EMERGING COMPETITION IN CALIFORNIA GAS MARKETS

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Hillard G. Huntington

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The California Energy Commission (CEC) organized this conference to help the Commission develop a sound analytical base for its natural gas policy and to promote a stimulating and informed exchange of ideas between policymakers, private sector decisionmakers, and industry analysts. This paper describes the major issues addressed during the conference, which included sessions on tracking North American natural gas markets, promoting competition through regulatory policy, meeting the challenges of the California gas market, transportation and electricity generation as potential growth markets, the influence of environmental policy on natural gas markets, and new markets for natural gas services. The paper focuses on identifying salient trends and issues raised in each session rather than on providing a detailed account of each talk. Not all speakers on a panel necessarily agree with all points mentioned for a particular session.

Commissioner Robert Mussetter of the CEC opened the conference by raising two issues: (1) Are we really introducing competition into the market place or is it simply rhetoric? and (2) Are regulatory agencies anticipating future problems or are they resigned to fighting the last war? He challenged the speakers and audience to help evaluate our progress and identify key future issues in making competition work in the California natural gas market.

TRACKING NORTH AMERICAN NATURAL GAS MARKETS

Chaired by John Rozsa of the CEC, this opening session emphasized the broader continental gas market within which the California gas market operates. Panelists included Dale Nesbitt (Decision Focus Inc.); Mark Segal, David Collyer, and Don Coletti (National Energy Board, Canada); and Gary Simon (Cambridge Energy Research Associates).

Dale Nesbitt said that formal modeling (with the North American Regional Gas model, or NARG) has led to several broad conclusions about North American gas markets:

(1) Pipe is cheap relative to gas. Hence, location is less important that resource costs. Resource assessments are critical, and consistency across resource basins and national boundaries is paramount.

(2) Gas displaces gas, not oil. Canadian gas will compete with US gas. New gas production technology will displace old technology. The continental gas market is a zero-sum game with winning gas suppliers gaining at the expense of other gas suppliers.

(3) Price declines when gas displaces gas. Increased competition more than offsets the large fixed costs required for new pipelines, resulting in lower regional gas prices.

(4) Gas and oil prices are decoupled and do not track each other on a BTU parity basis. The size of the switchable market, where consumers can switch rapidly between gas and oil, is key to the oil-gas price relationship. The switchable market will decline with de-industrialization.

(5) The oil price is high, but not for long. Gas prices will have a more difficult time competing with relatively inexpensive foreign oil, as domestic gas resource costs gradually push gas prices higher.

(6) Pipeline projects are viable when resource costs in the supply region are low and value in the demand region is high. Otherwise, the difference between the delivered and

wellhead prices determined by market forces will be insufficient to pay for the full pipeline costs.

Some preliminary NARG simulations run by the National Energy Board were discussed by Mark Segal and his colleagues. Oil prices were assumed to rise from $17 (1990$) in 1992 to $22 by 2010. The simulations did not incorporate environmental policies which would limit substitution of oil for gas, although they will in additional rounds. The Western Canada conventional resource base was about 10% higher than estimated for the 1988 NEB supply/demand report.

The results indicated that production would peak around the year 2000 in both Canada and the US. Alberta's wellhead price would remain below the US wellhead price, reflecting higher transportation costs for Canadian gas. Due to the low oil price path, gas prices would rise above heavy fuel oil prices, causing much of the noncore demand to be shed by 2000. However, gas would compete well against light fuel oil, and hence, gas use would grow in combined-cycle gas-turbine applications. Canadians would gain a larger share of the California market, but the big story is the displacement of southwestern gas by gas from the Rocky Mountains in meeting California's gas demand.

Gary Simon questioned the conventional wisdom on gas supply. This view projects: (1) declining US reserves and deliverability, (2) reduced gas supplies emanating from a rig count about 50% of its peak, and (3) a price of $2.50 per MMBTU required to stimulate substantial gas volumes. But why is price declining and deliverability rising?

