Application No.: A.08-09-023
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Date: March 6, 2009
Witness: Edward Fong

SOUTHERN CALIFORNIA GAS COMPANY

ADVANCED METERING INFRASTRUCTURE

CHAPTER II

SUMMARY OF AMI BUSINESS CASE

Errata to

Prepared Direct Testimony

of

Edward Fong

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

March 6, 2009

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I. INTRODUCTION

Southern California Gas Company ("SoCalGas") is requesting California Public Utilities Commission ("CPUC" or "Commission") approval to deploy a gas advanced metering infrastructure ("AMI") over the 2009-2015 timeframe. The estimated deployment cost for the SoCalGas AMI is approximately $1.08~~1.09~~ billion, of which $901~~903~~ million is capital expenses and $178~~187~~ million is operating and maintenance ("O&M") expenses. Included in the $1.08~~1.09~~ billion of estimated expenses, is a request for $~~12.4~~12.7 million of pre-deployment funding.

SoCalGas AMI cost estimates are based on AMI vendor responses to a set of request for proposals ("RFP") issued in May 2008. SoCalGas compared the cost of implementing: (1) a hybrid AMI system that would utilize the Southern California Edison Company ("SCE") AMI network for the SoCalGas meters that are located in the SCE overlap territory combined with another selected AMI technology for the remainder of the SoCalGas meters ("Hybrid") with (2) a standalone AMI network that would cover all of the gas meters in SoCalGas' service territory ("Stand Alone"). Vendor proposals (bids) for AMI technology, information system integration, endpoint deployment, program management, and a meter data management system ("MDMS") are being evaluated. Several competing AMI technologies were proposed by different vendors. SoCalGas cost estimates reflect the proposals from the short listed vendors. In addition, SoCalGas requested that vendor proposals explicitly include water and electric meter capability as part of the vendor technology offering.

II. SUMMARY OF RESULTS

SoCalGas cost estimates and resulting business case analyses demonstrate that SoCalGas ratepayers are better off by approximately $121~~137~~ million in present value of revenue requirement terms[1] under the Stand Alone scenario. Therefore, SoCalGas proposes to implement

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[1] See Tables II-2 and II-3, Net Present Value ("NPV") of Revenue Requirements. Hybrid scenario (Table II-2) shows NPV of $102~~123.8~~ million of costs and Stand Alone scenario (Table II-3) shows NPV of $~~13.2~~19.0 million of benefits for a total difference of $121~~137~~ million.

a Stand Alone AMI system for the complete SoCalGas service territory. Table II-1 shows the breakdown of SoCalGas meters within: (1) SCE's service territory; (2) San Diego Gas & Electric Company's ("SDG&E") service territory; and, (3) remaining SoCalGas meters that are not in SCE's or SDG&E's service territories.

Table II-1

SoCalGas Estimated Meters

Deployment Period 2009 – 2015

(000's)

	2009	2010	2011	2012	2013	2014	2015
SCE Overlap	3,786	3,822	3,864	3,911	3,959	4,009	4,059
Non-SCE Overlap	1,854	1,872	1,893	1,916	1,939	1,964	1,988
SDG&E Overlap	104	105	106	107	109	110	111
Total	5,744	5,800	5,863	5,934	6,007	6,082	6,159

For the Hybrid scenario, SoCalGas estimated SCE AMI network service fees on an incremental costs basis. SoCalGas used the vendor responses to the RFP for AMI module per unit costs, installation costs of gas modules, Information Technology ("IT") systems and systems integration and costs for MDMS installation and development. SoCalGas also estimated several incremental equipment and network communications costs based on the SDG&E experience, although specific SoCalGas customer information system ("CIS") integration efforts are estimated for the SoCalGas AMI cost estimates. Meter replacement cost estimates assume current per unit cost experienced by SoCalGas.

Most important, SoCalGas' Stand Alone cost estimates represent a base case that sets the "not to exceed" limit. SoCalGas issued an RFP for vendor bids that meets the basic functionality requirements identified in the testimony of SoCalGas witnesses Mr. Mark Serrano (Chapter III) and Mr. Christopher Olmsted (Chapter IV). Vendor proposals could provide solutions that would integrate directly with SCE's AMI system or solutions that could be independent of SCE AMI technology (Stand Alone technology). SoCalGas reserved the right to select the vendors that will provide the greatest long-term value to SoCalGas' ratepayers.

Tables II-2 and II-3 include the present value of revenue requirements ("PVRR") of costs and benefits for SoCalGas' assumed Hybrid scenario and the Stand Alone scenario, respectively. Tables II-2 and II-3 include the total present value of operating benefits and customer gas conservation benefits and reduced theft as well as societal benefits (i.e., environmental benefits from reduced emissions).

Table II-2

Undiscounted Cash Flow and

Present Value of Annual Revenue Requirements and Societal Benefits

Hybrid Scenario

($millions)

