CALIFORNIA GAS: A BRIEF HISTORY AND RECENT EVENTS

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The author discusses recent developments and ongoing issues related to regulatory authorities, contracts and pipeline matters affecting the gas industry in California, in comparison to elsewhere in the United States and Canada. Included is a review of some of the more important decisions of the Federal Energy Regulatory Commission, the California Public Utilities Commission and the National Energy Board. This paper is solely the work of the author. The views expressed herein do not necessarily represent the views of the author's firm or any client of that firm.

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I. INTRODUCTION

Substantial sales of natural gas to the State of California have been a staple of the Alberta economy for over 30 years. Only recently has Alberta and Southern Gas Co. Ltd. ("A&S") been dislodged from its place as the highest volume exporter of natural gas to the United States. As is well known, A&S sells to Pacific Gas Transmission ("PGT") which in turn sells to Pacific Gas and Electric Company ("PG&E"), the major utility of northern California and one of the largest investor-owned utilities in North America. A&S and PGT are both subsidiaries of PG&E. In addition, substantial volumes of Alberta gas flow to the southern California market through the prebuilt facilities of the Alaska Natural Gas Transportation System ("ANGTS"). The major distributor in southern California is the Southern California Gas Company ("SoCal").

The importance of sales to California cannot be overestimated. Although it does produce a certain amount of its own energy, California has a tremendous appetite for natural gas from outside sources. In 1990, the average requirements of the state were 5.3 billion cubic feet a day or nearly 2 trillion cubic feet per year. Northern California

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consumed approximately 2.35 bcf a day or 858 bcf in the year.[1] Since PG&E serves 37 counties in northern and central California, sales to the northern California market involve either a sale or transportation by PG&E. In recent years, A&S has provided nearly 50% of PG&E's required gas supply.

Projections show that California will continue to be an important market for Canadian gas, albeit a far more competitive one. New pipelines into the state, increased capacity in existing lines and profound changes to the regulatory climate are combining to ensure that the marketing of gas in California will be completely different from previous experience.

There can be few people in the Canadian petroleum industry who have not heard in recent times of the California Public Utilities Commission ("CPUC") and its actions to change the way gas is sold within California. Many have only become aware of the activities of the CPUC recently and are not aware of its past decisions with respect to deregulation. It almost appears as if the CPUC has suddenly taken a hardline position, particularly with respect to A&S gas, that it had not taken before.

It must be borne in mind that the CPUC is a regulator in a state which consumes far more gas than it produces. It has an obligation to advance the broad public interest in California and, accordingly, tends to look first to the interests of consumers rather than producers. Its actions since the commencement of deregulation in the early 1980s, some of which are summarized in this paper, must be seen in that context.

Although this paper examines the substantial history leading up to the present dispute over the sales arrangements for Canadian gas in the northern California market, it does touch on decisions affecting the entire state.[2] There are various decisions through the same time frame which affect SoCal and other California distributors but the emphasis is with respect to Canadian gas trade to California which necessarily means concentrating on PG&E.

This discussion also compares actions which have taken place at the federal level on both sides of the Canada - United States border and considers their interrelationship with decisions of the CPUC. The federal regulators in both Canada and the United States are obliged, far more than local regulators, to strike a balance between the interests of producers and consumers. The actions which will be examined herein reflect more of a recognition of consumer interests. The federal decisions which are discussed contained consequences which became heavy financial burdens for many producers. Regulators at all levels have had to grapple with these competing interests.

1. *California Gas Report*, California Gas and Electric Utilities, 1991.
2. Speech by Donald McMorland, President and CEO of A&S, Executive Enterprises Inc. conference, November 19, 1991, San Francisco.

II. DEREGULATION

"Deregulation" is a term often used in relation to the natural gas industry over the last few years and frequently misapplied. Although not found in all dictionaries, it has been noted by Webster's Ninth New Collegiate Dictionary[3] as being "the act or process of removing restrictions and regulations." Especially for those who usually work in the regulatory arena, this definition will be met with a certain amount of derision. There has not been nor is it contemplated that there will be a complete removal of restrictions and regulations with respect to the transportation and sale of natural gas. This is particularly true in Canada.

The principal document dealing with the deregulation of natural gas in Canada is the Agreement on Natural Gas Markets and Prices of October 31, 1985 entered into by the governments of Canada, Alberta, British Columbia and Saskatchewan (the "Agreement"). Paragraph 4 of that document is quite plain in applying limitations to how much deregulation occurs. The first sentence reads, "[i]t is the intention of the parties to the Agreement to foster a competitive market for natural gas in Canada, *consistent with the regulated character of the transmission and distribution sectors of the gas industry.*" [Emphasis added]. Clearly, the authors of the Agreement recognized that unrestricted free market forces were incompatible with the regulated and monopolistic nature of the system to transport and distribute gas. Subsequent actions of regulators and governments have maintained close supervision over transmission and distribution and, to a lesser extent, the purchase and sale of natural gas.

Deregulation is more accurately described as the removal of restrictions and regulations, as far as possible, from the purchase and sale of natural gas. It also encompasses attempts by regulators, to the extent possible, to render the transportation and distribution of natural gas more consistent with the deregulated character of the purchase and sale of the commodity. In fact, it is in this latter area that difficulty has arisen, both in California and elsewhere.

Partial deregulation of the transmission system is more pronounced in the U.S. than in this country. Many gas markets in the United States are served by more than one pipeline and a certain amount of competition does exist between long-line transmission systems. The same is not true in Canada. Neither TransCanada Pipelines Limited ("TCPL") nor Westcoast Energy Inc. ("Westcoast") is subject to any reasonable degree of competition in their principal markets in Canada. Until such time as more gas can physically be brought into Canadian markets from U.S. sources, any competition that exists will be severely constrained.

The California market was, until recently, served by only three pipelines. One is owned and operated by PGT and already described. The other two transport gas to the southern California boundary at a point near Topock, Arizona. These are the systems of El Paso Natural Gas Co. ("El Paso") and TransWestern Pipeline Co. ("TransWestern").

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3. Thos. Allen & Son Limited, Markham, Ontario, 1987.

None of PGT, El Paso or TransWestern enters the State of California. PG&E's Line 400 transports gas from the California border near Malin, Oregon to points south. Both the PG&E and SoCal systems extend to the California border near Topock. Traditionally, PG&E has obtained a portion of its gas supply from El Paso and transported it north into its main market area on its Line 300.

