Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application: 15-04-012
Exhibit No.: SDG&E-07

PREPARED DIRECT TESTIMONY OF

JEFFREY J. SHAUGHNESSY

~~CHAPTER 7~~

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF SECOND AMENDED APPLICATION

CHAPTER 7

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

~~December~~ February 9~~1~~, 201~~5~~6

#301913

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PREPARED DIRECT TESTIMONY OF

JEFFREY J. SHAUGHNESSY IN SUPPORT OF SECOND AMENDED APPLICATION

~~(~~CHAPTER 7~~)~~

I. PURPOSE AND OVERVIEW

The purpose of this testimony is to provide the marginal cost basis for the development of commodity rates as well as the cost basis for the allocation of commodity costs and Ongoing Competition Transition Charge ("CTC") costs to the customer classes. Marginal commodity costs are the incremental electric commodity costs incurred on behalf of utility customers, and are composed of marginal energy costs and marginal generation capacity costs. Marginal energy costs ("MEC") are the added energy costs incurred to meet electricity consumption. Marginal generation capacity costs ("MGCC") relate to the added costs incurred to meet electric demand. San Diego Gas & Electric Company ("SDG&E") is proposing in this General Rate Case ("GRC") Phase 2 Application to allocate costs to reflect the marginal commodity costs developed herein.

My testimony is organized as follows:

Section II – Proposed Change to Time of Use ("TOU") Periods: SDG&E proposes a change to the time of use period definitions in Chapter 1, the Testimony of SDG&E witness Cynthia Fang. All calculations included herein show results with SDG&E's proposed time of use period definitions.

Section III – Calculation of Marginal Energy Costs: MEC are the projected energy costs incurred to meet electricity consumption. Since SDG&E transacts in the California Independent System Operator ("CAISO") markets, the marginal energy costs are based on monthly electric forward market prices specific to South Path-15 ("SP-15") and an annual hourly profile of electricity prices representative of the San Diego area. A Renewable Portfolio

Standard ("RPS") adder is also included since added load requires added renewable energy under the RPS.

Section IV – Calculation of Marginal Generation Capacity Costs: MGCC relate to the added costs incurred to meet electric demand. MGCC are calculated based on long-term considerations and are based on the net cost of new entry of a combustion turbine ("CT"), the long-term cost of adding new capacity. This amount is equal to the fixed costs of a CT less expected profits from energy and ancillary service markets.

Section V – Commodity Revenue Allocation: presents the proposal to use marginal costs coupled with the Equal Percent of Marginal Costs ("EPMC") methodology to allocate the authorized commodity revenue requirement to each customer class based on the calculated MEC and MGCC in Sections III and IV.

Section VI – CTC Revenue Allocation: presents an updated allocation for CTC revenues.

Section VII – Summary and Conclusion: provides a summary of recommendations.

Section VIII - Statement of Qualifications: presents my qualifications.

My testimony also contains the following:

- **Appendix – Glossary of Acronyms**
- **Attachment A – Commodity Marginal Costs**
- **Attachment B – Commodity Revenue Allocations**
- **Attachment C – CTC Revenue Allocations**
- **Attachment D – Summary of Updates from April Filing**

II. PROPOSED CHANGE TO TIME OF USE PERIODS

SDG&E proposes a change to the TOU period definitions addressed in Chapter 1. Table JJS-1 presents the currently authorized standard TOU periods[1] and proposed TOU periods.

Table JJS-1

Current Standard Time-of-use Periods		Proposed Time-of-use Periods	
Summer on-peak	11am - 6pm non-holiday weekdays	**On-peak**	4pm - 9pm daily
Winter on-peak	5pm - 8pm non-holiday weekdays		
Off-peak	12am - 6am & 10pm-12am non-holiday weekdays and all weekends/holidays	**Super off-peak**	12am - 6am non-holiday weekdays and 12am - 2pm weekends/holidays
Semi-peak	All other times	**Off-peak**	All other times

This testimony presents updated marginal commodity cost calculations and updated commodity revenue allocations that reflect SDG&E's proposed time of use period definitions.

III. CALCULATION OF MARGINAL ENERGY COSTS

MEC reflect expected future energy market conditions to assess future hourly electricity prices. Since the goal is to forecast future hourly prices, SDG&E used a forecasted hourly profile for 2016 based upon net demand in the SP-15 market[2] and projected monthly on-peak and off-peak 2016 SP-15 electric market forward market prices. The result is a profile of hourly electricity prices for calendar year 2016. The prices in SP-15 are used since SDG&E's load is in the SP-15 market area and forward prices are available for SP-15.

