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May 15, 2006

Mr. Bob Middleton **VIA e-mail: IEED@bia.edu**
Attn: 1813 Right-of-Way Study
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Department of the Interior
1849 C. St. NW, Mail Stop 2749-MIB
Washington, DC 20240

Mr. David Meyer
Attn: 1813 Right-of-Way Study
Office of Electricity Delivery and Energy Reliability
Department of Energy
1000 Independence Ave., SW
Washington, D.C. 20585

Re: Southern Ute Indian Tribe Supplemental Comments – 1813 Right-of-Way Study

Gentlemen:

In accordance with the Department of Energy Notice of May 5, 2006, 71 Federal Register 26483, the Southern Ute Indian Tribe hereby submits supplementary comment and information regarding the study mandated by Section 1813 of the Energy Policy Act of 2005. In enacting Section 1813, Congress assigned the Department of the Interior and the Department of Energy a formidable task, i.e., to evaluate the status and policy implications associated with the issuance of tribal consent for energy-related rights-of-way across tribal lands. The breadth of the study, the volume of energy-related right-of-way transactions in Indian country, and the short time frame within which to complete the report have presented major challenges. We appreciate the Departments' efforts in soliciting information and comment from the public and from tribes. Like many tribes, the Southern Ute Indian Tribe views these matters of critical importance, and we have participated actively throughout the process, including attendance at public scoping meetings and public hearings, presentation of case studies, and internal record review and document production.

It is unmistakably clear to participants in this process that Indian tribes universally perceive this study, and any possible legislation that may result from its conclusions, as a threat to a fundamental principle of federal Indian policy. From the earliest dealings of the United States with Indian tribes, federal Indian policy has reflected a recognition that tribes have the right to control their lands and that the United States is obligated to protect those lands from encroachment by others. Historical abrogation of treaties, forced removal and relocation, and the vagaries of federal Indian policy present examples of disregard of this principle. Nevertheless, longstanding, existing law confirms that rights-of-way across tribal lands may not be issued without tribal consent. Any action by the United States to compromise or remove that tribal consent requirement implicates matters of the highest order. We believe that the Departments have a solemn duty to honor the tribal consent requirement in fashioning their recommendations. We also submit that there has been no demonstration of a national interest that could possibly justify a recommended change in the existing system.

I. Required Findings.

Congress expressly directed that the Section 1813 report include:

(1) an analysis of historic rates of compensation paid for energy rights-of-way on tribal land;

(2) recommendations for appropriate standards and procedures for determining fair and appropriate compensation to Indian tribes for grants, expansions, and renewals of energy rights-of-way on tribal land;

(3) an assessment of the tribal self-determination and sovereignty interests implicated by applications for the grant, expansion, or renewal of energy rights-of-way on tribal land; and

(4) an analysis of relevant national energy transportation policies relating to grants, expansions, and renewals of energy rights-of-way on tribal land.

The following addresses each of these issues from the Southern Ute perspective.

A. Historic Rates of Compensation

The energy industry has crossed Southern Ute lands for various purposes for many decades. The Tribe has consented to the issuance of rights-of-way for: regional and local electric transmission; regulated interstate gas transmission pipelines; gas gathering pipelines; local utility distribution systems; and road access to energy facilities. The Tribe has supplied the Department of the Interior's research contractor, Historical Research Associates, with specific examples of transaction documents and detailed compilations related to rights-of-way. Until approximately 1970, the Tribe relied upon the Bureau of Indian Affairs to set the compensation

for use of the Tribe's lands. Typical transactions involved the payment of a one-time roddage fee. The term of the rights-of-way varied from fixed terms of ten, twenty, or fifty years, or, in some cases for so long as the lands were used for prescribed purposes. Under these older transactions, there was no review or revision of the compensation during the term of the right-of-way, and the method of determining compensation bore no relation to the value of the right-of-way to the business or economic return of the grantee. Further, it was not uncommon for a grantee to continue to use a tribal right-of-way in trespass following the expiration of a fixed term.

Commencing in the 1970s, the Tribe began taking a more active role in reviewing and negotiating the compensation to be received for granting or renewing rights-of-way. Clearly the Tribe desired compensation that exceeded amounts previously established by the Bureau of Indian Affairs. The Tribe consented to grants or renewals of rights-of-way with many companies, including El Paso Natural Gas Company and Northwest Pipeline Company. Increasingly, the Tribe looked to creative alternatives for determining compensation. For example, in the case of Colorado Ute, an electric transmission and generation company, the Tribe granted an electric transmission line right-of-way of unlimited duration in exchange for the conveyance by Colorado Ute to the Tribe of a 1500-acre ranch located within the boundaries of the Southern Ute Indian Reservation. Negotiations with energy companies also often resulted in contributions to tribal scholarship programs as a condition for tribal consent.

Located in the northern portion of the San Juan Basin, portions of the Tribe's lands have been leased to energy companies under the supervision of the Bureau of Indian Affairs since approximately 1950. Over time, tribal leaders became convinced that the federal government was not focused on protecting the Tribe's interest either in the leasing process or in ensuring company performance of lease obligations. In response, commencing in 1974, the Southern Ute Tribal Council placed a moratorium on the issuance of oil and gas leases. In 1980, the Tribe established its own energy resource office in order to gather information regarding the Tribe's natural gas resources and to assist in monitoring pre-existing lease compliance. Following passage of the Indian Mineral Development Act of 1982, the Tribe slowly began discussions with interested companies about non-traditional oil and gas lease arrangements, and by the mid-1980s, the Tribe had entered into several negotiated mineral development agreements that provided the Tribe participation opportunities in the development of the Tribe's resources.

The significance of the Tribe's growing expertise about its own energy resources cannot be overstated as it relates to rights-of-way issues. By the late 1980s, the Tribe had hired professional geologists and reservoir engineers who had carefully evaluated the remaining energy potential of the Reservation. Those experts knew that tribal coalbed methane resources presented a meaningful opportunity for the Tribe to improve economically. Preliminary exploration of coalbed methane showed tremendous promise; however, the on-Reservation gas gathering facilities of El Paso Natural Gas and Northwest Pipeline Company were not adequate to transport anticipated production volumes into interstate facilities. Tribal experts had no success in convincing the managers of El Paso or Northwest of the need for or the financial

opportunities associated with expansion of gas gathering systems to Reservation areas where coalbed methane development appeared likely.

In order to stimulate expansion of gas gathering capacity, the Tribe approached a smaller gas gathering company that conducted activities on the Reservation. On August 28, 1990, the Tribe entered into a novel agreement with Western Gas Supply Company ("Westgas"), a subsidiary of Public Service Company of Colorado. The Westgas Agreement renewed all pre-existing Westgas rights-of-way for a period of eleven years. Additionally, the Tribe provided blanket consent for rights-of-way for any new gas gathering lines that Westgas might install on the affected portions of the Reservation. The Agreement provided that all renewals and grants under the Agreement would expire eleven years from the effective date of the Agreement. In exchange for the renewals and grants, Westgas agreed to pay the Tribe a fee of one and one-half cents per mmbtu for all gas gathered through a central compressor plant. The "throughput fee" arrangement mutually aligned the interests of the Tribe and Westgas in the successful, expanded development of coalbed methane from the Reservation, and that resource has proven to be a significant source of natural gas for the Nation.

In the last twenty years, the Tribe has successfully concluded negotiations for grants or renewals of interstate pipelines with El Paso Natural Gas Company, Northwest Pipeline Company (Williams), TransColorado, TransWestern, and Mid-America Pipeline Company. In no instance have parties been unable to obtain tribal consent for renewal of rights-of-way for interstate facilities. To be sure, the Tribe has attempted to optimize the compensation it receives for such renewals, but it has also been flexible in working with companies to identify mutual interests. For example, during its most recent negotiations with El Paso Natural Gas Company, the Tribe agreed to renew a right-of-way for El Paso's major interstate pipelines for a period of twenty years. The Tribe desired, however, to acquire portions of El Paso gas gathering facilities located on the Reservation, the right-of-way for which were also about to expire. As compensation for renewal of the interstate pipeline right-of-way, the Tribe paid El Paso $2 million dollars for portions of the on-Reservation gathering system. In other instances, the Tribe has bargained for capacity commitments in interstate lines that could be used to transport tribal natural gas resources.

Although the compensation or value paid for tribal consent for energy-related rights-of-way has certainly increased over the last 40 years, so have the Tribe's financial demands as a government. Unlike many state and local governments, the Southern Ute Indian Tribe does not currently impose any taxes on the business activities of pipeline companies operating on the Reservation. The Tribe and those conducting business with the Tribe have been able to accommodate their respective interests through good faith negotiation and consensual agreements.

B. Standards and Procedures for Determining Fair and Appropriate Compensation for Right-of-Way Grants, Expansions, and Renewals.

Congress has directed the Departments to make recommendations regarding standards and procedures for determining "fair and appropriate" compensation for right-of-way grants, expansions, and renewals. Existing law states that, unless waived by a tribe, the compensation for any grant or renewal of a right-of-way "shall be not less than but not limited to the fair market value of the rights granted, plus severance damages, if any, to the remaining estate." 25 C.F.R. 169.12 (emphasis added). Additionally, applicants for rights-of-way are required to pay for damages resulting from the survey or facility construction related to the right-of-way. 25 C.F.R. 169.13. The regulations place no upper limit on the amounts that a tribe may demand as compensation for use of its lands, and there is no appeal mechanism for overriding a tribe's exercise of that discretion. In other words, existing law simply confirms that a tribe's consent is required as a condition for obtaining a grant or renewal of a right-of-way across tribal lands and that a tribe may establish conditions for issuing that consent. Under this system, it is incumbent upon a right-of-way applicant to communicate effectively with the tribe whose lands are desired for use.

In contrast to existing law, El Paso Natural Gas Company and other industry representatives have urged that a fixed standard be established for determining compensation for tribal rights-of-way. Further, if consensus cannot be achieved with the tribe, industry desires a mechanism for the forced use of tribal lands through the Secretary of the Interior. Proposed legislative revisions proffered by the industry would establish "generally accepted principles of property valuation" as the guide and would restrict compensation levels to "fair market value, plus severance damages, if any, to the remaining estate." While some within industry have suggested the acceptability of some additional Indian land premium, the basic industry position embraces an approach in which use of tribal land can be forced and compensation would be based upon the amounts payable to private landowners in condemnation proceedings.

Like other tribes, the Southern Ute Indian Tribe strongly opposes any change in existing law and procedures. The industry approach simply fails to consider the unique nature of tribal land and the elaborate backdrop of Indian law and policy related to tribal land use. The suggestion that private land and tribal land are comparable ignores the governmental status of Indian tribes and the legitimacy of tribal governmental power to effectuate tribal policy and to meet tribal needs in broad areas. In this regard, tribes – who clearly have the right to say "No" under existing law – believe that they should receive some portion of the economic value or commercial benefit conferred upon the applicant for use of tribal land. Particularly in light of the commercial sophistication of the energy industry, changing the rules of the game in a way that could force tribes to grant renewals of expiring rights-of-way is grossly unfair to tribes – no matter how sympathetic the predicament of the industry applicant.

That having been said, energy companies who have bargained for fixed term rights-of-way across tribal lands may find themselves in difficult circumstances as those rights-of-way come up for renewal. If the passage of time and intervening circumstances have made alternative relocation of interstate pipeline or electric transmission facilities unavailable or infeasible, the value and cost of renewal may be relatively high, particularly when measured against the cost of

private land rights-of-way that are subject to condemnation. In such situations, renewal of a tribal land right-of-way may be the only option available to an applicant for continued use of facilities that involved large capital investments. The exclusivity of the renewal option correspondingly increases the value of the renewal and the compensation that can be demanded by a tribe for its consent to renew. Were a tribe in such a circumstance to refuse to renew the right-of-way and demand curtailment of use of a facility that provides the exclusive means for meeting national energy demand, the societal value of the energy facility could justify some heightened scrutiny or federal encouragement of tribal consent for renewal. Such circumstances, however, are extremely rare in nature. In almost all instances, the energy supplied through tribal lands can be delivered from alternative facilities. In any event, we are not aware of any instance in which the expiration of a right-of-way for interstate facilities has resulted in immediate curtailment of such use. Finally, in such unique circumstances, Congress would appear to have the ultimate power to enact special legislation carefully tailored to the circumstances and to proceed with a public taking in conformity with full due process and compensation requirements. In almost every instance, the renewal applicant and the tribe can be counted on to reach agreement for renewal once the mutual interests of renewal are identified and effectively communicated.

In making final study recommendations, we urge the Departments to retain the existing standards and procedures for establishing "fair and appropriate" compensation for energy rights-of-way crossing tribal lands.

C. Tribal Sovereignty Implications.

As indicated in the Tribe's prior comments and in comments submitted by other tribes, any deviation from the tribal consent requirement set forth in existing law will be a fundamental and unjustified departure from principles of tribal sovereignty over tribal lands.

D. National Energy Transportation Policies.

We are not aware of any national energy transportation policies that require diminution of the tribal consent requirement related to the grant, renewal, or expansion of energy-related rights-of-way crossing tribal lands.

II. Additional Considerations, the Red Cedar Case Study, and Economic Analysis.

In attempting to justify amendment of existing law, the industry has boldly asserted that the tribal consent requirement threatens the availability of energy products to consumers. The fear that Indian tribes are abusing their powers at the expense of consumers has been used by the industry to solicit support from the public and worried governmental officials for a dramatic change in law. Contrary to the assertion that the sky is falling, many tribes in the West possess significant energy resources and have been active contributors in meeting the Nation' energy demands. In

support of existing law, the Tribe submits two additional items. First, the Red Cedar case study illustrates the importance to consumers of retaining tribal control over the use of tribal land.

Further, it is apparent that the Section 1813 study arose from the unresolved negotiations between El Paso Natural Gas and the Navajo Nation for renewal of a right-of-way for a major interstate gas pipeline that crosses 900 miles of Navajo Nation land. El Paso has publicized the compensation demands of the Navajo Nation for renewal of that right-of-way and has suggested that the impact of meeting the Navajo Nation's demands would unduly burden consumers of natural gas.

As its second additional item, attached to these comments is a report commissioned by the Southern Ute Indian Tribe to evaluate the impact on consumers of meeting the compensation required by the Navajo Nation and other tribes in the southwestern United States for natural gas rights-of-way crossing their lands. The report, "Impacts on Natural Gas Markets of Charges Assessed For Tribal Rights-of-Way in the Southwestern United States," was prepared by Dr. Dale Nesbitt, President of Altos Management Partners, Inc. Dr. Nesbitt is an economist of national reputation in regard to natural gas markets, whose firm has developed leading models utilized by the National Petroleum Council in evaluating national energy demands. The report clearly demonstrates that the compensation demanded by the Navajo Nation, coupled with that paid to other southwestern tribes for major pipeline rights-of-way, is insignificant in a national context. Simply put, the claims of adverse consumer impact made by El Paso and industry organizations are nothing more than an effort to take revenue from tribes – not for the benefit of consumers, but for corporate profit-taking.

A. The Red Cedar Case Study.

As previously mentioned in these comments, the Tribe entered into a novel gas gathering agreement with Westgas in August of 1990, which was needed to construct gas gathering capacity for development of tribal coalbed methane gas. The Westgas Agreement granted blanket consent for rights-of-way on Southern Ute lands in exchange for a volumetric through-put fee associated with the Westgas system. Several years after entering into this historic agreement, Westgas' parent company, Public Service Company of Colorado, decided to sell Westgas. All rights-of-way associated with the Westgas system were scheduled to expire in 2001. The Tribe wanted to own and control the Westgas system to facilitate continued development of coalbed methane. Law did not permit forced renewal of the Westgas rights-of-way, and, without assurances that the Tribe would renew those rights-of-way, other potential purchasers were reluctant to purchase the system.

In order to secure the capital needed to purchase the Westgas system, the Tribe formed a joint venture with the Stephens Group from Little Rock, Arkansas, known as Red Cedar Gathering Company. The Red Cedar joint venture purchased the Westgas system in 1994 for approximately $87 million. The system at that time delivered approximately 125,000 mcf per day. Since purchasing the system, the Tribe and its partners have invested more than $145

million in system improvements. These commitments of substantial capital dramatically increased system deliverability. As a result, Red Cedar has provided national consumers an increase of more than 1.7 trillion cubic feet of gas above what would have been available without the acquisition and investment. The Tribe was able to add to the Nation's energy supply only because of the power to consent or not consent to energy-related rights-of-way.

B. Dr. Nesbitt's Study of Impacts.

In conducting his evaluation, Dr. Nesbitt considered the annual Navajo Nation compensation demand of $22 million (as reported by El Paso) and an estimate of annual compensation of $10 million derived by other southwestern tribes, for a total of $32 million. In order to assess the consumer impact of such charges, he converted that estimated tribal compensation to a unit fee on a volumetric basis to arrive at an estimated cost $0.02 per mcf. In his evaluation of the effect of such unit fees on consumers, Dr. Nesbitt found as follows:

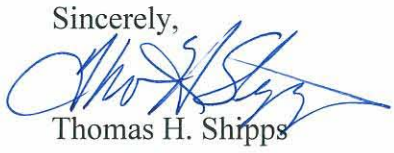
> The incremental impact of the tribal payment is negligible, nondiscernible, in every market in North America. It is zero, as it must be under known competitive market theory. The tribal payment is so small in the large gas markets of North America so as to be immeasurable, as it must be by theory. . . . No one in the Market will be impacted by the imposition of [the] tariff arising from the tribal ROW charges at the conservative levels under consideration here.

In sum, industry assertions that tribal right-of-way compensation demands are imposing a material burden on consumers are unsubstantiated.

Conclusion

The Southern Ute Indian Tribe urges the Departments to recommend a continuation of existing law and policy with respect to the grant, renewal, and expansion of energy-related rights-of-way across tribal lands. Existing policies have served effectively in fostering tribal economic development and in ensuring that energy resources are readily available to consumers. The Tribe appreciates the opportunity to comment on these important matters.

Sincerely,



Thomas H. Shipps

cc: Clement J. Frost, Chairman
Bruce Valdez

Attachments:

1. Dr. Dale M. Nesbitt, "Impacts on Natural Gas Markets of Charges Assessed For Tribal Rights-of-Way In the Southwestern United States (May 15, 2006).

2. Technical Appendix.

3. Southern Ute Indian Tribal Council Resolution No. 2006-81 (April 11, 2006) (adopting principles related to tribal consent for rights-of-way crossing tribal lands).

RESOLUTION NO. 2006-81

RESOLUTION
OF THE
COUNCIL OF THE SOUTHERN UTE INDIAN TRIBE
April 11, 2006

WHEREAS, authority is vested in the Southern Ute Indian Tribal Council by the Constitution adopted and approved by the Southern Ute Indian Tribe of the Southern Ute Indian Reservation, Colorado on November 4, 1936, and amended October 1, 1975 and August 27, 1991, to act for the Tribe; and

WHEREAS, Section 1813 of the Energy Policy Act of 2005 requires the Departments of Energy and Interior to prepare a study on the compensation practices and policy implications associated with the issuance of tribal consent for energy-related rights-of-way crossing tribal lands ("Right-of-Way Study"); and

WHEREAS, the Right-of-Way Study is a matter of great importance to the Tribe and to all tribes and may have significant implications regarding future legislation and tribal sovereignty; and

WHEREAS, under longstanding law, the consent of the governing body of a tribe must be obtained as a condition for the grant or renewal of a right-of-way across tribal lands; and

WHEREAS, the tribal consent requirement is a critical aspect of tribal sovereignty that allows tribal governments to negotiate acceptable terms, including those related to tribal jurisdiction, environmental and cultural resources, duration, and compensation, for the use of tribal lands; and

WHEREAS, Tribal Council has reviewed the attached statement of principles and has determined that these principles should be incorporated in the Right-of-Way Study and should be considered in maintaining federal law and policy.

NOW, THEREFORE, BE IT RESOLVED, that the Southern Ute Indian Tribal Council hereby approves the attached statement of principles and authorizes distribution of this Resolution as an official policy statement of the Tribe.

BE IT FURTHER RESOLVED that the Tribal Council directs that a copy of this resolution be forwarded to the Departments of Energy and Interior for inclusion in the record related to the Right-of-Way Study.

BE IT FURTHER RESOLVED that the Chairman of the Southern Ute Indian Tribe is hereby delegated the authority to execute any documents needed to carry out the intentions of this Resolution.

This Resolution was duly adopted this 11th day of April, 2006.

Mr. Matthew J. Box, Vice Chairman
Southern Ute Indian Tribal Council

CERTIFICATION

This is to certify that there were (4) of the regularly elected Southern Ute Indian Tribal Council members present at the above meeting at which (3) voted for and (0) against, it being a quorum and the above resolution was passed.

Ms. Zerhrena Richards, Recording Secretary
Southern Ute Indian Tribal Council

INDIAN TRIBES – PARTNERS IN AMERICA'S ENERGY FUTURE
SECTION 1813 RIGHT-OF-WAY STUDY – TRIBAL PRINCIPLES

1. **Tribal Sovereignty and Consent.** The power of tribes to prevent third parties from using tribal lands without tribal consent is a critical element of tribal sovereignty that has been established in Federal law and policy for over 200 years. The tribal consent requirement to the use of tribal lands should be honored and preserved.

2. **Conditions to Consent.** The tribal consent requirement includes the power of tribes to place conditions on the use of tribal lands, including conditions related to tribal jurisdiction, preservation of environmental and cultural resources, duration of use, and compensation.

3. **No Negative Effects.** Adherence to the tribal consent requirement has resulted in greater energy production in Indian country and lower energy costs to consumers. The tribal consent requirement for rights-of-way has not had a noticeable negative effect on the availability or cost of energy to consumers.

4. **Preservation of Tribal Jurisdiction.** No right-of-way agreement or other business arrangement that permits third-party use of tribal land should reduce the sovereign power of a tribe over its lands or the activities conducted on its lands in the absence of the specific consent of the tribe.

5. **Restricted Duration of Rights-of-Way.** Federal law and policy should not be changed to require perpetual rights-of-way or automatic renewals of rights-of-way because such changes would deprive tribes of management and control of their lands.

6. **Negotiated Compensation.** Tribes should continue to have the right to negotiate compensation for the use of tribal land that gives tribes a fair share of the economic benefits produced by use of their lands. Such revenues sustain tribal governments and cultures.

7. **National Security.** Indian nations are an integral component of energy security of the United States, not a threat to that security. History demonstrates that tribes have permitted critical energy facilities to be used pending compensation negotiations even in cases where tribal rights-of-way have expired.

8. **Industry Partnerships – Best Practices.** Federal law and policy should provide positive incentives to tribes and industry to foster partnerships and the mutual alignment of economic interests related to energy development, transmission and distribution.

9. **Appropriate Deference.** As reflected in the Indian Tribal Energy Development and Self Determination Act of 2005, deference to tribal decision-making should remain a fundamental component of Federal Indian energy policy.

10. **Allottee Experience.** The creation of a Federal administrative valuation process for fixing tribal right-of-way compensation would be an affront to tribal sovereignty and, as shown by the disastrous Federal management of Indian allottee resources, would be a mistake.

IMPACTS ON NATURAL GAS MARKETS OF CHARGES ASSESSED FOR TRIBAL RIGHTS-OF-WAY IN THE SOUTHWESTERN UNITED STATES

By

Dr. Dale M. Nesbitt
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May 15, 2006

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1 OVERVIEW OF FINDINGS

1.1 Tribal Rights-of-Way Charges (ROW Charges) Have Zero Discernible Effect on Wholesale Natural Gas Prices Anywhere in North America

ROW charges on pipes that traverse tribal lands in the Southwestern United States that would induce a volumetric tariff difference of $0.02/Mcf for all pipes emanating from or traversing the greater San Juan/Four Corners area will have zero discernible effect on market prices anywhere. It might be tempting to think that displacements plus production from lower cost sources of gas in the face of such costs would be the reason that ROW charges on the order of $0.02/Mcf will have zero discernible impact on market prices in the (large) downstream markets. Displacements might of course be relevant; however, that is not the primary reason that the price impacts of these $0.02/Mcf tribal tariffs are zero in downstream markets. The primary reason is that the pipes traversing the greater Four Corners area will increasingly become inframarginal sources of supply for all downstream regions and markets that they serve. As inframarginal sources, their specific costs of operation (and therefore any ROW charges that might be paid to third parties) will, from a structural perspective, have zero effect on market prices. There can be no other answer—inframarginal sources have zero impact on market prices. This is a fundamental tenet of competitive market economics, and we shall show why graphically as well as quantitatively within this document. The implication is clear—the tribal ROW costs do not impact downstream markets at all. That means that the issue of tribal ROW costs is strictly a "zero sum game" between the tribe and the pipeline company. No party outside those two is impacted and needs to be consulted. In this evaluation, we will quantify the market impact of ROW charges that are reasonably representative of those likely to occur and those that have occurred in the past. It is useful before presenting conclusions to proceed through the logic by which we have estimated the ROW transit charges for purposes of this market impact analysis and then to focus on the quantitative market assessment.

1.2 Estimated Impact of Tribal ROW Charges on Pipeline Tariff Levels in and Around the Southwest

In this market impact assessment, we have assumed the following levels of annual charges:

Navajo: $22 million
Southern Ute: $5 million
Other: $5 million
Total: $32 million

We emphasize that these ROW charges are both representative and reasonable, not necessarily the precise levels that are proposed, demanded, nor final ROW charges. (It is not our intent to represent agreed charges or precise charges under consideration. Our estimates have no official status as an "offer" or a "receipt." They are intended to be representative.) That said, we believe such fees are very much in the realm of possibility and quite appropriate for this market evaluation. For purposes of this evaluation, the total tribal ROW charge is estimated to be $32 million annually for all pipes in the region.