More recently, two new pipelines have been constructed by the Mojave Pipeline Company ("Mojave") and the Kern River Gas Transmission Company ("Kern River"). Both pipelines end within California in Kern County, the locale of substantial enhanced oil recovery operations. At the moment, restrictions exist on PG&E's ability to take delivery of significantly greater volumes from these new pipelines and the expanded El Paso and TransWestern systems. However, the CPUC wants to investigate the possibility of an expansion of Line 300.

III. DEREGULATION IN THE UNITED STATES: FEDERAL

Historically, control over natural gas prices was exercised by the Federal Power Commission, the predecessor of the Federal Energy Regulatory Commission ("FERC"). Some wellhead prices were set at very low levels which bore little resemblance to the results produced by market forces. This plus a number of other considerations led to passage by the United States Congress of the *Natural Gas Policy Act*[4] of 1978 ("NGPA"). This was also the time of rising prices of energy generally, including gas exported from Canada to the United States. All these factors led to a critical examination of all aspects of the business by the FERC. In the years since, the FERC has issued a series of orders aimed at eliminating anti-competitive forces and improving access to the interstate pipeline system. These in turn have had an effect on the sale of gas into the State of California and the subsequent actions of the CPUC.

This paper contains a brief description of the more important orders issued by the FERC. It is by no means exhaustive.

The first FERC order to be discussed is number 380, issued on May 25, 1984.[5] Order 380 eliminated variable costs from pipelines' minimum commodity bills. At that time, as is still the case for the time being, U.S. interstate pipelines had modified fixed variable tolls. Many of a pipeline's fixed costs are recovered in the demand component. However, a portion is recovered in the commodity component. Recovery of the fixed costs in the commodity portion of the toll depends on the amount of gas transported and is meant to provide an incentive to increase load factors.

To help ensure recovery of costs, many pipelines set minimum commodity bills which caused the FERC two concerns. The first was that customers taking gas at levels below the minimum commodity bill were paying for costs which were not actually incurred by

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4. 15 U.S. Code, Ch. 3301.

5. 49 Fed. Reg. ¶22,778 (June 1, 1984), 27 FERC ¶61, 318, FERC Statutes and Regulations ¶30,571. For a more complete discussion of Order 380, see A.R. Madigan et al., "Regulation and Deregulation of the Natural Gas Industry in the United States" (1986) 25 Alta L. Rev. 2.

the pipeline. Secondly, and more importantly, the Commission was concerned that the minimum bills discouraged competition.

The decision specifically dealt with minimum take provisions and rendered inoperative tariffs providing for the recovery of purchased gas costs when that gas was not taken by the buyer. However, the Commission emphasized that it was not attempting to interfere with any take-or-pay obligation that a cost-of-service type pipeline might have with its supply sources.[6]

The far-reaching effects of Order 380 are obvious and led to many petitions for rehearing. PGT was among those seeking clarification. Ultimately, the FERC issued Order 380-A on July 30, 1984.[7] The CPUC was an intervenor in those proceedings specifically requesting clarification that the FERC intended to render inoperative any pipeline rate schedule or tariff providing for the recovery of purchase gas costs for gas not taken by the buyer. The FERC confirmed that this was precisely what it meant, but did agree to defer the effect of the rule until November 1, 1984. Effective that date, PGT and PG&E agreed to amend their Service Agreement for the purchase of gas at Malin, Oregon to eliminate the physical take obligation of PG&E and to substitute an equitable purchase clause. At the same time, the take-or-pay requirement in the Service Agreement was reduced from 60% to 50%.

Also at the same time, the International Agreement under which PGT purchases its supplies from A&S at Kingsgate, British Columbia was revised to lower the annual take-or-pay requirement to 50%. In addition, PGT agreed to purchase gas in accordance with the equitable purchase clause referred to above. The clause, as set out in the International Agreement, reads as follows:

> Buyer (P.G. and E.) shall purchase gas hereunder on an equitable, annual equivalent percentage basis with its purchases of gas from its other suppliers, provided the price and cost relationship of the supplies, and all applicable laws and regulations, allow such an arrangement. The percentage of purchases hereunder shall be measured against the authorized export volumes as in effect under the export licenses granted by the National Energy Board of Canada to Alberta and Southern Gas Co. Ltd. for the sale of gas to Seller (Pacific Transmission) at the International Boundary near Kingsgate, British Columbia and the related daily contract quantity for the Canadian supply. It is understood that in implementing this gas purchase undertaking, Buyer (P.G. and E.) shall take into account the gas purchasing policies of the Public Utilities Commission of the State of California, as in effect from time to time. Buyer (P.G. and E.) shall endeavour, as nearly as practicable and consistent with its own operational requirements, to minimize requests for changes in the rates of delivery hereunder.
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> Upon reasonable notice, Buyer (P.G. and E.) shall provide Seller (Pacific Transmission) with information demonstrating that these undertakings are being fulfilled.

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6. FERC Statutes & Regulations ¶30,571, at 30,974.
7. 49 Fed. Reg. ¶31,259 (August 6, 1984), FERC Statutes and Regulations ¶30,584.

Order 380 is significant because, for the first time, the synchronization between purchases by A&S from its producers at the wellhead downstream to the ultimate sale to PG&E was no longer in place. PG&E and PGT, in a joint submission, raised this difficulty with the FERC in the proceedings which led to Order 380-C.[8] However, the FERC pointed out that many domestic pipeline suppliers were faced with the same difficulty.

PG&E and PGT also contended that the FERC's actions could interfere with U.S. Government policy concerning imports of Canadian gas. They also questioned the FERC's authority since imports were at that time under the jurisdiction of the Economic Regulatory Administration ("ERA").

The FERC rejected this argument, saying in part:[9]

> ... the rule does not apply to minimum take provisions in any contracts between foreign and domestic companies. The rule only applies to the tariffs and rate schedules under which jurisdictional pipelines sell natural gas to their customers. The fact that the Commission's ruling *may* adversely impact on the terms or conditions of a contract beyond the Commission's jurisdiction, a fact which has not been demonstrated by record evidence, cannot be relied upon to frustrate the Commission's authority to regulate interstate pipelines.

The FERC also noted that such effects were not restricted to Canadian producers but had an impact on their American counterparts.

