,246	$ 47,874	$ 496,606	$ 260,766	1120
2: Unlimited Invest, flat electric rate ($0.16/kWh)	2x 500 kW nat. gas engine with abs. cooling, 4x 60 kW microturbine with abs. cooling	$ 809,555	$ 15,294	$ 505,381	$ 288,880	1240

Table A- 21: Photovoltaic Installation Subsidy Sensitivity for San Bernardino USPS

PV subsidy ($/W)	3.34 (50% of cost)	4.00	5.00	5.50	6.00
natural gas engines capacity (kW)	1000	1000	1000	1000	1000
microturbine capacity (kW)	120	120	120	0	0
photovoltaic capacity (kW)	0	0	0	700	950
peak electricity load (kW)	1550	1550	1550	1550	1550
Test Year Energy Bill	$ 911,830	$ 911,830	$ 911,830	$ 898,275	$ 856,735
these results are for Case 2 (Unlimited Investment)					

Table A- 22: Standby Sensitivity for San Bernardino USPS

Standby Charge ($/kW)	0	2	4	6.6	8	10	12	16	20	25	30	35
Generation Only Installed Capacity (kW)	165	165	165	110	110	55	55	0	0	0	0	0
CHP Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0
Abs. Cooling Installed Capacity (kW)	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	500	0
Goal Function ($)	$825,093	$853,053	$881,013	$916,350	$934,998	$960,607	$985,927	$1,034,261	$1,082,261	$1,142,261	$1,194,210	$1,222,442
Max. Electric Load (kW)	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550

Table A- 23: Spark Spread Sensitivity for San Bernardino USPS

Percent of Natural Gas Prices	50	70	80	90	95	100	105	110	120	140	160	180	200
Generation Only Installed Capacity (kW)	310	110	110	110	110	110	110	55	55	55	0	0	0
CHP Installed Capacity (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0
Abs. Cooling Installed Capacity (kW)	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	500	0
Yearly Energy Cost	$675,557	$753,195	$808,240	$862,890	$ 889,767	$ 916,350	$942,541	$969,157	$1,019,708	$1,109,574	$1,180,595	$1,227,441	$1,247,668
Max. Electric Load (kW)	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550	1550
actual nat. gas price ($/kWh)	0.0090	0.0126	0.0144	0.0162	0.0171	0.0180	0.0189	0.0198	0.0216	0.0252	0.0288	0.0324	0.0360
electricity price (do nothing case) ($/kWh)	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324	0.1324
spark spread	14.7	10.5	9.2	8.2	7.7	7.4	7.0	6.7	6.1	5.3	4.6	4.1	3.7
spark spread (percent of actual NG price)	14.7 (50%)	10.5 (70%)	9.2 (80%)	8.2 (90%)	7.7 (95%)	**7.4 (100%)**	7.0 (105%)	6.7 (110%)	6.1 (120%)	5.3 (140%)	4.6 (160%)	4.1 (180%)	3.7 (200%)

Appendix B. Summary of Results

Table A- 24: Summary of Financial Results

Site	**Base Case Utility Costs**		**DER Cost Estimate***		**DER Benefits Estimate**		**DER Benefits Estimate**	
			Capital costs included		Capital costs included		Capital costs NOT included	
	Actual $/year	DER-CAM	Site Estimate $/year	DER-CAM Scenario 5	Site Estimate $/year	DER-CAM Benefits $/year	Site Estimate $/year	DER-CAM Benefits $/year
A&P	NA	245,000	240,641	235,000	4,359	10,000	8,312	11,777
GSB	NA	490,000	NA	571,000	NA	-81,000	NA	218,495
The Orchid High tariff	1,333,000	1,700,000	965,261	1,300,127	367,749	399,873	700,000	732,124
The Orchid Low tariff	1,333,000	1,474,000	965,251	1,277,673	367,749	196,327	700,000	528,578
BD Biosciences Pharmingen	315,000	334,000	245,000	266,000	70,000	68,000	103,085	96,888
USPS San Bernardino (DG only)	1,283,000	1,261,000	1,269,000	1,137,000	14,000	124,000	75,000	217,544
USPS San Bernardino with absorption cooling	1,283,000	1,261,000	1,210,000	1,054,000	73,000	207,000	159,000	303,695

* These are all costs for energy system including annualized capital costs, DG fuel costs and utility costs for residual electricity and natural gas purchases. It is calculated for the site by annualizing the site's DER system capital costs, adding base case utility bills and subtracting expected energy bill savings. In DER-CAM it is the goal function of the model.

** The Orchid's tariff rate changed during the site's DER system installation decision process, from $0.16/kWh to $0.19/kWh, and was modeled both ways.

Table A- 25: Comparison of Site DER System Selection Decisions

Site	Actual DER system	DER-CAM optimal solution
A&P	60 kW Microturbine (60 kW) with CHP	60 kW Microturbine (60 kW) with CHP
GSB	600 kW Fuel Cells 600 kW capacity: (3 x 200 kW) with CHP and absorption chiller	765 kW PV (1 x 100 kW), natural gas engines (3 x 55 kW) with CHP, and natural gas engine (1 x 500 kW) with absorption chiller
The Orchid	800 kW Propane engines (4 x 200 kW) with CHP and absorption chiller	900 kW Propane engines (2 x 200 kW) with CHP, (1 x 500 kW) with absorption chiller
BD	300 kW Natural gas engines (2 x 150 kW) with CHP	500 kW Natural gas engine (1 x 500 kW) with CHP
USPS	500 kW Natural gas engines (1 x 500 kW) no CHP, electric chiller, perhaps additional absorption chiller	1120 kW Natural gas engine (2 x 500) kW with absorption chiller, and microturbines (2 x 60 kW) with absorption chiller

B.1 Sample Daily Consumption Patterns

This section contains the sample hourly load patterns for the Orchid and BD Biosciences Pharmingen test sites. Four graphs are provided for each site representing heating and cooling loads during the months of January and July.

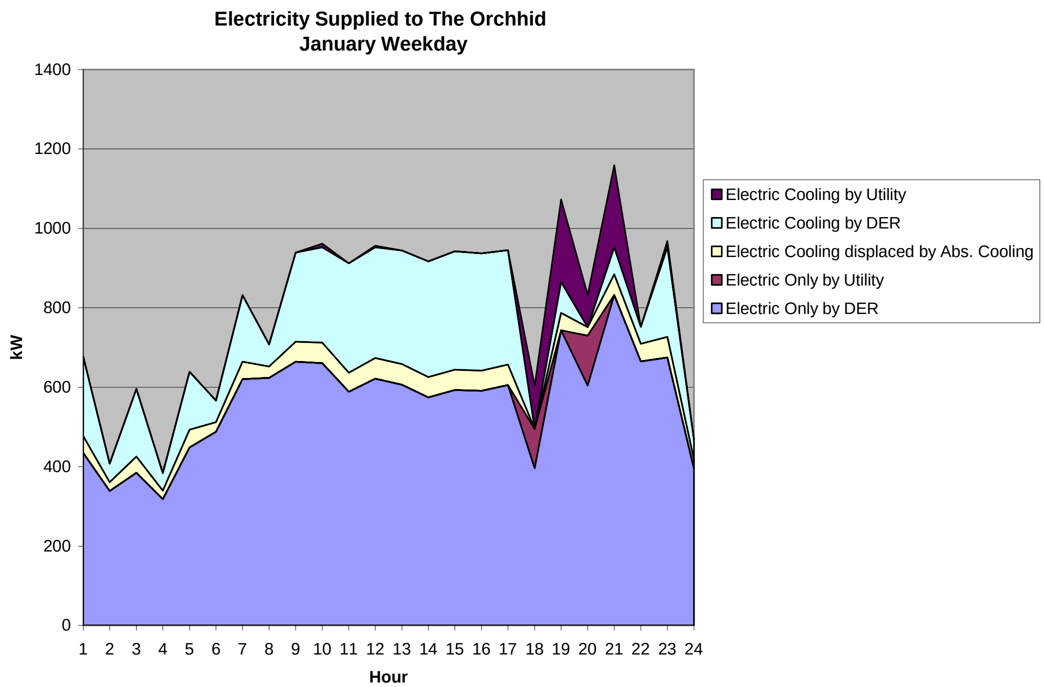


Figure A- 1: January Weekday Electricity Supplied to the Orchid

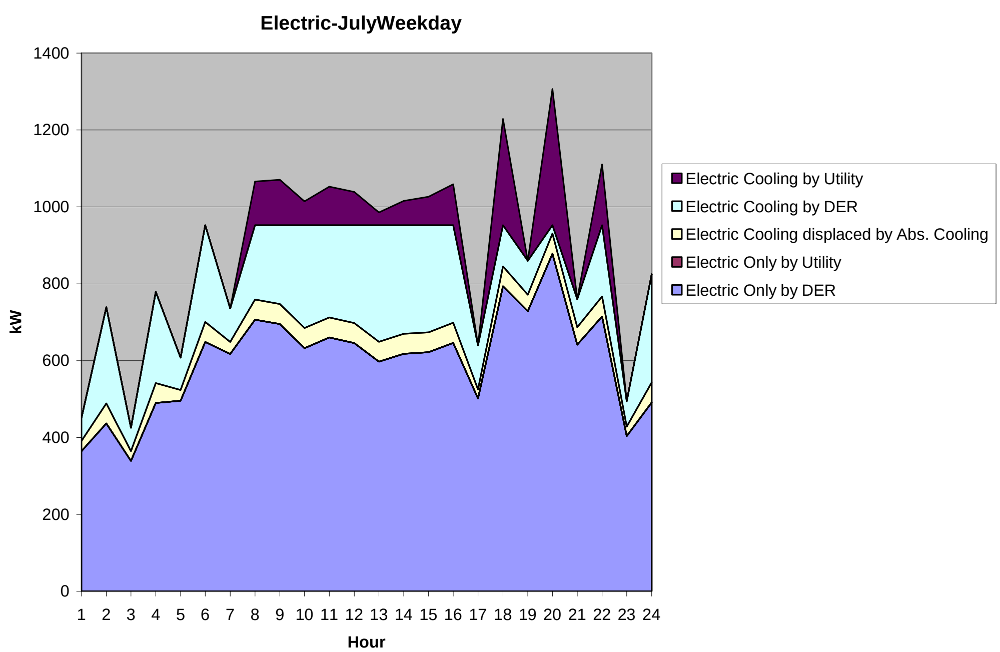


Figure A- 2: July Weekday Electricity Supplied to the Orchid

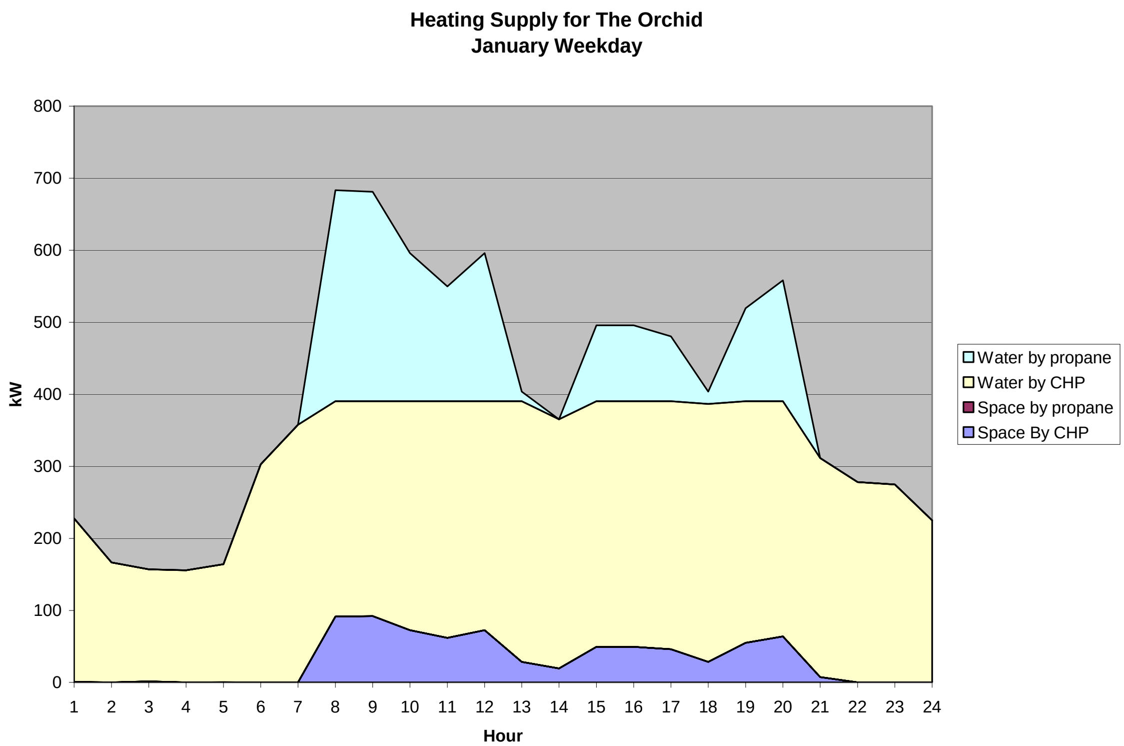


Figure A- 3: January Weekday Heating Supplied to the Orchid

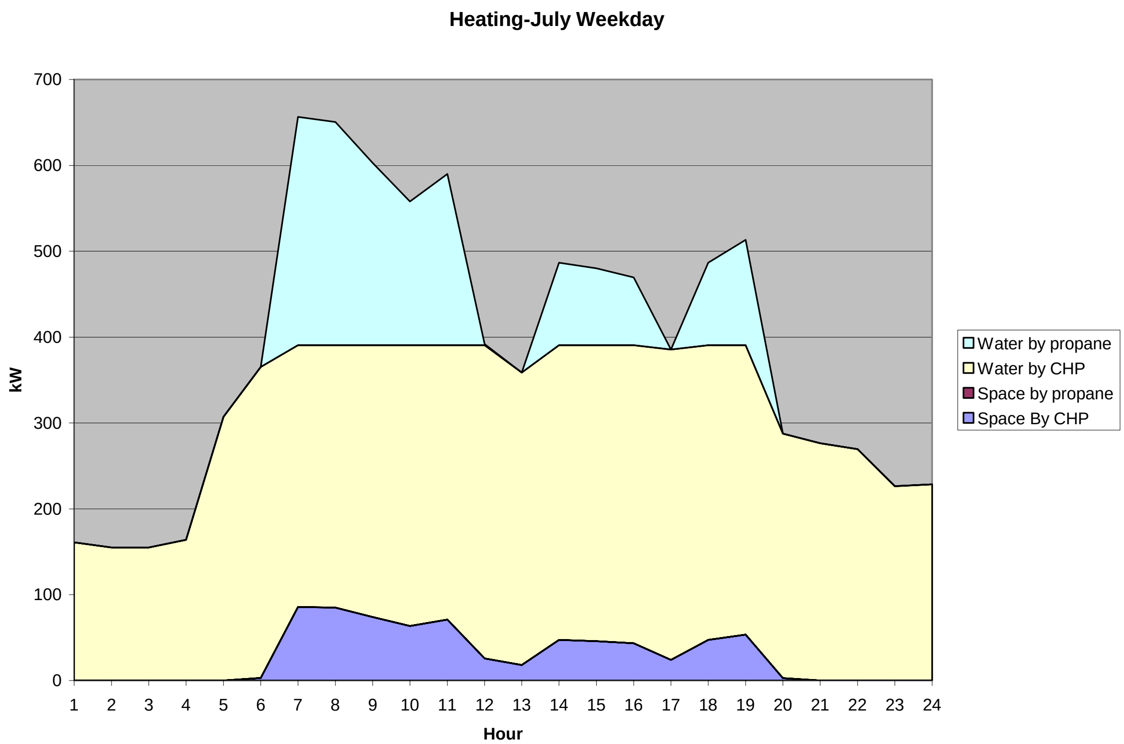


Figure A- 4: July Weekday Heating Supplied to the Orchid

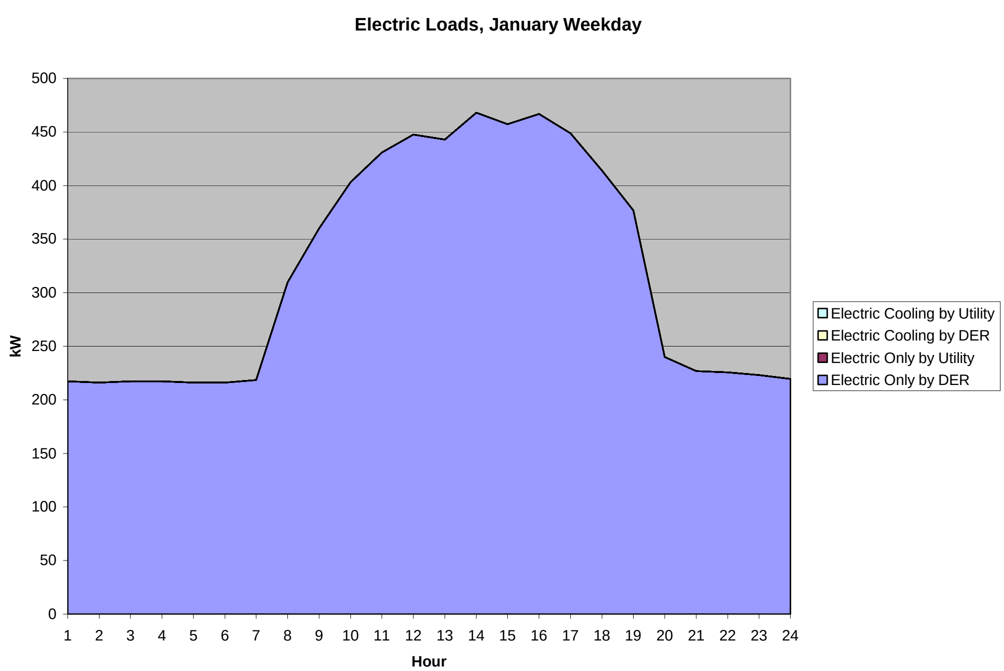


Figure A- 5: January Weekday Electricity Supplied to BD Biosciences Pharmingen

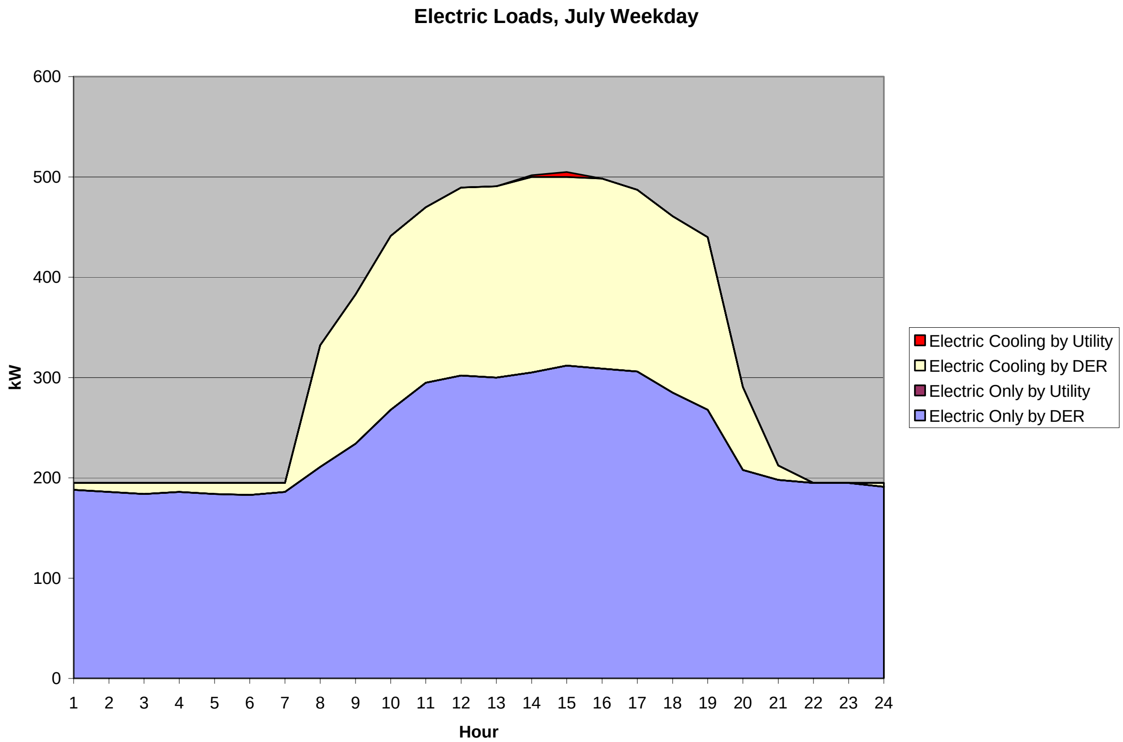


Figure A- 6: July Weekday Electricity Supplied to BD Biosciences Pharmingen

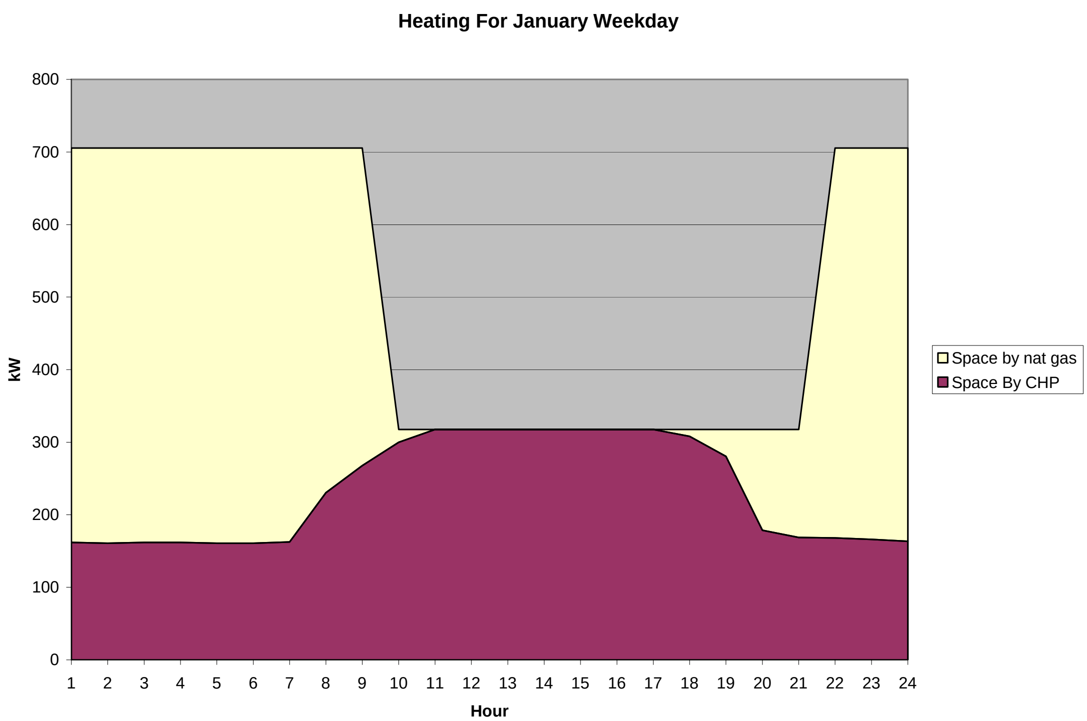


Figure A- 7: January Weekday Heating Supplied to BD Biosciences Pharmingen

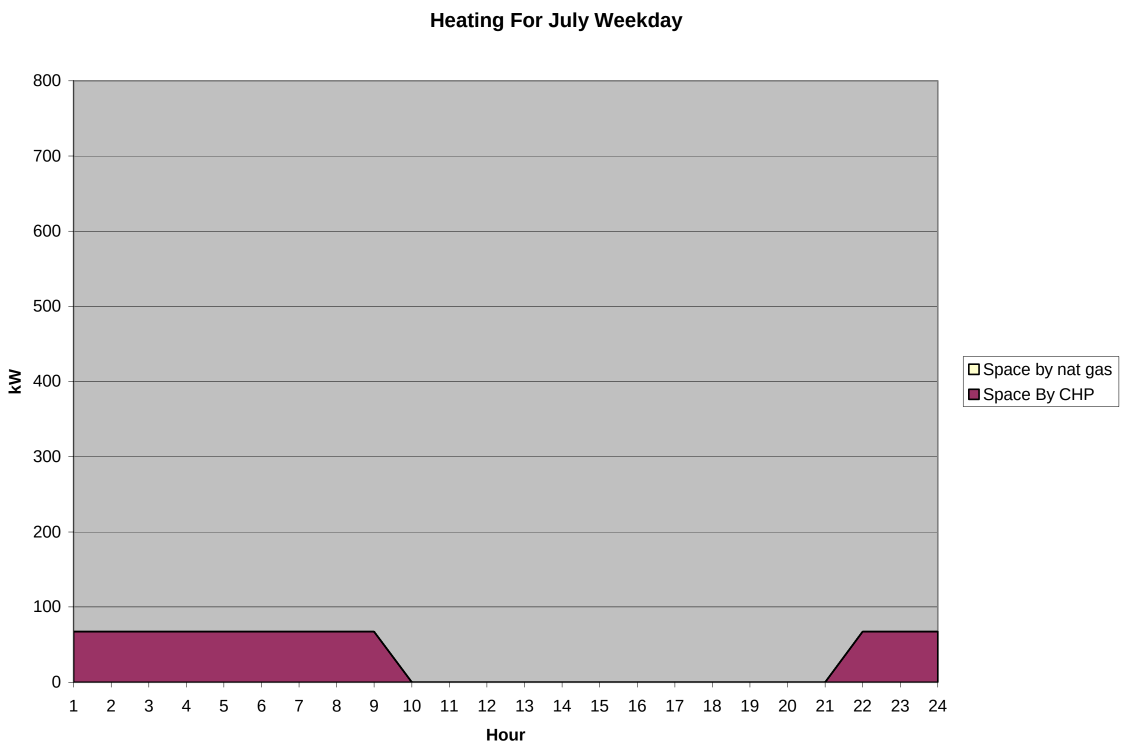


Figure A- 8: July Weekday Heating Supplied to BD Biosciences Pharmingen

Appendix C. Selected Sites for Case Study Analysis and Description of DER System

Table A- 26: Sites Selected for DER-CAM Analysis

Site	Location/Utility	Type of facility	Installed Technology
AA Dairy*	Candor, NY NYS Electric & Gas	Dairy Farm	Digester biogas system converted 130 kW diesel engine
A&P*	Hauppauge, NY (Long Island) Long Island Power Authority	Supermarket	60 kW Capstone microturbine, CHP for space heating & desiccant dehumidification
East Bay Municipal Utility District	Oakland, CA PG&E	Administration Building	10 x 60 kW Capstone microturbines, 150 ton absorption chiller and CHP
Guarantee Savings Building	Fresno, CA PG&E	12 story office building for IRS and INS	3 x 200 kW Phosphoric Acid Fuel Cells, CHP, 350 kW (100 ton) adsorption chiller
The Orchid*	Big Island, Hawaii Hawaiian Electric Light Company	Resort Hotel	4 x 200 kW propane fired engine with 240 ton absorption and CHP
BD Biosciences Pharmingen	San Diego, CA San Diego Gas and Electric	Industrial bio-technology supplier	2 x 150 kW natural gas engines, CHP space heating
San Bernardino US Postal Service	Redlands, CA Southern California Edison	Mail handling facility	500 kW natural gas engine without CHP
Wyoming County Community Hospital*	Warsaw, NY NYSEG electricity and Rochester Gas and Electric natural gas	Hospital	560 kW natural gas engine with CHP and absorption cooling

* Indicates sites with operating DER systems

Appendix D. Financial Calculations

The following definitions and terminology (Table A- 27) help to clarify the financial calculations presented in this section.

Table A- 27: Definition of Financial Terms Used in Analysis

Base Case	The annual cost of paying electric and natural gas utility bills at a facility prior to installing a DER system.
Capital Cost	The up-front, turnkey DER system cost. It is considered in this respect a one time cost at the start of a project.
Annualized Capital Cost	This is the Capital Cost turned into an annuity over the expected lifetime of the technology at a given interest rate. The default values for most DER technologies were 12.5 years at 7.5%. PV systems were given lifetimes of 20 years. Annual compounding is assumed.
DER Annuity	The annual cost of installing and operating a DER system. This cost includes the annualized capital cost of the DER technology, O&M costs, fuel purchases, and the cost of purchasing any additional electricity and natural gas from the utility. It is an annual cost over the lifetime of the DER technology.
Annual Payment	The cost of operating a DER system including O&M costs, fuel purchases, and the cost of purchasing any additional electricity and natural gas from the utility. These are the costs of providing energy services to a facility if the DER system capital costs are paid in full at the start of the project
Annual Benefit (A)	The difference between the Base Case and the Annual Payment. These benefits are the reduction in annual expenses as a result of installing a DER system without considering the Capital Cost. They do not consider any annuities (e.g. loan payments) involved with the Capital Cost. That is, these benefits assume the Capital Cost is paid in full at the start of project.
Annual Net Benefit (B)	The difference between the Base Case and DER Annuity. These benefits are the reduction in annual expenses as a result of installing a DER system including considering the Capital Cost. They include any annuities (e.g. loan payments) involved with the Capital Cost. That is, these benefits assume the Capital Cost is annualized over all the years of the DER project's expected lifetime.

The following formulas (Table A- 28) are then available from the above definitions:

Table A- 28: Financial Formulas

Financial Formulas
Base Case = Scenario 1 of DER-CAM
DER Annuity = Scenario 5 of DER-CAM
DER Annuity = Base Case – Annual Net Benefit (B)
DER Annuity = Annualized Capital Cost + Annual Payment
DER Annuity = Annualized Capital Cost + Base Case – Annual Benefit (A)

Annual Payment = Base Case – Annual Benefit (A)
Annual Benefit (A) = Annual Net Benefit (B) + Annualized Capital Cost
Annual Benefit (A) = Annualized Capital Cost + Base Case – DER Annuity
Annual Net Benefit (B) = Base Case – DER Annuity
Annual Net Benefit (B) = Base Case – Scenario 5

See Section 2.2.4 for a description of Net Present Value and Payback analysis and the financial conversion formulas used to compute these values.

Table A- 29 lists financial information about the actual DER system and the benefits obtained through its installation and operation.

Table A- 29: Summary of Actual Project Costs and Benefits as Estimated by Site and DER-CAM

Source of Financial Estimates	Project Cost	Grants Received	Annual Benefit (without capital cost)	Net Present Value (NPV) (including grants)	Payback (including grants)
A&P	$145,000	$95,000	$8,312	$51,826	6 years
A&P DER-CAM	$145,000	$95,000	$11,777	$94,274	4.2 years
GSB	$4,353,375	$2,100,000	NA	NA	NA
GSB DER-CAM	$4,353,375	$2,100,000	$218,495	$(518,466)	10.3 years
The Orchid	NA	$0	$700,000	$2,917,754 estimate	3.8 years
The Orchid DER-CAM	$2,636,109	$0	$732,124	$3,091,430	3.7 years
BD	Confidential	$112,500	$103,085	$530,000 estimate	2.5 years
BD DER-CAM	Confidential	$112,500	$96,888	$506,218	2.7 years
USPS DG only	$480,000	$0	$75,000	$115,057	6.4 years
USPS DG only DER-CAM	$480,000	$0	$217,544	$1,246,014	2.2 years
USPS Absorption Cooling	$680,000	$0 ($204,000 potential)	$159,000	$581,520	4.3 years
USPS Abs. DER-CAM	$680,000	$0 ($204,000 potential)	$303,695	$1,729,543	2.2 years

NA = not available
Estimated values are derived from DER-CAM data rather than information provided directly from site.

Table A- 30: Site Peak Electric Load and DER System Capacity Information

Site	Peak Load	DER Capacity	Percentage of Peak
AA Dairy*	75 kW	Digester biogas system converted 130 kW engine	170%
A&P*	600 kW	60 kW Capstone microturbine, CHP for space heating & desiccant dehumidification	10%
East Bay Municipal Utility District	2000 kW	600 kW Capstone microturbines, 530 kW (150 ton) absorption chiller and CHP	30%
Guarantee Savings Building (GSB)	600 kW – 900 kW	600 kW Phosphoric Acid Fuel Cells, CHP, 350 kW (100 ton) adsorption chiller	70% -100%
The Orchid*	1400 kW	800 kW propane fired engine with 840 kW (240 ton) absorption and CHP	60%
BD Biosciences Pharmingen	700 kW	300 kW natural gas engines, CHP space heating	40%
Rochester International Airport*	2100 kW	1500 kW natural gas engines, CHP and absorption cooling	70%
San Bernardino U.S. Postal Service	1600 kW	500 kW natural gas engine without CHP	30%
Wyoming County Community Hospital*	850 kW	560 kW natural gas engine with CHP and absorption cooling	70%

The results of the first validation are given in Table A- 31 and graphically in Figure A- 9.