We want to convert this to a volumetric charge for a very important reason. Volumetric charges affect market prices directly. Demand charges and volume-independent charges may or may not affect market prices. It is our intent to calculate the maximum degree to which the anticipated tribal ROW charges can impact market prices. By converting annual charges to volumetric equivalents, we are able to calculate the maximum possible effect these charges could have on market prices. If after such conversion, the effect on market prices is small, we can be sure of two things. First, the assumed tribal ROW charges are immaterial in downstream markets. Second, if such charges are maintained as monthly or recurrent charges, they are even less material in affecting downstream market prices than calculated here. We are intending in this evaluation to calculate the maximum possible impact these ROW charges could have on downstream natural gas markets, and the calculation summarized herein does precisely that.

One way to estimate the impact of tribal ROW charges on traversing pipeline tariffs is to consider the Navajo-El Paso situation alone and infer what magnitude of ROW transit charges might be implied on a volumetric basis from that discussion. To do so, we have attempted to access relevant information from a recent El Paso rate case. Following are the reported capacities-to-deliver at the various terminal points of the El Paso system.

Table 1: El Paso System Delivery Capacities (mmcfd Capacity)

State		Location	Capacity (mmcfd)
CA		Ehernburg + Topock	2,890
		Mojave	400
		North Baja	500
			3,790
NV			162
AZ			1,259
NM			179
TX			423
Total System (sum from above)			5,813
Total System (per ElPaso rate case testimony)			5,342

The above capacities represent the total delivery capabilities at the various points. El Paso has reported that only approximately 60 percent of this total delivery capacity has been contracted as firm service. In order to expedite the calculation, let us assume that only the firm service holders will pay the ROW transit charge (a very conservative assumption), meaning that the total capacities on the El Paso system that are under firm service contracts at the export points and therefore pay the ROW charges is 3,205 mmcfd.

If we convert to trillions of cubic fee per year, we obtain the aggregate export deliverability of El Paso at the various export points to be 1.1696 Tcf/yr. If we divide the $22 million in Navajo ROW charges by this magnitude of exportable gas, we obtain a volumetric rate of $0.0188/Mcf delivered. It would seem that $0.02/Mcf delivered would be an upper bound on the Navajo tariff.

We can view the tariff impacts of ROW charges in yet another way to obtain another benchmark on the magnitude of ROW tariff under consideration here. Altos' model runs and gas data indicate approximately 1.8 Tcf/yr of gas flowing into, within, and out of the Greater San Juan/Four Corners/El Paso area today. If one took the entire estimated tribal ROW charges of $32 million and divided by this aggregate gas flow in the region, one would obtain an upper bound on the ROW charges and their impact on pipeline tariff. (This is an upper bound because volumes are going to be shown in the Altos model runs to be increasing into, within, and out of the greater San Juan region, and the model is going to show when, how much, and why.) If we divide $32 million by 1.8 Tcf/yr of gas, we obtain a total imputed tariff in the region of approximately $0.0178/Mcf delivered.

In light of these two data points (Navajo only and aggregate regional), a volumetric ROW transit fee of $0.02/Mcf would seem to be a very appropriate and reasonable value of the ROW transit fee impact on pipeline tariffs to be considered. Not only that, we would argue that a $0.02/Mcf volumetric tariff would be a conservative figure (meaning it is higher than probably will occur) for the following reason. If the volumes flowing through this region increase (as we will see that they will), because we have assumed a volumetric tariff by design (whether or not one actually exists in the market), we will be overstating the payments to the tribes and the consequent impacts on tariffs in our analysis. We shall see in fact that is the case—loads through the regions will be increasing and our volumetric tariff will be overstating the payments to the tribes and the consequent impacts on tariffs and therefore downstream markets. We are on safe ground arguing that a $0.02/Mcf tariff on pipelines traversing this region should be an upper bound. We will see, notwithstanding that this is an upper bound, that the impact of these conservatively stated tribal ROW charges and their impacts on tariffs will be zero in downstream markets.

1.3 How Did We Determine that Tribal ROW Charges Have Negligible Effects on North American Regional Prices?

In order to quantify the impact on North American (and world) markets for natural gas arising from changes in assessed transportation tariffs on pipes that emanate from or cross tribal lands in the greater Four Corners and San Juan region, we postulated two cases or scenarios and ran them through the Altos North American Regional Gas (NARG) model. The first case is a reference case or a "business as usual" case in which tariffs are maintained at the levels that were estimated in the National Petroleum Council

(NPC) version of the NARG model.[1] This is the business as usual or historical ROW cost-traversal tariff case. We term this the base case or reference case. As we shall see, the primary motivation for this case is to serve as a reference point against which to compare the incremental impacts of tribal ROW charges.

Against this reference case, we postulated a high transit tariff case (with regard to tribal ROW charges) in which all pipelines that emanate from or cross the greater Four Corners and San Juan area pay a volumetric ROW tariff of $0.02/Mcf lower than the base case. That is, we assume that the tribal tariff is deleted from the NPC case, all else equal. (We are not assuming that such tariff will be deleted. Rather, we want to analyze whether deletion of such payment, all else equal, will have any impact on markets or if it can be considered a "money grab" away from the tribes by pipeline companies with no market being affected one way or the other.) We term this the reduced ROW charges or reduced tariff case, all else equal. This reduction of the pipeline cost by $0.02/Mcf is intended to represent what would happen if the pipelines that cross the region do not pay a ROW charge. As stated previously this magnitude of tariff reduction, $0.02/Mcf, is designed to be substantially larger than the ROW charges that are truly at issue here.

Differences between the base case and the reduced tariff case show explicitly the impacts in all the located, regional markets in North America (and the world) that would be induced by the Southern Ute and other prospective tribal ROW charges by all the pipelines that traverse the region. To emphasize, the difference in Topock price between the reference case and the reduced ROW charges case in the Altos model, all else equal or ceterus parabis, is completely and totally attributable to the tribal ROW payment. By creating two cases that differ solely in terms of the tribal payment, we are able to quantify the market impact of the tribal payment and nothing else. We shall see that the Altos NARG model (the same model that was built and used by the NPC and Altos) implies absolute zero impact on the market of all tariff arising from the tribal ROW charges in aggregate and therefore Southern Ute tariffs in particular.

Assuredly the magnitude of the actual tribal ROW charges on the market will be lower in magnitude than those that represent the difference between these two scenarios. It is our specific intention in creating this case to overstate the prospective payments to the tribes from every pipeline that comes in contact with the greater Four Corners and San Juan regions and thereby to overstate the impact of such fees on upstream and downstream markets. In so doing, we endeavor to create a very conservative case for purposes of this evaluation, one based on a higher-than-proposed and higher-than-anticipated ROW charges and consequent elevation in pipeline rates than is actually in question here. In so doing, we are endeavoring to have a conservative case, an upper

[1] The Supplemental Modeling Team of the NPC selected and used the Altos NARG model during its 2003 natural gas study. (Altos is referenced on page 3 of the Executive Summary of their report.) Altos Management Partners Inc. in no way represents nor speaks for the NPC or any of its members nor has any authorization to do so. Altos results and findings are solely and exclusively its own results and findings and cannot and should not be attributed to the NPC or any of its members. We merely reference the NPC data and models, which we consider to be the finest and most accurate available.

bound, on the impact of ROW charges on markets throughout North America. If in this conservative, higher-than-expected ROW charges case there is negligible price decrement (as is the case, to be shown herein), it follows directly that there is smaller and therefore even more negligible or zero price decrement under the true ROW charges that will characterize the real world in the Southwest. To wit, we have postulated a high ROW charges case, and we run two runs through the Altos model that show that it has zero impact on any downstream market (as must be the case in competitive markets by inframarginal sources), and thereby shown that the ROW charges actually proposed by the tribes have zero impact on any downstream market.

The specifics of how we implemented the reduced ROW charges case are as follows. The prospective difference of $0.02/Mcf in the transportation rates of pipelines and pipeline segments traversing the Greater Four Corners and San Juan Basin lands was reflected in several transportation nodes in the model, specifically in the area around the San Juan Basin in the Four Corners area. In those regions, we subtracted $0.02/Mcf from the transportation rate for model nodes representing the following pipeline segments:

- The entire El Paso Natural Gas system including but not limited to San Juan Basin facilities. The cost is imposed on the entire El Paso system.

- The entire Transwestern Pipeline's system including but not limited to the San Juan Basin Lateral for delivery of gas received in the San Juan Basin and delivered into the Transwestern mainline

- It is worth noting that all gas emanating from the Permian basin moving west is included in the above volumes for El Paso's and Transwestern's systems

- Southern Trails Pipeline

- Local deliveries of San Juan Basin gas to local New Mexico and Arizona markets

- Northwest Pipeline and TransColorado Gas Company deliveries (southward) into the San Juan Basin area from the Rocky Mountains area

The intent was to more than span pipelines that cross Southern Ute, Navajo and other tribal land and of course to fully incorporate those that do. We reiterate, we are not meaning to assert that these ROW charges will or should be levied in all these regions. We are meaning to assert simply that this is the scenario that was evaluated relative to the base case. Any differences between this scenario and the base case are solely and exclusively attributable to the tariff arising from the tribal ROW charges. By this method, we are able to isolate the direct economic and market impacts of the tariff arising from the tribal ROW charges.

1.4 What Is the Incremental Impact of the Tribal Payment?

The incremental impact of the tribal payment is negligible, nondiscernible, in every market in North America. It is zero, as it must be under known competitive market theory. The tribal payment is so small in the large gas markets of North America so as to be immeasurable, as it must be by theory. The tribal payments in question in this proceeding would not "deflect the gas price meter." No one in the market will be impacted by the imposition of tariff arising from the tribal ROW charges at the conservative levels under consideration here. The impact of these tariffs is zero on all market prices everywhere. The difference in price in selected regions between the two cases is lower in magnitude than the ability of the model to discriminate a difference. This must not be interpreted as a weakness in the model. On the contrary, we shall show that it is the right answer.

To be clear, the inability to discern price decreases that occur in the market when if the tariff arising from the tribal ROW charges were eliminated is not at all a flaw or shortcoming in the model. Quite the contrary, when the ROW charges are changed, the model appropriately changes the entire North American exploration and production and pipeline utilization system so as to fully arbitrage and adapt the change. With a $0.02/Mcf change in and around the San Juan, there is more than enough flexibility in and around the San Juan and all other producing basins in North America plus any and all LNG that lands to fully displace and fully arbitrage away that small an impact on price. The two cases that are the subject of this report show quantitatively that the incremental impact on markets of the tribal payments is zero.

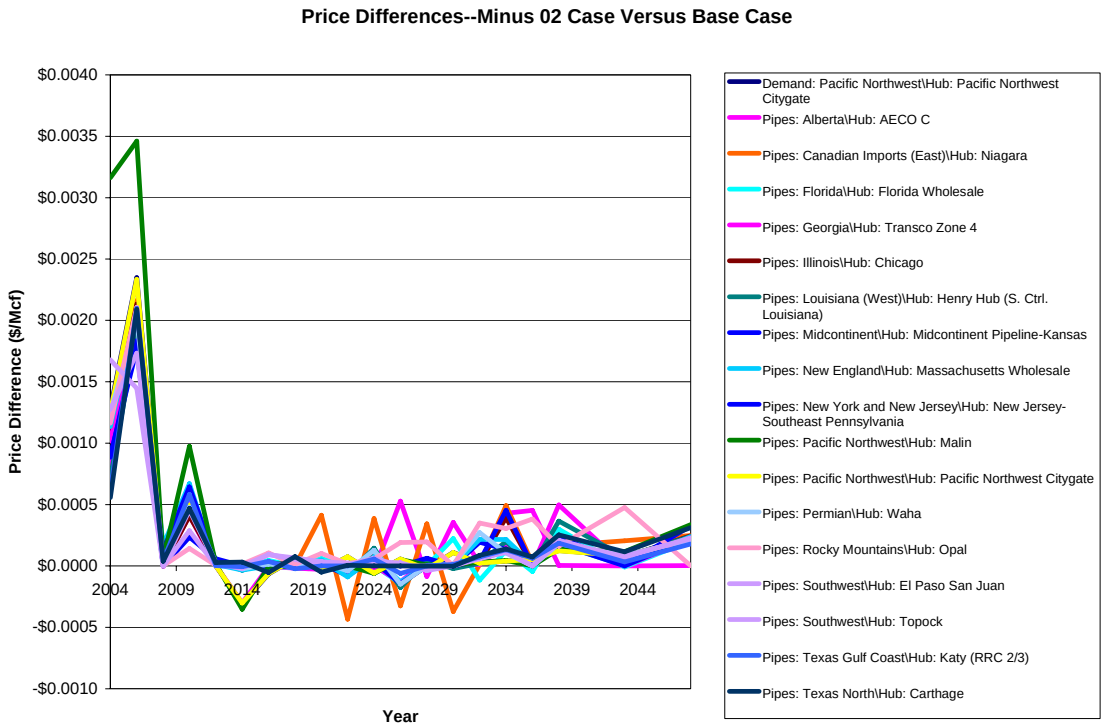
Figure 1 plots the incremental price impact of the tariff arising from the tribal ROW charges. It represents the price at selected hubs throughout North America in the case in which the tribal payments have been eliminated minus the price at those same selected hubs in the case in which the tribal payments are made at the proposed levels. We hasten to state that the price differences in Figure 1 are zero in our iterative model. Please refer to the vertical axis. The magnitudes of numbers there are literally infinitesimal.

The Altos model prices are probably accurate to within ½ of a cent per Mcf, and the numbers in Figure 1 are beneath that particular level of "convergence fuzz." The numbers in Figure 1 should be interpreted to be zero—beneath the ability of the model to discriminate. It would not be appropriate to assert that the prices differences in the figures are, because they cannot be reduced to absolute zero, "large because Altos has said that the model cannot discriminate between -1/10 of a cent and 1/10 of a cent." That would be inappropriate and incorrect and in fact preposterous on its face. What this plot says is that the price differences everywhere in North America arising from the tribal ROW charges are negligibly small. We are going to show using graphs and conceptual illustrations why this is and must be the case with regard to the tariff arising from the tribal ROW charges. The analytical answer we will present shortly indicates from a

theoretical-economic perspective why tariff differences of inframarginal sources less than ½ of a cent per Mcf can result in zero price changes in downstream markets.

It is clear that if there is zero price impact arising from the imposition of the tariff arising from the tribal ROW charges, there is zero impact on any downstream market. No consumer in any downstream market is at all affected by the imposition of the tariff arising from the tribal ROW charges. As such, it would be completely inappropriate to involve any such customer or customer group in the consideration of tribal ROW charges. No customer group is affected. The prices they see are completely invariant to the tribal ROW charges at the levels assumed here (which are overstatements as we have argued). Any assertion that the tariff arising from the tribal ROW charges "comes down on California or other gas customers" is wrong. On the contrary, any proposal by a pipeline that traverses tribal lands "not to pay the tariff arising from the tribal ROW charges" is tantamount to a proposal by that pipeline to simply take money directly away from the tribe and keep it for itself. Such a proposal is no more than a Trojan Horse to take money otherwise destined for the tribes away from them and to keep it for pipeline shareholders. It is a naked, overt "money grab" from the tribes. Downstream customers are neutral; there is no impact on them. Debate over ROW charges at the magnitude herein is a zero sum game in which pipeline owners are proposing to divert dollars away from the tribe and keep them for themselves, a direct dollar for dollar conscription from the tribe into the pockets of their shareholders.

Figure 1: Price Differences Between Base Case and Reduced Tariff Case



From the perspective of a pipeline proposing not to pay these ROW charges, the effect is not unlike a 7-11 holdup: "Just walk in and take the money right out of the tribal cash register, put it in a bag, walk out of the store, deny it to the store owner, and keep all those ROW charges for your own shareholders." Is there a further danger that new energy legislation can be used as a precedent-breaking mechanism to permanently deny ROW monies to the tribes and hand it over to pipelines, a literal "getaway car?" It needs to be clearly understood that ROW charges at the level here have zero impact on downstream prices; they simply transfer dollars between the tribes and the pipelines.

Our analysis, using the same model that was used by the NPC by the supplemental modeling group, shows definitively that it cannot be argued that the imposition of tribal ROW charges imposes costs on customers in California, the Southwest, or elsewhere. Changes in gas price in those regions is nondiscernible with or without the tribal ROW charges and any tariff impacts it has. We shall discuss what this means shortly. There are solid structural and market reasons why the ROW charges will have zero impact on any downstream market anywhere in North America, and we shall now show why.

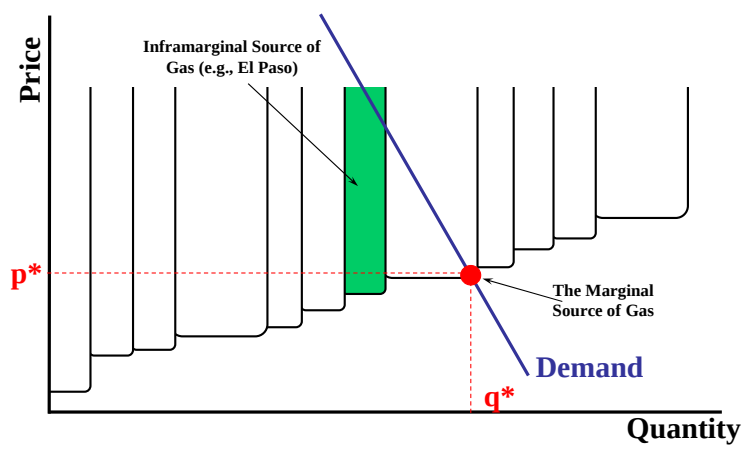
1.5 Graphical Analysis

How can it possibly be true that the imposition of a 2 cent transit fee will have zero impact on market prices anywhere downstream from that point? The answer is clear and simple. In fact, it is the only acceptable answer in a competitive market setting. Figure 2 illustrates graphically the situation in natural gas markets downstream from the pipes that traverse the tribal areas of the Southwest. All of the individual supply curves (which are stacked in ascending order of cost) represent a combination of upstream supply curves combined with pipeline transportation costs and volumes to a market hub such as Topock. In the case of the curve in the form of Figure 2 for California, the "supply stack" represents the combination of all pipelines that serve California market—El Paso North, Transwestern, El Paso South, Baja Norte, Kern River, PGT, PGT Expansion, etc. Each pipeline has a capacity (the width of its supply curve), and each pipeline has a cost (a combination of the gas price at the upstream end of that pipeline plus the pipeline cost to California).

One and only one of these sources is the "marginal source," as shown in Figure 2. The marginal source of gas into the market is the "last in-first out" source for the market. It is the specific supply curves that the demand curve happens to contact. It is NOT any of the supply curves that the demand curves does not contact. By "last in-first out," which is a fundamental characteristic of a marginal source, if demand eroded for even a day, the marginal source would erode one-for-one. If demand increased, the marginal source would increase one-for-one. The "last in-first out" source of gas is in economics parlance the source whose full cost sets the price for the entire market. Indeed, it is the marginal source of gas whose cost represents the price that will occur in the market. This is clearly indicated in the figure. It is the cost of the last supply curve on the right that is contacted by the demand curve that sets the price.

The critical question arises, and the answer is clearly evident if we modify the diagram in Figure 2 to represent what would happen if the tariff arising from the tribal ROW charges were not paid by the pipelines to the tribes but were instead kept by the pipelines. The cost of the pipes (the pipeline tariff) would drop, but the capacity would be unaffected. The supply situation into the downstream market would now appear as in Figure 3, which is modified from Figure 2 in that the source whose cost was dropped is not shown as lower. The pipeline from which the tariff were withheld from the tribes would be reduced in cost as shown in the figure by exactly the amount of the tariff withheld. This cost reduction that would be realized by the pipeline because of its withholding of ROW charges to the tribes would render the supply-demand diagram from Figure 2 into California into the new form in Figure 3. Everything would be exactly as before, but the pipeline who was withholding ROW charges from the tribe would have a lower supply curve. The cost of that pipeline doing business would be reduced as shown in Figure 3.

Figure 2: The Market Situation in a Region Downstream from the Pipe in the Base Case

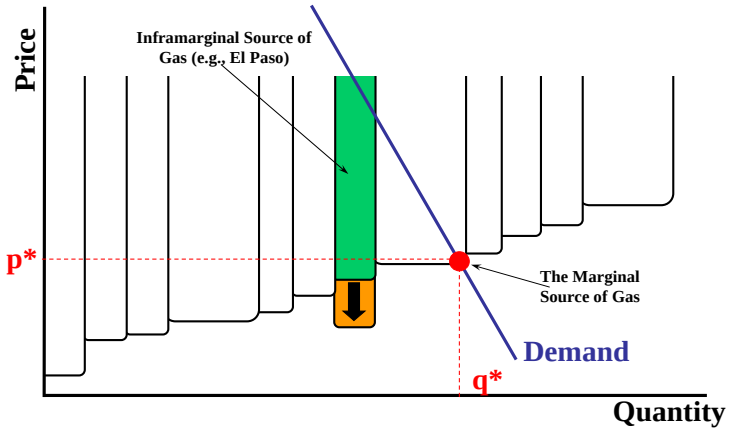


Now for the fundamentally important insight: What change in market prices would and should occur from the reduction in that pipe who does not pay the tribal ROW charges? The answer, clearly visible from the orientation of the two figures (with and without the tribal ROW charges) is that the market clearing price and the volume of gas flowing at that price <u>will not be affected at all</u>. It will be absolutely identical in the two cases. There must be zero difference between the two cases for all sources of gas that are not the marginal source of gas in any region. The tribal tariff on an inframarginal source will have zero impact on any flow into the California or other markets. Figure 3 is unequivocal on that.

By withholding ROW charges on an inframarginal source, the pipeline will de facto be "taking away" the fee from the tribes dollar for dollar and not having any impact on anyone in the market. No other agent in the market is affected besides the pipeline and the tribe. Conversely, by imposing a fee of the magnitude considered here, the tribe

will not be imposing any costs on any downstream customers. This is a quintessential zero sum situation. Any pipeline who argues that ROW charges should be minimized in order not to impact downstream prices is incorrectly representing (or misrepresenting) the situation in those markets. It is clear both from the two Altos model runs and from the diagrammatic exposition that the transit tariffs, whether they are paid by the pipelines to the tribes or not, will have zero effect on downstream markets. No California or other consumer will be involved. This is a quintessential zero sum game between the pipe and the tribe.

Figure 3: The Market Situation in a Region Downstream from the Pipe in the "Without Tariff" Case



The magnitude of dollar transfer from the tribe to the pipeline is equal to the orange area in the diagram. This orange area, if not paid by the pipeline to the tribe, represents a direct conscription of dollars by the pipeline away from the tribes, a direct "money grab" by the pipeline away from the tribes. There is absolutely zero effect on any downstream customer from this "money grab" as long as the pipes upon which it applies are inframarginal (i.e., inside the margin) and as long as the tariff difference in question is small and does not force the supply curve to a point above the market price. In order for that to occur, one would have to be considering dollars per Mcf, not pennies per Mcf, and that is simply well outside the range considered or anticipated here. Any ROW charges imposed on an inframarginal source have absolutely zero impact on any downstream market. The difference between Figure 2 and Figure 3 make this crystal clear. It is no wonder the model runs comparing the "with ROW charges" versus the 'without ROW charges" cases result in zero difference in market price. According to Figure 2 and Figure 3, that is the only possible answer. If the model were not getting it, the model would be wrong. Any assertion that the issue of payments to the tribes would affect downstream markets is wrong. It does not for all inframarginal pipes. The model is telling us that the pipes in question are inframarginal in California and other markets. We will discuss that in more detail below.

1.6 What Is There to Discipline the Tribes from "Asking for the Moon?"

Is there anything to limit what the tribes might ask? Of course there is. Let us use an analogy. This report was written on a Dell laptop. What is there to keep Dell from charging the $20 million this laptop would have been worth during the 1960s when people were using IBM mainframe computers in college? It is clearly worth $20 million. Don't we need a government agency to restrict Dell from demanding $20 million or withholding service? The answer is this: "There is competition." That is what keeps Dell from raising the price to $20 million.

And so it is with pipelines. If the price goes too high, the loads go to zero as the pipeline becomes noncompetitive. The tribes know, as do the pipelines, that if the transportation cost goes too high, people find alternatives. If they find alternatives (i.e., if physical bypass facilities are actually built), the pipelines in question and the tribes lose everything. Transit fees are subject to the same market discipline as Dell. That analysis here indicates that the level of ROW charges both historically and anticipated are in no way noncompetitive and in no way suppress use of the pipelines that traverse the Southwest.

