STATE OF CONNECTICUT

BEFORE THE DEPARTMENT OF PUBLIC UTILITY CONTROL

DPUC Review of Southern Connecticut	**)**	
Gas Rates and Charges	**)**	**Docket 99-04-18, Phase 3**
DPUC Review of Connecticut Natural	**)**	**Docket 99-09-03, Phase 2**
Gas Rates and Charges	**)**	

SUPPLEMENTAL TESTIMONY OF

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ON BEHALF OF

THE OFFICE OF CONSUMER COUNSEL

Resource Insight, Inc.

JULY 13, 2001

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I. Introduction

Q: Are you the same Paul Chernick who filed direct testimony in this proceeding?

A: Yes.

Q: What is the purpose of this supplemental testimony?

A: I supplement my preliminary review of the proposal of Southern Connecticut Natural Gas (SCG or Southern) and Connecticut Natural Gas (CNG) (collectively, the Companies) on the inclusion of gas costs in the earnings-sharing mechanisms (ESMs) based on (1) the Companies' responses to discovery, (2) the transcript of the hearing on June 25, 2001 in this proceeding, and (3) information provided in Docket No. 01-04-04, concerning the BP Energy Alliance contract and the Companies' supply strategies.[1]

Q: Is there important background to ths proceeding of which the Department should be mindful?

A: Yes. I understand that there are two court appeals on earlier related proceedings. These appeals can affect what the Companies propose in this proceeding. The Office of Consumer Counsel also reminds me that its participation here does not bind it as to positions in the appeals.

Q: Please summarize the Companies' proposal for inclusion of gas-cost savings in the ESMs.

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[1] I cite discovery responses as "RES REQ-No.," where "RES" is the respondent and "REQ-No." is the request and number. I generally refer to the Companies' common positions, although I sometimes mention the data or responses of an individual company.

A: The Companies propose to retain half of the savings computed in separate formulas for savings in total demand cost, the dollars-per-MMBtu difference between the Company's commodity cost and NYMEX prices for gas at Henry Hub, and the percentage of gas that is unaccounted-for (UAF). Each of the first two formulas contains a placeholder for adjustments for non-merger-related changes. In all cases, calendar 2000 would be the base year for computing the savings. Any category with a saving from 2000 would be split, while any showing an increased cost would be ignored.

Q: Please summarize your supplemental testimony.

A: These additional materials confirm my preliminary evaluation of the Companies' proposal. This evaluation is as follows:

- The proposal does not meet the Department's requirements of a "detailed methodology" for identifying and quantifying merger-related savings and equitably allocating merger benefits among subsidiaries. The Companies' explanations of how they would implement their proposal are vague, incomplete and rife with inconsistencies. The Companies either have not considered the important issues or refuse to acknowledge the adverse effects that their proposal can have on ratepayers. The proposal is not complete or ready to be implemented.
- The proposal does not meet the Department's requirement that the sharing mechanism appropriately balance the interests between ratepayers and shareholders (Order in Docket 99-09-03 Phase II at 39). The Companies propose an asymmetric sharing of savings, claiming that cost increases are not merger-related, while retaining a share of all cost reductions for shareholders, regardless of the origin.

- Although it consists mostly of superficially simple formulas, the Companies' proposal does not serve the Department's goal of a sharing mechanism that can implemented with minimal regulatory oversight, under which

  > The sharing process would be accomplished without the need for financial review or extensive overearnings proceedings. Under this alternative, savings are shared immediately and automatically. (Order in Docket 99-09-03 Phase II at 8)

  The proposal leaves each company the discretion of including any changes in costs as "merger-related," without listing the types of changes that are to be reflected and without providing formulas for computing those changes. Approving this filing now would just defer the crucial issues to each annual ESM review. In every ESM proceeding, the Department would need to review each ad-hoc adjustment proposed by the Company, and consider whether additional adjustments are required for non-merger-related changes the Company did not mention.

- The proposal for sharing benefits among affiliates also leaves too much discretion to the Companies, which could lead Energy East to divert savings to the affiliates for which shareholders retain the greatest share of those savings.

Q: What is your recommendation?

A: I recommend that the Department reject the Companies proposal and again direct the Companies to file a detailed methodology for identifying and quantifying merger-related savings. Since that methodology must be consistent with the Gas Cost Reduction Plans, those filings should occur after the Gas Cost Reduction Plans are approved. The Companies should be required to demonstrate that their new proposal will not reward shareholders for random fluctuations in costs and sales, or for increasing costs to ratepayers, both of which are possible under the current proposal.

The Department should resolve the issues of identification and quantification of savings in advance, to discourage the Companies from later advancing opportunistic interpretations of vague guidelines in the light of what will then be past experience. Lightening the regulatory process for these companies will be impractical until the structure of the sharing mechanism and the shortcomings of the Companies' proposal have been fully resolved. The Department should not approve a proposal that the proponents cannot explain.

The utilities current proposals would be an administrative headache, since the Department would need to review in each annual ESM proceeding a raft of Company-proposed ad-hoc adjustments to the savings computations, and check all of the Companies' operations to ensure that they have not failed to include offsetting adjustments. Precedents regarding the scope of appropriate adjustments would be constantly changing. The Department has stated its intent that the ESMs should be simple and easy to administer; the Companies' proposals are the exact opposite. Therefore, the Department should remind the Companies that they will not receive any gas-cost savings in the ESM until they comply with the previous orders, and provide a methodology that complies with the Department's substantive and procedural objectives.

II. Failure to Provide the Required Detailed Methodology

Q: What was the Department's intent in requiring a "detailed" filing?

A: In approving an Incentive Rate Plan and permitting the Companies to recover their acquisition premium through a share of synergy savings, the Department limited that sharing to "the tangible customer benefits achieved by the merger." (Order in Docket No. 99-04-18, Phase III, at 20; Order in Docket 99-09-03, Phase II, at 18). To that end, the Department required that the Companies file a "*detailed* methodology on how merger-enabled gas-cost savings will be identified and quantified" (SCG Order at 21; CNG order at 19–20; emphasis added).

The Department clearly placed the burden on the Companies to show that all of the cost reductions they claim are indeed merger-related:

> The Department expects that the Company's Gas Cost Reduction Plan will present both (a) steps that the Company could take to reduce its gas costs if it were operating alone, and (b) additional cost-reducing steps that are merger-enabled. The Department also expects that, in presenting its Gas Cost Reduction Plan for approval, the Company will be prepared to demonstrate why each merger-enabled step could not be accomplished by the Company operating on a stand-alone basis. Finally, the Department expects that its approval of the Company's Gas Cost Reduction Plan will identify the steps that the Department considers to be merger-enabled, and thus the steps that qualify for savings-sharing. (CNG Order at 11)

Q: In what specific ways do the Companies filings fail to meet the Department's requirements of a "detailed methodology?"