Table A- 31: Validation of Base Case Cost of Utility Bills Prior to DER Adoption

	Base Case Utility Costs ($/year)		
Site	**Actual**	**DER-CAM**	**Ratio**
A&P	New building	$245,000	NA
GSB	New building	$490,000	NA
The Orchid	$1,333,000 (estimate)	$1,474,000	1.11
BD	$315,000	$334,000	1.06
USPS	$1,283,000	$1,261,000	0.98

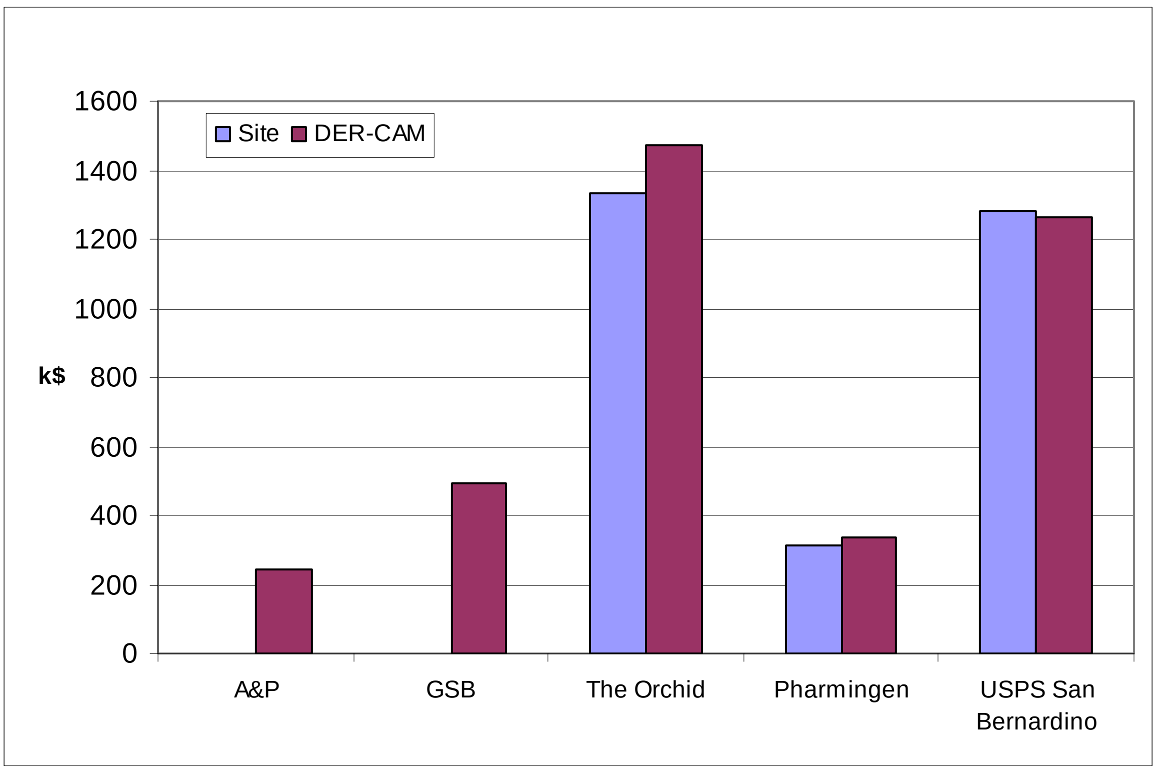


Figure A- 9: Validation of Base Case Utility Bills Prior to DER Adoption

The second part of the validation compares the actual and DER-CAM Scenario 5 analysis DER annual costs, such as capital costs of the DER technologies, the operation and maintenance costs, and the utility purchases of electricity and gas bills. The results of this validation comparison are presented in Table A- 32 and Figure A- 10.

Table A- 32: Validation of DER System Annual Costs

	DER System Annual Costs ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$241,000 estimate	$235,000	0.98
GSB	NA	$571,000	NA
The Orchid	$965,000 estimate	$1,278,000	1.32
BD	$245,000	$266,000	1.09
USPS	$1,269,000	$1,137,000	0.90
USPS with absorption chiller	$1,210,000	$1,054,000	0.87

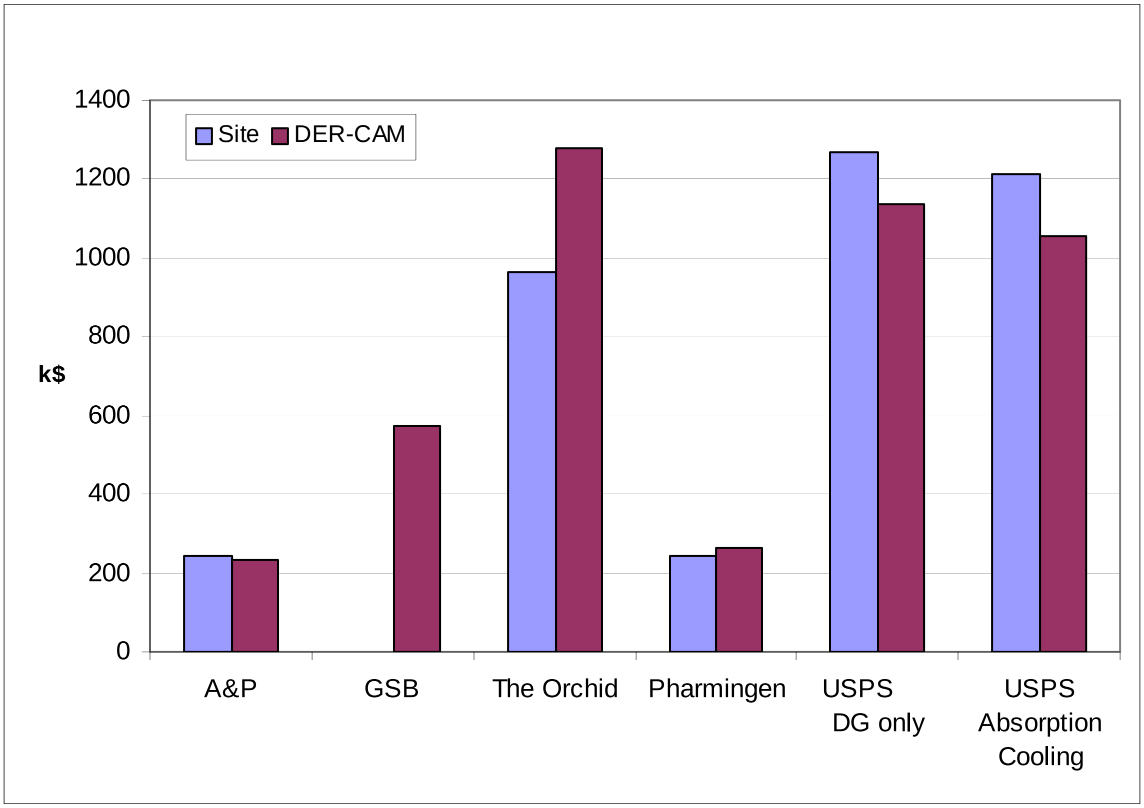


Figure A- 10: Validation of DER System Annual Costs

Another way of evaluating the results of installing a DER system (the second type of validation) is to compare the economic benefits estimated by the site with those computed by DER-CAM. Most sites quantified their expected benefits even if they did not have figures on their historic energy costs. The comparison of calculated benefits between the site and DER-CAM is presented in Table A- 33 and Figure A- 11. Annual net benefits include capital cost payments.

Table A- 33: DER Annual Net Benefits Including Capital Costs (Base Case to Scenario 5)

	DER Annual Net Benefits ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$4,000	$10,000	2.5
GSB	NA	$-81,000	NA
The Orchid	$368,000	$196,000	0.53
BD	$70,000	$68,000	0.97
USPS	$14,000	$124,000	8.9
USPS with absorption chiller	$73,000	$207,000	2.8

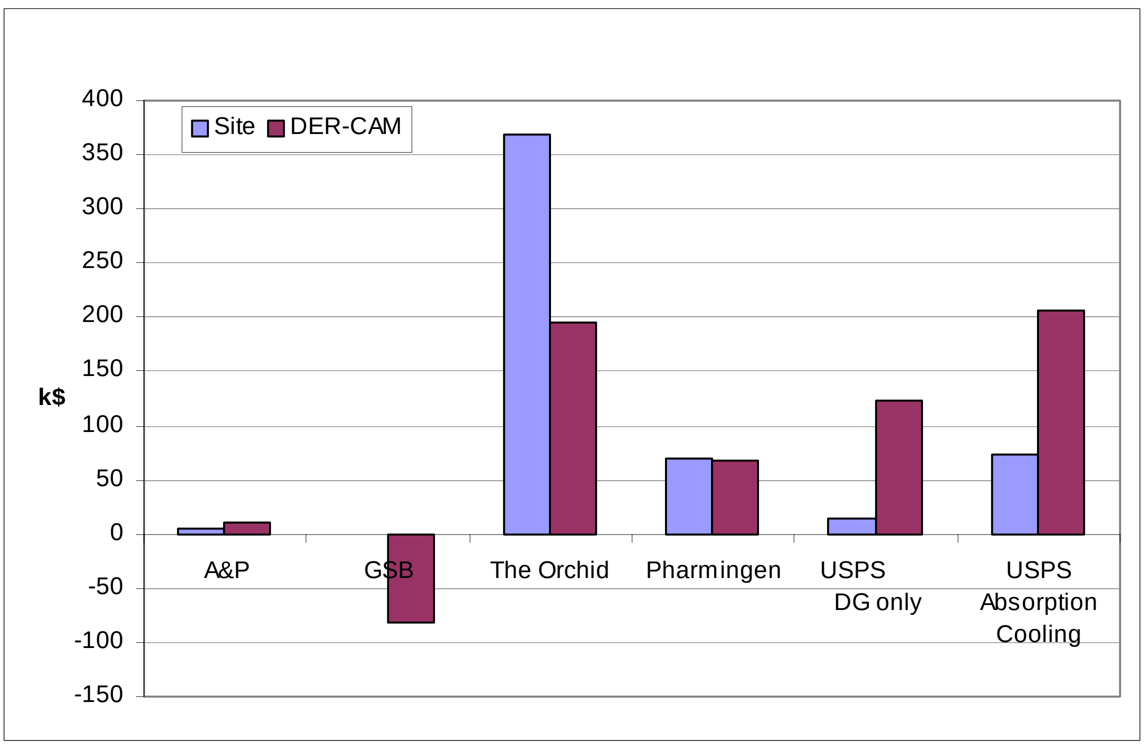


Figure A- 11: DER Annual Net Benefits Including Capital Costs (Base Case to Scenario 5)

The data in Table A- 34 and Figure A- 12 are the benefits of the DER project without considering the capital costs. That is, these benefits are the reduction in utility bill cash flows only and do not consider payments to a third party such as a bank loan or to an energy service company for the capital equipment. The DER-CAM benefits are considered with respect to Scenario 5. The Orchid's results are given the tariff rate ($0.16/kWh also referred to as the low rate) they had at the time of their DER decision although their estimated benefits is from current (high) tariff rates ($0.19/kWh).

Table A- 34: DER Annual Benefits Without Capital Costs

	DER Annual Benefits ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$8,000	$11,777	1.44
GSB	NA	$218,495	NA
The Orchid	$700,000	$528,251	0.75
BD	$103,000	$97,000	0.94
USPS	$75,000	$217,544	2.9
USPS with absorption chiller	$159,000	$303,695	1.9

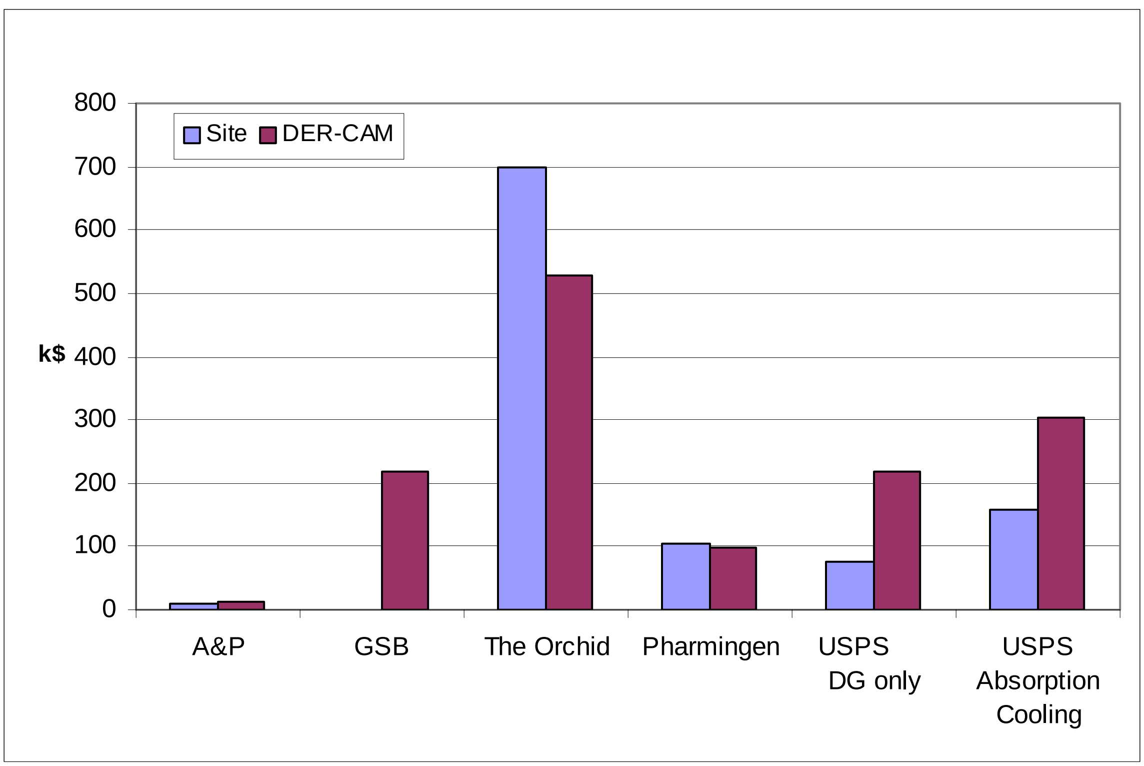


Figure A- 12: DER Annual Benefits Without Capital Costs

The Orchid was also modeled at their new higher tariff rates (approximately $0.19/kWh instead of $0.16/kWh) in order to compare their current estimated savings to the results from DER-CAM. The results are presented in the following three sets of tables and figures.

Table A- 35: Validation of DER System Annual Costs (The Orchid at High Tariff Rate)

	DER Annual Costs ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$241,000	$235,000	0.98
GSB	NA	$571,000	
The Orchid	$965,000	$1,300,000	1.35
BD	$245,000	$266,000	1.09
USPS	$1,269,000	$1,137,000	0.90
USPS with absorption chiller	$1,210,000	$1,054,000	0.87

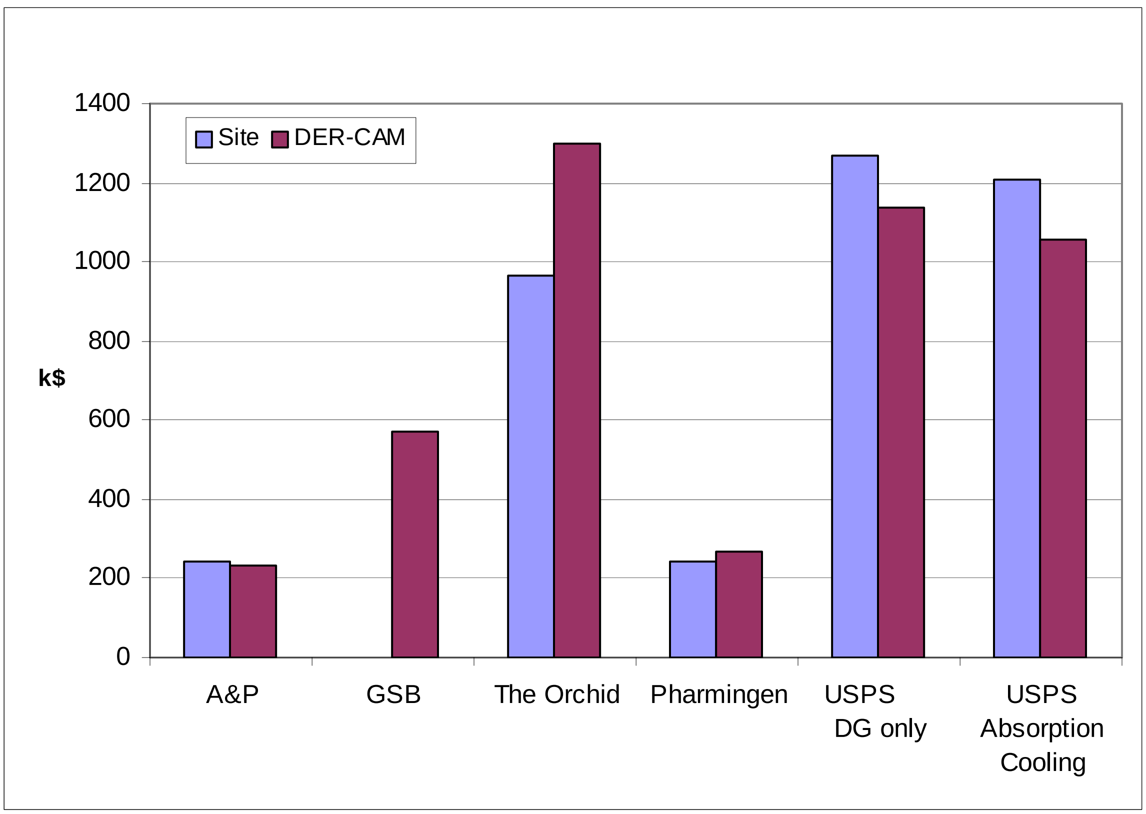


Figure A- 13: Validation of DER System Annual Costs (The Orchid at High Tariff Rate)

Table A- 36: Validation of DER Annual Net Benefits (Including Capital Costs, The Orchid at High Tariff Rate)

	DER Annual Net Benefits ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$4,359	$10,000	2.3
GSB	NA	$(81,000)	NA
The Orchid	$368,000	$400,000	1.1
BD	$70,000	$68,000	0.97
USPS	$14,000	$124,000	8.86
USPS with absorption chiller	$73,000	$207,000	2.84

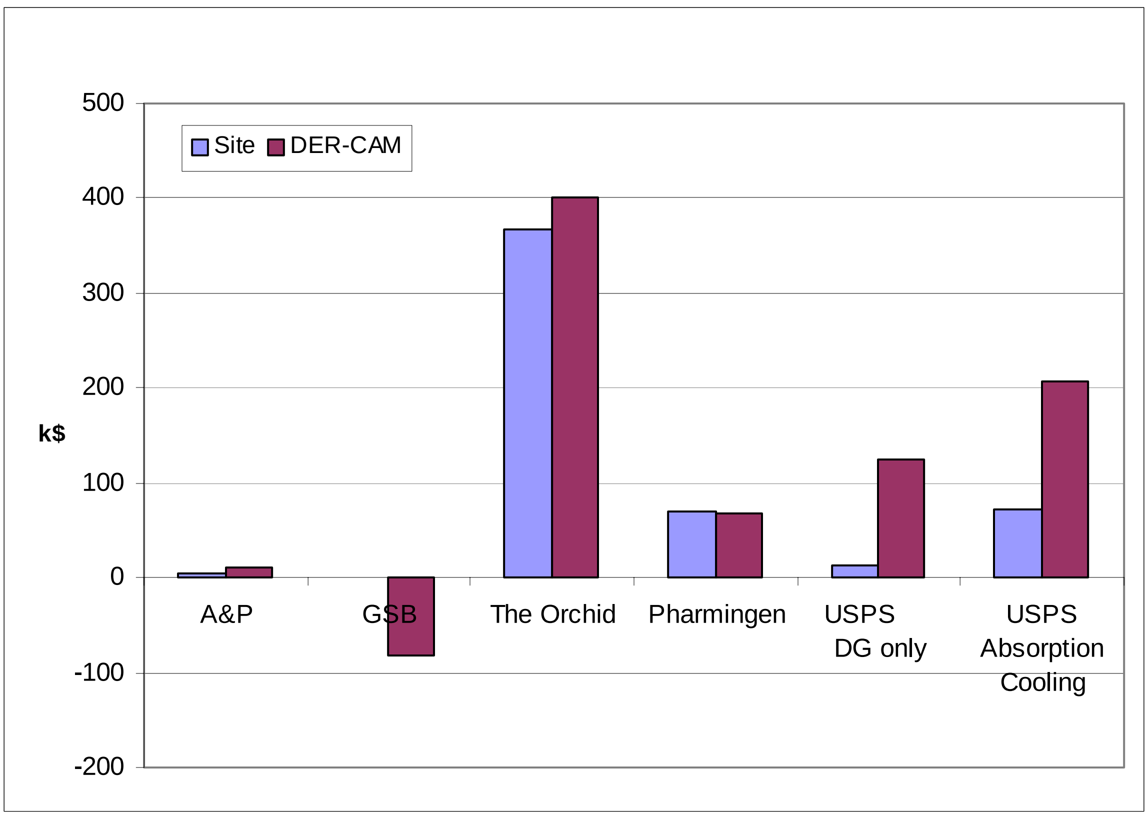


Figure A- 14: Validation of DER Annual Net Benefits (Including Capital Costs, The Orchid at High Tariff Rate)

Table A- 37: Validation of DER Annual Benefits (Without Capital Costs and The Orchid at High Tariff Rate)

	DER Annual Benefits ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$8,312	$11,777	1.44
GSB	NA	$218,495	NA
The Orchid	$700,000	$732,124	1.05
BD	$103,000	$97,000	0.94
USPS	$75,000	$217,544	2.9
USPS with absorption chiller	$159,000	$303,695	1.9

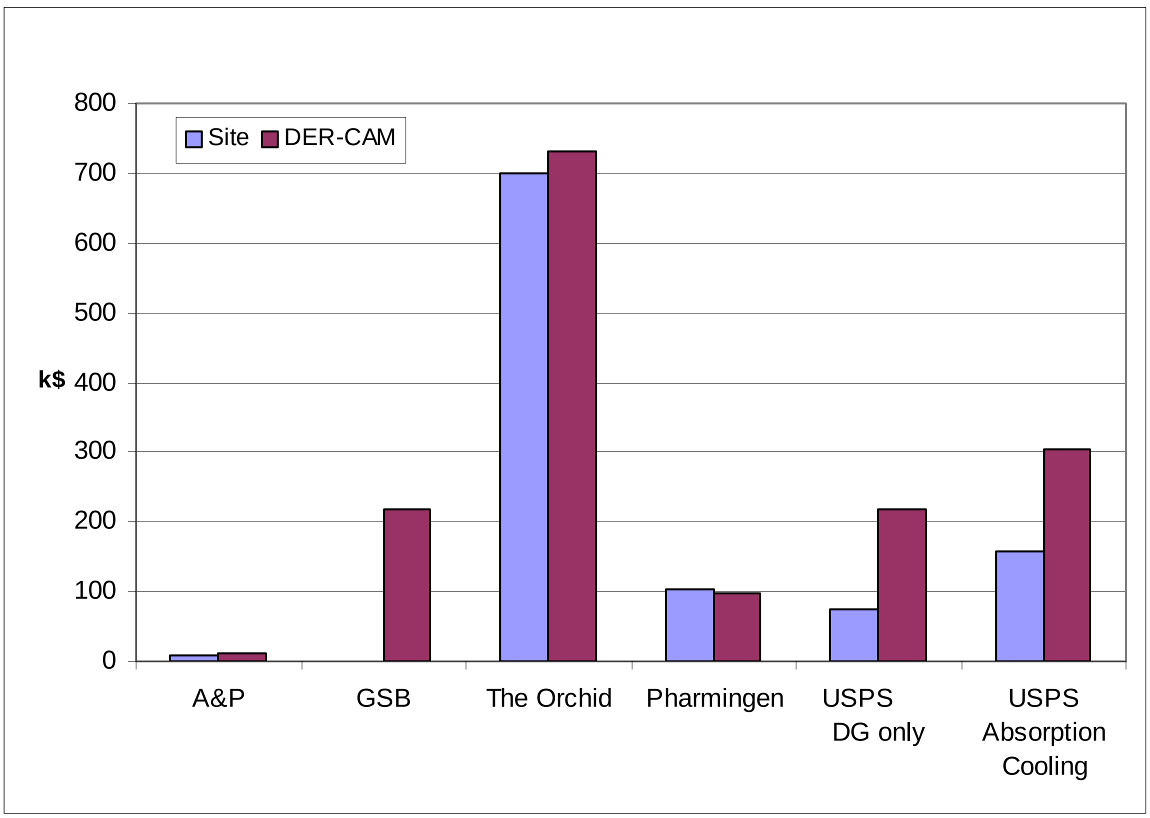


Figure A- 15: Validation of DER Annual Benefits (Without Capital Costs and The Orchid at High Tariff Rate)

The DER system annual costs and benefits were also compared between the site's estimates and DER-CAM's Scenario 2. This comparison will emphasize differences between the site's DER installation decision and the optimal solution in DER-CAM given unlimited restrictions on technology type, capacity, and residual heat configurations.

Table A- 38: DER System Costs Comparing Site vs. DER-CAM Scenario 2 (The Orchid at Original Low Tariff Rate)

	DER System Costs for Scenario 2 ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$241,000	$235,000	0.98
GSB	NA	$403,000	NA
The Orchid (low tariff)	$965,000	$1,253,000	1.30
BD	$245,000	$234,000	0.96
USPS	$1,269,000	$912,000	0.72
USPS with absorption chiller	$1,210,000	$912,000	0.75

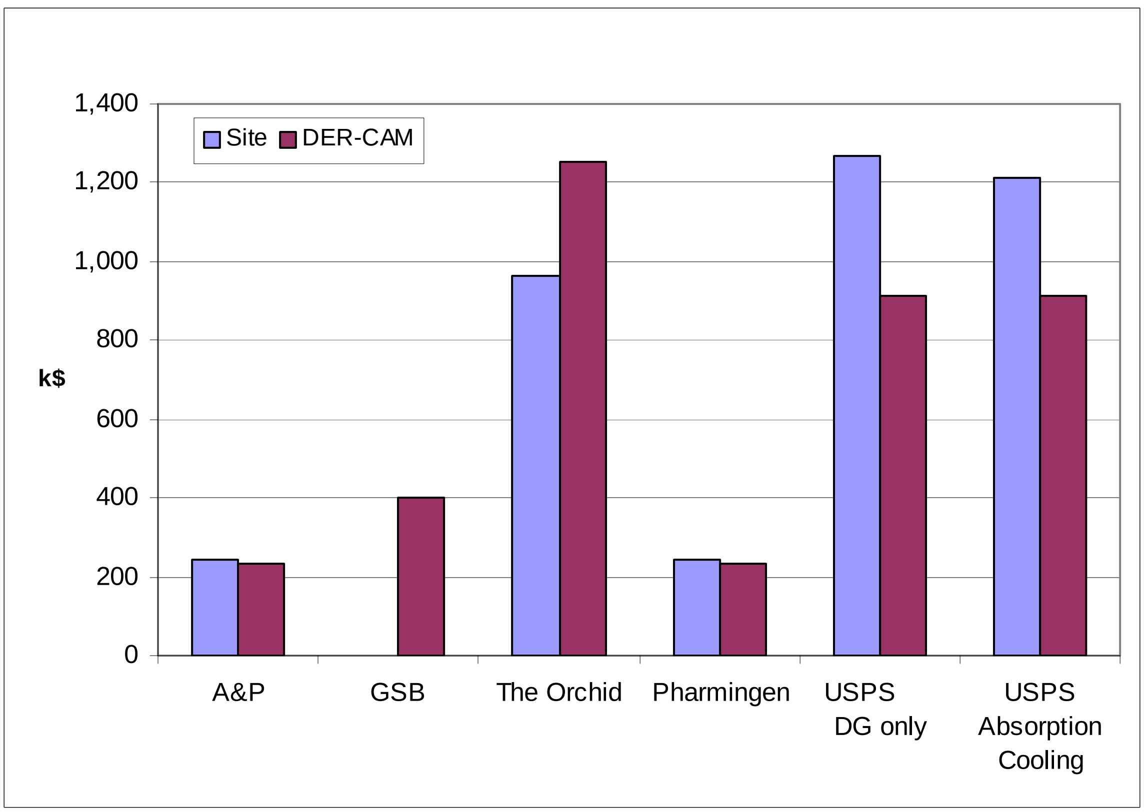


Figure A- 16: DER System Costs Comparing Site vs. DER-CAM Scenario 2 (The Orchid at Original Low Tariff Rate)

Table A- 39: Comparison of DER Annual Net Benefits Including Capital Costs for Scenario 2 (The Orchid at Low Tariff Rate)

	DER Annual Net Benefits Including Capital Cost for Scenario 2 ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$4,000	$10,000	2.5
GSB	NA	$87,000	NA
The Orchid (low tariff)	$368,000	$221,000	0.60
BD	$70,000	$100,000	1.43
USPS	$14,000	$349,000	24.93
USPS with absorption chiller	$73,000	$349,000	4.78

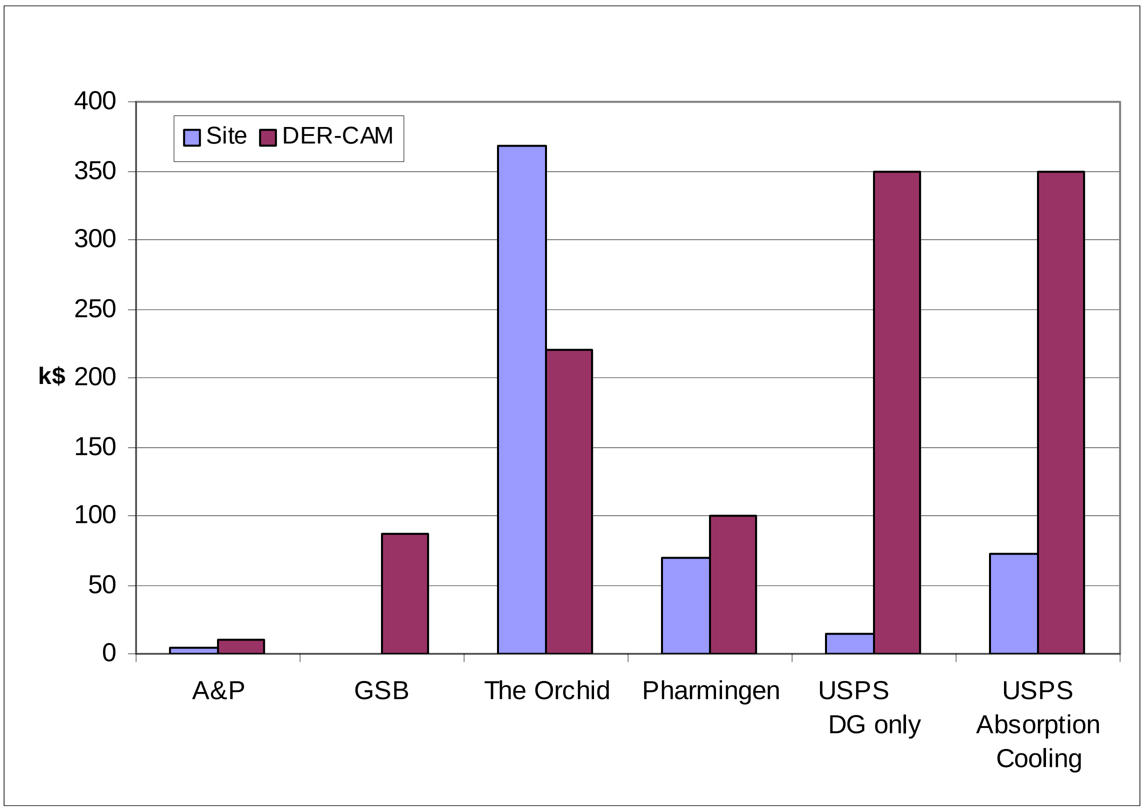


Figure A- 17: Comparison of DER Annual Net Benefits Including Capital Costs for Scenario 2 (The Orchid at Low Tariff Rate)

Table A- 40: Comparison of DER Benefits Without Capital Costs for Scenario 2 (The Orchid at Low Tariff Rate)

	DER Annual Benefits Without Capital Cost for Scenario 2 ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$8,000	$12,000	1.44
GSB	NA	$387,000	NA
The Orchid	$700,000	$553,000	0.79
BD	$103,000	$129,000	1.25
USPS	$75,000	$443,000	5.91
USPS with absorption chiller	$159,000	$446,000	2.81

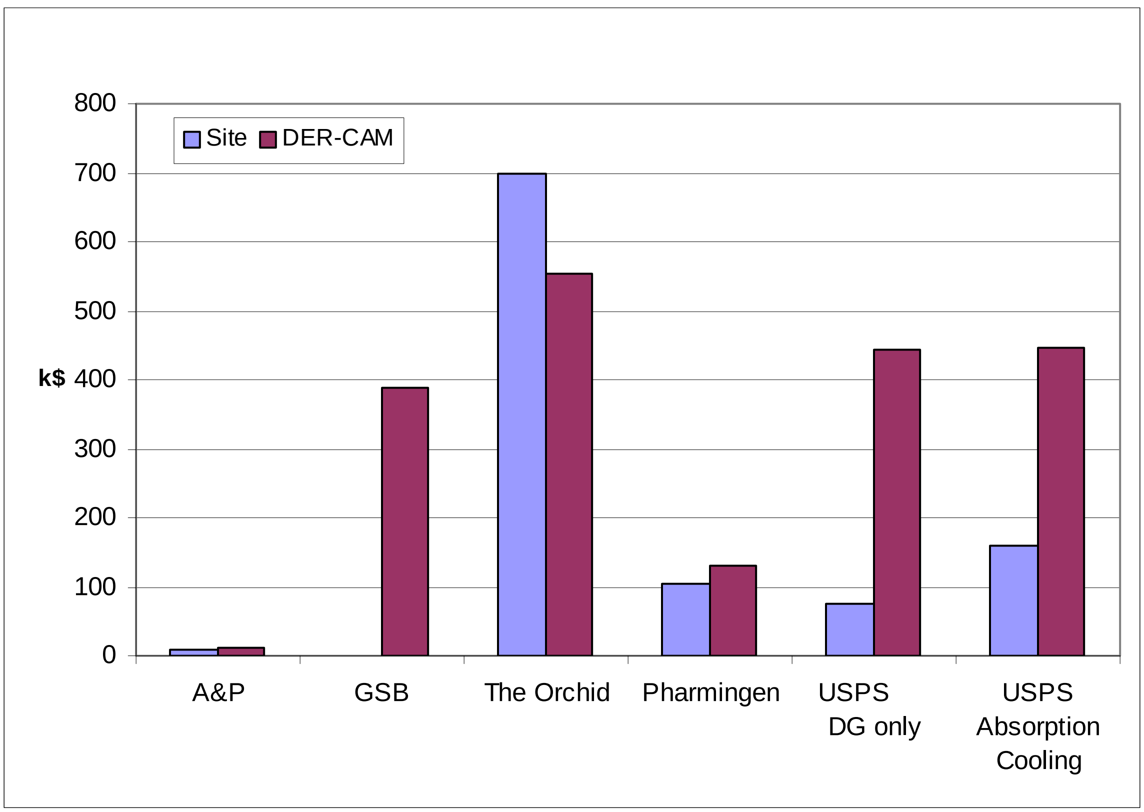


Figure A- 18: Comparison of DER Benefits Without Capital Costs for Scenario 2 (The Orchid at Low Tariff Rate)

A comparison of Base Case costs with The Orchid at high (new) tariff rates is presented in Table A- 41 and Figure A- 19. This was done because The Orchid provided us with benefits based on current (high tariff) rate data as opposed to pre-DER system installation estimates. The decision to install a DER system would have been made at the older, lower tariff rate. The validation of costs and benefits between the site's estimates and DER-CAM is done at the higher tariff rates because The Orchid provided us with an estimate of their DER annual benefits based on the new, higher tariff rate.