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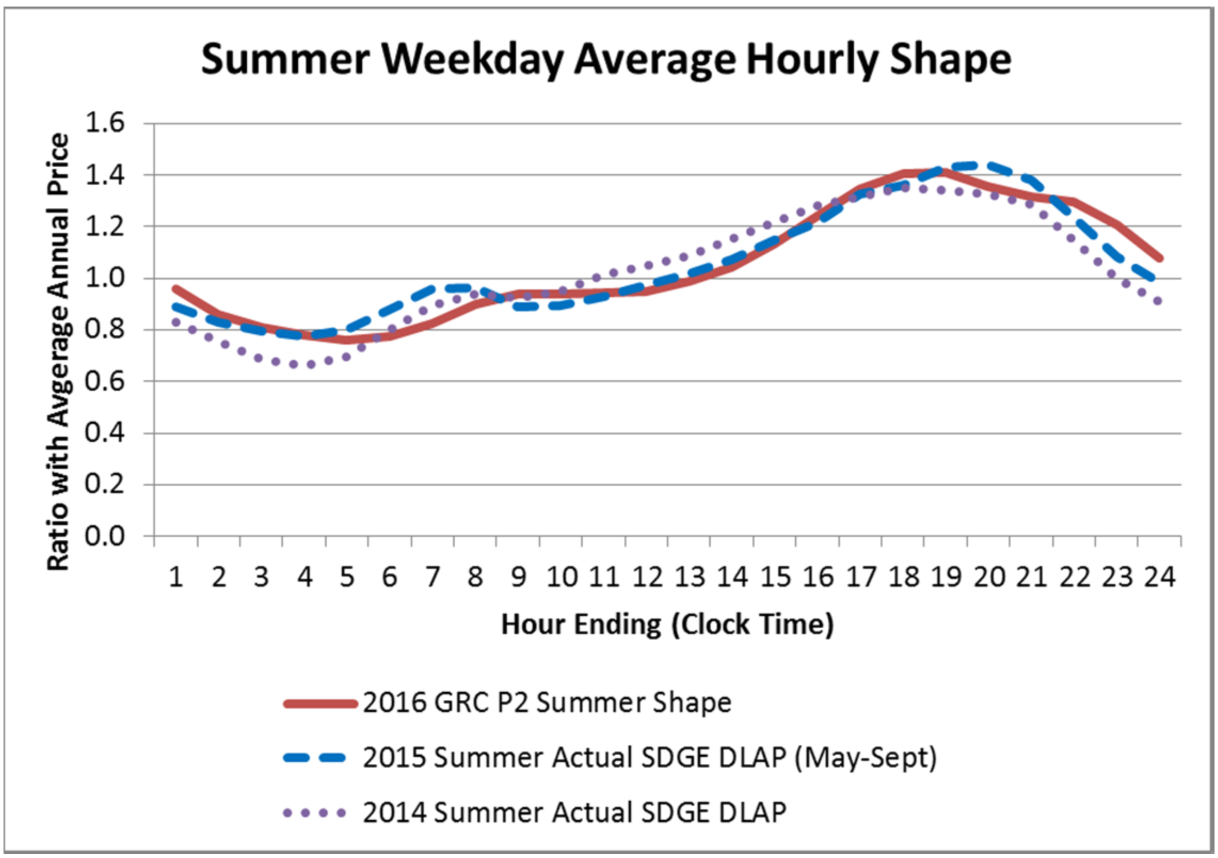
[1] SDG&E currently offers several optional residential rate schedules with different TOU period definitions. As described in the direct testimony of Ms. Fang, SDG&E proposes one TOU period definition for all rate schedules.

[2] The hourly price profile was developed and used in SDG&E's 2015 and 2016 Energy Resource Recovery Account ("ERRA") Forecast Proceedings (A.14-04-015 and A.15-04-014)

