Docket	:	A.13-06-013
Exhibit Number	:	
Commissioner	:	Michel Peter Florio
Admin. Law Judge	:	Julie Halligan

OFFICE OF RATEPAYER ADVOCATES
California Public Utilities Commission

MONITORING AND EVALUATION REPORT

Southern California Gas Company's
Gas Cost Incentive Mechanism

April 1, 2012 through March 31, 2013
GCIM Year 19

Application 13-06-013

San Francisco, California
October 25, 2013

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CHAPTER 1

SUMMARY AND RECOMMENDATIONS

1.1 Introduction and Summary

On June 14, 2013, the Southern California Gas Company (SoCalGas) submitted its Gas Incentive Cost Mechanism (GCIM) Year Nineteen (Year 19) Application (A.) 13-06-013. In its application, SoCalGas reports on results for the twelve month gas procurement operation ending March 31, 2013. The Office of Ratepayer Advocates (ORA) performed an audit and evaluation of the documents submitted by SoCalGas of its GCIM Annual Report. The details and results of ORA's review are presented in Chapter 2 of this GCIM Monitoring and Evaluation (M&E) Report. ORA's evaluation verifies SoCalGas’ their recorded gas costs were below the benchmark, which resulted in savings for ratepayers. ORA confirmed that SoCalGas' recorded costs were below the lower tolerance band, which results in a reward of $5,830,965 to SoCalGas' shareholders and a ratepayer benefit of $28,907,566.

The M&E Report evaluates the SoCalGas GCIM computations, Purchase Gas Account (PGA), and SoCalGas’ performance under the GCIM mechanism. Table 1-1 below summarizes SoCalGas' Year 19 performance, which is based on detailed GCIM monthly reports of core commodity transaction activities.

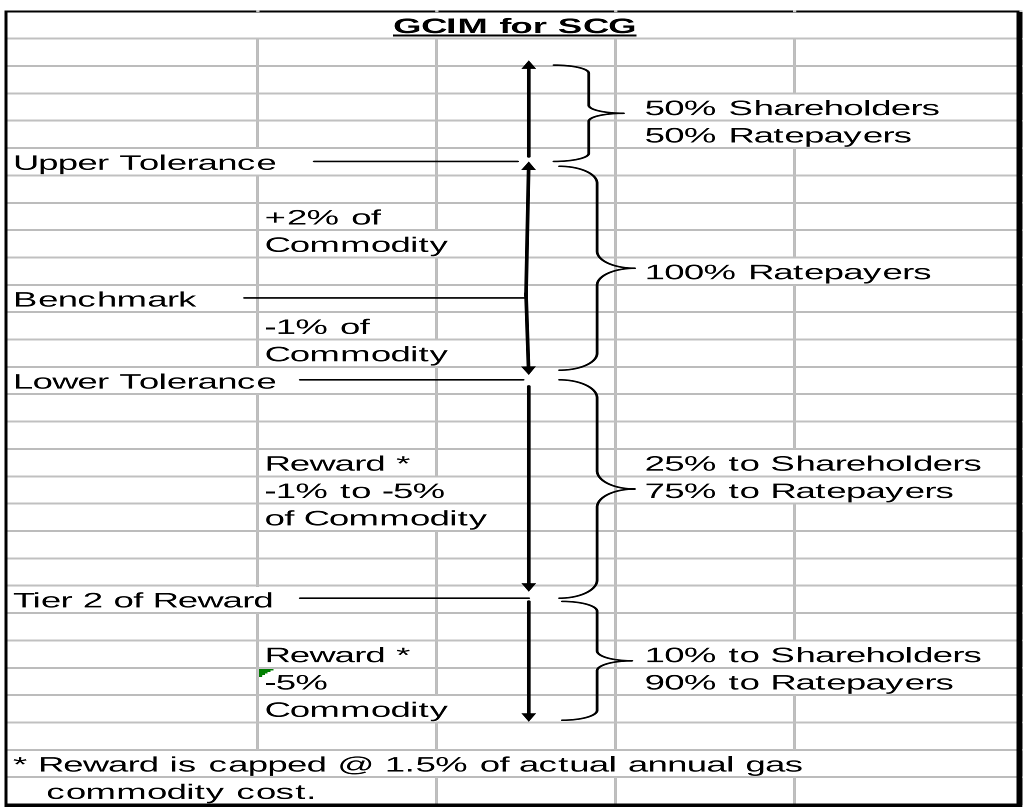
Table 1-1

Summary of GCIM Year 19 Performance ($ 000’s)		
1	Benchmark Costs	$1,308,126
2	Actual Costs	$1,273,388
3	GCIM Total Savings	$34,739
4	Ratepayer Savings	$28,908
5	Shareholder Computed Reward	$5,831

1.2 Background

The objective of the GCIM is to provide an incentive for reducing natural gas procurement costs, as well as related costs such as transportation, storage capacity, financial hedging, and retail core gas sales. This incentive mechanism is used as a ratemaking tool that is designed to increase efficiency in administering regulatory controls. It provides a framework for the utility in the form of a benchmark that is used to determine whether actual purchase costs are within a stated range referred to as a tolerance band. If SoCalGas' actual costs, as measured against the GCIM benchmark, were between the upper and lower range limitations of the tolerance band, there is no shareholder penalty or reward for the GCIM period. If actual gas costs fall outside the tolerance band, ratepayers and SoCalGas' shareholders share the gains or losses that occur outside the tolerance band. Detailed results of the tolerance band calculation are reported in Chapter 2 of this Report.

The following is a graphical view of how the tolerance band functions in determining the shared costs for SoCalGas' shareholder and ratepayers:



The upper limit of the tolerance band is set at two percentage points above the benchmark commodity costs and the lower limit of the tolerance band is set at one percentage point below this benchmark. When SoCalGas' actual costs fall within this tolerance band, the benefits or losses accrue to the ratepayers account.[1]

In cases where actual costs fall outside the tolerance band, the benefits or losses are shared between shareholders and ratepayers. The amounts of these benefits or losses are based on whether the actual costs are above the upper or lower limits of the tolerance band. For example, if actual costs were to exceed the upper two-percent (2%) tolerance limit, the excess costs are shared 50-50 between ratepayers and shareholders. If actual costs are between the lower one-percent (1%) tolerance limit and the five-percent (5%) range is below the benchmark commodity costs, this would produce savings that are shared at twenty-five percent (25%) for shareholders and seventy-five percent (75%) for ratepayers. If actual costs are more than five percentage points below the benchmark commodity costs, the savings are shared as ninety-percent (90%) savings for ratepayers and a ten-percent (10%) reward for shareholders. The SoCalGas reward is capped at 1.5% of the commodity benchmark costs.