Interviews by CERA with the exploration and production divisions of major producers reveal a different picture. (1) Drilling efficiency is greater--due to such developments as 3-D seismic testing, improved signaling, and horizontal drilling. (2) More wells are being recompleted, thereby keeping deliverability from falling. (3) The extra costs are relatively low for producing more gas from areas where there has already been large investments. In particular, Gulf deliverability has been maintained because pipelines are near and the associated production costs are low. (4) Producers have lowered their price expectations to about $2 per MMBTU. This adjustment has lowered the finding and developing costs associated with new gas sources.

PROMOTING COMPETITION

This session, also chaired by John Rozsa, focused on the effectiveness of regulatory policy in promoting efficiency in the US, Canadian, and California gas markets. The panelists--Michael Lynch (Federal Energy Regulatory Commission), G. Campbell Watkins (DataMetrics Limited), and Arlon Tussing (Arlon Tussing & Associates)--addressed two issues: (1) what has been accomplished, and (2) what hurdles remain.

Regulatory policy in all regions has introduced more competition, resulting in substantially more efficient markets than would have prevailed under the status quo. During the 1980s, there has been a total transformation of the gas industry.

Partial decontrol of US wellhead prices was begun with the 1978 Natural Gas Policy Act. That same act also included blanket transportation provisions (Section 311) that allowed the much-needed flexibility in moving gas between pipelines while avoiding the need for certificates. By 1989, 66% of transportation was gas moved under Section 311. Order 436 established open access to pipelines in 1985; by 1986, 35% of firm capacity was open access.

Within a wellhead region, the market is very competitive. Elimination of reserves dedicated exclusively to a particular pipeline has led to greater efficiency, as gas is allocated to the highest-valued uses. "Take-or-pay" for many pipelines has been replaced by "take-or-release", as contracted volumes are made available to the spot market. Prices are renegotiated every 30 days even under long-term contracts. The spot market becomes the source of security by providing gas at some price.

Still, some problems remain. "Take-or-pay" obligations hang over some pipelines. Without minimum bills or a similar commitment at the consuming end of the pipe, they remain financially exposed under such obligations. In addition, seasonal fluctuations in the spot price are more extreme than would be expected for a storable commodity such as gas.

What needs to be done to make the market more efficient? While buyers and sellers can find themselves pretty well in the short-term, 30-day market, the situation is not as rosy in the long-term market. Firm transportation represents a small part of the market--4% in 1987; 16% in 1989. Holders of firm-supply contracts don't have access to firm transportation. Michael Lynch suggested the solution is to push for comparable transportation, not to rescind the banning of minimum bills (Order 380). There is also a need to make transportation rates reflect market conditions through flexible discounting in pipeline tariffs. And finally, firm transportation rights need to be established and capacity brokering implemented in order to allocate pipeline space more efficiently.

Canadian gas policy has undergone substantial revision during the 1980s. Since 1985, the NEB surplus test for gas exports was first loosened and then abolished. Exports are now market determined. At the provincial level, Alberta has relaxed its surplus test, moving from 25 to 15 years of protection. A floor on royalties discourages very low wellhead prices. British Columbia has eliminated the surplus test and has maintained a floor on royalties.

Campbell Watkins said that the impact of deregulation in Canada has made the upstream segment very competitive. Marketed production is distributed widely across a number of firms, although market shares of remaining reserves are somewhat more concentrated. Prices are renegotiated every 1 to 2 years. Legislation requires producer approval of contract terms.

The Alberta wellhead markets are workably competitive but not perfectly competitive. Some market power, particularly in the export market, remains, allowing firms to influence market-clearing prices to some extent. Domestic prices remain lower than the export price for long-term contracts. Over time, spot prices have moved closer to contract prices in the domestic market, but not so in the export market.

Under the Free Trade Agreement, the Canadian government can control output through the proportionality provision, in which the Canadian share of output can be maintained. The US can challenge any supply restrictions. Prices cannot be raised through export taxes.

In the future, gas trade constraints will not entirely evaporate. New pressures for limiting gas trade could mount once the current buyers' market is transformed into a sellers' market.

The inadequacy of pipeline capacity has isolated Alberta and California to some extent from the competitive supply and demand forces of the North American market. The expansion of new pipelines will reduce this market power in these two regions.