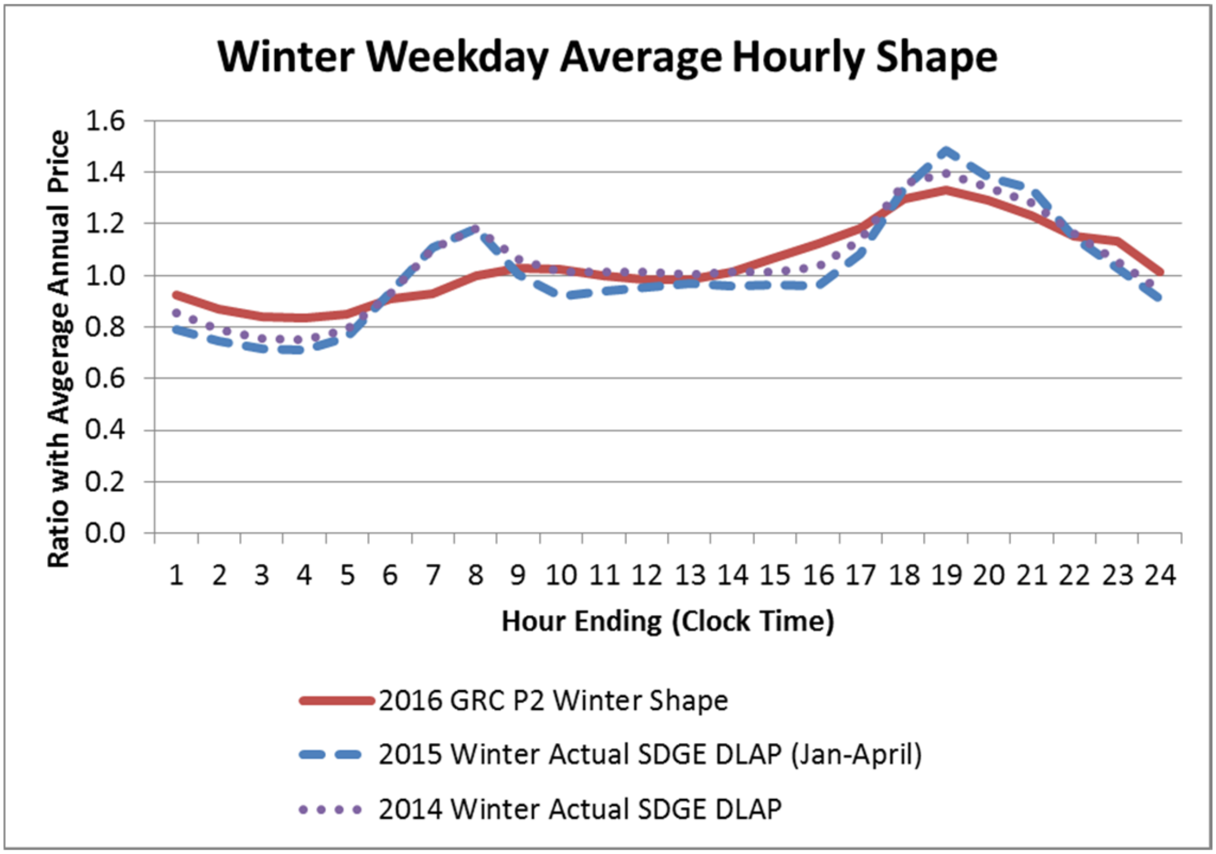
The SDG&E forecasted 2016 hourly price shape, based on SP-15, is illustrated in Chart JJS-1 and Chart JJS-2 for the average summer and winter non-holiday weekdays, compared to the actual SDG&E Default Load Aggregation Point ("DLAP") prices observed in 2014 and 2015 through September, which is 4 summer months and 4 winter months.[3]

Chart JJS-1: Summer Weekday Hourly Shape



[3] Locational Marginal Prices ("LMP"), From 01/01/2014 To 09/30/2015, Market: DAM, Node: DLAP_SDGE-APND http://oasis.caiso.com/. Note that these prices are not weather adjusted.

Chart JJS-2: Winter Weekday Hourly Shape



For the development of the average hourly prices, the monthly on-peak and off-peak forward prices are multiplied by the monthly on-peak and off-peak hourly demand profiles to arrive at hourly prices. The hourly prices are then aggregated by the appropriate time periods to develop the TOU marginal energy prices. The resulting MEC ratios with the annual average price by proposed TOU period are shown in Table JJS-2. The average annual price is calculated to be $32.38 per MWh, or 3.238 cents per kWh.

Table JJS-2: MEC Factors and Prices by TOU Period

	Proposed TOU Periods				
	MEC Factors			MEC Cents per kWh	
	Summer	Winter	x Average	Summer	Winter
On-Peak	1.295	1.210	Annual Price	4.193	3.917
Off-Peak	1.032	1.024	(3.238	3.342	3.316
Super Off-Peak	0.789	0.843	¢/kWh)	2.554	2.729

The SP-15 forward prices represent the wholesale cost of energy in 2016. But, incremental energy will not be entirely purchased from the wholesale market because of California's 33 percent RPS mandate. Twenty-five percent of incremental energy in 2016 will be renewables pursuant to legislation.[4] In order to capture the full marginal cost of energy, an RPS premium is added to the wholesale energy prices after they are grouped by TOU period. The RPS premium is defined as the "Green Value," calculated by the California Public Utilities Commission's ("Commission") Energy Division, minus the average annual SP-15 energy price, then multiplied by the RPS Target for 2016 of 25%; ($0.079131/kWh – $0.03238/kWh) x 25% = $0.01144/kWh. The RPS adder is a single value for all hours of the year, as the RPS requirement is yearly (i.e. it's a % of yearly energy sales). The resulting total MEC by TOU period are shown in Table JJS-3.

[4] Established in 2002 under Senate Bill 1078, accelerated in 2006 under Senate Bill 107 and expanded in 2011 under Senate Bill 2.