Table A- 41: Comparison of Base Case Costs (The Orchid at High Tariff Rate)

	Base Case Utility Costs ($/year)		
Site	**Actual**	**DER-CAM**	**Ratio**
A&P	NA	$245,000	NA
GSB	NA	$490,000	NA
The Orchid	$1,333,000 (estimated)	$1,700,000	1.28
BD	$315,000	$334,000	1.06
USPS	$1,283,000	$1,261,000	0.98

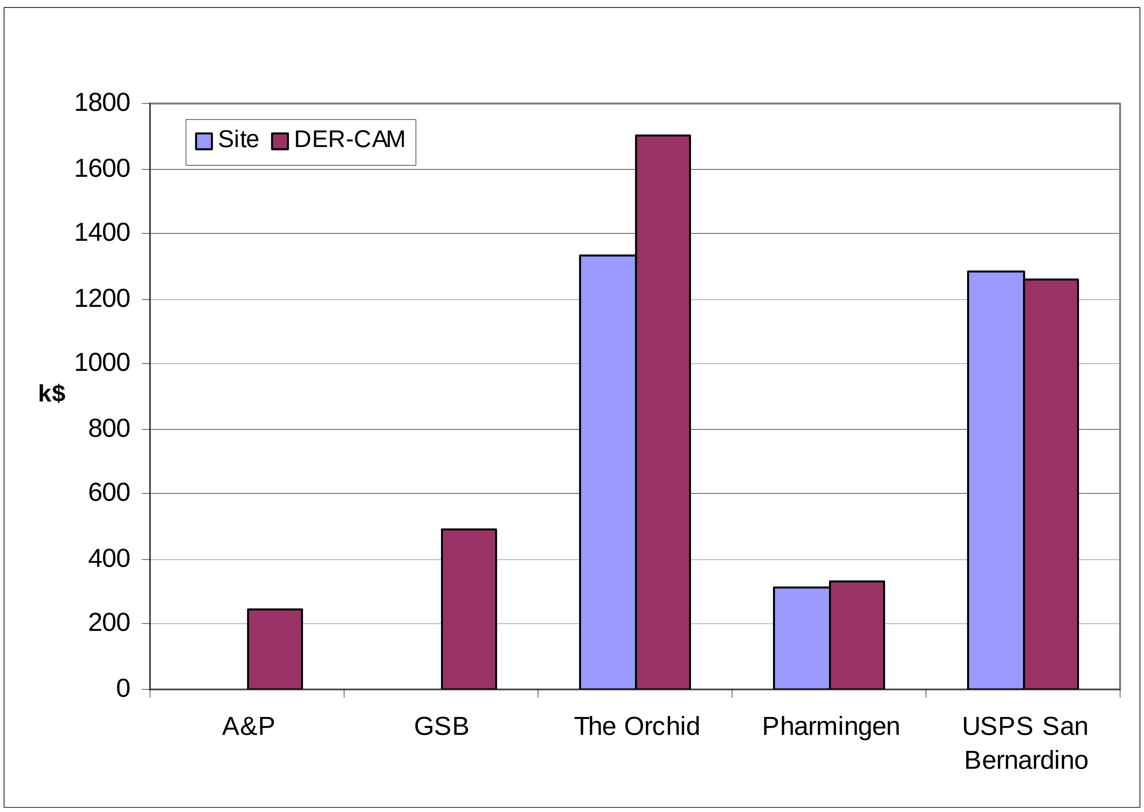


Figure A- 19: Comparison of Base Case Costs (The Orchid at High Tariff Rate)

Table A- 42: DER System Costs Comparing Site vs. DER-CAM Scenario 2 (The Orchid at High Tariff Rate)

	DER Cost Optimal Solution (Scenario 2) ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$241,000	$235,000	0.98
GSB	NA	$403,000	NA
The Orchid (high tariff)	$965,000	$1,264,000	1.31
BD	$245,000	$234,000	0.96
USPS	$1,269,000	$912,000	0.72
USPS with absorption chiller	$1,210,000	$912,000	0.75

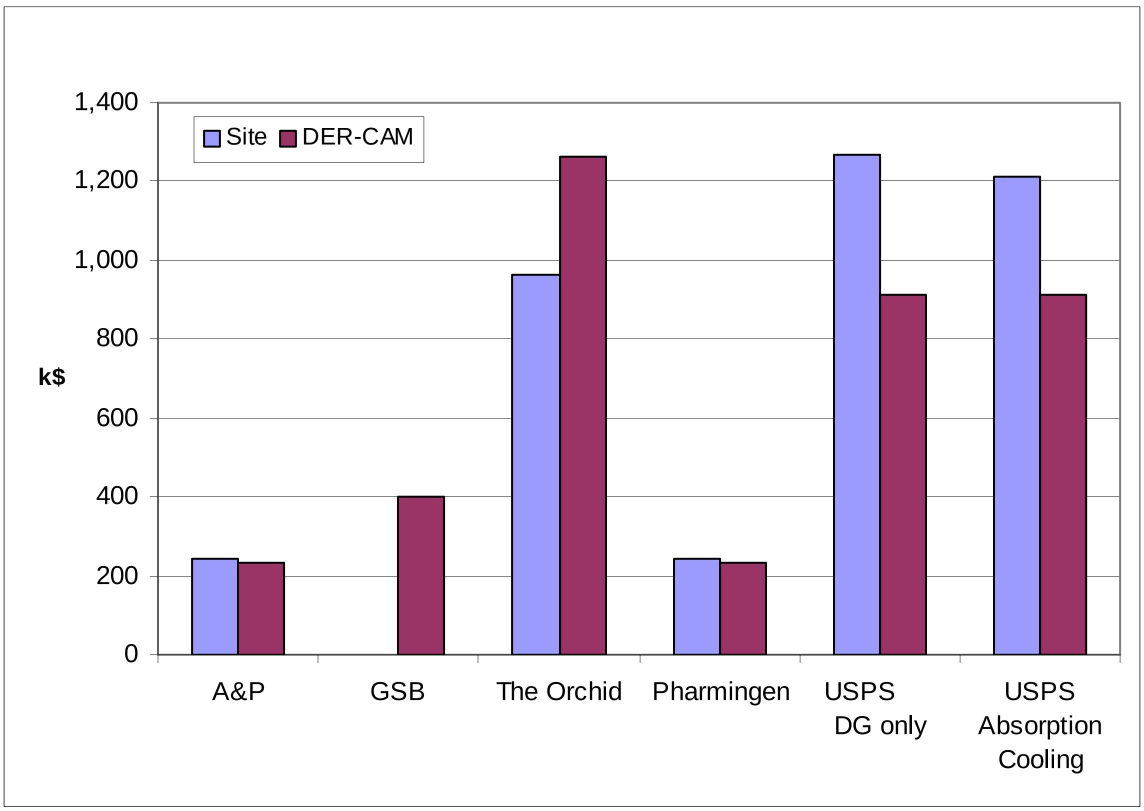


Figure A- 20: DER System Costs Comparing Site vs. DER-CAM Scenario 2 (The Orchid at High Tariff Rate)

Table A- 43: Comparison of DER Annual Net Benefits Including Capital Costs for Scenario 2 (The Orchid at High Tariff Rate)

	DER Annual Net Benefits Including Capital Cost for Scenario 2 ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$4,000	$10,000	2.5
GSB	NA	$87,000	NA
The Orchid	$368,000	$436,000	1.18
BD	$70,000	$100,000	1.43
USPS	$14,000	$349,000	24.93
USPS with absorption chiller	$73,000	$349,000	4.78

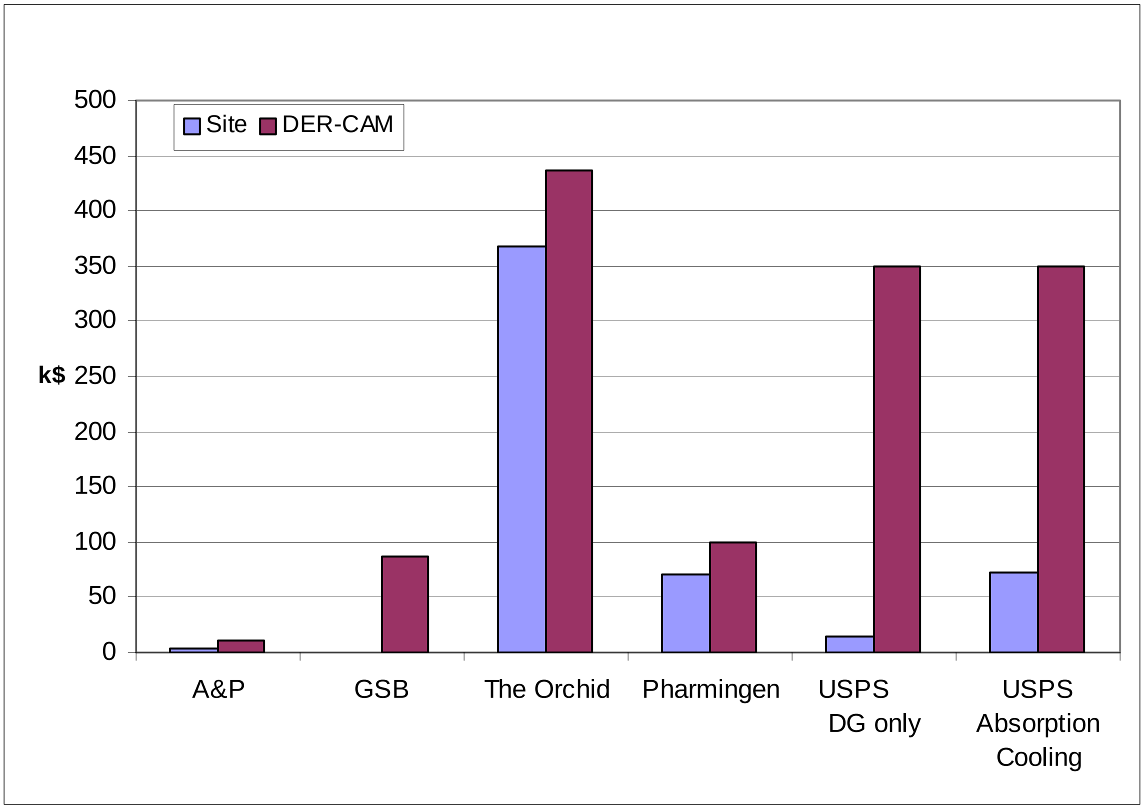


Figure A- 21: Comparison of DER Annual Benefits Including Capital Costs for Scenario 2 (The Orchid at High Tariff Rate)

Table A- 44: Comparison of DER Annual Benefits Without Capital Cost for Scenario 2 (The Orchid at High Tariff Rate)

	DER Annual Benefits Without Capital Cost for Scenario 2 ($/year)		
Site	**Actual Site Estimate**	**DER-CAM**	**Ratio**
A&P	$8,000	$12,000	1.44
GSB	NA	$387,000	NA
The Orchid	$700,000	$768,000	1.10
BD	$103,000	$129,000	1.25
USPS	$75,000	$443,000	5.91
USPS with absorption chiller	$159,000	$446,000	2.81

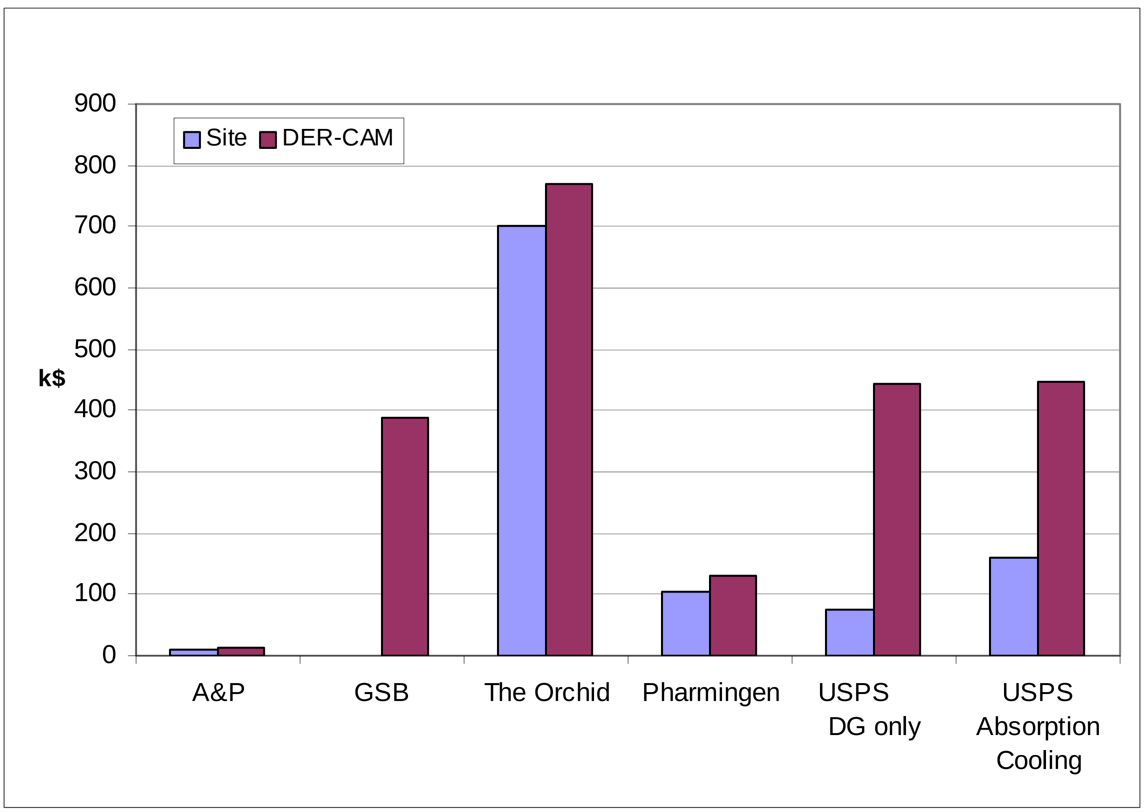


Figure A- 22: Comparison of DER Annual Benefits Without Capital Cost for Scenario 2 (The Orchid at High Tariff Rate)

The final validation involves comparing the site's actual technology installation decision with those obtained in DER-CAM. Table A- 45 presents the technologies installed at the test site compared to the optimal solution in DER-CAM.

Table A- 45: Comparison of Site DER System Selection Decisions

Site	Actual DER system	DER-CAM optimal solution
A&P	60 kW Microturbine (60 kW) with CHP	60 kW Microturbine (60 kW) with CHP
Guarantee Savings Building	600 kW Fuel Cells 600 kW capacity: (3 x 200 kW) with CHP and adsorption chiller	765 kW PV (1 x 100 kW), natural gas engines (3 x 55 kW) with CHP, and natural gas engine (1 x 500 kW) with absorption chiller
The Orchid	800 kW Propane engine (4 x 200 kW) with CHP and absorption chiller	900 kW Propane engines (2 x 200 kW) with CHP, (1 x 500 kW) with absorption chiller
BD Biosciences Pharmingen	300 kW Natural gas engines (2 x 150 kW) with CHP	500 kW Natural gas engine (1 x 500 kW) with CHP
USPS San Bernardino	500 kW Natural gas engines (1 x 500 kW) no CHP, electric chiller, perhaps additional absorption chiller	1120 kW Natural gas engine (2 x 500) kW with absorption chiller, and microturbines (2 x 60 kW) with absorption chiller

The results presented in Table A- 45 are the key results derived in this work, the head-to-head comparison of DER technologies chosen at the site and the technologies recommended by DER-CAM.

Appendix E. Capital Cost and Grant Information for Selected Sites

One goal of this case study report is to collect information on different DER sites, the technologies installed, the costs involved, and the availability and influence of grants and rebates on the technology selection decision. This information can also be used to improve the accuracy of DER-CAM by improving the DER technology capital cost input data. Table A- 46 presents some of the most interesting data obtained in this regard. The turnkey costs are obviously useful for the DER-CAM modeling process since the total installed capital costs are used as a foundation for the computations. These data provide insight into the costs of different DER technologies, the configurations of residual heat use (CHP, absorption cooling, etc.), the capacities and geographic location installed, and the level of grants the project received.

Table A- 46: Capital Cost and Grant Information for Selected Sites

Site	Installed Technology	Total Cost	Capital Cost ($/kW)	OM Fixed Cost ($/kW)	OM Variable Cost ($/kWh)	Grants
AA Dairy*	Digester biogas system converted 130 kW diesel engine	$363,000 $61,000 without digester system	$2792 $/kW total, $469.23 no digester	$12,000 per year, $92.31/kW		EPA Ag Star $24,000, Local Soil Conservation District $120,000
A&P*	60 kW Capstone microturbine, CHP for space heating & desiccant dehumidification	$145,000	$2417/kW	$35,000 for 6 years maint., $5800 per year, $97.22/kW		$145,000 plus $45,000 for monitoring DER system
East Bay Municipal Utility District	10 x 60 kW Capstone microturbines, 150 ton absorption chiller and CHP	$3,900,000 (total funding) $184,522 for absorption chiller and heat exchanger	$6500	$43,000 per year $71.67/kW		$855,000 rebate, and $1.9 million low interest loan

Site	Installed Technology	Total Cost	Capital Cost ($/kW)	OM Fixed Cost ($/kW)	OM Variable Cost ($/kWh)	Grants
Guarantee Savings Building	3 x 200 kW Phosphoric Acid Fuel Cells, CHP, 350 kW (100 ton) adsorption chiller	$4,353,375	$7255.63/kW	$112,140/year $186.9/kW		SELFGEN, CPUC benefits through PG&E $1.5 million DOD CCFC Grant $600,000 Loan for $2.6 m from UTC
The Orchid*	4 x 200 kW propane fired engine with 240 ton absorption and CHP				$0.015/kWh	
BD Biosciences Pharmingen	2 x 150 kW natural gas engines, CHP space heating	Turnkey cost Confidential. Includes personal, auxiliary equipment, delivery and installation	NA Confidential Typical price is 10.5 cents		$0.0125/kWh	
San Bernardino US Postal Service	500 kW natural gas engine without CHP	$450,000 $625,000 with abs.	$900/kW $1250/kW with absorption			
Wyoming County Community Hospital*	560 kW natural gas engine with CHP and absorption cooling	$1,013,690	$1810/kW			NYSERDA funded 50% of $25,000 feasibility study

* Indicates sites with operating DER systems

Site	Installed Technology	Total Cost	Capital Cost ($/kW)	OM Fixed Cost ($/kW)	OM Variable Cost ($/kWh)	Grants
Other Sites						
Byron Bergen (upstate NY school)*	8 different engines. 7 diesel, 1 natural gas, 2 absorption chillers, on site natural gas well and two boilers. 1450 kW total Grid independent	$3 million	$2069/kW			$2,760,000 State rebates for capital projects at schools. Taxpayer direct cost was $240,000
International Paper (paper mill), grid connected	Analysis of two different CHP systems, grid connected 7 MW gas turbine	$6,000,000	$857/kW			
International Paper, off grid	3 x 3.4 MW gas turbines off grid	$10,000,000	$962/kW			
PC Richards (Long Island 600,000 ft^2 warehouse)	300 kW or 450 kW natural gas fired cogen units with or without an absorption cooling system proposed. Values are for 300 and 450 with absorber	$628,000 for 300 kW $889,701 for 450 kW both with absorbers	$2093/kW $1977/kW	$28,974/year for 300 kW $34,369/year for 450 kW both with absorbers		

Site	Installed Technology	Total Cost	Capital Cost ($/kW)	OM Fixed Cost ($/kW)	OM Variable Cost ($/kWh)	Grants
Rochester International Airport*	2 x 750 kW natural gas engines, CHP and absorption cooling	$4,295,476 total project $3,293,185 minus lighting upgrades (used this figure as total)	$2195			
Sea Crest* Health care facility, Coney Island	60 kW CHP Ford NG engine	$225,000	$3700	$10,000 per year, $167/kW		

Appendix F. GAMS

F.1 Introduction to GAMS model

In this section, the DER-CAM model is presented. This version of the model has been programmed in GAMS[44]. This section contains a description of GAMS and a mathematical formulation of the present version of the model. The results presented are not intended to represent a definitive analysis of the benefits of DER adoption, but rather as a demonstration of the current DER-CAM. Developing estimates of realistic customer costs and thermodynamic parameters is an important area in which improvement is both essential and possible.

F.2 Model Description

The evolution of DER analysis began with a spreadsheet version (see Marnay *et al.* (2000)). Follow-up reports used GAMS to solve the Customer Adoption Model (see Rubio *et al.* (2001) and Marnay *et al.* (2001)). The next study extended that model to account for carbon taxes (see Siddiqui *et al.* (2002)). CHP technologies were implemented in the next round by accounting for heating and cooling loads (see Bailey *et al.* (2002)). It was found in this case that the availability of heat exchangers and absorption cooling enabled the µGrid to reduce the cost of meeting its energy needs even further. In this study, the model is made more realistic by accounting for the intricacies of the utility tariff structure, including monthly variation in fuel prices, and incorporating a more detailed thermodynamic model of the energy flows in the system. The model's objective function, which has not essentially changed, is to minimize the cost of supplying electricity to a specific µGrid by using distributed generation to meet part or all of its electricity and heating requirement. In order to attain this objective, the following questions must be answered:

- Which distributed generation technology (or combination of technologies) should the µGrid install?
- What is the appropriate level of installed capacity of these technologies that minimizes the cost of meeting the µGrid's energy requirement?
- How should the installed capacity be operated in order to minimize the total bill for meeting the µGrid's electricity and heating loads?

It is then possible to determine the technologies that the µGrid is likely to install, to predict when the µGrid will be self-providing and/or transacting with the macrogrid, and to determine whether it is worthwhile for the µGrid to disconnect entirely from the macrogrid.

The essential inputs to DER-CAM are:
- The µGrid's electricity and heating load profiles;
- Either the default electricity tariff (assumed to be from SDG&E) or the CalPX (or CAISO IEM) price at all hours of the test years (1999 and 2000), which are alternative electricity purchase options for the µGrid;

[44] GAMS is a proprietary software product used for high-level modeling of mathematical programming problems. It is owned by the GAMS Development Corporation (http://www.gams.com) and is licensed to Berkeley Lab.

- Capital, O&M, and fuel costs of the various available DER technologies, together with the interest rate on customer investment;
- Basic physical characteristics of alternative generating technologies;
- Thermodynamic parameters that govern the efficiency of CHP applications.

Outputs to be determined by the optimization are:
- Technology (or combination of technologies) to be installed;
- Capacity of each technology to be installed;
- When and how much of the capacity installed will be running during the test year;
- Total cost of supplying the electricity requirement;
- Whether or not the customer should, from an economic point of view, remain connected to the grid;
- Heating and cooling cost savings resulting from the application of CHP.

The important assumptions are:
- Customer decisions are taken based only on direct economic criteria. In other words, the only benefit that the µGrid can achieve is a reduction in its energy bill.
- All data are known with complete certainty, i.e., the energy loads, fuel prices, and IEM prices for the duration of the test year are all given.
- The µGrid is not allowed to generate more electricity than it consumes. On the other hand, if more electricity is consumed than generated, then the µGrid will buy from the macrogrid either at the default tariff rate or at the IEM price. No other market opportunities, such as sale of ancillary services or bilateral contracts, are considered.
- There is a fixed relationship between the amount of recoverable heat and electricity generated by each DER unit based on the manufacturer's technical specifications.
- Manufacturer claims for equipment price and performance are accepted without question, nor is any deterioration in output or efficiency during the lifetime of the equipment considered. Furthermore, start-up and other operating costs are not included.
- Neither reliability and power quality benefits nor economies of scale in O&M costs for multiple units of the same technology are taken into account. This underestimates the benefit of DER to many potential µGrids.

F.3 General Algebraic Modeling System (GAMS)

GAMS is a proprietary software package that solves optimization problems. The actual mathematical program is modeled via user-defined algebraic equations. GAMS then compiles them and uses standard solvers to solve the resulting problem. Since the current problem is a mixed integer program (MIP), the CPLEX solver is utilized. The foremost advantage of using GAMS is that it allows researchers to build models that can be quickly altered to address different situations or perform sensitivity analysis.

F.4 Mathematical Formulation

This section describes intuitively the core mathematical problem solved by DER-CAM. It is structured into three main parts. First, the input parameters are listed. Second, the decision variables are defined. Third, the optimization problem is described for two possible tariff options.

Variables and Parameters Definition

Parameters (input information)

Time Scale Definition

Name	***Definition***
Day Type	Week or weekend
Season	Summer (May through September, inclusive) or winter (the remaining months)
Period	On-peak (hours of the day 1200 through 1800, inclusive, during summer months, and 1800 through 2000 during the winter), mid-peak (0700 through 1100 and 1900 through 2200 during the summer, and 0700 through 1700 and 2100 through 2200 during the winter), or off-peak (0100 through 0600 and 2100 through 2200 during all months)

Customer Data

Name	***Description***
$Cload_{m,t,h,u}$	Customer load (electricity or heating) in kW for end-use *u* during hour *h*, day type *t* and month *m (*end-uses are electric-only, cooling, space-heating, water-heating, and natural-gas-only)

Market Data

Name	***Description***
$RTPower_{s,p}$	Regulated demand charge under the default tariff for season *s* and period *p* ($/kW)
$RTEnergy_{m,t,h,u}$	Regulated tariff for electricity purchases during hour *h*, type of day *t*, month *m* and end-use *u* ($/kWh)
$RTCDCh\arg e_m$	Regulated tariff charge for coincident demand, i.e., residual electric-only or cooling load that occurs at the same time as the monthly system peak ($/kW)
$RTCCharge$	Regulated tariff customer charge ($)
$RTFCharge$	Regulated tariff facilities charge ($/kW)
$IEM_{m,t,h}$	IEM price during hour *h*, type of day *t*, and month *m* ($/kWh)
$NGBSF_m$	Natural gas basic service fee for month *m* ($)
$NatGas\Pr ice_{m,t,h}$	Natural gas price during hour *h*, type of day *t*, and month *m* ($/kJ)

Distributed Energy Resource Technologies Information

Name	***Description***
$DERmaxp_i$	Nameplate power rating of technology *i* (kW)

$DERlifetime_i$	Expected lifetime of technology *i* (a)
$DERcapcost_i$	Overnight capital cost of technology *i* (\$/kW)
$DEROMfix_i$	Fixed annual operation and maintenance costs of technology *i* (\$/kW)
$DEROMvar_i$	Variable operation and maintenance costs of technology *i* (\$/kWh)
$DERhours_i$	Maximum number of hours technology *i* is permitted to operate during the year (h)
$DERCostkWh_i$	Production cost of technology *i* (\$/kWh)
$S(i)$	Set of end-uses that can be met by technology *i*

Other parameters

Name	***Description***
IntRate	Interest rate on DER investments (%)
DiscoER	Disco non-commodity revenue neutrality adder[45] (\$/kWh)
FixRate	Fixed energy rate (\$/kWh) applied in some cases[46]
$Solar_{m,h}$	Average fraction of maximum solar insolation received (%) during hour *h* and month *m*
StandbyC	Standby charge in \$/kW/month that SDG&E currently applies to its customers with autonomous generation
NGHR	Natural gas heat rate (kJ/kWh)
$t(m)$	Day type in month *m* when system demand peaks
$h(m)$	Hour in month *m* when system demand peaks
α_i	The amount of heat (in kW) that can be recovered from unit kW of electricity that is generated using DER technology *i* (this is equal to 0 for all technologies that are not equipped with either a heat exchanger or an absorption chiller)
β_u	The amount of heat (in kW) generated from unit kW of natural gas purchased for end-use *u* (since the electricity-only load never uses natural gas, the corresponding β_u value equals 0)
$\gamma_{i,u}$	The amount of useful heat (in kW) that can be allocated to end-use *u* from unit kW of recovered heat from technology *i* (note: since the electricity-only and natural-gas-only loads never use recovered heat, the corresponding $\gamma_{i,u}$ values equal 0)

[45] This value is added to the IEM price when the customer buys its power directly to the wholesale market. The *DiscoER* compensates the distribution company (disco) for transporting the electricity purchased from the IEM to the customer. This term is calculated such that, if the µGrid's usage pattern were identical under the IEM pricing option and the regulated tariff option, the disco would collect identical revenue from the customer.

[46] If the model user selects this option the customer always buy its energy at the same price.

Variables

Name	**Description**
$InvGen_i$	Number of units of the *i* technology installed by the customer
$GenL_{i,m,t,h,u}$	Generated power by technology *i* during hour *h*, type of day *t*, month *m* and for end-use *u* to supply the customer's load (kW)
$GenX_{i,m,t,h}$	Generated power by technology *i* during hour *h*, type of day *t* and month *m* that is sold into the IEM (kW)
$GasP_{m,t,h,u}$	Purchased natural gas during hour *h*, type of day *t*, and month *m* for end-use *u* (kW)
$DRLoad_{m,t,h,u}$[47]	Purchased electricity from the distribution company by the customer during hour *h*, type of day *t*, and month *m* for end-use *u* (kW)
$\mathrm{Re}\,cHeat_{i,m,t,h,u}$	Amount of heat recovered from technology *i* that is used to meet end-use *u* during hour *h*, type of day *t* and month *m* (kW)

Problem Formulation

There are two slightly different problems to be solved depending on how the μGrid acquires the residual electricity that it needs beyond its self-generation:

1. by buying that power from the disco at the regulated tariff; or
2. by purchasing power at the IEM price plus an adder that would cover the non-commodity cost of delivering electricity.

Option 1: Buying at the Default Regulated Tariff

The mathematical formulation of the problem follows:

$$\min_{\substack{InvGen_i \\ GenL_{i,m,t,h,u} \\ GenX_{i,m,t,h} \\ \mathrm{Re}\,cHeat_{i,m,t,h,u}}} \quad \sum_m RTFCharge \cdot \max\left(\sum_{u \in \{electric-only,cooling\}} DRLoad_{m,t,h,u} \right) + \sum_m RTCCharge$$

$$+ \sum_s \sum_{m \in s} \sum_p RTPower_{s,p} \cdot \max\left(\sum_{u \in \{electric-only,cooling\}} DRLoad_{m,(t,h) \in p,u} \right)$$

$$+ \sum_m \sum_{u \in \{electric-only,cooling\}} RTCDCharge_m \cdot DRLoad_{m,t(m),h(m),u}$$

---

[47]Only the three first variables are decision ones. This fourth one (power purchased from the distribution company) could be expressed as a relationship between the second and third variables. However, for the sake of the model's clarity, it has been maintained.

$$
\begin{aligned}
&+\sum_m\sum_t\sum_h\sum_u DRLoad_{m,t,h,u}\cdot RTEnergy_{m,t,h} \\
&+\sum_i\sum_m\sum_t\sum_h\sum_u \left(GenL_{i,m,t,h,u}+GenX_{i,m,t,h}\right)\cdot DERCostkWh_i \\
&+\sum_i\sum_m\sum_t\sum_h\sum_u \left(GenL_{i,m,t,h,u}+GenX_{i,m,t,h}\right)\cdot DEROMvar_i \\
&+\sum_i InvGen_i\cdot\left(DERcapcost_i+DEROMfix_i\right)\cdot AnnuityF_i \\
&+\sum_m\sum_i InvGen_i\cdot DERmaxp_i\cdot StandbyC \\
&+\sum_m\sum_t\sum_h\sum_u GasP_{m,t,h,u}\cdot NGHR\cdot NatGas\Pr ice_{m,t,h}+\sum_m NGBSF_m \\
&-\sum_m\sum_t\sum_h\sum_i GenX_{i,m,t,h}\cdot IEM_{m,t,h}
\end{aligned}
\tag{1}
$$

Subject to:

$$Cload_{m,t,h,u}=\sum_i\left(GenL_{i,m,t,h,u}\right)+DRLoad_{m,t,h,u}+\beta_u\cdot GasP_{m,t,h,u}+\sum_i\left(\gamma_{i,u}\cdot\mathrm{Re}\,cHeat_{i,m,t,h,u}\right)\forall\, m,t,h,u \tag{2}$$

$$\sum_u\left(GenL_{i,m,t,h,u}+GenX_{i,m,t,h}\right)\le InvGen_i\cdot DER\max p_i\quad\forall\, i,m,t,h \tag{3}$$

$$AnnuityF_i=\frac{IntRate}{\left(1-\dfrac{1}{\left(1+IntRate\right)^{DERlifetime_i}}\right)}\forall\, i \tag{4}$$

$$\sum_u\left(GenL_{j,m,t,h,u}+GenX_{j,m,t,h}\right)\le InvGen_j\cdot DER\max p_j\cdot Solar_{m,h}\quad\forall\, m,t,h\ \ if\ \ j\in\{PV\} \tag{5}$$

$$\sum_m\sum_t\sum_h\sum_u\left(GenL_{i,m,t,h,u}+GenX_{i,m,t,h}\right)\le InvGen_i\cdot DER\max p_i\cdot DERhours_i\ \forall\, i \tag{6}$$

$$\sum_u \mathrm{Re}\,cHeat_{i,m,t,h,u}\le\alpha_i\cdot\sum_u\left(GenL_{i,m,t,h,u}+GenX_{i,m,t,h}\right)\forall\, i,m,t,h \tag{7}$$

$$\mathrm{Re}\,cHeat_{i,m,t,h,u}=0\quad\forall\, i,m,t,h\quad if\quad u\notin S(i) \tag{8}$$

$$GenL_{i,m,t,h,u}=0\quad\forall\, i,m,t,h\quad if\quad u\in\{space-heating,water-heating,natural\text{-}gas\text{-}only\} \tag{9}$$

$$DRLoad_{m,t,h,u}=0\quad\forall\, m,t,h\quad if\quad u\in\{space-heating,water-heating,natural-gas-only\} \tag{10}$$

Equation (1) is the objective function that states that the μGrid will try to minimize total cost, consisting of:

- Facilities and customer charges;
- Monthly demand charges;
- Coincident demand charges;
- Disco energy charges ;
- On-site generation fuel and O&M costs;
- DER investment cost;
- Standby charges, if applicable;
- Variable and fixed costs for natural gas used to meet certain end-uses directly.