Arlon Tussing expressed some concern that policymakers continue to embrace the conventional wisdom paradigm of gas market supply and demand that anticipates rising gas prices. This view is based upon the mistaken premise that current R/P ratios constrain future production. When curtailments were widespread in 1976, the industry operated with an R/P ratio equal to 13. Today with slack conditions, the R/P ratio has fallen to 8.

MEETING THE CHALLENGES OF THE CALIFORNIA GAS MARKET

With Jairam Gopal (California Energy Commission) moderating, John Fick (Southern California Gas Company), Shelley Fust (Enron Gas Marketing), Paula Rosput (Pacific Gas Transmission Company), and Jerry van der Linden (Altamont Gas Transmission Company) highlighted the critical issues that need to be resolved for an efficiently operating California gas market.

California gas markets will be influenced by forces operating more broadly throughout North America as well as by factors specific to the state. Shelley Fust said that within North America, gas issues have undergone three phases since 1985: (1) "What pipeline capacity" has been largely resolved by 1989; (2) "Whose capacity" and how should it be allocated remains a key concern; and (3) Competition for reserves is just beginning to emerge.

Whose capacity raises the question of who has access to pipeline capacity. Historical entitlement has governed this decision in the past, but increasingly the need to make capacity available to the highest bidder is being recognized. Shelly Fust discussed Transco's efforts to open its pipeline system to new market participants. They have unbundled capacity so that 100% of sales are made at the wellhead, and anyone can obtain access. They have also unbundled the merchant sales service and have introduced capacity brokering establishing multiple assignment of firm transportation rights.

Shelley Fust said that competition for reserves will intensify as gas markets become tighter in the coming years. Nationally, the industry is beginning to see a shift from spot to long-term contract sales, after years of reluctance by buyers to commit to contracts. Long-term contracts reduce transaction costs and price volatility. Fixed-price contracts with high load factors are now being negotiated for 2-10 years. She expects that soon more than 50% of gas supplies will be sold under long-term contracts. Meanwhile, competition for 30-day sales has increased, leading to more price volatility for these purchases.

North American markets will be faced with several key issues during the 1990s: (1) the resolution of capacity allocation; (2) the effect of new pipeline capacity on regional competition for reserves; (3) the nature of long-term commitments in purchasing gas supplies; and (4) new industry products and financial instruments for allocating risks among gas purchasers and sellers.

Paula Rosput said that California gas markets face a decline in traditional supplies, increasing requirements (particularly for power generation), and a greater need for pipelines and distributors to meet diversity in end-use demand, to provide adequate reliability, and to anticipate competitive gas procurement conditions.

Gas flow patterns in North America are likely to change significantly, with more gas moving counterclockwise. Canadian gas will move southwest to California, while southwestern US gas will move in a northeasterly direction. As a result, California's gas supply picture will be changed substantially. Stable or declining reserves in California's traditional U.S. supply areas contrast sharply with Canadian wellhead markets, where reserves have not declined. San Juan supplies appear to rely heavily on tax breaks, while infrastructure constrains supplies from the overthrust region. While additional demands from enhanced oil recovery and cogeneration are in doubt, gas requirements are expected to grow in the core and power generation sectors and with environmental policies favoring gas use. Without new pipeline capacity, these trends portend a potential for future curtailments.

Paula Rosput said that California gas markets face several future challenges or unresolved issues. First, how will new pipeline projects affect gas prices in California? The dominant effect appears to be that supplemental sources will compete with traditional sources, thereby lowering prices. Second, will the unbundling of noncore procurement result in low-value buyers with unstable demands in the non-core sector financing new, high-cost pipeline projects? Third, will the needed pipeline infrastructure be built, given modified fixed-rate tariffs and other regulatory decisions that directly influence the financing of new pipeline projects? And fourth, will the traditionally regulated intrastate capacity--which has largely been protected from competitive market pressures--keep pace with the market-based interstate capacity?

John Fick discussed how California distributors are now considering new intrastate projects that could increase the coordination between interstate and intrastate capacity allocation. These projects allow marketers to look for buyers and will have capacity brokering. The utilities would like to offer firm capacity rights on intrastate connections to new interstate projects. The California Public Utility Commission wants capacity brokering and rolled-in pricing.