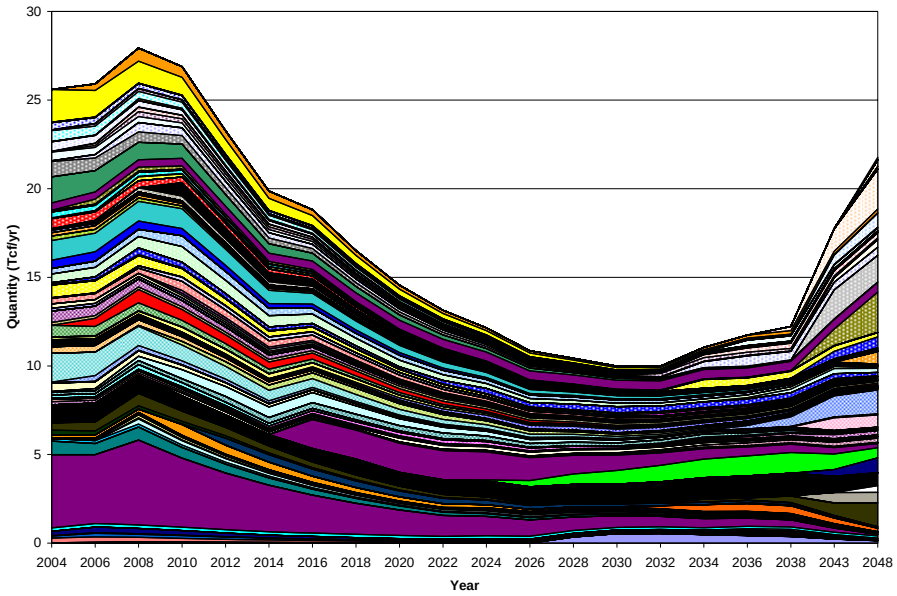
2 FUTURE NATURAL GAS MARKETS AND THE IMPACT OF ROW CHARGES THEREUPON

This section outlines the results from the Altos model run for the base case (with tribal ROW charges) and the case without the tribal ROW charges. This section is included so that one can understand why it is that the tariff changes attendant with the ROW charges do not elevate or change prices in downstream markets. The discussion here also lends insights into sources and dispositions in gas markets in the United States and Canada.

2.1 North American Total Indigenous Supply

We begin by plotting projected North American natural gas supply for the coming several decades by producing region (producing basin) and by technology type. This projection is based in significant part on the National Petroleum Council (NPC) supply and resource assessment estimates, which we believe are unique and uniquely accurate in the business. These resource assessments and corresponding finding, development, and production cost estimates have been made by people who know the most about production costs, volumes and schedule and people who have "seen the seismics." For our present purposes, it is less important to enumerate the specific regions that comprise the stack in Figure 4 than it is to consider the aggregate height of the curve—total indigenous North American production.

Figure 4: Indigenous Supply in North America (Base Case)



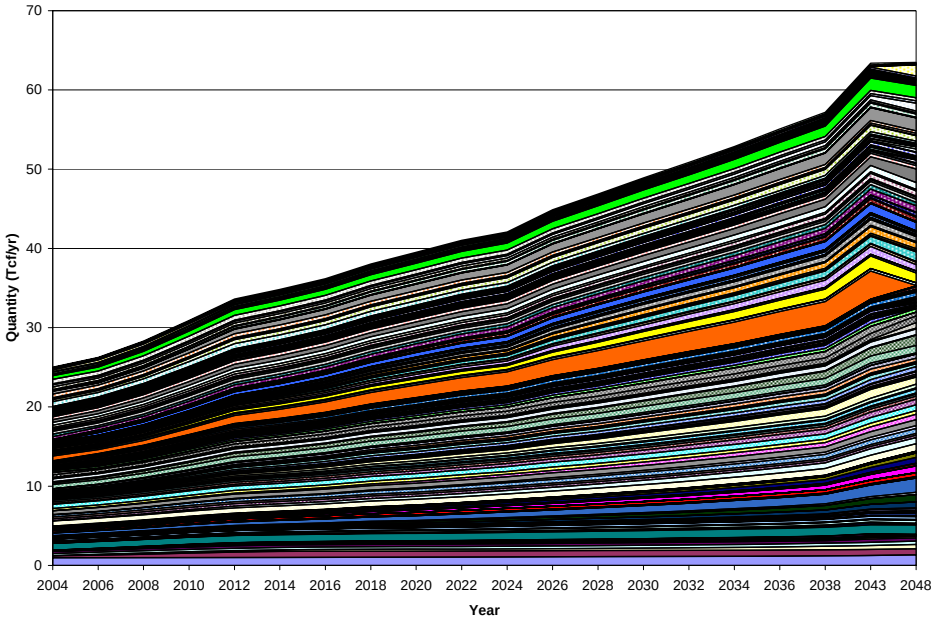
The important thing to notice in Figure 4 is that domestic resource production in North America, the aggregate envelope of North American production, is headed for decline after an ephemeral increase to a peak. This ephemeral increase to a peak represents North American producers exploiting the remaining low cost resource that exists in North America (primarily in the Rocky Mountains and certain other regions in small quantities). The NPC resource base and supply estimates tell us that the resource base is going to be unable to support domestic consumption before much longer. The overall message of the figure is that North American gas is today and increasingly into the future rather strongly depleted and is not destined to sustain domestic demand many more years.

Another implication of the plot in Figure 4 is that a domestic source of gas will be the marginal source of gas. LNG, which is destined to enter in increasingly large quantities, will be an inframarginal source of gas in North America. This tells us why the tribal ROW charges at the levels considered here are not going to prices in downstream consumer markets—they are increasingly associated with inframarginal sources.

2.2 Total American Demand

The total demand for gas in North America, inferred from the NPC demand models in all sectors other than electric power and from the Altos North American Regional Electricity (NARE) model inside the electric power sector is depicted in Figure 5.

Figure 5: North American Natural Gas Consumption (Base Case)



We emphasize that this demand projection takes account of investment, operation, retirement, and retrofit of generation plants in the electric power sector and takes explicit account of tradable emissions allowances for SOx, NOx, and Hg. This is critically important to the result because the emergence and increasing tightening of SOx, NOx, and Hg allowances disincentivizes coal fired generation in favor of natural gas fired generation. The stimulative effect of tradable emissions allowances for SOx, NOx, and Hg is explicitly accounted for in the North American demand projection in Figure 5. This is not crucially important to the present insights regarding tribal ROW charges, but it frames the projections in terms of the still-increasing level of North American demand.

2.3 North American Total Imports of LNG

What fills the gap between North American demand in Figure 5 and North American supply in Figure 4? The answer is obvious—LNG. In fact, it is the economic competitiveness of LNG that actually creates the gap. It is often ignored in natural gas market analysis and projections that it is the price-competitiveness of LNG that causes it to enter. LNG does not enter just for the heck of it. LNG enters because its cost is lower than the cost of the domestic resource base. That selfsame phenomenon has happened in the crude oil business in North America for the past three decades—lower cost imported crude displaces higher cost domestic crude. That same phenomenon is now beginning to drive the gas business—lower cost imported LNG displaces higher cost domestic natural gas production.

There are those who argue that magnitudes of LNG such as that in Figure 5 might not be realistic. That selfsame comment was made in the 1970s regarding imported crude oil. "We will never be importing 65 percent of our crude oil!" was the mantra. Competitive forces swept away the depleting domestic crude oil industry, and competitive forces are likely to sweep away the depleting domestic natural gas industry. The economic force we are talking about here is colossal. We should point out that if we limit LNG imports below the levels in Figure 5, the results generated here will be even more true. If LNG imports are restricted, LNG will by construction always be an inframarginal source of gas to North America. In that situation, any pipeline that moves any LNG will be inframarginal in its downstream market.

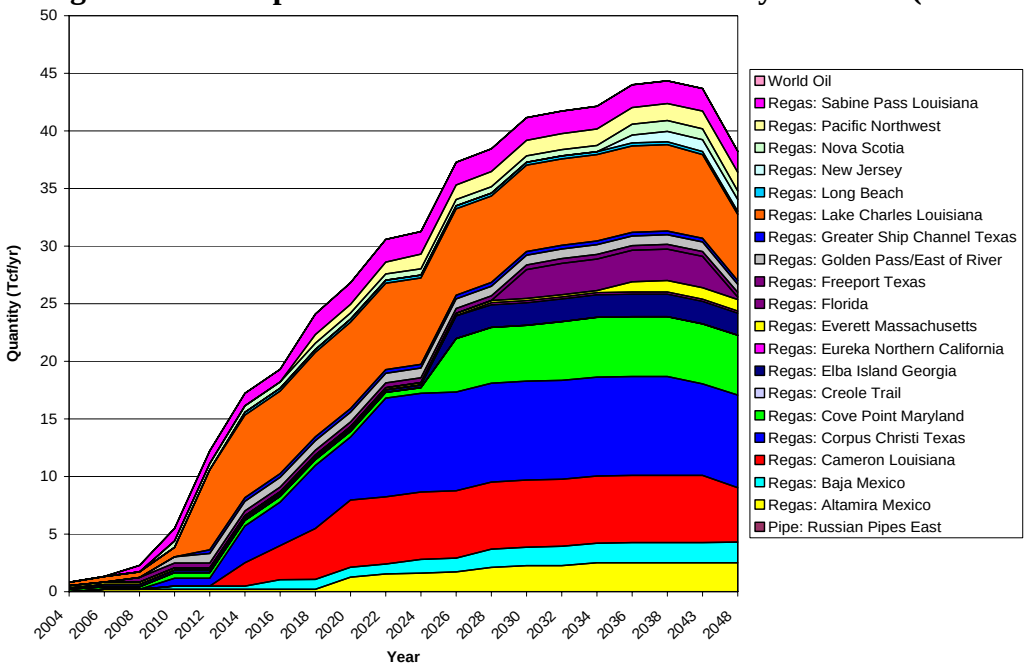
We now turn from the issue of aggregate flows, production, and consumption to various regional prices, flows, and quantities that explain the results here that the tribal ROW charges will have no impact on downstream prices.

2.4 Prices at Selected Hubs in North America

What are the market prices at the various hubs projected in the base case (business as usual)? Figure 7 presents the prices from the base case at various hubs throughout North America. Figure 8 calculates the basis differential for all the locations in Figure 7. The prices are somewhat "bumpy" owing to discrete assumptions regarding the timing

and magnitude of entry of various LNG facilities, McKenzie Delta, and Alaskan gas. There are some fairly large assets that are timed to enter the North American market at certain points in time, and such "lumpy" entry at those points in time induces transients in the price. The fact that these prices are bumpy does not obviate their veracity.

Figure 6: Imports of LNG into North America by Location (Base Case)



There are several price and basis insights that emerge from Figure 7. First, prices everywhere but the Pacific Northwest and Canada follow one temporal pattern, and prices in the Pacific Northwest and Canada follow quite a different temporal pattern. There are very large price bumps that occur in the middle years in places such as Florida. (We have made assumptions regarding the magnitude and timing of entry into Florida that induced such bumps.)

The basis differentials plotted in Figure 8 indicate that the basis at virtually every location in North America increases (becomes more positive in magnitude) relative to the Gulf (Henry Hub). To wit, every location in North America increases in price relative to Henry Hub. This increase in price everywhere relative to the Gulf occurs because the Gulf Coast becomes the major import location for LNG and therefore becomes the major source of North American gas. The major source of North American gas must by economic logic become the "low water mark" with regard to price in the entire continent. We know that gas must flow from regions of abundance (low price) to regions of scarcity (high price) through the North American pipeline system. As the ultimate source of most of the gas in North America, the Gulf Coast logically must experience its local price of natural gas to be lower than that in the rest of the country. Notice in Figure 8 there are a few regions that have a different pattern, namely the Canadian and Pacific Northwest regions of North America. We will discuss why later in this section.

Figure 7: Prices at Selected Hubs in North America (Base Case)

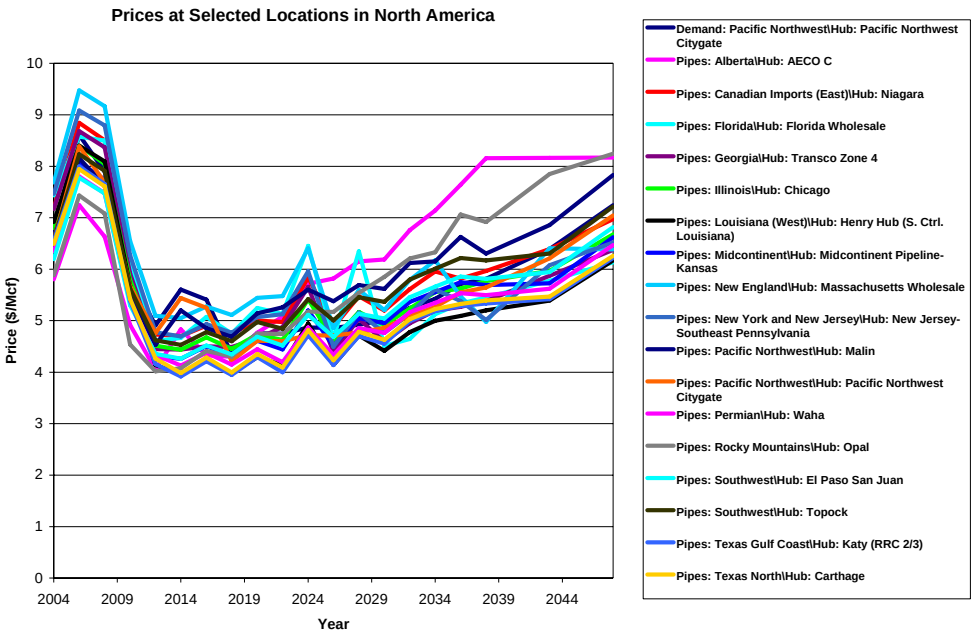
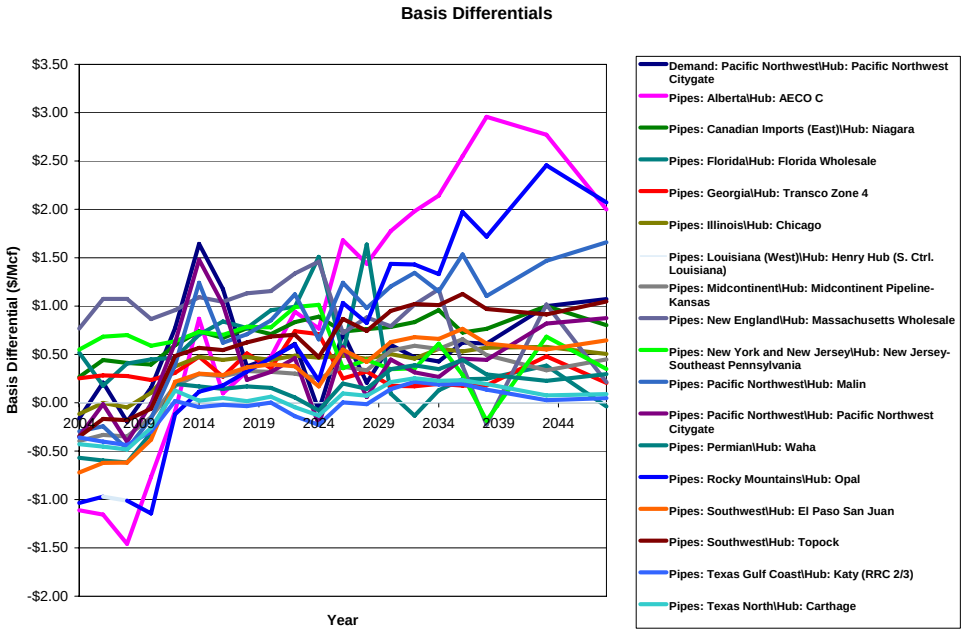


Figure 8: Basis Differentials from Selected North American Hubs to Henry Hub (Base Case)



2.5 The Greater San Juan Basin

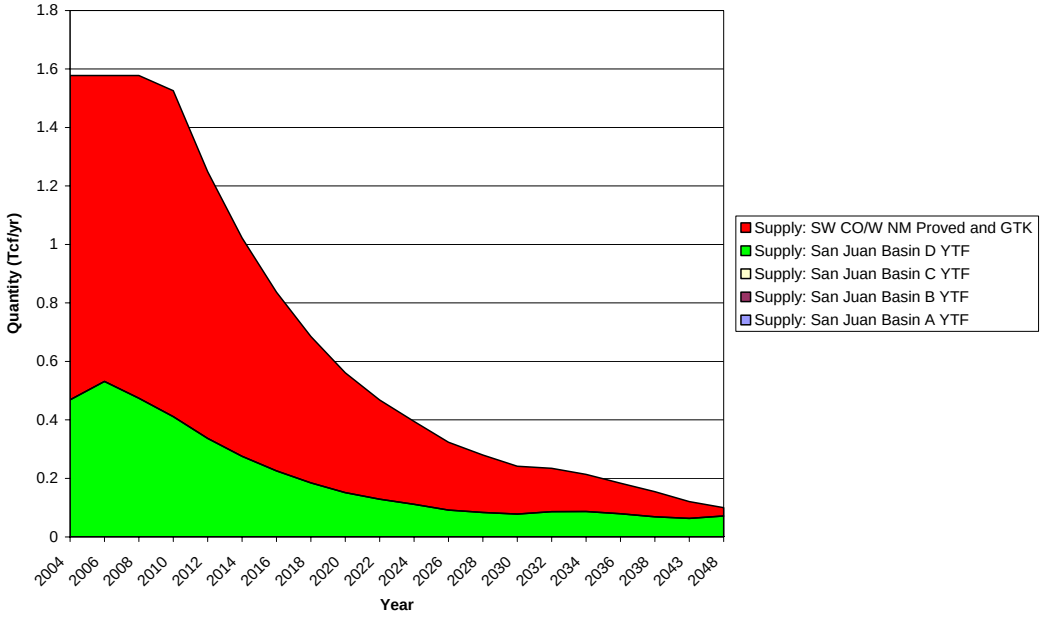
Figure 9 depicts the total indigenous natural gas production in the San Juan basin and its composition forward in time in the base case. It is clear that San Juan basin production is destined to drop substantially within a decade. We shall see what will replace that declining production shortly. The red wedge in Figure 9 represents San Juan production and "growth to known," which is designated GTK by the NPC. The green wedge in the figure represents continuous formation production in the San Juan basin, designated the "D" portion of the resource base. (The NPC used designations such as A, B, C, D, etc. to characterize alternative deposits of resource. The NPC supply report is comprehensive with regard to their resource work.)

Indigenous natural gas production in the Greater San Juan Basin is destined to decline over time. The greater San Juan is a mature basin, having been produced since the 1930s or even earlier. According to the NPC, virtually all the large conventional, discrete fields have been found and produced. Statistically there are nothing but small fields left to be found, and the growing preponderance of gas production in the basin will be unconventional gas (coalbed methane and tight formations). It is well known that the preponderance of gas left to be found and produced in the San Juan basin is continuous formation gas (coalbed methane). The incremental finding and development cost of continuous formation gas is higher than that of large-field conventional gas. As a higher cost source, continuous formation gas is relegated to compete with LNG and other higher cost sources if it is to enter and participate in downstream markets. We see from the size of the green wedge in Figure 9 that the continuous formation gas will compete against LNG for a while until it is depleted.

Figure 9 is a somewhat stark picture of the future for San Juan area natural gas. Is there any gas entering the region to make up for the declining gas? If so, from where? The answer, as we shall see, is a definitive yes. There is an additional source of gas that will be entering the region and making up for the inexorable decline. To see what that is and where it comes from, let us examine the magnitude and sources of gas entering the Southwestern pipeline system from all immediately contiguous regions. Figure 10 shows that the magnitude of gas imported into the Southwest remains constant for about a decade and then begins to increase substantially. Notice that all of the increase is coming from the Permian Basin (the two blue rapidly increasing wedges in the center of the diagram). Notice further that virtually none of the gas entering the Southwestern pipeline system comes from the Rocky Mountains. This is important. All the gas entering the region in the long term comes from the Permian, not the Rockies. As we shall see shortly, Rocky Mountain supply is not intrinsically large, and Rocky Mountain supply is going to be proceeding directly to its downstream markets, not routing indirectly through the Greater San Juan Basin. This is an important finding. Pipes such as TransColorado southward from the Rocky Mountains are going to see loads drop to zero. Interestingly, there are already proposals to reverse TransColorado to flow from south to north. The Altos base case would argue that is an appropriate response to market force in the longer term, hauling gas that enters from the Permian plus gas that is produced in the San Jan

northward to offset Rockies decline when it occurs. Lines such as El Paso and Transwestern coming from the Permian Basin in West Texas are going to see loads remain constant for a while and then escalate rather significantly. It is easy to infer where this increase in loads is coming from. It is coming from LNG and the increasing share of the North American market that LNG will command coming from the Gulf Coast of Texas and Louisiana.

Figure 9: Greater San Juan Wellhead Natural Gas Production in the Altos Base Case (Base Case)

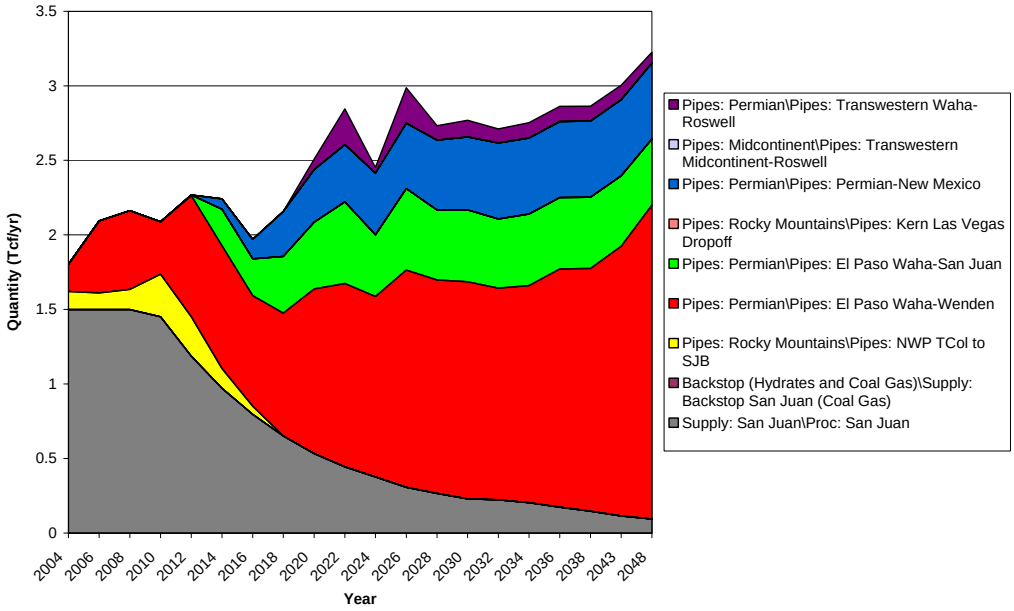


It is clear that the pipelines that traverse the tribal lands from the Permian basin (El Paso South, El Paso North, and Transwestern) are going to see strong and growing loads. Pipelines that traverse the tribal lands from the Rocky Mountains are going to see declining loads in southbound directions and prospectively some loads in northbound directions. It is also clear that LNG is becoming the primary source of supply throughout North America, precisely as has occurred with crude oil, and that is going to dramatically change pricing and loads in the gas business. That also is going to ensure that the tariff arising from the tribal ROW charges are going to have a negligible impact on market prices upstream, midstream, and downstream of those tariffs. Those tariffs at the proposed levels are minuscule, increasingly so, in the grand design of the North American gas business. The reason is that in markets such as California, the marginal source is going to be a local source, Canadian source, or Rockies source. LNG will be inframarginal. That is what the model runs are telling us.

What are the exports (outflows) from the Southwestern Pipeline system, and where are they going? The answer might be surprising at first blush, but Figure 10 presages exactly where that gas might be going. In particular, LNG is clearly coming from the Gulf Coast, proceeding through the Permian Basin, and heading for markets in the

Southwest and California. This is exactly what one might expect, particularly if California LNG is restricted in any way (as it is by assumption in the Altos base case). Figure 11 enumerates exports from the Southwestern pipeline system. The blue plus black plus gray plus red wedges in the diagram represent exports to California. Notice that they are growing. This means that LNG is increasingly landing in the Gulf of Mexico and being transmitted across Texas and across the traditional El Paso/TransWestern corridor to markets in California. If access to LNG ports were to be limited in California (as is assumed here), this is precisely what is going to happen in California. This assumption much more strongly underscores the value of the transit rights for El Paso and Transwestern than an assumption that more LNG will land in California. It also more strongly underscores that the $0.02/Mcf volumetric tariff assumed here for the tribal ROW charges is very much an upper bound because it is by construction in these cases volume dependent. (In the real world it might be a fixed annual fee so that it drops with increased volume.) This further underscores that we have safely overstated the tribal ROW charges so that our results certainly apply to the smaller charges that are anticipated to occur in real world markets.

Figure 10: Gas Imported into the Southwest Pipeline System (Base Case)



2.6 The Permian Basin

Let us proceed one level upstream to the Permian Basin of West Texas. What level of indigenous production is expected to occur there? What level of exports from the region to points West and North? What level of imports from points East. To begin, consider the projected indigenous production in the Permian Basin in the Altos Base Case depicted in Figure 12. Notice in the figure that indigenous Permian Basin gas is slated to drop continuously and inexorably throughout the foreseeable future after a rather sharp

near term escalation. There was a bit of uncertainty in the NPC resource and cost estimates for the Permian, and some observers viewed it as aggressive or optimistic. Rather than overriding the NPC assessment, which was bullish in the near term, we simply accepted it. That is why we see the near term spike in production. After the exhaustion of the initial low cost portion of the Permian resource base, there simply is not the magnitude of conventional gas resident within the basin according to the National Petroleum Council supply data base.

