Application No: A.11-11-
Exhibit No.:
Witness: Beth Musich

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding	)	A.11-11- (Filed November 1, 2011)

PREPARED DIRECT TESTIMONY

OF BETH MUSICH

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

November 1, 2011

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PREPARED DIRECT TESTIMONY

OF BETH MUSICH

I. QUALIFICATIONS

My name is Beth Musich. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I am employed by the Southern California Gas Company (SoCalGas) as Director of Energy Markets and Capacity Products for SoCalGas and San Diego Gas & Electric Company (SDG&E).

I hold a Bachelor of Science degree in Mechanical Engineering from Colorado School of Mines. I have been employed by SoCalGas since 1993, and have held positions of increasing responsibilities in the Marketing and Regulatory departments. I have been in my current position since November 2010. In my current position, I manage service to the largest gas customers of SoCalGas, specifically large electric generators, EOR and wholesale customers. I also manage the unbundled storage program, the Operational HUB services and minimum flowing supply purchases, policies and procedures for scheduling and nominations on the SDG&E and SoCalGas systems, daily operation and enhancements to SoCalGas' Electronic Bulletin Board (EBB), and all aspects of SDG&E and SoCalGas' interconnect and operational balancing agreements with all suppliers delivering natural gas into the utility system. I also manage the Transmission Planning Department for both utilities.

II. PURPOSE & OVERVIEW OF COST ALLOCATION

The purpose of my direct testimony on behalf of SDG&E and SoCalGas (collectively "Utilities") is to present proposals to: 1) support the continued decoupling of the Utilities' profits from their noncore transportation revenues through continuation of 100% balancing account treatment for those revenues; and, 2) extend the Phase 1 2009 Biennial Cost Allocation

Proceeding (BCAP) Settlement adopted in California Public Utilities Commission (Commission) Decision (D.) 08-12-020 through the term of this Triennial Cost Allocation Proceeding (TCAP).

III. SUPPORT OF CONTINUED BALANCING ACCOUNT TREATMENT FOR NONCORE TRANSPORTATION REVENUES

The Utilities recommend continuing the 100% balancing account treatment currently in place for system throughput in order to continue to align shareholder, customer, and Commission interests in achieving energy efficiency goals. This 100% balancing account treatment was adopted by the Commission in D.09-11-006 for the current 2010-2012 TCAP period and provides a clear directive to SDG&E and SoCalGas management that it is not to take actions to increase noncore throughput by de-emphasizing aggressive energy conservation and efficiency efforts during the term of the settlement. SoCalGas and SDG&E do not believe now is the time to make a change to that policy and place shareholders at risk for the throughput on the system. Such a change in policy would effectively create a conflict between the interest of the Utilities to maximize profits and the State's energy efficiency policies.

In D.09-09-047, the Commission affirmed that cost-effective energy efficiency measures are the State's highest energy priority. The Commission instituted a comprehensive, long-term energy efficiency strategy to achieve the ultimate goal of making energy efficiency a way of life. This goal reflects the Energy Action Plan policy placing energy efficiency at the top of the loading order in response to growing energy demand. It would send the wrong message to place shareholders at risk for system throughput by providing an incentive to increase energy usage. The 100% balancing account treatment for noncore revenues should continue and is in alignment with the State and Commission's objectives concerning energy efficiency.

In R.04-01-025, the Commission recognized that its effort to develop "new policies to guard against a future natural gas shortage" required a re-examination of "at-risk" ratemaking policies.[1/] More specifically, the Commission expressed the concern that:

> "At risk" type of conditions may create incentives to the utilities to focus too much upon short-term gains or potential losses rather than long-term results. Yet it is the long-term supply situation, where we risk potentially serious consequences … [T]hese ratemaking policies may create incentives to the utilities not to have slack capacity, in order to protect their shareholders from any risks. This could undermine the utilities' cooperation with new suppliers of natural gas or independent storage operators. Yet, we need slack capacity and flexibility to enhance California's access to sufficient supplies of natural gas at various times of the year and to make sure that competition at the California border is viable.

Specific risk factors affecting potential profits or losses for the Utilities could potentially shift the Utilities' perspective away from ensuring adequate and reliable service to all of their customers. First and foremost, the focus of the Utilities should be upon providing adequate, safe and reliable service, at reasonable rates to all of their ratepayers in their service territories.[2/]

There can be no doubt that placing the Utilities "at risk" for noncore gas throughput is inconsistent with California energy and regulatory policy. The market conditions that formed the original basis for placing utility shareholders at risk for gas throughput have changed significantly and no longer support such an approach for the Utilities as recognized by the Commission in the Utilities' last cost allocation proceeding. The Commission should ensure that the Utilities' risk structure is fully aligned with the State's policy objectives promoting energy efficiency and the construction and maintenance of sufficient utility infrastructure and slack capacity to meet future demand.

[1/] OIR, *mimeo*, p. 22.
[2/] *Id*. at 22-23.

In considering this issue, the Commission should recognize that: a policy that promotes throughput risk cannot be harmonized with policies promoting energy efficiency and infrastructure slack capacity; there is no strong policy served by placing the Utilities at risk for gas throughput; and, in particular, the factors that influence electric generation demand on the utilities' systems are largely influenced by factors outside the Utilities control. The Commission should therefore continue its established policy and not place the Utilities at risk for noncore throughput.

The current 100% balancing account treatment for noncore transportation revenues aligns the long-term interests of shareholders, customers, and the Commission, to maximize cost-effective energy efficiency by decoupling utility profits from the level of gas throughput. Therefore, the Utilities firmly believe that energy efficiency program goals that the Utilities are obligated to achieve are mutually exclusive with an at-risk condition predicated on maximizing system throughput.