He also noted two other problems. Distributors often don't have the flexibility to serve noncore customers by allowing them to trade off reliability with a lower price. In addition, distributors need more gas storage capability. Southern California Gas has two noncore storage programs on a bid basis. One is for electric utility generation during the smog season (late summer & fall) and the other for the remainder of the year.

Most of the discussion focused on generic problems rather than specific pipeline proposals. Jerry van der Linden noted, however, that the Kern River project had now been approved. One of the other proposed projects--Altamont--would hook up with the Kern River project in bringing gas south from Alberta. Since the conference, the WyCal sponsors have asked the FERC to put their application on hold, making it unlikely that it will proceed.

TRANSPORTATION AND ELECTRICITY GENERATION: GROWTH MARKETS FOR NATURAL GAS?

Hillard Huntington (Stanford University) chaired this session focusing on two sectors where increased gas demand is anticipated. Speakers included Howard Mueller (Electric Power Research Institute), Leo Thomason (California Natural Gas Vehicle Advisory Committee), Paul Nelson (Natural Fuels Corporation), and Jackson Mueller (Simpson Paper Company).

Howard Mueller emphasized that gas use for power generation is more than simply an issue of technology choice. Utilities planning to become more dependent on gas will need to become much more knowledgeable about gas markets. The gas option poses several risks. Uncertainties about gas supply and demand generally place upward rather than downward pressures on gas prices. For example, environmental policies promoting gas use will increase gas prices through higher demand. A study done jointly for the Electric Power Research Institute and Edison Electric Institute expects increased gas demand by utilities in the future but at levels below its historical peak.

Fuel switching between gas and oil remains critical to gas market dynamics and the availability of a reliable gas source for utilities. It can also cap gas prices to levels at or below heavy fuel oil prices. Many previous studies have estimated this fuel-switchable capacity at 1/3 of the total market, or about 6-7 Tcf/year. A recent EPRI study, based partly upon interviews with utilities, estimated nominal or physical switching capacity to be only 4.5-5.0 Tcf. The size of this market decreases to 3.8 Tcf when limited to quick sustained switching only, to 2.3 Tcf if switching to distillate fuel oil is excluded as well, and to 1.6 Tcf if one also excludes oil-gas switching capacity in the Southwest. The latter estimate represents the amount of switching that could be realized quickly for swings of about $0.60 per mcf in the relative prices of natural gas and residual fuel oil. Environmental policy can significantly reduce the switching capability within this price range by raising the costs of switching. Seasonal patterns of fuel use are also important for switching capacity. The smooth operation of backup fuel markets is also necessary, making fuel switching a more viable option on the East and West Coasts. Residual fuel oil markets perform more efficiently along the coasts than inland (e.g., in the Southwest) due to their access to international markets. All in all, the size of the switching market appears to be declining.

The gas option also requires utilities to consider operating costs beyond the plant, raising issues like gas storage. It requires significant coordination between the gas and electric industries. Peaks in electricity industries are more severe and unpredictable than in the gas industry. Uncertainty about base load demands can be particularly destabilizing. Errors in anticipating future gas needs for generation, with as little lead time as one day, can threaten short-run stability in the gas industry.

Compressed natural gas is starting to be used worldwide for powering light, medium, and heavy trucks and buses--so-called fleet vehicles. Its use for individual passenger cars is limited by the fact that fuel tanks would leave little space for storage.

Leo Thomason emphasized that environmental benefits drive the demand for natural gas vehicles (NGVs); use of this fuel reduces emissions across the board, keeping NMHC, NOx, and CO emissions within the California Air Resources Board (CARB) standards. Among liquid fuels, it also emits the lowest amount of carbon dioxide, a key greenhouse gas. Growing NGV demand could have a significant environmental impact because fleet vehicles travel about 2.5 times the number of miles traveled by passenger cars.

The use of NGV's has been encouraged by subsidies in some regions of the world. Recent CEC estimates show compressed natural gas being the lowest cost alternative to gasoline for transportation. Major automobile producers are announcing new designs in NGVs.