Figure 11: Exports from Southwestern Pipes (Base Case)

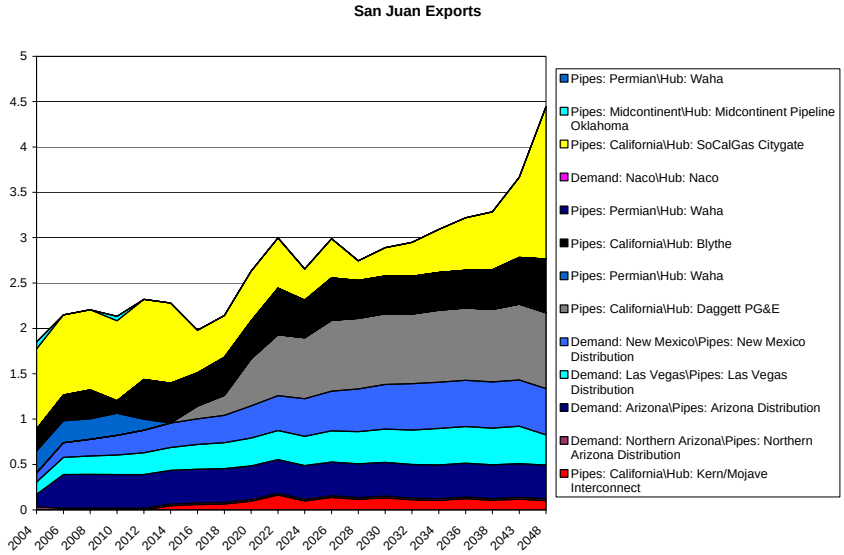
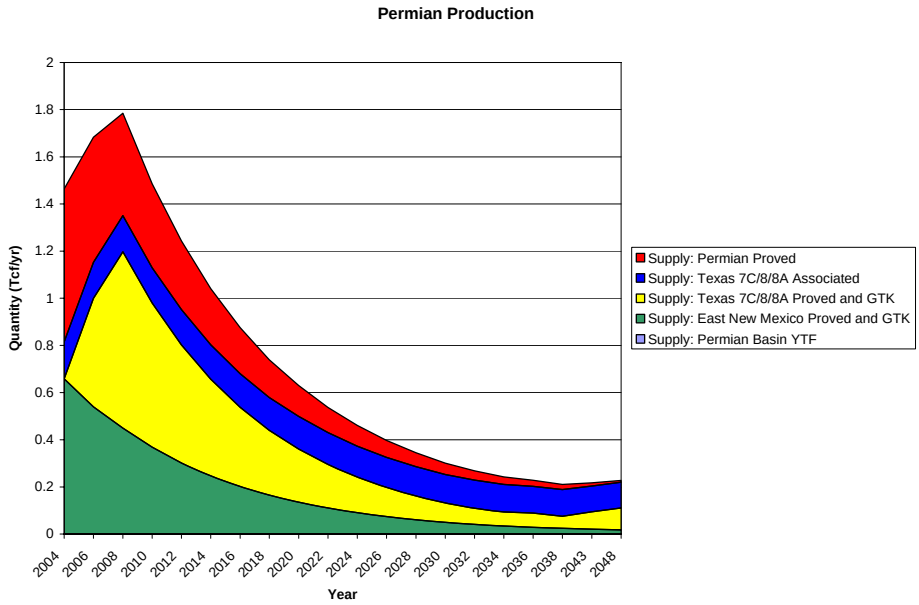


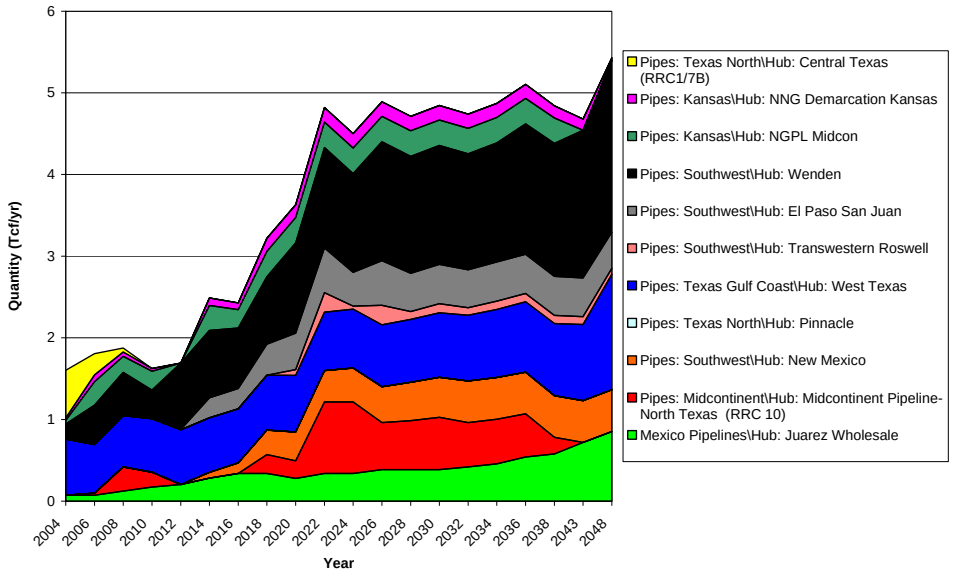
Figure 12: Indigenous Supply in the Permian Basin (Base Case)



Continuing with the Permian Basin, we turn to the issue of gas exported from the Permian Basin to contiguous regions. What contiguous regions receive how much gas from the Permian Basin? Figure 13 indicates that the Permian Basin exports a large and increasing quantity of gas to the west. The black and gray areas in the diagram represent exports to Arizona, New Mexico, and California through the El Paso and Transwestern corridors, the pipes that cross the tribal lands.

Where does the Permian Basin gas come from? The answer is obvious. It comes increasingly from the Texas Gulf Coast. It is indicated on the diagram as Teco and Valero gas, implying that it is delivered by a (rapidly growing) Texas intrastate natural gas pipeline system shipping westward from the Texas Gulf Coast. This is one of the starkest and more insightful results from the NPC study—the fact that the domestic resource base simply will not support historical levels of production at the prices that LNG can be landed and therefore that the domestic natural gas market is destined to become much more like oil than it has been in the past. (This is Altos' findings based directly on the data and conclusions of the NPC study.) The expression "becomes much more like oil" means that LNG becomes the main and growing source of gas supply in North America (just as imported crude oil is the main and growing source of supply in North America). Both are priced at their long run marginal cost on world markets.

Figure 13: Exports from the Permian Basin to Contiguous Regions (Base Case)

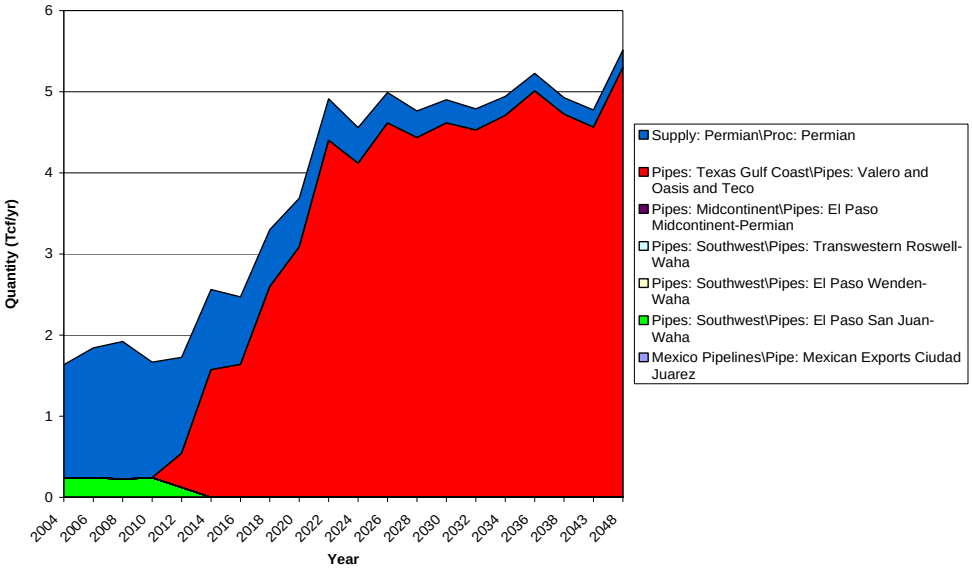


2.7 The Permian and the San Juan

To summarize, the San Juan basin is increasingly turning to continuous formations (e.g., coalbed methane and tight sands), whose incremental production costs are high and are increasingly going to have to compete with LNG. The Permian basin is turning to

smaller, deeper fields, whose incremental production costs are higher than today and higher than LNG. However, when those sources are exhausted (in the sense that their production cost rises to the landed cost of LNG netforward to the appropriate basins), they will endure sharp and strong competition from LNG. In short, Permian and San Juan gas are ultimately going to become decreasingly cost competitive relative to LNG. As we see in these figures, LNG is going to crowd out the higher cost portions of this resource base.

Figure 14: Imports to the Permian Basin (Base Case)



Volumes emanating in the greater San Juan basin and Permian base are going to be falling in the coming years. The foregoing graphs are clear. However, volumes emanating on the Texas Gulf Coast and flowing through the Permian and through the San Juan to California are going to increase in future years. The pipelines crossing tribal lands are going to experience large loads, and they are not going to be a big element of cost with or without the tribal ROW charges.

2.8 The Greater Texas Supply and Pipeline Market

Let us examine the magnitude of LNG imports into Texas. We have plotted the sources of gas in the Texas Gulf in the Altos base case in Figure 15. Notice that the magnitude of LNG imports in Texas is slated to increase. This gas not only serves the Texas market itself, but it also is exported from the Texas market to the West as we have seen. Increasingly, Texas becomes a landing point and source of LNG transfer westward to Arizona, New Mexico, California, and other points to the westward. This would change if we allowed by assumption California to be a large LNG importer. We did not believe that to be reasonable.

Figure 15: Sources of Gas in Texas Gulf (Base Case)

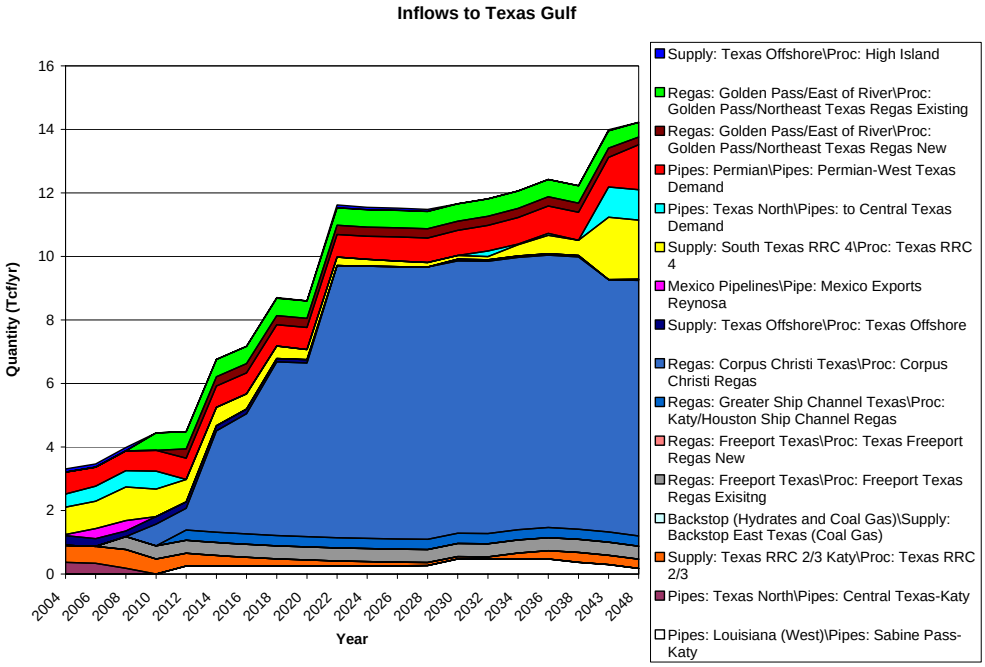


Figure 16: Indigenous Production of Natural Gas in Texas (Base Case)

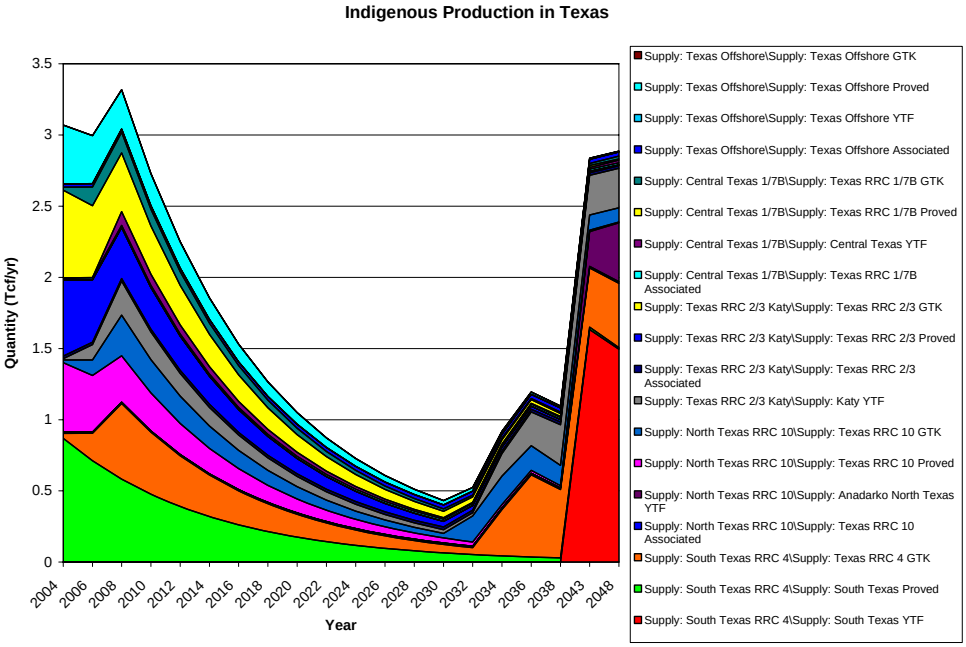
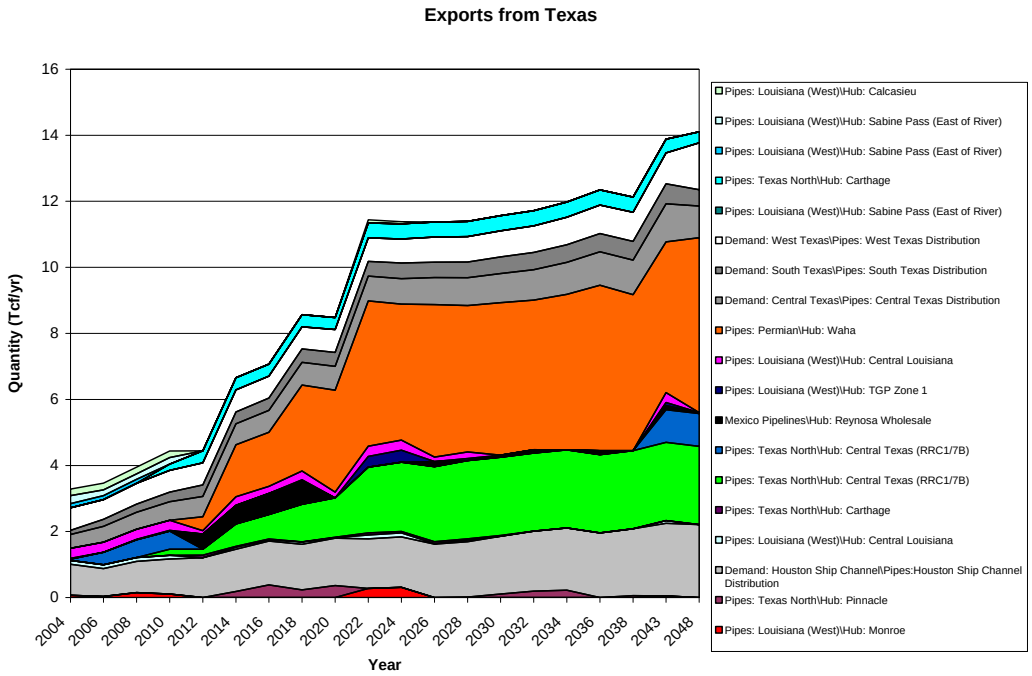


Figure 17: Exports of Gas from Texas (Base Case)



2.9 Rocky Mountains

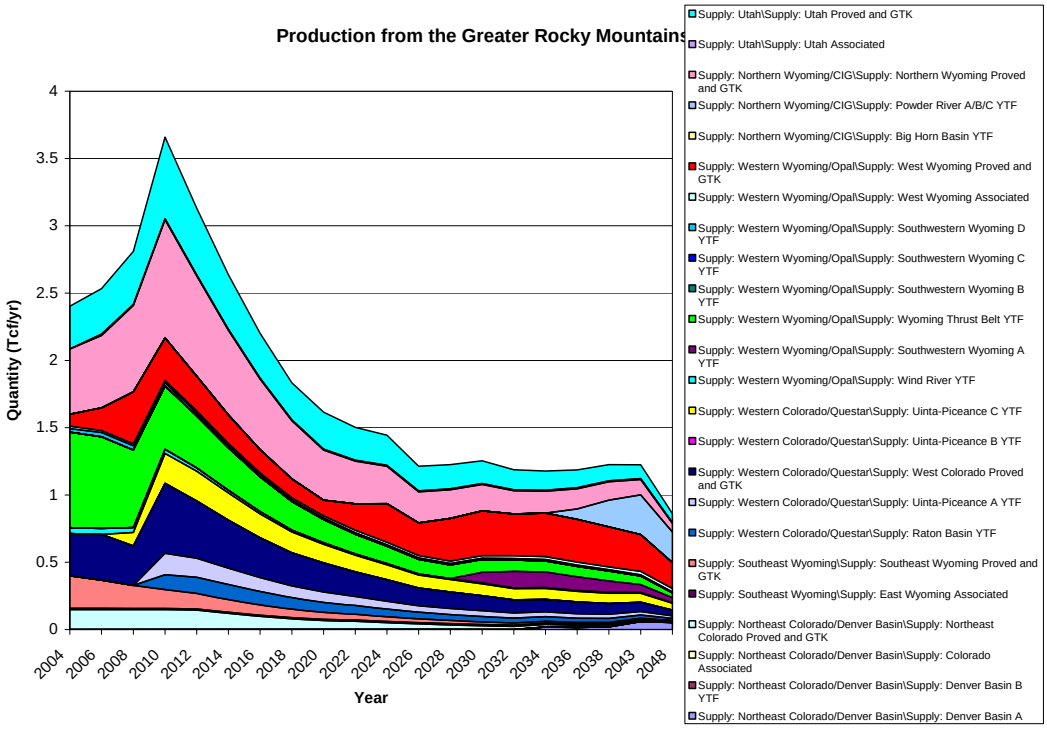
Natural gas from the Rocky Mountains has been argued in some quarters to be the messiah of the industry and the continent. This is neither correct nor reasonable. Rocky Mountain gas is going to spike, and then it is going to become increasingly strained. Notwithstanding hyperbole from certain segments of the market, there really is not a particularly large quantity of natural gas in the Rocky Mountains according to the NPC supply data base,[2] and access to support exploration and production is denied to a substantial portion of that gas because of Federal and/or state restrictions. Notice that indigenous Rocky Mountain production increases significantly for about eight years and then goes into decline as indicated by the top of Figure 18. This represents the quick access to and depletion of the indigenous Rocky Mountain resource base. There is little doubt that this is destined to occur. The only thing that could obviate this result is if the Federal or state governments restrict access to this resource even more severely than has happened today or historically.

If one were to carefully consider the diagram in Figure 18, one would begin to notice that the volume of conventional natural gas in discrete formations (the low cost gas) in the Rocky Mountains is increasing rather rapidly and then decreasing, being

[2] One need only reference the United States Geological Survey World Energy program to realize that the Rocky Mountains resource is not a world class resource, not by any stretch. It is a very, very modest resource by world standards.

replaced by continuous formation gas. One would expect the market price of natural gas in the Rocky Mountains to be increasing. We saw that to be the case.

Figure 18: Indigenous Natural Gas Production in the Rocky Mountains (Base Case)

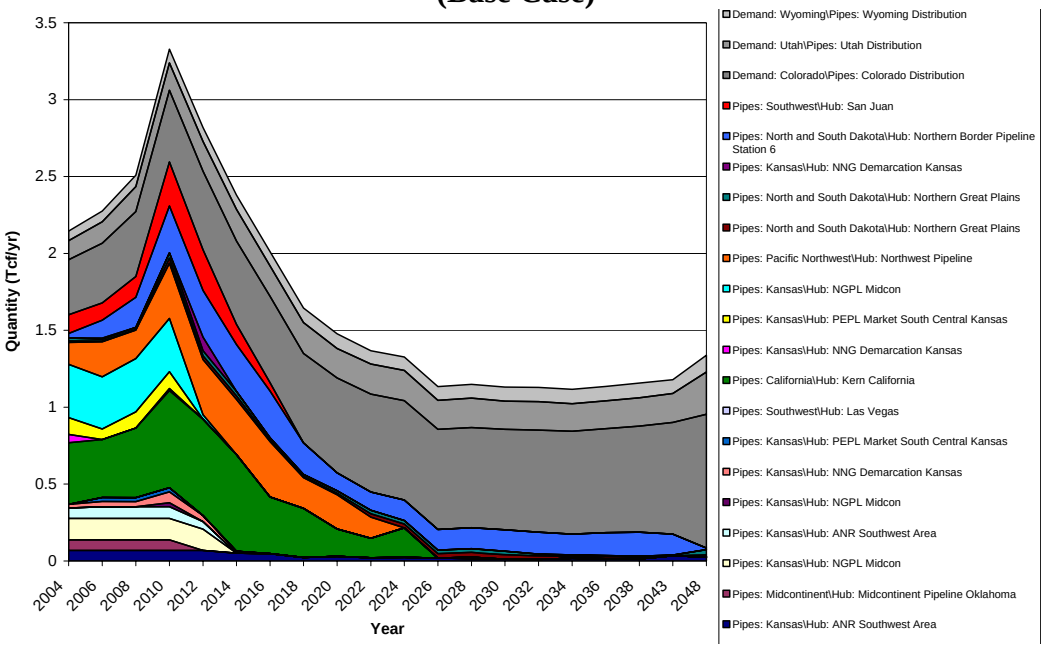


We should point out that this scenario assumes that the land availabilities assumed by the NPC will in fact occur in the future. This means that most of the gas in the Rocky Mountain region is or will be "in play" and available for production during the next ten or twenty years. In particular, of the approximately 150 Tcf of gas assessed to be present in the Rocky Mountains basins by the NPC (which is not particularly large when considered in the context of North American gas demand at almost 30 Tcf per year), access remains blocked to at least 65 Tcf of that gas by federal action and regulation in this case. If we blocked access to even more of this resource, we would have seen less peaking and a more rapid decline of Rocky Mountain production and the Rocky Mountain and directly downstream regions looking for LNG more quickly than occurs in the base case.

What is the destination of the from the Rocky Mountain producing regions? Is any of it going to or through the greater San Juan basin? The answer is a definitive no. Figure 19 illustrates the destinations of Rocky Mountain gas. The various shades of gray at the top of the diagram represent local, indigenous consumption in the Rocky Mountain region (e.g., the Utah, Colorado, and Wyoming indigenous demand regions). These regions are growing over time, and they take an increasing fraction of indigenous Rocky Mountain production over time. More interestingly, notice in the diagram that there are massive exports (the orange wedge) to the Pacific Northwest via Northwest pipeline and

large but decreasing exports to California (the green wedge) via the Kern River pipeline. The Rockies are the only viable competitor in the Pacific Northwest, but as we have already seen California can get Gulf Coast LNG via the traditional El Paso and Transwestern route.

Figure 19: Exports to Contiguous Regions from the Rocky Mountains (Base Case)



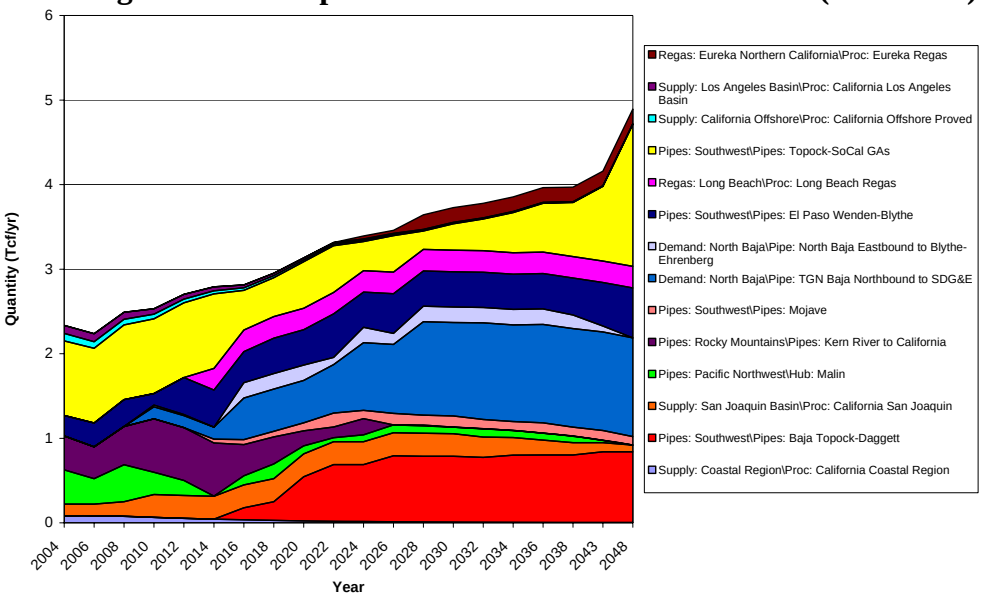
Interestingly, gas exports from the Rocky Mountains to the Midwestern United States have at most ten more years to run, and then they drop quite rapidly to zero. This is because Louisiana and Texas LNG become the more attractive source of supply (lower cost, more competitive). This is not an encouraging message for pipelines such as Trailblazer, CIG, Kinder Morgan, or El Paso's Continental pipeline that proceed eastward from the Rocky Mountains. The Altos base case indicates that movements will occur along that route for at most ten years. After that, they will have to be reversed if they are to move gas in the right direction. (We have not considered that in this case.) The market will not support the movement of gas from the Rockies eastward as LNG grows on the Gulf Coast, but it will support westward movement.