Commission Decision (D.) 94-03-076 originally approved the GCIM program, with subsequent changes and extensions that essentially enhanced the current program incentives. Most recently, D.10-01-023 changed the treatment of winter hedging costs by allowing twenty-five percent (25%) of net hedging gains and losses relating to winter gas purchases to flow through to the GCIM calculation, and seventy five percent (75%) of costs to be passed through directly to core customers.

1.3 GCIM Summary

To provide a historical perspective, Table 1-2 provides a summary of GCIM results over the past five years. The GCIM savings in Year 19 are comparable to the prior three years. ORA's supporting calculations for Year 19 are described in Chapter 2 of this M&E Report.

[1] D.02-06-023 at p. 4 (dated June 6, 2002)

Table 1-2

GCIM Year	Period	Total Cost Savings ($ Million)	Ratepayer Savings ($ Million)	Shareholder Reward ($ Million)
15	2008-2009	75.6	63.5	12.1
16	2009-2010	39.9	33.9	6.0
17	2010-2011	40.9	34.7	6.2
18	2011-2012	37.5	32.1	5.4
19	2012-2013	34.7	28.9	5.8

1.4 Natural Gas Storage

To ensure dedicated core storage capacity, Commission Decision D.06-10-029 allows SoCalGas to revise its Preliminary Statement, Part VIII, and GCIM, to reflect changes in mid-season minimum core inventory targets. [2] Prior to making a revision, SoCalGas is required to seek agreement from ORA and The Utility Reform Network (TURN) to make these changes. SoCalGas filed Advice Letter 4372, and obtained agreement from ORA and TURN for mid-season minimum storage target of 47 Bcf as of July 31, 2012, and a winter season target for October 31, 2012 of 82 +0/-2 Bcf. In Chapter 2, ORA provides a review of minimum targets to actual capacity holdings. The results show SoCalGas met the mid-season and winter season minimum core inventory storage targets.

In D.08-12-020, the Commission adopted the Phase One Settlement Agreement dated August 22, 2008[3], which eliminates the upper tolerance for core storage by combining San Diego Gas & Electric Company's (SDG&E) and SoCalGas' balancing requirements in order to balance their storage capacity. As of April 1, 2009, SoCalGas implemented the core balancing requirements. For this reporting period, SoCalGas reported no core imbalance charges.

1.5 Financial Hedging in GCIM Year 19

Pursuant to D.10-01-023, Ordering Paragraph 5, starting in April 2010, SoCalGas did not need to file Winter Hedging Plan Report, instead they need to include 25% of winter hedge transactions into GCIM. ORA reviewed the Hedging Report's

[2] Advice Letter 4372, Effective July 19, 2012

[3] D.08-12-020, Decision Regarding the Phase One Issues and the Motion to Adopt the Settlement Agreement, (dated Dec. 2, 2008)

financial gains and losses including all minimum hedge requirements of the plan, based on the methodology described in Chapter 2 (Sections 2.10 and 2.11) and Commission policies and practices.

In GCIM Year 19, SoCalGas performed its winter hedging based on a ratio of twenty-five percent (25%) of all net gains and losses, which were included in the GCIM. The remaining seventy-five (75%) was excluded from the GCIM mechanism, which result in costs passed through to core customers.

In addition to core winter hedges, SoCalGas transacted non-winter hedges. During this period, SoCalGas' non-winter hedges resulted in a gain of $3,354 which was included in the GCIM.[4] The results also reflect a decline in hedging costs, which appears to result from less hedging transactions and less price volatility. Table 1-3 shows the results of SoCalGas' hedging activities for the most recent five-year period.

Table 1-3

GCIM Year	Losses outside the GCIM Mechanism ($Millions)	Losses inside the GCIM Mechanism ($Millions)	Total Hedging Losses ($Millions)
15	35.11	1.96	37.07
16	8.92	4.82	13.74
17	3.11	2.30	5.41
18	1.00	0.30	1.30
19	.75	.25	1.00

1.6 Interstate Capacity

The Commission established interstate pipeline contract approval procedures for SoCalGas, SDG&E, and Pacific Gas and Electric Company in D.04-09-022 for an initial period of five years.[5] These procedures included authorized capacity planning ranges to provide flexibility in meeting its regional market demands and regulatory compliance requirements pertaining to their respective Biennial Cost Allocation Proceedings (BCAP) or advice letter filings.[6]

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[4] As discussed in Section 2.10 below, regarding "Financial Derivatives Included in the GCIM."

[5] Ordering Paragraph 2 in D.04-09-022.

[6] Conclusion of Law 6 in D.04-09-022.

In accordance with the capacity guideline procedures adopted in D.04-09-022, SoCalGas, ORA, TURN, and the Energy Division conduct on-going discussions regarding interstate capacity requirements and SoCalGas' acquisition of interstate capacity. ORA serves as a resource for addressing compliance issues that have an impact on acquisition and/or reduction of interstate capacity.

Effective November 26, 2010, Advice Letter 4158 addresses SoCalGas' capacity planning range for its combined gas portfolio with SDG&E for its winter and non-winter requirements. The updated minimum capacity for non-winter requires 948.0 MDth/d, and maximum capacity of 1,264.0 MDthd. For winter, the combined portfolio minimum capacity is 1053.4 MDth/d and maximum capacity of 1,264.0 MDth/d.

Results reported by SoCalGas for actual monthly activity of its core firm transportation capacity holdings, shows the utility met the minimum capacity requirements established in D.04-09-022. The reported capacity holdings varied from of 948.6 MDth/d from April 2012 to 1053.4 MDth/d in March 2013[7].

1.7 Secondary Market Services Transactions

Secondary Market Services (SMS) produce revenues from core gas supplies and resources not needed for reliability requirements. SoCalGas meets this regional market demand, while simultaneously applying these revenues to directly offset core commodity costs. As a result, this reduces core gas costs, which achieve SoCalGas' primary objectives of ensuring supply and service reliability at a low cost.[8]

For the reporting period, SoCalGas shows net SMS revenues in the GCIM of $9,479,464[9]. This is a six percent (6%) decrease from prior year. This change appears to result from market conditions and system service and reliability requirements. These revenues provide SoCalGas the ability to lower its core commodity costs.

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[7] See discussion in Section 2.14 below.

[8] See A.12-06-005, at pp. 3-4.

[9] See discussion in Section 2.12 of Chapter 2 below.

1.8 Conclusion

ORA recommend a shareholder reward to SoCalGas in the amount of $5,830,965 for GCIM Year 19 to be recovered through its Purchased Gas Account. ORA confirmed ratepayer benefits in the amount of $28,907,566 in GCIM Year 19. ORA will continue monitoring and evaluating the GCIM and collaborate with SoCalGas and other parties to identify any modifications needed to enhance GCIM effectiveness. SoCalGas and ORA agree to present any proposed changes of the GCIM to the Commission for approval.