Table JJS-3: Total Marginal Energy Prices

Proposed TOU Periods

	Wholesale (¢/kWh)	RPS Adder (¢/kWh)	Total (¢/kWh)
Summer (May 1 - October 31)			
On-peak : 4pm - 9pm daily	4.193	1.144	5.337
Off-peak: All other hours	3.342	1.144	4.486
Super off-peak: 12am - 6am non-holiday weekdays and 12am - 2pm weekends/holidays	2.554	1.144	3.698
Winter (November 1 - April 30)			
On-peak: 4pm - 9pm daily	3.917	1.144	5.061
Off-peak : All other hours	3.316	1.144	4.460
Super off-peak: 12am - 6am non-holiday weekdays and 12am - 2pm weekends/holidays	2.729	1.144	3.873
	RPS Premium	4.575	
	RPS %	25%	

These total marginal energy costs shown in Table JJS-3 above are input values for the commodity cost allocation to customer classes presented in Section V.

IV. CALCULATION OF MARGINAL GENERATION CAPACITY COSTS

The methodology employed by SDG&E in calculating MGCC can be viewed as a net cost of new entry approach. MGCC answers the question: What price would be required to incent a new generator to enter the market and sell firm capacity? The answer is calculated based on the cost of building the facility less anticipated revenues from California's energy markets. SDG&E computes MGCC by calculating the cost of building a new CT including all permitting, financing, and development costs and deducting expected earnings in California energy and ancillary service markets. SDG&E uses publicly available information to provide a transparent calculation.

To estimate a CT's fixed cost, SDG&E uses the installed cost for a CT addition, $1,316/kW, and fixed and variable Operations & Maintenance ("O&M") from the California Energy Commission's ("CEC") Estimated Cost of New Renewable and Fossil Generation in California Report, CEC-200-2014-003-SD.[5] The installed cost is converted to a short-term annual cost using a real economic carrying charge approach ("RECC"), and then fixed O&M and various loaders are added.[6] Finally, the cost is escalated to 2016 dollars using escalators developed in SDG&E's 2016 GRC Phase 1.[7]

To calculate the net cost of capacity, projected market earnings from California's energy and ancillary service markets are deducted from the annualized cost of a CT. SDG&E uses a 4-year average of the SP-15 energy revenues minus operating costs as the market earnings and SP-15 ancillary service revenue from the CAISO Department of Market Monitoring Annual Report on Market Issues & Performance.[8] The resulting MGCC calculation is shown in Table JJS-4.

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[5] Tables 59 and 60 CEC Estimated Cost of New Renewable and Fossil Generation in California, March 2015.

[6] SDG&E RECC factors include property tax in the RECC factor.

[7] A.14-11-003, Ex. SDG&E-33, Direct Testimony of Scott R. Wilder, p. SRW-5 at Table SDG&E-SRW-2: Summary of Cost Escalation Indexes.

[8] Table 1.9 *Financial analysis of new combustion turbine (2011-2014)* 2014 Annual Report on Market Issues & Performance, California ISO Department of Market Monitoring, June 2015.

Table JJS-4: MGCC

Marginal Generation Capacity Cost	
	2016 $/kW-Yr
Short-term Marginal Cost of a Combustion Turbine	$165.29
Less Energy Market Earnings	$43.69
Less Ancillary Service Market Earnings	$3.44
Marginal Generation Capacity Costs	$118.16

The MGCC is an input for the commodity cost allocation to customer classes presented in Section V.

SDG&E used Loss of Load Expectation ("LOLE") results presented in Chapter 3, the direct testimony of SDG&E witness Robert Anderson for generation capacity cost allocation. This LOLE approach is an accepted methodology to allocate generation capacity needs to months, day, and hours.[9] The use of the top 100 hours is consistent with the past SDG&E approach in the GRC Phase 2.[10] The LOLE approach was also used in SDG&E's 2015 Rate Design Window ("RDW").[11] SDG&E proposes to continue basing commodity capacity allocation on the top 100 hours of forecasted need. SDG&E allocated capacity to seasons, days (weekdays/weekends), hours and TOU periods as shown in Table JJS-5.

[9] A.14-01-027, Chapter 3 Direct Testimony of D. Barker and 2013 California Net Energy Metering Ratepayer Impacts Evaluation prepared for the California Public Utilities Commission, by Energy and Environmental Economics ("E3").
[10] A.11-10-002, SDG&E 2012 General Rate Case Phase II Chapter 3 Second Revised Testimony of William G. Saxe.
[11] A.14-01-027, SDG&E 2015 Rate Design Window Filing Chapter 3 Prepared Direct Testimony of David T. Barker.

Table JJS-5: Top 100 Hour Loss of Load Expectation

LOLE % by TOU Period		
Proposed TOU Periods	**Summer**	**Winter**
On-peak : 4pm - 9pm daily	76.7%	0.0%
Off-peak: All other hours	23.3%	0.0%
Super off-peak: 12am - 6am non-holiday weekdays and 12am - 2pm weekends/holidays	0.0%	0.0%
Total	100.0%	0.0%

V. COMMODITY REVENUE ALLOCATION

SDG&E proposes no change to the current methodology to use the EPMC revenue allocation methodology to allocate the authorized commodity revenue requirement to customer classes.