Notice further that the only quantity of Rocky Mountain gas that crosses anywhere near the greater San Juan/Four Corners region is the red wedge (TransColorado). This is not an important pipeline or pipeline load in the larger scheme. In a word, gas from the Rocky Mountains goes directly to final markets in the Pacific Northwest and California in the short and long term and the Midwest only in the short term. It does not go indirectly to those markets through the greater Four Corners or San Juan basins. That means the Rocky Mountains gas will not enter the tribal lands. Rocky Mountains gas is not an important issue in this consideration.

2.10 California Markets

From whence does California get its natural gas? This is an important consideration for this analysis, for it dictates in significant degree what will be the price of gas in California, the WECC, and in fact on the entire continent. The sources of gas in the California market are those depicted in Figure 20. In the near term, gas deliveries to major markets such as California come from the Rocky Mountains and Canada via direct routes that bypass the Four Corners/greater San Juan Basin altogether (e.g., Kern River and TCPL/PGT). Thereafter, gas into California comes primarily through the El Paso and Transwestern system, ultimately having been imported into the Texas Gulf. However, the marginal source into California is a Canadian, local, or Rockies source, not a Southwestern source.

Figure 20: Imports of Natural Gas into California (Base Case)

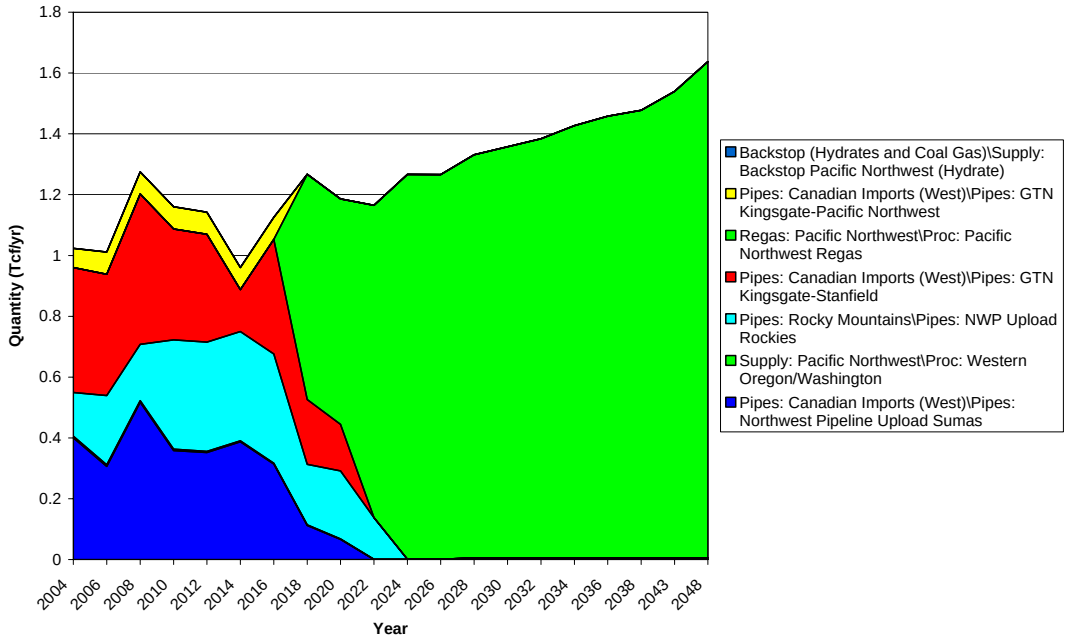


The California market has been the subject of discussion regarding tribal ROW costs. Let us consider the California market realistically. The California market is approximately 2-3 Tcf per year. At a modest price of only $5.00/Mcf, this is a $10 billion per year wholesale natural gas market. If the entire $32 million in annual tribal payments were ascribed to the California market, that would represent the fraction $32 million/$10 billion, which is the fraction 0.003 of that market or the percentage 0.2 percent (3/10 of 1 percent). If the entire tribal ROW cost were all suddenly "downloaded" to the California market (which will NOT occur for reasons we have already made clear), the entirety of the tribal ROW payment would represent a minuscule, indeed almost unmeasurable, impact on California market price. We emphasize that it is not appropriate to ascribe these costs to a single market, California or otherwise. The hypothetical discussion in this paragraph would be a tremendous overstatement. And yet it would imply at most a 3/10 of 1 percent impact on the market if totally concentrated there.

2.11 The Pacific Northwest

The Pacific Northwest is moving toward a much more dire situation than California. This has not been well understood by some in the industry. Because of the impending decline in Canadian and Rockies gas and because of the paucity of other sources, the Pacific Northwest can be expected to be 100 percent reliant on LNG in the long term. The prices in the Pacific Northwest are going to rise to the point at which that occurs. If the prices did NOT rise to the point at which that occurs, the Pacific Northwest would experience chronic and widespread shortages. That will not happen; the price will rise to the point at which the market is met.

Figure 21: Sources of Gas into the Pacific Northwest (Base Case)



Rather than focusing on just California, let us consider that the WECC gas market is headed toward a level of perhaps 7 Tcf/yr. This means that the comments made for California are diluted in the WECC market by a factor of 2/7 (representing the prorating of the WECC market relative to the California market). It is not credible to argue that tribal ROW charges has any measurable effect whatsoever on any WECC, California, or national market prices.

3 WHAT IS THE BOTTOM LINE?

The bottom line is that pipeline companies are is proposing to directly conscript dollars from the tribes by denying them their ROW charges. To do so is a naked, overt dollar grab by the pipelines. We have shown that there is absolutely zero impact on any

downstream market with or without these ROW charges. These ROW charges have absolutely zero impact on any downstream market—zero. There is no consumer impact whatsoever from the tribal ROW charges. Quite the contrary, the issue of ROW charges is strictly a zero sum game between the pipelines and the tribes. It would absolutely not be correct to argue that the payment by pipelines Paso to the tribes for transmission rights imposes any harm in the form of a price increase on any gas customers anywhere. That will NOT happen. The price will be invariant to any ROW charges of the levels considered here. The NPC-Altos model clearly demonstrates that, and the economic methodological argument tells you definitively why. The payment to the tribes by the pipelines is by analogy no more important than "the rabbit in the elephant stew." You simply cannot taste the rabbit in the elephant stew. Any proposal by the pipelines to withhold tribal ROW payments is no more than a direct money grab by the pipelines away from the tribes. No third party is affected in any way. In reality, they are not parties to the consideration of ROW charges at all.

TECHNICAL APPENDIX: IMPACTS ON NATURAL GAS MARKETS OF CHARGES ASSESSED FOR TRIBAL RIGHTS-OF-WAY IN THE SOUTHWESTERN UNITED STATES

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May 13, 2006

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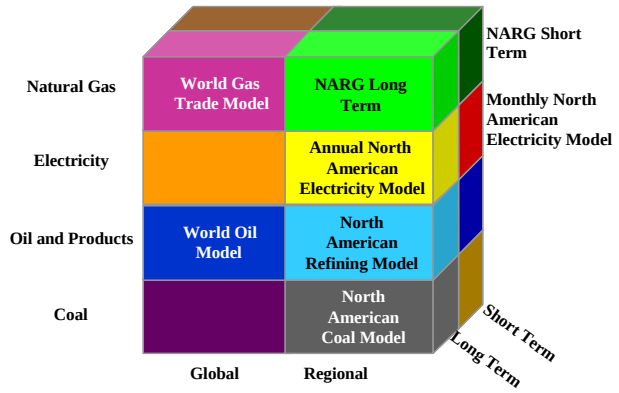
1 ANALYTICAL APPROACH AND RESULTS

1.1 Altos Brings Fully Integrated Assessment Among Disparate Energy Forms

There is no way to understand the impact of ROW charges on price without formalized technical and data elements and without a fully valid and verifiable, automated approach—ergo a model (or more to the point a modeling **system**). Relying on a simple or simplistic model (e.g., a linear programming or a production simulation model) or even worse subjective judgment, retainer consultancy services, or advocacy testimony by consultancies would get the right answer randomly at best. At the very best, such methods are usually mere advocacy for a self-interested point of view.

Altos has been able to provide market impact assessments that are fully integrated, spanning world and North American natural gas, world and North American crude oil, North American refined products, North American coal, and tradable North American emissions allowances including SOx, NOx, Hg, and CO_2. The Altos product line, fully supported by data and fully operational within a single, world class, user friendly, common economic modeling system, gives a dimension of experience and methodology as illustrated in Figure 1. We have used the Altos North American Regional Gas (NARG) Model for this assessment, supplemented by inputs from the National Petroleum Council supplemental modeling and supply groups and the Altos World Gas Trade Model. We have also used the Altos North American Regional Electricity (NARE) model in concert with the North American tradable emissions model to calculate the gas burn for power generation in North America.

Figure 1: Altos Offers a Complete Interconnected Suite



The remainder of this section discusses the individual elements of the suite, beginning with the simplest and moving to the more complex and more integrated. The objective is to establish the comprehensiveness and correctness of the approach and the data and why the results we have obtained are what they are.

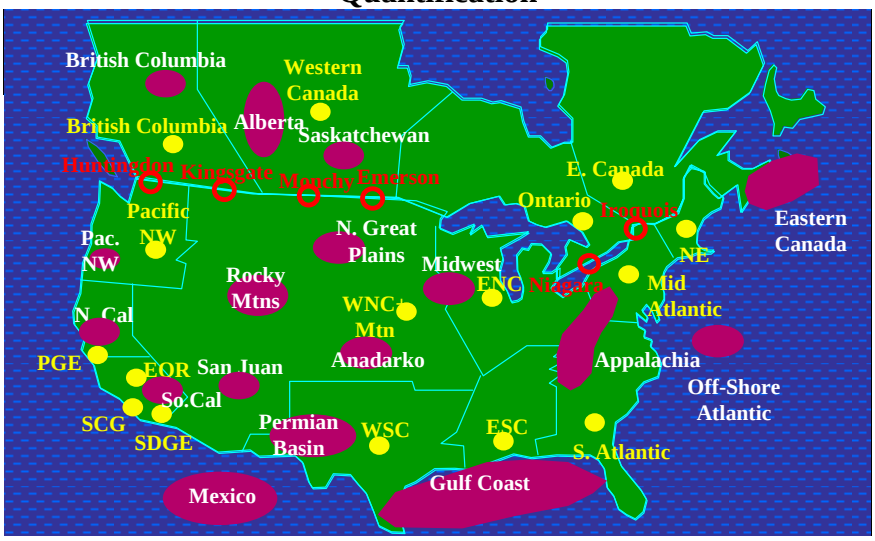
1.2 North American Regional Gas (NARG) Model

The Altos NARG model is implemented in two time frames

- Short Run Version (typically 48 months forward in 1 month intervals).
- Long Run Version (40 years forward in annual and biennial intervals).

We have used the long run version for this evaluation. The NARG model was selected by the Supplemental Modeling team of the National Petroleum Council (NPC) for its very well known 2003 study.[1] (Altos Management Partners is referenced on page 3 of that report.) In our judgment, the NPC supply, pipeline, and demand data are the best and most knowledgeable available in the industry, and they are available through Altos under license to the NPC. (The last section of this appendix is the NPC license documentation. That section is a verbatim reproduction of the NPC's own document characterizing that model and data. That section is not an Altos document—it is an NPC document—and it is incorporated hereto by reference.) Altos has collaborated with the USGS on the supply data and with Dr. Kenneth Medlock formerly an employee of El Paso during the NPC study and now with Rice University. Dr. Medlock did the modeling on that project and put together all the demand data. All the data used in this assessment are fully transportable, visible, and reviewable under license to Altos. The Altos NARG is pictured in iconic form in Figure 2.

Figure 2: The Altos NARG Model Is Used for This Market Impact Quantification



[1] Altos Management Partners Inc. in no way represents nor speaks for the NPC or any of its members nor has any authorization to do so. Altos results and findings are solely and exclusively its own results and findings and cannot and should not be attributed to the NPC or any of its members.

1.3 How NARG Represents North American Natural Gas Markets

NARG simulates how regional interactions among supply, transportation, and demand interact to determine market clearing prices, flowing volumes, reserve additions, and new pipeline entry and exit throughout the North American market. The geographic scope of the NARG model is shown iconically in Figure 2. In the long-run version used for this evaluation, NARG represents a forward time horizon of forty years. (The short run version, which represents month-by-month a forward time span of 60 months) takes into account storage injection and withdrawal as well as supply, transportation, and demand. NARG has been in continuous existence and use since 1983 and has been used for most major pipeline expansion decisions and most of the resource basin profitability evaluations in North America since that time. It was used in the landmark National Petroleum Council 2003 study on natural gas, to which El Paso contributed directly. It has an accurate track record largely because of its structure and approach, which are scrupulously based on graduate textbook economic theory of competitive markets for depletable resources, commodities, transportation and other assets in spatially distributed markets systems.

The NARG quantifies a number of important properties of the North American gas markets, which are summarized in the forthcoming couple of sections.

1.3.1.1 Price Lies at the Heart of the Question of Market Impacts of Tribal Payments, and NARG Focuses on Price

Economics is the science of price. Fundamental microeconomics is the science of price. Price is the OUTPUT of an economic model, not an input, not a byproduct, and certainly not the product of subjective guesswork or "netback" calculations. Price is a difficult attribute of the energy system to quantify, not to be trifled or subjectively guessed nor statistically estimated. The issues at stake here underscore the need for predicting price under alternative transmission cost treatments, and this implies the need for a truly economic approach and perspective on regional gas markets throughout North America.

In a nutshell, we have quantified and understood the degree to which nodal/local prices and national prices will be affect by changes in transportation cost that might result from payment of ROW charges for pipes that cross tribal lands. To wit, we have calculated the impact on market price everywhere in response to a change in ROW charges on pipes that emanate from or cross tribal lands in the Southwestern United States. The need to make such calculations cannot reliably be met by models or methods based on production simulation, linear programming, nonlinear programming, subjective guesswork, statistical extrapolation, or system dynamics approaches, for such models are NOT economic models and are therefore NOT capable of quantifying price. For example, "shadow price" from such models is not price. System lambda from such models is not price. System lambda plus some sort of "adder" is not price. None of these

ad hoc substitutes is price. Price is the current and future point at which a regionally and spatially interconnected set of supply and demand curves cross each other, no more, no less. That is what the NARG model brings—an accurate way to understand and project price and basis and to project capacity additions, production, and retirements that go right along with those prices and bases and to understand quantitatively how much impact will result in various nodal and national markets as a result of tribal ROW charges.

1.3.1.2 Gas Markets Are Tightly Interconnected

The gas events of the past decades have underscored just how **INTERCONNECTED** the North American natural gas system is on a continent-wide basis. No longer do energy decision makers doubt that the price system—spot prices, contract prices, futures prices, over-the counter forward prices, and ancillary "hub" service prices—inter-link economic events in such disparate locations as Northern California, the Pacific Northwest, Alberta, the Rocky Mountains, the San Juan, the Permian, the Anadarko, the Gulf of Mexico, Sabine, Corpus Christi, Everett, and elsewhere. Methane may not travel at the speed of light, but prices virtually do. If one is to truly understand the market for San Juan, Permian, or other gas north, south, east, and west of that location, one must individually understand each of the interconnected elements of the North American gas system and the specific linkages and interactions among them. To do so, one must put those details together into an integrated whole.

In representing and understanding the interconnectedness of the gas business, it is not OK to rely on a simple spreadsheet calculation, an enumeration of pipeline alternatives, or a non-equilibrium modeling technology. It is not sufficient to do an accounting of deliverability or pipeline capacity on a monthly basis and expect to learn anything substantive. It is not correct to argue that transit tariffs are automatically passed on to customers in the form of higher prices. That completely misses the reorientation of North American gas markets that occurs when ROW charges change. Quite the contrary, one needs to represent how each and every supply basin and LNG import location through each and every pipeline competes in each and every market over time and how the price of gas forms and changes in each and every such market over time as a result. One needs to solve the complete "combinatorial problem" of gas supplies and pipelines in every market in North America. To understand markets as interconnected and intertwined as North American gas markets requires a simultaneous solution concept, one that simultaneously competes everything against everything else everywhere and considers the indirect and direct effects of such competition everywhere. It is not acceptable to represent only some of the existing and prospective competition. This is what we believe the NPC supplemental modeling team was thinking when they used NARG.

The NARG modeling technology recognizes that there is a zero sum aspect to natural gas importation, production, and transmission—for anyone to win, someone else must lose. This is the intrinsic nature of commodity and service markets; they are

fiercely competitive and zero sum by nature. The availability of additional gas commodity does not mean more market. On the contrary, it means more competition for the same fixed market. NARG recognizes and carefully balances the interests of the various competing parties and represents the zero sum nature of the North American gas business.

1.3.1.3 Interconnectedness Requires that We Understand Price Differentials Throughout the Entire Continent--Understanding Gas Volumes Alone is Not Enough

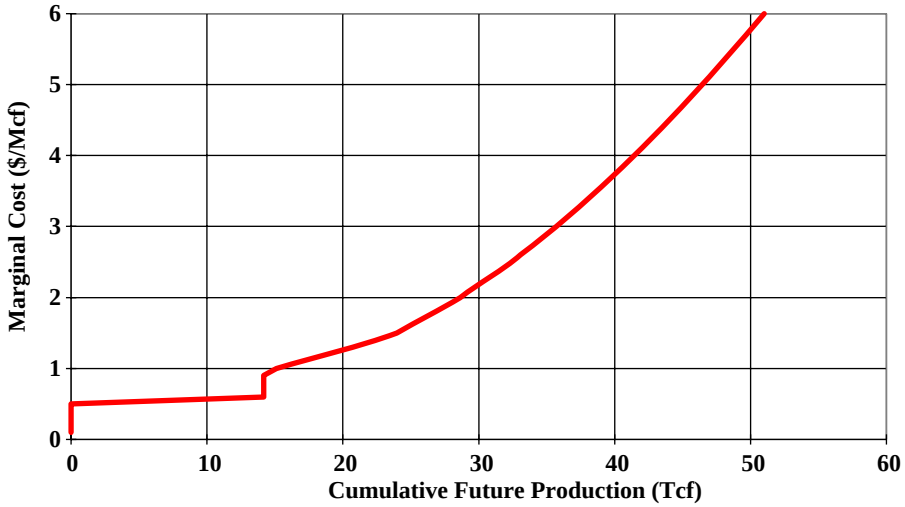
In achieving the market understanding one needs, the foremost issue is not whether there are sufficient gas volumes entrapped in sediments, coal beds, tight formations, or conventional formations in the Gulf Coast, Rockies, Permian, San Juan, or any other region or whether there are sufficient imports. The issue is not whether there is enough gas in the ground to sustain volumes for a pipeline emanating from that region or to serve markets from that region. If the mere existence of large upstream volumes were sufficient, we would have seen the Alaska Pipeline completed and entering the market a long time ago! (There are at least 35 Tcf entrapped in the Prudhoe gas cap and neighboring formations and 100 Tcf or more in the immediately contiguous regions.) We would have seen Canadian polar pipelines, the Sable Island pipeline, Alliance, and Altamont long ago. We would have seen pipelines from Qatar and the rest of the Middle East to Europe, pipelines from Mexico to the United States, and the Sakhalin pipeline from Russia to Japan. The mere existence of gas means nothing. It is the downstream competitiveness of that gas that matters. This is what NARG quantifies. That is one of the key issues here.

An important issue is whether the cost of gas in a given region is low enough so that when all the pipeline export costs from the producing region are added to the gas cost, the gas-plus-export cost will be competitive in the downstream markets it aspires to serve. Can an aspiring export region meet or beat the market price in the downstream regions it aspires to serve? <u>The pipeline question is a question of prices and price differentials, not a question of gas volumes.</u> We have framed the LNG problem in terms of market prices as well as volumes, not simply the magnitude of gas import capacity or infrastructure capacity. We have framed the tribal transit problem in terms of market prices and basis as well as volumes.

To understand the relationship between prices and quantities, we have found it particularly convenient to assemble a comprehensive collection of resource price-quantity supply curves to characterize the gas resource in every producing region of the continent. Figure 1 illustrates a NARG price-quantity supply curve (for the Rocky Mountain shallow conventional portion of the North American resource base). A complete set of supply curves, one for every increment of resource in every producing basin, is contained in the model and has been used for this analysis. These curves are based on the NPC 2003 Continental resource assessment as supplemented by the ongoing assessments by

the United State Geological Survey. They are available under license agreement from Altos and the NPC.

Figure 3: Rocky Mountain Supply



We should mention that in supply curves of the form in Figure 3 that the flat shelf-like at the lower left corresponds to presently proved reserves. Such proved reserves can be produced to market at variable operating cost; most or all fixed costs have already been expended and sunk. Once currently proved reserves are expended, producers are relegated to bear full incremental finding costs including capital and operating costs. The stairstep jump in the curve represents the fact that the incremental finding cost of the next Mcf above and beyond today's proved reserves will require capital and operating cost and will entail a "jump" in full cycle production cost. The upward tilting portion of the supply curve to the right of the stairstep corresponding to proved reserves represents the undiscovered resource base. The curve in aggregate represents the volume and the cost of the entire resource base, disaggregated by type of resource and by producing basin. Collectively, these disaggregated resource supply curves characterize the resource base basin by basin in North America.

1.3.1.4 NARG Explains and Predicts How and Why Gas Flows from Low Priced Regions to High Priced Regions and What Such Flow Implies

The North American natural gas system has become an example of supply-demand economics at work, with market prices and market prices alone dictating where gas volumes flow to and flow from. In the competitive gas market of today and of the future, gas flows from lower priced areas to higher priced areas (and not the reverse). Furthermore, such flows occur only when the difference between the high priced area and the low priced area is sufficiently large to cover all the variable costs of a pre-existing pipeline and all the fixed plus variable costs for a yet-to-be-built "greenfield" pipeline. Gas flow does not magically create price differentials in the market. Quite the contrary,

it is the price differential that creates the gas flow. This is the unique perspective embedded in NARG; gas flows in response to market price differentials and never otherwise. NARG projects gas prices and price differentials throughout the North American gas system under as many future scenarios we might like. By so doing, we are able to identify all pipeline routes, both prospective and existing, that are destined to experience positive gas flows and at the same time all pipeline routes that are destined to cease flowing or never begin to flow in the first place. We are able to posit alternative LNG regasification capacity scenarios. We are able to identify all producing basins that will produce and sell gas and all producing basins that will not. We are able to postulate alternative tribal ROW charges, and that is precisely what we have done here.

1.4 World Gas Trade Model (WGTM)

Altos has what we understand to be the only operational world natural gas model in the industry—the WGTM model. The WGTM is offered only as a long run model. Specifically, it has a 40 year forward horizon in the same multiennial intervals as the NARG model. For this evaluation, WGTM is fully and completely and tightly integrated and interconnected with NARG (in particular with the version of NARG selected by the NPC for its 2003 study). That means that North America and the world are run in simultaneous, fully iterated, fully interconnected lockstep, meaning in turn that the world depends on North America and North America depends on the world. This is a uniquely powerful capability, and it brings unique accuracy to the evaluation. We have seen how important LNG is to the North American gas market and to this evaluation.

The Altos worldwide supply, pipeline, LNG, and demand data are believed to be the best available in the industry, and they are exclusively available through Altos. Altos has collaborated with the USGS on the supply data worldwide (every assessment unit in the world). WGTM is pictured in iconic form in Figure 4, and its connection to and integration with NARG is noted. In particular, we have inserted the NARG model built by Dr. Kenneth Medlock as an El Paso employee working on the NPC project and several other industry people working on the NPC project into the Altos World Gas Trade Model.

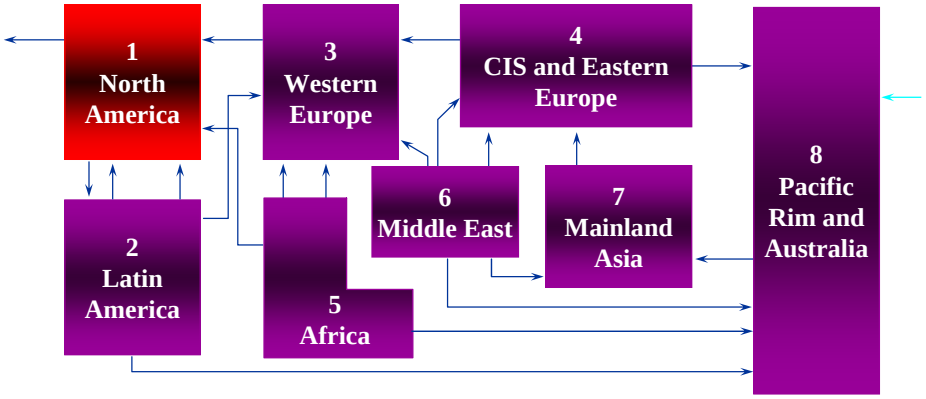
WGTM, which was initially built on a multiclient program in 1990, simulates how regional interactions among supply, transportation, and demand interact to determine market clearing prices, flowing volumes, reserve additions, and pipeline entry and exit through 2040. The WGTM divides the world into major geographic regions that are connected by marine freight and on occasion by pipeline. Within each major region are very detailed representations of all market elements: production, liquefaction, transportation, market hubs, regasification and demand by country or sub area. All significant existing and prospective trade routes, LNG liquefaction plants, LNG regasification plants and LNG terminals are represented. Competition with oil and coal is modeled in each region. The ability to model the related markets for emission credits and how these may impact LNG markets is included. The model represents this detail in a

total of 421 regional diagrams: 9 world LNG shipping regions, 22 liquefaction regions, 15 regasification regions, 33 pipeline regions, 169 supply regions and 173 demand regions. Each regional diagram describes how market elements interact internally and with other regions. These contain

- 441 elastic demand nodes
- 3 inelastic demand nodes
- 1010 market hubs
- 1615 transportation nodes
- 438 supply nodes
- 74 exogenous supply nodes

for a grand total of 3581 nodes and 4297 links. This is a model of quite substantial size and granularity. (Numbers of nodes and links correct to within a couple of percent.)