The next major order by the FERC, Order 436, was issued the following year on October 9, 1985.[10] Shortly described, Order 436 established rules for non-discriminatory access to interstate transportation service.[11] Order 436 also provided an option to customers of pipelines to reduce their contract demand levels for sales service from the pipelines. In other words, the FERC made it possible for customers to eliminate, over a phased-in period, their obligation to purchase gas from the pipeline company.

The rule is very lengthy, exceeding 140 pages, but the FERC does make it clear that conditions in the industry have changed and that it wishes to both "retain and revise utility-type regulation over the interstate *transportation* function" while at the same time "allow the *commodity* market for natural gas to continue to develop in a competitive fashion."

The effect of Order 436 in allowing reductions in contract demand was profound. It created considerable contractual liability for pipeline companies which had contracted for system supply gas with various producing interests. Subsequently, the FERC has allowed recovery of costs incurred as a result of the reduction in level of takes in pipeline tariffs.

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8. 49 Fed. Reg. ¶43,625 (October 31, 1984), FERC Statutes and Regulations ¶30,607.
9. FERC Statutes & Regulations ¶30,607, at 31,193.
10. 50 Fed. Reg. ¶42,408 (October 18, 1985), FERC Statutes and Regulations ¶30,665.
11. Also discussed in more detail in the Madigan et al article, *supra* note 5.

The point to be noted is that to attain a competitive market in the sale of the commodity, the FERC was prepared to affect existing contractual relations.

Problems concerning the take-or-pay liability created by Order 436 led to various actions in the Federal Court system. On June 3, 1987, the United States Court of Appeals for the District of Columbia Circuit vacated Order 436 and remanded it for further proceedings. The result was FERC Order 500.[12] It set new rules, on an interim basis, for minimizing take-or-pay liability and providing for equitable sharing between pipelines and customers of costs of settling outstanding take-or-pay obligations and restructuring existing contractual arrangements. Ultimately, the final rules were set out in a series of subsequent orders.

Responding to previous FERC orders, PGT filed for the introduction of interruptible service under section 311 of the NGPA. On July 28, 1989, the FERC accepted PGT's open-access filing for both firm and interruptible service.[13] The filing was a response to a FERC initiative to increase access as much as possible to existing pipeline capacity and particularly to allow use of space not being used on a firm basis.

On January 24, 1990, the FERC issued an Order on Contested Settlement dealing with a toll settlement which had been submitted by PGT on May 16, 1988.[14] It accepted a portion of this settlement, made other orders and directed PGT to file revised tariff sheets and associated contracts reflecting the elimination of cost-of-service treatment for gas costs from PGT's rate schedules and eliminate its minimum commodity bill. In a subsequent order, the FERC rejected rehearing and confirmed its directive that PGT cease using cost-of-service rates.

The final order of the FERC to which reference will be made is Order 636, issued on April 8, 1992.[15] Order 636 is the rule flowing from the so-called Mega-NOPR or Notice of Proposed Rulemaking which was issued on July 31, 1991. The rule eliminates bundled sales services by pipelines and indeed terminates existing pipeline sales contracts which are combined with transportation. Such contracts are to be converted into separate sales and transportation contracts but sales customers may, at their option, reduce or terminate sales service. Order 636 makes numerous other decisions, but one of the key points from the California perspective is that it provides for a capacity reallocation program which is to be operated by the pipeline through an electronic bulletin board. Also, the FERC adopted a straight fixed-variable design whereby all the pipelines' fixed costs, including return on equity, are recovered through demand charges. This is identical to the full fixed-variable rate design which is common on Canadian pipelines. Order 636 recognizes that there will be transition costs, including the cost of restructuring producer contracts and provides a mechanism for recovery of such costs, if prudently incurred.

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12. 52 Fed. Reg. ¶30,334 (August 14, 1987), FERC Statutes and Regulations ¶30,761 (August 7, 1987).
13. 48 FERC ¶61,125, Docket RP89-200-000.
14. 50 FERC ¶61,067, Dockets RP87-62-000 and RP86-148-000.
15. 59 FERC ¶61,030, Docket RM91-11-000 and RM87-34-065.

As will be seen, some elements of Order 636 have a specific effect on previous decisions by the CPUC. However, there have been numerous motions for rehearing of Order 636 and it is premature to say that it is now in its final form.

IV. DEREGULATION IN CANADA: FEDERAL

This paper does not propose to discuss the various reasons for deregulation occurring in this country. What it does is discuss some decisions which were taken at the federal level to effect deregulation to the benefit of consumers. A number of events had helped to bring about deregulation including the decline in gas sales to the U.S. because of high border prices, which peaked at $4.94 U.S./mcf, and the hopelessly optimistic domestic scenario under which gas leaving Alberta was being priced. For these and other reasons, various parties representing both consuming and producing interests set up a Summit Group which looked into the possible resolutions. However, a conclusion was not reached until the very last day of the 1984 - 1985 gas year and it was reached by the federal Government and producing interests alone.

Reference has previously been made to the Agreement on Natural Gas Markets and Prices of October 31, 1985 among the governments of Canada, Alberta, British Columbia and Saskatchewan ("Agreement"). That document in turn flowed from an earlier agreement among the same entities dated March 28, 1985 and entitled "The Western Accord, an Agreement between the Governments of Canada, Alberta, Saskatchewan and British Columbia on Oil and Gas Pricing and Taxation" (the "Western Accord"). The Western Accord called for a more flexible and market-oriented pricing regime for the domestic pricing of natural gas. For its part, the Agreement attempted to effect that and also to create "...an orderly transition which is fair to consumers and producers....[16]" It also called for enhanced access to natural gas supplies meaning, presumably, in part, improved access to the transportation system. Reference has already been made to paragraph 4 of the Agreement which promised to "foster a competitive market for natural gas in Canada, consistent with the regulated character of the transmission and distribution sectors of the gas industry."

Recognizing the importance of the transportation sector of the natural gas industry, paragraph 7 of the Agreement requested the National Energy Board ("NEB") to review certain matters. The paragraph reads in full:

> To enable the market-responsive pricing system to operate within the intent of this Agreement, the governments request the National Energy Board to review the following concerns:
>
> (i) whether inappropriate duplication of demand charges will result from possible displacement of one volume of gas by another; and

16. Agreement paragraph 1.

(ii) whether the policy regarding the availability of T-Service, as outlined in the Board's latest TransCanada Pipelines toll decision is still appropriate, taking into account, among other things, interested parties' views on the fair and equitable sharing of take-or-pay charges.