CHAPTER 2
MONITORING AND EVALUATION AUDIT

2.1 ORA’s GCIM Reward Evaluation

In its submitted Gas Cost Incentive Mechanism (GCIM) Year 19 Application (A.) 13-06-013, SoCalGas reports on results for the period April 1, 2012 through March 31, 2013. ORA conducted a review and evaluation of SoCalGas’ accompanying report. The results from this evaluation include work papers from its compilations, which are incorporated as exhibits in Appendix A.

ORA’s evaluation incorporates the provisions of Advice Letter 4089, which was a revision to reflect changes to SoCalGas’ natural gas operations and services adopted in D.10-01-023. This Advice Letter was in effect as of April 21, 2010.

ORA's evaluation of SoCalGas’ GCIM performance for the year ending March 31, 2013, shows total savings in gas costs of $34,738,531. These savings are based on the difference between the actual costs of gas of $1,273,387,819 and the GCIM benchmark market index of $1,308,126,351. These savings are shared between ratepayers and SoCalGas shareholders. ORA has confirmed that the GCIM sharing mechanism results in ratepayer savings of $28,907,566.13 and a shareholder reward of $5,830,965. Table 2-1 shows ORA’s summary of the SoCalGas GCIM savings for Year 19 based on the calculated tolerance band levels shown in Table 2-2 and GCIM benchmark dollars.

TABLE 2-1 Southern California Gas Company GCIM Year 19 Reward Calculation April 1, 2012 Through March 31, 2013				
				SCG Annual Report
GCIM Year 19 Annual Report: Total Savings Below Benchmark			$	34,738,531
Amount of Lower Tolerance Band Not Subject to Sharing (0%-1%)			$	11,414,670
Ratepayers' share:			$	11,414,670
Amount Subject to 75%-25% Sharing (1%-5%)			$	23,323,861
Ratepayers' share: 75%		75%	$	17,492,896
Shareholders' share: 25%		25%	$	5,830,965
Amount Subject to 90%/10% Sharing (> 5%)			$	-
Ratepayers' share: 90%		0%	$	-
Shareholders' share: 10%		0%	$	-
Cap on Shareholder Rewards = 1.5% of commodity costs:	$	1,106,728,472	$	16,600,927
Total Ratepayers' Share:			$	28,907,566
Total Shareholders' Share:			$	5,830,965
Total Savings:			$	34,738,531

2.2 Summary of Benchmark and Actual Costs

Table 2-2 shows an annual summary of monthly gas commodity costs that is the basis for the 1.5% cap of the shareholder reward shown in Table 2-1. The calculated tolerance bands and the related actual commodity cost of gas are measured annually against a benchmark. The benchmark is based on the prevailing published natural gas price indices for gas delivered from the mainline to the California border. See Exhibits 2-1F and 2-1G for Border and Mainline Index Price.

To make a comparison of actual price per volume to the published market spot price, ORA determined the price per unit of volume by applying a ratio of actual commodity costs of $1,106,728,472 to total actual net volume of 387,144,888 (Exhibit 2-1C) derived from mainline and border pipelines, to arrive its price of $2.86 per unit.

This price of $2.86 is compared to the border and mainline spot prices, which show SoCalGas results were below the benchmark average spot prices.

TABLE 2-2
Southern California Gas Company
Tolerance Band Review GCIM Year 19
April 1, 2012 Through March 31, 2013

Month	Benchmark Dollars	Actual Dollar	(Over)/Under Benchmark	Upper Tolerance Dollars 2%	Lower Tolerance Dollars 1%	Lower Tolerance Dollars 5%	Actual Commodity Cost
Apr-12	$76,465,027	$75,380,369	$1,084,658	$1,246,842	$623,421	$3,117,105	$61,257,434
May-12	$57,071,070	$54,489,000	$2,582,071	$867,208	$433,604	$2,168,020	$40,778,332
Jun-12	$100,990,182	$99,077,420	$1,912,762	$1,746,086	$873,043	$4,365,214	$85,391,521
Jul-12	$91,798,218	$90,587,183	$1,211,035	$1,572,310	$786,155	$3,930,776	$77,404,481
Aug-12	$128,151,081	$126,034,896	$2,116,186	$2,291,083	$1,145,541	$5,727,707	$112,437,948
Sep-12	$77,515,805	$75,643,420	$1,872,385	$1,285,488	$642,744	$3,213,720	$62,402,010
Oct-12	$103,617,424	$101,328,250	$2,289,174	$1,794,882	$897,441	$4,487,205	$87,454,935
Nov-12	$95,627,206	$92,436,185	$3,191,021	$1,637,848	$818,924	$4,094,620	$78,701,389
Dec-12	$203,003,854	$196,652,914	$6,350,941	$3,773,071	$1,886,535	$9,432,677	$182,302,608
Jan-13	$153,543,028	$150,908,983	$2,634,045	$2,792,082	$1,396,041	$6,980,204	$136,970,032
Feb-13	$135,662,446	$131,555,806	$4,106,640	$2,419,982	$1,209,991	$6,049,955	$116,892,461
Mar-13	$84,681,010	$79,293,395	$5,387,615	$1,402,459	$701,229	$3,506,147	$64,735,321
Total	**$1,308,126,351**	**$1,273,387,819**	**$34,738,531**	**$22,829,340**	**$11,414,670**	**$57,073,350**	**$1,106,728,472**

2.3 Review of Benchmark Volumes and Market Costs

Table 2-3 shows the components of mainline and border dollar costs. ORA reviewed GCIM Year 19 records, which show total benchmark gas costs of $1,141,467,003. These costs consist of mainline benchmark commodity costs of $1,021,773,895 and benchmark border commodity market costs of $119,693,108. Border costs are calculated by the Southern California border costs of $128,321,757, and SoCalGas City-Gate price net credit of $8,628,649. The credit balance is because of more gas being sold than its purchases.

The total benchmark market costs include flow through costs of volumetric interstate transportation of $7,331,340 and interstate capacity reservation charges of $159,328,007 plus the mainline benchmark commodity cost of $1,141,470,003 for a total of $1,308,126,350.