Figure 4: Altos Has Embedded NPC NARG into the Altos World Gas Trade Model



The World Gas Trade model is equipped with the latest supply information we could find via Altos' collaboration with the United States Geological Survey World Energy Program and Altos' proprietary depletable resource model. In particular, Altos has used the field size and depth distributions assembled under the USGS World Energy Program as the fundamental basis for our gas supply curves. The country by country world demand forecasts are taken from the International Energy Agency, who updates them approximately annually. The gathering-liquefaction-shipping, regasification infrastructure estimates are estimated and updated annually. Using this vertically and horizontally model of world gas, we perform sophisticated studies to simulate the effect of an array of factors that can impact world gas demand: price, GNP, weather, lag and other phenomena.

The world gas trade model has been used to address the following world gas questions:

1.) **PRODUCTION.** In every producing basin in the world

- What is the fair market value, i.e., the price, of gas and how will it evolve into the future?

- What volume of gas will the market absorb at that price? What is the size of the gas market seen by each producing basin worldwide?

- How much of the market will be dedicated to local use, overland pipelines, and LNG? Where will the gas go?

- What will the production cost be? As producing basins are exploited, what will be the time schedule of production cost? We have answered this question in part using the USGS World Energy Program assessment.

- What will the profits (price minus production cost) be?

- How will profits differ among alternative producing regions or prospects? Which producing basins offer the highest profit potential?

- How much will profits differ between existing and incremental new facilities?

- How much are reserves in the ground, producing assets, and acreage worth? If a company were to purchase reserves, what is the maximum amount it should be willing to pay? If a company were to sell reserves, what is the minimum amount it should be willing to accept?

- How should a producer comprise his portfolio of gas producing assets? What particular combination of assets should a producer assemble, and how should he measure their risk-return characteristics?

- With regard to capital budgeting of exploration, toward what regions of the world should those capital budgets be directed? Is there more return on an investment in Indonesia or Russia? If investment is chased out of North America, where is the best place in the rest of the world to implement it? Is it better to "get cheaper in existing areas" or "move into new areas?"

- Is it a good idea to integrate downstream, building gathering and pipeline infrastructure along with upstream infrastructure? Is there any intrinsic profitability in gathering and transportation infrastructure, or is all the profit upstream?

2.) **MARKETS.** For each existing and prospective producing region around the world

- What is the "natural market" for gas leaving each particular world region, i.e., toward which market will the gas gravitate? To what region will it be transported? At what volumes? This is a critically important question, for it gives proper strategic direction to your marketing department.

- What price will be received in each nodal market worldwide?

- What are the competing sources in each market and how will they affect gas price?

- What is the fair market value of gas (i.e., the price) at each existing and prospective import point in the industrialized countries (the United States, Canada, Japan, Taiwan, Korea, Europe)?

- How much gas will be imported at that price?

- Are there bottlenecks that preclude access to certain markets? If so, what is their effect?

3.) **TRANSPORTATION VOLUMES, ROUTES, AND MARGINS.** Where is gas likely to flow regionally and worldwide? What are the economically viable "from's" and "to's" in the Atlantic rim, the Pacific rim, and elsewhere and how will they evolve over time?

- What margins are available to transporters along these and other (noncompetitive) routes?

- What will be the transportation value along each route and in aggregate over all routes?

- How much shipping capacity will be required and when?

- How will it grow over time?

- Where will it be dispatched, Pacific or Atlantic?

- Are shipping margins large enough to sustain incremental new tankers in both the Atlantic or Pacific, or will tankers be commissioned in the Pacific and later dispatched to the Atlantic?

- When and how much incremental new shipping will be economic?

- Where will bottlenecks occur, and how much profit potential do bottlenecks offer?

4.) **HOW ARE GAS AND OIL PRICES RELATED?** What are future oil prices likely to be?

- Under what conditions (if any) will gas and oil prices be coupled? Independent?
- Will gas-on-gas competition in domestic markets
  - Drive the fair market value of gas at LNG import terminals below the price of oil?
  - Compress LNG prices and margins to producers?
- How profitable will oil be relative to gas? Should producers continue to search for oil, viewing gas as a byproduct, of should producers actively seek gas in certain regions?
- Are gas contracts indexed to oil price credible, sustainable, enforceable contracts that will be maintained? Conversely, are they out of kilter with the market to such a degree that they will be obviated?

5.) **PROSPECTS FOR LNG IN UNITED STATES MARKETS.** What is the fair market value of gas at each existing and prospective import terminal?

- How much gas will be absorbed at each and over what period of time?
- If producers were to offer a different price (i.e., a subsidy or an incentive)
  - How much volume would they sell?
  - How much revenue would they earn?
  - How much cost would they bear?
  - How much profit would they make?
- When if ever will existing facilities operate at capacity?
- When if ever will incremental new capacity be profitable?
- What domestic source will be displaced by LNG at each import terminal? On each and every overland pipeline:
- How much infrastructure from the seacoasts to the markets (that does not exist now) be required? What will its cost be? What will be the basis differential in the market across that infrastructure?
- What level of government policy or incentives would be expected or justified?

- How important are issues such as regional and national demand growth, new technology, and other domestic considerations?

6.) **PROSPECTS FOR LNG IN EUROPE.** What is the fair market value of gas at each existing and prospective import point?

- How much gas will be absorbed at each?

- If producers offer a different price

  - How much volume would they sell?
  - How much revenue would they earn?
  - How much cost would they bear?
  - How much profit would they make?

- When if ever will existing facilities operate at capacity?

- When if ever will incremental new capacity be profitable?

- What source will be displaced by LNG at each European import terminal?

  - Russian gas
  - Algerian gas
  - Indigenous Continental European and North Sea gas
  - Norwegian gas
  - United Kingdom gas

- Does LNG from far away places such as Qatar, Nigeria, or Latin America make sense economically in Europe?

- How will emerging free trade change gas markets and prospects for pipeline and LNG imports? What if pipelines offer universal open access?

- Will European markets become more competitive and more tightly controlled by a few players?

- What policy, incentives, restrictions, or protectionist measures might be implemented and how might they affect the gas business?

7.) **PROSPECTS FOR LNG IN JAPAN AND KOREA.** What is the fair market value of gas at each existing and prospective import point?

- How much gas will be absorbed at each?

- If producers offer a different price?

- How much volume would they sell?

  - How much revenue would they earn?
  - How much cost would they bear?
  - How much profit would they make?

- To what extent would gas imports compete with nuclear, electric, or other Japanese policy initiatives?

- To what extent does or will Japan exert monopsony power over existing and prospective LNG providers?

- When will present capacity be fully utilized?

- What profit margins will be realized on present capacity?

- When and where will new capacity be economic?

- What margins will be available to incremental new investors in each producing and consuming region?

- What schedule of investment should support industries plan for

- Does LNG from far away places such as Qatar or Alaska really have a chance in Japan, or is Japan better off to buy from more contiguous locations such as Indonesia, Malaysia, or Australia?

- What policy, incentives, restrictions, or protectionist measures might be implemented and how might they affect the gas business?

8.) **REALISTICALLY SUSTAINABLE GOVERNMENT POLICY.** There is a tremendous amount of misinformation regarding the inherent sustainability of various prospective government actions. In particular, people frequently assume that certain government actions will be pursued in spite of the fact that they might never be sustainable in the market. People systematically ignore "Laffer curve" effects. Laffer curve effects occur when a government take becomes so large as to suppress overall economic activity and thereby to reduce rather than increase revenues to the government.

- What will be the true market consequences of various "government takes" such as lease bonus payments, percent of sales royalties, Btu taxes, production sharing arrangements, or transfer of property rights after some prespecified number of years?

- How much direct and/or opportunity cost is inherent in producer government subsidies and incentives?

- What does nationalization such as has occurred in Venezuela and Bolivia imply for LNG supply and export?

- What magnitude of producer government subsidy is truly sustainable?

- What would various subsidy or rent expropriation actions mean in terms of debt service or deadweight economic (e.g., GNP) loss?

- Would credit constraints become binding?

- Would producer governments (e.g., Mexico) be expected to modify export or foreign ownership policy? When? Would such modification be credible to multinational producers?

- Would consumer governments be expected to levy import tariffs, consumption taxes, or other security and trade balance measures?

- How much would coordinated consumer strategies truly cost? Could they be realistically sustainable?

1.5 Brief Technical Overview of the MarketBuilder Methodology that Underlies NARG and WGTM

We believe that the North American Regional Gas (NARG) model and the World Gas Trade Model (WGTM) and the software tradenamed MarketBuilder within which they are implemented are the only models locational (nodal) prices simultaneously, correctly, and consistently with the behavior of a collection of disparate goal seeking economic agents that collectively comprise a market. This is the notion of a market as taught in all respectable graduate schools in the world. Keep in mind, within MarketBuilder as well as within the real world, nodal prices are inherently dynamic—they are intrinsically and inherently a forward/future price. Any notion that located nodal prices are not full forward price schedules is patently incorrect. (Serial, static prices for example have no justification.) Located nodal prices are intrinsically both current and forward in nature. In the real world as well as the model world, located nodal prices must satisfy the zero arbitrage condition over time and over space or else they cannot possibly be valid. It must not be possible to borrow and lend money to or from a “bank” (as represented by whatever discount rate you might assume) and beat the model solution; yet models other than MarketBuilder allow exactly that to occur in their solutions. A correct model must not have arbitrary or systematically “dumb” forecasts of future located nodal prices; otherwise it is wrong. It must be a rational expectations model. A correct model must calculate the "fair market value" of congestion by calculating a zero

arbitrage price at the upstream end of each transportation link and a zero arbitrage price at the downstream end of each transportation link, taking full account of transmission capability limitations and generation capability limitations. MarketBuilder does so.

That is precisely the solution MarketBuilder calculates—zero arbitrage over time and over space across the production, generation, transmission, consumption, and distribution assets throughout the market. It has the full energy solution embedded within it—prices and capacity additions as well as volumes. MarketBuilder embeds the correct definition of market prices and locational prices (nodal prices)—zero arbitrage over all time dimensions and over all spatial dimensions, i.e., all nodal locations. MarketBuilder gives a dynamic rational expectations solution (the only model that does so as far as we know). As far as we know, MarketBuilder is the only modeling technology consistent with accepted decentralized multiagent microeconomic theory that embeds within it as a coproduct the energy flow physical solution.

1.6 Does MarketBuilder Honor the Physical Flow Equations, Does It Honor "Chemistry and Physics?"

The following statement may sound heretical, but it is true: Chemistry and physics are part of economics. Chemistry and physics are embedded in the production relationships embedded in our economic models. MarketBuilder balances commodity inflows and outflows at every hub in the entire network and at every node (i.e., every plant or pipe) in the entire network. To wit, it balances inflows and outflows at every node in the network and thereby honors the first law of thermodynamics (energy conservation). In addition, it represents the physical and chemical processes that happen within each asset in the energy system—each power plant, each gas pipeline, each power line, each compressor station, each end use consumption process. It honors the second law of thermodynamics by postulating thermal efficiencies strictly less than 100 percent for each of those processes. To summarize, it honors energy conservation at junctions and hydrological flow loss and loss factors along pipelines. It honors thermal efficiency losses (heat rates) in pipeline compression. Conservation of energy and mass and the second law of thermodynamics are a simple and direct byproduct of MarketBuilder, deeply embedded within the calculation.

There can be no confusion on this point. It is occasionally argued that "economics is too trivial to solve physical energy and material balance equations." That is simply not true. If one posits a production function for each process and material and energy balances at each node in an economic model, one embeds the first and second laws of thermodynamics as a byproduct. MarketBuilder does that.

1.7 How Do You Know MarketBuilder Is Right?

It is important to emphasize the structure and features of MarketBuilder. We emphasize first and foremost that economics is not an "art," it is a science. Major universities give Ph.D. degrees in mathematical economics, and they only teach microeconomics one way out of one set of textbooks with one set of methodologies and one approach, and they teach that there is only one methodologically correct way to solve market and physical flow problems. There is no question or equivocation about that. They give oral and written qualifying Ph.D. examinations from one methodology taken from one set of graduate economics textbooks, and everybody knows precisely where to find those textbooks. There is no judgment, "art," arbitrariness, or creativity in mathematical economics. Economics is a cold, hard, rational, systematic, explicit, quantitative science. The state-of-the-art graduate microeconomics textbooks are well known; there is absolutely no question what they are or what is in them or where to find them:

- Andreu Mas-Colell, Michael D. Whinston, and Jerry R. Green (Harvard Economics Professors), **Microeconomic Theory**, Oxford University Press, 1995, 981 pages.

- Hal R. Varian (University of Michigan economics professor), **Microeconomic Analysis**, Third Edition, 1992, W. W. Norton and Company, New York.

- Dasgupta, Partha and Heal, Geoffrey, **The Economics of Depletable Resources**, Oxford University Press, 1979.

Literally every graduate economics program in the world uses one or all of these texts, and they do not teach other ways of thinking about or implementing microeconomic theory or practice. We have carefully applied those principles here.

There is one more critically important point. There is no mention whatsoever in microeconomics textbooks of linear programming as being able to represent a market setting. There is no notion of whether a market minimizes or maximizes some national "welfare function" by forcing all agents within the country to march in simultaneous lockstep in accord with the welfare function. There is only one accepted way to address the microeconomic market dimension—the decentralized way--and MarketBuilder strives to embody it.

1.8 What Is So Great About the Mas-Colell et. al. and Varian Microeconomic Approach That Has Been Applied for This Evaluation?

The answer is that it is descriptive of the way individual, independent, autonomous market agents behave in the real world, and it embeds hundreds of thousands of man years including all the economics Nobel laureates and others to do so. No other approach can claim the level of effort that 300 calendar years of economics can. It does not make arbitrary assumptions about collective or individual behavior. It does not make arbitrary assumptions about the first or second law of thermodynamics—the embedded production functions and energy balances honor them. It makes simple yet empirically desirable assumptions about individual goal-directed behavior in a market system. Here is a précis of those assumptions:

- **Price taking, profit maximizing producers (including producers, transmission owners, end users) competing and complementing each other in a network of supply chains that comprise electric, gas, and other energy systems.** It is true that energy markets contain myriad independently operating, self-interested, profit-maximizing producers. MarketBuilder represents each and every such producer as a profit-seeking entity and computes the balance of forces that applies in an economy comprised of such simultaneous profit-seeking entities. This is markedly different, and quite correctly so, than production simulation, LP, nonlinear programming, OPF, and other similar models that are driven by a single, aggregate social welfare function or a simple spreadsheet simulation.

- **Price taking, utility maximizing consumers competing in a network of supply and consumption chains.** Analogous comments to producers apply. Consumers independently pursue their private self interests, and MarketBuilder represents such pursuit.

- **Walrasian equilibrium (market clearing).** In the real world (as well as the model world), markets clear. There is neither excess supply nor excess demand because prices adjust. Some people might not like how high or how low prices actually have to go in order to effectuate the adjustment and market clearing mechanism, but prices demonstrably and empirically clear markets. People are not injecting electricity into the ground the blue waters of Lake Tahoe or the Mississippi River. People are not flaring gas. People are not shredding or abandoning automobiles. People are not abandoning excess foodstuffs or walking away from excess office space or housing. Markets are clearing; prices are ensuring that they always do clear. Walrasian equilibrium is a mathematically precise condition that means zero excess supply and zero excess demand in any market at every point in time and every point in every supply chain because prices adjust in the market at every time at every point in every supply chain. Price is the slack variable, the "degree of freedom," in the model just as it is in the real world that causes this to occur. Indeed, price is the ultimate "degree of freedom" that clears markets. MarketBuilder applies pure Walrasian equilibrium to decentralized decision making by producers and consumers.

- **Zero arbitrage across space or across time at equilibrium.** The model solution must have the property that market agents fully arbitrage everything that is arbitrageable in the market, all the time fully honoring all first and second law of thermodynamics conditions in physical markets. Profit maximizing producers, utility maximizing consumers, and Walrasian equilibrium give the zero arbitrage solution. MarketBuilder gives a zero arbitrage solution spatially and temporally. Without the zero arbitrage condition, agents are for example able to withdraw and deposit money from a bank and beat the model solution, and the model solution always looks foolish as a result. Allowing unexercised arbitrage to remain in a final model solution is incorrect, and we do not do it.

- **There must be zero incentive for agents to change away from the market clearing prices and quantities that the model calculates.** Every agent in your model must be pursuing a "best response" to the actions of every other player. There must be no incentive for any player in your model to change away from what he or she is doing. That is a property of MarketBuilder and of Mas-Colell et. al. and Varian's microeconomic theory, one that MarketBuilder carefully embeds.

- **The first and second laws of thermodynamics must be honored at every conversion or transmission process in the network and at every hub or busbar in the network.** Economics does not trump or obviate the fact that material balances, Btu balances, and volumetric balances must occur everywhere. MarketBuilder has that property. This property is sometimes under-recognized—the production functions and production relationships in economics are the economists' embodiment of physical laws of chemistry and physics. Production functions are a component of economics, an essential component, but assuredly not the only component. Production functions are sufficiently explicit and sufficiently general to be able to represent first and second law of thermodynamics considerations.

MarketBuilder is implemented consistently with Mas-Collell et. al., Varian's, and Dasgupta and Heal's graduate economic textbooks. The Walrasian equilibrium method as specified in those textbooks is mathematically sophisticated and difficult; there are no shortcuts such as Excel spreadsheets.

The textbooks document the standard microeconomic approach in an objective, non-self-interested way. Mas-Colell et. al., Varian, and Dasgupta and Heal can be purchased and read independently and objectively. They have been extensively and exhaustively reviewed.

1.9 What Benchmarking or Validation Has Been Done with MarketBuilder?

MarketBuilder users benchmark their results, and we have provided a bit of our own benchmarking over the years. There are several important examples of benchmarking that merit discussion herein.

1. The typical and most obvious type of benchmarking our clients do is retrospective analysis of projects the model gave an "aye" or a "nay" in previous years. As an example, it is known in the public domain that Duke used our model to set their bids for the Morro Bay and Moss Landing plants and to calculate their margin capture in preparation of their ultimately successful bid for those units. It is easy to retrospectively benchmark that model's recommended valuation against that bid and the yield it earned. Far and away the best benchmarking companies do is profitability and margin capture benchmarking. Profit is what matters to them, and profitability benchmarking is what they want to emphasize.

2. The next type of benchmarking is the more academic form of benchmarking that falls under the general rubric of statistical matching of historical data. While this has been successfully done with MarketBuilder and its predecessor beginning as early as 1975 by Lawrence Livermore Laboratory and continued by EPRI and other organizations. PG&E has placed historical evaluations into public testimony. If done incorrectly, historical calibration can be an inherently dishonest procedure if it is manipulated to build a false sense of confidence. While business customers ask whether there are historical validation studies, people rarely find one willing to spend their money on it. When the chips are down, they are comfortable with the transparency and accuracy of MarketBuilder and would rather invest in price prognostication and decision making. Notwithstanding our view (and the market's view) of historical validation, we and our clients have done a lot of it. It has always proven successful.

3. The third type of benchmarking grew out of the "model validation" discussions of the late 1970s and early 1980s. Because of the strong and growing commitment in the government to our LEAP model (which was the internal name they were using for MarketBuilder at the time. We were using the tradename GEMS at the time. We now use the tradename MarketBuilder), EIA decided to independently validate the LEAP model. EIA expended in excess of $1 million with Oak Ridge National Laboratories to validate our GEMS model. In particular, EIA endeavored to verify and validate the software, data, results, underlying economic theory, suitability and completeness of documentation, accuracy of forecasts, sensitivity analysis, and other relevant attributes of the program. In effect, EIA subjected the LEAP model to the most severe and comprehensive professional peer review they could muster in order to ensure that it was operating correctly and was appropriate for EIA's intended needs. (In EIA's judgment, Oak Ridge was an independent third party who could perform an objective, dispassionate, credible, independent, third party validation.) As part of the validation, Oak Ridge made a number of suggestions (which were ultimately incorporated into our model and software) and gave the GEMS approach

and software a clean bill of health. The validation effort was so detailed that an Oak Ridge Ph.D. actually calculated and programmed the first partial derivative of every line of code in the model, validating and verifying every line of code in the model, and he did so without our help or participation on a strictly third party basis. We would be surprised if any other model has ever withstood this level of scrutiny, i.e., ours is probably the only model in existence that has been independently validated to such a degree. We believe such validation underscores the credibility and accuracy. Details and voluminous documentation related to the independent third-party validation are available from Oak Ridge. (There was a set of reports at least two feet thick validating, verifying, and giving a clean bill of health to the GEMS approach.) Oak Ridge subsequently licensed their own copy of our GEMS software and used it to support their own project work in support of the Fossil Energy Division of the Department of Energy. Oak Ridge, Argonne, Los Alamos, Lawrence Livermore, and Lawrence Berkeley laboratories have all become licensees of the GEMS software. The software has enjoyed substantial success among the Department of Energy research laboratories.

4. A difficult, comprehensive, and dynamic type of benchmarking is to deliver results to trading and marketing people for the "acid bath" those people give them. Traders and trading companies are the most difficult of reviewers and benchmarkers. Trading company people have detailed market savvy, so benchmarking with trading company people is both very difficult yet very revealing. We do trader benchmarking from time to time.

5. The fifth type of benchmarking has been peer review by distinguished professionals. Hired by EPRI to validate and compare various models, Prof. William Hogan of Harvard University offered the following commentary Professor Hogan wrote in a letter to Dale Nesbitt

> ***"I have enclosed for your information a copy of my report to EPRI on the examination of alternative methodologies for building combined energy models. Starting with a view favoring hierarchical systems as the most convenient organizing framework, I became, as you can see, a complete convert to the Brock-Cazalet-Nesbitt view of the world. It has been an education for me, and I thank you for it."***

The Brock-Cazalet-Nesbitt view of the world Professor Hogan alludes to is the MarketBuilder approach. The Brock-Cazalet-Nesbitt view of the world to which Professor Hogan refers was reviewed in our peer reviewed work for the National Science Foundation in which review was sought and received from Nobel Laureate Dr. Ken Arrow of Harvard/Stanford, Nobel laureate Dr. Paul Samuelson of MIT, Dr. Dale Jorgenson, head of Harvard Economics, Dr. Edward Hudson of Harvard, Dr. Alan Manne of Stanford, Dr. David Starrett of Stanford, Dr. David Nissen then with DOE and presently with Poten and Partners, and others. We have published peer

refereed papers in the most prestigious academic journals (Operations Research, Management Science, Economique Applique, Energy, Energy Journal), which indicates a degree of acceptance by the "best and the brightest."

6. The sixth type of benchmarking is this: Can the model and the modelers stand up to the contentious, sometimes bitter, adversarial, hotly contested, zero sum, legal procedures in rate cases, legislative, executive, or other proceedings? The answer is yes, as will be discussed in a later section of this appendix.

7. The final type of benchmarking is whether or not people are willing to bet their money on MarketBuilder. Companies do bet money on MarketBuilder and have done so for thirty years.

1.10 Data--Reliable Cost and Economic Estimates

This section addresses the question of whether the model technology is populated with accurate and reliable data. As Figure 5 indicates, we have strived to use the best and most current data in North America and the world. Beginning with supply, Altos has had an agreement with the United States Geological Survey (USGS) whereby the USGS delivered to Altos its best and most current United States and world natural gas supply data. Altos also has had an agreement with the National Petroleum Council whereby we have access to their supply data, which is clearly the best in the industry assembled in our view by the most cognizant people. The NPC supply data lies at the heart of our supply data base.

With regard to pipeline data, we have the best and most current pipeline data in North America. Originally assembled by Benjamin Schlesinger and Associates under contract to the California Energy Commission in 1987 and continuously revised and upgraded since then, the present pipeline data has undergone extensive review and updating from the CEC, Altos, and our rather extensive clientele. The Canadian pipeline data was taken from the NEB.

On the demand side, we had to segment (as NARG has) the market in the traditional way (residential, commercial, industrial net of petrochemicals, petrochemicals, electric generation, transportation as relevant). Within each segment, we have had to represent demand and the price sensitivity thereof. We have done so using the econometric-statistical techniques of Dr. Medlock (formerly with El Paso now with Rice University) working for the NPC, the CEC, and others as well as the more traditional core and noncore segmentation developed by Altos.

Figure 5: Sources of NARG Data (NPC Version)

	UNITED STATES	CANADA	REST OF WORLD
SUPPLY	NPC/USGS	NPC/USGS	USGS
PIPES	Altos	Altos	Altos/ Vendors
LNG	Altos/ Cheniere	Altos/ Cheniere	Altos
DEMAND	Altos/Rice/ EIA	Altos/Rice/ EIA	OECD/ IEA
ELECTRIC	NERC/ EIA	NERC/ EIA	NONE

2 ALTOS BACKGROUND

2.1 Where Are You Located? Where Are the People Who Maintain the Model Located?

Altos Management Partners (Altos) is headquartered in Los Altos, California (near Stanford University) and operates as a California C Corporation. The people who maintain the model and the underlying software are located primarily in the San Francisco Bay Area and work out of our Los Altos office. We have software development personnel in Alberta, Canada, and we have senior consultants and modelers in Washington DC and Houston. The people who maintain the model are located at our Los Altos, California office, but the people from Alberta, Washington DC, and Houston provide regional assistance. In addition to our own companies, we have executed partnership agreements with Black and Veatch (Lukens Energy) in Houston, Texas. We have had partnership agreements in the recent past with Global Energy Solutions in Boulder, Colorado and with the United States Geologic Survey (USGS) in Menlo Park, California. Those organizations collaborate in commercial applications of NARE and the entire suite of MarketBuilder models. The USGS provides its North American and world gas, oil, and liquids data base commercially through the cooperative agreement with us.