Subtracted from the total cost are revenues, if any, from self-generated electricity that is sold into the IEM.

The constraints to this problem are expressed in equations (2) through (10):

- Equation (2) enforces energy balance (it also indicates the means through which the load for energy end-use *u* may be satisfied).
- Equation (3) enforces the on-site generating capacity constraint.
- Equation (4) annualizes the capital cost of owning on-site generating equipment.
- if DER technology *j* is a PV cell, then equation (5) constrains it to generate in proportion to the solar insolation.
- Equation (6) places an upper limit on how many hours each type of DER technology can generate during the year (most of the technologies are allowed to generate during all hours of the year, but diesel generators, for example, are allowed to run for only 52 hours per year according to California legislation).
- Equation (7) limits how much heat can be recovered from each type of DER technology.
- Equation (8) prevents the use of recovered heat by end-uses that cannot be satisfied by the. particular DER technology (for example, heating loads cannot be met by a DER technology not equipped with a heat exchanger).
- Equations (9) and (10) are boundary conditions that prevent electricity to be used directly to meet heating loads.

Option 2: Buying from Alternative Energy Providers

The problem's mathematical formulation follows:

$$\min_{\substack{InvGen_i,\, GenL_{i,m,t,h,u} \\ GenX_{i,m,t,h}}} \sum_m \sum_t \sum_h \left(\sum_u DRLoad_{m,t,h,u} \right) \cdot \left(IEM_{m,t,h} + DiscoER \right)$$

$$+ \sum_i \sum_m \sum_t \sum_h \sum_u \left(GenL_{i,m,t,h,u} + GenX_{i,m,t,h,u} \right) \cdot DERCostkWh_i$$

$$+ \sum_i \sum_m \sum_t \sum_h \sum_u \left(GenL_{i,m,t,h,u} + GenX_{i,m,t,h,u} \right) \cdot DEROMvar_i$$

$$
\begin{aligned}
&+\sum_{i} InvGen_i \cdot \left(DERcapcost_i + DEROMfix_i\right) \cdot AnnuityF_i \\
&+\sum_{m}\sum_{i} InvGen_i \cdot DER\max p_i \cdot S\tan dbyC + \sum_{m} NGBSF_m \\
&+\sum_{m}\sum_{t}\sum_{h}\sum_{u} NGHR \cdot GasP_{m,t,h,u} \cdot NatGas\Pr ice_{m,t,h} \\
&-\sum_{m}\sum_{t}\sum_{h}\sum_{i} GenX_{i,m,t,h} \cdot IEM_{m,t,h}
\end{aligned}
\tag{1a}
$$

Subject to:

equations (2) through (10)

This formulation differs only in the objective function, equation (1a), which now charges the IEM price for each hourly time step plus the non-commodity revenue neutrality adder. Note that the same mathematical formulation can be used if the model user wants to simulate a fixed price for all customer energy purchases. In that case, all IEM hourly prices are simply set to the fixed desired value.

Appendix G. Site Questionnaire

Name:____________________________ Job Title:_________________________

Organization:_______________________

For all questions, please feel free to attach supplemental data if this is easier than transferring the information into this document. Please be clear in referencing which data sets apply to which questions. Excel spreadsheets are wonderful.

<u>Your Business</u>

1. Please state the type of facility and type(s) of business activity conducted, and whether your business is for-profit or non-profit.

2. For which buildings did you consider implementing DER? What is primary use of each building, and what is the square footage of each?

Building Name	Primary Use	Sq. Footage

3. What was primary motive for considering DER installation?

Cost Savings on current electricity rates	
Savings on expected future rate increases	
Reliability	
Availability of Cheap Fuels (e.g. biomass)	
Incentive Programs (government rebates, etc.)	
Other (please specify)	

4. Is the electricity and recovered heat (if any) from the new generation technology allocated for any specific services, or is it for general building/facility use?

5. Have you installed any energy saving technologies, such as energy efficient lighting or windows?

6. Was combining services (either energy demand or technology supply) with neighboring businesses considered (e.g. sharing waste heat)?

7. Did any side projects or business opportunities result from installing DER? Are there future expansion plans in terms of business services enabled by your distributed energy system?

8. What were the biggest barriers to the project, for example, environmental permitting, neighbor opposition, engineering study costs, installation and retrofit costs, and how were they overcome, or how did they kill the project?

9. Did you perform a risk assessment for this project? Which risks did you consider, and how did you quantify them?

10. How do resource uses interact with surrounding community or local businesses?

11. Did the project result in benefits or drawbacks to the community? For example: district heating, the creation of long term jobs, noise complaints.

Load Data

1. Please provide detailed site and end use electricity, thermal and cooling loads used in the DER and CHP technology implementation decision-making process, if available. Please be as specific as possible (i.e. hourly loads if available).

If these are not available, what proxy measure did you use, if any, in your analysis?

2. If these data are not available, may we gather this information from your local utility?

3. Was this load information available and used in the decision making process?

4. Heating Loads: what temperature is the load at(e.g. water heating, space heating, or industrial process?), and what is the power required? What type of technology is used to meet heating requirements?

5. Cooling Loads: what temperature is the load at, and what is the power required? What type of technology is used to meet cooling requirements?

6. Does your generator run at constant or variable loads?

Energy Prices/Tariffs

1. Which utility service territory are you located in and to which electricity tariff schedule was your site subject to at the time the decision to (not) implement was made? Please provide the schedule number, if available.

Service territory	Tariff Schedule

2. Were you under constant rate schedule or Time of Use?

3. Please provide gas and electricity prices from the period in which your DER implementation decision was made.

4. If this pricing information is not available to you, may we contact your local utility to get this information?

5. What is the current price of electricity and natural gas at the site in question?

6. Was a sensitivity analysis performed during your decision-making process, regarding fuel or electricity prices, or other cost changes? If so, please describe the analysis and its results:

7. At the time of your decision, were you expecting to be subjected to stand-by charges? If so, what were they?

8. Was there a net-metering price offered? If so, what was it ($/kW)

9. If connecting to the grid, what grid interconnection fees were imposed?

10. Were disconnection fees imposed (if applicable)? If so, what were they?

11. Are you (or were you) subject to any other fees demanded by your utility?

Generation Technology Costs

Technology Considered*	Estimated operating life-time	Capital Cost (before delivery/installation	Delivery, Installation Cost	Cost of Required Ancillary Equipment	Fixed Annual O&M ($/kW)	Variable Annual O&M ($/kW)	Max. Number of Allowable Operating Hours per Year

*Please list technology implemented first. If no technology implemented, please list closest contender first. Please be specific, listing model name/number if possible.

1. Please list reasons why particular technologies were not included in your analysis, if applicable.

Technology	Reason for not considering it

2. What is the source of fuel for the implemented technology?

3. What, if any, power conditioning equipment needed to be installed at the request of the utility? By your own volition?

4. Please list the types of ancillary equipment required, including fuel conditioning, (remote) monitoring,

Technology	Installed Cost

5. Did your organization have a pre-existing relationship with the technology vendors? If so, did this affect your technology implementation decision (through discounts, shared costs, etc.)?

6. If you installed multiple units of the same type, did you experience savings on a per unit basis? Were there other factors affecting your decision to install multiple smaller units?

<u>Technology Performance</u>

1. Please provide the following performance characteristics. If they aren't available to you, please provide a contact name at the technology vendor from whom we can get this data:

Efficiency (or heat) Rate	
Recoverable Heat in BTUs	
Recoverable Heat temperature	

% heat from jacket cooling loop vs. from exhaust	
Predicted Availability (up-time) of equipment – hours per month or if not always on then % of time available when required	
Actual Availability (up-time) of equipment – hours per month or if not always on then % of time available when required	

2. Were there any ramp-up or start-up factors considered that would affect performance?

Implementation Costs and Operating Factors

1. What changes needed to be made to the facilities to install the DER equipment?

2. Please list any equipment compatibility and connection issues (generator to CHP equipment for example).

3. Do you have an estimate for the conversion costs of CHP or absorption cooling capabilities (pipes, heat exchangers, etc.)?

4. If installed, were there any difficulties encountered with absorption chillers, or desiccant dehumidification?

5. What energy management software used? How much did it cost and was special training needed?

6. Who is responsible for operating the system (*i.e*. current staff used or outsourced)? What personnel operating costs (*e.g*. on site monitor or remote) did you expect, and do these match the costs you are experiencing?

7. Did the gas supply need to be upgraded (high pressure for example)? What were the costs involved to do so?

8. Were there other expected or unexpected maintenance cost issues?

9. Did any site location issues cause problems (*e.g.* lack of space, unfavorable conditions, roof couldn't support weight, access to spot difficult for delivery truck, doors too small, etc.).

10. Did you require an inspection from public officials such as fire marshal? What was the cost or time involved with these inspections?

Appendix H. Site Pictures

H.1 A&P Waldbaum's Supermarket

Figure A- 23: A&P Waldbaum's Supermarket

Figure A- 24: Capstone 60 kW Microturbine, MicroGen Heat Exchanger, and Munters Unit

Figure A- 25: Compressors Inside of Control Room

H.2 Guaranteed Savings Building

Figure A- 26: Guaranteed Savings Building

Figure A- 27: Construction of Parking Garage Where Fuel Cells Will Be Housed

Figure A- 28: Whole Building Internal Renovations in Preparation For New Tenants

H.3 The Orchid Resort

Figure A- 29: The Orchid Resort

Figure A- 30: Generation Equipment (Propane Engines) and Islanding Switch

Figure A- 31: Propane Tank

H.4 BD Biosciences Pharmingen

Figure A- 32: BD Biosciences Pharmingen

Figure A- 33: Water Heating and Cooling Loops

Figure A- 34: Site for the Two 150 kW Natural Gas Engines with Excess Heat Radiator in Background

H.5 San Bernardino USPS

Figure A- 35: San Bernardino USPS facility

Figure A- 36: San Bernardino mail handling equipment (annex space)

Figure A- 37: San Bernardino USPS rooftop (evaluated as potential PV site)

Figure A- 38: San Bernardino USPS mail handling equipment (main building area)

Appendix I. Electricity and Natural Gas Tariffs

Tariff information was obtained from site information at the time of their DER decision making. When this was not obtainable, tariff sheets from utilities were obtained on-line. Demand charges are increased by 10% to account for differences between monthly peak values (what demand charges are based on) and average peak values (DER-CAM uses a monthly average profile for each month).

Electricity Tariffs:

		A&P Hauppauge, NY	Garuanteed Savings Bank Fresno, CA	Orchid Resort* Mauna Lani, HI	Pharmingen Torrey Pines, CA	San Bernardino USPS Redlands, CA	Wyoming County Community Hospital Warsaw, NY
	Summer months	June- Aug	May- Oct	flat rate	May-Sept	June- Sept	May- Sept
	Summer On Peak hours	11h-18h	11h-18h	flat rate	11h-18h	12h-18h	07h-21h
	Summer Mid Peak hours	06h-11h, 18h-22h	06h-11h, 18h-22h	flat rate	06h-11h, 18h-22h	08h-12h, 18h-23h	21h-22h
	Summer Off Peak hours	00h-06h, 22h-24h	00h-06h, 22h-24h	flat rate	00h-06h, 22h-24h	00h-08h, 23h-24h	00h-07h, 22h-24h
	Winter months	Jan-May, Sept-Dec	Jan- Apr, Nov- Dec	flat rate	Jan- Apr, Oct- Dec	Jan- May, Oct- Dec	Jan- Apr, Oct- Dec
	Winter On Peak hours	17h-20h	17h-20h	flat rate	17h-20h	08h-09h	07h-21h
	Winter Mid Peak hours	06h-17h, 20h-22h	06h-17h, 20h-22h	flat rate	06h-17h, 20h-22h	09h-21h	21h-22h
	Winter Off Peak hours	00h-06h, 22h-24h	00h-06h, 22h-24h	flat rate	00h-06h, 22h-24h	00h-08h, 21h-24h	00h-07h, 22h-24h
Energy Price ($/kWh)	Summer On Peak	0.0928	0.1596	0.1600	0.1548	0.1954	0.0707
	Summer Mid Peak	0.0928	0.1596	0.1600	0.1060	0.1090	0.0707
	Summer Off Peak	0.0928	0.1596	0.1600	0.0857	0.0881	0.0439
	Winter On Peak	0.0779	0.1117	0.1600	0.1486	0.1212	0.0707
	Winter Mid Peak	0.0779	0.1117	0.1600	0.1037	0.1212	0.0707
	Winter Off Peak	0.0779	0.1117	0.1600	0.0814	0.0892	0.0439
Power Price (Demand Charge) ($/kW peak montly usage during particular time of day)	Summer On Peak	11.39	7.37	0.00	7.84	19.75	8.54
	Summer Mid Peak	0.00	0.00	0.00	0.00	2.97	0.00
	Summer Off Peak	0.00	0.00	0.00	0.00	0.00	0.00
	Winter On Peak	11.10	1.82	0.00	0.00	0.00	8.54
	Winter Mid Peak	0.00	0.00	0.00	7.48	0.00	0.00
	Winter Off Peak	0.00	0.00	0.00	0.00	0.00	0.00
Coincident Price ($/kW)	Summer On Peak	0.00	0.00	0.00	20.38	0.00	0.00
	Summer Mid Peak	0.00	0.00	0.00	20.38	0.00	0.00
	Summer Off Peak	0.00	0.00	0.00	20.38	0.00	0.00
	Winter On Peak	0.00	0.00	0.00	6.44	0.00	0.00
	Winter Mid Peak	0.00	0.00	0.00	6.44	0.00	0.00
	Winter Off Peak	0.00	0.00	0.00	6.44	0.00	0.00
Peak Power Charge ($/kW peak monthly usage)		0.00	0.00	12.10	0.00	7.26	0.00
Standby Charge ($/kW DER Capacity)		0.00	2.17	11.40	0.00	6.60	0.00
Facility Charge ($/month)		21.56	75.00	375.00	43.50	299.00	16.00

Natural Gas Tariffs:

	A&P		Garuanteed Savings Bank		Orchid Resort*	*these are propane prices	Pharmingen		San Bernardino USPS		Wyoming County Community Hospital	
	Hauppauge, NY		Fresno, CA		Mauna Lani, HI		Torrey Pines, CA		Redlands, CA		Warsaw, NY	
month	**cost ($/kJ)**	**cost ($/therm)**	**cost ($/kJ)**	**cost ($/therm)**	**cost ($/kJ)**	**cost ($/therm)**	**cost ($/kJ)**	**cost ($/therm)**	**cost ($/kJ)**	**cost ($/therm)**	**cost ($/kJ)**	**cost ($/therm)**
January	8.29E-06	0.87	8.76E-06	0.92	9.94E-06	1.05	5.26E-06	0.55	6.27E-06	0.66	4.19E-06	0.44
February	7.85E-06	0.83	8.33E-06	0.88	9.94E-06	1.05	4.99E-06	0.53	5.30E-06	0.56	4.19E-06	0.44
March	8.17E-06	0.86	8.07E-06	0.85	9.94E-06	1.05	5.14E-06	0.54	5.28E-06	0.56	4.19E-06	0.44
April	8.40E-06	0.89	7.10E-06	0.75	9.94E-06	1.05	4.40E-06	0.46	5.40E-06	0.57	4.19E-06	0.44
May	8.50E-06	0.90	6.85E-06	0.72	9.94E-06	1.05	4.94E-06	0.52	6.09E-06	0.64	4.19E-06	0.44
June	8.71E-06	0.92	5.84E-06	0.62	9.94E-06	1.05	4.71E-06	0.50	5.64E-06	0.60	4.19E-06	0.44
July	8.46E-06	0.89	6.47E-06	0.68	9.94E-06	1.05	4.82E-06	0.51	4.19E-06	0.44	4.19E-06	0.44
August	7.80E-06	0.82	5.75E-06	0.61	9.94E-06	1.05	5.28E-06	0.56	3.91E-06	0.41	4.19E-06	0.44
September	7.27E-06	0.77	5.55E-06	0.59	9.94E-06	1.05	5.39E-06	0.57	4.19E-06	0.44	4.19E-06	0.44
October	6.69E-06	0.71	6.10E-06	0.64	9.94E-06	1.05	5.31E-06	0.56	3.73E-06	0.39	4.19E-06	0.44
November	8.14E-06	0.86	6.77E-06	0.71	9.94E-06	1.05	5.60E-06	0.59	4.06E-06	0.43	4.19E-06	0.44
December	7.81E-06	0.82	7.56E-06	0.80	9.94E-06	1.05	5.99E-06	0.63	5.94E-06	0.63	4.19E-06	0.44

Appendix J. DOE-2

DOE-2 is building simulation software developed at the Ernest Orlando Lawrence Berkeley National Laboratory (LBL).[48] DOE-2 predicts the hourly energy use of a building. Inputs to DOE-2 include details of the building design and construction materials, hourly weather information, and HVAC equipment.

Norman Bourassa of LBL developed generic building models for use in DOE-2 for the following types of buildings: fast food restaurant, hospital, large hotel, large office building, large retail building, school, restaurant, super market, small hotel, small office building, small retail building, and warehouse. All models are based on San Diego, CA building codes. For each building type, a spreadsheet was developed for users to input known building data (including floor space of the building and weather data). From this spreadsheet, a macro was used to run DOE-2 with the given data.

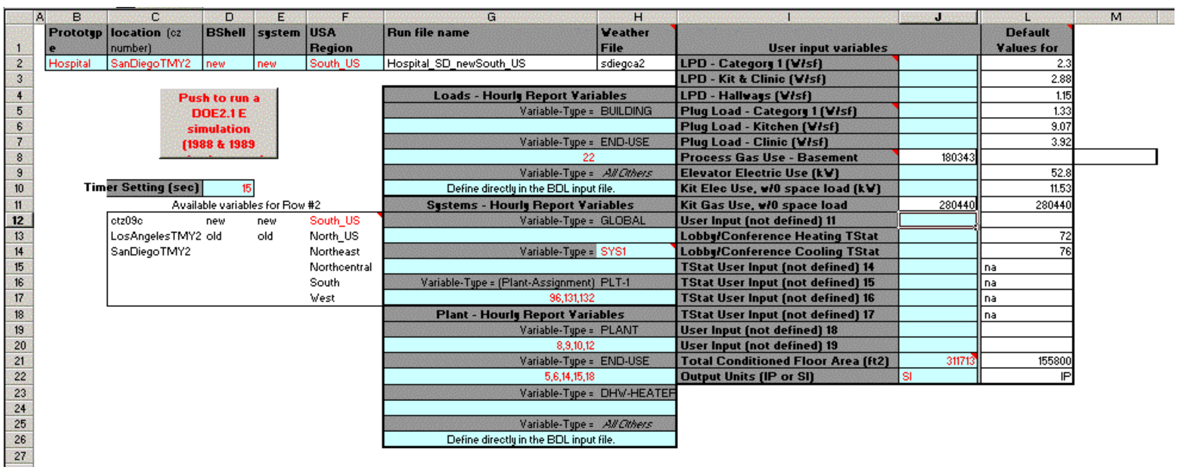


Figure A- 39: DOE-2 user interface developed for DER-CAM team

DOE-2 results were most often used to obtain load shapes for some or all of the 5 load inputs to DER-CAM (electric only, cooling, space heating, water heating, natural gas only). These shapes were then scaled to match data provided by sites. For example, if natural gas usage for space heating was given as an annual total by the site, DOE-2 space heating loads could be scaled so that the annual total from the scaled results matched that provided by the site.

48 http://gundog.lbl.gov/

Appendix K. Load Profiles

DER-CAM inputs include the following 5 categories of hourly load data.

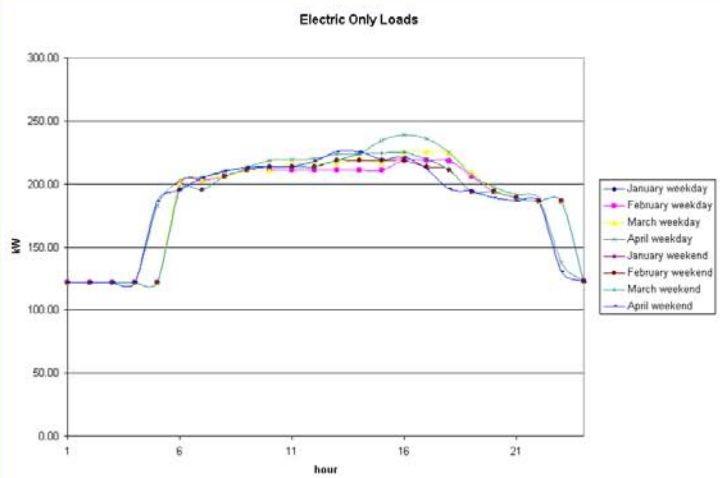
- *Electric only*: loads that can only be met by electricity. For the purposes of DER-CAM modeling, this is all electric loads except air cooling.
- *Cooling*: the electric load required to meet air cooling loads.
- *Space Heating*: the amount of energy supplied to air to meet air heating loads.
- *Water Heating*: the amount of energy supplied to water to meet water heating loads.
- *Natural Gas Only**: the amount of natural gas required for loads that can only be met by natural gas.

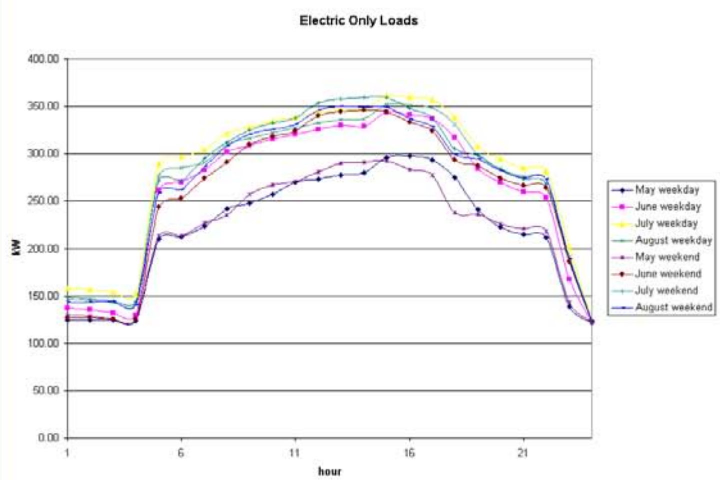
*For The Orchid Resort, Natural Gas Only loads are met by Propane

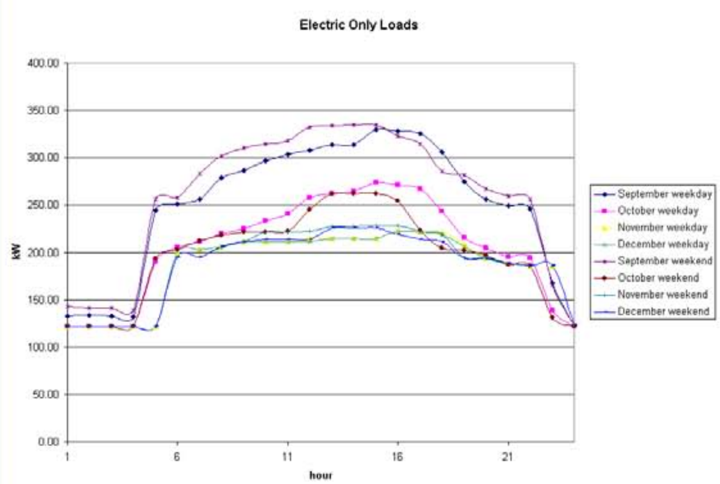
Load data of varying detail was provided by all sites. Scaled results from DOE-2 and the authors' discretion were used to develop hourly load data to match less detailed information provided by the site when necessary.

All load data used in this report is presented in the following pages.

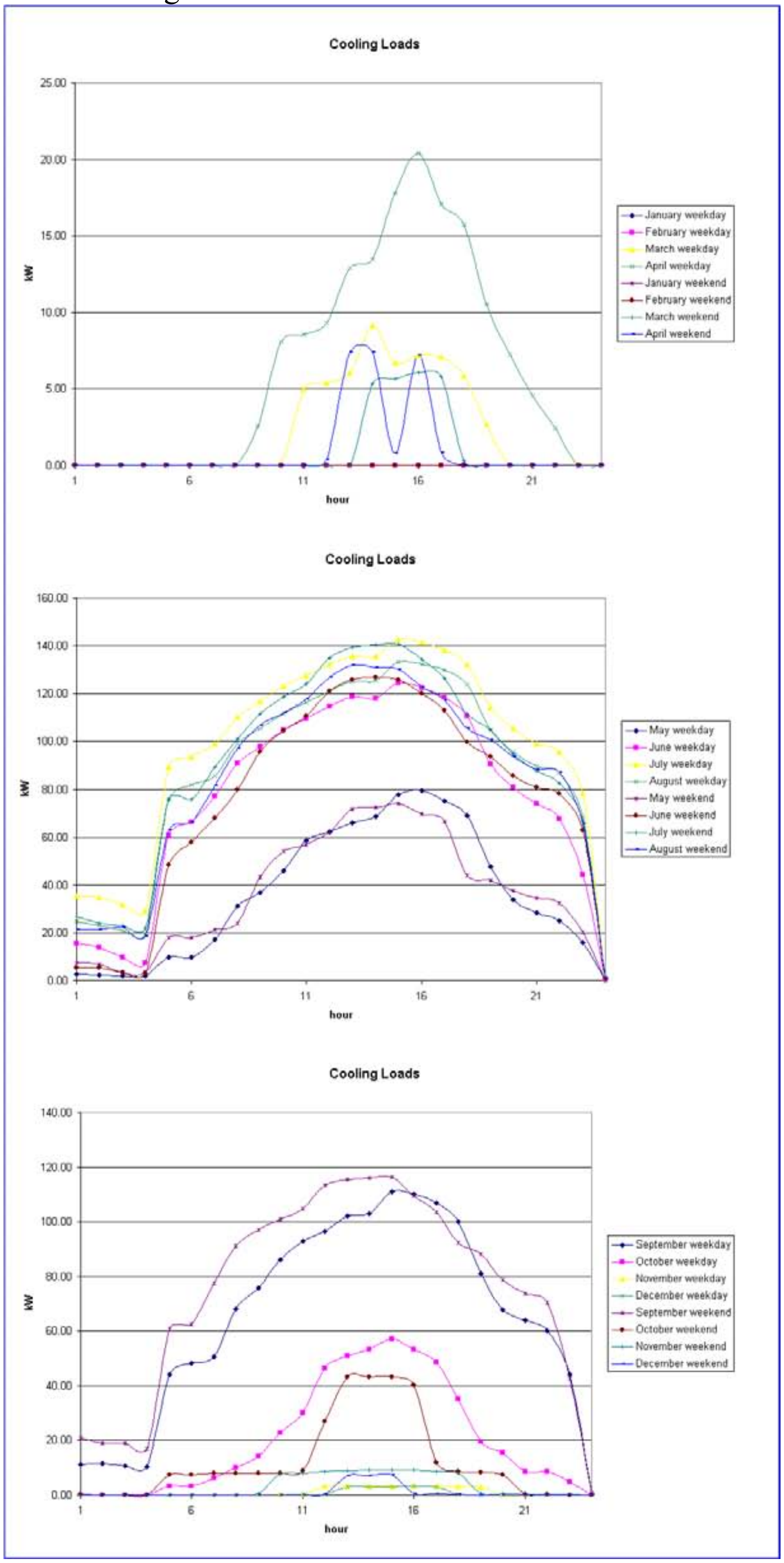
A&P: Electric Only



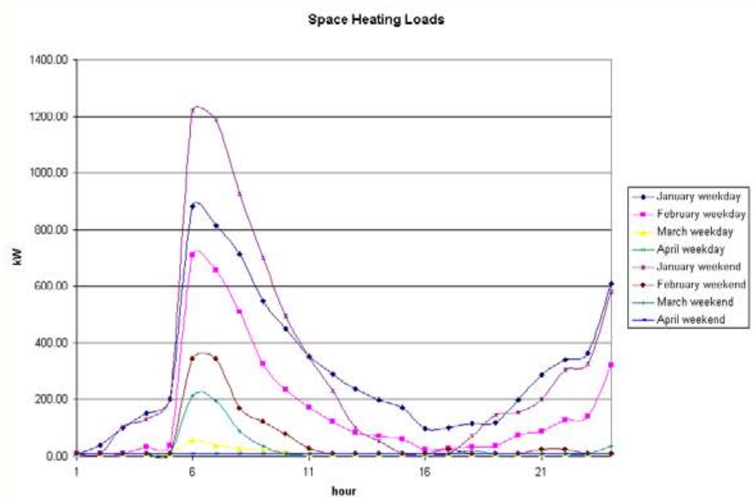


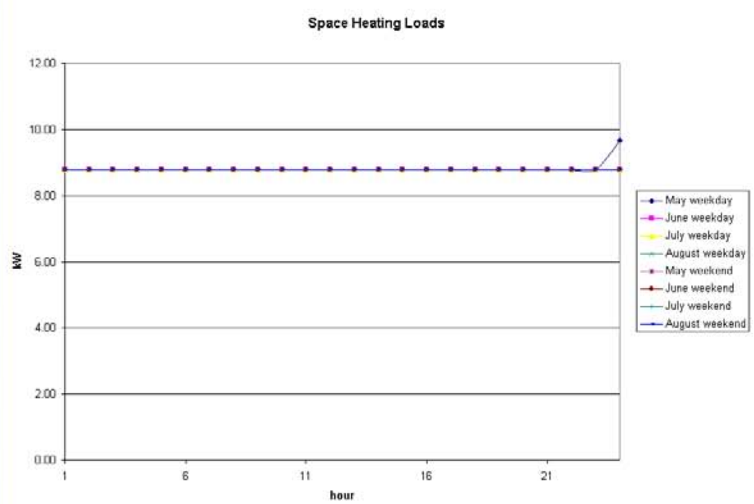


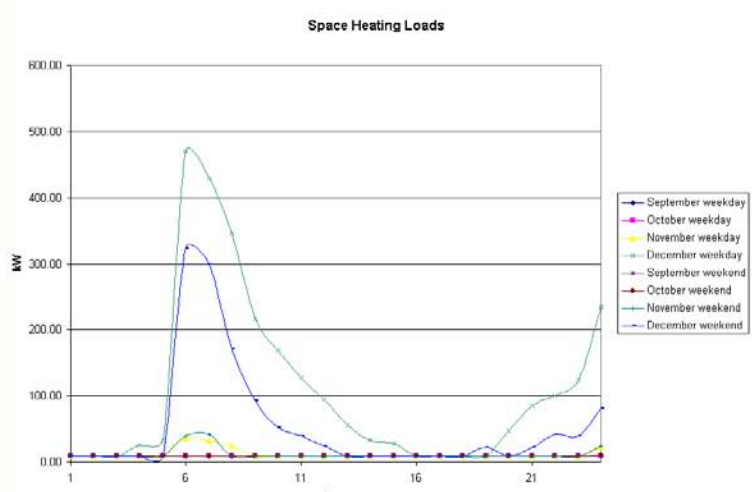
A&P Cooling:


Cooling Loads
kW
hour
January weekday
February weekday
March weekday
April weekday
January weekend
February weekend
March weekend
April weekend
Cooling Loads
kW
hour
May weekday
June weekday
July weekday
August weekday
May weekend
June weekend
July weekend
August weekend
Cooling Loads
kW
hour
September weekday
October weekday
November weekday
December weekday
September weekend
October weekend
November weekend
December weekend