<u>**Replaced Entire Table II-2**</u>

		IT Development		Gas Module and Meter Installation Years					Post Deployment
	Total	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016-2034**
Undiscounted Cash Flow									
Costs	2,240.6	25.6	72.9	175.0	204.9	218.6	227.5	207.4	1,108.7
Operating Benefits	(2,882.7)	(2.2)	(2.3)	(10.8)	(29.1)	(51.7)	(63.9)	(79.2)	(2,643.3)
Other Rate Payer Benefits	(789.2)	-	-	(1.7)	(5.3)	(9.1)	(12.5)	(16.5)	(744.1)
Societal Benefits	(29.2)	-	-	(0.1)	(0.4)	(0.6)	(0.9)	(1.2)	(26.0)
Present Value Revenue Requirement									
Costs	1,151.1	(6.2)	(5.6)	67.0	83.3	97.5	109.3	111.7	694.0
Operating Benefits (76.2% of Costs)	(877.7)	(1.9)	(1.8)	(5.3)	(14.3)	(24.9)	(33.4)	(40.0)	(756.0)
Terminal Value	(22.2)	-	-	-	-	-	-	-	(22.2)
Conservation Benefits	(148.0)	-	-	(1.2)	(3.5)	(5.5)	(6.9)	(8.4)	(122.4)
Reduced Losses (theft)	(1.0)	-	-	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.8)
NPV Revenue Requirement & Other Rate Payer Costs (Benefits)	**102.3**	**(8.1)**	**(7.4)**	**60.4**	**65.5**	**67.1**	**69.0**	**63.2**	**(207.4)**
PV Societal Benefits									
Reduced Emissions	(8.3)	-	-	(0.1)	(0.2)	(0.4)	(0.5)	(0.6)	(6.5)
NPV Societal Costs (Benefits)	**93.9**	**(8.1)**	**(7.4)**	**60.4**	**65.2**	**66.7**	**68.5**	**62.6**	**(213.9)**

Table II-3

Undiscounted Cash Flow and

Present Value of Annual Revenue Requirements and Societal Benefits

Stand Alone Scenario

($millions)

Replaced Entire Table II-3

		IT Development		Gas Module and Meter Installation Years					Post Deployment
	Total	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016-2034**
Undiscounted Cash Flow									
Costs	1,842.8	25.5	64.4	168.2	200.5	210.6	215.8	194.1	763.7
Operating Benefits	(2,905.1)	(2.2)	(2.3)	(10.8)	(29.0)	(51.7)	(63.9)	(79.2)	(2,665.9)
Other Rate Payer Benefits	(829.2)	-	-	(1.7)	(5.3)	(9.1)	(12.5)	(16.5)	(784.0)
Societal Benefits	(29.2)	-	-	(0.1)	(0.4)	(0.6)	(0.9)	(1.2)	(26.0)
Present Value Revenue Requirement									
Costs	1,039.6	(6.3)	(8.2)	63.0	77.5	90.6	101.4	104.4	617.1
Operating Benefits (85% of Costs)	(883.3)	(1.9)	(1.8)	(5.3)	(14.3)	(24.9)	(33.4)	(40.0)	(761.7)
Terminal Value	(26.4)	-	-	-	-	-	-	-	(26.4)
Conservation Benefits	(148.0)	-	-	(1.2)	(3.5)	(5.5)	(6.9)	(8.4)	(122.4)
Reduced Losses (theft)	(1.0)	-	-	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.8)
NPV Revenue Requirement & Other Rate Payer Costs (Benefits)	**(19.0)**	**(8.2)**	**(10.0)**	**56.5**	**59.7**	**60.2**	**61.0**	**55.9**	**(294.2)**
PV Societal Benefits									
Reduced Emissions	(8.3)	-	-	(0.1)	(0.2)	(0.4)	(0.5)	(0.6)	(6.5)
NPV Societal Costs (Benefits)	**(27.3)**	**(8.2)**	**(10.0)**	**56.4**	**59.5**	**59.8**	**60.5**	**55.3**	**(300.6)**

Tables II-2 and II-3 represent the cash flow of estimated expenses and benefits during the deployment period for the Hybrid and Stand Alone scenarios, respectively. Table II-3 Stand Alone scenario shows that approximately 85.0%~~84.5%~~ of the total AMI life cycle costs are covered by estimated operating benefits (on a revenue requirements basis).[2] The Hybrid scenario analysis shows that approximately 76.2%~~74.9%~~ of the total AMI life cycle costs are covered by estimated operating benefits. These cash flows represent the actual undiscounted estimated capital and O&M expenditures and benefits during the deployment period (2009-2015). Tables II-2 and II-3 also show the cash flows of estimated expenses and benefits converted to the present value of revenue requirements.

[2] 85.0%~~84.5%~~ = PVRR Operating benefits/PVRR costs = $883.3/$1,039.6~~888.6~~ /$~~1,051.0~~

III. BACKGROUND AND FOUNDATION FOR THE AMI BUSINESS CASE

Witness Ms. Michelle Mueller (Chapter I) has provided a synopsis of the basic foundation provided the Energy Action Plan (EAP) and EAP II for AMI. In addition, the Commission conducted an extensive proceeding, R.02-06-001, that developed business case analysis guidelines for Advanced Metering, Demand Response and Dynamic Pricing. As a result of R.02-06-001, the Commission directed Pacific Gas & Electric ("PG&E"), SCE and SDG&E to file applications proposing AMI deployment.

A. PG&E and SDG&E AMI Deployments Include AMI Gas Modules and Daily Gas Meter Reads

The Commission authorized funding for AMI deployment for PG&E in Decision (D.) 06-07-027 and SDG&E in D.07-04-043. PG&E and SDG&E are combined gas and electric utilities and funding for their AMI projects included installation of gas communication modules (gas modules) on gas meters to provide daily meter reads. The Commission authorized funding of approximately $1.7 billion for PG&E to install AMI on 5.1 million electric meters and 4.2 million gas meters. The Commission has authorized funding of approximately $570 million for SDG&E to install AMI on 1.4 million electric meters and 900,000 gas meters. In total, the Commission has approved and authorized funding that would deploy over 5 million gas AMI modules within the State.