Under SDG&E's commodity revenue allocation proposal, the authorized commodity revenue requirement is allocated among customer classes based on the proposed marginal generation capacity and energy revenue cost responsibilities by customer class. The unit marginal generation capacity and energy costs, presented in Sections III and IV above, are multiplied by the appropriate cost drivers to develop the marginal commodity revenue allocations by customer class.

Marginal energy cost revenues by customer class are developed by multiplying the applicable marginal energy prices ($/kWh) by the 2016 forecasted TOU energy usage in each TOU period for each customer class.

Marginal capacity cost revenues by customer class are developed by multiplying the unit marginal generation capacity cost ($/kW/year) by each class' estimated contribution to total bundled load based on the top 100 hours with the highest expected need for new resources, described in section IV above.

The sum of the resulting marginal generation capacity and energy revenues are used to determine the commodity EPMC allocation factor, defined as the commodity revenue requirement divided by the commodity marginal cost revenues. The EPMC allocation factor is then used to scale the commodity marginal cost revenues to ensure that the sum equals the authorized commodity revenue requirement. The EPMC rates and resulting commodity class allocations are shown in Attachment A and Attachment B, respectively.

VI. CTC REVENUE ALLOCATION

CTC revenues are also allocated based on the "Top 100 hours" allocation methodology, as adopted by the Commission in D.00-06-034. In this proceeding, SDG&E does not propose to change the allocation methodology. Instead, SDG&E merely proposes to update the top 100 hour data for the more recent 3 years available, 2009-2011, used to allocate the CTC revenue requirement. The "Top 100 hours" methodology allocates revenues based on the customer classes' contribution to the top 100 hours of system load during a given annual period. The resulting CTC class allocations are shown in Attachment C.

VII. SUMMARY AND CONCLUSION

For the foregoing reasons, the marginal commodity costs presented herein as well as the proposal to use the EPMC revenue allocation methodology to allocate the authorized commodity revenue requirement to customer classes are reasonable and should be adopted. In addition, SDG&E recommends that the Commission adopt its proposal to update the data used to allocate the CTC authorized revenue requirement under the current “Top 100 hours” allocation methodology.

This concludes my prepared direct testimony.

VIII. WITNESS QUALIFICATIONS

My name is Jeffrey J. Shaughnessy. My business address is 8330 Century Park Court, San Diego, California 92123.

I have been employed as a Project Manager in the Rate Strategy & Analysis group in the Customer Pricing Department of San Diego Gas & Electric Company since 2014. My primary responsibilities include the development of cost-of-service studies, determination of revenue allocation, and support of electric rate design in various regulatory filings. I began work at SDG&E in 2011 as a Business Analyst and have held positions of increasing responsibility in the Electric Rates group.

I received a Bachelor of Arts in Finance from Michigan State University in 2007 and a Master of Arts in Economics from San Diego State University in 2011.

I have previously submitted testimony before the Federal Energy Regulatory Commission.

APPENDIX – GLOSSARY OF ACRONYMS

CAISO	California Independent System Operator
CEC	California Energy Commission
Commission	California Public Utilities Commission
CT	Combustion Turbine
CTC	Competition Transition Charge
DLAP	Default Load Aggregation Point
E3	Energy and Environmental Economics
EPMC	Equal Percent of Marginal Costs
ERRA	Energy Resource Recovery Account
GRC	General Rate Case
LMP	Locational Marginal Prices
LOLE	Loss of Load Expectation
MEC	Marginal Energy Costs
MGCC	Marginal Generation Capacity Costs
O&M	Operations & Maintenance
RDW	Rate Design Window
RECC	Real Economic Carrying Charge
RPS	Renewable Portfolio Standard
SDG&E	San Diego Gas & Electric Company
SP-15	South Path-15
TOU	Time of Use

ATTACHMENT A

Commodity Marginal Costs

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY MARGINAL COSTS AND EPMC RATES & REVENUES, PROPOSED TOU - CHAPTER 7 (SHAUGHNESSY)

