Decision 14-12-040 December 18, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Address Natural Gas Distribution Utility Cost and Revenue Issues Associated with Greenhouse Gas Emissions.	Rulemaking 14-03-003 (Filed March 13, 2014)

DECISION RESOLVING PHASE 1 ISSUES AND ADDRESSING THE MOTION FOR ADOPTION OF SETTLEMENT AGREEMENT

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DECISION RESOLVING PHASE 1 ISSUES AND ADDRESSING THE JOINT MOTION FOR ADOPTION OF SETTLEMENT

Summary

This decision approves, with modifications, a Phase 1 Settlement between Pacific Gas and Electric Company, the Office of Ratepayer Advocates, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Company (collectively, the Settling Parties) concerning certain policies, programs, rules and tariffs necessary for natural gas corporations to comply with the California Cap and Greenhouse Gas Emissions and Market-Based Compliance Mechanisms'[1] (Cap-and-Trade Program) regulations imposed by Air Resources Board (ARB) as a result of the California Global Warming Solutions Act of 2006 (Assembly Bill 32).[2] The ARB regulations are contained in Title 17 of the California Code of Regulations (Title 17). Pursuant to Sections 95840, 95851(b), and 95852(c) of Title 17, natural gas utilities must comply with the Cap-and-Trade regulations beginning January 1, 2015.

This decision adopts modifications to the Settlement where we find that the Settlement, as proposed, is not in the public interest.

The rulemaking remains open to address the Phase 2 issues.

1. Procedural Background

On March 19, 2014, the Commission issued Rulemaking 14-03-003 to address issues related to Greenhouse Gas (GHG) cost and revenues resulting from the implementation of Air Resources Board's (ARB's) GHG Cap-and-Trade program for natural gas corporations.

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[1] Title 17, California Code of Regulations, Sections 95801-96022.

[2] Statutes of 2006, Chapter 488.

Assembly Bill (AB) 32 granted ARB broad authority to regulate GHG emissions to reach the goal of having GHG emissions in 2020, no higher than the 1990 level. In response to AB 32, ARB established an economy-wide cap on major sources of GHG emissions, including large point-source emitters, electricity deliverers and fuel suppliers, and created a market-based mechanism to encourage organizations and individuals to make efficient decisions about how to reduce emissions. ARB adopted the Cap-and-Trade Program in December 2011, and the regulation became effective on January 1, 2012. ARB phased in the reach of compliance obligations[3] under the Cap-and-Trade Program. Those subject to a compliance obligation are deemed "covered entities." Under the Cap-and-Trade program, ARB allocates GHG allowances to electric and natural gas utilities on behalf of ratepayers. ARB prohibits electric investor-owned utilities from using these allowances for their own compliance obligations; they must all be consigned to ARB's quarterly auctions, and the proceeds must be used for the benefit of retail customers. However, ARB allows natural gas utilities to use a portion of these allowances for their own compliance obligations, while the remainder – 25% of these allowances in 2015, escalating 5% annually – must be consigned to ARB's quarterly auctions, and the revenue these sales generate must be used for the benefit of retail customers.[4]

Beginning on January 1, 2013, the Cap-and-Trade Program covered operators of facilities that annually emit at least 25,000 metric tons of carbon dioxide equivalent gas ($MTCO_2e$) as well as first deliverers of electricity. In

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[3] Entities having a compliance obligation under the Cap-and-Trade regulation are responsible for possessing and ultimately surrendering appropriate compliance instruments (either GHG allowances or offsets) to account for their annual GHG emissions.

[4] 17 CCR § 95893.

Decision (D.) 12-12-033 the Commission adopted initial rules addressing cost recovery, rate design and the use of revenues generated by the auctioning of GHG allowances that ARB allocates to the electric utilities. Natural gas suppliers become covered entities beginning on January 1, 2015. The natural gas suppliers' compliance obligation is equal to the GHG emissions that would result from full combustion or oxidation of the natural gas they deliver to California end-use customers, less the emissions from natural gas delivered to entities that are separately regulated as covered entities.[5] Like all covered entities, natural gas suppliers must fulfill their compliance obligations under the Cap-and-Trade Program by surrendering to ARB an amount of compliance instruments – emission allowances and offsets – equal to their regulated emissions during each compliance period.

The first compliance period includes the years 2013 and 2014 (during which time natural gas suppliers have no compliance obligation); the second compliance period includes 2015 through 2017; and the third compliance period includes 2018 through 2020.

As we noted in the Order Instituting Rulemaking (OIR), ARB's regulation creates new procurement costs for natural gas corporations under the Commission's jurisdiction that could affect gas rates. Gas utilities have two potential sources of Cap-and-Trade-related costs: As regulated natural gas suppliers that deliver gas to California end-users, and as owners and operators of facilities that directly emit at least 25,000 $MTCO_2e$ per year and are covered entities under the Cap-and-Trade regulation. Some natural gas corporations own and operate compressor stations that ARB currently regulates as covered entities.

[5] Title 17, California Code of Regulations Section 95852(c).

Others may operate compressor stations that currently fall below the 25,000 $MTCO_2e$ emissions threshold for inclusion as a covered entity, but that may, at a later date, exceed this threshold, and therefore become covered entities. Thus, when the Commission considers Cap-and-Trade-related costs that natural gas corporations experience, we must consider their dual costs as natural gas suppliers and as owners of covered facilities.

The OIR specified the preliminary scope as: How covered entities should track and recover costs of Cap-and-Trade compliance; how covered entities should procure compliance instruments; how the revenue from the sales of allowances allocated to covered entities by ARB should be used; how natural gas utilities should forecast Cap-and-Trade-related costs; how these costs should be reflected in customers' rates; and the scope and structure of any necessary education and outreach efforts.

Following the April 29, 2014, prehearing conference, the assigned Commissioner and Administrative Law Judge (ALJ) issued a July 7, 2014, Ruling and Scoping Memo that determined the proceeding would be conducted in two phases. According to the Ruling and Scoping Memo, the first phase would address priority issues to allow natural gas utilities to begin compliance with the Cap-and-Trade Program adopted by the ARB pursuant to AB 32. These priority issues include: Providing authority and adopting any necessary rules for the natural gas utilities to procure Cap-and-Trade compliance instruments; providing authority for the natural gas utilities to track, record and recover costs associated with Cap-and-Trade compliance; approving a methodology and mechanism for natural gas utilities to forecast Cap-and-Trade-related costs; and other additional issues. Phase 2 would address the remaining issues including the use of GHG revenue, GHG outreach and education, and the percentage of allowances natural gas corporations must consign to auction. A further ruling will address the schedule for Phase 2.

The Ruling and Scoping Memo set forth the issues to be decided in Phase 1 as follows:

1.1. Procurement Authority

1. What authority is needed for natural gas corporations to procure Cap-and-Trade compliance instruments related to their natural gas compliance obligation?
2. What rules and limits should govern how natural gas corporations with a compliance obligation should procure Cap-and-Trade compliance instruments and whether these rules and limits should mirror those adopted in Decision 12-04-046 for electric utilities?
3. Should these rules apply equally to each natural gas corporation, or should the Commission apply different rules depending on the size of the utility and whether it is an integrated electric and gas utility?