B. SDG&E's Experience with AMI Implementation Provides SoCalGas with a Reasonable Benchmark for Vendor Cost Estimates of the Hybrid and Stand Alone Scenarios

SDG&E is working with the current SCE AMI technology vendor. SCE and SDG&E are deploying similar AMI technologies. The most significant difference between the SCE and SDG&E AMI deployment is the installation of AMI gas modules for SDG&E. SDG&E's technical knowledge of gas and electric meter integration provides a solid basis or reality check for SoCalGas' per unit cost estimates for gas modules, gas meters and installation in the Hybrid scenario. Moreover, SDG&E's experience with evaluating, designing and integrating MDMS software that includes both electric and gas meter reads provides SoCalGas an IT architectural foundation for integration with current SoCalGas legacy systems and potential integration with SCE systems. SoCalGas per unit cost estimates for gas modules, gas meters and installation have been validated by SDG&E's experience and knowledge.

C. Integration with SCE's AMI System Will Require Enhancements to Separately Collect and Track the SoCalGas Meter Read at the Electric Meter Level and Head-End System and Require Additional Hardware

SoCalGas could install SCE AMI compatible gas modules that will be able to communicate with SCE electric meters and utilize the SCE backhaul communications network for data transmission back to SCE AMI network and data systems and ultimate transfer of gas meter read data to SoCalGas data servers and MDMS. However, the current SCE AMI technology is not currently designed for splitting meter reads for different companies and would require modification to the electric meter end-point recognition capabilities, head-end system and possibly to SCE's MDMS architecture to include SoCalGas meter asset information. In addition, the SCE AMI technology architecture will require more SCE collector meters (cell relays) and additional head-end server and MDMS capacity as SoCalGas gas modules are integrated into SCE's AMI network.

IV. BUSINESS CASE ANALYSIS

A. Implementation of a Stand Alone AMI System is the Best Alternative for SoCalGas Customers

SoCalGas compared the cost of the Hybrid gas AMI system with a SoCalGas Stand Alone AMI system. SoCalGas developed and analyzed the potential Hybrid case with cost estimates, assuming that SCE's AMI technology will accommodate SoCalGas gas meter reads and such reads will be provided at some reasonable service fee that will reflect SCE's incremental cost attributable to the additional gas meter reads. SoCalGas evaluated alternative stand alone AMI technologies via its RFP process. SoCalGas provides cost estimates that are based on SoCalGas gas modules communicating through SCE's AMI network and the SoCalGas Stand Alone network. SoCalGas carefully considered the potential synergies of using the SCE AMI network, but the necessary bifurcation of SoCalGas customers between two different AMI technologies, additional SCE cell relay meter requirements, additional repeaters for gas module communications, and the integration of multiple head-end AMI systems led to higher costs.

B. Deployment of the Hybrid Only AMI System with SCE/SoCalGas Overlap Customers is Not a Viable Solution

SoCalGas recognizes the logic of Division of Ratepayer Advocates ("DRA") witness Mr. Blunt's statement in prepared testimony in SCE's AMI proceeding, A.07-07-026.

> "The potential public policy failure of funding an exclusive-for-electricity-network is one of 'sub-optimization'."[3]

Mr. Blunt expands on the discussion of using the future AMI network to serve gas and water ratepayers and the common sense logic of not duplicating two or three different communications for gas and water reads.

However, if SoCalGas implemented AMI only for SoCalGas customers in SCE's service territory using SCE's chosen technology, then the SoCalGas customer base would literally be bifurcated between the "haves" and "have-nots". With that in mind, SoCalGas would then be required (in the interest of fairness and equity) to implement a standalone AMI system for the SoCalGas customers located in the non-SCE areas of SoCalGas service territory. Therefore, two separate systems would be needed and the added cost of interfacing and integrating with two different "head-end" systems would be necessary. Moreover, the identification, dispatching, and

[3] DRA Testimony, Chapter 6, Chris Blunt, p. 6-2, lines 1-2.

tracking of gas module, network communications and new installations would be complex since SoCalGas would need to interface asset management and customer information systems with SCE's head-end system and SoCalGas' head-end system.

C. SoCalGas Operational Efficiencies are Reflected in Estimated Benefits and will Net Against Gas AMI Deployment Revenue Requirements During the Deployment Period

SoCalGas estimates approximately $~~888.6~~883.3 million of operational benefits (present value of cost savings and future cost avoidance) from eliminating manual meter reading, reducing customer services field ("CSF") order activities and customer billing activities. Post-deployment AMI operational benefits and costs will be reflected in SoCalGas' post-deployment general rate case ("GRC") revenue requirement requests. The SoCalGas RFP process evaluated the total life cycle costs of a complete SoCalGas AMI deployment covering SCE's overlap service territory (approximately 4.0 million meters by year-end 2015) and the remaining non-SCE territory (approximately 2.0 million meters). SoCalGas determined that the potential SCE synergies were not sufficient to overcome integration cost between two different AMI systems and systems integration necessary to interface with the SCE AMI head-end and MDM systems. SoCalGas "stand alone" net benefits are greater in the Stand Alone scenario than in the Hybrid scenario. Communications network costs are a small portion of total project costs (typically around 10%). Therefore, potential synergies from using SCE AMI communications network are relatively small compared to the additional cost for integration and addition of gas module end-points to SCE's electric meter collectors, head-in capacity and SCE synchronization with SoCalGas meter asset management systems.