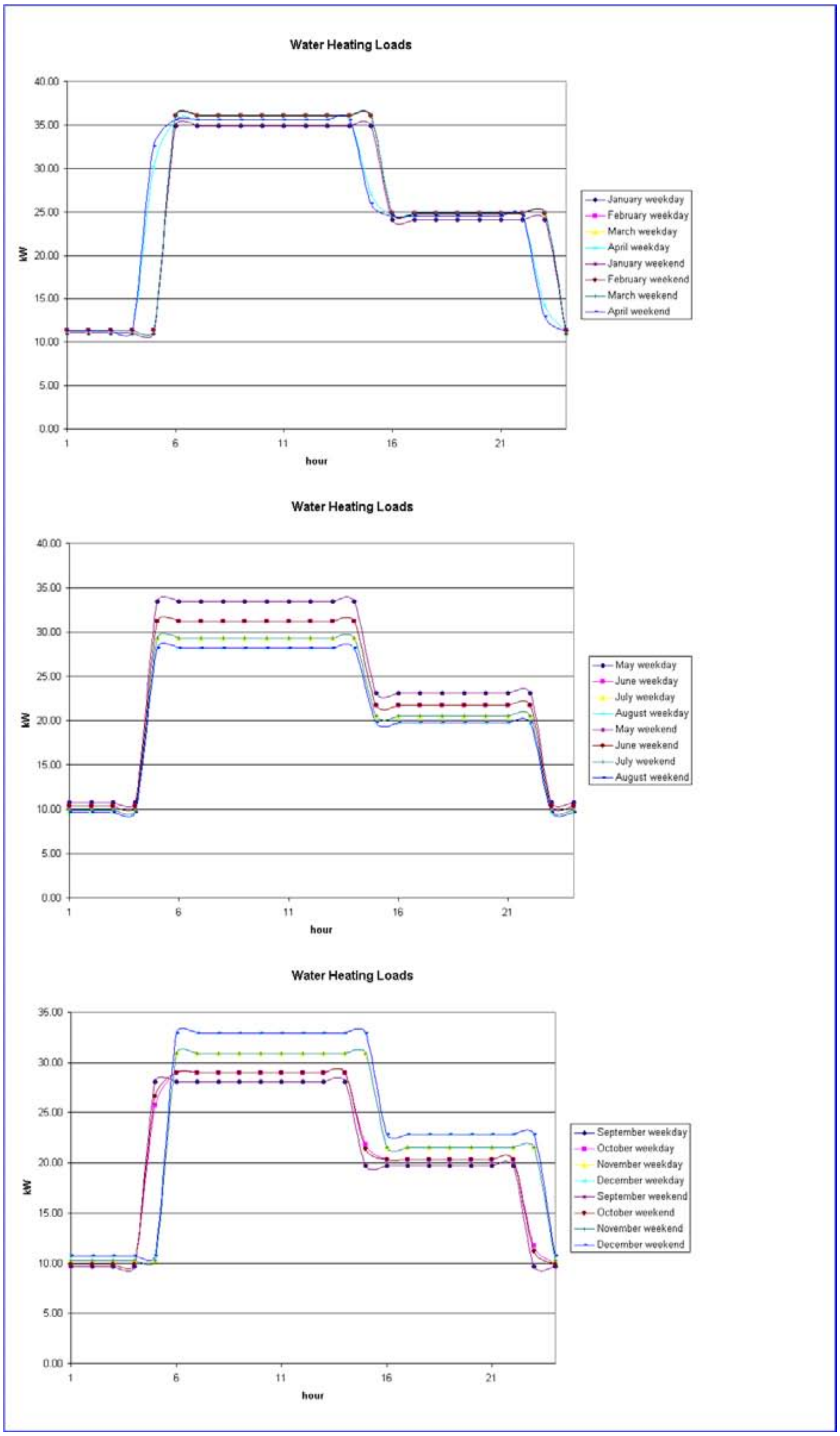
A&P: Space Heating



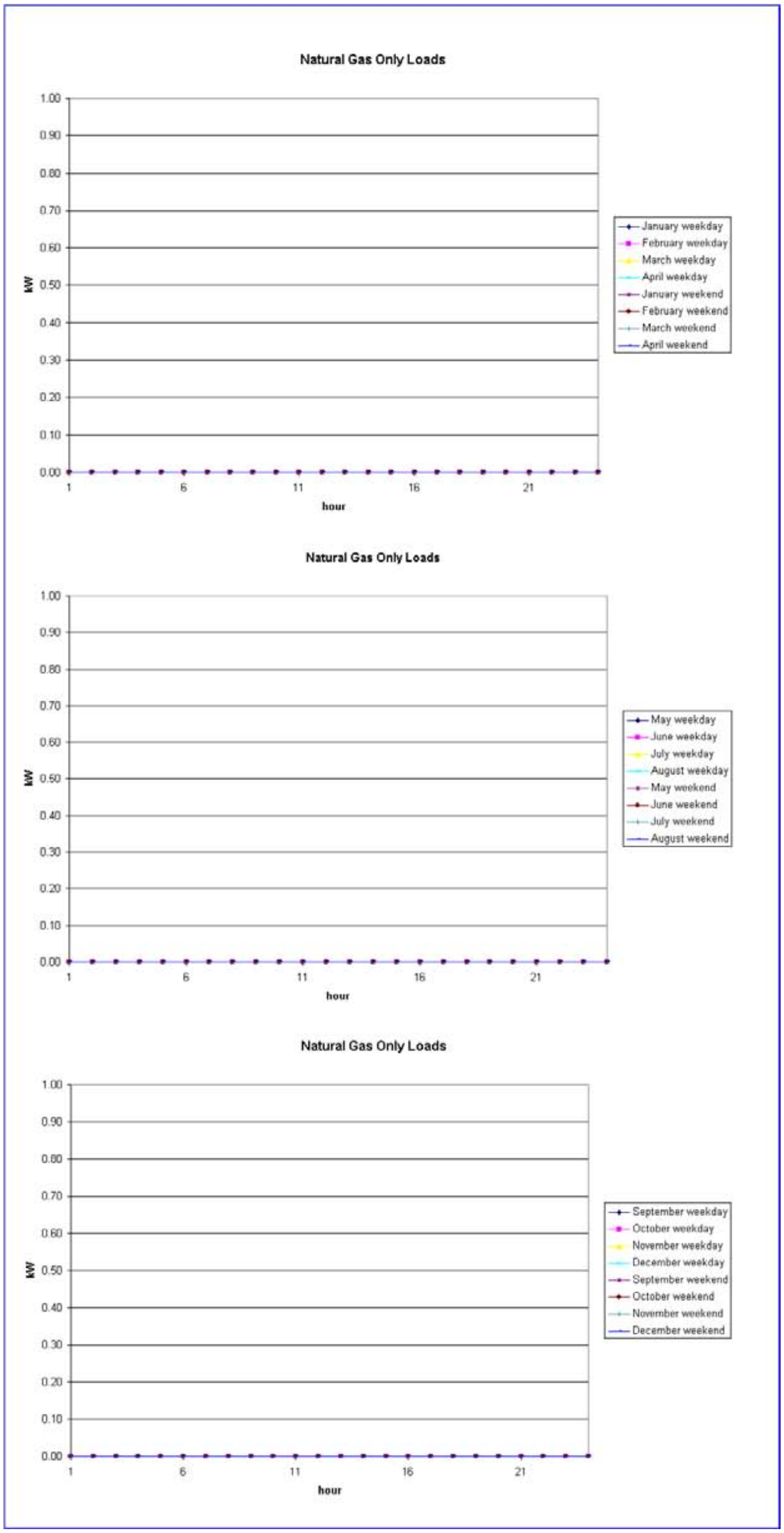




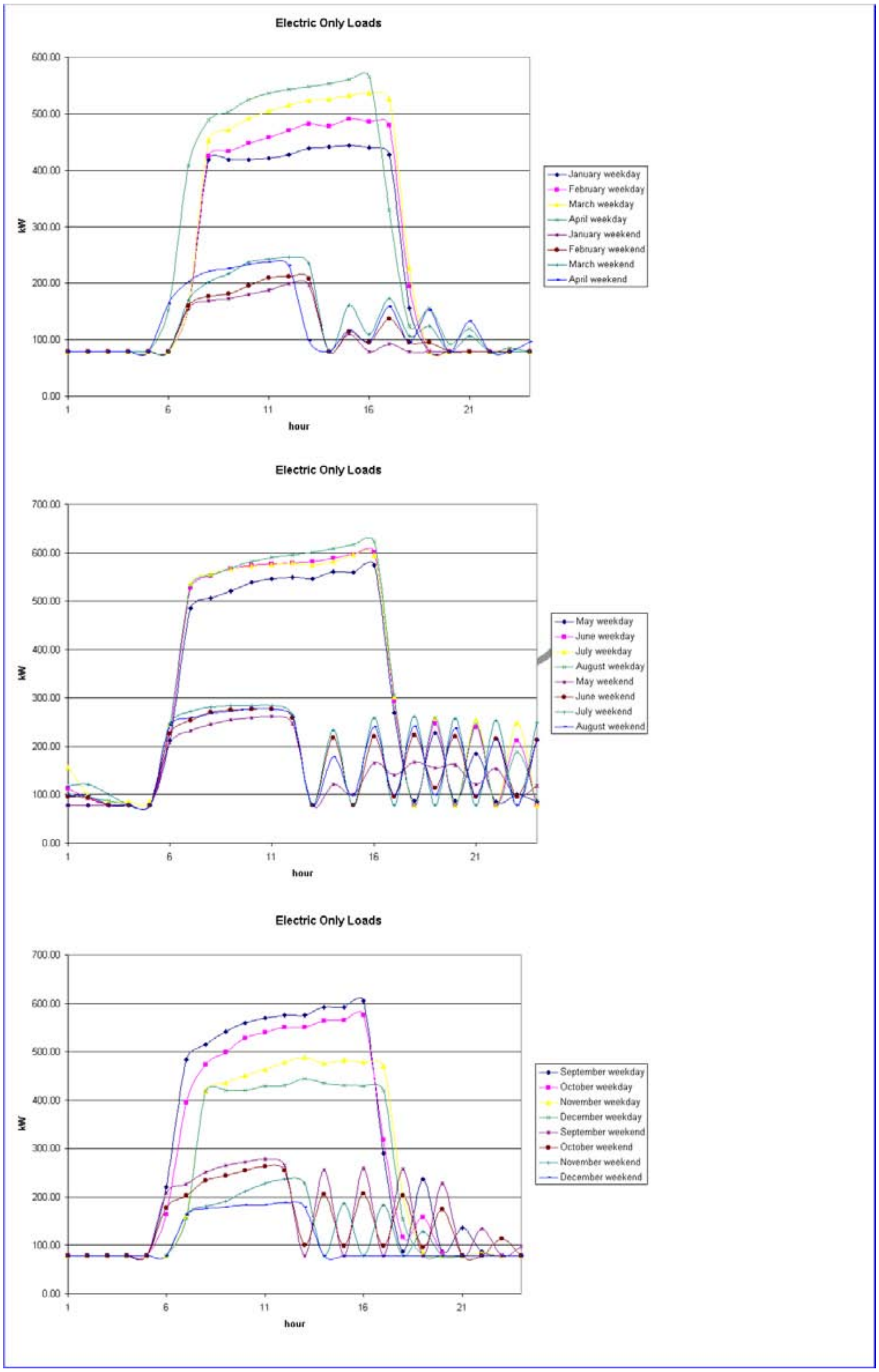
A&P: Dehumidification (Water Heating used as a proxy)



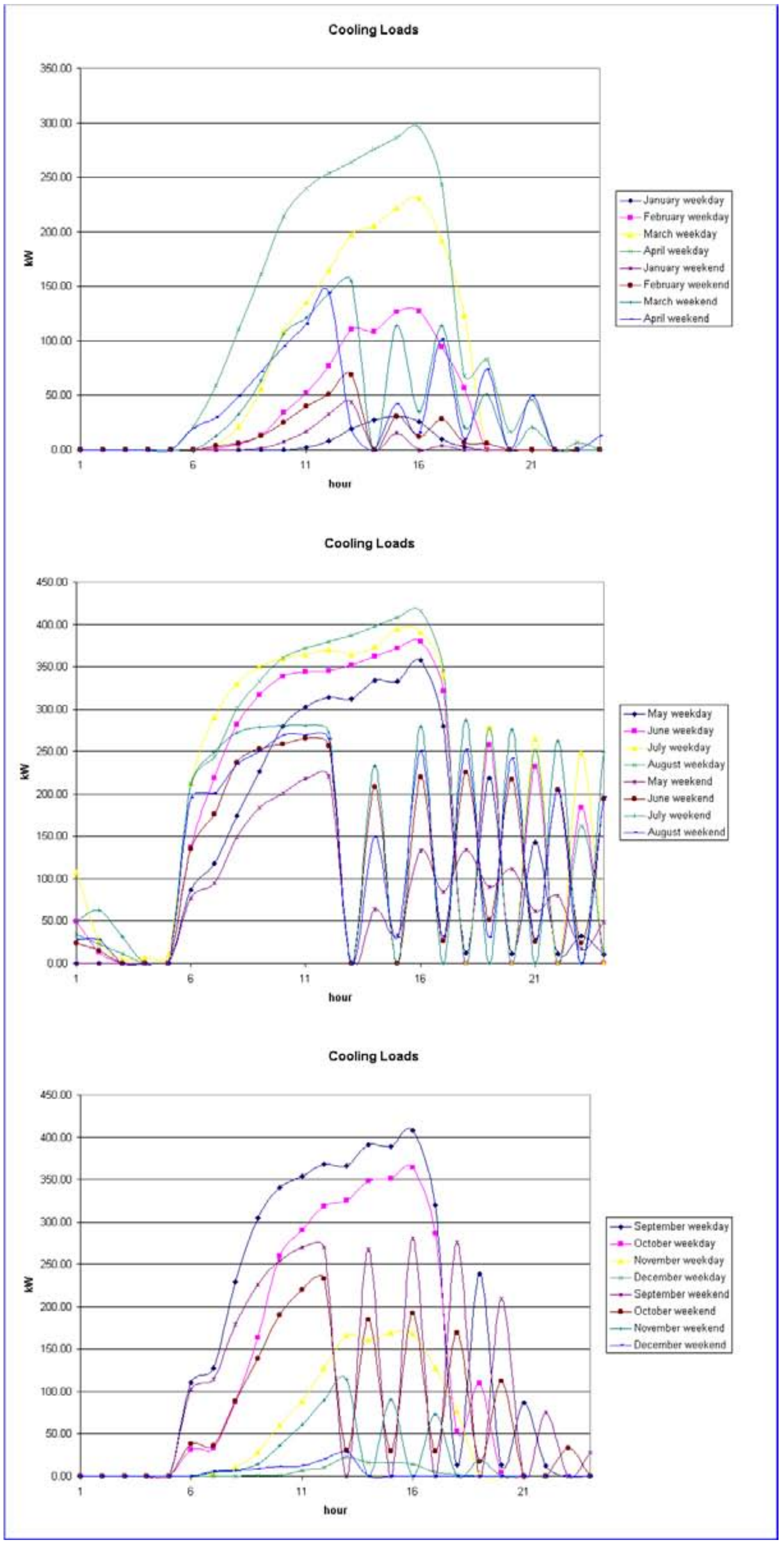
A&P: Natural Gas Only



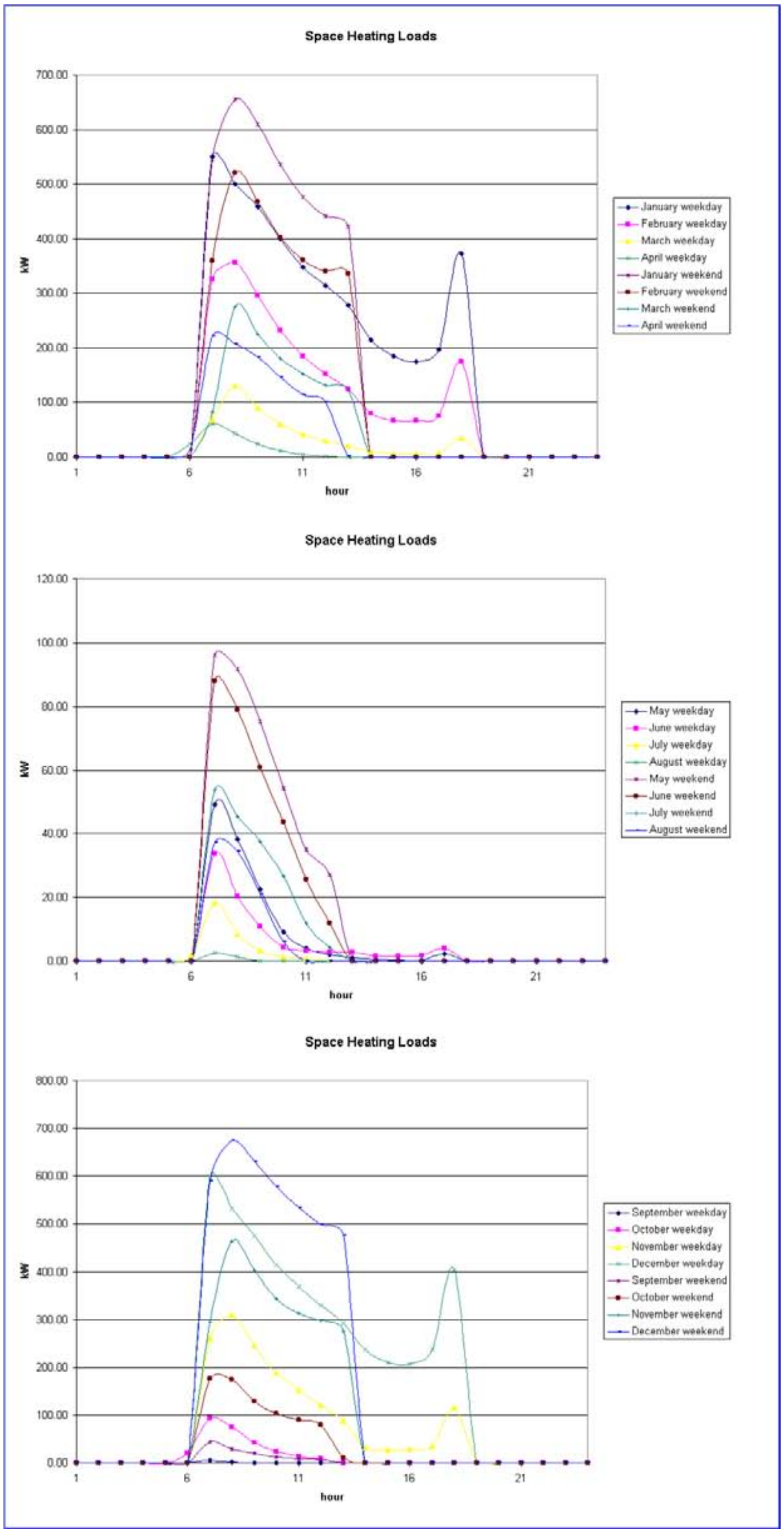
Guaranteed Savings Building: Electric Only Loads



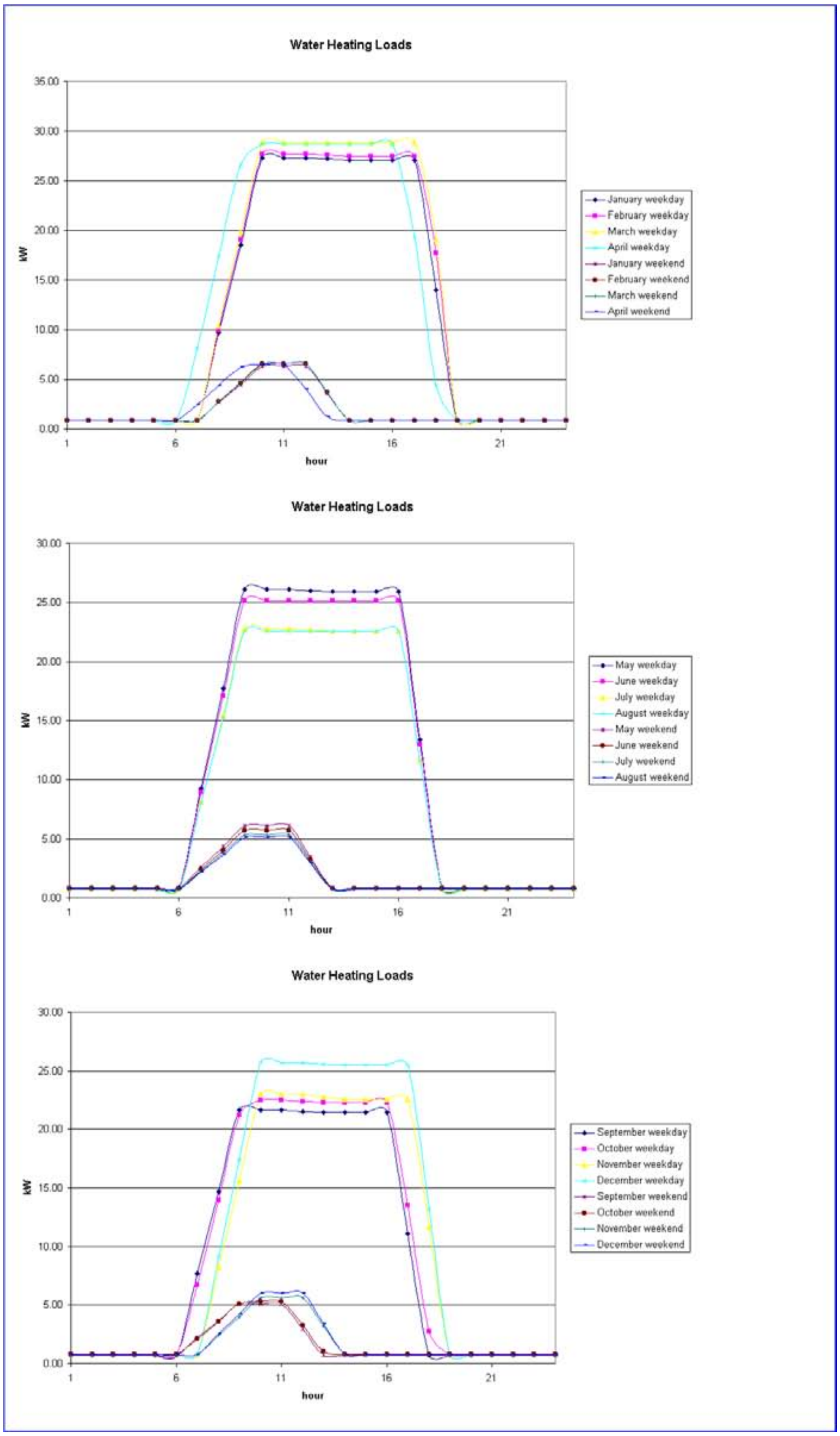
Guaranteed Savings Building: Cooling Load



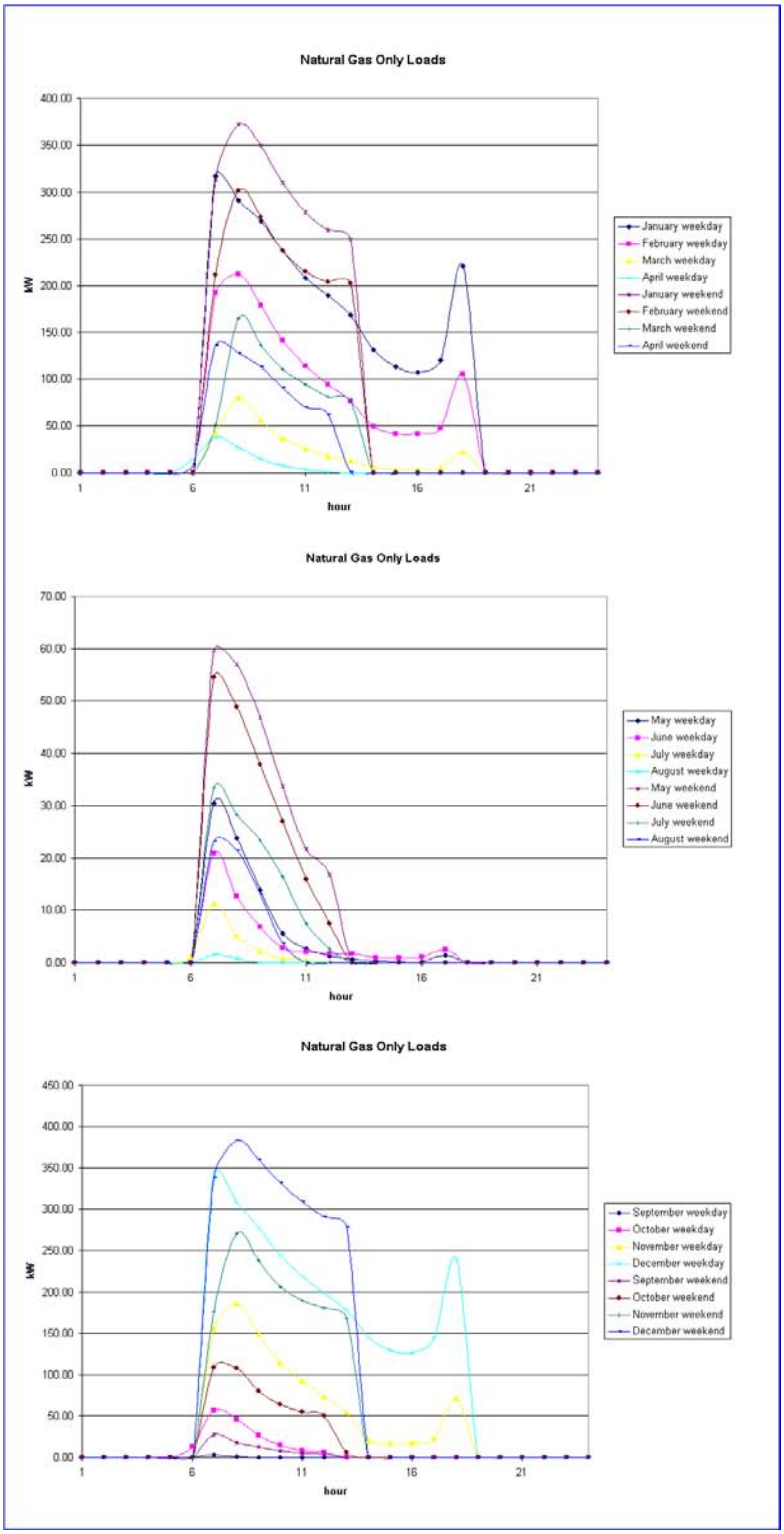
Guaranteed Savings Building: Space Heating Loads



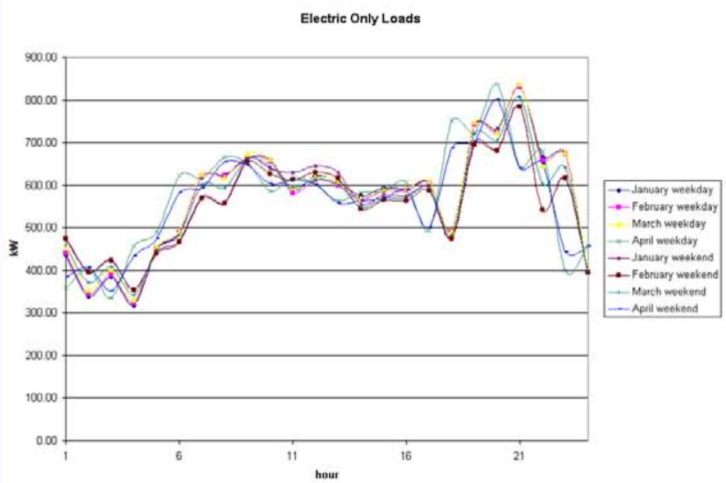
Guaranteed Savings Building: Water Heating Load

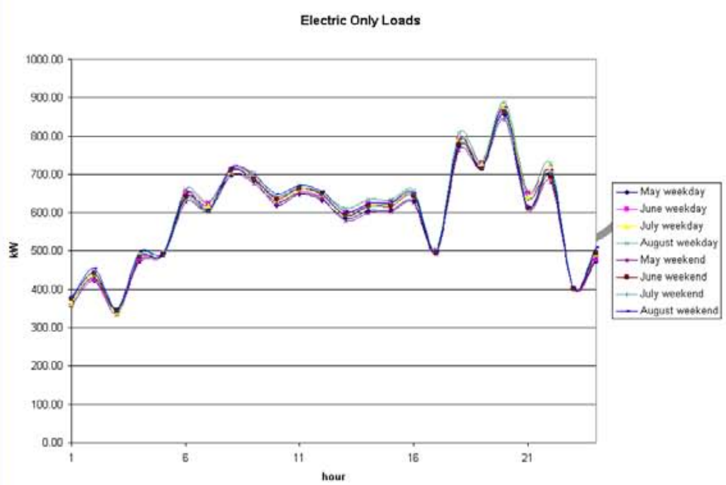


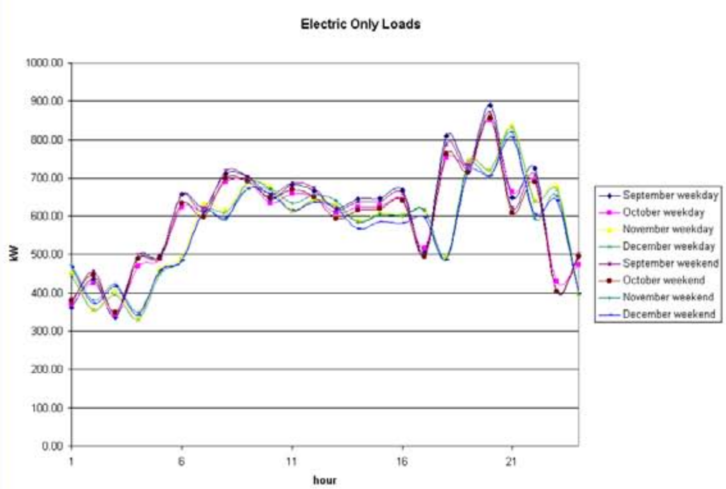
Guaranteed Savings Building: Natural Gas Only Load