TABLE 2-3
Southern California Gas Company
Benchmark Dollar Components
GCIM Year 19
April 1, 2012 Through March 31, 2013

		Benchmark Dollars
Annual Report:		
Mainline Benchmark Costs		$ 1,021,773,895
Southern California Border Costs	128,321,757	
SoCalGas City-Gate Commodity Costs	(8,628,649)	
PG&E Topock/City-Gate Costs	-	
Sub-Total Border Benchmark Commodity Costs		$ 119,693,108
Total Benchmark Commodity Costs		$ 1,141,467,003
Flow-Through Costs:		
Transport Costs from Mainline:		$ 7,331,340
Benchmark Reservation Charges:		159,328,007
Total Benchmark Market Costs:		$ 1,308,126,350

ORA's Table 2-3A shows the net total benchmark purchase volume is 396,811,575 MMBtus. This net total benchmark purchase volume consists of 362,318,101 in net mainline purchase volumes, plus 34,493,475 MMBtus in net border purchase volumes. The actual transported volume at 387,144,888 MMBtus is the actual total purchase volume that SoCalGas received during the period. A difference of 9,666,688 MMBtus was noted between the net benchmark purchase and actual transported volume. This difference is referred to as shrinkage volume, which represents uses and losses in gas during transportation.

TABLE 2-3A

Southern California Gas Company

TABLE 2-3A

BENCHMARK Market Volumes (In MMBtus)

GCIM Year 19

April 1, 2012 through March 31, 2013

Month Year	Mainline Volumes	SoCalGas Border Volumes	SoCalGas City-Gate Volumes	All Border Volumes	Net Total Benchmark Volumes	Actual Transported Volumes
Apr-12	29,499,293	4,069,540	(1,607,884)	2,461,656	31,960,949	31,173,356
May-12	28,945,055	3,810,604	(8,333,030)	(4,522,426)	24,422,629	23,656,103
Jun-12	29,012,149	5,171,086	1,503,635	6,674,721	35,686,870	34,908,673
Jul-12	28,964,130	2,655,038	(567,598)	2,087,440	31,051,570	30,244,953
Aug-12	29,822,988	5,960,675	3,675,361	9,636,036	39,459,024	38,610,776
Sep-12	28,269,661	2,014,105	(4,068,510)	(2,054,405)	26,215,256	25,435,458
Oct-12	29,182,047	5,539,542	(2,893,949)	2,645,593	31,827,640	31,051,374
Nov-12	31,587,677	(63,625)	(6,378,722)	(6,442,347)	25,145,330	24,339,164
Dec-12	32,593,026	2,758,922	15,039,302	17,798,224	50,391,250	49,557,283
Jan-13	32,292,895	2,359,098	7,110,786	9,469,884	41,762,779	40,915,472
Feb-13	29,764,524	9,779,057	(3,262,000)	6,517,057	36,281,581	35,476,420
Mar-13	32,384,656	(1,667,061)	(8,110,897)	(9,777,958)	22,606,698	21,775,856
Total:	362,318,101	42,386,981	(7,893,506)	34,493,475	396,811,576	387,144,888

Benchmark Vol (MMBtus)	396,811,576
Less: Actual Transported Vol	387,144,888
Shrinkage	9,666,688

2.4 Actual Gas Costs and Volumes

As shown in Table 2-4, ORA examined the actual gas cost commodity capacity which consists of mainline commodity cost; border net and city gas purchases; reported gross-to-net gas commodity costs; interstate volumetric transportation costs; and reservation capacity charges. Results show re-calculated costs to be consistent and are also supported by SoCalGas documentation. ORA confirmed the mainline pipeline purchases of $1,127,701,117 and border pipeline and city gate purchase of $287,513,261 for an aggregate total of $1,415,214,378 with total purchase volume of 396,811,577 MMBtus.

Gas commodity costs for purposes of gas sales are deducted from core purchases, which results in net purchases of $1,106,728,473. These adjustments to purchases include Secondary Market Service Revenues of $9,479,464 and gains from GCIM financial derivative transactions of $246,324 that are included as part of actual commodity costs.

Accordingly, net revenues from secondary market transactions using core assets, such as parks and loans, are included as a credit to actual commodity costs.[10] The gross revenues of $10,544,385.08 were adjusted for related operating overhead costs of $1,064,920.36, resulting in net revenues of $9,479,464.72.

ORA's calculation shows SoCalGas' interstate volumetric transportation costs at $7,331,340 along with firm reservation capacity charges of $159,328,007. These costs are added to the total commodity costs of $1,106,728,472 in arriving at the actual cost of gas of $1,273,387,819 as shown in Table 2-4.

A review of mainline purchase volume required adjusting volume sales of 38,206,744 MMBtus (Table 2-4) to mainline volume 400,524,845 MMBtus to arrive at a net mainline volume of 362,318,101 MMBtus. The border purchases of 90,086,796 MMBtus were also adjusted for sales volume from the SoCal Border of 8,222,918 MMBtus and SoCal City-Gate of 47,370,402 MMBtus to arrive at net border purchases of 34,493,476 MMBtus. Thus, total net volume for the reporting period was 396,811,577 MMBtus.

[10] Advice Letter 4089 filed March 22, 2010, and effective April 21, 2010.

TABLE 2-4
Southern California Gas Company
Actual Gas Costs Components -GCIM Year-19
April 1, 2012 through March 31, 2013

Mainline Commodity Purchases	Volumes		Dollars
El Paso Permian	85,099,745	$	235,996,586
El Paso San Juan	104,977,176		289,362,522
Transwestern Permian	2,362,098		7,074,833
Transwestern San Juan	101,273,640		292,028,204
Kern River Pipeline	81,157,501		233,836,665
Enterprise-Waha	4,185,499		13,338,864
Questar Southern Trails-SJ	1,289,423		4,333,087
NOVA	20,055,910		51,303,683
GTN: Kingsgate/Malin/Stanfield	123,853		426,674
Total Mainline	400,524,845	$	1,127,701,117
Border and City Gate Purchases			
Border	50,609,900	$	153,887,137
SoCalGas-City Gate	39,476,896		133,626,123
Total Border	90,086,796	$	287,513,261
Total Mainline and Border Purchase	490,611,641	$	1,415,214,378
Gas Sales (deductes)			
Mainline	(38,206,744)	$	(112,019,494)
Border	(8,222,918)		(28,377,888)
SoCalGas- City Gate	(47,370,402)		(158,855,384)
Total Gas Sales	(93,800,064)	$	(299,252,765)
Other Revenues/Costs			
Net Secondary Market Revenue:		$	(9,479,465)
GCIM Derivative Transactions			246,324
Total Other Revenues/Costs		$	(9,233,141)
Total Commodity Costs		$	1,106,728,472
Interstate Reservation and Volumetric Transport Cost			
Interstate Volumetric Transport Costs		$	7,331,340
Reservation Charges			159,328,007
Total Related Commodity Costs		$	166,659,347
Total Volume and Costs	396,811,577	$	1,273,387,819

2.5 Mainline and Border Gas Sales

Table 2-5 provides a breakdown by pipeline for SoCalGas' gas sales. In addition, a compilation of gas sales and volume for the period is shown in Exhibit 2-4C.

