



PROCESS PERFORMANCE IMPROVEMENT CONSULTANTS, LLC

**Determination of Available Capacity and
A Review of Maintenance on the El Paso Natural Gas Co. System
for the Period
November 1, 2000 through March 31, 2001**

**Mark L. Hereth and John S. Zurcher
Hartford Steam Boiler Inspection and Insurance Co.**

March 10, 2002

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1.0 Introduction

HSB was retained to provide an independent evaluation of the methodology used by El Paso Natural Gas Company (EPNG) to determine how much capacity it could make available during the period November 1, 2000 to March 31, 2001. In addition, we were charged with conducting a review of the maintenance performed and maintenance deferred by EPNG on its system during this same time.

We interviewed employees of the company responsible for Gas Control and Maintenance Planning and reviewed direct testimony of Messrs. Somerhalder, Walker and Wilcox and Ms. Shelton. We also reviewed the direct testimony of Mr. Flanders of the Federal Energy Regulatory Commission (FERC) staff and Mr. Yoho, who testified on behalf of Southern California Edison (SCE). We also reviewed EPNG's written responses to information requests from the FERC staff and Various Parties in RP00-241-006, as well as, documents produced by EPNG.

In the report, we describe the physical configuration of the EPNG system. We then identify and discuss factors that impact the amount of physical capacity the company can make available. These are factors largely out of the control of the company and that

introduce transients into pipeline operations. We next describe the approach the company used to manage the pressures in the system in accordance with the letter and spirit of pipeline safety regulatory requirements and in full consideration of the transient operating conditions.

Based on our evaluation, we conclude that EPNG's method of determining available capacity was sound and appropriate in view of the transient conditions and other restrictions on the EPNG system. Furthermore, based on our review of numerous days of operating data, we believe that EPNG correctly determined the amount of available capacity during the relevant period. In addition, we conclude that the company made reasonable and prudent judgments in the selection of maintenance events to take during the relevant period, as well as those it deferred.

2.0 Background on EPNG System

The EPNG system is a large system comprising over 10,000 miles of pipeline and 298 compressor units at 56 compressor stations that have approximately 900,000 horsepower of compression. EPNG's system has two mainlines (northern and southern). These two mainlines are connected by three crossover lines: the Permian-San Juan Crossover line, the Havasu, and the Maricopa line. We characterize this system as a reticulated system because of the interconnectedness of the two mainlines and the three crossovers. There is storage close to the supply end of the system, at Washington Ranch, that is used to help manage line pack and store excess gas.

Gas is supplied into EPNG's northern and southern mainlines through three supply basins: the San Juan Basin, the Permian Basin and the Anadarko Basin. The San Juan Triangle system transports gas from the San Juan Basin and delivers it into EPNG's northern mainline. Because the capacity of the San Juan Triangle is less than the capacity of EPNG's mainlines, shippers cannot typically source all of their gas from that basin.

The EPNG system contains a multitude of receipt, delivery, and interconnect points. There are four (4) delivery points at the California border and 227 delivery points in east-

of-California (“EOC”) locations. The system also has approximately 145 receipt points where it can receive gas from producers in the San Juan, Permian, and Anadarko basins. Finally, the system has 42 mainline interconnects where the EPNG system connects with other interstate, intrastate, and international pipeline systems capable of delivering gas to or receiving gas from EPNG.

3.0 Determining Available Capacity

3.1 The Approach for Determining Available Capacity

The Line 2000 Flowsheet filed by EPNG in FERC Docket No. CP00–422 is used by EPNG as a basic reference point when determining the amount of available capacity. That flow diagram depicts the maximum volume EPNG’s system can transport on a peak day under a set of steady-state operating conditions. Steady-state conditions are those that remain the same day-in and day-out, not subject to change. However, as described in greater detail below, EPNG does not flow gas on a steady-state basis; rather, EPNG operates its system under transient conditions, which are a dynamic set of operating conditions.