1.2. Cost Recovery

1. How should each natural gas corporation with a compliance obligation track and recover costs associated with GHG Cap-and-Trade Program compliance, either as a natural gas supplier or as an owner and operator of gas compression stations that may be regulated under Cap-and-Trade as Covered Entities?
2. What existing authority does each natural gas corporation have to track and record Cap-and-Trade costs, and what new authority is needed?
3. How should Cap-and-Trade related be allocated between core and non-core gas customers?
4. What tariff changes are necessary to introduce GHG costs in rates?

5. Should Cap-and-Trade-related costs be temporarily deferred from rates if the Commission has not resolved revenue implementation details before January 1, 2015?

1.3. Forecasting

1. What methodology, and what procedural mechanism, should the natural gas corporations use to forecast annual Cap-and-Trade-related costs and potential allowance revenues?
2. Can the natural gas corporations rely on public, non-confidential data to report forecasts publicly without violating ARB confidentiality rules that prevent disclosure of market sensitive information?

1.4. Other

1. Natural gas corporations may have end-use customers that are large emitters due to their on-site combustion of natural gas or other fuels and that ARB regulates as covered entities. What steps should the corporations and the Commission take to ensure that these customers are not double-regulated for their GHG emissions?
2. Should each natural gas corporation annually publish the Cap-and-Trade-related costs that may be present in natural gas rates, and can natural gas corporations publish such costs without violating ARB confidentiality rules regarding disclosure of market sensitive information?
3. What competitive neutrality issues should be considered to ensure that potential Cap-and-Trade-related costs and revenues are implemented in a manner that treats CPUC-regulated gas distribution utilities and non-regulated gas suppliers fairly?
4. Should the Commission exempt independent gas storage providers from the obligation to participate as a respondent in this rulemaking?

Comments on the Phase 1 issues were filed by the National Asian American Coalition, the Ecumenical Center for Black Church Studies and the Los Angeles Latino Chamber of Commerce (collectively, the Joint Minority Parties) and the Environmental Defense Fund (EDF) on August 12, 2014. On August 15, 2014, opening comments were filed by the California Solar Energy Industries Association (CALSEIA), the Indicated Shippers,[6] and jointly by Lodi Gas Storage, LLC, Gill Ranch Storage, LLC, Wild Goose Gas Storage LLC, and Central Valley Gas Storage (collectively, the Independent Storage Providers). The Settling Parties also filed joint opening comments on August 15, 2014. The Joint Minority Parties and the Settling Parties filed reply comments on the Phase 1 issues on August 26, 2014, and September 2, 2014, respectively.

2. Joint Motion and Settlement

On July 25, 2014, the Settling Parties filed a Joint Motion to Adopt Settlement (Joint Motion) to approve ratemaking standards and mechanisms on cost forecasting, cost recovery, purchasing limits, consignment and proposed 2015 forecast revenue requirements for the utilities' compliance with AB 32 natural gas supplier GHG Cap-and-Trade program obligations beginning January 1, 2015. Pursuant to Rule 12.1(b) of the Commission's Rules of Practice and Procedure (Rules), the Settling Parties provided timely notice of a Settlement Conference. The formal Settlement Conference was held on July 3, 2014. The Joint Motion and Settlement (Attached as Appendix A) are described below.

In response to the Joint Motion, the Natural Resources Defense Council (NRDC) and the EDF (filing jointly), Waste Management, Bioenergy Association

[6] Indicated Shippers member companies include Aera Energy LLC, BP Energy, Chevron U.S.A., Inc., Shell Oil Products and Occidental Energy Marketing Inc.

of California and the California Association of Sanitary Agencies (jointly), the Indicated Shippers, and CALSEIA, each filed comments on August 25, 2014. The Settling Parties filed a reply to the comments on the Joint Motion on September 9, 2014.

The Joint Parties state that the Settlement is guided by the July 7, 2014, Scoping Memo and Ruling in this proceeding. As stated in the Joint Motion, the Settlement is the result of several parties' interest in quickly resolving the Phase 1 issues related to cost forecasting, cost recovery and limits on the utilities' purchases of GHG compliance instruments. The Joint Motion explains that the Settling Parties held differing views on several issues including cost forecasting, cost recovery, and purchasing limits and the Settlement therefore represents a compromise that the Settling Parties believe addresses each of the issues in a fair and balanced manner.

As described below and in Appendix A, the Settlement recommends adoption of the following ratemaking standards and criteria for the utilities' procurement of natural gas-related GHG compliance instruments under AB 32, and for the forecasting, recording, ratemaking recovery and reporting of the costs of those instruments.

2.1. Purchasing Rules

The Settlement uses the Cap-and-Trade compliance instrument purchasing rules adopted for electric utilities in D.12-04-046, Ordering Paragraph 8, as a starting point, and then modifies this framework to reflect the continuing development of California's Cap-and-Trade market. Under the proposed Settlement, the natural gas utilities would be authorized to procure compliance instruments according to the following general purchasing rules: (1) Each utility would be authorized to procure GHG compliance instruments to satisfy its net natural gas compliance obligation, including carbon allowance derivatives; (2) Each utility would comply with the ARB's requirements regarding minimum consignment of allowances for auction, and is not required to consign more than the ARB minimum for auction; and (3) Each utility would only procure offsets certified by the ARB, and would procure no more than 8% of its compliance requirements in the form of offsets.

In lieu of a requirement that offset sellers assume the risk of invalidation of the offsets, each utility will take reasonable measures to prudently manage invalidation risk. According to the Settlement, each utility would use a separate formula to limit GHG product procurement associated with its net natural gas supplier compliance obligation or the "Net Natural Gas Compliance Obligation Purchase Limit," but a utility shall not use a planning standard more conservative than a 1-in-20 cold year for the current year to calculate its Net Natural Gas Compliance Obligation Purchase Limit.

The Settlement provides that each utility may procure allowances from the ARB. Each utility may procure allowances using forward contracts and will apply its standard procurement and collateral requirements to these transactions. A utility may procure authorized compliance instruments or carbon allowance derivatives through: (a) a competitive request for offer (RFO) process, (b) a broker or exchange that has been pre-approved by the Commission through a Tier 2 Advice Letter (AL) filing, or (c) a direct bilateral transaction. Each utility using a bilateral transaction must apply any applicable procurement credit and collateral requirements, and apply any applicable affiliate transaction rules.

Prior to purchasing GHG compliance instruments on an exchange or from a brokerage firm not previously approved by the Commission for such procurement, the Settlement proposes that each utility must submit a one-time

Tier 2 AL detailing: (1) what exchange or brokerage firm it seeks to use, (2) the liquidity and transparency of the pricing offered by the exchange or brokerage firm, specifically for California GHG compliance instruments, including an explanation of how the price of products procured on the exchange or through the brokerage is market-based; and (3) the regulatory authority or authorities to which the brokerage firm is subject.