As a result of this direction, the NEB issued its Procedural Order RH-5-85 on November 12, 1985. The hearing commenced on January 13, 1986 and consumed 44 hearing days, including argument.

One of the more contentious issues at the hearing was how to resolve the duplication of demand charges. Under the then existing gas sales regime, TCPL transported and sold virtually all of the gas moving on its system. Sales were in large part made to distributors, who in turn sold to end users. The Agreement contemplated that end users would be able to contract for their own sources of gas and arrange transportation of their own on the TCPL system. Most distributor contracts with end users were for one year or less, so there was little difficulty for an industrial user to allow its contract with its distributor to expire and set up its own arrangement. However, the distributors had longer term contracts with TCPL with substantial demand charge liability. A situation had developed whereby it was feasible that an end user could become obliged for its own demand charges on TCPL while the distributor remain liable for demand charges which were originally incurred to service that same end user.

The NEB's solution was to determine tolls on operating demand volumes, which were defined as the level of the distributor's Contract Demand (CD) contracts less volumes displaced by certain direct sales. In other words, the NEB decided that, for every unit of gas which displaced system gas, the affected distributor would be excused from paying that unit's demand charge to TCPL.

The byproduct of the NEB's decision was to facilitate the displacement of system sales and accordingly cause a decline in the level of take by TCPL from its system producers. The NEB, conscious of this concern, recommended that all TCPL system users should help bear the expense of carrying TCPL's existing take-or-pay obligation in the Alberta Cost of Service. Accordingly, the Government of Alberta later passed the *Take-or-Pay Costs Sharing Act*,[17] which remains in effect to this day.

TCPL challenged the decision of the NEB in the Federal Court of Appeal.[18] Its questioning of the NEB's jurisdiction was based on the decision constituting an effective amendment of contracts between TCPL and its distributors over which the NEB has no authority. However, the Court ruled the NEB was performing its main function of setting just and reasonable tolls, that the effect on the contracts was incidental thereto and, therefore, the appeal was denied.

Notwithstanding the indirect effect on producers supplying gas to TCPL, the NEB did retain a restriction on how far the operating demand mechanism could go. Distributors

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17. S.A. 1986, c.T-0.1, as amended.

18. *TransCanada Pipelines Limited* v. *National Energy Board*, [1987] 2 W.W.R. 253, 72 N.R. 172, 49 Alta. L.R. (2d) 1 (F.C.A.).

were denied the right to self-displace. In the RH-5-85 proceeding, some distributors had sought permission to convert their CD contracts with TCPL into transportation contracts, thereby enabling them to purchase gas at a cheaper price than they could obtain from TCPL. The request was denied. The prohibition was maintained in the RH-3-86 Decision[19] and the MH-1-87 Decision.[20]

However, in Phase I of proceeding RH-1-88,[21] another long hearing, the issue was placed on the agenda for consideration by the NEB on its own motion.

The fact that self-displacement was theoretically possible again flows from a series of events which broke the contractual linkage between the wellhead and the burner tip. As most people are aware, the previous marketing arrangement was that producers would sell to aggregators which were usually pipelines. TCPL, in this case, purchased the gas at the wellhead, looked after transportation in Alberta and transported its own gas for its own account for sale to the distributors at the city gate. These sales were made under CD contracts which included both the sale and transportation. While TCPL's CD contracts had at one time contained a take-or-pay or minimum bill obligation, that had been removed in an earlier toll hearing, convened pursuant to NEB Order RH-3-86.[22] This was done at the same time that all of the pipeline's fixed costs were included in the demand charge.[23] Consequently, the distributors argued that they had no legal obligation to take. They also argued that, absent a pricing agreement on October 31, 1988, there could be no continuing contracts. For their part, producers argued that there was at least a moral obligation to take gas and that the Agreement, in paragraphs 13 and 14, certainly intended that this be the case.[24]

Persistence can pay off. On their fourth attempt, the parties favouring self-displacement succeeded in persuading the NEB that it should occur. They were able to do this notwithstanding the clear evidence heard by the NEB on the potential adverse effects on producers to the TCPL/Western Gas Marketing Limited (WGML) pool, as well as the TOPGAS consortium which had financed TCPL's take-or-pay liability. With some justification, the NEB took the position that TCPL/WGML and its producers should be able to compete effectively with other gas supplies for the distributors' markets.

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19. NEB Decision RH-3-86, dated May 1987, released June 17, 1987.
20. NEB Decision MH-1-87, dated September 1987, released October 19, 1987.
21. Order dated February 17, 1988, Decision dated November 1988.
22. Order RH-3-86 dated July 25, 1986.
23. *Supra* note 21.
24. Paragraphs 13 and 14 read as follows:

"13. Prior to November 1, 1986, negotiations shall commence between distributors, shippers and the producers supplying the gas in question respecting the price to be paid for natural gas delivered under existing contracts. Prices resulting from such negotiations shall come into effect November 1, 1986 and as agreed thereafter. Where contract renegotiation between buyers and sellers, whether of price or volume, takes place in good faith and on a voluntary basis, governments will not obstruct the resulting commercial transactions.

14. In the absence of an Agreement between a shipper and a distributor, or a producer and a shipper, on the price to be paid for gas under existing contracts on November 1, 1986, and thereafter, the price shall be determined through arbitration."

> The Board continues to regard TOPGAS and any take-or-pay problems which may arise as private contractual matters relating to gas supply obligations between the TOPGAS consortium, TCPL/WGML, and its producers. The Board is not convinced that, in moving to a market responsive environment, system gas could not compete effectively with other gas supplies for the distributors' markets.[25]

In allowing removal of the double demand charge and the prohibition against self-displacement, the NEB took steps which, though strictly speaking within its jurisdiction, had much broader implications in areas which are clearly not. The ruling on self-displacement was not appealed. Presumably, the affected parties concluded that the Federal Court of Appeal would once again uphold the NEB's powers to amend tolls and tariffs, notwithstanding the incidental effects of such actions.