To identify trends, ORA completed a review of performance by comparing prior year sales. The mainline sales of $112,019,494, is a sixteen percent (16%) decrease from prior year; border sales of $187,233,272, a twelve percent (12%) decrease; and total sales of $ 299,252,765 is a fourteen percent (14%) decrease from GCIM Year 18.

Mainline volume sales were 38,206,744 MMBtus, a one percent (1%) decrease, and border volume sales of 55,593,320 MMBtus, a five percent (5%) decrease from GCIM Year 18. The total volume sales of 93,800,064 MMBtus represent a four percent (4%) decrease from prior year.

According to SoCalGas' Gas Acquisition team,[11] the decrease in sales was due to market conditions. The natural gas price has been lower than the prior year's price, but sales volumes for current year were not affected much by the gas price.

SoCalGas reported gas purchases and sales transactions with affiliate San Diego Gas & Electric Company and SoCalGas Capacity Products. SoCalGas reports all purchases and sales were completed through arm's length transactions via brokerage firms. It was disclosed there were no Secondary Market Sales (SMS) and financial transactions with existing affiliates during GCIM Year 19.

[11] A.13-06-013, Southern California Gas Company: Master Data Request of the DRA for Application of Southern California Gas Company's Year 19 GCIM.

Southern California Gas Company
Table 2-5
Summary of Mainline and Border Sales -GCIM Year-19
April 1, 2012 - March 31, 2013

Mainline Pipelines		Sales	Volume (MMBtus)
El Paso Permian	$	(49,520,951)	(16,985,052)
El Paso San Juan		(39,291,344)	(14,055,595)
Transwestern Permian		(3,374,562)	(1,045,347)
Transwestern San Juan		(5,401,776)	(1,860,584)
Kern River		(7,607,941)	(2,349,432)
Enterprise Waha		(2,784,987)	(774,700)
Questar Southern Trails SJ		-	-
NOVA-AECO		(2,543,560)	(703,280)
GTN Stanfield		(424,877)	(117,408)
GTN Malin		(1,069,497)	(315,346)
Total Mainline	$	(112,019,494)	(38,206,744)

Border Pipelines		Sales	Volume (MMBtus)
Border	$	(28,377,888)	(8,222,918)
SoCal City-Gate		(158,855,384)	(47,370,402)
PG&E Topock/City Gate		-	-
Total Border	$	(187,233,272)	(55,593,320)
Total Sales to Volume	$	(299,252,765)	(93,800,064)

2.6 Interstate Volumetric Transport Costs

The volumetric transport costs are treated as variable costs, which is based on the volume of interstate pipeline gas supplies delivered to end-users and/or to the city-gate. The total interstate volumetric transportation costs for GCIM Year 19 are shown in Table 2-6.

Pipelines show the El Paso transport cost of $5,344,203; Transwestern cost of $1,283,869; Kern River cost of $436,639; Questar Southern Trials cost of $15,440;

Canadian Path cost of $246,229; and Mojave cost of $4,961. Total aggregate volumetric transport costs for the period were $7,331,340.

Table 2-6
Southern California Gas Company
Summary of Actual Pipeline Commodity Transport Costs
GCIM Year-19
April 1, 2012 Through March 31, 2013

Month/ Year	El Paso Transport	Trans- Western	Kern River	Questar Southern Trails	Canadian Path	Mojave	Total Transport Costs
Apr-12	$ 519,433	$ 83,014	$ 31,005	$ -	$ 20,559	$ 4,961	**$ 658,972**
May-12	492,084	89,941	29,900	-	20,752	-	**$ 632,677**
Jun-12	495,461	89,100	31,001	-	20,191	-	**$ 635,752**
Jul-12	484,413	88,388	31,896	-	21,252	-	**$ 625,949**
Aug-12	505,505	92,435	31,990	-	21,240	-	**$ 651,169**
Sep-12	380,935	102,326	40,038	-	19,547	-	**$ 542,845**
Oct-12	397,474	107,621	38,077	-	21,161	-	**$ 564,333**
Nov-12	409,857	127,077	40,105	3,587	19,634	-	**$ 600,259**
Dec-12	421,795	130,186	42,614	2,965	21,035	-	**$ 618,595**
Jan-13	429,353	124,670	41,469	3,710	20,542	-	**$ 619,743**
Feb-13	387,791	119,242	38,077	1,954	18,923	-	**$ 565,986**
Mar-13	420,102	129,871	40,468	3,225	21,395	-	**$ 615,060**
Totals:	**$ 5,344,203**	**$ 1,283,869**	**$ 436,639**	**$ 15,440**	**$ 246,229**	**$ 4,961**	**$ 7,331,340**

2.7 Interstate Reservation Charges

Table 2-7 shows monthly reservation charges by pipeline. Comparing these costs to prior year, El Paso charges were $42,846,783, which reflects a 20% decrease; Transwestern costs of $27,723,400, an increase of 5%; Kern River charges of $28,983,823, an 18% increase; and Canadian Path's charges of $15,629,704, less than 1 % increase from the prior year. SoCalGas reported a new contract with Mojave for $125,320, and Questar Southern Trails for $262,148. Backbone Transportation Service (BTS) is the new name that replaces Firm Access Rights (FAR) for capacity contracting. The procedures for contracting continue to operate the same in those interstate purchase contracts, which enable a supplier access rights into the SoCalGas system at a specified receipt point throughout the year. Backbone Transport Service contracts of $43,756,830 increased by 52% from the last GCIM period. Total reservation charges of

$159,328,007 increased by 7% from the prior year. Results show overall changes from prior year correlates with increases in capacity volume for the GCIM Year 19 period.