D. Gas Conservation Impact and Benefits

Under their AMI programs, PG&E and SDG&E collect reads from gas meters on a daily basis, with daily usage intervals, which can be presented on the web to the customer. Month-to-date customer usage and bill information can also be made available to customers using a telephone via an interactive voice response ("IVR") system.[4] The ability for the customer to access and view their usage and billing data during the monthly billing cycle provides a foundation for customer behavioral changes as noted in Dr. Sarah Darby's testimony (Chapter V). SoCalGas' AMI RFP identified the potential need for hourly gas usage data to be collected, transmitted and stored on enterprise servers 2-3 times per day. Specifically, SoCalGas will provide early high bill alerts to the customer, thereby promoting and facilitating gas usage reduction from a portion of the customer base. These estimated information impacts and corresponding behavioral changes are described in SoCalGas witness Dr. Darby's testimony (Chapter V) and estimated conservation impacts are described in witness Mr. J. C. Martin's testimony (Chapter VI).

E. The Hybrid Scenario Cost Estimates Include SCE AMI Services Fees and Charges that are Assumed to be Incremental Cost Based

These incremental costs are extrapolated from SDG&E's incremental costs for additional communication network collectors (cell relay meters) and repeaters for gas modules, incremental license fees for head-end software based on the increased number of gas module end points, incremental connectivity costs (WAN backhaul), and additional back office support for troubleshooting.

Any additional fees and charges based on incremental SCE activities needed to support gas module integration into SCE AMI system would only increase the total cost of the Hybrid scenario. SoCalGas has included the minimum identifiable incremental cost to SCE using the SDG&E experience of adding gas modules to iTRON's OpenWay® network. SoCalGas has not included the additional lost benefits that SCE may incur with the likely addition of more electric cell relay meters. Cell relay meters are not able to have the remote connect/disconnect functionality and therefore will reduce SCE's operating benefits. SoCalGas accepts that SCE must include an adder for the incremental AMI project risks and opportunity costs for additional

[4] Month-to-date usage and bill available on the IVR is similar to the financial institutions having account balances available through the telephony channel.

resources as a result of SoCalGas AMI gas module services. Nevertheless, if SCE does end up providing AMI services to SoCalGas, the Commission should have oversight and review of SCE fees and charges to SoCalGas to avoid inter-utility ratepayer subsidization and to optimize the usage and capabilities of SCE AMI network. SoCalGas estimates of incremental SCE costs attributable to integration of SoCalGas gas modules with SCE's AMI system are conservative.

Therefore, in the Hybrid scenario, SoCalGas estimates AMI deployment predicated on integration with SCE's AMI system. Estimated SCE service fees or charges for integration with SCE's AMI system are solely based on the incremental costs attributable to SoCalGas' additional gas meter endpoints and impacts on SCE's AMI network, hardware, software, operations maintenance and systems integration. These incremental costs include one-time deployment costs and going-forward annual costs for these incremental activities and expenses.

F. SoCalGas' AMI Project Provides Net Societal Benefits of $27.3~~21.5~~ Million and Net Ratepayer PVRR Benefits of $19.0~~13.2~~ Million Given an Approximate 1% Conservation Impact.

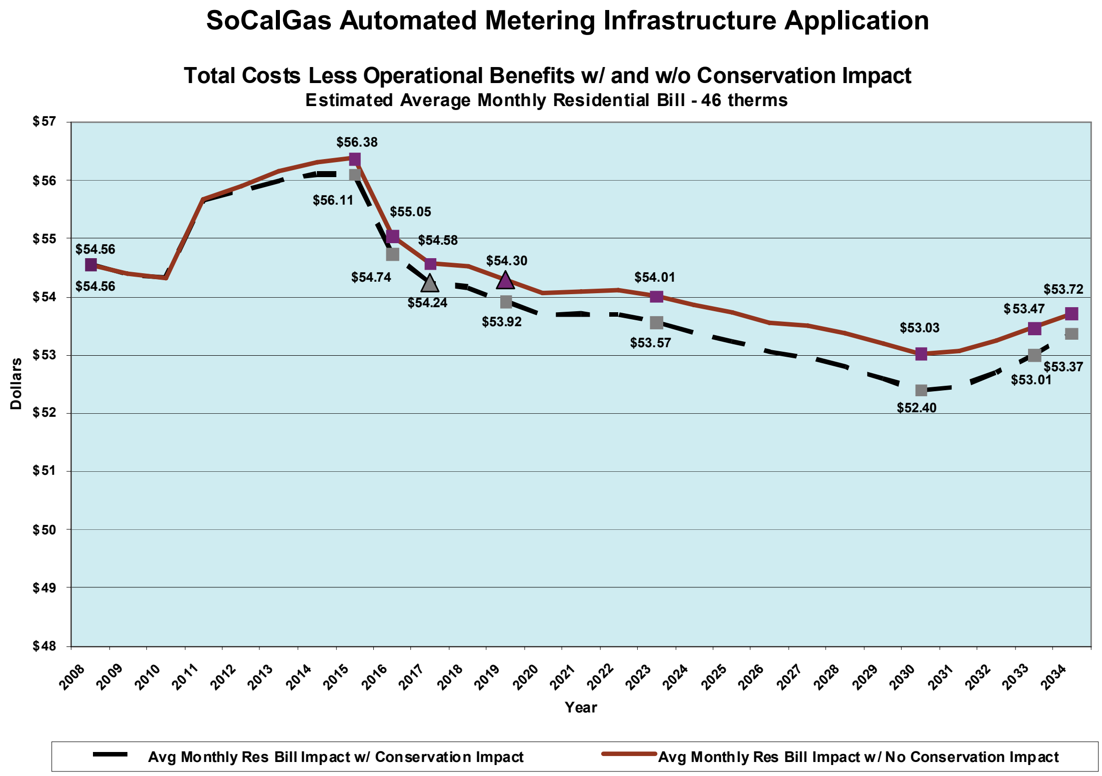
As shown in Table II-3, the present value of revenue requirements and conservation impact shows ratepayer benefits of approximately $19.0~~13.2~~ million given a 1% conservation impact. The overall impact on the average residential customer bill is shown in Figure II-1. Assuming an average annual conservation impact of 1% of core customer gas throughput, the average residential customer is expected to have lower bills by year 2017 (just two years after SoCalGas AMI deployment is completed). The average residential bill will continue to decline thereafter until year 2030.[5]

[5] AMI gas modules installed in 2011 are then terminated in year 2030 (estimated 20 year book life).