A: The Companies' filings fall far short of compliance, for the following reasons:

- The Company does not present a methodology for distinguishing between merger-enabled changes and those that are not merger-related.
- The proposed formulas have a placeholder for adjustments for non-merger related cost changes. Yet, even for changes that are identified or

acknowledged to be not merger-related, the Companies present no methodology for calculating the associated adjustments.

- The Companies propose to base the calculation of incremental synergies on an historic pre-merger year, but the filings do not even provide the base-year values that the Companies propose to use in their compliance filing. The Companies provided some historical data in response to discovery, but explicitly specified only one of the six base-year values.
- The Companies do not provide the inter-affiliate allocation method that they would actually apply in an ESM filing. Rather, they expect the Department to rely on them to choose a reasonable allocation and forgo any review until the ESM filing.
- The Companies' presentation of their proposal is vague and rife with inconsistencies.

The Department requires that the Companies make a positive showing that the cost reductions to be shared could not have occurred absent the merger. In contrast, the Companies are requesting approval of a savings-sharing process based on the presumption that all cost reductions are merger-related, unless shown otherwise in some unidentified way.

Not only do the Companies not comply with the Department's conditions for sharing gas-cost synergies, they suggest that they cannot comply. In response to GA-552, the Companies claim that it is too difficult to project what gas prices would be in the absence of the merger:

> It would be extremely difficult to derive a "what if" scenario for shadow pricing. That scenario would have to make critical assumptions as to what Southern's gas supply function and results would have looked like absent the merger. We feel it is more appropriate to compare the most-recent historical results with future results to measure such savings which eliminated the "what if" assumptions….

A. Identifying Merger-Related Savings

Q: Have the Companies presented a methodology for identifying the merger-related savings?

A: No. The methodology in Schedule A of the filings, as clarified in discovery, starts with the assumption that any reductions in unit commodity cost, total demand charges, or UAF are merger-related, and that any increases are unrelated to the merger. Schedule A also provides for adjustments for non-merger-related changes, without specifying what those would be or how they would be identified.

When asked about the range of changes that could be unrelated to the merger, the Companies responded that such changes were "largely" in pipeline and storage tariffs, and declined to list any other non-merger-related factors that could affect costs (SCG OCC-57, -61; CNG OCC-397).

When pressed specifically regarding capacity releases, CNG acknowledged that capacity release sales could be non-merger-related, but asserted that whether the transaction is non-merger-related would have to be determined on a case-by-case basis (CNG OCC-406).[2]

Rather than developing the required methodology for identifying non-merger-related changes, the Companies only say that "unexpected" non-merger-related changes could be addressed under their proposal if they arise:

> No other changes have been identified at this time. However, the Company's proposal would not preclude addressing unexpected changes that are non-merger related. (SCG OCC-58, -64; CNG OCC-401)

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[2]The same response noted that CNG's activity in capacity release has been "limited," which may foreshadow attempts to get most future capacity releases classified as merger-related and eligible for the ESM.

Q: Are tariff changes really the only foreseeable non-merger-related changes in the Companies' gas costs?

A: No. There are several other categories in which non-merger-related changes are likely, although the exact nature of those changes cannot be determine in advance. For example, the Companies themselves acknowledge that as stand-alone utilities they could take the following steps:

- replace a terminated contract with a new lower-priced contract (CNG OCC-404)
- participate in the capacity release market (CNG OCC-406),
- conduct bilateral transactions with other LDCs that are not an Energy East subsidiary (CNG OCC-407),
- make off-system sales (CNG OCC-406)

All of these changes are foreseeable. The ESM should include provisions that will identify and quantify these savings and adjust the base year values, or otherwise ensure that the savings are not treated as merger-related.

The Companies' approach in their negotiations with BP Energy stands in stark contrast to the position they are taking in this proceeding. The Companies' negotiations were based on extensive analyses that identified the actions that each Energy East affiliate could take as stand-alone utilities. Under the resulting agreements between BP and Energy East, the subsidiaries retain savings from trading activities up to what's called the First Gate, which represents an estimate of what the utilities could do on their own and is based (at least for CNG and SCG) on CNG's pre-merger trading practices.

B. Quantifying Changes Unrelated to the Merger

Q: Do the Companies' discovery responses provide any information on how adjustments for non-merger-related changes would be calculated under their proposal?

A: Only a little. The Companies describe adjustments for changes in pipeline tariffs including changes in pipeline retained-gas percentages, and for sales into the capacity-release market.[3] For the most part the Companies were unable or unwilling to specify a method of adjusting their calculation of merger savings, even for changes they recognized to be non-merger-related.

Q: Can you provide specific instances in which the Companies failed or refused to provide an adjustment for changes that they acknowledge to be non-merger-related?

A: Yes, in the following instances:

- Although CNG acknowledges that weather and billing will affect the percentage of received gas that becomes UAF, it refuses to adjust its calculation of improvement in UAF for these changes (CNG OCC-440). In fact, the formula does not even contain a placeholder for non-merger-related adjustments to UAF.
- The average gas cost per MMBtu would fall if the share of higher-cost resources in a utility's dispatch decreased due to reduced winter load or increased summer loads. Such changes are not likely to be related to the merger. Yet, the Company failed to explain how it would adjust for this

[3]Even these descriptions are vague and oversimplified, as I discuss elsewhere. For the capacity release, the Companies have explained how the savings would be calculated, but not how they would determine whether a release is merger-related.

change, despite a specific request for a sample calculation. (CNG OCC-405).

- The Companies clearly recognize that weather can affect the commodity differential, since they justify the choice of 2000 as the base year on the grounds that weather was near normal (SCG OCC-72). However, the Companies have not included any weather adjustment in their proposed commodity-savings calculation.
- The Companies acknowledge that replacement of a terminated contract with a new lower-priced contract can also be non-merger-related, but they declined to provide a methodology for adjusting the merger-savings calculation for non-merger-related changes of this type (CNG response to OCC-404).
- In its response to GA-344, CNG acknowledged that there could be such non-merger-related changes as new pipeline and storage contracts. However, the Companies claim to be unable to adjust their calculation of merger savings for these changes in market events:

> Any changes in the gas market, positive and negative, would be reflected in the actual results. The base period reflects an appropriate period as described in GA-319. It is not possible to factor in other market events due to uncertainty.

In addition, while the Companies provide an example for the pipeline retained-gas adjustment, that example discusses a change in the retained-gas percentage for a utility's entire portfolio (SCG OCC-75, -76). The Companies do not specify whether the retained-gas percentage would actually be

- adjusted only if a pipeline changed its tariffed percentage rate, and then only for the gas delivered over that pipeline,

or

- adjusted to reflect changes in the relative usage if different pipelines, since the fuel retention percentages differ with the pipeline.