The rulings discussed, as well as others, certainly had the effect desired by the NEB. TCPL became a fully open-access carrier. Its wholly-owned subsidiary, WGML, is still a major seller, although its share of TCPL throughput has declined over the years. In the meantime, many industrial parties have taken advantage of direct sales, as have distributors. The downward spiral in prices to producers hardly needs a reminder or documentation. The NEB admitted that the gas supply overhang resulting from the old requirement to have a 25 year supply of gas on hand helps depress gas prices. However, it stated its expectation that the competitive market unleashed by the Agreement would let prices rise or fall and bring supply and demand into balance.

The rulings with respect to TCPL had nothing to do directly with the situation in California. However, they demonstrate the means the NEB was prepared to use to open up access to monopolistic systems, with obvious benefits to the consuming public. The incidental effect of its actions on existing contractual arrangements was deemed necessary in order to effect the overall scheme of deregulation.

V. INITIATIVES IN CALIFORNIA

For more than 20 years after its initiation, the system connecting Canadian gas to California markets was relatively untouched by the CPUC. Periodically, PG&E had to apply to its regulator for approval to raise rates in response to an increased price for Canadian gas at the Canada/U.S. Border. The increased pricing also led to take-or-pay liability on the part of A&S, which obligation was guaranteed by the parent, again with CPUC approval.

One of the key early orders of the CPUC was one ordering an investigation into transportation of customer-owned gas from the California border to industrial facilities within California.[26] Owens - Illinois, Inc. requested the CPUC to order PG&E and SoCal to transport gas, owned by it, within California. Owens - Illinois stated that it was going to convert to oil rather than keep paying uneconomic prices for natural gas. This particular proceeding launched an investigation which led to other proceedings and started

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25. *Supra* note 21 at 12.
26. CPUC, I. 84-04-079.

the move to open access within California. Proceeding 85-02-068 was in effect a continuation of the earlier proceeding and made specific reference to FERC Order 380 as well as to the new gas export policy of the Canadian government. Reference was also made to the sequencing guidelines issued to both PG&E and SoCal.

By 1984, the escalation of the Canadian border price had ended and incentive pricing of Canadian gas was in place. Nevertheless, high prices for Canadian gas were still a concern and PG&E implemented a sequencing policy so as to take supplies in order of ascending incremental costs, taking into account "...contract minimums, regulatory directives, and operating constraints...."[27]

A further interim opinion on transportation was issued on December 20, 1985.[28] Concerns about minimum bill obligations on the part of local distribution companies (LDC's) had created reluctance on the part of the CPUC to order open-access transportation. However, FERC had issued its Order 380 in May of 1984 and had recently decided to grant pipelines blanket transportation certificates. The CPUC accordingly decided that transportation of customer-owned gas was feasible and authorized long-term transportation contracts. However, it continued to reject short-term transportation service as incompatible with the utilities' obligation to serve retail customers because the obligation applied even to those who used transportation for short periods of time.

The concern about short-term transportation was not long lived. In Decision D.86-03-057, the CPUC reconsidered the matter and decided to order the provision of short-term transportation on the LDCs under its jurisdiction.

In this Decision, the Commission also distinguished between core and non-core customers, definitions which are routinely used today. Further, it stated its intention that the utilities should not formulate a new gas acquisition policy:[29]

> We expect that the utilities will adopt a portfolio strategy for core market gas purchases, utilizing a mixture of short and long-term contracts. In the future, we will insist that the utilities justify their purchase strategy ... (under the) general guideline of minimizing gas acquisition costs over the long-term.

Even then, the CPUC expressed some concern about the pricing of natural gas in the short and long term. Although stating its belief that "...some degree of long-term price stability benefits core ratepayers," the CPUC expressed its intention to see whether pipeline gas supplies offered long-term price stability. It stated its expectation to see substantial evidence that long-term contracts would provide for gas price moderation. Otherwise, the CPUC appeared to question why Utilities would not use the spot market.

Evidence that the CPUC wanted the utilities under its jurisdiction to refine their gas-acquisition practices continued. On June 5, 1986, an Order Instituting Investigation by

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27. CPUC, D.84-12-067 at 15.
28. CPUC, D.85-12-102.
29. CPUC, D. 86-03-057 at 10.

Rulemaking was issued.[30] The CPUC succinctly stated its rule for a core supply portfolio:[31]

> Utilities should undertake to procure for their core market customers a portfolio supply which reasonably results in certainty of supply, tends to minimize costs, and minimizes sudden price swings. The portfolio should be balanced so that in a normal year some spot or short-term gas purchases are taken to round it out. In a cold year, short-term purchases would increase.

The CPUC specifically rejected long-term gas purchase contracts as the exclusive source of core supply.

In this Decision, the CPUC also sounded a warning note on take-or-pay costs. It stated very clearly that utilities should not bear responsibility for damages under such contracts unless specifically mandated by the FERC. Other conditions were spelled out for future core procurement reasonableness reviews.

In the same Decision, the CPUC voiced its continuing concern that the monopoly which PG&E and SoCal enjoyed over firm transmission rights to California would be a barrier to customers who preferred firm transportation-only service. It stated:[32]

> We are very interested in SoCal and PG&E allowing these parties access to interstate capacity, by agreeing to use interstate capacity rights on their behalf, during the period from now until SoCal and PG&E have acquired enough experience operating under the new industry structure to be able to make decisions on whether to release more permanently some portion of these capacity rights.

This rulemaking decision proposed rather than implemented new rules for utility transportation and procurement services and rate designs. Although it only invited comments and established their scope, it provided an indication of CPUC thinking.

On December 3, 1986, the CPUC issued its Order Instituting an Investigation by Rulemaking into proposed refinements for a new regulatory framework for gas utilities.[33] The Order was a follow-up to OIR 86-06-007 and a wide-ranging discussion on how the state's utilities should be regulated. It dealt with how access to interstate transmission was to be facilitated. While noting that PG&E planned to retain its interstate pipeline rights so long as they were beneficial to its customers, it opined that PG&E should review its needs from time to time and in light of changing market conditions. One such change would be open-access transportation within the State of California. A Canadian submitter, Petro-Canada Inc., had suggested that the utilities be required to use their interstate capacity rights on behalf of customers who only wanted transmission. However, the CPUC deferred making a decision on this matter but encouraged end-users to make use of interruptible transportation under section 311(a) of the NGPA.

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30. CPUC, R.86-06-006.
31. *Ibid.* at 16.
32. *Ibid.* at 22.
33. CPUC, D.86-12-010.