Figure II-1

Annual Residential Bill Impact

Replaced Entire Figure II-1



G. Revenue Requirements and Ratepayer Benefits

The deployment period (2009-2015) cash flow and revenue requirements (undiscounted) for cost and benefit categories are shown in Table II-4 (by year). In addition, the undiscounted life cycle expenses and benefits (capital and O&M cash flow) for each of the major cost categories are shown in Figure II-2. As shown in Table II-3, the present value of operating benefits (revenue requirements) is approximately 85.0%~~84.5%~~ of total life cycle expenses.

Table II-4

Annual Cash Flow and Revenue Requirements (undiscounted)

SoCalGas Stand Alone Scenario

Deployment Period 2009-2015

($millions)

Replaced Entire Table II-4

Cash Flow	**Total**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Costs								
Capital	900.9	22.2	60.4	143.0	169.7	175.1	176.3	154.2
O&M	178.2	3.2	4.0	25.2	30.7	35.5	39.5	39.9
Total	1,079.1	25.5	64.4	168.2	200.5	210.6	215.8	194.1
Benefits								
Capital	51.0	-	-	4.1	9.5	16.1	11.3	10.0
O&M	188.2	2.2	2.3	6.7	19.5	35.6	52.6	69.2
Total	239.2	2.2	2.3	10.8	29.0	51.7	63.9	79.2
Gas Theft Reduction	0.3	-	-	0.0	0.0	0.1	0.1	0.1
Conservation	44.8	-	-	1.7	5.3	9.0	12.4	16.4
CO_2 Reduction	3.2	-	-	0.1	0.4	0.6	0.9	1.2
Total	48.4	-	-	1.8	5.7	9.7	13.4	17.7
Revenue Requirements								
Costs								
Capital	540.5	(10.7)	(14.6)	62.4	86.3	113.2	141.3	162.5
O&M	181.0	3.3	4.1	25.5	31.2	36.1	40.2	40.6
Total	721.5	(7.4)	(10.5)	87.9	117.5	149.3	181.5	203.2
Benefits								
Capital	21.4	-	-	0.6	1.9	5.0	6.4	7.6
O&M	190.9	2.3	2.3	6.8	19.8	36.1	53.4	70.2
Total	212.3	2.3	2.3	7.4	21.7	41.0	59.8	77.8
Gas Theft Reduction	0.3	-	-	0.0	0.0	0.1	0.1	0.1
Conservation	44.8	-	-	1.7	5.3	9.0	12.4	16.4
CO_2 Reduction	3.2	-	-	0.1	0.4	0.6	0.9	1.2
Total	48.4	-	-	1.8	5.7	9.7	13.4	17.7