The product of Scheduling Cycle Two (2) is a flow plan. The flow plan reflects the total scheduled volumes through various points on the system. It is transmitted to Gas Control so that it can make any necessary adjustments to the remote operating controls of the EPNG system, such as valve and flow controls, to enable the system to flow the scheduled quantity of gas.

The process of evaluating available capacity begins each day at the morning meeting (7:45 AM MST). The prior day’s operational conditions are reviewed and serve as a starting point for the current day's operations. There is a review of the prior day’s maintenance activities, any facility outages that occurred, and the previous day’s throughput on each of the major segments of the system. The current day's planned operations, including any scheduled maintenance are reviewed, to determine the effect of such activities on available capacity.

EPNG staff constantly monitors the conditions on the pipeline system. That monitoring includes any outages at compressor units or other facilities that occur on the system during the day; the volumes of gas shippers are taking or delivering as compared to the scheduled amount; delivery and receipt pressures and volumes at upstream and downstream pipeline systems; and all other factors that can impact the operation of the system.

We understand that EPNG determines the capacity that it can actually make available on a day-to-day basis in light of the dynamic set of operating conditions. This is referred to as a performance-based analysis. This approach includes evaluation of the prior day throughput and maintenance outages, as well as current day operations plan and planned outages. In general, in determining available capacity, the fundamental approach has been to make as much capacity available as possible. Available capacity is adjusted downward only after determining that the system physically cannot transport gas at the available capacity level that has been set.

Periodically company personnel apply a computer model to help in evaluating the impact of capacity for planned maintenance or facility changes. Stoner and Associates developed the model that provides only steady-state prediction of capacity. The model has two applications in this context. First, when maintenance is planned affecting capacity, it is used to estimate the capacity reduction. Second, it is used to estimate changes in capacity, in planning for and after completion of changes to facilities or the addition of new facilities.

3.2 Debits and Credits Do Not Account For How This System is Operated

In reviewing the testimony in this case, it appears that Mr. Flanders, as well as SCE and their consultant, Mr. Yoho, view the process of determining available capacity in a fashion similar to that of managing a general ledger in accounting. The perception is that there is a starting balance as reflected in the Line 2000 Flowsheet, and that factors that result in transient system behavior can be managed as “debits” or “credits”. This analogy is appropriate for planning and scheduling but is not an appropriate reflection of intra-day operation, and hence, how capacity is actually made available within a system like

EPNG's. The transient nature of the system requires one to understand the factors that influence available capacity. These factors are described below.

4.0 Factors Affecting Available Capacity

In our review of the El Paso system, we find there are 15 factors that impact available capacity. The factors are listed in Table HSB -1. As indicated on the table, 13 of the 15 factors are not within EPNG's control. Of these thirteen, only four of these can be planned for in scheduling and operation. The other nine are unpredictable and gas control personnel must utilize engineering expertise to manage these factors.

As shown in Table HSB – 1, some of these factors are under the control of multiple parties. When considering the factors and the parties who control the factors, in conjunction with all receipts, deliveries and interconnects, this yields more than 500,000 possible permutations. Permutations are changes that manifest themselves in operation of the pipeline as transients. Given this characteristic, the system does not lend itself to precise mathematical analysis; it requires application of experience and sound engineering expertise.

We review each of these factors below and the impact it has on making capacity available within the system.

4.1 Packing

Shippers can leave gas on the system or deliver volumes in excess of nominated volumes. This is referred to as packing the system. It has the effect of raising line pressure and can result in reducing receipts upstream to manage line pressure. This is a factor that is clearly outside of the control of EPNG, and EPNG gas controllers must operate the system to accommodate resulting pressure increases.

4.2 Overpull

Overpull or overdraft occurs when shippers take more gas out of EPNG's system than they introduce into it. Overpull creates imbalances that reduce the pressure of the system, thereby reducing line pack. This is a factor that is clearly outside of the control of EPNG,

and EPNG gas controllers must operate the system to accommodate resulting pressure reductions.