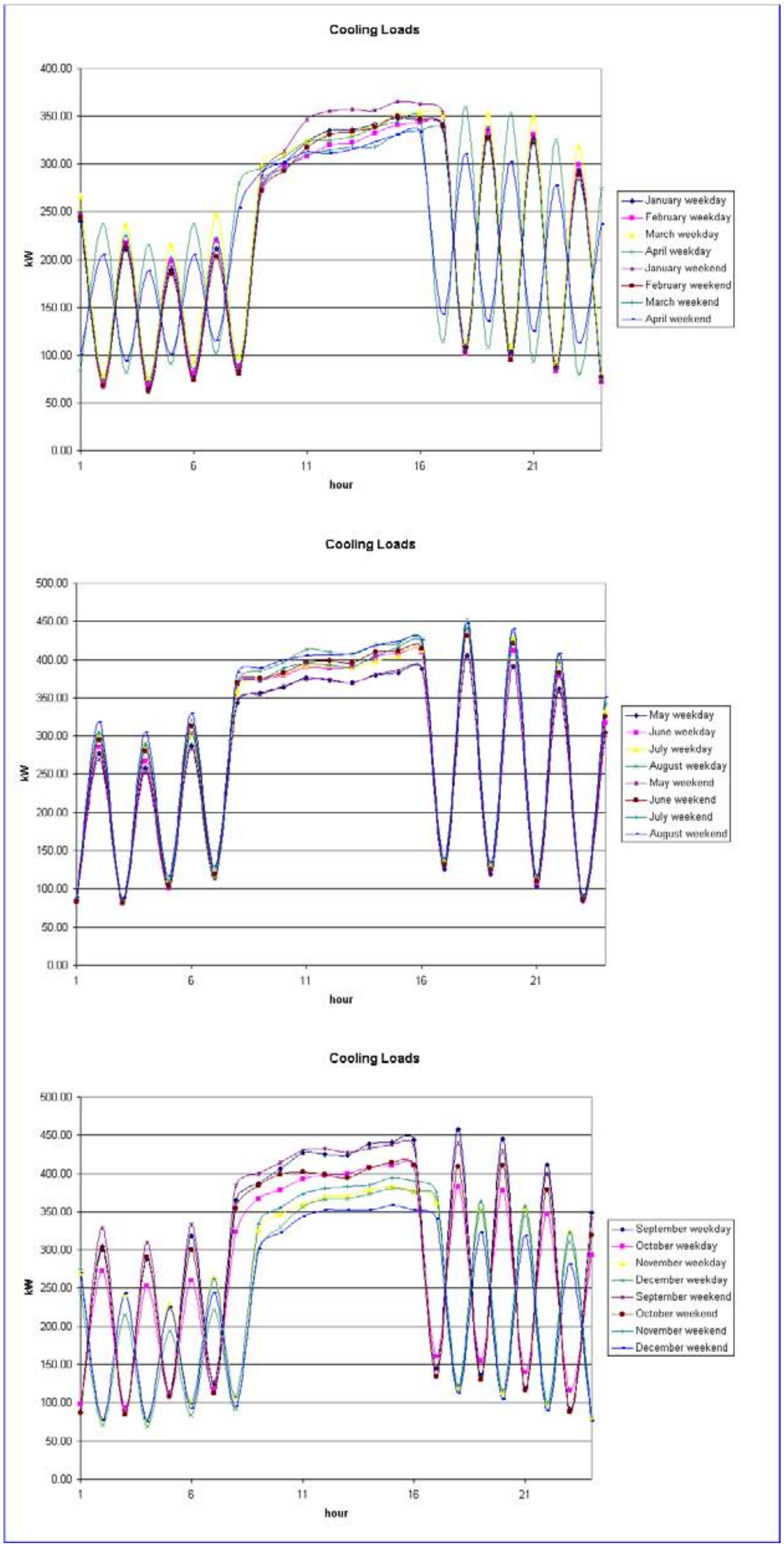
The Orchid Resort: Electric Only Loads



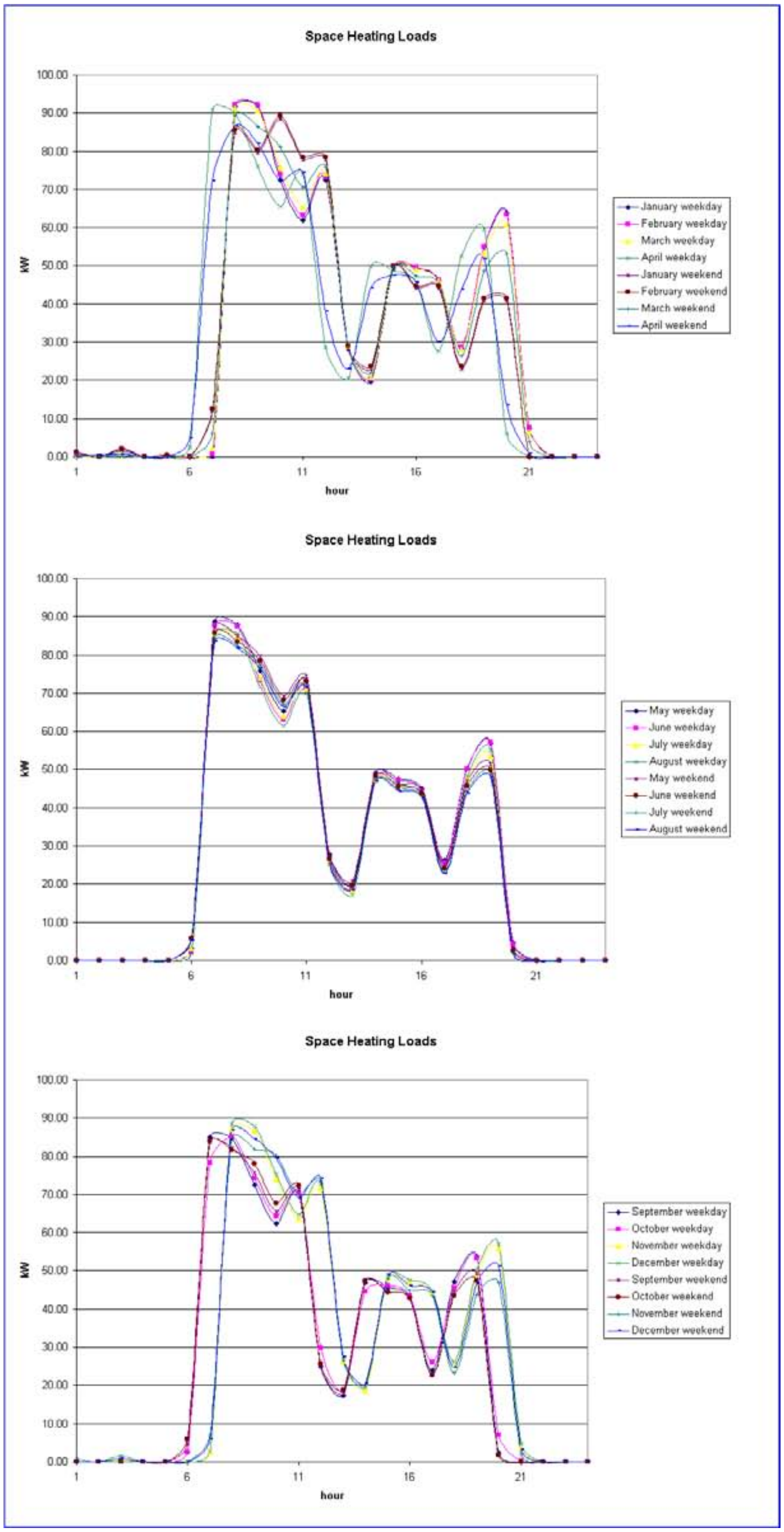




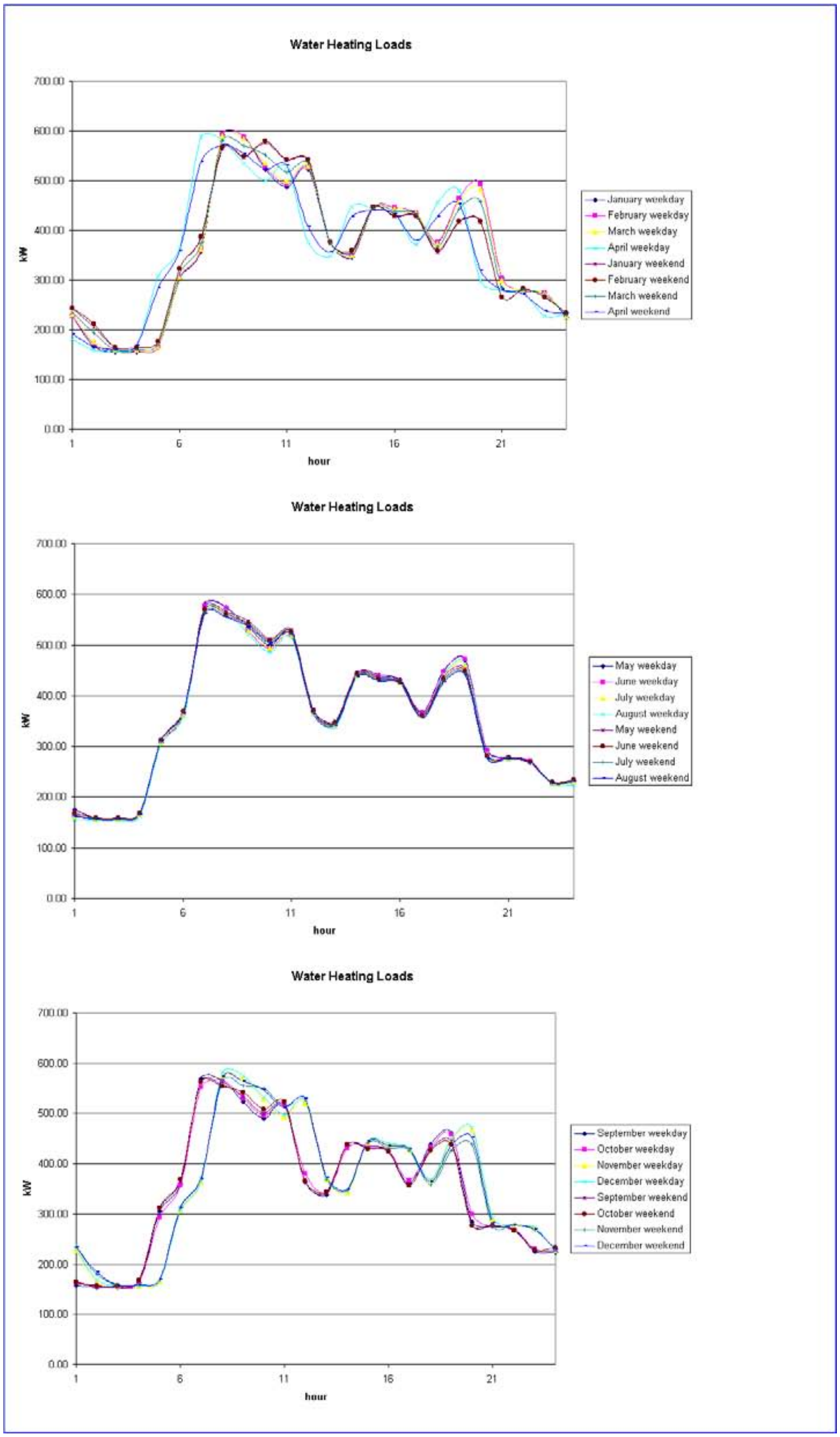
The Orchid Resort: Cooling Load



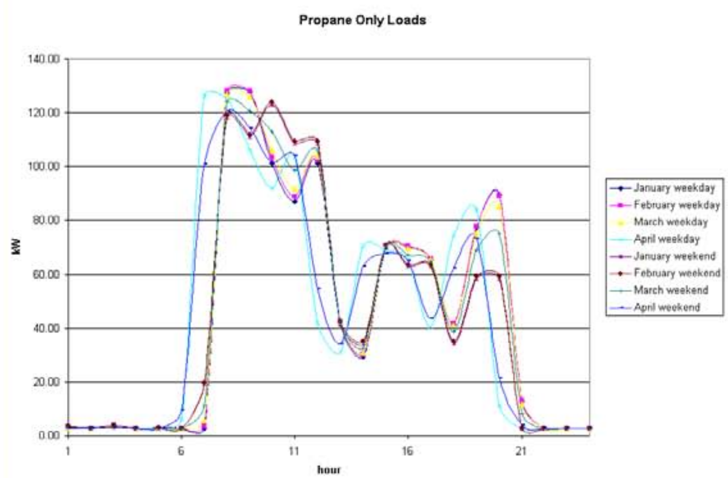
The Orchid Resort: Space Heating Load

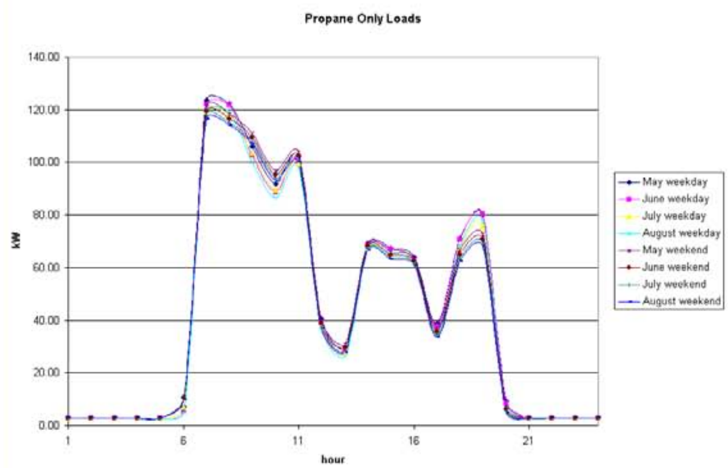


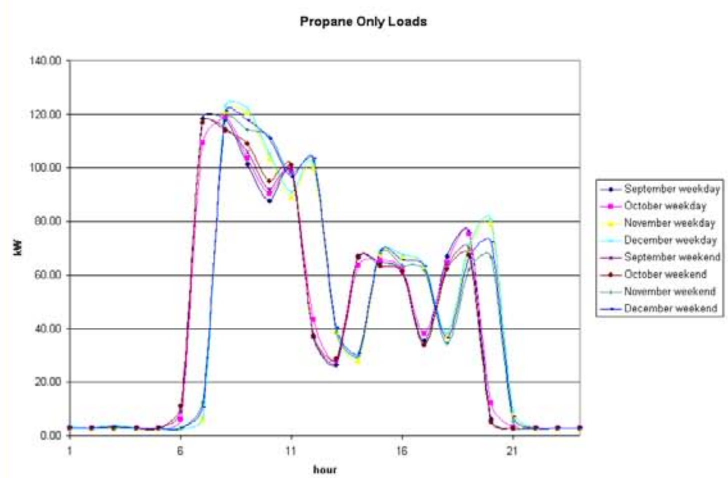
The Orchid Resort: Water Heating Load



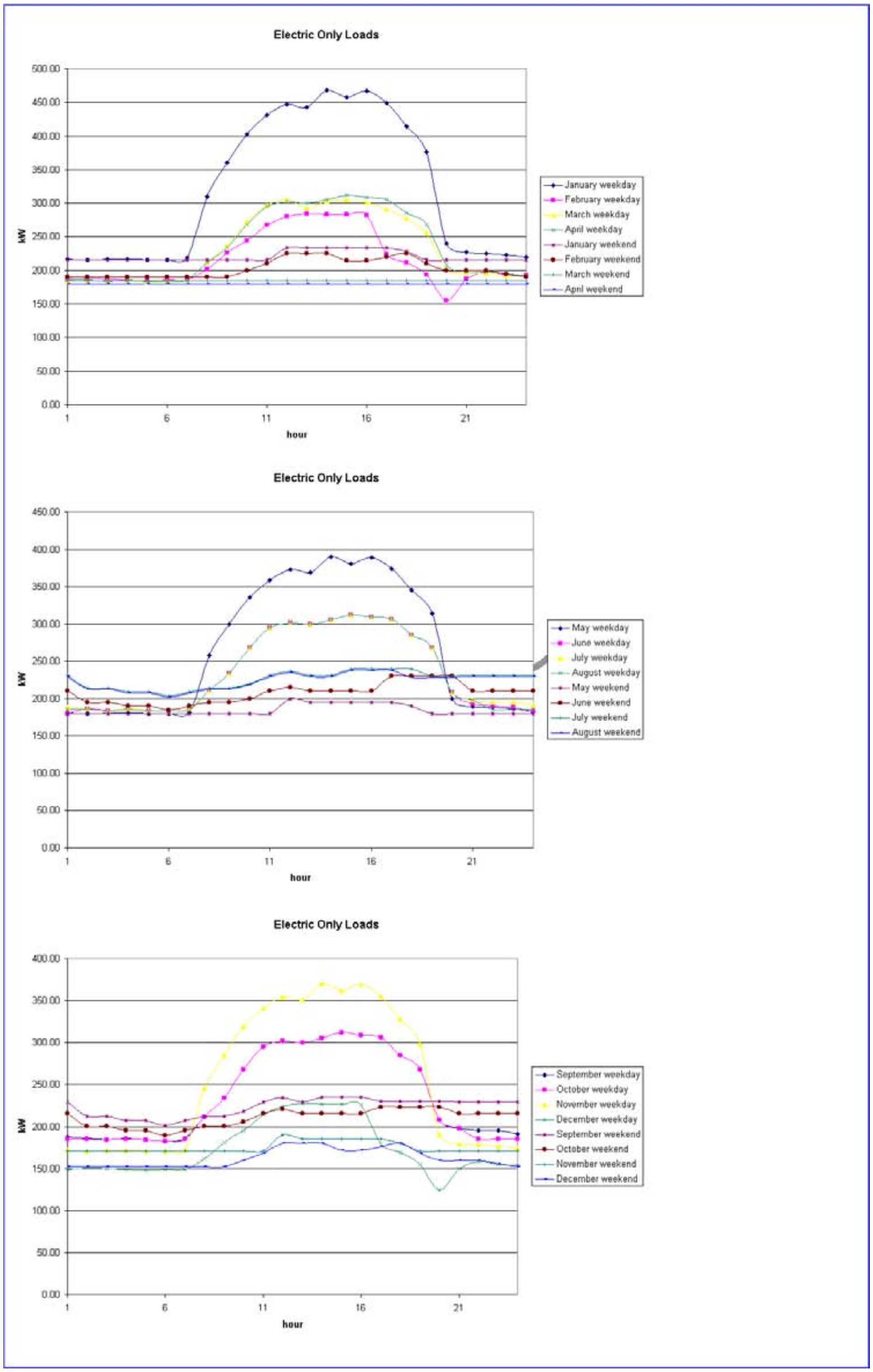
The Orchid Resort: Propane Only Load



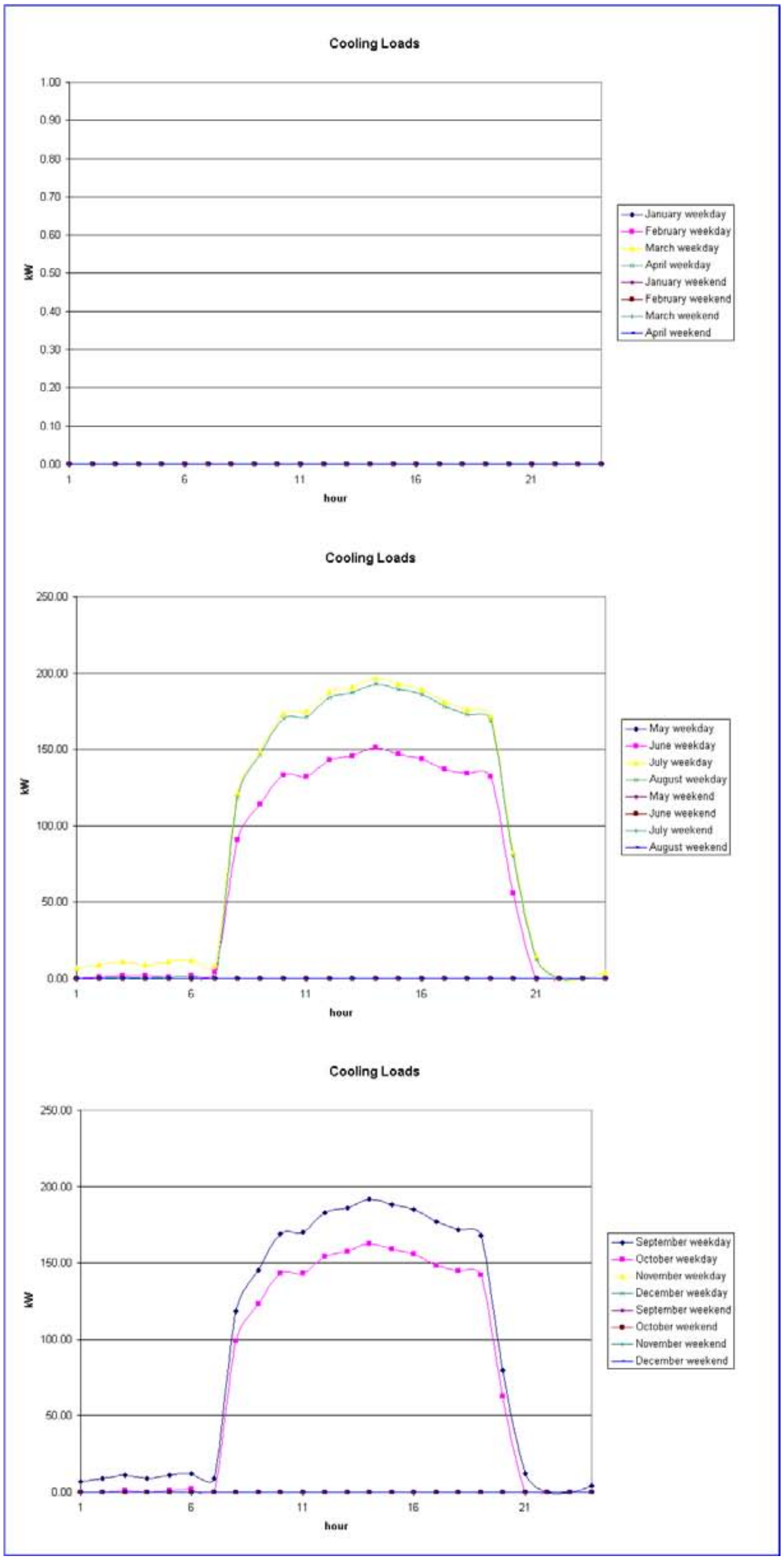




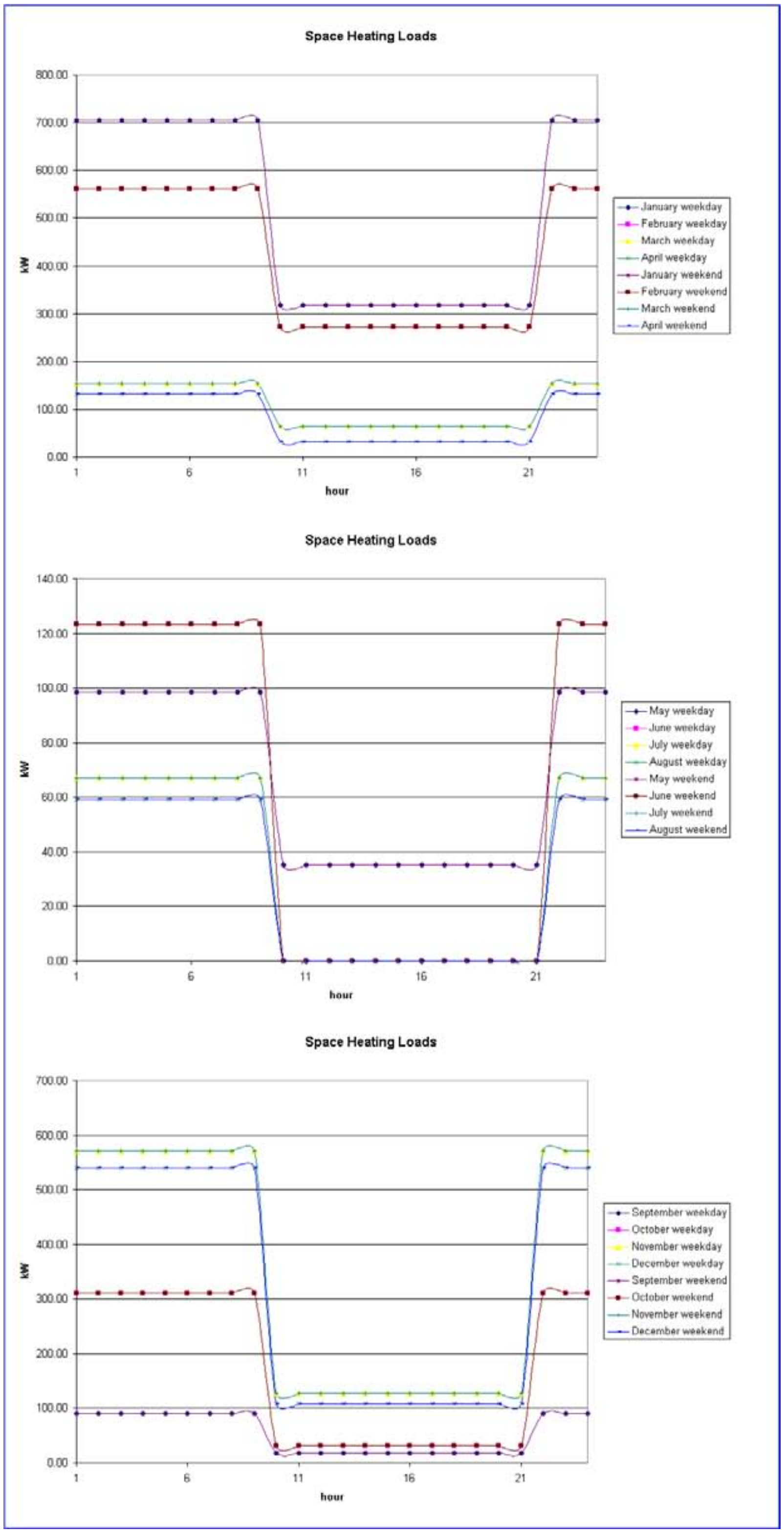
BD Biosciences Pharmingen: Electric Only Load



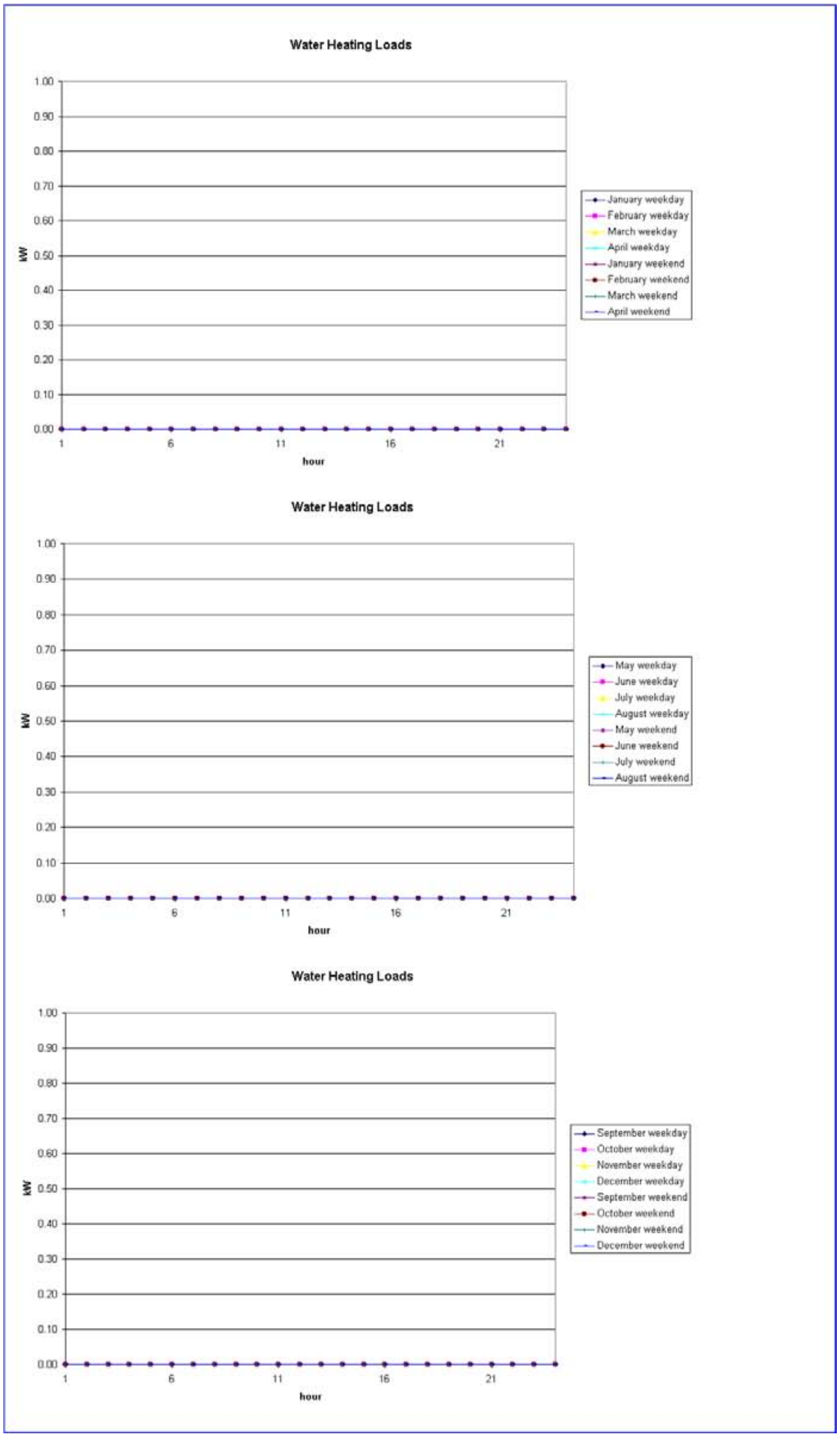
BD Biosciences Pharmingen: Cooling Load



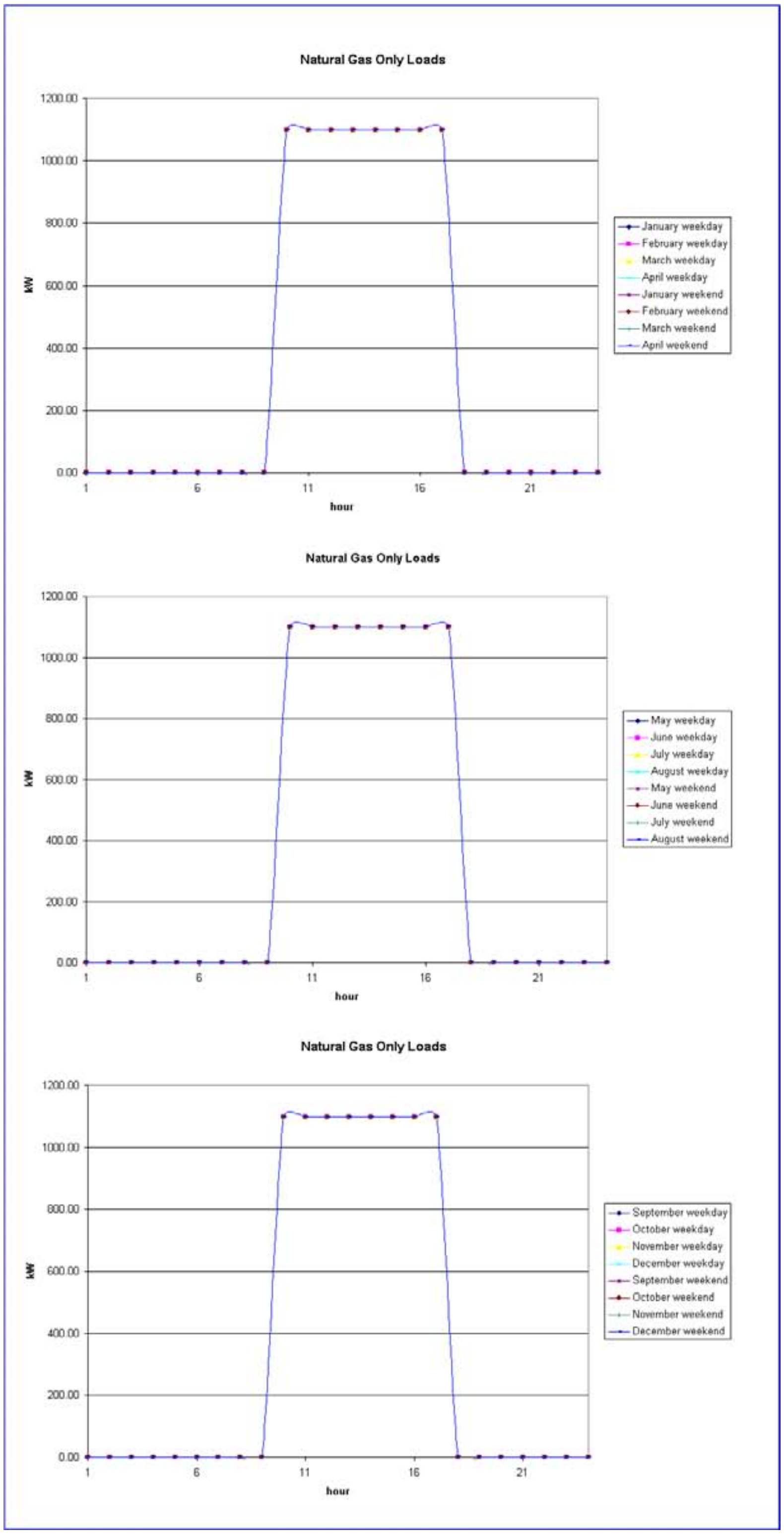
BD Biosciences Pharmingen: Space Heating Load



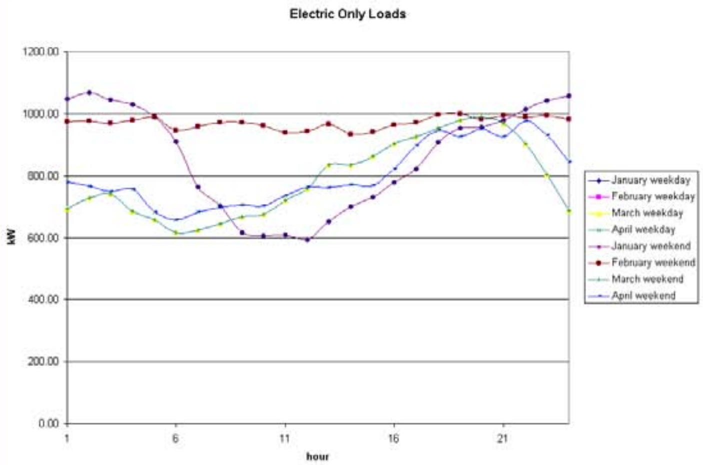
BD Biosciences Pharmingen: Water Heating Load

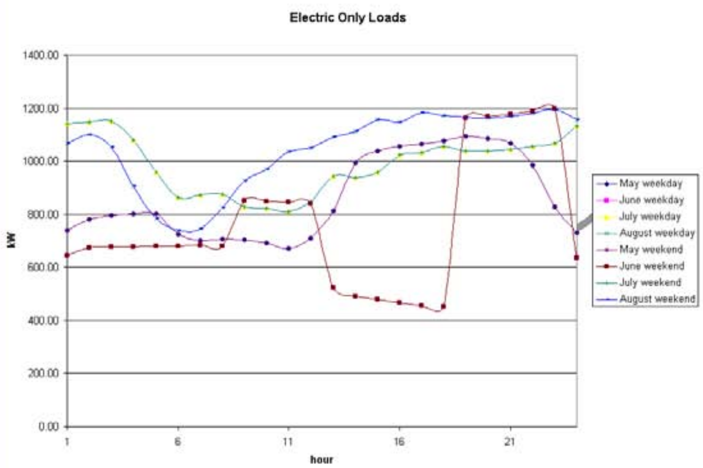


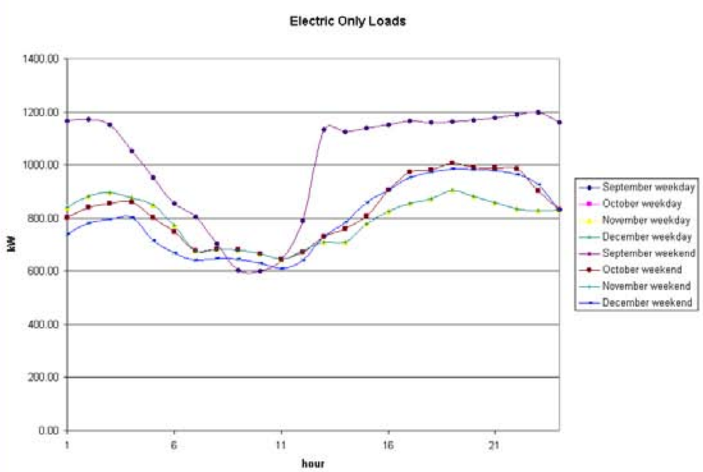
BD Biosciences Pharmingen: Natural Gas Only Load