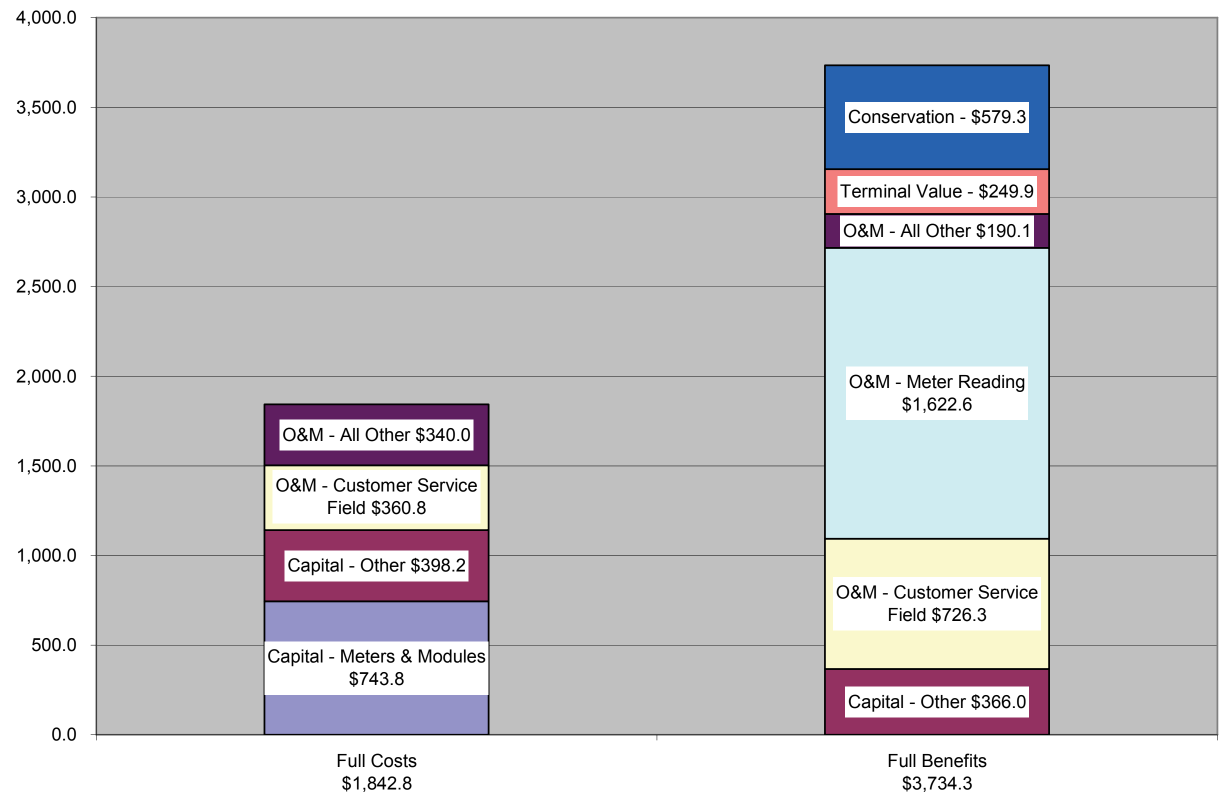
Figure II-2

Undiscounted Cash Flow Costs and Benefits Comparison

SoCalGas Stand Alone Scenario

($millions)

Replaced Entire Figure II-2



SoCalGas witness Mr. Olmsted (Chapter IV) identifies estimated direct costs of $146.4~~140.9~~ million related to IT systems development and integration-related costs and the deployment of an AMI communications network. The bulk of the estimated IT expenditures will occur in 2009-2010. Gas module deployment and meter replacements will start in 2011. SoCalGas witness Mr. Serrano (Chapter III) identifies approximately $620.1~~633.4~~ million of project management, gas modules, gas meters, installation and other expenses for the deployment period 2009-2015. The estimated costs identified in Mr. Olmsted's and Mr. Serrano's testimony are in direct cost and 2008 constant dollars.

As shown in Figure II-2, the estimated operating benefits resulting from elimination of manual meter reading, elimination of a subset customer services field (CSF) orders and a reduction in billing exception processing leads to substantial operating benefits. The majority of the estimated benefits reflect reductions in workforce. Table II-5 summarizes the estimated workforce impacts from 2008 levels. Witness Mr. Serrano discusses the specific work and activity level reductions in his testimony (Chapter III).

Table II-5

Estimated Workforce Impacts

(FTE = Full-time equivalent)

Employee Reductions in 2016 *

	Headcount	FTEs
Meter Reading**	1085	718
CS Field	~~142~~ 208	~~142~~ 208
Billing	35	35
Other	9	9
Total Reductions	~~1271~~ 1337	~~904~~ 970

* Reduction from 2008 levels

** Includes part-time and full-time workforce in all SoCalGas service territory, including SDG&E overlap

V. KEY BUSINESS CASE ASSUMPTIONS

A. A 20-Year Gas Module Useful Life is Used in the Business Case Calculations

Vendor responses to the SoCalGas AMI RFP have provided estimated 20-year useful life for the gas modules since the battery life is expected to be 20 years. At the end of the battery life (which assumes up to 2-3 meter reads per day are transmitted), the gas modules are assumed to be no longer useful. Witness Mr. Serrano expands on the 20-year battery life and failure rates in his testimony (Chapter III).

B. The Term of Business Case is From 2009-2034 or 26 Years

Specifically, IT systems development and integration is planned for 2009-2010. Gas module installation should begin in 2011 with initial deployment completed by year-end 2015. A 20-year gas module life means that the last useful year for the gas modules deployed in 2015 will be year 2034 (assumes that the first year of the gas module is the year of the installation). Witness Mr. Michael Foster (Chapter VII) testimony discusses the 26-year term of the AMI analysis period.

C. A Terminal Value Calculation is Necessary Because Gas Modules and Gas Meters Will Continue to Have Remaining Useful Life After 2034

The terminal value of the gas modules with remaining book life is the discounted stream of annual benefits per gas module for their remaining book life. The terminal value is approximately 2.5%~~3%~~ of the total benefits of the business case. Witness Mr. Foster's (Chapter VII) testimony discusses the terminal value calculation.

D. Cost for AMI Deployment in the SDG&E Overlap Territory is not Included in the Analysis

SoCalGas has been authorized funding to deploy drive-by remote automated meter reading ("RAMR") in its test year ("TY") 2008 GRC. SoCalGas will have deployed approximately 150,000 RAMR units by 2009. SoCalGas is planning to use the GRC RAMR funding for deploying AMI in the SDG&E overlap services territory (estimated to be 106,000 SoCalGas meters in 2011).

E. Project Contingency of 10% of Deployment Period Estimated Costs is Included in the Estimated Deployment Cost of $~~1.09~~1.08 Billion

SoCalGas has included an overall AMI project contingency of 10% or approximately $~~99.1~~98.1 million in the total estimated costs during the deployment period. For a project of this financial magnitude and the long duration of the deployment period (2009-2015), a 10% project contingency is prudent and reasonable amount. See Table II-6. Specifically, this contingency encompasses deployment capital and O&M expenses as described in the testimony of witnesses Mr. Serrano (Chapter III), Mr. Olmsted (Chapter IV), and Mr. Martin (Chapter VI). The purpose of project contingency is to cover unanticipated, unknown or irreducible risks that may impact project schedule, resource availability, functional requirements and other circumstances. See Figure II-3 for contingency as part of the sharing mechanism.

Table II-6

Project Contingency

($millions)

Replaced Entire Table II-6

	Contingency Components		
	O&M	Capital	Total All
Chapter 3 - Serrano	$13.4	$65.7	$79.2
Chapter 4 - Olmsted	$2.8	$16.2	$18.9
TOTAL ALL	**$16.2**	**$81.9**	**$98.1**

VI. TESTIMONY CROSS-REFERENCE FOR COSTS AND BENEFITS

Table II-7 provides a cross reference to major estimated cost and benefit elements and witness testimonies (chapter reference).