Factor	Operator	Shipper	Office of Pipeline Safety	EPNG
Customer Window Limits	P			
Packing		U		
Overpull		U		
Non-ratable Pull		U		
Low Pressure Delivery		U		
Underperformance-Low Volume		U		
Shipper Rights for Receipt and Delivery		U		
Full Requirements Shippers EOC		U		
Ambient Temperature				P
CAO Pressure Reduction			P	
Planned Maintenance			P	P
Unplanned Maintenance				U
CAO Maintenance			P	
Compressor Fuel				U
Storage - Washington Ranch				U

Legend: Letter in column indicates party controls factor.

P - Indicates factor can be planned for.

U - Unpredictable impact.

4.3 Non-ratable pull

Some shippers take gas on an uneven hourly basis; i.e., they take gas at variable flow rates or intermittently cease taking gas during the day. Electric power plants, particularly peaking plants, can operate in a mode resulting in non-ratable pulls. This causes EPNG's line pack and line pressures to fluctuate, further reducing the pressure in the system. This is another factor that is clearly outside of the control of EPNG, and EPNG gas controllers must operate the system to stabilize resulting imbalances.

4.4 Low Pressure Delivery

A low-pressure delivery is a delivery to EPNG at pressures substantially lower than what it is designed to receive. Production operators may experience production declines or mechanical problems that result in deliveries into the EPNG system at lower pressures. Upstream producers and gathering systems may also experience freeze-offs and shutdowns for maintenance and emergencies on upstream pipelines. These all contribute to upstream operators delivering gas to EPNG at lower line pressures. This is a factor that is clearly outside of the control of EPNG, and EPNG gas controllers must operate the system to stabilize resulting imbalances.

4.5 Under-performance (Low Volume Delivery)

Delivery of a volume less than scheduled is referred to as under-performance. Under-performance can result from the reasons described above for low-pressure deliveries; however, it can also result from the shipper simply not delivering the full-scheduled volume. This has the effect of lowering the system pressure. This is clearly outside of the control of EPNG, and EPNG gas controllers must operate the system to stabilize resulting imbalances.

4.6 Shipper Rights for Receipt and Delivery

EPNG's firm shippers can nominate alternative delivery points that are in the same zone or an upstream zone instead of the primary points specified in their contracts. Shippers

can also ask EPNG to divert volumes scheduled to their primary points to go to other delivery points once the gas has started to flow. Diversion of gas in this manner is referred to as flow day diversion. This has the effect of changing the rates between scheduling cycles. This is a factor that is clearly outside of the control of EPNG, and EPNG gas controllers must operate the system to stabilize resulting imbalances.

4.7 Full Requirements Shippers East of California

Demand for gas by EPNG's East of California (EOC) customers impacts EPNG's available capacity for California. We understand that during the relevant period the EOC demand was higher than in previous years. Many of the EOC customers are firm, full requirements customers who have no limitations on the amount of gas they can nominate, except their nominations cannot exceed their daily gas needs. Their demand created a large degree of unpredictability during the relevant period. This is another factor that is clearly outside of the control of EPNG, and EPNG gas controllers must operate the system to stabilize resulting imbalances.

4.8 Custody Limits

EPNG can receive custody limits from interconnected pipeline operators. Such operators inform EPNG that they will not accept a total volume of gas that day in excess of the custody limit they establish. Custody limits constrain the amount of gas EPNG can schedule to a particular location that day. This is another factor that is outside of the control of EPNG, and EPNG gas controllers must operate the system to stabilize resulting imbalances.