Line No.	Description (A)	Unit (B)	Marginal Energy Rate w/ losses (C)	Marginal Capacity Rate w/ losses (D)	Marginal Energy Rate Revenue (E)	Marginal Capacity Rate Revenue (F)	Total Marginal Rate Revenue (G)	EPMC Energy Rate (H)	EPMC Capacity Rate (I)	EPMC Energy Rate Revenue (J)	EPMC Capacity Rate Revenue (K)	Total EPMC Rate Revenue (L)	Line No.
1	**RESIDENTIAL**				$346,155,336	$201,161,113	$547,316,449			$567,085,982	$329,550,453	$896,636,434	1
2	*Secondary*												2
3	**Summer**												3
4	On-Peak Demand	$/kW	0.00	7.25				0.00	11.88				4
5	On-Peak Energy	$/kWh	0.05659	0.00000				0.09271	0.00000				5
6	Off-Peak Energy	$/kWh	0.04753	0.02504				0.07787	0.04103				6
7	Super Off-Peak Energy	$/kWh	0.03891	0.00000				0.06375	0.00000				7
8													8
9	**Winter**												9
10	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				10
11	On-Peak Energy	$/kWh	0.05361	0.00000				0.08782	0.00000				11
12	Off-Peak Energy	$/kWh	0.04713	0.00000				0.07722	0.00000				12
13	Super Off-Peak Energy	$/kWh	0.04074	0.00000				0.06675	0.00000				13
14													14
15	**SMALL COMMERCIAL**				$93,369,698	$39,534,912	$132,904,610			$152,962,099	$64,767,727	$217,729,826	15
16	*Secondary*												16
17	**Summer**												17
18	On-Peak Demand	$/kW	0.00	6.68				0.00	10.95				18
19	On-Peak Energy	$/kWh	0.05659	0.00000				0.09271	0.00000				19
20	Off-Peak Energy	$/kWh	0.04753	0.02201				0.07787	0.03606				20
21	Super Off-Peak Energy	$/kWh	0.03891	0.00000				0.06375	0.00000				21
22													22
23	**Winter**												23
24	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				24
25	On-Peak Energy	$/kWh	0.05361	0.00000				0.08782	0.00000				25
26	Off-Peak Energy	$/kWh	0.04713	0.00000				0.07722	0.00000				26
27	Super Off-Peak Energy	$/kWh	0.04074	0.00000				0.06675	0.00000				27
28													28
29	*Primary*												29
30	**Summer**												30
31	On-Peak Demand	$/kW	0.00	6.65				0.00	10.89				31
32	On-Peak Energy	$/kWh	0.05632	0.00000				0.09227	0.00000				32
33	Off-Peak Energy	$/kWh	0.04731	0.02191				0.07751	0.03589				33
34	Super Off-Peak Energy	$/kWh	0.03879	0.00000				0.06355	0.00000				34
35													35
36	**Winter**												36
37	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				37
38	On-Peak Energy	$/kWh	0.05336	0.00000				0.08742	0.00000				38
39	Off-Peak Energy	$/kWh	0.04694	0.00000				0.07690	0.00000				39
40	Super Off-Peak Energy	$/kWh	0.04062	0.00000				0.06655	0.00000				40

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY MARGINAL COSTS AND EPMC RATES & REVENUES, PROPOSED TOU - CHAPTER 7 (SHAUGHNESSY)

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1	<u>**MEDIUM & LARGE COMMERCIAL/INDUSTRIAL**</u>				$298,190,930	$121,312,703	$419,503,633			$488,508,710	$198,739,485	$687,248,195	1
2	*Secondary*												2
3	**Summer**												3
4	On-Peak Demand	$/kW	0.00	10.24				0.00	16.77				4
5	On-Peak Energy	$/kWh	0.05659	0.00000				0.09271	0.00000				5
6	Off-Peak Energy	$/kWh	0.04753	0.01984				0.07787	0.03251				6
7	Super Off-Peak Energy	$/kWh	0.03891	0.00000				0.06375	0.00000				7
8													8
9	**Winter**												9
10	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				10
11	On-Peak Energy	$/kWh	0.05361	0.00000				0.08782	0.00000				11
12	Off-Peak Energy	$/kWh	0.04713	0.00000				0.07722	0.00000				12
13	Super Off-Peak Energy	$/kWh	0.04074	0.00000				0.06675	0.00000				13
14													14
15	*Primary*												15
16	**Summer**												16
17	On-Peak Demand	$/kW	0.00	10.19				0.00	16.69				17
18	On-Peak Energy	$/kWh	0.05632	0.00000				0.09227	0.00000				18
19	Off-Peak Energy	$/kWh	0.04731	0.01975				0.07751	0.03236				19
20	Super Off-Peak Energy	$/kWh	0.03879	0.00000				0.06355	0.00000				20
21													21
22	**Winter**												22
23	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				23
24	On-Peak Energy	$/kWh	0.05336	0.00000				0.08742	0.00000				24
25	Off-Peak Energy	$/kWh	0.04694	0.00000				0.07690	0.00000				25
26	Super Off-Peak Energy	$/kWh	0.04062	0.00000				0.06655	0.00000				26
27													27
28	*Transmission*												28
29	**Summer**												29
30	On-Peak Demand	$/kW	0.00	9.76				0.00	15.98				30
31	On-Peak Energy	$/kWh	0.05392	0.00000				0.08834	0.00000				31
32	Off-Peak Energy	$/kWh	0.04531	0.01892				0.07423	0.03099				32
33	Super Off-Peak Energy	$/kWh	0.03723	0.00000				0.06100	0.00000				33
34													34
35	**Winter**												35
36	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				36
37	On-Peak Energy	$/kWh	0.05111	0.00000				0.08374	0.00000				37
38	Off-Peak Energy	$/kWh	0.04501	0.00000				0.07373	0.00000				38
39	Super Off-Peak Energy	$/kWh	0.03899	0.00000				0.06387	0.00000				39