Finally, the Settlement details that each utility may re-sell natural gas supplier compliance instruments, but must report such sales to its Procurement Review Group (PRG) or, for Southern California Gas Company (SoCalGas), to its comparable consultative group comprised of representatives from Energy Division (ED), The Utility Reform Network (TURN), and Office of Ratepayer Advocates (ORA). For Southwest Gas (SWG), such sales would be reported to ORA and ED.

2.2. Cost Forecasting and Recovery

For cost forecasting and recovery, the Settlement provides that each utility would establish a two-way balancing account to track and record costs incurred to comply with the ARB natural gas supplier Cap-and-Trade program and company facility (e.g. gas compressor station) GHG compliance costs, including administrative costs not recorded elsewhere, as well as the revenues received from consignment of natural gas supplier allowances for auction under the ARB program.

The Settlement proposes that each utility would recover on a forecast basis through separate AL filings in June and updated in October of each year, its annual GHG compliance costs for the following year as a natural gas supplier through a specific GHG rate component, and for company facility GHG costs, as necessary, through base rates, subject to annual true-up and subject to the existing right of ORA and other parties to challenge any costs that are inconsistent with the utility's procurement authority. SoCalGas and San Diego Gas & Electric Company (SDG&E) would update their existing New Environmental Regulation Balancing Account (NERBA) subaccounts for Facilities and End-Users to no longer record costs associated with Cap-and-Trade program. Any balances in these accounts would be transferred to the new GHG compliance balancing accounts and collected as part of the annual true-up for those accounts.

The Settlement sets forth the initial 2015 forecasted GHG compliance costs, and the associated revenue requirements, that each utility would use for purposes of recovering its 2015 forecasted costs in rates, as shown in Table 1, below. The Settlement notes that actual costs may differ from the forecasted amounts due to the difference between the proxy compliance instrument prices used at the time the utilities forecasted costs and the utilities' actual net compliance obligations.

The costs and revenue requirements would be trued-up by each utility annually pursuant to the two-way balancing account established for reviewing and recovering such costs. In years subsequent to 2015, the Settlement proposes that each utility would include its forecasted GHG compliance costs and revenue requirements in its annual natural gas filing or comparable advice filing.

Table 1

Forecasts of Natural Gas Utility 2015 Revenue
Requirements to Recover Cap-and-Trade Compliance Costs

Utility	End-User Revenue Requirement ($000, inc. FF&U)	Utility Facilities Revenue Requirement ($000, inc. FF&U)
SoCalGas	$74,313	$2,692
SDG&E	$13,130	$ 378
PG&E	$63,460	$3,230
Southwest Gas	$ 2,594	

The Settlement provides that GHG compliance costs would be collected from core and non-core customers, excluding those customers who are exempt because they are subject to direct regulation under the ARB's rules, through a new gas rate schedule for this purpose. GHG compliance costs will be allocated between customer classes on an equal-cents-per-therm basis. For cost allocation and rate design purposes, each utility's currently-adopted gas transportation volume throughput forecast would be adjusted to exclude exempt volumes associated with exempt customers and exempt emissions.

2.3. Reporting Requirements

Under the proposed Settlement, Pacific Gas and Electric Company (PG&E) and SDG&E would be required to periodically review recent and prospective transactions with their respective PRGs. SoCalGas would be required to periodically review recent and prospective transactions with its comparable consultative group comprised of representatives from the Commission's ED, ORA and TURN. SWG would be required to report any sales transactions to ORA and ED.

In addition, the Settlement proposes that each utility must prepare and submit an annual report listing its purchases and sales of all natural gas supplier compliance instruments including GHG allowances, allowance futures and forwards, and offsets and offset forwards, carbon allowance derivatives and any agreements with counterparties to purchase compliance instruments in the future. The report must list the quantity, source, clearing mechanism, and the price of natural gas supplier compliance instruments purchased by the utility and the quantity, buyer, clearing mechanism, and price of all natural gas supplier compliance instruments sold by the utility.

2.4. Minimum Consignment

The Settlement provides that each utility will comply with the ARB's minimum consignment of allowances for auction and is not required to consign more. For purposes of cost forecasts for 2015, the Settlement assumes that each utility will consign 25% of its allowances to the ARB auction.

2.5. Availability of Public Information

According to the proposed Settlement, each utility would use its best efforts for publicly disclosing a proxy calculation of annual natural gas supplier GHG compliance costs and potential allowance revenues that uses con-confidential, non-market-sensitive data and is consistent with ARB's confidentiality rules.

3. Standard Review of Settlements

The requirements for settlements are set forth in Article 12, Rules 12.1 through 12.7 of the Commission's Rules of Practice and Procedure. The general criteria for Commission approval of settlements are stated in Rule 12.1(d) which provides that "[t]he Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest."

The Settling Parties bear the burden of proof to show that the Settlement is reasonable and the regulatory relief it requests is just and reasonable.

As a matter of public policy, the Commission favors settlement of disputed issues if the resolution is fair and reasonable in light of the whole record. This policy supports worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce undesirable results.[7] However, the Commission cannot simply defer to the Settling Parties as to whether the Settlement is in the public interest, particularly when it is not an all-party Settlement. In this case, where there are disputed terms, the Commission will look closely at the record to address the Settlement.

4. Discussion

The record in this proceeding consists of the OIR, comments and replies on the OIR, the Joint Motion and attached Settlement, and the replies to the Joint Motion. The majority of the parties in this proceeding are either parties to the Settlement or have indicated that they are not opposed the Settlement (as is demonstrated by the comments and replies filed in response to the Joint Motion and attached Settlement). No party opposes the settlement outright, and the record reflects limited opposition to certain of the settlement terms. With the exception of certain specific elements, as we discuss below, the Settlement is reasonable in light of the whole record in this proceeding. The Settlement is adopted with the modifications discussed below. The modifications we require address certain deficiencies in the Settlement that, if not modified, would not be

[7] D.92-12-019, 46 CPUC2d 538,553.

in the public interest, and that should be considered in more detail in Phase 2 of this proceeding.

First, we find that the cost forecasts and cost recovery process proposed in the Settlement are lacking in detail, and there is insufficient record on the natural gas utilities' Cap-and-Trade compliance cost forecasts and the assumptions underlying those forecasts to assess their reasonableness. We therefore modify the Settlement Section 7(c) to deny the utilities' 2015 forecasted Cap-and-Trade compliance costs without prejudice. We will require revised detailed 2015 forecasts in Phase 2 of this proceeding and consider whether and how the forecasting methods approved for electric utilities in D.14-10-033 should apply to the natural gas utilities. Additionally, the lack of detail regarding the methodological assumptions underlying these forecasts, including whether they properly account for customers that are directly covered entities under Cap-and-Trade, leaves unresolved substantive policy concerns and hinders our ability to evaluate whether approval of future cost forecasts is appropriate for Staff disposition in Tier 2 ALs, as the Settling Parties have proposed in Settlement Section 7(a). We therefore modify Settlement Section 7(a) and 7(c) to deny this proposed procedural mechanism to approve annual Cap-and-Trade compliance cost forecasts through a Tier 2 AL or via the utilities' annual natural gas true-up filing. This issue should be considered more fully in Phase 2. We also note that Settlement Section 7(c) regarding rate design provides inadequately detailed information to explain the mechanics of how the utilities will ensure that customers that are directly covered entities will be exempt from carbon costs in natural gas rates. The utilities have not explained how this will be implemented through tariff modifications and in coordination with information that ARB will provide each year. Until such time as the Commission approves forecasts of

2015 Cap-and-Trade-related costs and rate design requirements, the utilities shall defer Cap-and-Trade-related costs from inclusion in natural gas rates.