4.9 Ambient Temperature

Ambient temperatures are known to have an impact on available capacity of a natural gas pipeline system. We start with the principle that a natural gas pipeline will have more capacity in cold weather than it will in warm weather for two reasons. Gas at higher temperatures at a given pressure occupies a larger volume than gas at lower temperatures, and in a space of fixed volume within the pipeline, the capacity is lower during the shoulder and summer months. In addition, air has a lower density at higher temperatures,

in effect, yielding less oxygen per cubic foot of gas, resulting in compressors providing less horsepower during shoulder months. Adjustments were made to available capacity to reflect the impact of ambient temperatures on the EPNG system.

4.10 Corrective Action Order Pressure Reductions

The Office of Pipeline Safety's Corrective Action Order (CAO) resulted in restricting pressure in the ruptured line as well as adjacent and other associated lines. Specific details regarding the way in which pressure was restricted are described below in Section 6.1. The CAO had the impact of restricting the volumes that could be moved through the Southern system and restricted the company's flexibility in managing pressure.

4.11 Storage

EPNG owns and operates a storage field at Washington Ranch. Gas can be either injected into the field or withdrawn to help manage line pack. The location of the field, approximately 25 miles west of the Pecos River, limits the role it can play in managing line pack. This storage is not at or near significant delivery points, so it does not provide the flexibility that market area storage will provide. For comparison purposes, examples of market area storage are the Howell Field on the end of the Panhandle and Trunkline long haul systems, or the Leidy Field at a key juncture on the grid-like Dominion (CNG) system.

4.12 Compressor Fuel

EPNG collects fuel for compression based on its projected demand for the day. The volume of fuel becomes a factor that has to be managed as the volume consumed can be significantly lesser or greater than projected for the day. This effect is exacerbated or mitigated depending on whether the pipeline is undergoing pack or being drawn down. It is out of the control of the operator and must be managed in conjunction with all the other factors.

4.13 Maintenance (Planned, Unplanned and CAO)

In general maintenance can be classified in one of two ways: planned and unplanned. Planned maintenance is also referred to as scheduled maintenance. As described below there was a special class of planned maintenance during the relevant period associated with the Office of Pipeline Safety's CAO. (Note: Planned, Unplanned and Maintenance related to the CAO comprise three (3) of the fifteen factors affecting capacity). Unplanned maintenance is outside of the control of EPNG, and EPNG gas controllers must operate the system to stabilize resulting imbalances.

During the relevant period, available capacity was adjusted as necessary to account for the impact of maintenance activities. Maintenance activities, which are required to operate a safe and reliable pipeline system, may require portions of EPNG's system, such as compressor units, to be taken out of service while the maintenance is performed. Such outages can reduce the capacity of the system. Our review of EPNG's scheduling process indicated that when maintenance was required due to safety considerations, EPNG scheduled such maintenance as soon as possible. Maintenance required for reasons other than safety considerations was attempted to be scheduled to minimize the impact of such activities on shippers. EPNG attempted to schedule as little maintenance as possible in traditional peak months such as January.

In general, EPNG posts planned maintenance events that have the potential to impact available capacity on its electronic bulletin board (EBB). This is done monthly, just prior to bid week (20th of each month). Maintenance outages, shutdowns and overhauls effecting throughput are also posted on the company's web site. EBB postings notified shippers of the reduction in available capacity caused by each of the maintenance events that occurred during the relevant period.

5.0 Management of Pressure

The amount of pressure needed to move capacity on any system is supplied by horsepower. Operating at pressures above those necessary to move the required volumes wastes fuel, increases emissions, promotes unnecessary wear on equipment and requires

unnecessary manpower. To summarize pressure management we provide the following discussion.

5.1 Overview of Pressure Management

Control of the pipeline system is achieved by monitoring the pressures throughout the system and then reacting to the undesired pressure changes. Two methods to control pressure changes are to change compressor utilization and to change storage utilization.