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1	**AGRICULTURE**				$13,840,284	$4,594,612	$18,434,896			$22,673,726	$7,527,084	$30,200,809	1
2	*Secondary*												2
3	**Summer**												3
4	On-Peak Demand	$/kW	0.00	5.63				0.00	9.23				4
5	On-Peak Energy	$/kWh	0.05659	0.00000				0.09271	0.00000				5
6	Off-Peak Energy	$/kWh	0.04753	0.01327				0.07787	0.02174				6
7	Super Off-Peak Energy	$/kWh	0.03891	0.00000				0.06375	0.00000				7
8													8
9	**Winter**												9
10	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				10
11	On-Peak Energy	$/kWh	0.05361	0.00000				0.08782	0.00000				11
12	Off-Peak Energy	$/kWh	0.04713	0.00000				0.07722	0.00000				12
13	Super Off-Peak Energy	$/kWh	0.04074	0.00000				0.06675	0.00000				13
14													14
15	*Primary*												15
16	**Summer**												16
17	On-Peak Demand	$/kW	0.00	5.61				0.00	9.19				17
18	On-Peak Energy	$/kWh	0.05632	0.00000				0.09227	0.00000				18
19	Off-Peak Energy	$/kWh	0.04731	0.01321				0.07751	0.02164				19
20	Super Off-Peak Energy	$/kWh	0.03879	0.00000				0.06355	0.00000				20
21													21
22	**Winter**												22
23	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				23
24	On-Peak Energy	$/kWh	0.05336	0.00000				0.08742	0.00000				24
25	Off-Peak Energy	$/kWh	0.04694	0.00000				0.07690	0.00000				25
26	Super Off-Peak Energy	$/kWh	0.04062	0.00000				0.06655	0.00000				26
27													27
28	**LIGHTING**				$4,137,271	$1,330,067	$5,467,338			$6,777,848	$2,178,971	$8,956,819	28
29	*Secondary*												29
30	**Summer**												30
31	On-Peak Demand	$/kW	0.00	9.33				0.00	15.29				31
32	On-Peak Energy	$/kWh	0.05659	0.00000				0.09271	0.00000				32
33	Off-Peak Energy	$/kWh	0.04753	0.01024				0.07787	0.01677				33
34	Super Off-Peak Energy	$/kWh	0.03891	0.00000				0.06375	0.00000				34
35													35
36	**Winter**												36
37	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				37
38	On-Peak Energy	$/kWh	0.05361	0.00000				0.08782	0.00000				38
39	Off-Peak Energy	$/kWh	0.04713	0.00000				0.07722	0.00000				39
40	Super Off-Peak Energy	$/kWh	0.04074	0.00000				0.06675	0.00000				40
41													41
42	**TOTAL RATE REVENUE SUMMARY**												42
43													43
44	**RESIDENTIAL**				$346,155,336	$201,161,113	$547,316,449			$567,085,982	$329,550,453	$896,636,434	44
45	**SMALL COMMERCIAL**				$93,369,698	$39,534,912	$132,904,610			$152,962,099	$64,767,727	$217,729,826	45
46	**MEDIUM/LARGE C&I**				$298,190,930	$121,312,703	$419,503,633			$488,508,710	$198,739,485	$687,248,195	46
47	**AGRICULTURAL**				$13,840,284	$4,594,612	$18,434,896			$22,673,726	$7,527,084	$30,200,809	47
48	**LIGHTING**				$4,137,271	$1,330,067	$5,467,338			$6,777,848	$2,178,971	$8,956,819	48
49	**TOTAL**				$755,693,519	$367,933,407	$1,123,626,926			$1,238,008,364	$602,763,719	$1,840,772,084	49

ATTACHMENT B

Commodity Revenue Allocations

ATTACHMENT B.1

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY REVENUE ALLOCATION - CHAPTER 7 (SHAUGHNESSY)

Commodity Marginal Cost Allocation by Customer Class

		PROPOSED GRC P2 (PROPOSED TOU)				
		MARGINAL ENERGY COSTS		MARGINAL CAPACITY COSTS		
Line No.	Customer Class (A)	% Allocation (B)	$ Allocation (C)	% Allocation (D)	$ Allocation (E)	Line No.
1	RESIDENTIAL	45.81%	$346,155,336	54.67%	$201,161,113	1
2	SMALL COMMERCIAL	12.36%	$93,369,698	10.75%	$39,534,912	2
3	MEDIUM/LARGE C&I	39.46%	$298,190,930	32.97%	$121,312,703	3
4	AGRICULTURAL	1.83%	$13,840,284	1.25%	$4,594,612	4
5	LIGHTING	0.55%	$4,137,271	0.36%	$1,330,067	5
6	TOTAL	100.00%	$755,693,519	100.00%	$367,933,407	6