Elsewhere in the Decision, the CPUC dealt with the benefits of long-term contracts versus purchasing spot gas. While voicing the opinion that supply availability was not a major concern in a deregulated, competitive market, the CPUC acknowledged the benefit of long-term contracts and acknowledged that a certain price premium was probably necessary. The CPUC stated that:[34]

> ...until we gain a better understanding of the deregulated supply market, we instruct the utilities generally to structure the core portfolio so as to moderate to some extent the upward variation in prices in exchange for likewise foregoing the full magnitude of downward price variation.

The CPUC did this on the basis that the core market was "price-risk adverse." If future analysis showed that the core was less price-risk adverse than the CPUC had concluded, the goal of price security would be de-emphasized.

The Decision did not implement the rules that were established. It consolidated two previous dockets for the purpose of joint hearings on the issue of how the orders in the two proceedings should be implemented.

Throughout this period, the CPUC continued with regular consideration of various matters. It continued to call for a more flexible market-responsive rate design to encourage a more competitive gas industry, a goal not unique to the CPUC. It deferred to the FERC with respect to the sharing or brokering of interstate pipeline capacity, but did state that some form of capacity brokering would be necessary to foster a competitive market in California gas supply.

In Decision D-87-05-069, a system for inter-utility transportation of natural gas within California was established. Such a program would allow Canadian gas to be marketed in southern California, and gas from other areas to be marketed in the northern part of the state. The CPUC noted the possible difficulty that PG&E's ties with A&S and PGT might present:[35]

> PG&E's affiliate relationship with PGT and its Canadian gas supplier, Alberta and Southern (A&S), may present PG&E with mixed motives in negotiating inter-utility rates for moving third-party Canadian gas, because this gas may directly compete with supplies available through A&S.

Concerns about exclusive access to PGT by PG&E continued with increasing numbers of Canadian producers becoming interested parties in CPUC proceedings. On October 16, 1987, the CPUC issued its Decision D-87-10-043, being an Order Instituting Investigation into Procurement and System Reliability Issues deferred from D-86-12-010. PG&E had proposed the sale of excess core gas supplies to certain non-core customers at discounted prices. However, many Canadian producer interests objected. They claimed that PG&E had first chance to claim all capacity on PGT and that it would keep PGT full with core and "excess" supplies, making it impossible for anyone else to obtain PGT capacity.

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34. *Ibid.* at 77.
35. CPUC, D.87-05-069 at 72.

However, this decision did not impose any new rules since it was soliciting comments on a number of issues. The CPUC decided that a workshop would be held on how best to share firm interstate capacity among parties in the California marketplace.

In another proceeding, it was suggested that the utilities be ordered to procure a core supply portfolio with certainty of supply at the lowest possible cost with gas purchases to be subject to annual reasonableness review and prior approval for longer term contracts with affiliates. Contracts with affiliates had to have "regulatory out" clauses.[36] However, once again, this proceeding did not institute new rules but proposed changes in core and non-core procurement and invited comment.

Proof of changing attitudes in CPUC thinking was becoming evident. "We no longer believe that the regulated utility serves a necessary role in the non-core procurement market. Further, we believe that access to gas transportation would be improved by removing the regulated utility from the non-core procurement business."[37] In the same proceeding, the CPUC started suggesting the Utility Electricity Generation ("UEG") departments of combined utilities be required to set up gas purchasing departments separate from the core gas procurement department. Such a proposal has a clear impact on PG&E, the bulk of whose business is concerned with electricity generation and distribution. The whole issue of UEG attracted more attention later. The reason is that this portion of the utility business occupies a great deal of firm capacity on pipelines supplying California, capacity which some saw as more appropriate being freed up, at least in part, for other shippers.

By 1990, it was plain that the CPUC was becoming increasingly bothered by PG&E's ownership of PGT and A&S and the possible complications that this presented. This became evident with the issuance of a new order early in the year.[38] The proceeding did not establish new rules, but invited comment from interested parties. However, a number of comments made by the CPUC are worthy of note:[39]

> Alberta and Southern (A&S), for example, brokers all of the gas PG&E purchases from Canadian producers under contracts which are still binding... we believe the relationship between A&S, PGT, PG&E and Canadian producers has created a problem for California consumers, however, PG&E should not be required to end its corporate relationship with A&S at this time. It should, however, be required to end its preference for A&S gas supplies when current contracts expire.

In this proceeding both the government of Canada and the Alberta Petroleum Marketing Commission ("APMC") filed briefs voicing concern about the threat to market relationships between Canadian suppliers and California utilities. Another intervenor was

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36. CPUC, R.88-08-018, Order Implementing Rulemaking Into Natural Gas Procurement and System Reliability, August 10, 1988.

37. CPUC, R. 90-02-008, Order Implementing Rulemaking to Change the Structure of Gas Utilities' Procurement Policies, February 7, 1990, at 3.

38. CPUC, D. 90-07-065, Order Implementing Rulemaking to Change the Structure of Gas Utilities' Procurement Practices, January 18, 1990.

39. *Ibid.* at 13.

the School Project for Utility Rate Reduction ("SPURR"). That organization, which accounted for a separate decision later, urged that the utilities be required to offer transportation services to the core.

The CPUC was disposed to issue rules requiring each utility to offer a core subscription service and a firm transportation service but recognized that access to PGT could be difficult because of PG&E's exclusive use of that pipeline. Further, that usage was high because of the high core demand which was maintained by a high volume of core elect service including that for PG&E's own UEG.

In the end, the CPUC proposed that PG&E be required to make available to non-core customers all PGT capacity not needed for the core. Other rules were to reduce core demand and thereby free up access. However, the CPUC stated:[40]

> We reluctantly propose that customers must purchase from PG&E's brokering affiliate in recognition that PG&E has contractual obligations which may be binding over the short term.

In part to provide access to PGT, the CUPC proposed that electric departments of combined utilities be prohibited from subscribing to core service for more than 15% of their average annual requirements.

It will be noted that the tone of this decision is more critical of PG&E, its Canadian gas supply and its UEG purchases through the core-elect program. More limitation on UEG purchases was proposed than in previous decisions. Further, PG&E was ordered to achieve renegotiation of the A&S gas purchase contracts by December 31, 1991 and criticised for a perceived lack of cooperation in taking steps to make a more competitive environment possible.