The Companies have not addressed to which commodity cost the changed-retention percentage would be applied: only the cost of commodity on the pipeline that changed its retention rate, or the average commodity cost, or some weighted average of the commodity costs of the lines whose usage changed. Nor have they addressed whether the averaging or weighting would use base-year volumes, current-year volumes, or current-year volumes adjusted for non-merger-related changes. When CNG was asked for the actual base-year fuel-retention percentage that it would use in its calculation of merger savings—a calculation that requires a methodology for dealing with multiple retention rates—CNG provided only the various pipeline tariff sheets (CNG OCC-415).

C. Setting Base-Year Values

Q: Regarding the failure of the Companies to specify the base-year values, did the filings provide any of those values?

A: No. The filings contained base-year values for each of the three parameters, but the values are described as "illustrative only." The illustrative values are identical for the two companies.

Q: Were these omissions corrected on discovery?

A: Not entirely. On discovery, each Company provided calendar-2000 data that should set the base-year values of the demand cost and the commodity cost differential, but do not explicitly propose to replace the illustrative values with the historical data. In the case of CNG, the Office of Consumer Counsel asked specifically for the values that would be used in the computation, and received only a reference to the historical data.

For unaccounted-for gas, CNG specifies the percentage it proposes to use in the computation, but that value is derived in a manner inconsistent with the CNG's description of how it would derive the UAF. I describe this inconsistency below. Southern has not specified a base-year UAF, and the historical UAF data provided by SCG are for gas years rather than the calendar years that would be used in the formula (SCG OCC-105).

Finally, if the adjustment for changes in pipeline fuel retention is to adjust for changes in the mix of commodity used from various pipelines, each Company must establish a base-year percentage for fuel retention. Neither Company has specified such a value.

D. Allocating Savings between Affiliates

Q: Do the filings provide the method the Companies would actually apply in allocating the savings from transactions between Energy East subsidiary utilities, in the context of PGA and ESM filings?

A: No. The Companies' filings propose, and Schedule B to the filings illustrates, sharing the benefit of each transaction among the subsidiaries participating in the transaction, in proportion to the subsidiary's sales. The discovery responses provide at least four inconsistent views of the Companies' thinking on this issue, most of which contradict Schedule B. The positions taken on discovery include the following:

1. Schedule B will govern all transactions.

The responses to SCG GA-535 and 538 and CNG GA-329, CNG OCC-419, -423 and -434 indicate that the Companies intend to rely on Schedule B's allocation of savings in proportion to sales. The response to GA-538 states that in *any* transaction benefiting only NYSEG and Southern, the allocation in Schedule B would be used regardless of the relative value NYSEG brings to the transaction just because "[a]bsent the participation of NYSEG, the savings would not be possible." Similarly, CNG OCC-419 states the Companies' intent that the utility using a resource pay the actual cost of the resource, and also pay a fraction of the net benefits (that is, the user's cost savings) to the provider of the resource, where the fraction would be determined by the utilities' sales.

2. Schedule B will be the last resort, when no other allocator is possible.

According to SCG, it intends to apply the Schedule B allocation method in only very limited circumstances, and does even not provide even an example of the type of transaction that would fall in this category:

> The proposed allocation, based on historical throughput, is only for those transactions where the benefit can not be attributed to specific entities. The Company is not proposing this as an allocator for all savings…. (SCG GA-537)

3. Transactions will be priced at market prices.

According to CNG OCC-430 and -431, the affiliate that uses a resource would pay the market price to the affiliate that provides the resource. There would be no explicit allocation of net benefits among subsidiaries. The resource provider would retain the margin of market price over cost and the user would retain the savings net of the market price of the gas.

Oddly enough, a series of responses (CNG OCC-419, -423, -434) justify Schedule B's allocation on the grounds estimating market price in the manner described in OCC-430 and -431 would be impractical:

> The market value of the resource can change every day. In addition, the market value may be judgmental. For these reasons it is preferable to use an allocation approach. (CNG OCC-423)

This is a curious argument, and not just because it contradicts the Companies' other responses. If two affiliates can determine that it makes economic sense for one to buy commodity (or capacity, or storage) from the other, they must know that the market price is higher than the seller's cost (or else the buyer would buy from the market), but less than the buyer's cost (or else the seller would sell into the market). Under the BP Energy Alliance, the Companies will be continuously monitoring the market for external transactions. The Companies' argument strains credibility.

4. Allocators will be chosen on a case-by-case basis, presented to the Department only in each annual ESM filing.

> Each allocation would be screened to consider whether the Schedule B formula is reasonably allocating the savings. If not, an alternative allocation method would have to be used.
>
> The Company would file all such transactions as part of its ESM filings. (CNG OCC-420)

Not only are the Companies unable to state more generally what their allocation method would be; they are unable to give a consistent explanation of how they would allocate the costs and benefits of specific transactions. Again the Companies are proposing to the Department that it forgo evaluation of the sharing methodology until its ESM compliance filing. The responses to discovery indicate that the Companies cannot be relied upon to develop a reasonable, consistent allocation method without the oversight of the Department in advance of the ESM filing.

Q: Can the Schedule B allocation leave a utility worse off than if it had sold its resources into (or purchased from) the market, without the merger

A: Yes. For example, suppose that SCG provides gas to NYSEG, and that the direct cost under SCG's contract is \$2/MMBtu. If so, the gas is worth

$2.50/MMBtu on the market, and NYSEG avoids the dispatch of a resource costing $2.75/MMBtu. If SCG sold this gas in the market (or sold it to NYSEG at market prices), it would have profited by $.50/MMBtu. Under Schedule B's sharing proposal, SCG receives only 30% of the $0.75 differential between SCG and NYSEG costs or $.225/MMBtu, a net loss to SCG of $.275/MMBtu. NYSEG on the other hand does well, saving $.525/MMBtu$.275/MMBtu more than it could save with a market purchase.

Regardless of whether NYSEG is buying or selling, Schedule B gives it the bulk of the savings, simply for being the larger company.

The Companies were unable to demonstrate that Schedule B's allocations will not result in Connecticut ratepayers being harmed by exchanges of resources among subsidiaries (CNG OCC-435).

Q: What is the Companies' rationale for this subsidy of NYSEG?

A: They point out that "Absent the participation of NYSEG [in a given transaction between NYSEG and SCG], the savings would not be possible" (SCG GA-538). This is not an adequate rationale for giving NYSEG 70% of the benefits in a bilateral transaction, since the savings would also not be possible absent the participation of (in this example) SCG.

Q: Does NYSEG provide a disproportionate share of the potential savings?

A: The Companies have not provided any evidence that it does. To the contrary, the Sharing Ratios in the Companies' BP Energy contracts, which represent Energy East's estimates of the potential for transactions by each affiliate, are much more heavily weighted toward SCG, and less toward NYSEG, than the sales ratios the Companies propose to use in this proceeding. These Sharing Ratios are based on extensive simulations of each subsidiary's potential transactions in the market.