Table 2-7
Southern California Gas Company
Summary of Reservation Charges By Pipeline
GCIM Year-19
April 1, 2012 - March 31, 2013

Month	El Paso Pipeline	Transwestern Pipeline	Kern River	Canadian Path	Mojave	Questar Southern Trails	Backbone Transportation Service	Total Reservation Charges
Apr-12	$ 4,322,315	$ 1,963,500	$ 2,171,035	$ 1,314,719	$ 106,040	$ -	$ 3,586,353	**$13,463,963**
May-12	$ 3,965,358	$ 2,028,950	$ 2,212,806	$ 1,325,082	$ 19,280	$ -	$ 3,526,515	**$13,077,991**
Jun-12	$ 4,006,393	$ 1,963,500	$ 2,141,425	$ 1,299,230	$ -	$ -	$ 3,639,598	**$13,050,147**
Jul-12	$ 3,965,358	$ 2,028,950	$ 2,212,806	$ 1,323,375	$ -	$ -	$ 3,026,264	**$12,556,753**
Aug-12	$ 3,965,368	$ 2,028,950	$ 2,212,806	$ 1,333,017	$ -	$ -	$ 3,405,637	**$12,945,779**
Sep-12	$ 3,408,808	$ 2,278,500	$ 2,514,625	$ 1,321,147	$ -	$ -	$ 3,175,485	**$12,698,565**
Oct-12	$ 3,413,795	$ 2,354,450	$ 2,598,446	$ 1,335,293	$ -	$ -	$ 3,606,997	**$13,308,982**
Nov-12	$ 3,358,302	$ 2,598,000	$ 2,563,139	$ 1,312,755	$ -	$ 54,360	$ 3,247,981	**$13,134,537**
Dec-12	$ 3,398,230	$ 2,684,600	$ 2,648,577	$ 1,334,177	$ -	$ 52,545	$ 3,613,581	**$13,731,710**
Jan-13	$ 2,320,139	$ 2,684,600	$ 2,655,031	$ 1,268,472	$ -	$ 54,360	$ 4,336,605	**$13,319,208**
Feb-13	$ 3,362,140	$ 2,424,800	$ 2,398,093	$ 1,207,025	$ -	$ 49,222	$ 4,656,080	**$14,097,358**
Mar-13	$ 3,360,578	$ 2,684,600	$ 2,655,031	$ 1,255,411	$ -	$ 51,661	$ 3,935,733	**$13,943,014**
Totals	**$ 42,846,783**	**$ 27,723,400**	**$ 28,983,823**	**$ 15,629,704**	**$ 125,320**	**$ 262,148**	**$ 43,756,830**	**$ 159,328,007**

2.8 Interstate Pipeline Utilization

In D.04-09-022, the Commission requires tracking a pipeline's utilization of capacity usage. This allows monitoring by ORA, The Utility Reform Network (TURN), and the Commission’s Energy Division and collaborating with SoCalGas on a bi-weekly basis via teleconference meetings.

Table 2-8 provides an overview of SoCalGas’ nominated capacity. Total core capacity was 465,710,374 MMBtus and nominated capacity was 455,419,767 MMBtus. The difference is the stranded capacity of 10,290,607 MMBtus, which is adjusted from core capacity.

Regarding the following pipelines, SoCalGas reports El Paso at 99.4% capacity; Foot Hills Pipeline, Ltd at 97.8%; Gas Transmission Northwest Corp. at 98.6%; Kern

River Gas Transmission at 97.4%; Mojave Pipeline 69.2%; NOVA at 97.7% (Canadian Path); Pacific Gas and Electric pipeline at 97.1% (Malin); Southern Trails 84.3%; and Transwestern Pipeline Company at 96.6%. The capacity cut of, 2,351,110 MMBtus, is subtracted from nominated capacity, which results in actual volume received of 453,068,657 MMBtus.

TABLE 2-8
Cumulative Core Capacity Utilization By Pipeline (In MMBtus)
GCIM Year 19
April 1, 2012 through March 31, 2013

Pipeline	Core Capacity	Less: Nominated Capacity	Stranded Capacity	Capacity Utilization %	Nominated Capacity	Actual Volumes Received	Capacity Cut
El Paso Natural Gas Company	161,632,217	160,606,476	1,025,741	99.4%	160,606,476	159,579,461	1,027,015
Foothills Pipe Lines Ltd	19,644,264	19,206,011	438,253	97.8%	19,206,011	19,177,106	28,905
Gas Trans Northwest Corp	19,165,420	18,893,501	271,919	98.6%	18,893,501	18,865,674	27,827
Ken River Gas Transmission Company	79,174,002	77,145,967	2,028,035	97.4%	77,145,967	77,013,735	132,232
Mojave Pipeline Co, LLC	1,300,000	900,000	400,000	69.2%	900,000	885,893	14,107
Nova Gas Trans. Ltd	19,804,091	19,352,635	451,456	97.7%	19,352,635	19,352,622	13
Pacific Gas & Electric	18,955,180	18,414,475	540,705	97.1%	18,414,475	18,389,547	24,928
Southern Trails	1,510,000	1,273,384	236,616	84.3%	1,273,384	1,264,498	8,886
Transwestern Pipeline Company	144,525,200	139,627,318	4,897,882	96.6%	139,627,318	138,540,121	1,087,197
TOTALS:	**465,710,374**	**455,419,767**	**10,290,607**	97.8%	**455,419,767**	**453,068,657**	**2,351,110**

2.9 Examination of the Purchase Gas Account (PGA)

Table 2.9 provides a PGA reconciliation of GCIM gas commodity costs. Total PGA commodity costs were $1,124,615,167, and reported GCIM commodity costs for SoCalGas' gas portfolio purchases was $1,106,482,148, which results in a variance of $18,133,019. The variance consists of $8,484,362 costs excluded from GCIM reported commodity costs and net Secondary Market Services revenue of $9,479,465 not reported in PGA gas costs. Other adjustments were for timing differences of $169,193, which consists of credit to PGA for System Integrity in Year 18, Royalty Payment for 2012 Goleta cushion gas conversion project, and broker commission fee in GCIM Years 18 and 19.

Table 2-9
Southern California Gas Company
PGA & GCIM Reconciliation of Commodity Cost
GCIM Year 19
For the Period April 1, 2012 - March 31, 2013

Total PGA Commodity Costs		**$**	**1,124,615,167**
Total GCIM Commodity Costs		**$**	**1,106,482,148**
Variance:		**$**	**18,133,019**
Reconciliation:			
Total PGA Commodity Cost		$	1,124,615,167
PGA Costs Excluded from GCIM Year 19:			
Borrego Springs LNG	116,561		
Realized (Gain)/Loss from OTC Hedge Transactions	5,990		
Realized (Gain)/Loss from Exchange Traded Transactions	1,107,171		
Realized (Gain)/Loss Foreign Currency Exchange	(84,719)		
Carrying Costs of Storage Inventory	139,742		
Interruptible Storage Charges	0		
Transportation Charges in PGA, not in GCIM	7,199,618		
Sub-Total PGA Excluded Costs:		$	(8,484,362)
GCIM Related Transactions Excluded from PGA:			
Net SMS Revenue		$	(9,479,465)
Timing differences for transaction fees and other gas costs excluded from GCIM		$	(169,193)
Total Reconciling Items:			(18,133,019)
Total GCIM Commodity Cost :		**$**	**1,106,482,148**

In addition to the PGA audit, a sampling test was conducted. Some purchase invoice samples for June 2012 were randomly selected. SoCalGas provided copies of supporting documents and purchase invoices for the purpose of the verification. Costs of these purchase invoices were traced to the monthly statement and then to the annual report. The selected purchase invoices reconciled with recorded amounts in the annual report.