Table II-7

Costs and Benefits and Witness Testimony

($millions)

Replaced Entire Table II-7

Benefits - Description	Deployment 2009-2015	Post-Deployment 2016-2034	Total	Chapter
O&M Operational/Rate Payer Benefits	120.7	1,080.6	1,201.3	3
Capital Rate Payer Benefits	44.4	225.7	270.1	3
Sub-Total Rate Payer Benefits (in constant 2008 $)	**165.1**	**1,306.2**	**1,471.3**	
Conservation Impact (in nominal $)	44.8	530.9	575.7	5 & 6
Terminal Value (in nominal $)	0.0	249.9	249.9	7
Theft (in constant 2008 $)	0.3	2.1	2.4	3
Sub-Total Non-revenue Requirement Benefits	**45.1**	**782.9**	**828.0**	
Environmental Impact (in nominal $)	3.2	26.0	29.2	5 & 6
Total All Benefits	**213.4**	**2,115.2**	**2,328.6**	
Overheads, Escalation, Sales Taxes on all Benefits	74.2	1,360.7	1,434.9	7
Total All Benefits (Loaded, Escalated, Undiscounted Dollars)	**287.6**	**3,475.9**	**3,763.5**	

Costs - Description	Deployment 2009-2015	Post-Deployment 2016-2034	Total	Chapter
O&M Operational Costs	86.4	128.1	214.5	3
O&M IT and Network Related Costs	20.3	136.0	156.3	4
Conservation Program Related Costs	5.5	0.0	5.5	6
O&M Portion of Project Contingency	16.2	0.0	16.2	2
Sub-Total O&M Costs (in constant 2008 $)	**128.5**	**264.0**	**392.5**	
Capital Operational Costs	533.7	154.5	688.2	3
Capital IT and Network Related Costs	126.0	34.1	160.2	4
Capital Portion of Project Contingency	81.9	0.0	81.9	2
Sub-Total Capital Costs (in constant 2008 $)	**741.6**	**188.6**	**930.3**	
Total All Costs (in constant 2008 $)	**870.1**	**452.7**	**1,322.8**	
Overheads, Escalation, Sales Taxes on all Costs	209.0	311.0	520.0	7
Total All Costs (Loaded, Escalated, Undiscounted Dollars)	**1,079.1**	**763.7**	**1,842.8**	
Net Benefits	**(791.5)**	**2,712.2**	**1,920.7**	

VII. OTHER REGULATORY ISSUES

A. The Cost Recovery of SoCalGas Assets That Are Replaced (e.g., gas meters and meter set assemblies) as a Result of Deploying SoCalGas AMI Shall Be Recovered on the Remaining Asset Life Schedule

Approximately 1.1 million additional gas meters will be replaced as result of SoCalGas' deployment of AMI during 2011-2015. These gas meter replacements are described in SoCalGas witness Mr. Serrano's testimony (Chapter III, Section VI.D.). Similar to cost recovery treatment in PG&E's, SDG&E's and SCE's AMI cases, meters that need to be replaced will retain the current cost recovery schedule and treatment. The remaining life of these meter assets are established in the gas meter asset classes. These meters need to be replaced because certain older family and types of meters are not compatible with the gas communications modules. In addition, SoCalGas will accelerate meter changes that would otherwise have been scheduled in the near-term post-deployment time period (2016-2020) into the deployment period. Accelerating planned meter changes into the deployment period will avoid significant post-deployment cost related to replacing recently installed gas modules with one that is compatible with the replacement meter. In other words, by accelerating planned meter changes, SoCalGas is avoiding a double purchase of gas modules during the near-term post deployment period, 2016-2020.

B. SoCalGas Proposes to Establish a Balancing Account to Record AMI Costs During the Deployment Period 2009-2015 And To Include The Operational Benefits Per Meter To Net Against Such Costs As The AMI Gas Modules Are Installed And Operating

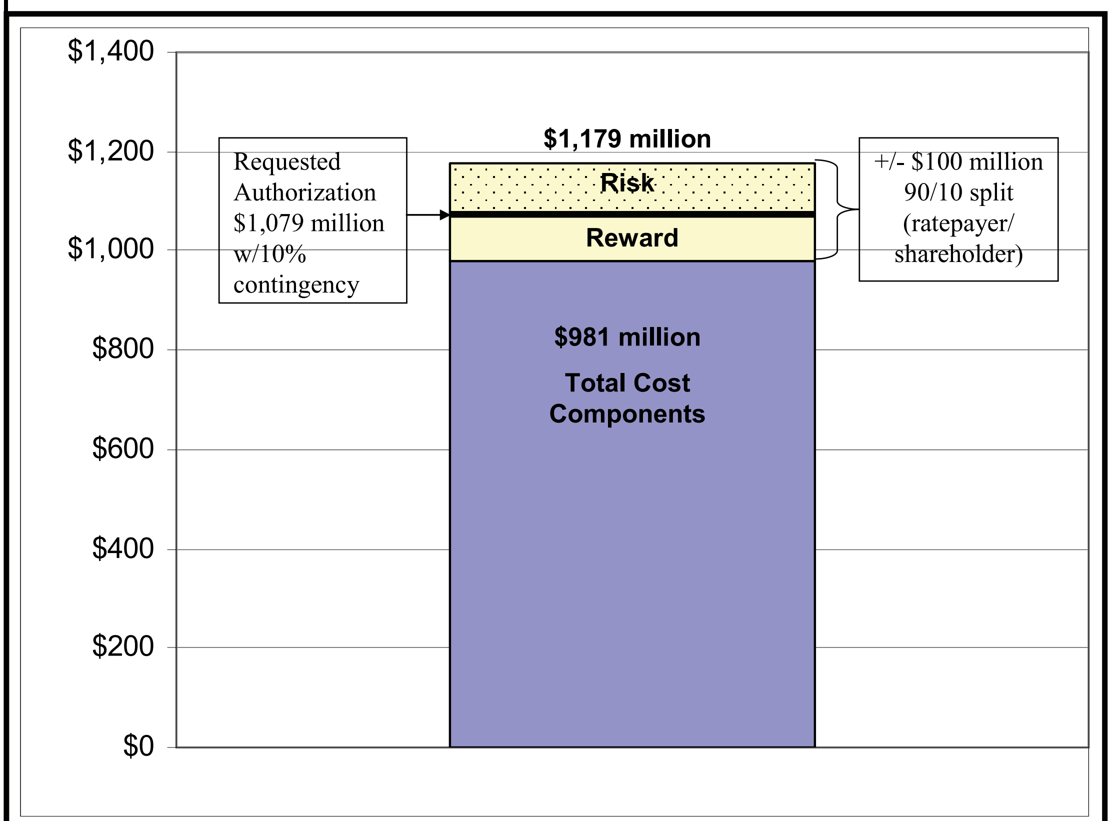
SoCalGas is requesting authorization to establish a balancing account to record AMI deployment costs and to record estimated benefits per each installed gas module. O&M benefits are estimated to begin an average of five months following the physical meter installation. The five month lag for realization of operational benefits is described in SoCalGas witness Mr.