Q: Have the Companies explained how affiliates will be compensated for non-gas services provided to other subsidiaries, and how that cost will affect the ESM?

A: No. The Companies have no proposal for allocation or compensation if the activity involves gas cost savings but only non-gas expenses, such as one subsidiary providing a gas-leak-reduction expertise to another.

> The Company's proposal related to merger-enabled gas-supply savings. Savings amongst subsidiaries for such things as outside contractors are not covered under this proposal. (CNG OCC-430)

Q: Can the Companies be trusted to select equitable allocations between Energy East affiliates?

A: No, despite the Companies' protestations. The Companies claim that "transactions with any of its subsidiaries provide benefits to the same set of shareholders," so Energy East would favor the transactions that provide the highest total benefit (SCG GA-538).

The Companies' claim is incorrect. Transactions between its subsidiaries *do not* provide benefits to the same set of shareholders, since savings to each companies benefit a different set of ratepayers and benefit shareholders to different extents. The sharing of costs and benefits is affected by the different treatment of gas costs and gas cost synergies in different Energy East jurisdictions: Massachusetts, New York, and Connecticut.

For example, NYSEG does not have a purchased-gas adjustment, and all gas-cost increases or decreases are borne entirely by shareholders (GA-554). Energy East shareholders will benefit from transferring cheaper resources, or a larger share of transaction savings, to NYSEG, which has no PGA and the shareholders retain 100% of the savings. The Companies acknowledge that Energy East benefits more from a dollar of savings allocated to NYSEG than a dollar allocated to other subsidiaries. (CNG OCC-433). They also point out that avoiding subsidies to NYSEG and hence Energy East shareholders requires that gas cost savings not be subject to arbitrary allocation.

In arguing for the ESMs, Energy East made the case that it would not minimize costs in the absence of economic incentives. The economic incentives that currently exist encourage Energy East to make inefficient business decisions and inequitable allocation decisions, since a dollar saved for NYSEG is more valuable than a dollar saved for CNG or SCG. Since Energy East has made much of its responsiveness to economic incentives, the Department cannot expect Energy East to do the right thing for Connecticut ratepayers where that conflicts with incentives for shareholders.

The Department must ensure that savings are allocated fairly between subsidiaries, under unambiguous rules and audited transparent procedures. It cannot leave that responsibility to the Companies.

E. Vagueness and Inconsistency

Q: Are there other examples of vagueness and inconsistencies in the Companies' discovery that attempts to describe their proposal?

A: Yes, for example:

- In the sharing of benefits among the subsidiaries, it is unclear which transactions will be allocated under the BP Alliance and which will be allocated under the ESM allocation method. The Company has not made that boundary clear (CNG OCC-426, -427, -428).
- It is unclear how the Companies would deal with a portfolio change that, for example, results in higher demand costs and lower gas-

commodity costs, but no change in overall gas costs.[4] While CNG OCC-411 claims that the demand-commodity cost tradeoff would be reflected in the separate calculations of demand savings and commodity savings, the asymmetry in the Companies proposal could result in the shareholders retaining a share of the commodity savings without bearing any portion of the higher demand costs.

- The Companies do not provide a consistent explanation of how the UAF percentage would be calculated.

Q: What is the inconsistency in the Companies' explanation of the UAF calculation?

A: The Companies filing clearly specifies in Schedule C that UAF would be calculated as

$$\frac{\text{System Deliveries–Company Use–Billed Sales}}{\text{System Deliveries–Company Use}}$$

The quantity (System Deliveries–Company Use–Billed Sales) is the sum of unbilled sales and unaccounted-for gas. In other words, this measure of the UAF includes unbilled sales.

The Companies are quite clear that they intend to include unbilled sales in the UAF, even though they acknowledge that variation in unbilled sales may distort the calculation of UAF improvement. The Companies assert that removing unbilled sales from the UAF is unnecessary and impractical, since:

- the calculation of UAF "will continue to calculate lost and unaccounted for as it has in the past," and

[4]The same situation could arise for lower demand costs and higher commodity costs. The commodity costs can vary due to differences in receipt points, pipeline charges, or retained-gas percentages.

- "the Company does not break down lost and unaccounted for" in a way that would allow it to identify unbilled sales. (CNG OCC-442)

Despite these protestations, CNG has specified that it will use a base-year UAF in its ESM filing that nets out unbilled sales (CNG OCC-436; -456). If unbilled sales are to be removed from the base-year UAF, they can and should be removed from the future-year UAF. In any case, the Companies must get clear on how they propose to compute UAF, and what measures of UAF they *can* compute; only then can the Department hope to sort out which measure of UAF is most appropriate.

Q: Did the Companies' oral direct testimony on June 25, 2001 provide any of missing detail on its gas-synergy sharing methodology?

A: No. The Companies' oral direct consisted largely of a discussion of the kinds of transactions the merger will enable the utilities to make. While this information is useful, this case is not primarily concerned with the *potential* for gas-cost merger synergies. This issue here is how the merger synergies can be identified and clearly linked to the merger.

III. Bias of the Proposal towards the Interests of Shareholders

Q: Does your review of the Companies' discovery responses support your earlier observation that the proposal is skewed in favor of shareholders?

A: Yes. The Companies' proposal clearly favors shareholders. The Companies hold the following views:

- Almost all cost reductions are merger-related. Since the Companies have not developed a methodology to identify and adjust the savings calculation for non-merger-related changes, their proposal would credit the shareholders with cost savings from changes that have nothing to do with efforts to reduce costs (e.g., the effects of warmer-than-normal weather, market events such as new pipelines and storage facilities) and from transactions that could have made in the absence of the merger (e.g., the First Gate level of BP Energy).

- All cost increases are not merger-related. In the Companies' view, merger savings cannot be negative (SCG OCC-72, CNG OCC-410):

> It is not possible for the merger-related benefits to be negative because adding lower-cost options, additional resources, new expertise and strategies, new market knowledge and increased scope/size cannot cause a cost increase compared to a scenario absent such things.

Therefore, under the Companies' proposal, if the savings, as calculated in Schedule A, were negative, shareholders would not bear any portion of the cost increase. (SCG OCC-72; CNG-410, -443).

- Even if gas costs increase, merger savings can be positive:

> It is possible for such merger savings to be positive if the PGA increases because absent the merger the increase would have been larger….

> The Company's proposal and the merger provide for the means to reduce costs compared to what they would have been absent the merger. (CNG OCC-408)

The Companies leave open the possibility that they will apply ad-hoc non-merger-related adjustments to allow the Companies to claim positive merger-related savings even when costs are increasing (CNG OCC-408, -409). If the Companies actually had a method for determining that the merger had mitigated increases, inclusion of some savings in the ESM might be justified. The Companies have no such method, reserve the right to make selective after-the-fact adjustments, and propose to ignore increases in other cost categories, even if those are related to the decrease for which the Companies would claim savings. For these reasons, the Companies' proposal is seriously biased.