Colorado has an active NGV program with the state government offering rebates to encourage this technology. Natural Fuels Corporation was formed by Colorado Interstate Natural Gas and two other partners to market compressed natural gas outside a regulated utility. It has no refining interests and thus focuses exclusively on selling natural gas. Paul Nelson said that they currently have 10 fueling stations. Customers will be able to plug in over night, a less costly option.

Natural Fuels Corporation is currently targeting the commercial gasoline-powered vehicle market traveling within a 50 mile radius. They plan on servicing 22,000 vehicles over the next 7 years, offering separate product packages for large fleets (20 or more vehicles) and small fleets (1-19 vehicles). They also plan on building public natural gas fueling stations.

Jackson Mueller discussed the experiences of purchasing natural gas for cogeneration. Simon Paper Company, a privately held company concentrating on the higher end of paper products and lumber, entered the cogeneration market through its experience of using waste wood for self-generation. As waste wood became more valuable as bark and for other uses, the company began to use natural gas 3 years ago. Environmental hazards also contributed to this decision. They sell their excess over on-site needs to the grid. When they perceived that their gas costs were out of line with the avoided cost determined by the utility, they bypassed the gas utility.

HOW ENVIRONMENTAL POLICIES INFLUENCE NATURAL GAS MARKETS

Chaired by David Kline (California Energy Commission), this session examined whether environmental policies would significantly expand natural gas use, and if so, what implementation problems might arise. Panelists included W. David Montgomery (Congressional Budget Office), David Harrison (National Economic Research Associates), and W. William Wood (California Energy Commission).

While gas possesses important environmental advantages over other fossil fuels, the effect of emission controls on natural gas use is far from clear. A simple scenario suggests increased gas use in the future. One limiting factor could be how readily additional gas supplies would become available at higher prices. Even focusing on the demand side alone, several significant complications were noted. Gas use is likely to increase in the transportation and industrial sectors, but by less than the commitments specified in various regulatory targets. Moreover, increased penetration by gas is more likely with market-based incentives than with regulatory programs dictating both the level of and technologies for emission control.

Clean air policies for mitigating acid rain represent a blend of federal regulations on new power plants and state regulations on old plants. Federal policy has historically emphasized the best available control technology (BACT) for controlling emissions, thereby encouraging the use of scrubbers to clean up coal rather than fuel switching. New federal provisions in the Clean Air Act (CAA) allow tradeable permits based upon the pounds of pollutants. These provisions may increase gad demand.

The prospects for increased gas use are very much tied to the success of efforts to establish tradable allowances to emit pollutants. These programs makes gas more valuable than before because the cost of using gas to reduce emissions can now be compared more directly with the cost of scrubbing coal; indeed, the latter will probably set the price for emission rights. However, it is not clear that this market will materialize. Many power plants have already switched to gas, and coal with scrubbers remains an option that is relatively inexpensive compared to other alternatives.

Clean air policies for mitigating emissions from vehicles appear on the surface to encourage strong growth in natural gas use. The California Air Resources Board (CARB) recently passed a 75% reduction in automobile emissions standards. However, natural gas vehicles will meet stiff competition from other fuels, as new developments push electric cars and reformulated gasoline as viable options. Even if all fleet vehicles move to natural gas, Gas Research Institute studies estimate a relatively modest impact on natural gas markets--an additional gas consumption of about 0.2 trillion cubic feet (TCF) per year, compared to a total consumption of about 18 TCF in 1990.