2.10 Financial Derivatives

ORA performed a review of hedging transactions for financial derivative transactions reported in the purchase gas account (PGA) to conform the appropriate GCIM calculation and to identify timing differences that were recognized within the GCIM period of April 1, 2012 through March 31, 2013.

Pursuant to D.10-01-023, twenty-five percent (25%) of winter hedging gains and losses are included in GCIM actual costs. Table 2-10 shows ORA's PGA Reconciliation of Financial Gains and Losses for reported NYMEX transaction and over-the-counter (OTC) clear transactions, as well as OTC swaps. Associated transaction fees are also included based on the date of contract when net results may be a financial gain or loss. Transactions that result in gains and/or cash receipts are offset against losses. Other adjustments include reversal of fees from GCIM Year 18. ORA's examination concluded that financial hedging losses for the period were $995,357, which consisted of non-winter hedges and winter hedges; the non-winter hedging for GCIM Year 19 recorded a gain of $3,354. The 25% of winter hedging loss is $249,678 which is included in the GCIM calculation. $749,033 of winter hedging cost (75%) are excluded from the GCIM. In general, natural gas prices are determined through the interaction of two types of markets: cash/financial markets and physical quantities of natural gas. The market involves the purchase and sale of both, when the physical quantities and financial instrument prices are connected to the price of natural gas in the physical market.

Publishers of industry newsletters such as *Platts*, and *Natural Gas Intelligence* take surveys of the price of transactions at a hub or city-gate, where natural gas is sold or delivered (Exhibit 2-1F). The surveyed prices are calculated into an average, which then results in an index of those prices. These index prices are used to base the price of gas at the hub, city-gate, or a specified location.

For hedging natural gas commodities, the most commonly used financial instruments are OTC and exchange derivatives often referred to as options and swaps. These financial instruments are traded in the form of standardized contracts. This standardization provides ease of transfer and the identification of prices.[12] These hedging transactions will generally incur related transaction fees, such as broker and premium fees to purchase the hedging contract.

SoCalGas claims to regularly assess and review on real time basis natural gas market fundamentals. Based on its review and assessment, the utility uses price trends, market fundamentals, and/or risk avoidance[13] to optimize hedge transactions. For forecasting natural gas prices, SoCalGas uses current future prices and basis values provided by Intercontinental Exchange and/or NYMEX, and may consult with Wood MacKenzie and/or PIRA services. SoCalGas states it does not rely on consultants to procure natural gas.[14]

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[12] U.S. Senate Permanent Committee on Investigations: Excessive Speculation in the Natural Gas Market, July 9, 2007.

[13] A.13-06-013, "Master Data Request of the DRA on the Application of Southern California Company's Year 19 GCIM, April, 2012-March, 2013"

[14] Id

TABLE 2-10 Southern California Gas Company PGA Reconciliation-Financial Gains & Losses GCIM Year 19			
All Non-Winter Hedge Transaction (Included in GCIM)	**GCIM - Yr 19**	**Recorded PGA - Yr 19**	**Variance**
NYMEX & OTC Transactions (Gain)/Losses	$ (27,096)		
Transaction Costs	$ 23,742		
Total:	$ (3,354)		
25% Winter Hedge Transaction (Included in GCIM)			
NYMEX & OTC Transaction (Gain)/Losses	$ 242,171		
Transaction Costs	$ 7,507		
Total:	$ 249,678		
Year 19 Financial (Gain)/Losses:	**$ 246,324**	**$ 1,113,161**	**$ 866,837**
Reconciliation:			
GCIM Year-19 Non-Winter & Winter Hedging Losses included in GCIM	$ 246,324		
Excluded 75% of Winter Hedge Loss from GCIM Year 19, included in PGA, not adjusted for timing differences	749,033		
Year 19 Total Financial (Gains)/Losses:	$ 995,357		
ADD: Timing Differences			
Exchange Traded Losses in GCIM Yr19, PGA Yr 18	(550)		
Exchange Traded Losses in GCIM Yr18, PGA Yr 19	4,480		
Exchange Traade Losses in GCIM Yr 19, PGA Yr 20	(16,100)		
Exchange Trade Losses in GCIM Yr 20, PGA Yr 19	129,850		
Broker Fees in GCIM Yr 18, PGA Yr 19	125		
Rounding (Pass)	(1)		
Total Timing Difference Items:	$ 117,804		
Reconciled Derivative PGA Account	**$ 1,113,161**	**$ 1,113,161**	**$ -**

2.11 Winter Hedges

SoCalGas reported $998,710 of winter hedging net losses. Table 2-11 shows twenty-five percent (25%) of net losses of $249,678, which are included in the GCIM. It was confirmed that $749,033, which represents seventy-five percent (75%) of total winter losses, was excluded from GCIM and included in the PGA for Year 19. These losses are directly allocated to core customers for the period. In addition, SoCalGas reported winter hedging transactions for OTC swap/option gains and losses; contract costs that include premiums; and transaction costs for broker fees.

For purposes of reconciliation, ORA determined related hedging costs based on contract date. If the contract date is beyond March 31, it is excluded from the reported GCIM period.

Table 2-11
Southern California Gas Company
Winter Financial Derivatives (Gains) Losses
GCIM Year-19
April 1, 2012 through March 31, 2013

Month	Winter Hedge (Gain)/Losses Included in GCIM	Winter Hedge Fee Included in GCIM	Winter Hedge (Gain)/Losses Excluded From GCIM	Winter Hedge Fee Excluded From GCIM	Winter Hedge Total
Apr-12	$ -	$ -	$ -	$ -	$ -
May-12	$ -	$ -	$ -	$ -	$ -
Jun-12	$ -	$ -	$ -	$ -	$ -
Jul-12	$ -	$ -	$ -	$ -	$ -
Aug-12	$ -	$ -	$ -	$ -	$ -
Sep-12	$ -	$ -	$ -	$ -	$ -
Oct-12	$ (78,225.00)	$ (2,012.96)	$ (234,675.00)	$ (6,038.88)	$ (320,951.84)
Nov-12	$ (168,605.00)	$ (5,222.97)	$ (505,815.00)	$ (15,668.91)	$ (695,311.88)
Dec-12	$ 6,040.00	$ (69.30)	$ 18,120.00	$ (207.90)	$ 23,882.80
Jan-13	$ 2,590.00	$ (114.12)	$ 7,770.00	$ (342.37)	$ 9,903.51
Feb-13	$ (1,998.75)	$ (87.98)	$ (5,996.25)	$ (263.95)	$ (8,346.93)
Mar-13	$ (1,971.75)	$ -	$ (5,914.25)	$ -	$ (7,886.00)
Total	**$ (242,171)**	**$ (7,507)**	**$ (726,511)**	**$ (22,522)**	**$ (998,710)**

	$242,171		**$726,511**
	$7,507		**$22,522**
25% Winter Hedge Included in GCIM:	**$249,678**	**75% Winter Hedge Excluded in GCIM:**	**$749,033**

2.12 Review of Secondary Market Services Revenues

SoCalGas manages its retail core using its assets of storage inventory, injection, withdrawal rights, and core supplies by applying them to Secondary Market Services (SMS). In particular, the SMS uses core assets to execute transactions and fees that are based on market conditions to generate these revenues. These SMS transactions offset core gas costs by using assets that are determined by management not to be directly needed for meeting core customer demand and reliability. The SMS revenue was $10,544,385 less $1,064,920 in overhead costs which results in net revenues of $9,479,465.