Serrano's testimony (Chapter III). The specific cost recovery mechanism and balancing account treatment are described in SoCalGas witness Ms. Allison Smith's testimony (Chapter VIII). At the authorized SoCalGas AMI expense levels, SoCalGas proposes a sharing mechanism for actual costs experienced above and below the authorized levels. SoCalGas proposes a similar sharing mechanism as authorized in the SDG&E AMI decision, D.07-04-043, whereby SoCalGas shareholders will be responsible for 10% of cost exceeding the authorized level and shareholders will retain 10% of the savings below the authorized level with a maximum reward/penalty of +/- $10 million (i.e., a +/- $100 million sharing band around the authorized deployment expenses of $1,079~~1,090~~ million).

Figure II-3

Risk/Reward Sharing Band

Replaced Entire Figure II-3



VIII. PRE-DEPLOYMENT FUNDING REQUEST

SoCalGas is requesting that the Commission approve $~~12.4~~12.7 million of pre-deployment funding. This request is consistent with Commission approval and authorization of pre-deployment funding for PG&E, SCE and SDG&E's AMI projects. SoCalGas has demonstrated compelling reasons for proceeding with AMI. The analysis presented herein demonstrates that SoCalGas' operating benefits cover a larger proportion of AMI life cycle costs than those in the AMI projects of the other utilities and that a lesser proportion of the ratepayer benefits depend on demand side reductions. Pre-deployment activities are identified in witness Mr. Serrano (Chapter III) and Mr. Olmsted's (Chapter IV) testimonies. Table II-8 summarizes SoCalGas' pre-deployment funding request.

Table II-8

2009 Pre-Deployment Funding

Replaced Entire Table II-8

Sponsoring Witness	Topic	Chapter	Request
Ed Fong	Contingency	2	$0.1
Mark Serrano	Operational Costs	3	$1.1
Chris Olmsted	IT and Network Costs	4	$0.1
John C. Martin	Conservation Communications	6	$0.1
Sub-Total O&M Costs			**$1.4**
Ed Fong	Contingency	2	$1.0
Mark Serrano	Operational Costs	3	$0.8
Chris Olmsted	IT and Network Costs	4	$7.3
Sub-Total Capital Costs			**$9.2**
Sub-Total All Direct Costs			**$10.6**
Total Overheads, Escalation, ad Sales Tax			$2.2
TOTAL ALL			**$12.7**

IX. CONCLUSION

The SoCalGas AMI business case provides a larger proportion of operating benefits to total life cycle costs than any of the other AMI cases submitted, authorized and approved by the Commission. In addition, the conservation benefits estimated by SoCalGas represent approximately 1% of core gas throughput in 2016 (1st post-deployment year). Deployment of SoCalGas AMI will not only provide substantial operating benefits, generate long-term conservation benefits but will finally enable the largest gas distribution utility in the United States to move into the 21st century of metering technology when the other three major energy utilities in California have already embarked on this path.

X. WITNESS QUALIFICATIONS

I am currently the Director of Customer Services Strategies for the Southern California Gas Company. I am responsible for directing, managing and planning various customer services projects and analyses that pertain to longer-term, integrated and comprehensive strategies for customer services. Prior to assuming my current position in January 2007, I was Director of Customer Operations from 2005-07, Director of AMI Regulatory Policy & Strategy from 2004-05, Director of Measurement & Meter Reading from 2002-04, Director of Customer Services Solutions from 2000-02, and Director of Revenue Cycle Services for from 1998-2000. I have directed and managed measurement, meter reading, billing, call center, branch office, credit and collections, customer services staff, direct access services and other customer services operations at SDG&E.

Prior to joining SDG&E in 1998, I held various director level management positions with the Southern California Gas Company in Human Resources, Organizational Development, Customer Contact, Customer Services Operations Staff, Information Technology, Operations Research and Planning.

I have testified before the California Public Utilities Commission on numerous occasions covering a variety of topics ranging from cost of service, measurement and meter reading to billing systems implementation. I am a graduate of University of California, San Diego with undergraduate and graduate degrees in Economics.

This concludes my testimony.