In a system with market area storage or storage at key points along the system, operation at steady state is feasible. However, in pipeline systems with limited storage or no market area storage, there are innumerable transients caused by constantly changing factors. As described above, EPNG's system is a pipeline system with limited storage. Pressure fluctuations, many of which are sudden and involve significant volumes, are numerous and usually uncontrollable by the operator. This is complicated with hundreds of receipt and delivery points, as well as with planned and unplanned outages both on and off system. The operator must anticipate and manage these changes to achieve both safety and reliability.

Once the EPNG system is scheduled, changes to receipt and delivery pressures are made by customers and shippers. Storage utilization can be changed in two ways, first with line pack and second with injection and withdrawal into storage fields. EPNG has only one storage field, which, due to its location and relatively small size, provides minimal flexibility for affecting pressure changes. Compressor utilization is the main pressure control method on the EPNG system.

5.2 Maximum Allowable Operating Pressure

The Office of Pipeline Safety, as specified in 49 CFR Part 192 (Pipeline Safety Regulations), requires pipeline operators to operate pipeline facilities in a manner so that they will not exceed the Maximum Allowable Operating Pressure (MAOP). This is borne out specifically in regulatory language and supported by an interpretation by the Office of Pipeline Safety. The interpretation for MAOP provides: "192.201(a)(2)(i), when it states "may not exceed" means "may never exceed.'" (Office of Pipeline Safety web site,

<http://ops.dot.gov>. Letter from Melvin A. Judah, Acting Associate Director for Pipeline Safety Regulation, Materials Transportation Bureau (predecessor of Office of Pipeline Safety), Department of Transportation, to William A. Slagg, Director, Gas Bureau, Engineering Division, Wisconsin Public Service Commission, dated February 1, 1982). MAOP is determined by a number of factors including the characteristics of the pipe or components, the post construction pressure test value, and the population density.

In addition to the requirement to operate facilities in a manner such that the operating pressure does not exceed MAOP, the regulations recognize that a pressure-related upset can occur. To protect the facilities from overpressure due to a pressure-related upset, the regulations require the installation of overpressure control devices to protect the pipeline in the event of an overpressure situation.

A careful balance must be achieved to manage both reliability and safety where pressure is concerned. For safety purposes, pressure is the most significant item to control and excursions above MAOP are not permitted. If they do occur, the operator must prepare a report that documents the abnormal conditions and what corrective actions were taken. Therefore prudent pipeline operators manage system pressures to never exceed MAOP, which often means that a safety margin below MAOP is necessary. From a deliverability standpoint, pressure is also the most significant item to control. When considering deliverability, maximizing pressure as close to MAOP is desirable; however, it must be done to ensure that MAOP is not exceeded.

5.3 The Role of Compression

On the EPNG system, compression is of two types, reciprocating compression and centrifugal compression. This compression is driven by reciprocating engines: gas fired turbines or electric motors. Each compressor is operated considering many factors effecting the safe and reliable operation of the pipeline system including compression, fuel usage, and minimization of pollutant emissions, maintenance optimization, among others.

EPNG's operation of its compression is reasonable considering all of the relevant factors. Units are not run when not needed in order to save fuel and reduce pollutants, units are maintained to provide reliability, and operation is performed in a manner that provides safe transportation.

Compressor discharge pressures require management for several reasons. Overpressure protection activation must be avoided. Suction pressures must be maintained to maximize compressor utilization. All these factors must be managed to avoid system shutdowns and upsets.

Of significant concern in system operation is the prevention of shutdowns and upsets. For example, if MAOP is exceeded and the unit overpressure protection shuts the unit down, a domino effect can occur. The pressure upstream of the station rises quickly causing idling or shutdown of the upstream compression, backup of gas to receipt points, operation above MAOP upstream or venting of upstream gas to atmosphere. The pressure downstream of the station decreases dramatically causing idling or shutdown of downstream compression and reduction of gas to delivery points. Considering all the potential negative impacts, controls are put in place to prevent these occurrences.