Q: Can you provide a numerical illustration of the asymmetry in the Companies' proposed savings sharing?

A: Yes. Using UAF data from CNG OCC-456, I compared the total UAF benefit over the four-year period, 1997–2000, from a 1996 base year, as it would be estimated under two sharing formulas:

- The Companies' method as described in CNG OCC-443 and -444, in which CNG shares in the change in UAF only if the UAF decreases.[5]
- A symmetrical sharing of positive and negative "improvements" in the UAF.

Since the Companies' calculation of UAF improvement does not contain any non-merger-related adjustments and since the Companies do not expect to be able to reduce losses to any significant extent at least in the short term (Tr. 4499), the pre-merger loss data provide a reasonable basis for estimating the variability in UAF over the next four years, with or without the merger.

Exhibit____PLC-S1 presents the results of my sample calculation. Under the Companies skewed formula, the shareholders would receive a total of $750 thousand over the four years, while the ratepayers' share would be a negative $3.1 million. Under a symmetric sharing formula, both shareholders and ratepayers would receive a negative benefit, ¯$1.2 million.

[5]The Companies refer to this saving as "gas cost avoided."

IV. Overstatement of Merger-Enabled Savings

A. Calculation of Demand-Cost Savings

Q: Please briefly describe the Companies' proposed calculation of demand-charge savings.

A: Demand-charge savings are calculated as the decrease in total demand costs from the base year, adjusted for tariff changes. Consistent with other aspects of the Companies' proposal, any increase in demand costs would be ignored.

Q: Can this calculation be relied upon to produce a reasonable estimate of merger-related demand-cost savings?

A: No. In addition to the lack of a methodology for identifying and quantifying non-merger-related adjustments discussed above, the Companies' proposal presents the following more specific problems:

- it lacks an adjustment for changes in demand,
- it lacks an adjustment for changes in market conditions, and
- it assumes that SCG, in particular, would be unable to alter its portfolio mix if it were a stand-alone utility.

Q: How would changes in demand affect the calculation of demand-cost savings?

A: The formula measures is based on a comparison of total costs, rather than of dollars per MMBtu (or per MMBTU-day) of demand. Therefore, if demand costs are reduced as a result of a fall in demand, that change would register as a merger-enabled savings, even though the change in demand has nothing to do with the Companies' cost-reducing efforts.

Q: Is a decrease in demand a realistic possibility?

A: Yes. The Companies' need for capacity can decline even though their customers' gas use remains stable. For example, large customers may switch from sales to transportation service. Or customers with dual fuel capability may switch from firm to interruptible sales service. These changes would free capacity for off-system sales or sales in the capacity release market.

Q: Do the Companies acknowledge that changes in market conditions could affect demand costs?

A: No. In the Companies view, "market conditions do not affect demand costs which remain FERC regulated and cost based" (SCG GA-533). The Companies overlook the effect that market events can have on potential for small utilities to profit from their excess capacity through such activities as participation in the capacity release program, swapping and off-system sales.

Q: What is the Companies' basis for assuming that SCG as a stand-alone utility would never be able to alter its portfolio?

A: The Companies contend that SCG "has little portfolio flexibility because it is committed to contracts that generally extend well into the future" (SCG OCC-54).

Q: Does the information provided by the Companies support their contention that SCG has little portfolio flexibility?

A: No. The Companies provided the following information:

- Before the merger, SCG sold excess capacity in the capacity release market. It reported in its 2000 Integrated Resource Plan (at V-2) that it considered its participation in the capacity release market to be an important part of its strategy to "optimize capacity:"

> …until its obligations as supplier of last resort are clarified, the Company must use caution in managing its pipeline transportation assets. SCG has also contracted with other gas providers to share its pipeline capacity (capacity release on a limited basis or with limited recall rights). By doing this, the Company has endeavored to optimize capacity idled by customers switching to firm transportation without losing the capacity needed for new customer growth.

- Several of SCG's pipeline and storage contracts will terminate within the rate plan period and most can be sold in the capacity release market (Integrated Resource Plan at V-3 through V-6; SCG OCC-54).
- The expectation of merger synergies from a exchange of some SCG domestic capacity for NYSEG's Iroquois Pipeline capacity depends on SCG's ability to reduce its contract capacity:

> The additional deliveries to Southern would allow for the reduction of other contracts and associated demand charges. Southern would contemplate an arrangement to share the value of the cost reduction with NYSEG. (SCG GA-556 (c))

Since Southern can reduce its total capacity requirements, and can swap resources (with or without the merger), the ESM must have some provision for identifying the amount of such changes that are not related to the merger.

B. Calculation of Commodity-Cost Savings

Q: Please briefly describe the Companies' proposed calculation of commodity-cost savings.

A: Commodity-cost savings are calculated as the change (from the base year) in the differential between (a) the actual weighted average commodity cost paid per the deferred gas filing and (b) the actual NYMEX weighted average cost of gas. The comparison of differentials will be also adjusted for non-merger-related changes, but the only adjustments that the Companies have recognized and explicitly included in their proposals are changes in tariffs and fuel-gas-retention rates.

Q: Can this calculation be relied upon to produce a reasonable estimate of merger-related commodity-cost savings?

A: No. As discussed above, without a clearly defined methodology for identifying and quantifying non-merger-related adjustments, this calculation cannot be relied upon to provide a reasonable estimate of merger savings. In addition to this general problem,

- the Companies inappropriately assume that all BP Energy Alliance savings are merger-related,
- the differential will reflect changes that have nothing to do with cost savings efforts,
- the Companies selected a particularly a high-cost year as the base year.

Q: What is the Companies' basis for claiming that all BP Energy Alliance savings are merger-related?

A: The Companies contend that in the absence of the merger, the LDCs would not be able to negotiate this kind of agreement with BP Energy. They have not demonstrated that the merger was a prerequisite for other types of alliances or cooperative activities with other utilities or marketers.

Q: Does inability of the Companies as stand-alone utilities to secure agreements with BP Energy justify considering all Alliance savings as merger-related?

A: No. As explained above (and in my initial direct testimony), the Companies retain savings from trading activities up to the First Gate, which is represents an estimate of what the utilities could do on their own and is based (at least for CNG and SCG) on CNG's pre-merger trading practices.

Q: What changes other than the Companies' cost-savings efforts could affect the commodity-cost differential?

A: The following factors, for example:

- weather,
- non-weather-related fluctuations in seasonal gas consumption patterns.

Q: How would weather conditions affect the differential?

A: For the past three years, 1998–2000, the differential between the Companies' monthly actuals and the NYMEX monthly index is, with few exceptions, positive in the months October through January and negative in all other months (based on data provided in SCG-GA-544 and data provided in CNG-OCC-418). When the ratios of monthly sendouts change, the weighted average of the differentials will change. A warmer-than-normal January will the reduce the high-differential sendout, reducing the average differential.