Southern California Gas Company
Table 2-12
Summary of Secondary Market Service Revenues
GCIM Year-19
April 1, 2012 through March 31, 2013

Month	SMS Revenue	Less: Overhead	Net Revenues
Apr-12	$ 99,350	$ (125,121)	$ (25,771)
May-12	$ 522,012	$ (287,126)	$ 234,887
Jun-12	$ 366,937	$ (64,295)	$ 302,643
Jul-12	$ 327,451	$ (66,569)	$ 260,881
Aug-12	$ 285,113	$ (67,625)	$ 217,488
Sep-12	$ 20,744	$ (49,880)	$ (29,136)
Oct-12	$ 85,095	$ (79,001)	$ 6,094
Nov-12	$ 2,364,880	$ (50,567)	$ 2,314,313
Dec-12	$ 139,576	$ (78,750)	$ 60,826
Jan-13	$ 1,488,686	$ (60,558)	$ 1,428,127
Feb-13	$ 2,019,028	$ (68,748)	$ 1,950,280
Mar-13	$ 2,825,513	$ (66,680)	$ 2,758,833
Totals:	$ 10,544,385	$ (1,064,920)	$ 9,479,465

2.13 SoCalGas Core Storage Inventory Targets

In D.06-10-029, the Commission approved a Joint Recommendation by ORA, TURN and SoCalGas to modify the utility's management and use of mid-season gas storage capacity for core customers. This recommendation requires more gas to enter storage during the summer for core customer use during the winter heating season. This decision requires SoCalGas to obtain agreement from ORA and TURN for mid-season inventory targets. These targets must be maintained or an agreement from ORA and TURN is needed if inventory storage changes are made by SoCalGas. In either case, these changes are reflected in the GCIM.

Effective December 4, 2008, in D.08-12-020, the Commission adopted Phase 1 of the 2009 SoCalGas' Biennial Cost Allocation Proceeding, (BCAP) Settlement Agreement, expending gas storage by 7 Bcf during the period of 2009 to 2014. Core storage inventory would receive total of 4 bcf starting 2009. The Settlement Agreement requires incremental inventory capacity by 1.0 Bcf each year starting in April 1, 2010 to April 1, 2013.

SoCalGas filed Advice Letter 4436 on December 14, 2012, which was approved by the Commission on January 13, 2013. This update changed the storage target variance allowance from +5/-2 Bcf, to +0/-2 Bcf.

Based on review of SoCalGas' inventory records, core physical inventory levels for July 2012, showed 47.4 Bcf, which met the 47 Bcf inventory target. For GCIM Year 19, the October 31, 2012 core storage inventory target was 82 Bcf, with a variance allowance of Bcf +0/-2. For October 31, 2012, SoCalGas reported core storage inventory at 80.3 Bcf, which is within the variance allowance of -2 Bcf. Adjustments to inventory were for non-core monthly imbalances, non-core inventories and SMS activities. The data shows that SoCalGas met the core inventory target requirements.

TABLE 2-13
Southern California Gas Company
Core Storage Inventory for Summer and Winter Targets
GCIM Year 19
April 1, 2012 through March 31, 2013

System Inventory (Bcf)	7/31/12	10/31/12
Bcf Target	47	82
Physical Inventory	129.92	133.4
Month End Imbalances	(7.41)	(3.22)
Less: Non-Core Inventory	(46.6)	(48.8)
CAT for July 31, 2012	(1.3)	0.0
Secondary Market Services	(27.2)	(1.1)
Total Core Storage Inventory Results	47.4	80.3

Note: CAT inventory only excluded in July

2.14 Interstate Capacity Procurement

Advice Letter 4158, effective November 26, 2010, authorized SoCalGas to update its Capacity Planning Range, which was based on the California Gas Report for 2010. The filing was to comply with D.04-09-022 to update SoCalGas and SDG&E's combined portfolio capacity for GCIM Year 18 and 19 winter and non-winter seasons, beginning in April 2011 and ending March 2013. The following table provides a summary of the minimum and maximum capacity value by season for the reporting period:

GCIM Year 19	**Season**	**Minimum Capacity Value**	**Maximum Capacity Value**
	Non-Winter 04/2012 to 10/2012	948.0 MDth/d	1,264.0 MDth/d
	Winter 11/2012 to 03/2013	1,053.4 MDth/d	1,264.0 MDth/d

The update enabled SoCalGas to hold firm interstate pipeline capacity at no less than 90% of its forecasted core average daily load during the spring and summer months, and no less than 100% during the fall and winter months. This established the minimum firm capacity for the period of April 2012 to October 2012 at 948.0 MDth/d, and 1,053.4 MDth/d for November 2012 to March 2013.

SoCalGas' GCIM Year 19 Application (A.13-06-013) in Appendix C reports actual capacity performance of 948.6 MDth/d from April 2012 to August 2012; 948.1 MDth/d from September 2012 to October 2012; and 1053.4 MDth/d for November 2012 to March 2013.

A review of interstate capacity schedules for new and renewed contracts during GCIM Year 19 shows a total volume of 419,759 MMBtus. Proportionally, El Paso Natural Gas comprises 60% of the interstate capacity; Kern River Gas Transmission, 15%, and Transwestern Pipeline, 25%. SoCalGas reports continuous efforts to attain shorter-term interstate capacity contracts in order to purchase more volume at competitive market prices. This change is to assist in ensuring availability of monthly supplies, as well as meet core storage demand. SoCalGas maintained a gas supply portfolio consisting of approximately 54% of long-term supply agreements; 42% month-to-month base load agreements; and 4% for daily net gas purchases.[15]

[15] A.13-06-013 Southern California Gas Company Year 19 (2012-2013) Gas Cost Incentive Mechanism.

APPENDIX A

EXHIBITS FOR GCIM YEAR 19 REPORT

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