Next, we find that the Settlement inappropriately limits the Commission's flexibility to direct the natural gas utilities to consign a higher percentage of their allowances to auction in the event that additional consignment is supported by the record to be developed in Phase 2 of the proceeding. We modify the Settlement Section 7(b)(i) to provide that the minimum consignment percentage will continue to be considered in Phase 2. In the interim, the utilities must comply with the minimum consignment percentage required by ARB. Third, Settlement Section 7(a) would inappropriately permit administrative costs of unknown magnitude and nature to be tracked and recorded through balancing accounts, instead of through a new memorandum account for administrative costs. While we find the Settlement's proposal for new balancing accounts appropriate, we will require the utilities to separately track any administrative costs in existing or new memorandum accounts, as further described below.

Finally, Settlement Section 7(c) would require the natural gas utilities to include a separate line item on customer bills reflecting carbon pollution costs. The question of how best to facilitate customer understanding of the impact of GHG on customer bills is an issue that will be addressed in Phase 2 of this proceeding. Furthermore, as stated above, costs related to procurement of natural gas allowances will not be included in rates until the forecast and revenue allocation methodologies are determined in Phase 2. In that regard, we modify Section 7(c) to deny the inclusion of the separate line item on customer bills. Though we find reasonable the Settling Parties' proposal that GHG compliance costs should be collected from core and non-core customers, excluding those customers that are exempt because they are subject to a direct compliance obligation, we defer consideration of how these costs will be implemented in tariffs until Phase 2.

4.1. Issue 1: Cost Recovery

The proposed Settlement would authorize each natural gas utility to establish a two-way balancing account to track and record costs incurred to comply with the ARB natural gas supplier Cap-and-Trade program and company facility (e.g. gas compressor station) GHG compliance costs, including administrative costs not recorded elsewhere, as well as the revenues received from consignment of natural gas supplier allowances for auction under the ARB program.

It is reasonable to approve the Settling Parties' request to establish two-way balancing accounts to track and record costs incurred to comply with the ARB natural gas supplier Cap-and-Trade program and company facility (e.g. gas compressor station) GHG compliance costs, as well as the revenues received from consignment of natural gas supplier allowances for auction under the ARB program is reasonable. Each utility shall submit a Tier 2 AL within 30 days of approval of this decision to create this balancing account. However, it is inappropriate for the utilities to track in these same balancing accounts administrative costs of unknown magnitude and nature; such costs should be subject to reasonableness review. We therefore modify the Settlement to require that administrative costs should be tracked and recorded in new memorandum accounts. Within 30 days of approval of this decision, each utility should file a Tier 1 AL to establish a new GHG administrative cost memorandum account.

As explained above, the Settling Parties have provided insufficient detail about the methodologies and assumptions that underlie their forecasts of Cap-and-Trade-related costs, including how they will address natural gas usage by customers that are directly covered entities under Cap-and-Trade and forecast the price of compliance instruments. It is therefore not possible to determine, at present, that it is appropriate to approve annual forecasts of GHG costs via an AL. We therefore modify the proposed Settlement to deny the process to seek approval of GHG cost forecasts. This issue should be addressed in Phase 2 of this proceeding.

In comments, the Settling Parties note that the Commission, in D.13-03-017, previously authorized PG&E to record GHG compliance costs associated with its compressor stations in its Gas Operational Balancing Account, or GOBA. The Settling Parties note that PG&E "does not plan to include gas compressor station GHG costs in the new balancing account."[8] PG&E's approach is reasonable at this time, because the natural gas utilities have been subject to ARB's requirement to procure GHG compliance instruments to cover the emissions of any natural gas compressor station emitting more than 25,000 $MTCO_2e$ per year since January 1, 2013, and those compliance costs are currently being recorded and amortized in the GOBA, pursuant to D.13-03-017. However in the future we prefer to consolidate the recording of ARB natural gas supplier Cap-and-Trade program and company facility (e.g. gas compressor station) GHG compliance costs, both operational and administrative, into the separate GHG costs balancing and memorandum accounts authorized in this decision. Following a decision in Phase 2 of this proceeding regarding the appropriate recovery of GHG compliance costs in rates, PG&E will be required to update the Compressor Station GHG Cost Subaccount of its GOBA balancing account to no longer record costs associated with the ARB natural gas supplier Cap-and-Trade program. At

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[8] December 8, 2014, Comments of the Settling Parties at 4, footnote 4.

that time, any GHG compliance cost balances in the Compressor Station GHG Cost Subaccount should be transferred to the new GHG balancing accounts and collected as part of the annual true-up for those accounts.

SDG&E and SoCalGas state that they were granted authority to create blanket balancing accounts called the NERBA in D.13-05-010, and each subsequently filed ALs establishing the NERBA, and subaccounts. However, while NERBA was contemplated in D.13-05-010, and SDG&E/SoCalGas were each authorized to create balancing accounts to track the costs associated with certain new regulatory expenses in the NERBA, they were not specifically authorized to track in the NERBA the costs of compliance with the natural gas GHG compliance.[9] Nevertheless, the ED approved the ALs subsequently filed by SDG&E and SoCalGas, to create the subaccounts for this purpose.

The resulting NERBA contains four different subaccounts, three of which record costs associated with AB 32, including potential costs associated with owning and operating covered compression stations and operating as a natural gas supplier.[10] The Sempra utilities' potential costs of complying with these obligations are recorded in the Cap-and-Trade Facilities Allowance Purchases Subaccount and the Cap-and-Trade End User's Subaccount,[11] respectively.

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9 D.13-05-010 at Conclusions of Law 9, provides only that "SDG&E/SoCalGas shall be authorized to establish a two-way balancing account called NERBA to record the following: the costs associated with a final EPA rule on the phase out of PCBs and the costs associated with complying with the mandatory reporting rule in Subpart W of Part 9 of Title 40 of the CFR."

10 *See* Sheet 1 of SoCalGas's Preliminary Statement – Part V – Balancing Accounts: NERBA; *see* also Sheet 2 of SDG&E's Preliminary Statement – Part IV – Balancing Accounts: NERBA.

11 *See* Sheet 2 of both SDG&E and SoCalGas' NERBA tariff papers.

Under the Settlement, SoCalGas and SDG&E would update the NERBA subaccounts for Facilities and End-Users to no longer record costs associated with Cap-and-Trade program. Any balances in these accounts would be transferred to the new GHG balancing accounts and collected as part of the annual true-up for those accounts. This approach is reasonable. SoCalGas and SDG&E should revise these NERBA accounts in the same Tier 2 AL that establishes the new two-way balancing account required above to track Cap-and-Trade-related costs and allowance revenues. Any administrative costs related to Cap-and-Trade should be recorded in the memorandum accounts as described above.