Q: Do the Companies acknowledge that weather affects the differential?

A: Yes. In their selection of the base year, the Companies recognized that weather can affect the differential, and assert that calendar 2000 is appropriate as the base year because it "reflected close to normal weather conditions" (SCG GA-533).

Q: What changes other than weather could affect relative monthly gas volumes?

A: Summer sendout could increase as a fraction of total sendout, reducing the average differential, as a result of any of the following:

- an increase in summer gas use by dual fuel customers in response to an increase in oil price;
- an increase in summer interruptible sales;
- winter peak reduction due to heating-customers' conservation efforts.

None of these events would be related to the merger, yet the Companies would claim a reward for them through the ESM.

Q: How important is the choice of base year?

A: The calculated commodity saving is very sensitive to the choice of base year. For SCG, 2000 had the highest differential ($0.721/MMBtu) of the past seven years, by far. In fact, in four out of the seven years, SCG's actual weighted average cost of gas was *less* than the NYMEX index, and the 1994–2000 average differential was only $.022/MMBtu. (SCG-GA-568 revised) If the seven-year average is representative of the commodity differential of SCG as a stand-alone utility, the use of the anomalous year 2000 would result in ratepayers paying the shareholders on average about $7 million annually

$$50\% \times 20{,}000{,}000 \text{ MMBtu} \times (\$0.721/\text{MMBtu} - \$0.022/\text{MMBtu})$$

without any improvement over SCG's past historical gas supply approach.

For CNG, the historical variation in differentials is less extreme, but the differential in 2000, $0.143/MMBtu, was still on the high end of the range of values over the seven years. In four out of the seven years, CNG's actual weighted average cost of gas was lower than the NYMEX index, and the 1994–2000 average differential was actually negative, at ¯$.083/MMBtu. (CNG-GA-323). The difference between 2000 and the historic average is $0.226/MMBtu, about a third for the SCG difference, but still substantial.

Q: What is the Companies' rationale for selecting 2000 as the base year?

A: The Companies contend that the 2000 differential is an appropriate baseline value because it reflects close to normal weather conditions and current market conditions, that is, the tightening of supply and substantial increase in price (SCG-OCC-72; SCG GA-533). In the Companies' view, using 1998 or

1999 would be inappropriate because these years had warmer-than-normal weather.

Q: Is the Companies' rationale for its choice of base year valid?

A: No, for the following reasons:

- The gas prices in 2000 were unprecedented and are not representative of gas market conditions in the rate plan period.
- The abnormal prices were primary cause of the high differentials in 2000; the difference in weather conditions was of secondary importance.

Q: What is the basis for your argument that the gas prices in 2000 are not representative of conditions in the rate plan period?

A: My argument is based on the following observations:

- As shown in Exhibit____PLC-S2, the pattern of average monthly spot price at Henry Hub in 2000 was highly atypical, with prices rising through the year and reaching unprecedented levels by the end of the year. Since January, prices have declined precipitously from the peak.
- Storage inventories were abnormally low going into the 2000/01 winter, an anomaly that SCG itself pointed out (SCG GA-558). Normal storage inventory going into future winters will reduce the differential between NYMEX and actual, since as SCG explains (at SCG GA-549):

> ...the use of storage may lower the commodity cost of gas both for the gas supply and the transportation charges.

- In the final months of 2000, SCG was operating under an asset-management agreement that does not appear to have produced adequate results. Southern paid an average gas cost of $11.305/MMBtu, more than 50% higher than CNG's average cost of $7.243/MMBtu. (SCG GA-568 revised, CNG GA-323 revised)

Q: What is the basis of your statement that weather was not an important driving factor?

A: I performed two analyses:

- a comparison of the commodity-cost differentials in 2000 with those in years with a similar or greater number of degree days.
- a comparison of the average of the commodity cost differentials in 1998, 1999, and 2000 assuming (a) no change across years in the monthly sales pattern or (b) no change across years in the monthly prices.

Q: What was the result of your first comparison?

A: Years that were normal or colder had smaller differentials than 2000 did. So did warmer-than-normal years 1998 and 1999.

A normal year in Hartford has about 6,150 degree-days; calendar 2000 was essentially normal with 6,192 degree-days. In 1997, a normal year with 6,111 degree-days, the commodity-cost differential was negative for both Companies, at -$0.056/MMBtu for SCG and -$0.147/MMBtu for CNG. In 1996, a colder-than-normal year with 6,229 degree-days, the differential was an even more negative -$0.363/MMBtu for SCG and -$0.494 for CNG.

Q: What was the result of your second comparison?

A: The results of these calculations are presented in Exhibit____PLC-S3. The actual 2000 differentials are much greater (and even different in sign) than the actual 1998 and 1999 differentials. These differences result from both the monthly differentials and the monthly pattern of sales in each year. Calendar

2000 differentials were increased both by weather (a larger fraction of sales in the winter) and by the unique pattern of monthly prices.

In Exhibit____PLC-S3, I compute the average annual differentials with one year's monthly sales (i.e., weather) and another year's monthly prices. While weather does have some effect, the pattern of monthly prices turns out to be much more important. For example, using the 1999 monthly differentials and 2000 weather produces an annual differential that is much more like 1999 than like 2000. While these calculations ignore some second-order effects (such as the effect of national weather on NYMEX gas prices), they suggest that the normal weather in 2000 was less important than the abnormal price patterns in determining the unusually large average commodity-price differentials.

C. Calculation of Unaccounted-for Gas Improvement

Q: Please briefly describe the Companies' proposed calculation of UAF improvement.

A: Savings from UAF improvements in a future year would be calculated as the product of (1) the reduction in the UAF, (2) system deliveries in the year, and (3) the average cost of gas in that year. The reduction in UAF would be calculated by comparing the UAF for the future year to the five-year average ended December 31, 2000.

Q: Can the Companies' proposed calculation be relied upon to estimate the UAF improvements enabled by the merger?

A: No. As I discussed in my initial testimony, the UAF calculation has the following problems:

- It allows incentives for improving metering accuracy, which reduces reported UAF, not by reducing real leaks or losses, but by increasing billings for gas and delivery service to customers.
- It includes no adjustment for UAF reductions that are not merger-related.
- It ignores sensitivity to weather and other non-merger-related fluctuations, even though the Companies acknowledge that weather will affect UAF (CNG OCC-442).

As illustrated in Exhibit____PLC-S1, since the Companies propose to share in UAF reductions but not to bear any increases, shareholders could benefit substantially from just random fluctuations in UAF, without having to make any real effort to reduce gas costs.

Q: What reductions in UAF do the Companies suggest may be possible?

A: The Companies suggest that by making use of "experience within other Energy East companies," namely NYSEG, they may have as a goal the reduction of their UAF to NYSEG's UAF value of 0.8% (SCG OCC-95). The Companies do not actually project that they *will* reduce their losses to 0.8%, although CNG did include this merger benefit in its estimates of merger synergies (Order in Docket 99-09-03, Phase II, at 10).