This decision led directly to a key decision in the California saga, the Gas Procurement Decision of September 25, 1990.[41] In this decision, the CPUC adopted final rules for the regulation of utilities' procurement practices. By and large, the CPUC took into account the terms of a settlement dated August 15, 1990 among most of the interested parties including most Canadian parties and PG&E itself. It restricted the activities of utility gas marketing affiliates, required each utility to offer a core subscription service but restricted the manner in which UEG's would acquire gas. It agreed to provisions of a settlement whereby PG&E would provide 450 million cubic feet a day of capacity to non-core transportation customers, of which 250 MMcf/d would be on PGT. This portion of the settlement has been characterized as the Access Agreement and was to remain in effect until August 1, 1994 when it was anticipated that new capacity from Canada to California would have been constructed. The CUPC dealt specifically with Canadian contracts and began by noting that it had, in an earlier proceeding in the year, directed PG&E to comment on the FERC's January 24, 1990 order which had found that PGT's

40. *Ibid.* at 31.

41. CPUC, D. 90-09-089.

minimum bill provisions were no longer reasonable.[42] Perhaps ominously, the CUPC noted:[43]

> According to DRA, PG&E is not obligated to buy any gas from PGT under the provisions of a recent FERC Order.

The DRA is the Division of Ratepayer Advocates, the consumer advocate branch of the CPUC. The DRA had also argued that A&S producers did not deserve any protection and characterized them as unwilling to move toward a more competitive market. The Commission itself stated that PG&E was not bound by the contracts between A&S and Canadian producers and warned that it might require PG&E's shareholders to assume liability for gas costs or terms of service which it found to be unreasonable.[44] However, the Commission also noted the Access Agreement, stated that it could not formally adopt it, but nevertheless applauded it as "an effective means to implement the rules we adopt today."[45]

The other significant component of the Gas Procurement Decision was to limit UEG purchases of firm transportation services to 65% of the total demand of the UEG. In other words, 35% of the UEG gas requirements was henceforth to be transported by interruptible services.

On February 21, 1991, the CPUC issued the SPURR Decision,[46] which adopted final rules governing transportation-only service for core customers who aggregate their loads. The decision enabled a group of schools to pool their requirements and obtain transportation capacity.

The last and perhaps most important decision to be discussed is the Capacity Brokering Decision of November 6, 1991.[47] In this decision, the CPUC adopted rules for brokering utilities' interstate pipeline capacity. The decision was rendered after a long decision by Administrative Law Judge Malcolm, which was critical of PG&E's purchasing practices.[48] Further, the CUPC had held an *en banc* hearing which allowed oral representations from numerous parties including PG&E, the Canadian Petroleum Association ("CPA"), the Independent Petroleum Association of Canada ("IPAC") and the APMC.

Once again, the CPUC reiterated its commitment to increase competition and capacity brokering. While deferring to FERC jurisdiction over interstate pipelines, it declared that

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42. 50 FERC ¶61,067.
43. *Supra* note 41 at 61.
44. *Ibid.* at 64-65.
45. *Ibid.* at 66.
46. CPUC, D. 91-02-040.
47. CPUC, D. 91-11-025.
48. CPUC, R.88-08-018, R.90-02008, Proposed Decision of A.L.J. Malcolm, mailed August 19, 1991.

the FERC had recognized that individual states have authority to allocate the firm transportation capacity required by local distributors.[49]

Notwithstanding that the CPUC had recently applauded the Settlement, the conclusion now was that this did not go far enough to promote competition. Concern was voiced about the amount of capacity that the Settlement provided for brokering. Paying specific attention to Canadian gas, the CPUC noted that DRA had filed a petition to modify Decision D. 90-09-089 because it objected to the Access Agreement and the requirement that non-core customers wishing to bring Canadian gas over the PGT line had to arrange purchases from A&S producers. Numerous Canadian parties and PG&E argued that the Access Agreement should continue until its proposed 1994 expiry.

The CPUC stated that it had never considered its recent decision as final and immutable until 1994. It therefore did not consider itself bound by the earlier decision. While acknowledging PGT's 50% take-or-pay obligation to A&S, the CPUC stated that the contracts between A&S and its Canadian suppliers were not part of the record and that A&S was not regulated by the CPUC. Finally, it stated that there was no evidence that PG&E had any legal obligation to purchase gas from A&S or any Canadian producer. Consequently, there were no contractual obligations precluding non-core access to PGT capacity.

Accordingly, the CPUC decided to institute capacity brokering, notwithstanding the opinion of some parties that this would constitute an infringement on the jurisdiction of the FERC. This meant that the Access Agreement no longer had any kind of CPUC approval. PG&E was required to implement a non-discriminatory capacity brokering program on PGT by the later of October 1, 1992 or 60 days after a FERC authorization was obtained by PGT to implement a plan. As we have seen, Order 636 of the FERC deals with this specific issue. The CPUC's Capacity Brokering Decision precedes Order 636 and directs PG&E to make every reasonable effort to open access on PGT, including converting its firm sales rights to firm transportation rights. However, FERC's Order 636 on capacity allocation has required the CPUC to examine its capacity brokering decision which may no longer be sustainable.

VI. SUMMARY OF REGULATORY ACTION

As can be seen, there are common themes voiced by each of the regulatory agencies examined. The overall goal throughout North America has been to foster competition in the natural gas industry for the benefit of both consumers and producers. Clearly, the benefits have accrued more to the former than the latter.

Actions at the federal level in the U.S. were of assistance to the CPUC in making its decisions. References have already been made to Decision 85-02-066 which mentions FERC Order 380 and the greatly expanded competition on the interstate pipelines connecting to California. The decision also made reference to the new Canadian

49. *Supra* note 47 at 8.

government gas export policy permitting more market sensitive pricing. Liberalizing transportation on the interstate systems enabled the CPUC to liberalize it within California.

VII. RECENT EVENTS

A. LEGISLATION

In its Capacity Brokering Decision, the CPUC expressed concern about the A&S gas pool and the netback pricing arrangement that A&S employs for its sales to the California market. Netback pricing is facilitated by the Alberta *Natural Gas Marketing Act*[50] ("NGMA"). Bill 41 was introduced in the Alberta Legislature last year and has since been proclaimed to form an amendment to the NGMA.[51] The amendment allows the Lieutenant Governor in Council to continue certain netback pricing agreements as binding on the parties to them notwithstanding that the contractual arrangements might have expired or terminated. A&S has been named as a designated shipper pursuant to the amendment and consequently, the netback pricing agreement in place between A&S and its producers is continued. The extension lasts until the government of Alberta terminates the Order, or the A&S producers agree to a termination or until November 1, 1994. Sales by A&S on a pooled basis run counter to the gas-on-gas competition being sought by the CPUC for sales of gas to California. The legislation can be seen as a stop-gap measure to permit renegotiation of gas supply arrangements to take place.