4.2. Issue 2: Cost Forecasts and Rate Design

As noted above, natural gas suppliers become covered entities beginning on January 1, 2015. The Settlement includes forecasted GHG compliance costs for 2015, along with the associated revenue requirements that each utility would use for purposes of recovering its 2015 forecasted costs in rates. The Settlement notes that actual costs may differ from the forecasted amounts due to the difference between the proxy compliance instrument price and forecasted procurement need, and actual compliance instrument price and actual net compliance obligation. The forecasted revenue requirements assume that each utility will consign 25% of its allowances to the ARB auction in 2015. Pursuant to the proposed Settlement, for the years subsequent to 2015, each utility would include its forecasted GHG compliance costs and revenue requirements in its annual natural gas true-up filing or comparable advice letter filing.

In comments on the OIR, the utilities indicate that an approved 2015 cost forecast is necessary to begin to recover GHG compliance costs in rates in a timely manner. However, the utilities have not enabled a timely review of their

2015 forecasts because they have not provided sufficient information on the record to determine whether the utilities' 2015 forecasts of compliance costs are reasonable.

The Settlement does not describe, for example, information that would be necessary to determine whether the 2015 cost forecasts are calculated in a reasonable manner. Each year, in order to accurately include GHG compliance costs in rates for the following year, the natural gas suppliers must forecast both GHG compliance costs and allowance revenue. In order to forecast the compliance cost and the resulting amount of allowance revenue that is available for the next year, the natural gas utilities must calculate, at a minimum:

1. The public unit price of compliance instruments used to estimate the cost of the net compliance obligation, and the method to estimate this price.
2. The utilities' expected net compliance obligation for 2015 in terms of $MTCO_2e$, and information to substantiate this forecasted obligation, including forecasts of allowances that the utility will receive from ARB.
3. Evidence that each utility's forecasted compliance obligation excludes the emissions from customers that are covered entities under ARB's Cap-and-Trade program. This includes adequate rate design proposals that demonstrate the utilities are capable of identifying customers that should be excluded from carbon pricing in natural gas rates.

Without this information, the 2015 forecasted compliance costs, and the associated revenue requirements, cannot be approved in today's decision. Moreover, we also cannot approve a procedural method for the utilities to annually seek approval of GHG costs for inclusion in rates, because there remains uncertainty about the methodologies the utilities should use when forecasting GHG costs and allowance revenues. Instead, we will require the natural gas utilities to file within 30 days of the adoption of this decision preliminary information for Phase 2 of this proceeding that includes data and supporting information in sufficient detail for the Commission to authorize 2015 GHG costs for recovery and to determine whether the forecasting methodology is reasonable and consistent with the law. Phase 2 of this proceeding will authorize an appropriate procedural mechanism for the utilities to seek annual approval of forecasts and recovery of GHG costs in years after 2015.

In preparation for the preliminary information filing requirement, the natural gas utilities should look to D.14-10-033, as corrected by D.14-10-055, in which we considered and approved standard procedures for use by electric utilities in filing GHG forecast revenue and reconciliation requests. D.14-10-033 also adopted confidentiality protocols and a methodology for developing a proxy GHG allowance price. The natural gas utilities should take these findings into consideration and provide forecasts that follow as closely as possible the methodologies and rules established in D.14-10-033.

The Commission has previously stated in D.12-12-033 that the electric utilities should not begin to recover GHG compliance costs in rates until the revenue allocation methodology and timing has been determined. We affirm that decision for natural gas utilities here. Although we permit the utilities to track and record GHG costs in a new balancing account administrative costs in new or existing memorandum accounts, cost recovery in rates should not begin until Phase 2 of this proceeding when the Commission resolves outstanding rate design issues and decides how natural gas allowance revenue should be allocated.

4.3. Issue 3: Procurement Rules

The Scoping Ruling identified three specific issues to be addressed with respect to the procurement authority of the natural gas utilities. First, what authority is needed for natural gas corporations to procure compliance instruments related to their natural gas compliance obligation; second, what rules and limits should govern how natural gas utilities should procure Cap-and-Trade compliance instruments and whether these rules and limits should mirror those adopted in D.12-04-046 for the electric utilities; and third, should these rules apply equally to each natural gas utility?

As provided in the Settlement, the Settling Parties propose that the Commission authorize regulated natural gas suppliers to: (1) purchase and sell allowances through Commission-approved exchanges, brokers, and via ARB auctions; (2) purchase offsets (including offsets where the buyer assumes the risk of invalidation) bilaterally, through brokers, and through a competitive RFO process; (3) insure or hedge (including the use of options) the invalidation risk of offsets; (4) enter into forward contracts for delivery of future purchases up to a Commission-defined limit; and (5) sell compliance instruments.

Although the proposed procurement rules differ from those adopted in D.12-04-046 for the electric utilities,[12] the Settling Parties maintain, and we agree, that the proposed rules contained in the Settlement more appropriately reflect the maturity of the market. As explained above, natural gas utilities will record compliance costs for their obligation as a natural gas supplier and for any

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[12] D.12-04-046 addressed the types of compliance instruments the electric utilities are authorized to procure, how and where the electric utilities can procure compliance instruments, and what quantities of compliance instruments the utilities may procure. This decision was issued on April 19, 2012, before ARB's first allowance auction on November 14, 2012.

applicable covered facilities (e.g., compressor stations). Therefore, these procurement rules shall apply to the purchase of all compliance instruments for a natural gas utility.

The Settlement also proposes a formula to determine the Net Natural Gas Compliance Obligation Purchase Limits. This formula is similar to that adopted for the electric utilities. The Settlement states that this formula is associated with a utility's net natural gas supplier compliance obligation. We approve the use of the proposed formula to determine the Net Natural Gas Compliance Obligation Purchase Limits. The purchase limit formula should apply to both the net natural gas compliance obligation and any applicable covered facilities.

4.4. Issue 4: Consignment Percentage

In its Cap-and-Trade regulation, ARB established a minimum percentage of allowances that natural gas utilities must consign to auction. This minimum percentage for the first year of the natural gas compliance obligation is 25%. The minimum consignment percentage then increases by 5 percentage points each year until it reaches 50% in 2020.[13] The Joint Motion and attached settlement provide:

> Each utility will comply with the ARB's requirements regarding minimum consignment of allowances for auction, and is not required to consign more than the ARB minimum for auction unless it determines that additional consignment reasonably mitigates costs to customers.[14]

For purposes of 2015 cost forecasts, the utilities assume that each utility would consign 25% of its allowances to the ARB auction.

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13 17 CCR Section 95893, Table 9-4.