For CNG, a reduction from the base year level of 1.75% to 0.8% would amount to a reduction of more than 275,000 Mcf (assuming system deliveries of 30,200,000 Mcf) (CNG OCC-456). For SCG, a reduction from 2.69% to

0.8% would amount to a reduction of over 500,000 Mcf (assuming system deliveries of 29,500,000 Mcf).[6]

Q: How do the Companies' identified opportunities for reducing UAF compare to historical variability in UAF and to goal of reaching a UAF of .8%?

A: The opportunities that the Companies have identified are relatively insignificant, considering that

- the UAFs of each utility vary substantially from year to year.
- the Companies have not identified any programs that they expect to significantly reduce losses. The savings that the Companies have estimated are very small compared to the historic variability and to the expectations the Companies have created. If the UAF of either SCG or CNG falls to NYSEG's 0.8%, it will likely be the result of good luck, not good management.

Q: What has been the historical variability in UAF?

A: Over the past ten years, CNG's annual UAF has ranged from ¯0.43% to 2.87%.[7] In eight out of the last 16 years, CNG's annual UAF has been below the proposed baseline value of 1.75%, in one year as much as 2.18% lower, without any merger-related UAF improvement programs (CNG OCC-456).

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[6]SCG has not provided the average UAF for the five calendar years ending with 2000. Therefore, for this calculation, I have used average UAF from the five most recent gas years, provided in response to SCG OCC-105.

[7]On a gas-year basis, SCG's annual UAF also varied substantially from 2.26% to 3.19%. (SCG OCC-105). The variability on a calendar year basis would probably be greater because of weather effects.

Q: Have the Companies provided any evidence that their loss-reduction programs will have a measurable effect on UAF and consumer bills?

A: No. The following information provided by the Companies indicate that the planned programs will not reduce losses to any significant degree:

- The Companies do not expect much from these efforts at least in the short term:

> At this point, of all of the boxes on Mr. Rudiak's charts, we don't expect the loss and unaccounted-for to be one of the more significant savings that will be achieved for customers quickly.
>
> We think these other methods that Mr. Rudiak described probably will have better impact, faster impacts, but it is an area that we are addressing, and we just have limited results at this point in time to really describe how we might be able to reduce costs through that, reducing lost and unaccounted-for. (Tr. 4498-4499)

- The Companies say that "these programs/efforts represent no significant additional costs" and hence do not require a cost-benefit analysis (SCG OCC-109; CNG-OCC-458). The lack of significant expenditures suggests that the utilities are not planning on implementing significant loss-reduction programs, at least during the rate plan period.
- The only loss-reduction estimates that the Companies have produced are 8,400 Mcf/year from SCG's Class-2 leak-backlog reduction, 60 Mcf from SCG's mains replacement, and 4,700 Mcf/year from CNG's Class-2 leak-backlog reduction (SCG OCC-109, -107, CNG OCC-485). These reductions are minuscule compared to the historical variability of UAFs and to the 275,000–500,000 Mcf reductions that would be required to reduce the UAF to 0.8%.
- Corrections in metering errors, which as I have explained should not be included in an ESM, are unlikely to reduce UAF. Southern believes that

its meters are accurate and has recently proposed a reduction in its testing program (SCG OCC-102, -103).

Q: Have the Companies demonstrated that their plans to reduce UAF are merger-related?

A: No. The Companies simply claim (at SCG OCC-110) that since no programs in the past were "specifically targeted" at reducing UAF, all future efforts are merger-related:

> No specific studies were undertaken by SCG in the past ten years that were specifically targeted at reducing the lost and unaccounted for gas percentage. Thus, the reason this exercise was identified as a merger enabled savings.

This claim appears to be more a matter of semantics than of fact. The Companies were reducing losses prior to the merger through main replacement, leak repair, and metering correction, even though these were not programs "specifically targeted" at loss reduction. Since the Companies agree that "these programs/efforts represent no significant additional costs," they do not appear to require any resources that were not available prior to the merger (SCG OCC-109; CNG OCC-458).

Q: Is the merger related to SCG's efforts to decrease its leak backlog?

A: No. The data suggest that the current backlog is a recent phenomenon, due to an increase in the number of leaks identified, rather than a long-standing problem that requires the special expertise of NYSEG to resolve.

Southern's leak backlog was small for most of the 1990s, until the most recent three years. In 1992, SCG started with a backlog of 26 leaks, identified 470 leaks, and repaired 494 leaks reducing the backlog to only 2. Southern's experience in 1993 was similar to that in 1992. From 1994 through 1997, however, SCG identified fewer leaks (about 250–300 annually) and repaired about the same number, so the backlog remained under 60. In 1998, the number of leaks identified jumped 75% to 498, and although the number of leaks repaired increased significantly by 57% to 392, the backlog increased to more than 160.[8] In 1999 and 2000, SCG identified more than 400 leaks annually, but repaired slightly more, gradually reducing the backlog (SCG OCC-99, -101). If SCG had been able to repair the same number of leaks in 1998 as it did in 1999 and 2000, the current backlog would be less than 30.

Since SCG was able to repair 494 leaks in 1992, has the expertise to keep up with leak rates at recent levels. During the 1990s, with low levels of new leaks, SCG may have become complacent and reduced its work force. In any case, the current backlog is primarily the result of an unexpected jump in identified leaks, rather than a lack of expertise. There is no evidence that reducing that backlog required (or is even facilitated by) the merger.

Q: Why should accelerated main replacement not be treated as a source of merger-related UAF reduction?

A: Southern's discovery responses clearly indicate that the accelerated main-replacement program is neither merger-related nor a program "specifically targeted at reducing" UAF.[9] In particular,

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[8]Leakage rates are affected by, among other things, levels of public and private construction, which disturb both pipes and overlying materials (such a roadways) that slow the release of leaked gas from the ground . As a result, infrastructure projects can increase leakage reports.

[9]The Companies should not need the additional incentive of the ESM to encourage them to replace mains. Ratepayers are already paying for main replacement and shareholders are earning a return on the investment. Main replacement reduces the Companies safety liabilities. In addition, SCG considers potential new business development in developing its annual plans for main replacement (Attachment to SCG OCC-107). Where main replacement also accommodates growth, shareholders benefit from the resulting revenues.

- The program "was prompted primarily by a proactive approach to safety" (SCG OCC-108) .
- The projected reduction in UAF is minuscule, at 60 Mcf per year (SCG OCC-107(d)).
- The program was not even initiated by the Company. The accelerated main-replacement program "was prompted by the DPUC Gas Safety Staff in SCG's recent rate case...." (SCG OCC-107(f)). The Decision in 99-04-18, Phase 1 dated 1/28/00 (before the completion of the SCG's merger with Energy East) "required Southern to increase its annual expenditures for planned cast iron main, bare steel main, and bare steel services by $3 million…." (SCG OCC-96 Attachment at 2).