Based on operating history and the current pressure profile, at certain points along the EPNG system compressor discharge is below MAOP. This is done to prevent exceeding of MAOP, activation of an overpressure device, or unit shutdown in the event of transients caused by receipt and delivery changes. Due to the rapid changes in pressure, control devices cannot physically respond quickly enough to avoid exceeding MAOP, without setting discharge pressures at an experienced based set point.

At other points along the EPNG system, compressor discharge is very near MAOP. This is done to "pack" the system in anticipation of demand. Demands often occur in excess of steady state capabilities diminishing the operating pressure. Therefore EPNG strives to pack the system when possible to meet demand when needed. Longer-term demands above steady state conditions can significantly diminish the operating pressure.

5.4 The Role of Safety Devices

To control the pressure of the pipeline system, several devices are used. For example, the compressor programmable logic controller controls the pressure out of the compressor; pressure regulator valves control pressure to pipelines that operate at a lower MAOP; and other pressure limiting devices may shut off flow in its entirety.

To prevent an overpressure situation on the pipeline system, several devices are used. For example, a high-pressure shutdown switch shuts down a compressor; pressure relief valves vent gas to the atmosphere thus relieving pressure; and other pressure limiting devices may shut off flow in its entirety. Overpressure protection as required by the Pipeline Safety Regulations is mandated to be set at the lower of 110% of MAOP or 75% of the Specified Minimum Yield Strength (SMYS) of the pipe. Since most of the EPNG pipelines are limited to operation at 72% of SMYS the equivalent factor is 104% of MAOP ($0.75/0.72 = 1.04$). Therefore overpressure protection for most of the EPNG system is limited to 104% of MAOP not 110% of MAOP.

5.5 Summary of Managing Pressure and MAOP

The transients introduced into the system by the 15 factors described in Section 4 result in a range of observed pressures. The upper end of the pressure range on the system is limited by the MAOP limit. The lower end of pressure range can vary from hour to hour and location to location. The range can be from a few pounds lower than MAOP to many pounds lower than MAOP. The numerous delivery points throughout the system and the abundance of receipt points on the north and east-end of the system exacerbate this. The fact is that a reticulated system like EPNG cannot operate at MAOP on a system-wide basis but rather at a level lower than MAOP. The EPNG system is unlike a grid transmission system with an abundance of storage and a high degree of flexibility. The later systems can and often do operate much nearer to MAOP on a continual basis.

6.0 Regulatory Environment Post Carlsbad

Of special concern during the relevant period was the regulatory environment after the Carlsbad incident.

6.1 Background on the Incident and Corrective Action Order

On August 19, 2000 EPNG experienced a rupture on one of the large-diameter pipelines on its southern system near where that system crosses the Pecos River south of the Carlsbad Compressor Station. The rupture resulted in a fire and the tragic deaths of twelve people who were camping nearby.

As a result of its preliminary investigation in the days immediately following the rupture, the Office of Pipeline Safety issued a Corrective Action Order to EPNG as provided in 49 CFR Part 190 on August 23, 2000. The Corrective Action Order was multi-faceted with primary emphasis on restricting pressure in the ruptured line as well as adjacent and other associated lines, while specifying an extensive inspection and testing program of those lines. The restrictions involved maintaining the pressure out of the stations upstream of Pecos to 668 psig (80% of line MAOP), the first valve section immediately upstream of Pecos was restricted to 538 psig (80% of line pressure at time of failure), and Pecos discharge was restricted to 660 psig (80% of line MAOP).

We have reviewed the Corrective Action Order issued by the Office of Pipeline Safety mandating restrictions and inspection/testing requirements as a result of the incident on Line 1103. In addition we reviewed the actions taken by EPNG to comply with the order.