A. Noncore Throughput Is Highly Sensitive To External Factors

The result of placing the Utilities at risk for noncore throughput is that any difference in actual throughput compared to the Commission's adopted demand forecast used to set customer rates would cause a variation in the recovery of the Utilities' fixed costs. An at-risk structure makes utility earnings rise or fall based on whether actual throughput is greater or less than the adopted demand forecast.

Noncore throughput, particularly for electric generation (EG), is highly sensitive to a number of factors outside of the Utilities' control. As Mr. Huang explains in his testimony, EG demand can be significantly affected by hydroelectric generation in the Pacific Northwest, California electricity demand, and the availability of renewable resources, all of which are entirely or largely outside the Utilities' control.

Furthermore, some of these factors are heavily influenced by weather that is clearly outside of the Utilities' control. As shown in Mr. Huang's testimony, the Utilities' EG demand is inversely related to hydroelectric power generation in the Pacific Northwest and California. When the hydro conditions are at normal conditions, EG demand on the Utilities' system is forecasted to average 261 MMDth. However, as hydro conditions vary from year-to-year, so will the EG gas demand. As Mr. Huang notes, historical hydro conditions have ranged between 57% and 155% of normal. Dry-year hydro, which is defined as hydro conditions expected once every 10 years, is about 70% of normal and can cause an increase in EG demand of about 37 MMDth above demand during an average hydro year.

Electricity demand is also a significant factor affecting EG demand for gas. The EG gas forecast is based on average weather conditions, but weather variability can cause electricity demand in southern California to vary by almost 1% from average weather. Given that natural gas is on the margin for generation, this can affect EG gas demand in southern California by about 12 MMdth /year or about 4% of annual forecast.

Another factor affecting EG demand that is outside the Utilities' control is the availability of renewable resources. As Mr. Huang explains, a difference of 1% in the assumed RPS goal for EGs in southern California is equal to about 1,500 GWh of renewable energy. If this amount of energy would need to be made up by natural gas-powered generation, forecasted throughput on the Utilities' systems would increase by approximately 12 MMDth/year.

While each of these factors – weather, hydro and renewable availability – can have a significant and uncontrollable effect on EG demand, they can also occur in the same year. This would have the effect of either ameliorating or exacerbating the overall EG demand variation.

As discussed above, there is a broad consensus view that energy efficiency is the number one priority in the fight against increased electricity usage and Greenhouse Gas (GHG) emissions. According to the California Energy Commission's (CEC) 2009 Integrated Energy Policy Report (IEPR), natural gas is used to generate 46% of the electricity in the State.[3/] As the State proactively works to reduce energy demand statewide, downward pressure will also be applied to the use of natural gas for electric generation.

Accordingly, placing the Utilities at risk for gas throughput serves only to:

- Re-couple profits and sales, counter to the long-term policy of aligning shareholder and customer interests to promote energy efficiency by decoupling profits from sales;
- Provide Utilities a financial incentive to increase the demand on their systems;
- Undermine the State's and Commission's policies to encourage energy efficiency;
- Place revenue recovery at risk for factors that cannot be controlled; and,
- Create a more antagonistic and burdensome regulatory environment where parties seek to shift forecasting risk to the Utilities' shareholders.

For all of these reasons, the Utilities strongly recommend that the Commission not place them at risk for noncore throughput since it simply does not serve the public interest and is contrary to sound regulatory policy.

[3/] California Energy Commission, 2009 Integrated Energy Policy Report, p.47.

IV. SUPPORT CONTINUATION OF PHASE 1 2009 BCAP SETTLEMENT FOR THE REMAINDER OF THE TCAP PERIOD

In D.08-12-020, the Commission adopted the Phase 1 Settlement Agreement in the Utilities 2009 BCAP. The Settlement Agreement addressed the issues primarily related to storage allocations between core customers, the Unbundled Storage Program, and storage balancing services, balancing rules, and the sharing mechanism for the Unbundled Storage Program through the year 2014.

The term provision of the Phase 1 Settlement Agreement (SA) was six years:

> This SA shall be in effect for six years (2009-2014 inclusive), and shall terminate on December 31, 2014. However, the SA will be extended, if necessary, to coincide with implementation (tariff approval) of and then-current BCAP or TCAP pending before the Commission on December 31, 2014. If no BCAP or TCAP is pending before the Commission on December 31, 2014, this SA shall terminate on that date.

The Commission has established a TCAP period of 2013 through 2015. Therefore, rather than re-litigating storage related issues for only a single year of the TCAP period the Utilities propose that the Phase 1 2009 BCAP SA be extended through the term of this TCAP.

It is clear from the Settlement language above that the settlement parties contemplated this very situation and that extending the Agreement through the term of this TCAP will allow the Commission to fully litigate storage-related issues in the succeeding TCAP period, without wasting resources evaluating new storage allocations, balancing procedures, sharing mechanism, and cost allocations for a single year of a three-year TCAP period.

The Utilities propose the same storage allocations in 2015 as in 2014 as shown in Ms. Fung's Table 23 for the year 2013. There would be two exceptions: the Unbundled Storage Program would receive an additional 1 Bcf of inventory in 2014 and 2016 as scheduled in the Honor Rancho Certificate of Public Convenience and Necessity (CPCN) Application, and the

Unbundled Storage Program would be allocated the incremental 145 MMcfd injection capacity of the Aliso Canyon modernization if that project is approved and in-place by 2015.

The Utilities believe extension of the Phase 1 2009 BCAP Settlement is consistent with the intent of the Settlement itself and warranted in this situation to provide consistent rules and storage allocations throughout the TCAP period.

This concludes my prepared direct testimony.