2.2 How Old Is Your Company? How Old Is the Model?

We understand that no modeling technology in the industry has been around and succeeding as long as our MarketBuilder technology. The modeling technology was first conceived in the early 1970s in a Ph.D. dissertation at Stanford University (Edward Cazalet's Ph.D. dissertation.) The first commercial implementation of the technology occurred in 1973-4 at Stanford Research and was called the Gulf-SRI Model. (Gulf-SRI was one of the premier seminal models in the industry.) Dr. Nesbitt worked with the model at SRI and later co-founded the consulting company Decision Focus Incorporated (DFI) in 1977, which was initially capitalized on the modeling technology and which expanded that technology substantially over the subsequent 18 years. During that time, DFI grew to become a $35 million, 165 plus person professional consulting firm based in part on the underlying technology (which was tradenamed GEMS during the DFI years). GEMS was used and developed continuously between 1977 and 1995, embodying hundreds of man years of development and application effort. In 1995, DFI divided into two parts, the energy part being transferred to Altos/MarketBuilder and the transportation part merging with another company which has since been merged twice again and now resides within Manguistics Inc. Altos offers a report detailing the history of the model and several successful validation activities that have focused on the model. We understand that GEMS/MarketBuilder is the only model that has endured a detailed third party audit and validation line by line by the Federal government. We will discuss this validation procedure in more detail below.

2.3 Is Altos the New Kid on the Block?

Altos is not at all the new kid on the block. Altos and its direct predecessor Decision Focus Incorporated (DFI) have been working on the MarketBuilder model and modeling technology continuously since 1973, a period of 32 continuous years. There is a companion document to the present document entitled "History of Generalized Equilibrium Prior to the Introduction of MarketPoint" that gives a detailed history of the approach. The history of the approach is summarized in Figure 6. The shaded area at the right indicates that in 1995, Altos began a seven year process to thoroughly modernize the software, embedding the time tested, validated, proven economic calculation algorithm in modern graphical, drag and drop, double click modeling software. The software and approach have been independently validated and used repeatedly for three decades in the power, gas, coal, oil, nuclear, renewables and other energy industries as well as a number of nonenergy commodity industries. MarketBuilder probably has more "miles on it" than any other approach in the industry.

Figure 6: The Altos Model Has Been in Continuous Existence for 32 Years

1970: Mexico CFE Model
1973: SRI-Gulf Model
1977: EIA LEAP Model
1979: TVA SAM Model
1981: EPRI IFM and LMSTM
1982: DOE World Oil Model
1983: North American Regional Gas (NARG) Model
1988: California Refining/Transportation Model
1989: World Gas Trade Model (WGTM)
1991: Crude Quality Model
1991: Western European Gas Model
1992: Southern Cone (South America) Model
1993: OG&E, Duke, Minnesota Power, SCE, CIPSCO, PP&L competitive electric models
1995: Southeastern Australia Model
1995: PanEnergy North American Regional Electricity Model
1995: Altos North American Electricity Model
1998: Altos Short Term NARG Model
2002: Completely Modernized Technology
2003: Modernized World Oil and Gas Models
2003: USGS and NPC partnerships
2004: Black and Veatch partnership

2.4 What Are the Proprietary Constraints on Your Model?

The software and all models are proprietary to MarketPoint Inc. They are leased for continuous in-house customer operation under a simple, standard, several page license agreement. (We will provide the license agreement upon request.) Under the license, licensees are free to distribute results and data from their onsite version of the model and to pursue their "normal" usual and customary business interests. This includes participating in testimony, public hearings, regulatory proceedings, and the legal system in general. Our clients find they are not trammeled relative to what they need to do to satisfy their analytical, professional, and legal obligations. They can even hire third

parties to run the MarketBuilder model as long as they do so at their site and sign and personally guarantee (above and beyond corporate guarantees) their compliance with the agreement. In litigation and regulatory proceedings, we provide the model to counterparties under their own license.

2.5 What Is Included in the License?

The license bundles and provides all the Altos models:

- North American Regional Electric (NARE) Model, which includes

  - Short Run Version (1 year).
  - Long Run Version (15 years).

  The NARE model also includes the tradable environmental emissions component.

- North American Regional Gas (NARG) Model, which includes

  - Short Run Version (36 months).
  - Long Run Version (40 years).

- World Oil Model.

- World Gas Trade Model (WGTM).

- Western European Gas Model (WEGM).

These models can be run individually, or they can be fully interconnected on our distributed processing grid.

2.6 If One Were To License the Altos Model, Would We Be "Chained" To Altos/MarketPoint, Or Is It Permissible To Have Other Consultants Work On It?

Our license allows any consultant or third party to work on the model at your facility. You have to honor the license agreement and take responsibility for them honoring the license agreement, but you can hire anyone to work with you and use our model. This is perhaps unique in the industry—specific provision to allow competitors to work with our software and models in your shop and under your supervision and responsibility. This frees you from being "held up" by us or by any other consultant; your work can be put out to bid or competition. It also frees you from being plagued with lead time when a lead consultant might be busy or otherwise disposed temporarily. It gives you broad flexibility.

2.7 Who Is Using the Model and What Are They Modeling?

Altos is able to disclose the names of all but one of its licensees. When and if you become a licensee, we will disclose it to you. Altos is not at liberty to disclose anything about client uses or applications, and we would choose not to make such disclosures even if we were not contractually bound to refrain from doing so. Preserving the confidentiality of our clients is a paramount concern and consideration of MarketPoint, Altos, and our partners, and we carefully do so. We are authorized to disclose who is a licensee and to disclose information that has already made its way into the public domain. Licensees are allowed "free trade" between each other, and the reason for allowing disclosure of identity of licensee is to facilitate such free trade. The California Energy Commission has been at the center of such free trade on the gas side in its Fuels Office, and they have benefited immensely from the industry contacts that have come with MarketBuilder. In particular, Mr. Jairam Gopal of the California Energy Commission has facilitated free trade among NARG users and has distributed their work product liberally to NARG users. Should your organization license NARG, you will be included in the free trade network to use or not use at your discretion.

Licensees and users of our technology (which are not specifically distinguished) include the following:

Licensees and Users of the MarketBuilder and (Predecessor) GEMS Approach

- Agip
- Alberta Department of Energy
- Amerada Hess
- Amoco
- Argonne National Laboratory
- Atlantic Richfield Company
- Baltimore Gas and Electric*
- Baytrust/Unilon
- BHP Petroleum
- British Gas
- British Petroleum
- California Energy Commission
- Calpine
- Canadian Energy Research Institute
- Chase Manhattan Bank
- Cheniere
- Chevron
- Conoco
- Consolidated Edison Corporation
- Department of Energy
- Dominion Energy
- Duke Energy
- El Paso Natural Gas
- Electric Power Research Institute
- Enbridge
- Energy Information Administration
- Energy Transfer
- Enron
- Enterprise Oil
- Exxon/Esso
- Fina
- Gas Research Institute
- Gulf Oil Corporation
- Hart Energy
- Harvard University
- Husky Oil

- Illinois Department of Energy and Natural Resources
- Lasmo
- Lawrence Berkeley Laboratory
- Lawrence Livermore National Laboratory
- Los Alamos National Laboratory
- Maxus Energy
- MidAmerica
- National Energy Board of Canada
- National Petroleum Council
- National Petroleum Council
- New York Gas Group (NYGAS)
- New York State Energy Office
- Northwest Energy Resources Company (NERCO)
- Northwest Natural Gas
- Nuclear Electric Ltd.
- Oak Ridge National Laboratory
- Office of Management and Budget
- Oryx
- Pacific Gas and Electric Company
- Pacific Gas Transmission Company
- Panhandle Eastern Pipeline Company
- Pennsylvania Power and Light Company
- Petro-Canada
- Phillips Petroleum
- Republic of Argentina
- Republic of Mexico
- Republic of Portugal
- Republic of South Korea
- Rio Tinto
- Santa Fe
- Sempra
- Shell
- Sohio
- Sonat
- Southern California Gas Company
- Stanford University
- Suez (Tractebel)
- Tennessee
- Tennessee Valley Authority
- Texaco
- Texas Utilities
- Total
- United States Geological Survey
- Williams Corporation
- Woodside Energy

2.8 How many market studies has the vendor performed?

Dozens. Dr. Nesbitt began his professional career in 1974 and has been performing market studies continuously ever since. One of Altos' main lines of business has been market studies. A partial list of such experience appears on the Altos website www.altosmgmt.com.

3 ALTOS TESTIMONY AND SELECTED PUBLIC DOMAIN PROJECTS

Altos Management Partners has a long and effective history dealing with public bodies in the legislative, executive, and judicial branches of domestic and foregoing bodies ranging from courts to government agencies.

3.1 The California Energy Commission California Pipeline Program

In 1989, the California Energy Commission (CEC) wanted to catalyze entry of new pipeline capacity into California to spur inter-pipe competition and drive down gas price. "How far will one or both of the primary entrants—Kern River or PGT Expansion--drive down price?" asked Richard Bilas, then a CEC Commissioner and later a California Public Utilities Commission President. Dr. Nesbitt delivered the definitive forward price analysis that demonstrated that each entrant would soften price in California and elevate price at its upstream terminus, that both pipes were needed, and that the entry of either Kern River or PGT Expansion would turn San Juan and Permian gas eastward rather than westward. Bilas told a gas conference in Canada: "When Dale Nesbitt told us boldly that southwest gas would turn backward and flow east, we all had a good laugh at his expense. His prediction was so far from what we had been thinking that it seemed preposterous at the time; it seemed to us it just couldn't happen. Well guess what. It happened exactly like he and NARG said it would. He was absolutely right, and I became a believer in NARG." Subsequently, both Kern River and PGT Expansion were constructed and expanded into California, and both continue to run virtually full just as NARG predicted.

3.2 Discount Rate Testimony Before the California Energy Commission

The California Energy Commission wanted to know what the right time value of money discount rate it should be using in its modeling and communication. This had become a difficult and contentious issue for them because they did not just want to default to allowed rates of return by organizations such as the California PUC. They wanted to use private sector rates of return in evaluating siting and pricing alternatives and other policy recommendations to the Governor and Legislature. The CEC hired Altos senior professionals to give en banc testimony to the Commission as a whole regarding the methodology for thinking about the private sector rate of return (discount rate) and the appropriate and proper numerical value to be using.

3.3 Yukon Pacific Trans Alaska Gas System (TAGS) Export Certificate Testimony

Altos professionals (using our erstwhile corporate name Decision Focus Incorporated) performed all the economic and market analysis that got Yukon Pacific the export certificate on their TAGS project from the Economic Regulatory Administration (ERA) over ten years ago. This work was performed under the banner of our previous company Decision Focus Incorporated, and it was sponsored at that time by Yukon Pacific, the company who applied for and ultimately won their export certificate as a result of our testimony. We still have a copy of that successful application before the ERA.

3.4 National Energy Board of Canada Biennial Forecasts

Beginning in 1988, the National Energy Board of Canada used our NARG model to support its biennial forecasting and other policy needs. The NEB used NARG to support export impact assessment and incremental impacts on Canadian citizens. The primary contribution of the National Energy Board and our other Canadian sponsors (Alberta Department of Energy, Canadian Energy Research Institute, Exxon/Esso Resources, Petro-Canada, TransCanada PipeLines) is to render NARG a realistic representation of Canadian supply, transportation, demand, and prospective new projects and resource regions. We were authorized by the National Energy Board and CERI to distribute their estimates of Canadian supply, transportation, demand, and exports determined using their data and our software.

3.5 Securing the MacKenzie Delta Pipeline Export License in Testimony Before the National Energy Board

Altos has a successful history in Canada advocating and securing an export license for the MacKenzie Delta pipeline. In the late 1980s, Gulf, Esso, and Shell became aware that the National Energy Board of Canada was using our NARG model to support their biennial planning process and their export certification procedures. They asked us to use the same model to analyze the marketability of MacKenzie Delta gas in its downstream markets in Caroline, Empress, and elsewhere and to analyze whether the MacKenzie Delta pipeline was truly an export pipeline, merely “flowing through” gas from the Arctic on its way to the United States.

We were able using NARG to show definitively to the public sector that the MacKenzie Delta pipeline was NOT a mere flowthrough pipeline. It was not correct or appropriate to argue that MacKenzie Delta gas would have zero effect on the Alberta market even if it ultimately flowed through to the United States. Quite the contrary, when the MacKenzie Delta gas hits the Albert market, it decreases the price in that market below what it would otherwise be without the pipeline. Such price decreases in

that market suppress production in Alberta that would otherwise occur and thereby suppresses aggregate Alberta production that would otherwise occur. Thereafter, part of the MacKenzie Delta gas must satisfy demand in Alberta that would otherwise have been served by higher cost Alberta gas. Consequently, only a part of the MacKenzie Delta gas flowing into Alberta could be argued to flow onward through to the United States. The other part suppresses the Alberta market price and the indigenous Alberta market production levels and therefore has a negative effect on Alberta producers.

We submitted written and oral testimony to the National Energy Board of Canada and won for the Gulf, Esso, and Shell consortium an export certificate for their project. The primary people responsible were Rick Daniel of Esso (currently with Alberta Energy Company) and Colin Campbell, a consultant to Shell.

3.6 Alberta Department of Energy

The Alberta Department of Energy is continually embroiled in royalty decisions with Canadian natural gas producers, and these royalty decisions can become contentious. To solve this problem, the Alberta Department of Energy used Dr. Dale Nesbitt to determine the appropriate level of royalty to be charged to Alberta producers. They used use to calculate in effect the "Laffer curve" for royalty level. They were specifically asking the question: What level of producer royalty maximizes revenue capture to the Canadian government. We helped the Assistant Premier of Energy in Alberta understand the answer and communicate it to constituents.

3.7 New York State Energy Office

The New York State Energy Office adopted the NARG model to determine how New York affects and is affected by United States and Canadian gas markets. The New York Gas Group (NYGAS), a consortium of all the New York gas utility companies, has acquired NARG to understand prices and availabilities of gas in the state and to orient their activities toward such understanding.

3.8 Valuation and FERC Testimony Supporting the PG&E/PGT Expansion Project

Altos people played a pivotal role in the entry of the PG&E/PGT Expansion in 1993. As early as 1985, our NARG model was definitively implying that if a new pipe were built from Alberta to California, it would run full, and the basis differential across that pipe would be more than big enough to pay all fixed and variable costs during every future year of its life. Altos knew this would be true even if Kern and incumbents El Paso and Transwestern were to enter (which indeed did occur before PGT). This insight was particularly controversial after Kern River began deliveries into the California

market because it was feared that a second entrant such as PGT Expansion would lose its shirt to Kern plus El Paso plus Transwestern. Based on our NARG analysis, the PGT Expansion was financed on the balance sheet of PG&E corporation as a whole. NARG helped them become supremely confident in a project that was supposed to fail because Kern River had beaten them to California. Interestingly, the PG&E board hired McKinsey to review our work as a condition of financing (McKinsey was chosen as the objective third party.) They gave it a clean bill of health and a full endorsement. The key clients on that project included then President Stephen Reynolds (now CEO of Puget Energy), Vice President Paula Rosput (subsequently President PanEnergy Power, Duke Energy North America, and now CEO of Atlanta Gas Light Company), Bob Howard (currently Vice President of PG&E California Gas Group), and Howard Ash (presently an Altos principal).

Shortly after the pipeline went into service, PGT again retained Dr. Nesbitt and Mr. Ash to help them prosecute their application before the FERC to shift from incremental pricing to system-wide rolled-in pricing (which PG&E strongly favored). In an extremely contentious, four month, 56 witness hearing before the FERC, Dr. Nesbitt and Mr. Ash were able to prove using NARG that rolled-in pricing would not change the market price of gas in California and that in fact the PGT project had already reduced gas price in California by $0.10/Mcf below what it would have been without the project and therefore that the entire state was already benefiting. Altos' testimony was instrumental in PGT's superior showing in the case. (The opponents actually settled before the judgment was announced because they realized they were beaten.)

3.9 Other Merchant Plant Testimony in Florida

Altos was the contractor of choice for the vast majority of FRCC merchant bids. We submitted testimony and advocated the bids for not only Duke New Smyrna Beach but also Okeechobee (PG&E Generating), Blue Heron (Calpine), Midway and Leesburg (Panda Energy), and Bonny (Cogentrix). We knew the nature of a deregulated FRCC power market cold, and we knew how much price depression would result from the entry of each and every one of those plants.

3.10 BC Gas Southern Crossing Pipeline Testimony Before the British Columbia Board of Public Utilities

During the four or five years previous to the time BC Gas hired Altos in 1997, winter gas demand in British Columbia had grown dramatically in the lower mainland portion of British Columbia (Vancouver/Victoria), faster than pipeline deliverability into the region has grown. Because of this growth, a large and increasing winter price differential has developed between the southwestern Alberta export location (Kingsgate/Yahk) and Vancouver/Victoria/Sumas. BC Gas Company proposed to build a pipe called the Southern Crossing to deliver gas westward from Yahk to Sumas, during

the high price, on-peak winter season and to deliver gas in the opposite direction from Sumas to Yahk during the off-peak fall-summer-spring seasons. Altos provided testimony that the market would sustain basis differentials across the project for enough time to pay for it and that the local regulators should embrace it. Altos was able to frame the proper view of the problem as a basis differential between Yahk and Sumas and to demonstrate the profitability of and the need for the project. We were able to quantify the basis differential from Yahk to Sumas as being high and very positive in the winter and very low and in fact negative in the summer. This meant that gas would flow from Yahk to Sumas at a very high price differential in the winter, and that very high price differential would pay the fixed cost of the pipe. Conversely, gas would flow from Sumas to Yahk in the summer, delivering British Columbia gas into the PGT system and thereafter downstream to high value markets in California and Eastern Washington and Oregon.

3.11 Testimony to FERC on the Famous FERC Order No. 436 in Behalf of Natural Gas Supply Association

In 1985, concerned about the deleterious effect of FERC Order No. 436 (pipeline unbundling) and its threats to abrogate take-or-pay contracts held by its members, the Natural Gas Supply Association and Amoco hired us to make the salient written testimony formulating the producers' stance. We were able to help move FERC away from outright abrogation of take-or-pay contracts and mandatory unbundling toward voluntary unbundling and preservation of producer rights. This allowed gas producers to recover more money than they otherwise would have had there been outright abrogation.

3.12 ERCOT Merchants

We provided market analysis and financing support for a plethora of power plants in ERCOT including Lost Pines II, Magic Valley (the Merchant Plant Deal of the Year in 1999), Bayer, Freeport, Corpus Christi, Hidalgo, Deer Park, and Channel. We told the developers and the banks what they were worth in the market that would unfold in ERCOT in the next 20 plus years. It is interesting to contemplate that our advice was viewed as highly "contrarian" in those days. People were saying that ERCOT had a 35 percent reserve margin and was a death sentence for any merchant plants. They were saying SERC and Entergy were much better. In retrospect, we were absolutely right on the market. The ERCOT merchants have made money, but the SERC and Entergy merchants have been unprofitable.

3.13 Duke California Plant Bids

Duke's California plant bids for Oakland, Moss Landing, and Morro Bay were done by Altos, whose models told them what those plants would be worth in the California

market. Those plants made a ton of money for Duke during their early years, as we knew they would. The repowered plants are now being offered for sale by Duke because California has seen the entry of more efficient equipment in the intervening years.

3.14 Merchant Entrants (Many Companies)

Altos has worked with developers and banks in Colorado, Las Vegas, New Mexico, Arizona, Maine, Missouri, MAIN, ERCOT, Washington, Oregon, Georgia, and elsewhere.

3.15 Georgia Power Plant Development (Client Confidential)

Most of the Georgia merchants located astride the Interstate pipelines. For a client, we determined whether there was electrically oriented locational advantage away from the Interstate, i.e., advantage that would justify the LDC tariff because the electrical constraints were more than offsetting.

3.16 Potrero San Francisco Plant Bid (Sonat)

We formulated the bid by Sonat for the San Francisco Potrero plant. It was ultimately won by Mirant. At the price Mirant paid, Sonat was positive because of Altos' analysis that they did not want it!

3.17 Otay Mesa

We told the sponsor to build the Otay Mesa plant ASAP and gave them the requisite information for the banks and the public sector to initiate the construction.

3.18 San Diego Regional Energy Office

We were hired to advise the group of governments regarding municipalization and municipalized power plant developments. In particular, they were hoping to purchase rights to the Otay Mesa plant. A consortium of communities headed by San Marcos was contemplating buying the rights to Otay Mesa and building it using tax preferred municipal financing. We were able to convince them not to undertake this option, which would have been disastrous for them. This required a lot of patient communication in the public sector.

3.19 Cajun Plant Bids

We formulated the bankrupt generation and transmission (G&T) Cooperative Cajun plant bids for PanEnergy/Duke, and we presented and advocated them to the bankruptcy judge in Federal bankruptcy court. At the price those plants sold for, our client was certain he didn't want them!

3.20 San Francisco Public Utilities Commission Community Aggregation Program

The City and County of San Francisco is considering decoupling from the local utility (PG&E) and buying its own power. Altos has been retained to be the lead strategy and analytical consultant to advise them exactly how to do that should they elect to do so and how to make money if they decide to do it. This has required a goodly bit of communication with the California Energy Commission and a number of local communities, not to mention the highly political San Francisco Board of Supervisors and their internal public utilities commission.

3.21 Merchants in New Jersey, Pennsylvania, and New York (Client Confidential)

We have done extensive market analysis, both regulated and nonregulated, of prospective merchant entry into key points within PJM and NYPP.

3.22 Southern California Merchant (San Bernardino)

We did a market analysis of a merchant in Southern California, fully analyzing the nature of the California market in a nonregulated state as well as various regulated states.

3.23 Coal Fired Merchants (Client Confidential)

We have performed market analysis of coal fired merchants in Nevada, New Mexico, Arizona, and elsewhere.

3.24 The Value of Existing Nuclear Generation Units

The Energy Information Administration hired Altos to quantify the value of the energy system "with" and "without" certain nuclear stations. They wanted to know if nuclear stations were valuable in their own right and were critical to the energy future. There is an EIA report detailing this result in a quite successful project that showed the very high value of baseload generation.

3.25 The Integrated Ruby Gas Pipeline/Ruby Generation Station (County of Eureka, Nevada)

The county of Eureka hired us to analyze the plant and get it sited in Eureka county. They wanted to know the intrinsic value of the plant and its logical property tax and other local impacts. We worked for Eureka county to advocate siting of the plant in its jurisdiction.

3.26 Bridgeport California geothermal plant property tax case

The local property tax assessors valuate one of Pacific Enterprise's geothermal plants very high. Working the law firm Gibson, Dunn, and Crutcher, we traveled to the local taxing authority and successfully litigated the case.

3.27 Contract Mix Testimony

We had a large practice advocating gas portfolio purchasing for most of the gas distribution companies in the country (e.g., National Fuel Gas, SoCal, PG&E, PSE&G, SDGE, Elizabethtown, Atlanta Gas Light, Nicor). This provided a long history of public presentations and advocacies. The contract mix program was extremely successful in most jurisdictions in which it was applied in developing a bilateral understanding of prudence on the part of the PUC and the affected utility.

3.28 President Ford's Synthetic Fuels Commercialization Team

Altos senior professionals working for Stanford Research at the time were retained by the Office of Management and Budget under the direction of Dr. William McCormick (CEO of CMS Energy at the time of its merger) to predict the market for synthetic fuels and to determine whether government intervention was in the national interest. Based in part on our model, the Ford Administration backed off from its initially aggressive position formulated in the latter days of Project Independence with regard to subsidizing the early introduction of synthetic fuels. In effect, the model and attendant analysis convinced them (and Congress) that large subsidies for early commercialization were not in the national interest. The model portended that any coal gasification plant that was actually built (such as the Great Plains coal gasification plant) would be an economic white elephant on the plains of North Dakota paid for in full by taxpayers, good for nothing except perhaps for holding disco dances inside the gasifiers or building water slides along the conveyor belts. They foretold that the variable operating cost of the plant would be higher than the market price of gas in the region, meaning that the fair market value of a $2 billion plant would be ***zero***. Investors (or guarantors) would lose the entire capital cost. See Interagency Task Force on Synthetic Fuels Commercialization **Recommendations for a Synthetic Fuels commercialization Program**, Government Printing Office, 1975. See also Manne,

Richels, and Weyant "Energy Policy Modeling: A Survey," **Operations Research**, Volume 27, No. 1, Jan.-Feb. 1979.

3.29 Committee on Nuclear and Alternative Energy Systems (CONAES)

Altos professionals had an important role on the National Research Council's Committee on Nuclear and Alternative Energy Systems (CONAES). This entailed a lot of multiparty public communication.

3.30 Department of Energy Market-Oriented Program Planning Study (MOPPS)

Altos professionals had an important role the famous Market-Oriented Program Planning Study (MOPPS), which gained a good deal of exposure as a novel and appropriate way to think of the legitimate role of government in the United States energy system. In particular, MOPPS underscored that market concerns had been underemphasized relative to political concerns in understanding the logical future evolution of the energy system and that market concerns should receive increased emphasis. Subsequent world and national events of the 1970s and 1980s underscored the prescience of the MOPPS study.