The South Coast Air Quality Management District (SCAQMD) has proposed stringent provisions for improving air quality in Southern California. David Harrison noted that the South Coast plan faces several critical obstacles. It imposes emission controls by specifying regulatory targets with no allowance for economic incentives and decentralized decisionmaking by individual households and firms. Thus, least-cost strategies for individual decisionmakers are not encouraged. It will also require massive commitments, calling for a 90% reduction in emissions in an area that already imposes the most stringent air quality regulations. While the program will produce some environmental gains, it will also impose substantially higher costs, estimated to be about $13 billion annually. These estimated costs are about 90% of the revenues raised through the California sales tax and amount to $2200 per household per year, according to David Harrison while Californians would be willing to pay for cleaner air, other studies have estimated that willingness to be about $70 per household on an annual basis. In addition, the detailed provisions of the plan will be very difficult to implement because they involve micro management of fuel use and economic activity at the individual or plant level. As a result, it is very likely that regulators and citizens will eventually decide that air quality programs are too costly and difficult to manage and that efforts to dictate fuel choice will be relaxed. Such developments would significantly reduce the regulatory pressures for increased natural gas use.

Market-based incentives are more flexible and hence more likely to succeed. Such programs are a more certain approach that ensure that some level of control is realized depending upon the imposed cost. They can be structured to reach certain aggregate target control levels for various emissions (at an unknown cost) or to impose certain pre-determined costs (at an unknown emission control level).

William Wood discussed a recent California Energy Commission study done in conjunction with the SCAQMD Scenario Report. It addressed some logistical problems of meeting seasonal gas demands in the year 2000 resulting from SCAQMD provisions, given constraints in natural gas pipelines. The study examined two scenarios, with and without new pipeline capacity. A critical concern is the variation in gas demand resulting from shifting peaks in power generation and the pressures that it places on the natural gas delivery system.

Global warming policies also paint a mixed picture. Carbon reduction requirements would increase the demand for gas in the near term when the limits are not too stringent. David Montgomery said that as unconstrained emissions grow relative to the imposed limits, however, gas could be strongly affected as well. Since gas is already relatively cheap, gas for oil substitution potential is limited everywhere. Meanwhile, substitution of gas for coal is likely only in the electric power sector. In the intermediate run, the higher costs of generating electricity can be expected to reduce electricity demand, with a disproportionate impact on gas, the marginal source of power for incremental units. In the longer run, limits are likely to be met by substituting noncarbon sources (e.g., nuclear) for gas. While the carbon content of gas (58 million tons (MMT) per quad) compares favorably with oil (82 MMT/quad) and coal (101 MMT/quad), significant carbon reductions can be achieved much more easily with options such as nuclear energy (0 MMT/quad).

David Montgomery also noted that natural gas production could be strongly affected by environmental policies under consideration that would treat drilling muds (currently exempt) as a toxic waste.

NEW SERVICES FOR NATURAL GAS MARKETS AND NEW MARKETS FOR NATURAL GAS SERVICES

This session, also chaired by David Kline, included as panelists Professor Vernon Smith (U. of Arizona), Paul Carpenter (Incentives Research, Inc.), and Katherine Elder (Pacific Gas &

Electric). It featured several new analytical approaches for understanding emerging gas products and services.

Experimental economics research at the U. of Arizona has been exploring the gains from exchanging bids to sell and buy gas and transportation under alternative conditions. A linear programming (LP) computer program simultaneously solves for the allocation of gas and transportation that achieves the maximum gains based upon the participants' bids. Market-clearing prices for gas and transportation also result from this process. Participants have incentives to state their true beliefs because they buy and sell rights using real money. The experimenter knows the willingness-to-pay (WTP) of buyers and the willingness-to-sell (WTS) of sellers--the amount they will offer at different prices. The computer program does not know these WTP and WTS. Participants are rewarded on the basis of the difference between their WTP (or WTS) over a range of quantities and the market-clearing price solved by the LP computer program. Various bidding arrangements can be ranked according to their efficiency--the ratio of consumer and producer gains actually realized to the gains that are theoretically possible.

Vernon Smith said that these studies have led to a number of policy-relevant findings. First, a more richly connected pipeline system increases efficiency, i.e., prices move closer to the optimal level. Second, severed pipeline/wellhead ownership produces somewhat more efficient outcomes. Third, simultaneous allocation of gas and transportation rights greatly improves efficiency relative to a system that sells gas and transportation separately. And fourth, joint ownership by sellers and transporters of a central dispatch facility (pipeline), or co-tenancy, converts a natural monopoly into a self-regulating system. By defining property rights, co-tenancy allows the economies of scale inherent in a central dispatch facility to coexist with competition. In this respect, a pipeline can be viewed like a large shopping mall. While competing with each other, individual shops gain by organizing themselves and sharing the infrastructure costs of the mall.