ATTACHMENT B.2

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY REVENUE ALLOCATION - CHAPTER 7 (SHAUGHNESSY)

Commodity Allocation by Customer Class

		CURRENT (11/1/2015)		PROPOSED GRC P2 (PROPOSED TOU)				
Line No.	Customer Class (A)	% Allocation (B)	$ Allocation (C)	% Allocation (D)	$ Allocation (E)	$ Change (F)	% Change (G)	Line No.
1	RESIDENTIAL	45.69%	$841,005,102	48.71%	$896,636,434	$55,631,333	6.61%	1
2	SMALL COMMERCIAL	11.34%	$208,679,888	11.83%	$217,729,826	$9,049,938	4.34%	2
3	MEDIUM/LARGE C&I	41.02%	$755,115,446	37.33%	$687,248,195	-$67,867,251	-8.99%	3
4	AGRICULTURAL	1.53%	$28,163,472	1.64%	$30,200,809	$2,037,338	7.23%	4
5	LIGHTING	0.42%	$7,808,176	0.49%	$8,956,819	$1,148,643	14.71%	5
6	TOTAL	100.00%	$1,840,772,084	100.00%	$1,840,772,084	$0	0.00%	6

ATTACHMENT C

CTC Class Allocations

ATTACHMENT C

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
CTC REVENUE ALLOCATION - CHAPTER 7 (SHAUGHNESSY)

CTC Allocation by Customer Class

		CURRENT (11/1/2015)		PROPOSED GRC P2				
Line No.	Customer Class (A)	% Allocation (B)	$ Allocation (C)	% Allocation (D)	$ Allocation (E)	$ Change (F)	% Change (G)	Line No.
1	RESIDENTIAL	40.89%	$7,837,705	40.79%	$7,819,092	-$18,613	-0.24%	1
2	SMALL COMMERCIAL	11.61%	$2,225,668	11.29%	$2,163,121	-$62,546	-2.81%	2
3	MEDIUM/LARGE C&I	46.48%	$8,908,586	46.80%	$8,971,122	$62,536	0.70%	3
4	AGRICULTURAL	1.02%	$195,919	1.10%	$211,480	$15,561	7.94%	4
5	LIGHTING	0.00%	$0	0.02%	$3,062	$3,062	NA	5
6	TOTAL	100.00%	$19,167,878	100.00%	$19,167,878	$0	0.00%	6

ATTACHMENT D

Summary of Updates

ATTACHMENT D

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
SUMMARY OF UPDATES FROM APRIL 2015 FILING – CHAPTER 7 (SHAUGHNESSY)

Witness	Location	Update
Jeffrey Shaughnessy	Section I	Removed language regarding SDG&E's 2015 RDW and replaced with reference to TOU proposal in this proceeding.
Jeffrey Shaughnessy	Section II	Removed language regarding SDG&E's 2015 RDW and replaced with reference to TOU proposal in this proceeding.
Jeffrey Shaughnessy	Table JJS-1	Removed information for TOU periods from SDG&E's 2015 RDW and replaced with reference to TOU proposal in this proceeding.
Jeffrey Shaughnessy	Charts JJS-1 and JJS-2	Refreshed graphs for updated 2016 forward prices, correction to 2014 historical prices and added 2015 historical prices.
Jeffrey Shaughnessy	Section III	Updated average annual price per updated 2016 forward prices.
Jeffrey Shaughnessy	Table JJS-2	Removed information from TOU periods in SDG&E's 2015 RDW and replaced with information for TOU periods proposed in this proceeding.
Jeffrey Shaughnessy	Section III	Updated RPS adder based on more recent "Green Value" and average wholesale price.
Jeffrey Shaughnessy	Table JJS-3	Removed information from TOU periods in SDG&E's 2015 RDW and replaced with information for TOU periods proposed in this proceeding.
Jeffrey Shaughnessy	Section IV	Updated $/kW CT cost per updated Final CEC report released March 2015 and updated CAISO report released June 2015.
Jeffrey Shaughnessy	Table JJS-4	Updated $/kW values per updated CEC and CAISO reports.
Jeffrey Shaughnessy	Table JJS-5	Updated information per new LOLE results because of updated hourly load forecast and modified presentation by proposed TOU period instead of hour.
Jeffrey Shaughnessy	Attachment A	Updated per new marginal costs based on proposed TOU periods in this proceeding.
Jeffrey Shaughnessy	Attachment B	Updated per new marginal costs based on proposed TOU periods in this proceeding.
Jeffrey Shaughnessy	Attachment C	Updated because of change in sales forecast.
Jeffrey Shaughnessy	Attachment D	Added.