Interruptible transportation is now available on the Canadian portion of the system transporting gas to northern California. As previously noted, interruptible transportation is also in place on PGT. Concerned that interruptible gas shipments might displace firm A&S sales, the government of Alberta turned to the system of NOVA Corporation of Alberta ("NOVA") and the *NOVA Corporation of Alberta Act*.[52] The Alberta Cabinet instituted the NOVA Terms of Service Regulation[53] on February 13, 1992. The scheme is very simple. NOVA may only provide interruptible service at a designated delivery point if the daily delivery capacity available at that point exceeds the contracted firm capacity at that point. Since gas pipelines can move greater volumes at lower ambient temperatures, the effect of the regulation is to restrict interruptible deliveries to the four coldest months of the year. NOVA's delivery point at Coleman, Alberta, sometimes known as ABC, was designated by the Minister of Energy.

Some parties expressed doubt about the Regulation's effectiveness because of the wording of the *NOVA Corporation of Alberta Act*. Consequently, the Minister of Energy introduced Bill 9 entitled the *NOVA Terms of Service Regulation Validation Act*.[54] The Bill, now proclaimed, consists of only two sections which validate the Regulation effective

50. S.A. 1986, c. N-2.8.
51. S.A. 1991, c. 25 (Bill 41).
52. R.S.A. 1980, c. N-12.
53. Alberta Regulation 67/92.
54. S.A. 1992, c. 26.

as of February 13 and protect NOVA and its directors, employees or agents from any action arising out of any action taken under the Regulation.

B. REGULATORY ACTION

On May 29, 1991, offended by the actions taken by the CPUC, the CPA brought an application to the NEB seeking a review of the NEB's Decision GH-5-88. The Decision in GH-5-88 had issued a new licence to A&S to sell gas to the California market until October 31, 2005. CPA argued that the CPUC was altering the nature of the market and consequently changing the criteria upon which the NEB had decided to issue the new licence.

Support in some areas for the CPA application was weak since it linked the main issue to any approval by the NEB of new export licences or proposed new facilities to add to the capacity of the transportation system to California. The new project is generally known as the PGT Expansion. Accordingly, on November 27, 1991, the CPA amended its Application which thereafter sought a review of the GH-5-88 Decision and Licence GL-111 which was issued as a result. The linking of the Application to the PGT Expansion was dropped.

The hearing started on February 24, 1992 and extended 11 days. As this paper is written, a decision has still not been issued although one is expected by the end of June, 1992.

Prior to the hearing, and on the basis of written submissions, the NEB issued interim orders on February 4, 1992. Order MOI-1-92 deals with short term export orders at Kingsgate and limits those in existence at February 4, 1992 to a maximum daily volume equal to the largest daily volume theretofore exported. Volumes in excess of this may be permitted provided filings are made with the NEB as to where the gas is destined and to whom it is being sold. New short term orders are possible but again information is required.

Order TGI-1-90 deals with access on the system of Alberta Natural Gas Company Ltd ("ANG"), the portion of the delivery system to California extending from Coleman to Kingsgate. The Order suspends the assignment clause contained in ANG's tariff by stipulating that no assignment can take place until it has been approved by the NEB.

The thrust of the two Orders, which are still in effect, is to limit the possibility of A&S system gas being displaced by other Alberta-sourced volumes or indeed certain B.C.-sourced gas.

A part of the Canadian portion of the PGT Expansion is added compression to be built by ANG. Approval for the proposal is contained in a decision released on May 21, 1992 by the NEB.[55] In conjunction with increased pipeline installation by Foothills Pipe Lines

55. GHW-2-91.

(South B.C.) Ltd. ("Foothills"), export capacity at Kingsgate will be increased by 872 MMcf/d. Foothills gains approval for its projects through earlier legislation approving ANGTS in Canada.

The PGT Expansion, on both sides of the border, and a rival project proposed by Altamont Gas Transmission Company, were subjected to a comparative review by the Energy Resources Conservation Board of Alberta ("ERCB"). The inquiry took place in March of 1992 and, as this is written, no decision or conclusion has been released, although one is expected shortly.

Meantime, in California, the CPUC has started an examination of the reasonableness of PG&E's gas purchases for the years 1988, 1989 and 1990. The DRA is asserting that PG&E was imprudent in its gas purchase practices in Canada and that accordingly it should be disallowed recovery of $392 million (U.S.). Other parties have also alleged unnecessary overpayments.

VIII. OTHER MATTERS

In the face of directives that clearly indicate that PG&E will have a diminished role in gas marketing in California, it has commenced commercial negotiations, together with A&S, to restructure the gas purchase arrangements for Alberta gas. These discussions are ongoing and are being assisted by a Facilitator appointed pursuant to the provisions of the NGMA and directives passed thereunder.

Actions have been commenced in the Court of Queen's Bench of Alberta against A&S, PG&E and, in some cases, PGT. Breach of contract and other allegations are advanced concerning takes of gas from producers in the A&S pool.

At the governmental level, Alberta and British Columbia are holding discussions with the CPUC pursuant to the Energy Consultative Mechanism ("ECM") to try to resolve the differences between the jurisdictions.

IX. CONCLUSION

The sale of gas into California is a complex matter which cannot receive full treatment in a paper restricted to the length of this one. Attempts by the CPUC to open up access to the California market go back for some years. In northern California, it is faced with a large LDC which has historically purchased a good deal of its supply from another country. PG&E's ownership of that delivery system has been viewed by some with apprehension and a belief that it has hindered more open access to Canadian supplies.

PG&E has now made arrangements to sell PGT, although the sale is on hold. The sale of ANG to TCPL is proceeding, so too are negotiations to restructure the manner in which Canadian gas is supplied to PG&E. The ECM mechanism is at work to attempt resolution of the differences between the CPUC on the one hand in Alberta and British Columbia on the other. The natural gas industry has faced many disruptions in the past. Hopefully, this one will be resolved soon and natural gas trade to California can return to normal.