3.31 Illinois Department of Energy and Natural Resources

The Illinois Department of Natural Resources retained Altos senior people to help them analyze the market and marketability of Illinois bituminous coal versus other coals (Western sub bituminous, Appalachian bituminous, and other coals). We built a rather extensive national multifuel model of coal, oil, gas, refining, generation, synfuels, and end use consumption in order to help Illinois position and market its coal industry.

3.32 Governments of Argentina, South Korea, and Portugal

Some twenty years ago, the Administration together with Congress initiated a rather innovative program termed the Country Energy Assessment (CEA) program. The concept underlying the CEA program was that the United States and a set of selected countries should work closely together in bilateral teams to develop analytical capability, data, and models to direct energy development in those countries. The program was designed to facilitate transfer of planning and decision making technology from the United States to various selected countries. The CEA program conducted an extensive search for the best modeling approach and supporting software and selected our modeling approach, largely because it was flexible enough to allow construction of models for other countries and at the same time fully capable of independent, ongoing use in other countries.

After our system was selected, bilateral programs were successively conducted in South Korea, Portugal, and Argentina. In each program, a detailed country model representing oil and gas, coal, nuclear fuel, electric generation, residential, rural/agricultural, commercial, industrial, and transportation demand was constructed and transferred to energy planners in the country. Those models have been used successfully and autonomously in those countries for a number of years subsequent to delivery.

3.33 PG&E Gas Price Cases

PG&E has hired Altos to advocate and justify their gas purchasing portfolio and the consequent pricing of that portfolio before the California PUC. Altos has provided such testimony in written and oral form to the CPUC.

3.34 Tractebel (Suez North America) versus AEP Dow Plaquemine Litigation

Tractebel (now Suez) recently sued American Electric Power (AEP) contenting that AEP failed to deliver the contracted capacity and energy from the Dow Plaquemine 3 on 1 cogeneration facility within the Entergy service territory near Baton Rouge, Louisiana. AEP had offered a tolling contact for capacity, energy, and ancillary services to Suez, and AEP failed to deliver capacity, energy or ancillary service. Tractebel sued AEP in Federal District court in the Southern Distinct of New York. Altos became a witness in behalf of Tractebel in the case. They case required Altos to develop and write definitive testimony quantifying the electric power markets in the eastern interconnect and using such quantification to calculate the specific losses to Tractebel from the default. That court case (which was a bench trial agreed to by both parties) was decided primarily in behalf of Tractebel, and the counterparty is deciding whether to appeal and continue the case at a higher level Federal court.

3.35 Legislature of New Mexico

After the basis blowout during the winter of 1995, the New Mexico state legislature began to wonder whether they ought to encourage or subsidize a new pipeline emanating from the San Juan basin and terminating in the Anadarko basin in Oklahoma and North Texas. Our NARG analysis proved definitively that they should **not** put up state funds for a direct pipeline route but instead should consider incremental expansion of El Paso. Fred Hansen, now with the New Mexico Oil and Gas Association, commented that the study was a watershed study for the legislature, heading off an otherwise poor and wasteful investment.

3.36 Governor of Alaska (Frank Murkowski)

Altos was hired to brief Alaska Governor Frank Murkowski on the market, marketability, and appropriate posture toward producers and pipeline and shippers in the Alaskan gas pipeline. This work is ongoing.

3.37 Chattanooga Gas Insurance Case

Thomas Choi and Dale Nesbitt of Altos were hired by Chattanooga Gas to oppose an insurance settlement offered by an insurance company for a fire that damaged the Chattanooga Gas LNG plant. The company offered a settlement equal to equipment replacement cost. Chattanooga contended, in a way that was precisely consistent with the insurance contract, that the insurance company also owed Chattanooga the value of lost business. Altos quantified the value of lost business due to lost LNG dispatch and advocated it in writing in Federal court in Atlanta. The case is still pending.

3.38 Atlanta Gas Light Corporation Capacity Plan Before the Georgia PUC

Altos' Thomas Choi, who heads the natural gas practice, provided expert testimony on behalf of Atlanta Gas Light before the Georgia State Public Utility Commission in September 2001. The testimony, available online at http://utilityregulation.com/content/orders/01GA50186.pdf, was pivotal in establishing AGL's case. Mr. Choi analyzed AGL's capacity plan for risk exposure and economic efficiency in preparing his testimony. He worked with AGL staff and other experts to prepare written testimony that was submitted to the PSC. After several days of media training and preparation, Mr. Choi and other experts provided two days of verbal testimony. As lead witness, Mr. Choi articulated AGL's position. Mr. Choi was complement by a commissioner for providing one of the clearest testimonies that he had ever heard. AGL prevailed.

3.39 ExxonMobil Contract Dispute with State of Alaska

William English was designated as an expert in crude oil pricing in litigation regarding a contract dispute between ExxonMobil and the State of Alaska. Testimony was related to crude oil pricing mechanisms and contracting practices. He testified in the case.

3.40 BP/Arco FTC crude oil pricing and contracting case

William English was designated as an expert in crude oil pricing and contracting in an FTC inquiry into the merger of BP and ARCO. Testified at the FTC's request as an

expert unrelated to the merging parties regarding crude oil contracting practices, the level of market competition and the likely impact of the merger on certain crude oil markets.

3.41 City of Long Beach versus Chevron

William English was asked to testify in an anti-trust case brought by the City of Long Beach and the State of California against Chevron. Testimony was related to crude oil contracting issues related to certain pipelines.

3.42 State of Alaska versus Chevron Tax Case

William English was asked to testify in a state tax hearing in which the State of Alaska was challenging a Chevron's royalty valuation for certain crude oils. Testimony was related to pricing methodology for the crude oils in question.

4 THE NATIONAL PETROLEUM COUNCIL NORTH AMERICAN REGIONAL GAS (NARG) MODEL AND DATA BASE

NATIONAL PETROLEUM COUNCIL 2003 NATURAL GAS STUDY

Data Developed by NPC for Supplemental Modeling Activities Using Altos/MarketPoint Models

CONDITIONS OF ACCEPTANCE AND USE OF DATA CONTAINED IN THIS CD-ROM

Recipients of this CD accept it on the basis that:

- The NPC's rights in this information and data developed by the National Petroleum Council (NPC) and contained in the CD and all the other documentation of the NPC 2003 Natural Gas study are protected by copyright.

- The NPC is making this information and data developed by the NPC available to interested parties as part of the NPC study's report documentation.

- The members of the National Petroleum Council have not endorsed nor approved this information and data contained in the CD but, only, approved the release of these materials as part of the study's report documentation.

- Recipients will not transfer this information and data developed by the NPC to a third party without the prior agreement of the NPC.

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- In no event will NPC, its study participants, or its contractors be liable for any damages whatsoever arising out of the recipients' use or inability to use this information and data contained in the CD.

DATA FILES DEVELOPED BY NPC FOR SUPPLEMENTAL MODELING ACTIVITIES

As part of the documentation of its 2003 Natural Gas study, the NPC is making available certain data that it developed. The study's principal modeling activity and its data CD are described on page 5 of this file. This CD contains files of the study's supplemental modeling activity that used Altos/MarketPoint models. The work carried out by the NPC Supplemental Modeling Team has been compiled on to two CDs. The first, containing data in Excel files, is available to all

interested parties, and the second, containing data in proprietary .mkp files, is available only to MarketPoint Software licensees. The two CDs contain the models and the input assumption, data and compilation routines. They do not contain model results, which the NPC decided not to release, because of lack of time for detailed peer review from all relevant study participants.

CD with Data in Excel Files

The first CD contains supporting files used to compile data and assumptions and prepare them in a format appropriate for use in the supplemental Altos modeling activities. These files contain data and assumptions developed by and proprietary to the NPC. As such, these files will be distributed to interested parties under conditions determined by the NPC. The files included are the following:

1. Supply Components

- *Discovery Process Model Conventional Onshore Plays.xls*. This file contains the model structure, the inputs and the outputs of a Monte Carlo simulation model used to simulate the sequence of discoveries of undiscovered gas resources in each of the onshore conventional gas plays. The model simulates a sequential sampling, without replacement, from each play *proportional* to size. Model output is the expected (mean) size of each of the next discoveries. A curve fit to these 25 discoveries provides the capability to estimate the size of the Nth discovery, and the success ratio is used to assess the average number of wildcats necessary to find the Nth discovery. The modeling team developed this approach to provide a compromise between assuming that fields are discovered strictly in order of size perfect information - or that they are discovered randomly - no information. This "discovery process model" was used to estimate the expected size of the first “Yet to Find” field, the 75th percentile discovery, and the mean of the small field fraction to provide three representative fields for each play. This discovery data was aggregated up to the regional level to provide the three points required by NARG to estimate regional marginal cost-of-supply curves. However, the preprocessing model is capable of generating marginal cost-of-supply curves *unique* to each play, allowing sensitivity analysis of the discovery process at the play level.
- Series of Preprocessing Files. These files are used to calculate the characteristics of the three point cost of supply curves and production profiles to be used in the NARG model. Each file contains comprehensive detail of resource, cost and development assumptions as well as the keys to aggregation from play level to the regionally aggregated level used in the model. In each of these files the input to the NARG model is characterized by cost of supply curves for capital expenditures (Cx1,2,3, Cy1,2,3) and operating expenditures (Ox1,2,3, Oy1,2,3) , where x is the quantity of gas

discovered and y is the unit cost. File names refer to either region or gas type as follows:

- *WCSB Preprocessor – 2003 NPC Study.xls*
- *Canada Offshore Preprocessor – 2003 NPC Study.xls*
- *CBM Preprocessor – 2003 NPC Study.xls*
- *GOM Preprocessor – 2003 NPC Study.xls*
- *L48 Preprocessor – 2003 NPC Study.xls*
- *Mexico Preprocessor – 2003 NPC Study.xls*
- *NCV Preprocessor – 2003 NPC Study.xls* (for unconventional gas)
- *Alaska Preprocessor – 2003 NPC Study.xls*

2. End-use Demand Components

NPC Demand Summary.xls. This file contains the equations and coefficients used to estimate initial demand for each sector at each US regional node in the NARG model. Equations and coefficients for residential and commercial demand were derived from analysis of detailed recent historical data. Equations and coefficients for chemical and other industrial demand were derived from the projections produced in the study's principal modeling activity, which benefited from detailed analysis of demand patterns and drivers by industrial sub-sector and type of use.

3. Electric power demand for gas

- *2003 Base Incremental Unit Spreadsheet_Fuel Switchable.xls*. This file contains the economic and operating assumptions for fuel switching power generation capacity used in NARE
- *NARE Data and Assumptions.xls*. This file contains the economic and operating assumptions for each type of power generation capacity used in NARE
- *NARG to NARE Mapping Tools.xls.* This file contains the conversions from the regional and time period specifications used in the NARG model to those used in the NARE model, to allow price and demand data to be readily transferred between the two models between iterations. (The team's modus operandi was to run the NARE model with an assumption of gas prices to the power sector; obtain results for gas demand for power generation which could be input to the NARG model; iterate back to the NARG model with revised gas prices to the power sector; continue until the two models produced reasonably close convergence).

CD with Data in MKP Files

The second CD contains the model files used to run the Altos/MarketPoint models. File names are:

. • *NPC 2003 NARG Reference.mkp*

. • *NPC_NARE_2003BaseCase_10-9-2003.mkp.*

The first file contains the North American Regional Gas (NARG) model. The second file contains the North American Regional Electricity (NARE) model. Both models are portrayed in the versions developed uniquely for the NPC study. The files contain data and assumptions proprietary to the NPC and model architecture proprietary to Altos Management Partners Inc. and MarketPoint Inc. As such these files will only be distributed to bona fide current licensees of Altos models.

STUDY BACKGROUND

In response to a March 13, 2002 request for advice from the Secretary of Energy, the National Petroleum Council (NPC) conducted a comprehensive study of North American natural gas issues. The study's report, *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*, was formally approved, presented to the Secretary, and publicly released by the NPC on September 25, 2003.

Study Report

Results of the 2003 NPC Natural Gas study are presented in a multi-volume report as follows:

- Volume I, *Summary of Findings and Recommendations*, provides insights on energy market dynamics as well as advice on actions that can be taken by industry and government to ensure adequate and reliable supplies of energy for American consumers. It includes an Executive Summary of the report and an overview of the study's analyses and recommendations.
- Volume II, *Integrated Report*, contains discussions of the results of the analyses conducted by the three Task Groups: Demand, Supply, and Transmission & Distribution. This volume provides further supporting data and analyses for the findings and recommendations presented in Volume I. It addresses the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions that may affect the potential for natural gas demand, supplies, and delivery through 2025. It provides insights on energy market dynamics, including price volatility and future fuel choice, and an outlook on the longer-term sustainability of natural gas supplies. It also expands on the study's recommended policy actions. This volume presents an integrated outlook for natural gas demand, supply, and transmission in the United States, Canada, and Mexico under two primary scenarios and a number of sensitivity cases.

  The demand analysis provides an understanding of the economic and environmental determinants of natural gas consumption to estimate how the industrial, residential/ commercial, and electric power sectors may respond

under different conditions. The supply analysis develops basin-by-basin resource and cost estimates, presents an analysis of recent production performance, examines potential technology improvements, addresses resource access issues, and examines potential supplies from traditional areas as well as potential new sources of supply such as liquefied natural gas and Arctic gas. The transmission, distribution, and storage analysis provides an extensive review of existing and planned infrastructure in North America emphasizing, among other things, the need to maintain the current infrastructure and to ensure its reliability.

- *Task Group Report Volumes and Appendices* include the detailed data and analyses prepared by the Demand, Supply, and Transmission & Distribution Task Groups and their Subgroups, which formed the basis for the development of Volumes I and II. The output of the study's computer modeling activities is also included. The Council believes that these materials will be of interest to the readers of the report and will help them better understand the results. The members of the National Petroleum Council were not asked to endorse or approve all of the statements and conclusions contained in these documents but, rather, to approve the publication of these materials as part of the study process.
- *CD-ROMs* are available as part of the study's report documentation. One CD contains further input/output on a regional basis for the study's principal modeling activities. That CD also contains digitized maps, which were used in assessing the potential impact of conditions of approval for access to key Rocky Mountain resource areas. Another CD contains the input data developed by the NPC for use in the study's supplemental modeling activities.

Study Models

As in the 1992 and 1999 studies, econometric models of North American energy markets and other analytical tools were used to support the analyses. Significant computer modeling and data support were obtained from outside contractors; and an internal NPC study modeling team was established to take direct responsibility for some of the modeling work. The Coordinating Subcommittee and its Task Groups made all decisions on model input data and assumptions, directed or implemented appropriate modifications to model architecture, and reviewed all output. Energy and Environmental Analysis, Inc. (EEA) of Arlington, Virginia, supplied the principal energy market models used in this study, and supplemental analyses were conducted with models from Altos Management Partners Inc. of Los Altos, California.

The use of these models was designed to give quantified estimates of potential outcomes of natural gas demand, supply, price and investment over the study time horizon, with a particular emphasis on illustrating the impacts of policy choices on natural gas markets. The results produced by the models are critically dependent on many factors, including the structure and architecture of the

models, the level of detail of the markets portrayed in the models, the mathematical algorithms used, and the input assumptions specified by the NPC Study Task Groups. As such, the results produced by the models and portrayed in the NPC report should not be viewed as forecasts or as precise point estimates of any future level of supply, demand, or price. Rather, they should be used as indicators of trends and ranges of likely outcomes stemming from the particular assumptions made. In particular, the model results are indicative of the likely directional impacts of pursuing particular public policy choices relative to North American natural gas markets. (Further model information is available in the Integrated Report and the Task Group Reports.)

MODELING METHODOLOGIES

This section describes the natural gas market modeling methodologies used by the NPC. The modeling framework developed and maintained by Energy and Environmental Analysis, Inc. (EEA) formed the basis of gas market outlooks in the current study. Additional work was conducted to apply data and develop underlying assumptions for models by Altos Management Partners Inc. so that these models could be considered for application in future NPC efforts, as well as to make NPC information more readily available to a wider group of users.

In the course of this study, the NPC developed databases related to resource base quantities and production costs, gas pipeline capacity and rates, and characterizations of gas demand volumes versus price. It is the intent of the NPC to make these data available to government agencies and other interested parties. The NPC also will continue working with government agencies, such as the USGS, to determine the feasibility of updating, utilizing, and maintaining the resource, engineering, and cost data developed by the NPC.

Resource Assessment Process

The NPC study's resource assessment was based on best practices learned from prior NPC studies and from other similar studies. It was designed to use publicly available data, to be play-based, and to provide a thorough review by geoscientists and engineers. The resulting assessment represents an industry consensus.

Many sources of public and commercial data were used. For the United States, data from the Minerals Management Service (MMS) and United States Geological Survey (USGS) comprised the baseline data. For Canada, the Canadian Gas Potential Committee (CGPC) assessment was primarily used. For Mexico, a combination of IHS Energy Group (IHS) and USGS data were used. Production performance data were derived from the Energy Information Administration (EIA), IHS, and NRG Associates (Nehring). Cost data were derived from the American Petroleum Institute (API) in the United States and the

Petroleum Services Association of Canada (PSAC) in Canada.

Cost Methodology

A critical part of the NPC study was estimating reasonable costs for use in the model to determine commercial resources. Costs were needed for all aspects of onshore and offshore gas development – exploration and development drilling, production and lease facilities, and operations and maintenance. Where possible, public and commercial databases were used to estimate costs. Sources included, among others, the API Joint Association Survey on Drilling Costs, the PSAC Well Cost Studies, and the EIA Oil & Gas Lease Equipment and Operating Costs report. In areas where adequate public and commercial data were not available, costs were based on available information and circulated for review and comment to industry experts familiar with costs in that area. Costs were then revised based on the input received. At each of the regional workshops, which were held primarily to review the resources, costs were also discussed in order to determine the key factors that might affect costs in that region (i.e., infrastructure, weather, drilling depths, etc.).

The costs used in the model are average costs for generic operations. For example, the well costs are for generic wells at an average drill depth. Actual costs will vary with regards to water depth, drill depth, pore pressure, rig type, etc., depending on specific locations. The same is true for development costs. Actual costs will depend on location, infrastructure, local conditions, well productivity, etc. All costs used in the modeling exercise were expressed in year 2000 dollars.

The Altos Models

In order to develop additional tools to supplement the EEA forecasting model in the future, the NPC also licensed the North American Regional Gas (NARG) model and the North American Regional Electricity (NARE) model from Altos Management Partners Inc. All characterizations of North American gas and electric power markets incorporated into the Altos model were developed by a modeling team that was part of the NPC natural gas study. Although significant progress was made developing input to the model, there was insufficient time during this study to thoroughly review the results with industry representatives and build this feedback into the model. At the time of publication, some changes were felt to be appropriate. The modeling frameworks and their associated algorithms are described below.

Précis of NARG/NARE Technique

The NARG/NARE models are based on textbook microeconomic techniques:

- **Price taking, profit maximizing producers competing in a network of supply chains that comprise the natural gas and electricity system.** Markets contain myriad independently operating, self-interested, profit-maximizing producers. NARG/ NARE represents every such producer as a profit-seeking entity and computes the balance of forces that applies in a network of simultaneous profit-seeking entities. (Resource producers are "Hotelling" rational expectations producers.)
- **Price taking, cost minimizing consumers competing in a network of supply and consumption chains.** Analogous comments to producers apply. Consumers independently pursue their private self interests. NARG/NARE represents such pursuit.
- **Walrasian equilibrium (market clearing).** In NARG/NARE as well as in the real world, markets clear. There is neither excess supply nor excess demand because prices adjust. Walrasian equilibrium means prices adjust to ensure zero excess supply and zero excess demand in every spatial market at every forward point in time, and that is what NARG/NARE calculates.
- **Zero arbitrage across space or across time at equilibrium.** In NARG/NARE, market agents fully arbitrage everything that is arbitrageable. There is no "low hanging fruit" left after the model solves. No one can lend or borrow from a bank and beat the model solution at any spatial location or any point in time. No one can reschedule production or consumption and beat the model solution.
- **Zero economic incentive for any agent to change away from the model solution.** Every agent in the model is pursuing a "best response" to the actions of every other agent in the model. There is (and must be) no incentive for any agent in the model to change away from what he or she is doing; otherwise, that agent would do so and the prices would change to a different level. There is an intrinsic stability of agent decision making at the NARG/NARE market solution.

The NARG Model

NPC used the long term version of the NARG model. For the purposes of the 2003 NPC study, 230 natural gas supply nodes and 72 demand regions were defined. The supply regions were aggregated from over 700 plays, and the demand regions were segmented into residential, commercial, chemical industry, other industry, and power generation. The model was configured through 2045. (Because results in the long term NARG model are computed and reported annually over a long time horizon, the gas storage component of the model, which represents seasonal load variations, was not used for this study.)

Users of NARG specify supply and demand nodes, and pipeline

infrastructure connections, called links, as follows:

- Supply, or "resource" nodes require cost-of-supply curves, which characterize the increasing marginal cost of bringing new gas to market. Cost-of-supply curves are derived from resource availability, production decline profiles, and cost data.
- Demand nodes require specification of demand volumes, price elasticity, and other variables such as income, weather, and population.

- Pipeline links, processing plants, and LNG terminals require capacity and tariff specification. The model constructs new capacity when user-defined economic criteria are met.

The NARE Model

The NARE model includes a database that contains every generating unit in North America (capacity, fuel-type, costs, etc.) along with power demand at every node or busbar in North America. Like NARG, NARE computes a "zero-arbitrage" solution to build, operate, and retire units within each region and across regional boundaries. Users input the capital and operating costs of new capacity, which are allowed to compete against existing capacity (which is aging and becoming more costly). Operation of the existing generation fleet at every given point in time is based on competitive economics. NPC seeded every region in NARE with the appropriate suite of competing new capacity addition nodes (including capital and operating cost) pertinent to that region. NARE now contains a comprehensive industry view of what is truly feasible in each of the 148 nodal regions that comprise North America complete with the cost of entry and operation. NARE projected what actually will be built as a function of the NPC capacity additions cost estimates.
Gas prices reported as output from the NARG model were input to the NARE model to project gas consumption based on economic dispatch of the generation. Gas burn projections from the NARE model were fed back into the NARG model, and it was rerun with that new gas burn to create a new gas price. This new gas price was then fed into NARE. This iterative process was used to reach convergence of price and demand between the two models.

Modeling Methodology

The NPC modeling team comprehensively customized the NARG and NARE models. The most important features incorporated into the NPC version of the models are outlined as follows.

<u>Resources and Supply</u>

Initially, the team modeled cost-of-supply curves for all geologic plays in North America. However, in order to simplify the computational load and improve model performance, the cost-of-supply data for proved reserves, proved growth, and undiscovered resources from over 700 plays were aggregated into 230 supply nodes.

Technical Resource**.** The technical resource included proved reserves, growth, and undiscovered resource assessments. The resource was also segmented into conventional gas (non-associated and associated gas) and nonconventional gas (shale gas, coal bed gas, and tight gas). Total resource assessments were adjusted to reflect current access restrictions.

Cost-of-Supply Curves**.** For each node and gas reservoir type, full development and operating costs were used for proved reserves growth and undiscovered resources, while only operating cost curves were used to define continued production of proved reserves. All costs were provided by an upstream cost estimating team within the Supply Task Group. As of the release of this report, the cost-of-supply curves had not been reviewed and analyzed by the Supply Task Group, and some changes were viewed to be appropriate to achieve consensus within the Supply Task Group on the cost-of-supply input to the Altos model. Detailed pre-processing spreadsheet models were developed to calculate the cost-of-supply input needed by the NARG model. The NRG Associates database was used to statistically estimate the Estimated Ultimate Recovery per well for each play.

The team developed a Monte Carlo simulation to forecast the size order of future discoveries. This "discovery process model" was used to estimate the expected size of the three representative undiscovered fields in each play needed to define a cost-of-supply curve. Technology improvement factors were used for both the capital and operating cost curves.

LNG Imports**.** Nodes were defined to represent existing and new LNG terminal capacity; the costs of landing and regasification were defined for each of these nodes. The model then computed import volumes that would be economic depending on local market price.

Arctic Gas**.** Alaska gas was assumed to be available in 2013 and Mackenzie Delta gas was assumed to be available in 2009, with initial pipeline capacities of 4 BCF/D and 0.9 BCF/D, respectively.

Pipelines

Existing Pipelines**.** Every major pipeline in North America was characterized by its capacity and fixed and variable tariff rates. Discounting based on load factor was incorporated.

Expansions and New Capacity**.** Potential expansions or new-build capacity were specified by year of availability, capital costs, operating costs, and capacities. The model then computed whether to utilize capacity based on the overall economics of transportation and regional price differentials. Near-term planned expansions were explicitly modeled.

Demand

Dynamic elasticity of demand was incorporated in the residential, commercial, chemical sector, and other industrial sectors. The power generation sector was modeled using NARE, and thus was characterized structurally rather than econometrically.

- The demand model incorporated exogenous factors such as economic growth, weather, and population.
- Gas demand was a model output for the residential, commercial, electric power generation, chemical sector, and other industrial sectors.
- For residential and commercial demand, price and income elasticity, as well as the influence of population and weather, were econometrically estimated from historical data.
- For chemicals and other industrial demand, price and income elasticity were estimated from projected price and consumption consistent with the detailed analysis undertaken by the NPC using expanded industrial model developed by EEA.
- For electric power gas demand, the results of NARE were input into NARG. The NARE model contained new-build power generation capacity assumptions.
- Specific model upgrades, such as integration into the World Gas model, increased industrial demand granularity, incorporating a price/income feedback loop, etc., are addressed in the Demand Task Group Report.

Further Altos Modeling Work

The NPC modeling team will continue working with the USGS to determine the feasibility of the USGS updating and maintaining the resource, engineering, and cost data used in the cost-of-supply pre-processor developed by the NPC.