14 Joint Motion, Appendix A, Section 7 (b)(i).

CalSEIA supports the proposed Settlement with the exception of this issue. CalSEIA argues this provision of the Settlement is contrary to the Commission's established principles for the Cap-and-Trade program, and that no record has been developed that supports deviating from its principles. CalSEIA claims that "the (ARB) left the decision on the actual number of allowances to consign to auction with the Commission, subject to the minimum."[15] CalSEIA states that the presumption should be that all allowances will be consigned to auction as quickly as possible unless and until it can be demonstrated that doing so would have negative impacts that outweigh the Commission's established principle that the price of goods and services reflects the full cost or carbon.

CalSEIA notes that in D.12-12-033 the Commission states:

> We believe that preservation of the carbon price signal is a high priority objective. Indeed it represents a foundational element of the Cap-and-Trade program that guides out thinking throughout this decision. An efficient allocation of society's scarce resources requires that the price of goods and services reflect the full, social costs of their production. Prior to the implementation of the Cap-and-Trade program, the price of carbon emissions generally has not been reflected in the prices consumers face for goods and services. In order to preserve the incentives the Cap-and-Trade program is intended to provide, the costs of carbon should generally be reflected in the price of electricity so that these costs can, in turn, be appropriately reflected in the price of goods and services that rely on electricity. Absent this, electricity consumption and consumption of goods and services that use electricity will be higher than the socially optimal level.[16]

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[15] CalSEIA Comments on the Joint Motion at 2.

[16] D.12-12-033 at 59.

EDF argues that "authorizing the utilities to consign only the ARB minimum would mute the consumer price signal to reduce natural gas and restrict the amount of revenue potentially available for GHG-reducing and cost-saving measures in the gas sector."[17] EDF/NRDC believe that a greater percentage of consignment than the 25% required by ARB would be more conducive to ensuring that a price signal could be available to natural gas users, potentially resulting in a reduced amount of natural gas usage. EDF suggests that, in the event that the Commission adopts the Settlement, the proposed ARB minimum be adopted as a placeholder for Phase 1, and allow parties the opportunity to present evidence and litigate the consignment issue during Phase 2. EDF/NRDC agree that approval of the minimum requirement is fine in Phase 1, but recommend that future years' consignment not be constrained by the Settlement.

The Settling Parties maintain that the consignment percentages were properly vetted and considered already by ARB during the development of the regulations, and the Commission should not revisit the balance struck by ARB.[18]

We find that the ARB regulations contemplate the possible consignment above the minimum. The ARB regulations state, in pertinent part:

> (1) when a natural gas supplier as defined in section 95811(c) is eligible for a direct allocation, it shall inform the Executive Officer by September 1, or the first business day thereafter of the amount of allowances to be placed in its Compliance and Limited Use Holding Account with the following constraints. The quantity of allowances placed into the Limited Use Holding Account will ***at least*** equal the amount of allowances

[17] EDF/NRDC Comments on Joint Motion at 3.

[18] Settling Parties Reply to Comments on the Joint Motion at 4.

> provided in section 95893(a) multiplied by the applicable percentage in Table 9-4.[19]

ARB's use of the language "at least," is clear, and permissive, meaning that the Commission could mandate or allow the natural gas utilities to exceed that minimum as it deems appropriate.

We agree with the Settling Parties that the minimum consignment percentage is appropriate for 2015, giving the timing of this decision; however, we find that the record is insufficient to determine whether additional consignment is cost-effective or warranted for future periods. We will therefore modify the Settlement such that the consignment percentage after 2015 will continue to be addressed in Phase 2 of this proceeding.

4.5. Issue 5: GHG Line Item

As we noted above, Phase 2 of this proceeding will address, among other things, the customer outreach and education issues stemming from the natural gas suppliers' obligations under the ARB's Cap-and-Trade program. While the Settling Parties do not address the outreach and education issues specifically in the Joint Motion or proposed Settlement, the Settlement would require the natural gas suppliers to include the GHG costs as a line item on customer bills for cost recovery. This issue is closely connected to (1) the question of how best to facilitate customer understanding of the impact of GHG costs on customer bills, and (2) GHG cost forecasts and rate design. Both of these issues will be addressed in Phase 2 of this proceeding. Therefore, we will modify the proposed Settlement such that the decision of how to communicate GHG costs in rates will be addressed in Phase 2 of this proceeding.

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[19] Title 17, California Code of Regulations, Section 95893 (b), emphasis added.

5. Other Issues

5.1. Exempt Entities

Under ARB's GHG Cap-and-Trade regulations, beginning in 2015, natural gas suppliers have a compliance obligation equal to the GHG emissions that would result from full combustion of all natural gas delivered to the utility's end users who are not covered entities. End-use customers who emit 25,000 metric tons of CO_2e or more per year are directly regulated by ARB and considered covered entities. The Settlement proposes that GHG compliance costs will be collected from customers, excluding covered entities, but does not include a detailed process for doing so.

The Indicated Shippers note that ARB's Cap-and-Trade program requires certain sectors, including emissions intensive and trade exposed (EITE) sectors, to submit compliance instruments to ARB for their direct GHG emissions resulting from the combustion of natural gas. This direct GHG compliance obligation for these sectors covers natural gas delivered by the natural gas utilities; therefore, recovering GHG compliance costs from these same customers through rates, creating an indirect obligation for the same emissions, would result in double payment of GHG compliance costs. The Indicated Shippers note that they support the Settlement to the extent it recognizes the need for the EITE exemption and establishes a framework for the EITE exemption from the proposed new gas rate schedule for GHG compliance costs. The Indicated Shippers request that the Commission require natural gas utilities to set up a detailed accounting procedure to ensure that the utilities do not collect GHG compliance costs directly from EITE customers.

We acknowledge the importance of excluding covered entities from GHG charges in natural gas rates, as they already pay for their GHG emissions associated with the direct combustion of natural gas. Because the Settlement does not detail the procedures necessary for the utilities to maintain an updated list of covered entities and appropriately exclude them from GHG costs in rates based on information they will receive from ARB, this decision declines to adopt this section of the Settlement. We modify the Settlement such that the process for excluding covered entities from GHG costs in rates will be determined in Phase 2 of this proceeding.

5.2. Independent Storage Providers

The Independent Storage Providers maintain that although they are natural gas corporations subject to the Commission's jurisdiction, they do not meet the criteria to be deemed "natural gas suppliers" under ARB's regulation. The Independent Storage Providers argue that while each Independent Storage Provider is the owner/operator of compressor facilities, each currently falls below the 25,000 $MTCO_2e$ per year that would subject them to ARB's compliance procurement obligations. The Independent Storage Providers point out that under the ARB's regulations, natural gas suppliers have "a compliance obligation for every metric ton CO2e of GHG emissions that would result from full combustion or oxidation of all fuel delivered to end users in California…."[20] They argue that they do not meet the definition of "natural gas supplier" because they do not distribute gas to end users in California, they merely provide a storage service for customers who themselves may be natural gas suppliers, or customers of natural gas suppliers. They suggest that excluding the Independent Storage Providers from the definition of natural gas supplier would ensure that natural gas delivered to end users for combustion in California is not counted

[20] Title 17, California Code of Regulations, Section 95802(a)(231).

twice, i.e., once by an Independent Storage Provider and then again by a natural gas supplier.