Q: Does this complete your testimony?

A: Yes.

Exhibit____PLC-S1:
Illustration of the Asymmetry of the Companies' Sharing Proposal

Average Actual Commodity Cos $5

	Year	*5-Year Avg* [1]	*Annual UAF%* [1]	*System Deliveries*	*Reduction from Base Year UAF%*	*Savings Incl Negatives*	*Savings Excl Negatives*	*Symmetrical Sharing btwn Ratepayers and Shareholders*	**Companies' Proposal** *Shareholders' Share*	**Companies' Proposal** *Ratepayers' Share*
Base Year	1996	1.40%								
	1997		2.09%	38,115,786	-0.69%	($1,314,995)	$0	($657,497)	$0	($1,314,995)
	1998		2.87%	34,640,341	-1.47%	($2,546,065)	$0	($1,273,033)	$0	($2,546,065)
	1999		1.32%	36,268,285	0.08%	$145,073	$145,073	$72,537	$72,537	$72,537
	2000		0.67%	37,312,172	0.73%	$1,361,894	$1,361,894	$680,947	$680,947	$680,947
Total						($2,354,092)	$1,506,967	($1,177,046)	$753,484	($3,107,576)

Notes:

[1] CNG OCC-456

Exhibit____PLC-S2:
Comparison of Monthly Trends in Gas Prices at Henry Hub

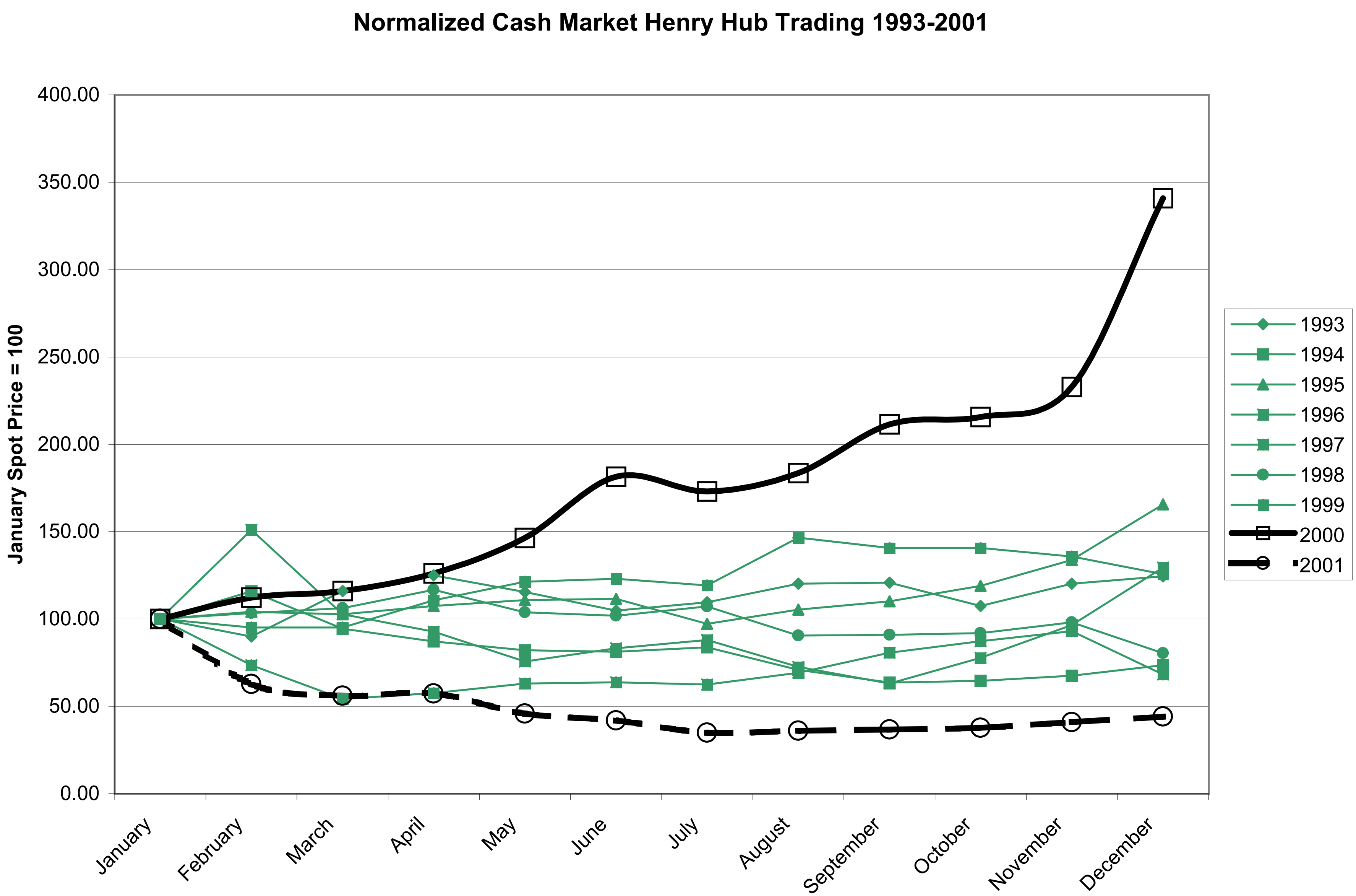

Exhibit PLC-S3:
Effect of Gas Price versus Sales on Commodity Cost Differential
(Dollars per MMBtu)

SCG Commodity Cost Differential

	Weighted by		
	1998 Sales	*1999 Sales*	*2000 Sales*
2000 Prices			
Wtd Avg NYMEX	3.430	3.431	3.563
Wtd Avg Actual	3.917	3.958	4.284
Differential	0.487	0.527	0.721
1999 Prices			
Wtd Avg NYMEX	2.053	2.035	2.066
Wtd Avg Actual	2.010	2.005	2.094
Differential	-0.043	-0.029	0.028
1998 Prices			
Wtd Avg NYMEX	2.161	2.167	2.151
Wtd Avg Actual	2.006	2.020	2.044
Differential	-0.155	-0.147	-0.107

CNG

	Weighted by		
	1998 Sales	*1999 Sales*	*2000 Sales*
2000 Prices			
Wtd Avg NYMEX	3.454	3.413	3.537
Wtd Avg Actual	3.578	3.547	3.680
Differential	0.125	0.133	0.143
1999 Prices			
Wtd Avg NYMEX	2.060	2.038	2.061
Wtd Avg Actual	2.166	2.164	2.204
Differential	0.106	0.126	0.143
1998 Prices			
Wtd Avg NYMEX	2.160	2.164	2.152
Wtd Avg Actual	1.915	1.930	1.934
Differential	-0.245	-0.234	-0.218