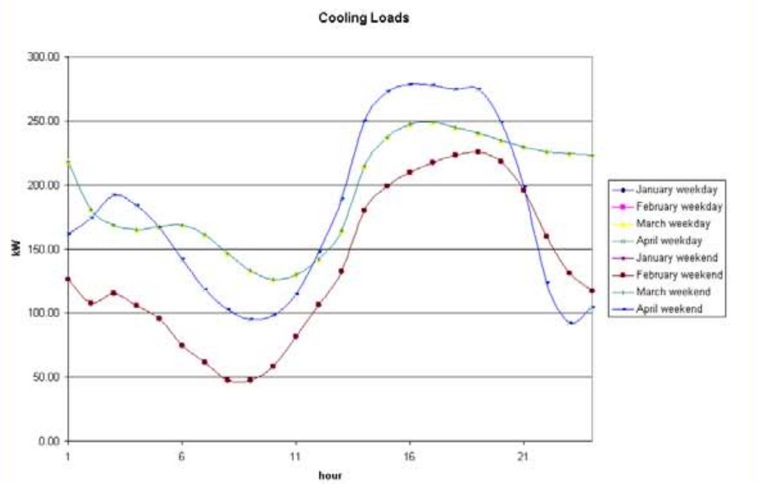
San Bernardino USPS: Electric Only Load

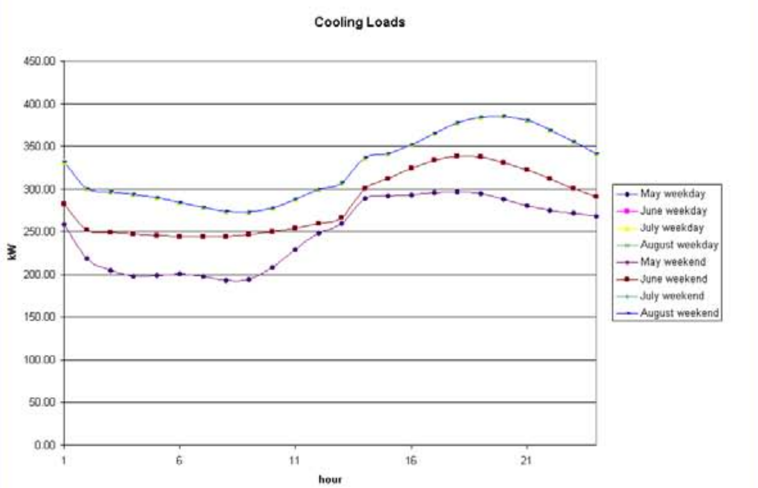


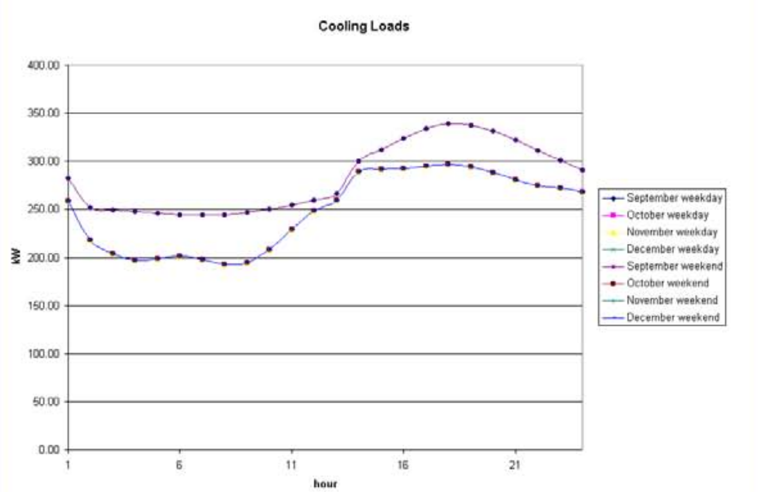




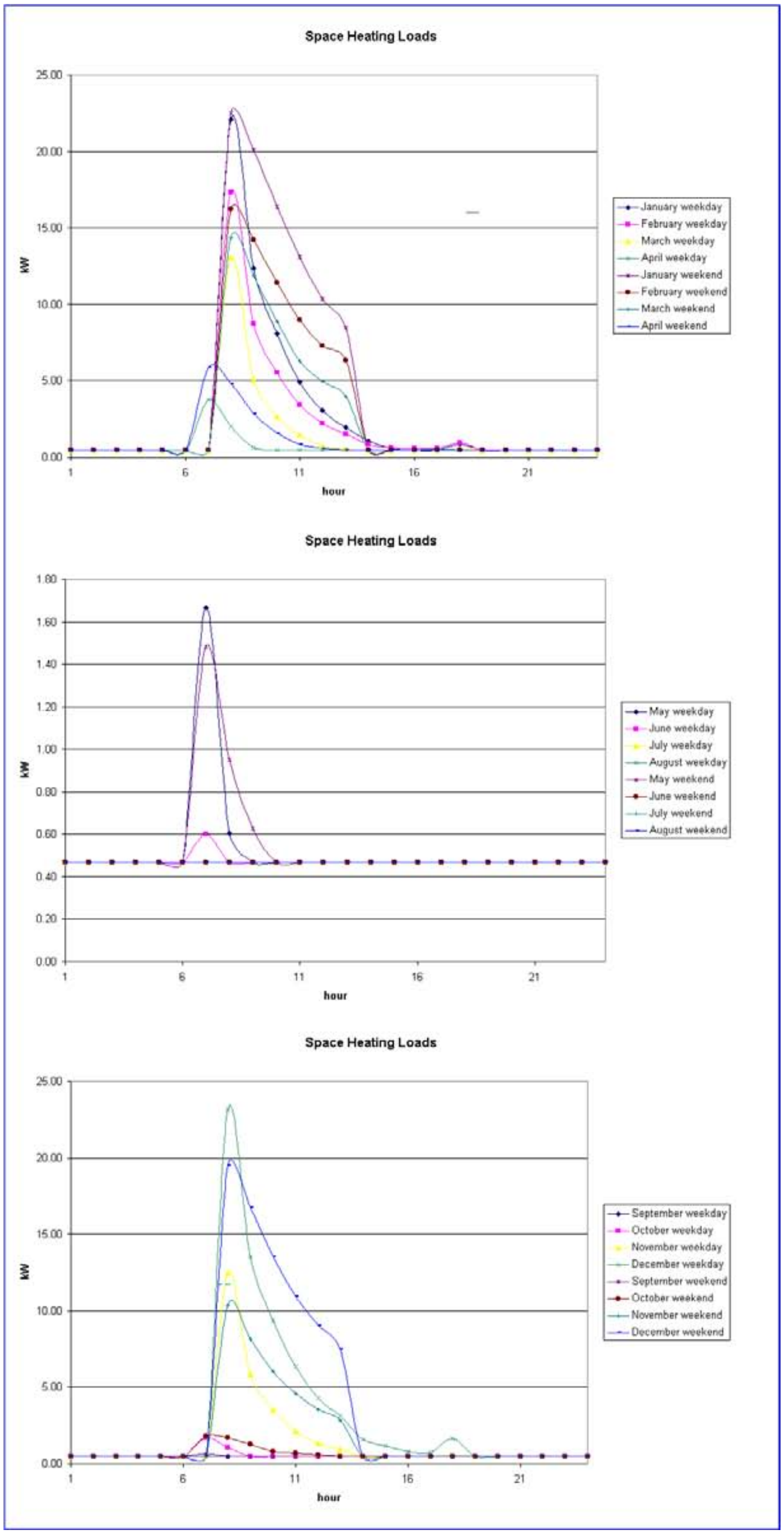
San Bernardino USPS: Cooling Load



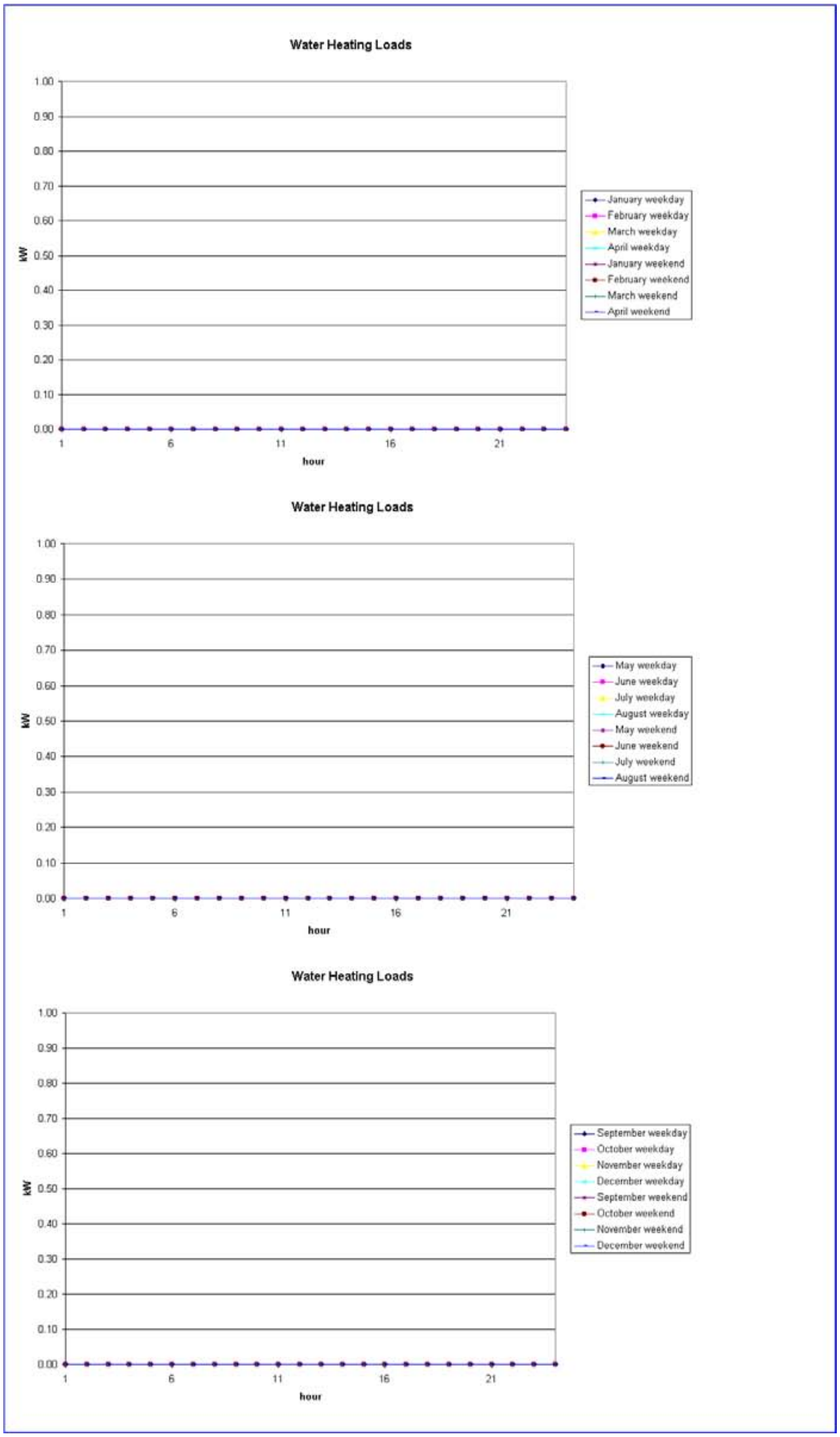




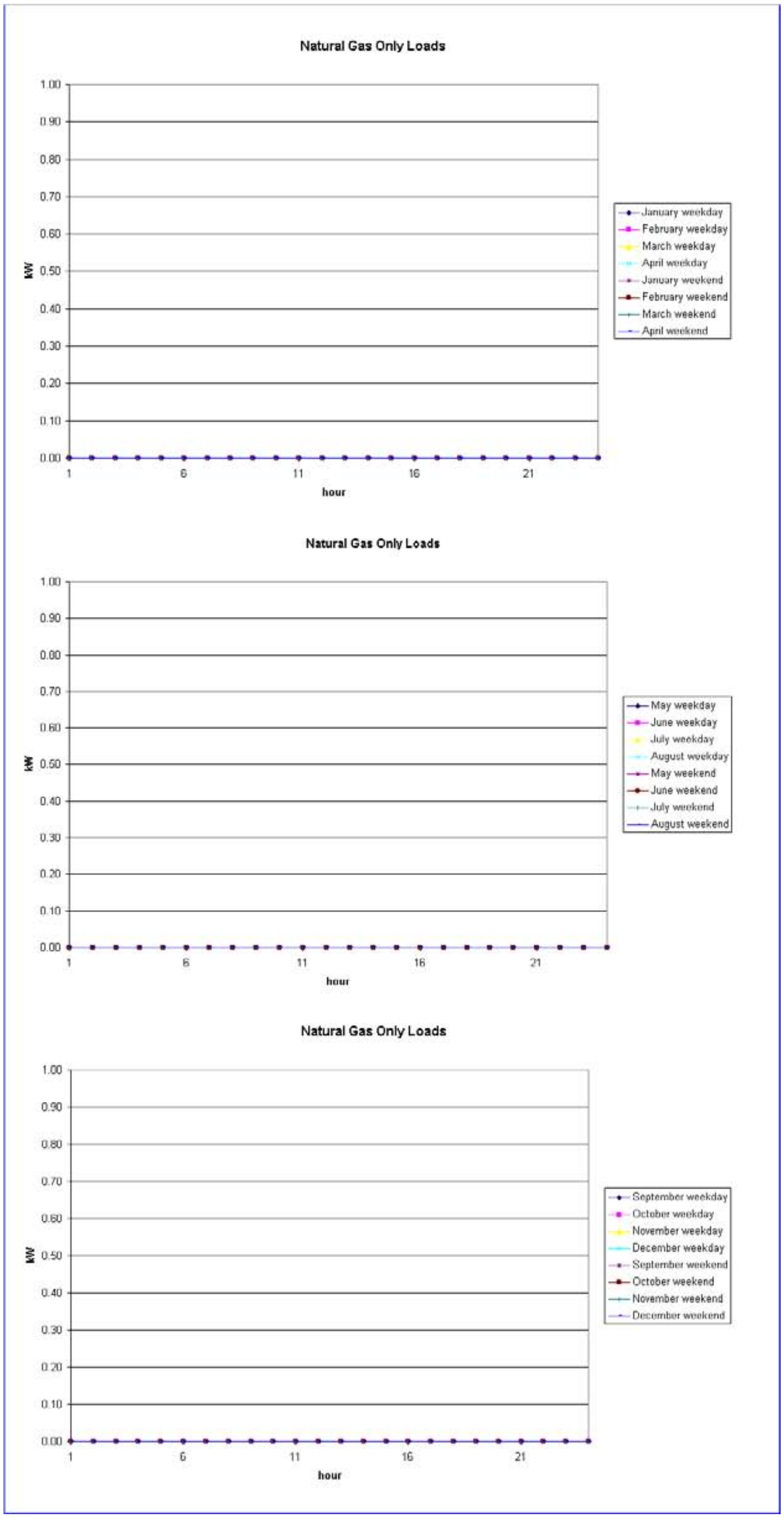
San Bernardino USPS: Space Heating Load



San Bernardino USPS: Water Heating Load



San Bernardino USPS: Natural Gas Only Load



Appendix L. Guaranteed Savings Building QF Calculation

SELF-GENERATION INCENTIVE PROGRAM Waste Heat Utilization Worksheet				
			References:	
CONVERSION FACTORS			California Public Utilities Code 218.5	18 CFR 292
1 kWh = 3,413 BTU NATURAL GAS CONVERSION FACTORS 1 CF= 1000 BTU 1 THERM=100,000 BTU 10 THERMS = MMBTU [BTU=British Thermal Unit] [kWh=kilowatt-hours] [CF=cubic foot] [MMBTU=one million BTU]			PUBLIC UTILITIES CODE SECTION 201-248 218.5. "Cogeneration" means the sequential use of energy for the production of electrical and useful thermal energy. The sequence can be thermal use followed by power production or the reverse, subject to the following standards: (a) At least 5 percent of the facility's total annual energy output shall be in the form of useful thermal energy. (b) Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output equals not less than 42.5 percent of any natural gas and oil energy input.	Title 18--Conservation of Power and Water Resources CHAPTER I--FEDERAL ENERGY REGULATORY COMMISSION, DEPARTMENT OF ENERGY PART 292--REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION
	Calculated Values			
1. Electrical Generator Operating Profile	INPUT / CALC VALUES	UNITS	Explanation	Substantiation (supporting analysis or documentation)
Rated Capacity (Gc) =	450	kW	Full load capacity of generator as specified by manufacturer at ISO conditions.	The value provided should be supported by Generating System specifications.
Generator Annual Operating Hours (T_1) =	8,736	hr/yr	Based on expected hours of operation & average load of the generator over a year period.	Estimated Hours of Operation must be known to get this value.
Est. Annual Electrical Generation (Ge) =	3,931,200	kWh/yr	(Ge)=(Gc)(T1)	
Est. Annual Electrical Generation (Ge_2) =	1.342E+10	Btu/yr	Conversion from kWh/yr to Btu/year (Ge2)=(Ge)(3413 kWh/Btu)	
Fuel Consumption Rate (Gfr) =	3,953,713	Btu/hr	Provided by manufacturer or calculated from rated capacity and generator efficiency or heat rate specifications. Based on lower heating value of fuel.	The value provided should be supported by Generating System spec sheet.
Annual Fuel Consumption (Gf) =	3.453E+10	Btu/yr	(Gf)=(Gfr) x (T1)	
2. Waste Heat Recovery (WHR) System Operating Profile				
Waste Heat Recovery Rate (Gw) =	2,025,000	Btu/hr	Recoverable heat as specified by manufacturer of generator or waste heat recovery unit at full load conditions. This is not total waste heat of the generator.	The value provided should be supported by Generating System specifications (if packaged unit), Waste Heat Recovery System specifications, or engineering analysis of recoverable waste heat.
WHR Annual Operating Hours (T_2) =	8,736	hr/yr	Based on expected hours of operation of waste heat recovery system over a year period. Should be equal or less than the hours of operation for the electrical generating system.	Estimated Hours of Operation for waste heat recovery must be analyzed to get this value.
Annual Heat Recovered (Ghr) =	1.769E+10	Btu/yr	(Ghr)=(Gw) x (T2)	
3. Thermal Load Characteristics				
Est. Average Thermal Load Rate (Qr) =	424,027	Btu/hr	The average annual thermal load rate. Industrial or commercial process (less heat contained in condensate return or make-up water); heating application (e.g., space heating, domestic hot water heating); space cooling application (e.g., thermal energy used by an absorption chiller).	The value provided should be supported by thermal load analysis. May be calculated from equipment ratings and/or historical fuel or electric bills or end-use equipment ratings and schedules.
Est. Annual Thermal Load Hours (T_3) =	8,736	hr/yr	The number of total thermal load hours per year. Probably not equal to hours of operation for electrical generating system.	Estimated hours of operation for process load, cooling load, and heating load should be analyzed to get this value.
Est. Annual Thermal Load (Qa) =	3.704E+09	Btu/yr	Qr x T3	
Utilized Waste Heat (Qu) =	3.704E+09	Btu/yr	Minimum of Qa or Ghr	
4. CA Public Utilities Code 218.5 Efficiency				
PU 218.5 (a) Efficiency (E_1) =	12%	%	(Qu)/(Ge2 + Ghr) Must be no less than 5.0%	
PU 218.5 Efficiency (E_2) =	44.1%	%	[(Ge2) + .5 x Qu] / Gf Must be no less than 42.5%	

Appendix M. Orchid Natural Gas to Propane Engine Conversion

The Orchid Resort uses four 200 kW diesel engines that have been converted to run on propane. The DER-CAM model had not yet considered such a technology. Data on converted diesel engines was not obtainable. In lieu of this, estimates were made as to the cost and performance of such engines relative to natural gas reciprocating engines because of the similarities in fuel type and engine compression ratios. It was assumed that The Orchid could choose from a variety of diesel-to-propane converted engines.

M.1 Turning actual natural gas engine data into generic engine data:

The natural gas engine data in DER-CAM was obtained from Katolight, a power generation equipment supplier[49]. Natural gas engines of the following capacities (in kW) were considered: 25, 55, 100, 215, and 500. It was notices that the price per kW for these engines (including engineering and installation costs) did not strictly follow the expected decline in cost with increasing capacity size (Figure A- 40). While this unexpected trend is represented in the DER-CAM natural gas engine data, it would be inaccurate to include this abnormal trend in the generic class of propane engines being created in DER-CAM.

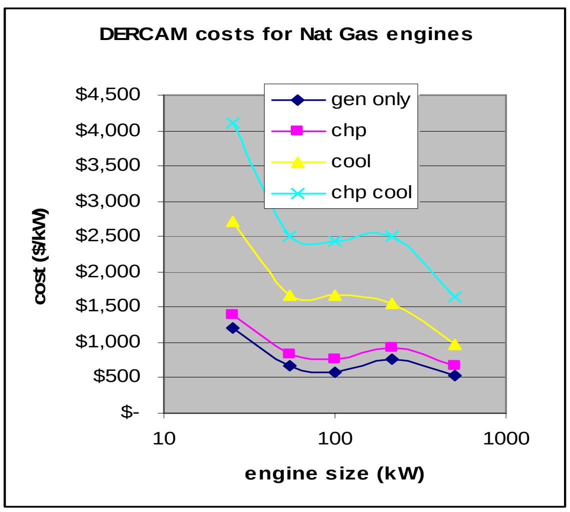


Figure A- 40: DER-CAM costs for natural gas engines

[49]Katolight, 100 Power Drive, Mankato, MN 56001
PH (507) 625-7973, FAX (507) 625-2968, PH 1-800-325-5450
http://www.katolight.com/

Costs for the 215 kW engines were reduce to create a more expected cost trend, as shown in Figure A- 41.

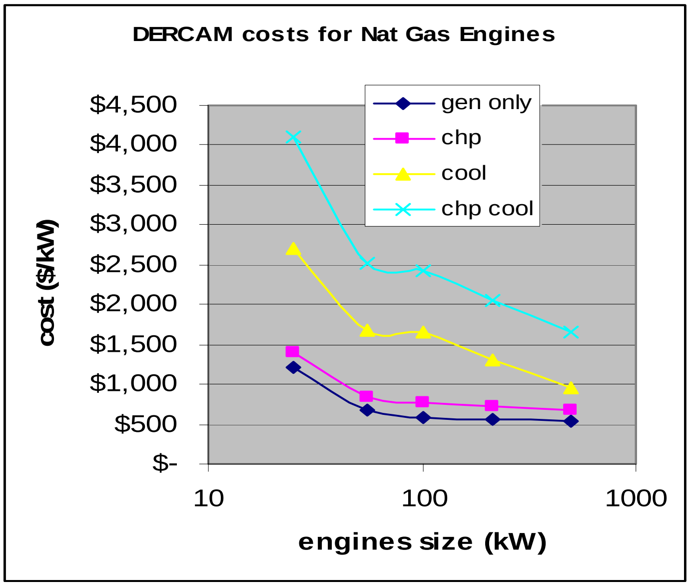


Figure A- 41: Modified costs for natural gas engines

The heat rates (inversely proportional to efficiency) for the Katolight engines also strayed from the expected trend. Heat rates for the 215 kW engines were reduced so that the generic class of engines followed the expected trend (decreasing heat rates with increasing engine capacity). The heat rates in DER-CAM and the modified heat rates are presented in Figure A- 42.

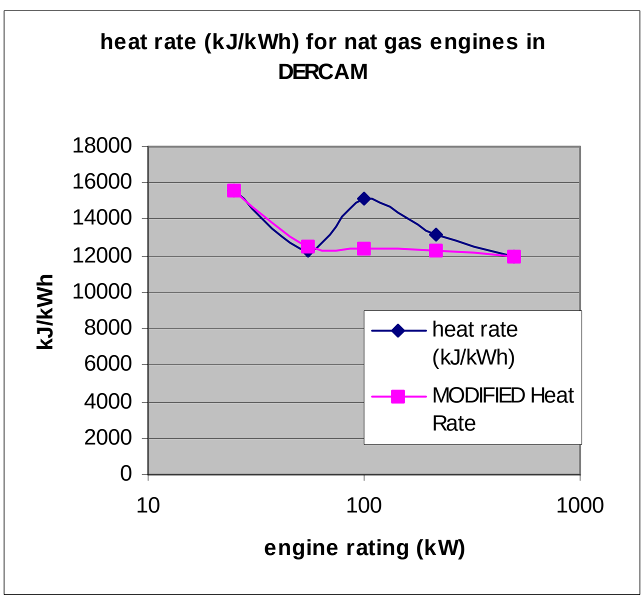


Figure A- 42: Heat rates in DER-CAM and modified heat rates for natural gas engines

The engine cost and engine performance data was next modified to match cost data provided by Hess and theoretical differences between natural gas and propane engine performance.

Engine size:

The propane engine sizes considered were the same as the natural gas engine options in DER-CAM. The one exception was the 215 kW natural gas engine: a 200 kW propane engine was considered instead (and assumed to have the same capital cost per kW and heat rate as the 215 kW engine). Thus, the following propane engine sizes (in kW) were considered: 25, 55, 100, 200, 500.

Engine Costs:

Engine and installation costs for the 200 kW engine with heat recovery were provided by Hess. From the data given, capital costs for the 200 kW engine and the 200 kW engine with heat recovery were known. Capital costs for the 200 kW engine with absorption cooling and the 200 kW engine with heat recovery and absorption cooling were estimated based on the information given.

For each type of technology package (engine only, engine with heat recovery (CHP), engine with absorption cooling, and engine with heat recovery and absorption cooling), the capital costs for the 200 kW unit in DER-CAM were scaled to obtain the capital costs quoted by Hess. These scaling factors were then used on the costs of all of the other engines of that particular technology package type.

Engine Performance:

Lacking heat rate data for propane engines from Hess or any engine manufacturers, a comparison of maximum theoretical efficiencies of natural gas and propane engines was done. For the air-standard Otto cycle (which approximates natural gas or propane reciprocating engines), the maximum theoretical efficiency, η, is given by

$$\eta = 1 - \frac{1}{r^{k-1}}$$

where “r” is the compression ratio and “k” is the specific heat ratio of the air and exhaust. The value of 1.4 was assumed for k, and compression ratios of 8 and 9.5 were assumed for natural gas and propane respectively. These values result in a maximum theoretical efficiency of 56% for natural gas engines and 59% for propane engines. It was assumed that this 5% increase in efficiency for propane engines was also applicable to actual engines. Thus, heat rates of natural gas engines were decreased by 5% to obtain heat rates for propane engines in DER-CAM.

Propane Engine Data in DER-CAM:

Table A- 47 below presents the technology data used in DER-CAM for propane engines at in consideration of The Orchid site.

Table A- 47: Propane engine data in DER-CAM

	capacity (kW)	**lifetime (years)**	**capital cost ($/kW)**	**Fixed operation and maintenance costs ($/kW)**	**Variable operation and maintenance costs ($/kWh)**	**heat rate (kJ/kWh)**
Engine only						
	25	12.5	3075	26.5	0.000033	14853
	55	12.5	1731	26.5	0.000033	11905
	100	12.5	1461	26.5	0.000033	11810
	200	12.5	1400	26.5	0.000033	11714
	500	12.5	1344	26.5	0.000033	11431
Engine with heat recovery (CHP)						
	25	12.5	3702	26.5	0.000033	14853
	55	12.5	2201	26.5	0.000033	11905
	100	12.5	2016	26.5	0.000033	11810
	200	12.5	1900	26.5	0.000033	11714
	500	12.5	1789	26.5	0.000033	11431
Engine with absorption cooling						
	25	12.5	4787	26.5	0.000033	14853
	55	12.5	2964	26.5	0.000033	11905
	100	12.5	2938	26.5	0.000033	11810
	200	12.5	2298	26.5	0.000033	11714
	500	12.5	1708	26.5	0.000033	11431
Engine with heat recovery and absorption cooling						
	25	12.5	5611	26.5	0.000033	14853
	55	12.5	3427	26.5	0.000033	11905
	100	12.5	3312	26.5	0.000033	11810
	200	12.5	2799	26.5	0.000033	11714
	500	12.5	2245	26.5	0.000033	11431

Appendix N. BD Biosciences Pharmingen Sample Data

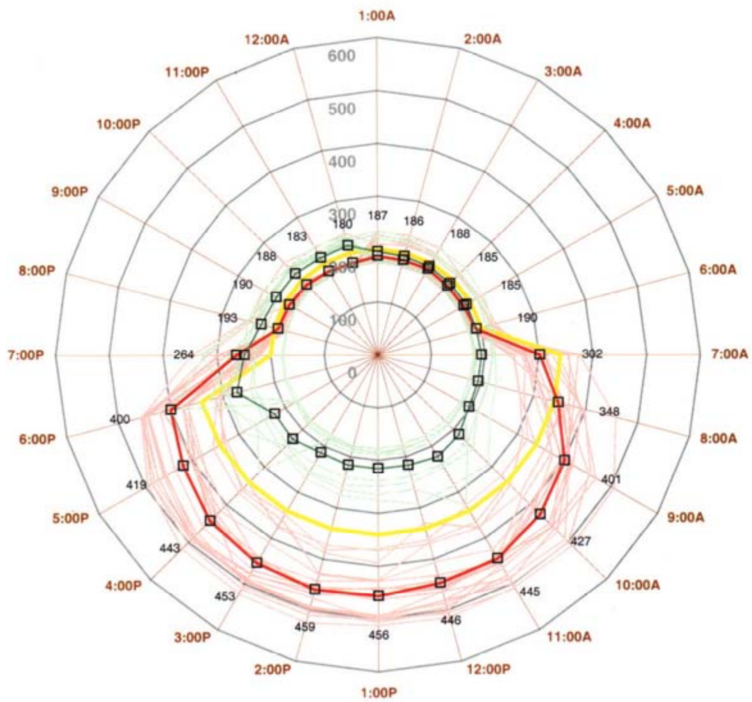


Figure A- 43: Sample Electricity 10995 Load Profile Provided by BD Biosciences Pharmingen for June 2001

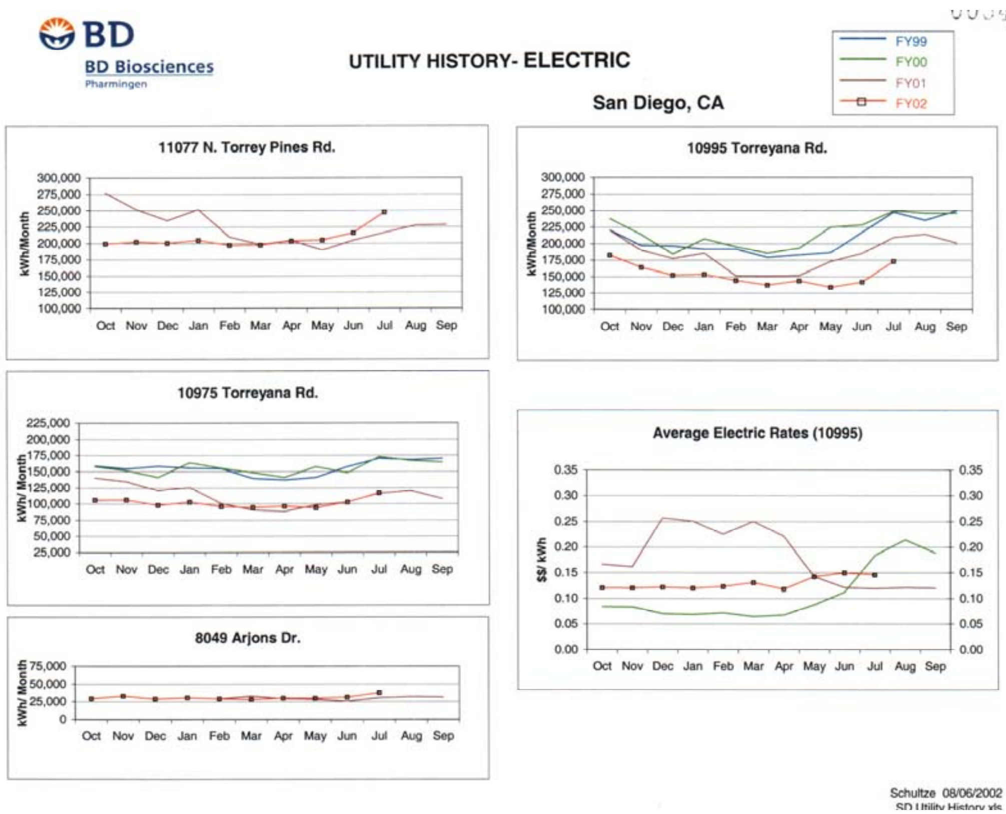
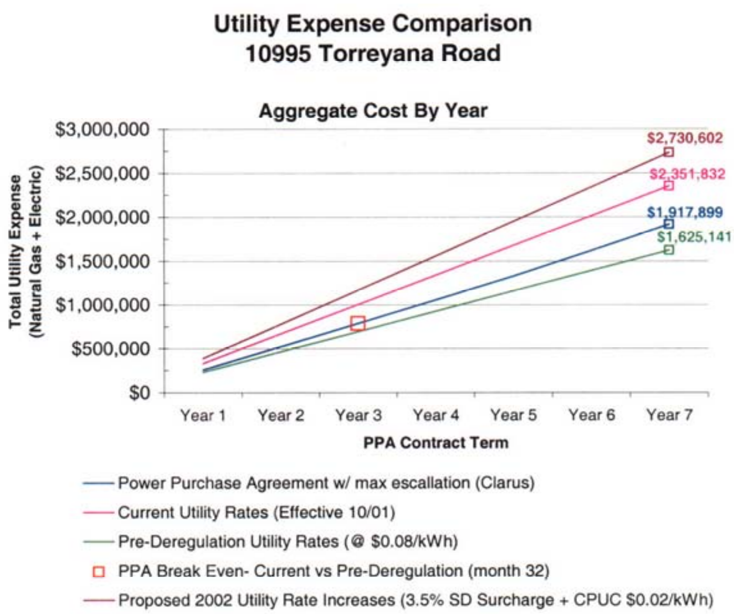


Figure A- 44: Electricity Bills for Several BD Biosciences Pharmingen Buildings (DER studies were done on the 10995 Torreyana Rd. Building).