The Independent Storage Providers further note that to the extent they use gas to run compressors, they are consumers of natural gas, but that currently emissions at each of the Independent Storage providers' facilities do not exceed the 25,000 $MTCO_2e$ per year threshold, and therefore they do not have a procurement compliance obligation for purposes of ARB's Cap-and-Trade program. They recognize that if, in the future, an Independent Storage Provider's facility exceeds the 25,000 $MTCO_2e$ per year limit, it will be subject to ARB's regulation. Finally, the Independent Storage Providers note that to the extent that an Independent Storage Provider becomes a covered entity due to its direct emissions levels, its compliance cost recovery would not be affected by resolution of the issues to be addressed in the OIR, because its cost recovery is entirely market-based. The Independent Storage Providers therefore request that the Commission determine that they are not respondents to this proceeding. We concur.

5.3. Southwest Gas

Under the proposed Settlement, Southwest Gas would be subject to the same reporting requirements as the larger California natural gas utilities and would be required to report any sales transactions to ORA and ED. In light of the more limited compliance obligation that is faced by Southwest Gas due to its smaller footprint in California, Southwest Gas is not required to report sales to a consultative group, as proposed in the Settlement. The annual report proposed by the Settlement[21] is sufficient for Southwest Gas.

6. The Proposed Settlement, with Modifications, is Reasonable in Light of the Record.

Under Rule 12.1(d), the Commission will only approve settlements, whether contested or uncontested, that are reasonable in light of the whole record, consistent with law, and beneficial to ratepayers. It is a well-established policy of the Commission to approve settlements if they are fair and reasonable in light of the whole record.[22] This policy supports many worthwhile goals, including reducing litigation expenses, conserving Commission resources, and allowing parties to reduce the risk of unacceptable litigation results.[23]

In this case, the Settlement Agreement, as modified, is reasonable in light of the whole record because it reflects the product of a negotiated compromise that is in the best interests of ratepayers and the Settling Parties themselves. The record reflects that the Settling Parties actively participated in this proceeding and that the Settlement reflects a compromise of the Settling Parties' initial positions.

The Settling Parties include the natural gas utilities, representing their shareholders, and ORA, representing the interests of ratepayers. Each of the Settling Parties is experienced in public utility litigation and has demonstrated a sound and thorough understanding of the issues, and could therefore reasonably be expected to make informed decisions during in the settlement process.

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[21] Each utility submits an annual report listing its purchases and sales of all natural gas supplier compliance instruments.

[22] *See, e.g.*, D.11-06-023 at 13. *See also* D.05-03-022 at 9.

[23] *Id.*

Generally, the Commission does not consider if a settlement reaches the optimal outcome on every issue. Rather, the Commission determines if the settlement as a whole is reasonable. However, Rule 12.4(c) provides that the Commission may reject a settlement and instead propose alternative terms.

Thus, for the reasons discussed above, and taken as a whole, the Settlement, as modified, is reasonable in light of the whole record.

6.1. The Settlement is Consistent with the Law

The issues resolved in the Settlement Agreement are within the scope of this proceeding. The Parties are unaware of any statutory provision or Commission decision, resolution, or policy that would be contravened or compromised by the proposed Settlement. The Parties have entered into the Settlement Agreement voluntarily, and they represent that the Settlement Agreement is fully consistent with all applicable laws and request that the Commission adopt the Settlement Agreement.

There are no terms within the Settlement agreement that would bind the Commission in the future or violate existing law. Therefore, we find the Settlement consistent with the law.

6.2. The Settlement is in the Public Interest

The Settling Parties' indicated that they engaged in dedicated settlement negotiations during the period before and after the issuance of the Assigned Commissioner's Scoping Memo and Ruling in this proceeding, in the interest of timely compliance with ARB's January 1, 2015. As is evidenced by the comments and reply comments on the OIR, the Parties initially held several divergent positions on many of the issues presented in Phase 1 of the proceeding. The proposed Settlement demonstrated that the Settling Parties fully considered the facts and the requirements associated with the natural gas utilities' compliance with ARB's Cap-and-Trade program and reached reasonable compromises on the issues.

Compared to the time required for a full evidentiary hearing on all disputed factual issues, as well as a briefing on the policy issues, the proposed Settlement expeditiously furthers the objectives of ARB's Cap-and-Trade program, achieves a significant savings in time, resources, and expenses for the Parties, the Commission, and the public, and results in a reasonable compromise of the disputed issues.

As the Commission has acknowledged, "[t]here is a strong public policy favoring the settlement of disputes to avoid costly and protracted litigation,"[24] and when the settlement is fair and reasonable in light of the whole record.[25] This policy supports many worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.[26] It is established Commission policy that "[a]s long as a settlement, taken as a whole, is reasonable in light of the record, consistent with law, and in the public interest, it will be adopted."[27]

We find the Settlement, with our modifications, to be reasonable in light of the record, consistent with the law, and in the public interest; thus we adopt the modified Settlement.

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[24] D.88-12-083 at 85.

[25] *See e.g.*, D.88-12-083 (30 CPUC2d 189, 221-223) and D.91-05-029 (40 CPUC2d. 301, 326). *See also* D.11-06-023 at 13.

[26] D.11-06-023 at 13.

[27] *Id.*

As allowed by Rule 12.4(c), we provide the Settling Parties 10 days after the issuance of this decision to either accept the modification we propose in this decision or request other relief. No later than 10 days following the issuance of this decision, the Settling Parties shall file a letter in this proceeding stating whether they accept the modifications adopted in this decision or if they request alternate relief.

7. Safety Considerations

The health and safety impacts of GHG are well known and were one of the reasons that the legislature enacted AB 32. Specifically, the Legislature found and declared that global warming caused by GHG "poses a serious threat to the economic well-being, public health, natural resources, and the environment of California."[28] The potential adverse impacts associated with global warming include the exacerbation of air quality problems, among other issues. This decision implements a key part of the GHG reduction program envisioned by AB 32, and, in doing so, will improve the health and safety of California residents.

8. Categorization and Need for Hearing

The July 7, 2014, Scoping Memo and Ruling of the Assigned Commissioner and Administrative Law Judge affirmed the categorization of this proceeding as ratesetting and determined that no hearings would be necessary for Phase 1.

9. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure.

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[28] AB 32 Findings and Declarations.

Comments were filed on December 8, 2014 by PG&E, ORA, SoCalGas, SDG&E, and Southwest Gas (jointly) and EDF and NRDC (jointly). No reply comments were received. All comments have been carefully considered. The proposed decision has been revised with respect to the approval of new natural gas GHG compliance memorandum accounts for PG&E and SDG&E. Revisions have also been made to improve clarity and consistency.

10. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Julie M. Halligan is the assigned ALJ in this proceeding.

Findings of Fact

1. The Settling Parties have complied with the provisions of Commission Rules of Practice and Procedure (Rule) 12 regarding settlements.

2. The Settling Parties represent natural gas utilities and ratepayers and therefore represent a balance the interests at stake.

3. The record reflects that the Settling Parties actively participated in this proceeding and that the Settlement reflects a compromise of the Settling Parties' initial positions.