Pacific Gas & Electric's (PG&E) capacity allocation program represents an attempt to implement some of this experimental research in day-to-day pipeline practice. PG&E's interest in this program began with the desire to find an alternative (one emphasizing willingness to pay) to the traditional end-use priority system for gas curtailments. The program was designed to use PG&E's rights only in an effort to integrate both interstate and intrastate capacity rights from wellhead to burnertip.

The process involves several steps. (1) Talk to customers about bottlenecks, define conceptual framework and identify the available capacity. (2) Take an inventory of core demand, selecting which capacity to use for core and core gas supplies. (3) Make the remaining capacity available to noncore customers on a firm basis. (4) Draw a diagram of the system. (5) Have noncore customers choose either firm or interruptible transportation service, indicating such items as which block, which path, and at what price. (6) Use an LP computer program to allocate customer bids based upon the submitted information. In the final step, the LP program determines (a) the price based upon the last block chosen and (b) a list of capacity owners by block and volume.

Katherine Elder said that PG&E is listening and responding to various criticisms of the approach. (1) While some have suggested two auctions (summer & winter), PG&E prefers one annual auction. (2) While the system focuses on the short-term rather than long-term capacity values, it has a secondary market for reselling rights. (3) Users might be hesitant to reveal their willingness to pay to regulators or the utility, although the program proposes that an independent auditor handle all bids. (4) Some dislike brokering by a distribution company, but PG&E feels that they need the ability to recall capacity for the core when it is needed.

Recent regulatory decisions have intensified interest in the capacity allocation program compared to just a few months ago. The next steps involve interstate pipelines applying for certificates for capacity brokering. Approval of distribution company proposals appear to be 12-18 months away.

A final major topic considered in this session was the opportunity to use methods for evaluating portfolio features of natural gas services now that they have become unbundled from each other. Such analysis applies to any supplier selling gas with different reliability conditions. The gas industry is confronted with the problem that it has no good measure of supply reliability. Moreover, firm transportation appears to be provided to distribution companies, perpetually.

Paul Carpenter said that one can think of a gas reservation charge as a forward-looking charge, or option charge. In essence, gas supply reliability becomes a "new service". The vestiges of the Natural Gas Act still remain, as the terms of firm access are not explicit. Ordinarily, a premium for reliability would not be necessary if purchasers could rely upon spot markets for backup gas supplies. But spot markets are sometimes too thin to rely upon them. Under these conditions, producers need to be compensated for warranting supplies.

Financial portfolio analysis can be used to estimate the value of rights to gas purchasers for the flexibility to switch between gas sources, based upon the uncertainty of market outcomes. This value depends upon the volatility in spot market prices and transaction costs.

SUMMARY

The discussion highlighted several essential points for understanding the future development of the California gas market and its relationship to the broader North American gas market.

- Natural gas has a large role to play in the California energy picture over the foreseeable future.

- Wellhead supplies from several different regions are available to meet modest demand growth at market-clearing prices not dramatically higher than today's level.
- The available pipeline and distribution system will be an important determinant of the price and reliability with which this gas will reach California.
- Federal and state regulatory policy will be redefining the role of and opportunities for gas pipelines and distributors, thereby influencing the outcome in the gas market.
- Growing gas use for electric generation will probably increase gas demand, but the overall impacts may be less than anticipated by many because the gas option poses several risks for electric utilities.
- The total fuel-switchable market appears to be declining in size. This decline may decrease the coupling between gas and oil prices.
- Increasingly strict environmental regulations tend to favor natural gas in many applications, but this relationship is also not straightforward.
- Natural gas vehicles clearly have a sizable role to play, at least as a transitional strategy for air quality improvement, but will have a relatively small impact on gas demand.
- Innovative market mechanisms, such as pipeline capacity bidding systems and financial instruments for allocating risks, can dramatically increase the efficiency of natural gas trade. Regulators should strive to capitalize on these potential benefits.