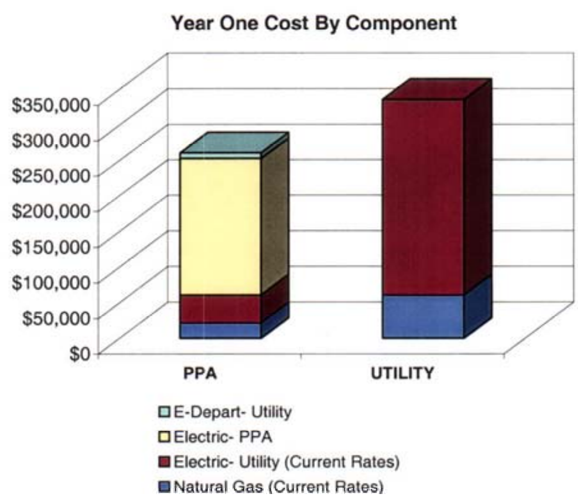


Figure A- 45: Savings Estimates Due to DER as Determined by BD Biosciences Pharmingen

Appendix O. SB USPS Sample Operation Log Sheet

Sample Chiller Log from San Bernardino USPS

Logs are kept daily for two 1.2 MW (350 ton) chillers (250 kWe at rated load) which supply cooling for the main building.

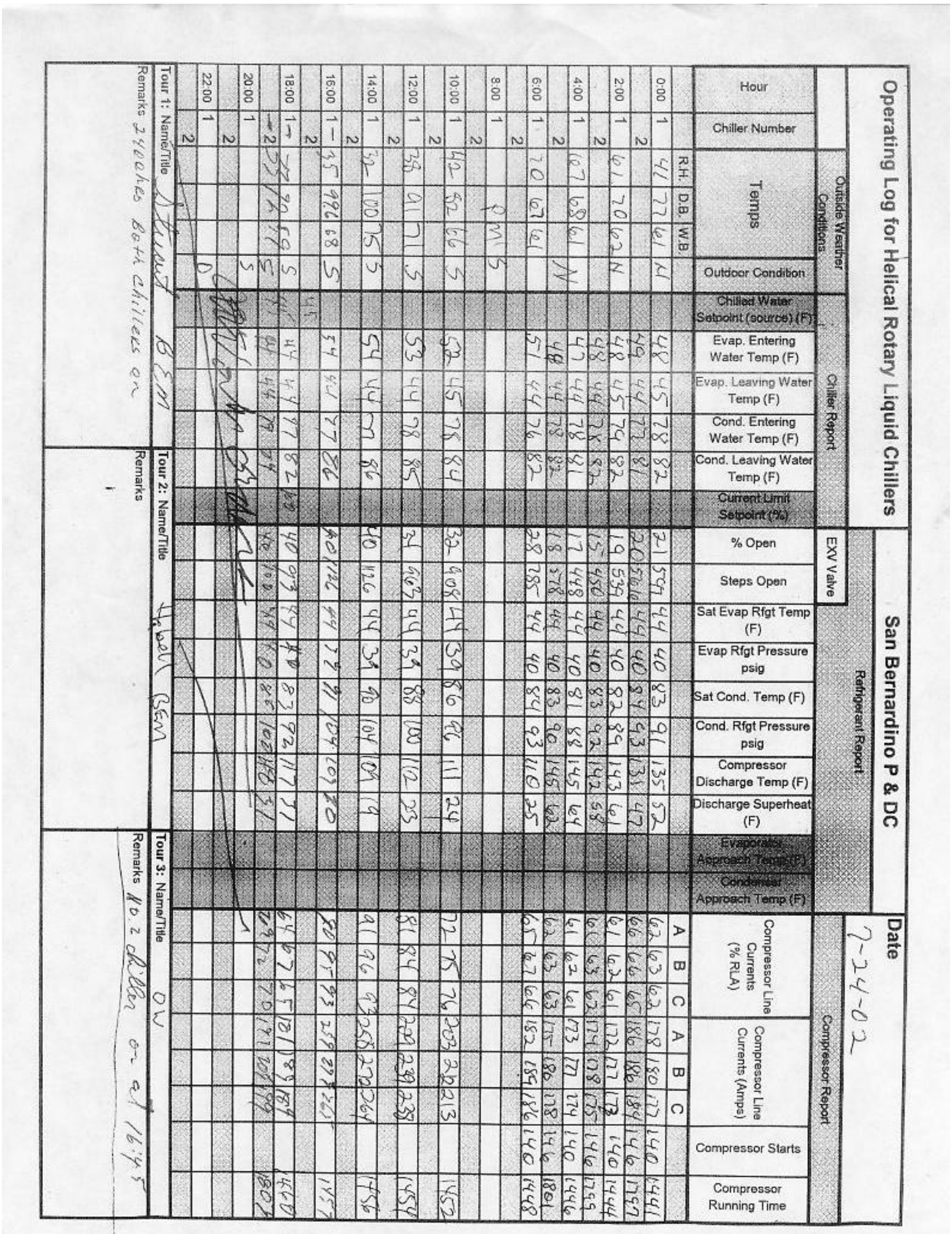


Figure A- 46: USPS Sample Operation Log Sheet

Appendix P. Technology Cost and Performance Data

Technology cost and performance data derived from information from manufactures.

Table A- 48: Diesel Engines Cost and Performance

		Capacity (kW)	Lifetime (years)	Capital Costs ($/kW)	Operation and Maintenance Fixed Costs ($/kW)	Operation and Maintenance Variable Costs ($/kWh)	Heat rate (kJ/kWh)
	site	all	all	all	all	all	all
15 kW Katolight diesel engine		15	12.5	2257	26.50	0.0000	18288
30 kW Katolight diesel engine		30	12.5	1290	26.50	0.0000	11887
60 kW Katolight diesel engine		60	12.5	864	26.50	0.0000	11201
105 kW Katolight diesel engine		105	12.5	690	26.50	0.0000	10581
200 kW Katolight diesel engine		200	12.5	514	26.50	0.0000	11041
350 kW Katolight diesel engine		350	12.5	414	26.50	0.0000	10032
500 kW Katolight diesel engine		500	12.5	386	26.50	0.0000	10314
8 kW Cummins diesel engine		8	12.5	627	26.50	0.0000	10458
20 kW Cummins diesel engine		20	12.5	1188	26.50	0.0000	12783
40 kW Cummins diesel engine		40	12.5	993	26.50	0.0000	11658
100 kW Cummins diesel engine		100	12.5	599	26.50	0.0000	10287
200 kW Cummins diesel engine		200	12.5	416	26.50	0.0000	9944
300 kW Cummins diesel engine		300	12.5	357	26.50	0.0000	10287
500 kW Cummins diesel engine		500	12.5	318	26.50	0.0000	9327

Table A- 49: Fuel Cells (base data derived from information from Guaranteed Savings Building data)

	with heat recovery	with absorption cooling		Capacity (kW)	Lifetime (years)	Capital Costs* ($/kW)	Capital Costs with CPUC rebate ($/kW)	Capital Costs with CPUC rebate and other incentives offered to GSB ($/kW)	Capital Costs with CPUC rebate for absorption cooling but not for non-cooling heat recovery ($/kW)	Operation and Maintenance Fixed Costs ($/kW)	Operation and Maintenance Variable Costs ($/kWh)	Heat rate (kJ/kWh)
			site	all	all	A&P, Orchid	Pharmingen	GSB	San Bernardino USPS	all	all	all
200 kW Phosphoric Acid Fuel Cell				200	12.5	4000	4500	3500	4500	0.00	0.0153	9480
200 kW Phosphoric Acid Fuel Cell	x			200	12.5	5359	3252	2652	5420	0.00	0.0153	9480
200 kW Phosphoric Acid Fuel Cell		x		200	12.5	6337	3840	3204	3840	0.00	0.0153	9480
200 kW Phosphoric Acid Fuel Cell	x	x		200	12.5	7256	4756	3754	4756	0.00	0.0153	9480

Table A- 50: Natural Gas Engines (base data derived from information obtained from San Bernardino USPS)

	with heat recovery	with absorption cooling		Capacity (kW)	Lifetime (years)	Capital Costs ($/kW)	Capital Costs with CPUC rebate ($/kW)	Capital Costs with CPUC rebate for absorption cooling but not for non-cooling heat recovery ($/kW)	Operation and Maintenance Fixed Costs ($/kW)	Operation and Maintenance Variable Costs ($/kWh)	Heat rate (kJ/kWh)
			site	all except Orchid	all except Orchid	all except Orchid	GSB, Pharmingen	San Bernardino USPS	all except Orchid	all except Orchid	all except Orchid
25 kW natural gas engine				25	13	1536	1536	1536	0.0000	0.0150	15596
55 kW natural gas engine				55	13	1008	1008	1008	0.0000	0.0150	12297
100 kW natural gas engine				100	13	902	902	902	0.0000	0.0150	15200
215 kW natural gas engine*				215	13	1097	1097	1097	0.0000	0.0150	13157
500 kW natural gas engine				500	13	856	856	856	0.0000	0.0150	12003
25 kW natural gas engine	x			25	13	1731	1212	1731	0.0000	0.0150	15596
55 kW natural gas engine	x			55	13	1162	813	1162	0.0000	0.0150	12297
100 kW natural gas engine	x			100	13	1092	764	1092	0.0000	0.0150	15200
215 kW natural gas engine*	x			215	13	1261	883	1261	0.0000	0.0150	13157
500 kW natural gas engine	x			500	13	1006	704	1006	0.0000	0.0150	12003
25 kW natural gas engine		x		25	13	3036	2036	2036	0.0000	0.0150	15596
55 kW natural gas engine		x		55	13	2005	1404	1404	0.0000	0.0150	12297
100 kW natural gas engine		x		100	13	1990	1393	1393	0.0000	0.0150	15200
215 kW natural gas engine*		x		215	13	1893	1325	1325	0.0000	0.0150	13157
500 kW natural gas engine		x		500	13	1294	906	906	0.0000	0.0150	12003
25 kW natural gas engine	x	x		25	13	4438	3438	3438	0.0000	0.0150	15596
55 kW natural gas engine	x	x		55	13	2838	1987	1987	0.0000	0.0150	12297
100 kW natural gas engine	x	x		100	13	2754	1928	1928	0.0000	0.0150	15200
215 kW natural gas engine*	x	x		215	13	2827	1979	1979	0.0000	0.0150	13157
500 kW natural gas engine	x	x		500	13	1972	1380	1380	0.0000	0.0150	12003

*The Pharmingen model contained a 150 kW engine instead of a 215 kW engine (to simulate the options Pharmingen actually had).
values for the 150 kW engine were interpolated from values for the 100 kW and 215 kW engines

Table A- 51: Microturbines (base data derived from data obtained from Andrew Wang of Capstone Microturbines)

	with heat recovery	with absorption cooling		Capacity (kW)	Lifetime (years)	Capital Costs* ($/kW)	Capital Costs with CPUC rebate ($/kW)	Capital Costs with CPUC rebate for absorption cooling but not for non-cooling heat recovery ($/kW)	Operation and Maintenance Fixed Costs ($/kW)	Operation and Maintenance Variable Costs ($/kWh)	Heat rate (kJ/kWh)
			Site	all	all	A&P, The Orchid	GSB, Pharmingen	San Bernardino USPS	all	all	all
30 kW microturbine				30	13	1862	1862	1862	0.0000	0.0150	14400
30 kW microturbine				30	13	1862	1862	1862	0.0000	0.0150	13800
60 kW microturbine				60	13	1290	1290	1290	0.0000	0.0150	12900
30 kW microturbine	x			30	13	2546	1782	2546	0.0000	0.0150	14400
30 kW microturbine	x			30	13	2546	1782	2546	0.0000	0.0150	13800
60 kW microturbine	x			60	13	2358	1610	2300	0.0000	0.0130	12900
30 kW microturbine		x		30	13	3352	2352	2352	0.0000	0.0150	14400
30 kW microturbine		x		30	13	3352	2352	2352	0.0000	0.0150	13800
60 kW microturbine		x		60	13	2322	1625	1625	0.0000	0.0150	12900
30 kW microturbine	x	x		30	13	5898	4898	4898	0.0000	0.0150	14400
30 kW microturbine	x	x		30	13	5898	4898	4898	0.0000	0.0150	13800
60 kW microturbine	x	x		60	13	3997	2997	2997	0.0000	0.0150	12900

Table A- 52: Photovoltaics (data obtained from RealGoods and PowerLight)

		Capacity (kW)	Lifetime (years)	Capital Costs ($/kW)	Capital Costs with CPUC rebate ($/kW)	Operation and Maintenance Fixed Costs ($/kW)	Operation and Maintenance Variable Costs ($/kWh)
	site	all	all	A&P, Orchid	GSB, Pharmingen, San Bernardino USPS	all	all
5 kW photovoltaic system		5	20	8650	4325	14	0
20 kW photovoltaic system		20	20	7450	3725	14	0
50 kW photovoltaic system		50	20	6675	3338	12	0
100 kW photovoltaic system		100	20	6675	3338	11	0

Table A- 53: Propane Engines (see Appendix M for the derivation of this data)

	with heat recovery	with absorption cooling		Capacity (kW)	Lifetime (years)	Capital Costs ($/kW)	Operation and Maintenance Fixed Costs ($/kW)	Operation and Maintenance Variable Costs ($/kWh)	Heat rate (kJ/kWh)
			site	Orchid	Orchid	Orchid	Orchid	Orchid	Orchid
25 kW propane engine				25	13	3075	27	0	14853
55 kW propane engine				55	13	1731	27	0	11905
100 kW propane engine				100	13	1461	27	0	11810
200 kW propane gas engine				200	13	1400	27	0	11714
500 kW propane gas engine				500	13	1344	27	0	11431
25 kW propane engine	x			25	13	3702	27	0	14853
55 kW propane engine	x			55	13	2201	27	0	11905
100 kW propane engine	x			100	13	2016	27	0	11810
200 kW propane gas engine	x			200	13	1900	27	0	11714
500 kW propane gas engine	x			500	13	1789	27	0	11431
25 kW propane engine		x		25	13	4787	27	0	14853
55 kW propane engine		x		55	13	2964	27	0	11905
100 kW propane engine		x		100	13	2938	27	0	11810
200 kW propane gas engine		x		200	13	2298	27	0	11714
500 kW propane gas engine		x		500	13	1708	27	0	11431
25 kW propane engine	x	x		25	13	5611	27	0	14853
55 kW propane engine	x	x		55	13	3427	27	0	11905
100 kW propane engine	x	x		100	13	3312	27	0	11810
200 kW propane gas engine	x	x		200	13	2799	27	0	11714
500 kW propane gas engine	x	x		500	13	2245	27	0	11431

Appendix Q. Capstone Turbine Costs and Performance

Table A- 54: Capstone Turbine Costs and Performance

From Andrew Wang at Capstone

	1 x 30 kW		2 x 30 kW		1 x 60 kW		2 x 60 kW	
	low	high	low	high	low	high	low	high
kWe	30	30	60	60	60	60	120	120
Microturbine	$ 34,340	$ 34,340	$ 68,680	$ 68,680	$ 49,430	$ 49,430	$ 98,860	$ 98,860
Heat recovery unit	$ 10,000	$ 10,000	$ 12,000	$ 12,000	$ 12,600	$ 12,600	$ 18,000	$ 18,000
Gas Compression	$ -	$ -	$ -	$ -	$ 6,975	$ 6,975	$ 13,950	$ 13,950
Fuel kit	$ 525	$ 525	$ 525	$ 525	$ -	$ -	$ -	$ -
total capital	*$ 44,865*	*$ 44,865*	*$ 81,205*	*$ 81,205*	*$ 69,005*	*$ 69,005*	*$130,810*	*$130,810*
USD/kWe	*$ 1,496*	*$ 1,496*	*$ 1,353*	*$ 1,353*	*$ 1,150*	*$ 1,150*	*$ 1,090*	*$ 1,090*
Site work	$ 4,000	$ 7,000	$ 6,000	$ 10,500	$ 4,000	$ 7,000	$ 6,000	$ 10,500
Installation	$ 15,000	$ 25,000	$ 22,500	$ 37,500	$ 15,000	$ 25,000	$ 22,500	$ 37,500
Engineering/permits	$ 4,500	$ 7,500	$ 6,750	$ 11,250	$ 4,500	$ 7,500	$ 6,750	$ 11,250
total labor	*$ 23,500*	*$ 39,500*	*$ 35,250*	*$ 59,250*	*$ 23,500*	*$ 39,500*	*$ 35,250*	*$ 59,250*
USD/kWe	*$ 783*	*$ 1,317*	*$ 588*	*$ 988*	*$ 392*	*$ 658*	*$ 294*	*$ 494*
TOTAL, USD	*$ 68,365*	*$ 84,365*	*$ 116,455*	*$ 140,455*	*$ 92,505*	*$108,505*	*$166,060*	*$190,060*
USD/kWe	***$ 2,279***	***$ 2,812***	***$ 1,941***	***$ 2,341***	***$ 1,542***	***$ 1,808***	***$ 1,384***	***$ 1,584***
	$ 2,546		$ 2,141		$ 1,675		$ 1,484	

Table A- 55: Sample Output Files Excerpts from DER-CAM Runs

Goal Function Cost	233885.7	Total yearly energy costs ($)		
Dist. Energy Purchases (peak) ($)	0			
Dist. Energy Purchases (Mid) ($)	0			
Dist. Energy Purchases (Off) ($)	1184.164			
Power PX Purchases ($)				
Costs for NON DER Gas Purchases ($)	48201.22			
Dist. Power Purchases ($)	522			
Dist. Power Coincident Charge ($)	0			
Self Gen. Investment costs ($)	44365.52			
Self Gen. Variable costs ($)	139612.8			
Total Carbon Emissions (kg)	436395.7			
Carbon Emissions Costs ($)	0			
Energy Sales ($)	0			
consumed energy (kWh)	4461457			
average price ($/kWh)	0.0524			
installed capacity (kW)	500	CHPGA-K-500	1	number of units selected
Annual Electricity-Only Load Demand (kWh)		technology selected: a 500 kW natural gas engine with heat recovery (CHP)		
1722359.109				
Annual Electricity Generation On-Site to Meet Electricity-Only Load (kWh)				
1639450.679				
Annual Electricity Purchase to Meet Electricity-Only Load (kWh)				
82908.4302				
Annual Cooling Load Demand (kWh)				
189634.0093				
Annual Electricity Generation On-Site to Meet Cooling Load (kWh)				
183009.02				
Annual Electricity Purchase to Meet Cooling Load (kWh)				
6624.9894				
Annual Cooling Load which is met by Absorption Chiller (kWh)				
0				
Annual Cooling Load which is met by Natural Gas (kWh)				
0				
Total Annual Electricity Generation On Site (kWh)				
1822459.699				
, sum of all heating loads (kWh)				
2549463.394				
Annual Natural Gas-Only Heating Load (kWh)				
1701005.85				
Annual Natural Gas-Only Load which is met by Natural Gas (kWh)				
1701005.85				

Annual Space Heating Load (kWh)				
848457.5435				
Annual Space Heating Load which is met by Natural Gas (kWh)				
320153.5678				
Annual Load of Space Heating which is met by CHP (kWh)				
528303.9757				
Annual Water Heating Load (kWh)				
0				
Annual Water Heating Load which is met by Natural Gas (kWh)				
0				
Annual Load of Water Heating which is met by CHP (kWh)				
0				
Annual DER Natural Gas Purchases (kWh)				
6076384.379				
Annual NON DER Natural Gas Purchases (kWh)				
2526449.272				
Annual Net Gas Purchase (kWh)				
8602833.651				
Annual Gas Bill ($)				
160477.0916				
Annual Net Diesel Purchase (kWh)				
0				
Annual Diesel Bill ($)				
0				
Annual On-site Carbon Emissions (kg)				
424756.3087				
Annual On-site Carbon Emissions from DER (kg)				
300015.4023				
Annual On-site Carbon Emissions from NG (kg)				
124740.9064				
Annual Off-site Carbon Emissions (kg)				
11639.3445				
Proportion of Carbon Emissions Produced On-site				
0.9733				
Proportion of Carbon Emissions from DER				
0.6875				
Proportion of Carbon Emissions from NG				
0.2858				

Proportion of Carbon Emissions Produced Off-site				
0.0267				
Energy Efficiency of System				
0.5012				
End-Use Energy Efficiencies				
electricity-only	0.2999			
cooling	0.2999			
space-heating	2.1201			
water-heating	UNDF			
naturalgas-only	0.8			
Fraction of Electricity-Only End-Use Met by On-Site Generation				
0.9519				
Fraction of Electricity-Only End-Use Met by Off-Site Generation				
0.0481				
Fraction of Cooling End-Use Met by On-Site Generation				
0.9651				
Fraction of Cooling End-Use Met by Absorption Chiller				
0				
Fraction of Cooling End-Use Met by Off-Site Generation				
0.0349				
Fraction of Cooling End-Use Met by Natural Gas				
0				
Fraction of Space-Heating End-Use Met by CHP				
0.6227				
Fraction of Space-Heating End-Use Met by Natural Gas				
0.3773				
Fraction of Water-Heating End-Use Met by CHP				
UNDF				
Fraction of Water-Heating End-Use Met by Natural Gas				
UNDF				
Fraction of Natural Gas-Only End-Use Met by Natural Gas				
1				
Annual On-Site Production of Energy (kWh)				
2350763.674				
Annual Total Energy Demand (kWh)				
4461456.512				
Fraction of Energy Demand Met On-Site				
0.5269				

Appendix R. Instructions for formatting load data output from DOE-2

Generate DOE-2 output using the DOE-2 generator spreadsheet after setting parameter values. Note: DOE-2 must be in a primary folder on the C drive in order to operate properly.
Path is C:DOE-2\from CD\LShape_models
Look for Excel spreadsheet of the type of facility you wish to model and open it. Fill in known parameters, choose any desired output profiles, and push run button.

This generates two files in the folder C:DOE-2\LshapeGenerator\Output\<NameofSpecificType>. The .hly file is the hourly load data (raw data) and the .out file is the output file with descriptions of what data was generated and some summary statistics. Look at the spreadsheet to determine what types of data was requested (the numbers in the cells) and then look for those numbers as column headings in the .out file to find a short title for the data and the units it is in.

Open the .hly file using Excel.
Use delimited, space delimiter to format data into columns.
Save as, change name to .xls in quotes, and file type to Excel workbook.

Make sure you save spreadsheet before running a macro since they can delete data from the spreadsheet if an error occurs.

Open “Small_Office…” spreadsheet in San Bernardino folder. Enable macros when opening.

Run the DataSetup Macro: This shifts data to where you want it to be for the load shape computations and formatting.

Open “LgOff12_…v4” spreadsheet in Guarantee Savings building folder. Run the DateMaker macro. Make sure the year is what you want. Otherwise copy and paste code into spreadsheet and change the year in the code.

Open “LgOff12….v5Max.
The version v5Max contains code in AveragerMan2 that computes the peak hourly load for each month and day type and the maximum average load. This is useful for computing how much DOE-2 loads lose of the peak in DER-CAM and hence how much of the demand charge is reduced.

Copy and past column and row titles from LgOff spreadsheet.

Find column data labels from the DOE-2 output file (.out file is the other file created when DOE-2 runs)

NOTE: The units for the data are written above the column with the data number label (the data number label is the number used in the load shape generator to request specific output data).

Convert any output from IP to SI units. Even if you request SI in the DOE-2 output some units come out as BTUs. To convert a column, place the multiplier factor in a cell. Click on that cell and copy, click on the top of the column to convert, press ctrl and shift simultaneously then push the down arrow to highlight the whole column. Select paste, special then click multiply. The whole column should be multiplied by the scalar and converted.

Fill in the columns for each of the 5 types of loads: Electric only, Cooling, Space Heating, Water Heating, and Natural Gas only. This should be done by referencing the appropriate data in the DOE-2 output columns for each day and hour of the year. Add data columns together if two types of data go into a category of load.

Run the AveragerMan macro. This macro calculates the average load for each hour of each month for weekdays and weekends for each of the 5 types of loads. It takes about 10 minutes for the laptop to run this macro.

To move to the end of a long column hold the control key and click the down arrow.

Appendix S. Sample Cover Letters to Individual Test Sites

This appendix shows sample cover letters that were sent out to each of the individual test site contacts. The first letter in Figure A- 47 is a sample of the letter sent after preliminary phone contact with prospective test sites in order to describe in detail the type of information sought for the report. The second letter, in Figure A- 48, and a tailored report copy for each test site was sent to the following 10 individuals:

- Bob Schultze (BD Biosciences Pharmingen)
- Wendy Gumb (BD Biosciences Pharmingen)
- Jennifer Collins (The Orchid)
- Orville Thompson (The Orchid)
- Steve Szychulda (San Bernardino USPS)
- Hugh Henderson (A&P)
- Jack O. Payne (Guarantee Savings Bank)
- Sam Logan (Guarantee Savings Bank)
- Ann Heiniger (Guarantee Savings Bank)
- Ron Allison (Guarantee Savings Bank)

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http://eetd.lbl.gov/ea/emp/ email: OCBailey@lbl.gov

Operated for the United States Department of Energy

1 July 2002

Ron Allison
Zahra Properties
Fresno, California

Dear Mr. Allison,

The US DOE is sponsoring the Energy Analysis Group at Ernest Orlando Lawrence Berkeley National Laboratory to research the adoption of small on-site generation technologies. As part of this work, we are developing a computer model designed to recommend specific Distributed Energy Resource (DER) technologies for on-site generation, based on customized site requirements and constraints.

We are considering including Zahra Properties' work in a case-study analysis report by Berkeley Lab for the DOE, and are seeking your permission to do so. Part of this report will involve validating our model based on experiences in the field. Since your firm has experience analyzing DER technologies for the Guarantee Savings Building, we would like to request your assistance with our validation process. We recognize the time constraints and rules of confidentiality you may be under, and will make every effort to work within both.

By allowing us to gather information on your implementation decision and the factors influencing it, you will be assisting our team at Berkeley Lab to guide research and policy aimed at promoting the implementation of distributed energy technologies across the nation, speeding our move to a system of lower-impact, distributed energy generation. Your participation in our study will allow you to expand the beneficial impacts of your efforts and learning to a larger audience, and directly contribute to the DOE Office of Distributed Energy Resource's stated goal of meeting 20% of the nation's generating capacity additions with DER by 2010.

We would like to obtain the electricity and thermal load data, along with the engineering and financial analysis used to select the DG/CHP technologies. We are interested in both how and why you came to your DER technology implementation decision, as well as technical data such as energy load profiles, tariff structures, and constraints to which your organization is subject. To enhance this case study report we would like to conduct short interviews with at least two people from your organization: a person involved in influencing the technology choice from a business perspective and an engineer responsible for the technology implementation. To minimize interruption to your organization's work schedules, we will conduct as much of the background interviewing as possible via e-mail and phone, but a brief visit to your site will most likely be necessary.

We will honor any requests to keep specific information confidential. It is important for us to reference your company's name and type of business, the developer you employed, Logan Energy, and to provide a clear description of the equipment you have installed. Your organization will have a chance to review the report before it is disseminated to the public.

We look forward to speaking with you about your participation in the DOE case study report and validation of our DER decision model.

Thank you for your consideration. Your assistance will be greatly appreciated.

Sincerely,

Owen Bailey
Lawrence Berkeley National Lab
Environmental Energy Technologies Division
OCBailey@lbl.gov

Figure A- 47: Sample Introductory Letter Sent to Prospective Test Sites

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY
Environmental Energy Technologies Division

MS 90-4000 tel:+1 (510) 495 2604
1 Cyclotron Rd fax: +1 (510) 486 6996
BERKELEY CA 94720-0001 mobile: +1 (510) 708 2952
http://eetd.lbl.gov/ea/emp/ email: OCBailey@lbl.gov

Operated for the United States Department of Energy

To: Ms. Ann Heiniger

From: Chris Marnay
Berkeley Lab

Date: 8 November 2002

Re: Drafts of Berkeley Lab study of on-site generation adoption

Thank you very much for participating in our study last summer. Your information and cooperation have been critical to our research.

When you spoke with Owen Bailey and provided your data to him, we offered to allow you to review our report before it is released.

Attached is the section of our report that covers your site. We would like you to read through and verify that there is no information included there that you would rather we not publish. Please note that some information pertaining to other sites has been removed pending their review. As a result, some information in text, tables, and figures, regarding other sites in the analysis has been removed from this version of the report.

We will soon be compiling the full report. Please respond to Owen Bailey by the end of the month if you have any reservations about release of material in the draft. If he does not hear from you by November 31, 2002, we will assume that release has been approved.

Please note the email contact for Owen Bailey: OCBailey@lbl.gov

Thank you again for your considerable contribution of time and effort to our work. We hope our work will help disseminate information about the interesting on-site generation project that you are developing.

Figure A- 48: Sample Cover Letter Sent to Individual Test Sites

Appendix T. Errata: Inaccurate Electrical Efficiency Data

The natural gas engine data used for analyses in this report was collected by the LBL DER team based on specification sheets for a sampling of natural gas engines on the market.

It was later learned that the natural gas engines considered and purchased by Clarus Energy from Coastintelligen were significantly more efficient that those represented in DER-CAM.

Although discovered after the writing of this report, a separate report looks at the BD Biosciences Pharmingen project in more detail and includes DER-CAM results using modified natural gas engine electrical efficiency data to match that of engines offered by Coastintelligen. That report is titled *A Business Case For On-Site Generation: The BD Biosciences Pharmingen Project*.

Table A- 56 below compares the electrical efficiency values used in this report's DER-CAM runs to those reported by Coastintelligen and to the updated values used in *A Business Case For On-Site Generation*. The DER-CAM technology database includes natural gas engines with electrical capacities of 25, 55, 150, 215, and 500 kW. Coastintelligen offers natural gas engines with electrical capacities of 55, 80, 150, 250, and 365 kW.

Table A- 56: Comparison of Electrical Efficiencies of Natural Gas Engines from DER-CAM and Coastintelligen

Natural Gas Engine Electrical Capacity (kW)	Electrical Efficiency Used in DER-CAM (Case Studies Report)	Electrical Efficiency Specified by Coastintelligen	Updated Electrical Efficiency Used in DER-CAM (Business Case Report)
25	23.1%		30.0%
55	29.3%	30.0%	30.0%
80		31.0%	
150	23.7%	31.8%	31.8%
215	27.4%		33.0%
250		33.6%	
365		33.6%	
500	30.0%		33.6%

Table A- 57 below compares the case results from this report to the more accurate results as reported in *A Business Case For On-Site Generation*. Although annual energy costs decrease with the improved efficiency of natural gas engines, it is significant to note that technology selections did not change for any of the cases.

Table A- 57: Case Studies Results and Updated Results (in parentheses)

CASE	Technologies Selected	Annual Energy Cost (updated)	Percentage of Case 1 Cost (updated)	Annual Savings Over Base Case (updated)	Electricity Purchases (updated)	Natural Gas Purchases - including purchase for engines (updated)	Self Generation Costs - capital costs of equipment plus maintenance (updated)
1: No Invest		$333,733 ($333,733)	100% (100%)		$273,085 ($273,085)	$60,648 ($60,648)	$0 ($0)
Pharmingen's Estimate of Annual Energy Costs without DER		$315,000			$260,000	$55,000	$0
2: Unlimited Invest	1x 500 kW nat. gas engine with CHP	$233,886 ($219,614)	70% (66%)	$99,847 ($114,119)	$1,707 ($522)	$160,477 ($147,171)	$71,702 ($71,921)
3: Unlimited Invest in nat. gas engines	1x 500 kW nat. gas engine with CHP	$233,886 ($219,614)	70% (66%)	$99,847 ($114,119)	$1,707 ($522)	$160,477 ($147,171)	$71,702 ($71,921)
4: Forced minimum investment in 150 kW nat. gas engines (gen. only)	3x 150 kW nat. gas engine	$275,710 ($246,661)	83% (74%)	$58,023 ($87,073)	$64,481 ($5,012)	$144,043 ($163,762)	$67,186 ($77,886)
4: Forced minimum investment in 150 kW nat. gas engines with CHP	3x 150 kW nat gas engine with CHP	$258,495 ($223,832)	77% (67%)	$75,238 ($109,901)	$32,842 ($1,462)	$160,516 ($151,657)	$65,137 ($70,714)
4: Forced minimum investment in 150 kW nat. gas engines (gen. Only) and 150 kW nat. gas engines with CHP	1x 150 kW nat gas engine, 2x 150 nat. gas engine with CHP	$261,109 ($226,447)	78% (68%)	$72,624 ($107,287)	$32,842 ($1,462)	$160,516 ($151,657)	$67,746 ($73,323)
5: Forced duplication of site decision: 2x 150 kW nat. gas engines with CHP	2x 150 kW nat gas engines with CHP	$266,162 ($233,996)	70% (80%)	$67,571 (99,737)	$66,614 ($35,234)	$150,735 ($144,374)	$48,813 ($54,388)
Pharmingen/Clarus Energy DER System	2x 150 kW nat gas engines with CHP	$245,000	Pharmingen estimate of annual savings: $70,000. This is 78% of their no-invest costs		$ 47,500	Estimated together by Pharmingen: $197,500	

Table A- 58 highlights results from the sensitivities done for this report and those in the revised DER-CAM runs.

Table A- 58: Comparison of Sensitivity Results

		Case Studies Report	Updated Results
Spark Spread Senstitivity	Installed Capacity at 50% Reduced Natural Gas Prices 50% (kW)	500	500
	Installed Capacity at 100% Increased Natural Gas Prices (kW)	500	500
Standby Sensitivity	Standby Charge Above Which Installed Capacity Begins to be Affected ($/kW)	$4	2
	Standby Charge above Which no Installed Capacity is Chosen	$28	$35
Flatrate Sensitivity	Installed Capacity at Flat Rate of $0.15/kWh (kW)	330	365

This discussion of the site in this report remains accurate and useful. The comparison of data in this errata provides readers with an impression of the magnitude of difference in DER-CAM results generated by different electrical efficiency assumptions.

References:

Coastintelligen website: http://www.coastintelligen.com/

Firestone, Ryan, Owen Bailey, Charles Creighton, Chris Marnay, and Michael Stadler (2003). A Business Case for On-Site Generation: The BD Biosciences Pharmingen Project. Berkeley Lab Report LBNL-52759.