4. The Settling Parties' proposed 2015 forecasts of GHG compliance costs lack sufficient detail to consider at this time.

5. The methodologies that underlie the Settling Parties' proposed 2015 forecasts of GHG compliance costs are insufficiently defined.

6. D.14-10-033 as corrected by D.14-10-055 established methodologies that specify how the electric utilities should forecast GHG costs and allowance revenue.

7. The natural gas utilities' Cap-and-Trade compliance costs should be collected from core and noncore customers, excluding those that are exempt because they are subject to a direct compliance obligation.

8. Settlement Section 7(c) contains insufficient information to explain the process through which the natural gas utilities will ensure that customers that are directly covered entities under Cap-and-Trade will be exempt from GHG costs in natural gas rates.

9. The Settling Parties' proposal to include a separate line item on customer bills to reflect carbon pollution costs is an issue that has implications for customer education.

10. The question of how best to facilitate customer understanding of the impact of carbon pollution costs on customer bills should be addressed in Phase 2 of this proceeding.

11. The Settlement inappropriately limits the Commission's flexibility to direct the natural gas utilities to consign a higher percentage of their allowances to auction.

12. The minimum allowance consignment percentage mandated by ARB in Title 17, California Code of Regulations Section 95893, Table 9-4, is appropriate for 2015.

13. The record is insufficient to determine whether additional consignment is cost-effective, warranted or in the public interest for future periods.

14. In light of the more limited compliance obligation that is faced by SWG due to its smaller footprint in California, it is not necessary to require SWG to periodically report recent and prospective transactions to the ORAs and the ED.

Conclusions of Law

1. The Commission has the authority to adopt a settlement when it is reasonable in light of the whole record, consistent with the law and in the public interest.

2. Settlements need not be joined by all parties.

3. The Phase 1 Settlement, as modified, is reasonable in light of the whole record.

4. The Phase 1 Settlement, as modified, is consistent with the law.

5. The Phase 1 Settlement, as modified, is in the public interest.

6. The Phase 1 Settlement, as modified, should be approved.

7. The Settling Parties' request for authority to establish two-way balancing accounts to track and record costs incurred to comply with the ARB's Cap-and-Trade Program and company gas compressor station GHG compliance, as well as the revenues received from the consignment of allowances that ARB allocates to the natural gas utilities is reasonable and should be approved.

8. SDG&E and SoCalGas should update their NERBA subaccounts to no longer record costs associated with the Cap-and-Trade program, and should transfer any balances in the relevant subaccounts to their new GHG balancing accounts.

9. PG&E, SDG&E, SoCalGas and SWG should establish new memorandum accounts to track the administrative costs directly associated with their Cap-and-Trade compliance.

10. Following a decision in Phase 2 of this proceeding regarding the appropriate recovery of GHG compliance costs in rates, PG&E should be required to update its Gas Operational Cost Balancing Account to no longer record costs associated with the ARB natural gas supplier Cap-and-Trade program. At that time, any GHG compliance cost balances in the Compressor Station GHG Cost Subaccount of the GOBA account should be transferred to the new GHG balancing accounts and collected as part of the annual true-up for those accounts.

11. Energy Division should conduct an annual reasonableness review of the actual administrative expenses recorded in the memorandum accounts.

12. The proposed procedural mechanism in Settlement Sections 7(a) and 7(c) to approve annual Cap-and-Trade forecasts through a Tier 2 AL or annual gas true-up filing should be denied without prejudice, pending further consideration in Phase 2 of this proceeding.

13. ARB's use of the language "at least," in Title 17, California Code of Regulations Section 95893 9(b)(1)(A) makes clear that ARB's consignment requirements are indeed a minimum requirement.

14. It is reasonable to modify the Settlement Section 7(b)(i) to provide that the minimum consignment percentage will be considered in Phase 2.

15. End-use customers who are directly regulated by ARB for their GHG compliance obligation e should be exempt from the natural gas supplier Cap-and-Trade Program GHG compliance costs imposed by the natural gas utilities.

16. The process for excluding covered entities from GHG costs in rates should be determined in Phase 2 of this proceeding.

17. The Independent Storage Providers should no longer be considered respondents to this proceeding.

18. The decision should be effective today.

19. This proceeding should remain open for Phase 2 and other outstanding issues.

O R D E R

IT IS ORDERED that:

1. This decision approves, with modifications, the Phase 1 Settlement agreement proposed by Pacific Gas and Electric Company, the Office of Ratepayer Advocates, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Company.

2. Pursuant to Rule 12.4(c) of Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company, the Office of Ratepayer Advocates, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Company shall, within 10 days after the effective date of this decision, file a letter in this proceeding stating whether they accept the modifications adopted in this decision or if they request alternative relief.

3. We adopt the terms and conditions of Section 7.a of the Settlement, as attached in Appendix A of this decision, with the following modifications:

   a. Administrative costs shall be recorded in new memorandum accounts as authorized herein.

   b. The proposed process to seek approval of GHG cost forecasts is denied. This issue should be addressed Phase 2 of this proceeding.

4. We adopt the terms and conditions of Section 7.b(i) of the Settlement, as attached in Appendix A of this decision, with the following modification:

   a. The Commission shall further consider the minimum allowance consignment percentages for year 2016 and beyond in Phase 2 of this proceeding.

5. We adopt the terms and conditions of Section 7.b(iv) of the Settlement, as attached in Appendix A of this decision, with the following modification:

a. Southwest Gas shall not be required to periodically report recent and prospective sales transactions to the Office of Ratepayer Advocates and the Energy Division, other than as part of the annual report listing its purchase and sales of all natural gas supplier compliance instruments including greenhouse gas allowances, allowance futures and forwards, and offsets and offset forwards, carbon allowance derivatives, and any agreements with counterparties to purchase compliance instruments in the future.

6. Pacific Gas and Electric Company, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Company shall each file a Tier 1 Advice Letter within 30 days of this decision to establish:

a) two-way balancing account to track and record costs incurred to comply with the Air Resource Board's (ARB) natural gas supplier Cap-and-Trade Program costs and company gas compressor station greenhouse gas compliance costs, as well as the revenues received from consignment of natural gas supplier allowances for auction under the ARB program; and

b) new memorandum accounts to track the administrative costs incurred to comply with the ARB's natural gas supplier Cap-and-Trade program.

7. San Diego Gas & Electric Company and Southern California Gas Company shall each file a Tier 1 Advice Letter within 30 days of the adoption of this decision to modify their existing New Environmental Regulation Balancing Account subaccounts for Facilities and End-Users to no longer record costs associated with Cap-and-Trade compliance.

8. Within 30 days of the issuance of this decision, each of the natural gas utilities shall file preliminary statements in Phase 2 of this proceeding that include revised forecasts of 2015 Cap-and-Trade-related compliance costs and allowance revenues according to the requirements of this decision and that reflect, as closely as possible, the methodologies that the Commission defined for the electric utilities in Decision 14-10-033.

9. Rulemaking 14-03-003 remains open to address Phase 2.

This order is effective today.

Dated December 18, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners

APPENDIX A