6.2 EPNG Response Plan

EPNG immediately initiated a program that involved trying to identify all other locations on the system where internal corrosion might have previously gone undetected and to undertake an extensive pipeline integrity assessment and remediation program to address internal corrosion. The reason for focusing on internal corrosion was based on the Corrective Action Order that in part states “Preliminary investigation of Line 1103 by OPS and National Transportation Safety Board (NTSB) investigators indicate that significant internal corrosion was visible on the failed section. Internal corrosion may have been a contributing factor in the line failure. The possibility of internal corrosion on other lines in the area is a safety concern”. This extensive program involved making

pipelines piggable, conducting smart pigging operations, investigating those areas where the smart pig indicated that there might be anomalies, evaluation of anomalies, repairing anomalies when necessary, and initiating preventive actions.

Numerous outages had to be planned for and conducted to carry out this extensive program. These outages were conducted before, during and after the relevant period. As of the date of this report, our understanding is that EPNG believes that all necessary work has been completed, however, final release from supervision of the Corrective Action Order has not been granted by the Office of Pipeline Safety.

The pressure restrictions ordered by the Office of Pipeline Safety have had a longer lasting and more deleterious affect on system operation than the inspection and testing program. As of the date of this report, the pressure restrictions have not been removed.

6.3 The Effect of the Pressure Restrictions

Under no circumstances are the pipeline segments to exceed the restricted pressure set forth in the CAO. With this constraint in place, EPNG must run somewhat below the restricted pressure to prevent exceeding the restricted pressure in case of an upset such as loss of a unit. For example, the Pecos compressor set point alarm is 646 psig instead of 660 psig. (SCADA data screen from Pecos Station). The 14 psig additional restriction is appropriate to ensure that the mandated restricted pressure is not exceeded. This action is common in the industry and based on the regulatory language and on an interpretation to 49 CFR Part 192. As previously stated, the interpretation for Maximum Allowable Operating Pressure (MAOP) states “192.201(a)(2)(i), when it states “may not exceed” means “may never exceed””. (Office of Pipeline Safety web site, <http://ops.dot.gov>. Letter from Melvin A. Judah, Acting Associate Director for Pipeline Safety Regulation, Materials Transportation Bureau (predecessor of Office of Pipeline Safety), Department of Transportation, to William A. Slagg, Director, Gas Bureau, Engineering Division, Wisconsin Public Service Commission, dated February 1, 1982).

To restrict the pressure to 538 psig in the pipeline segments immediately upstream of Pecos, EPNG added a pressure-limiting device to the mainline valves that are set to close at 520 psig. A bypass regulator set was installed on an expedited basis to control pressure to the restricted 538 psig. Once the mainline valve shuts, the regulator takes over and limits the pressure. At the time the installation was made, it was anticipated that the Office of Pipeline Safety Corrective Action Order would be satisfied within a few months and the pressure limiting devices would be removed. Instead, the order is still in place at this time and operation in this mode continues.

The mainline valves are large diameter valves and the pressure-limiting device completely closes the valve rather than throttling the valve to control pressure. The regulator controls the pressure. Due to transients in the pipeline, EPNG must however manage the pressure at the valve to something less than the 520 psig set point. Inadvertent closure of the mainline valves has had a limited domino effect both upstream and downstream of Pecos causing capacity reductions. To avoid this, EPNG operated the system at pressures on the suction of Pecos at averages of approximately 480 psig. The fact that the pipelines upstream and downstream of Pecos are not operating at full MAOP during the relevant period is attributable to the regulatory actions of the Office of Pipeline Safety rather than the discretionary decisions of EPNG.

6.4 Longer Term Impact Than Expected

Up until the fall of 2000, returning a pipeline to service was performed expeditiously by the pipeline operator. The cause of the failure was determined. The pipeline was repaired and returned to full service. Remedial actions for the affected pipeline, adjacent pipelines, and associated pipelines were scheduled for the near term.

Since the fall 2000, the Office of Pipeline Safety has handled failures on pipelines quite differently. The present approach is to shut down the pipeline immediately. Repairs are not allowed to begin until after a full field investigation by government agencies and by the company are completed. Once repairs are complete the pipelines may be allowed to

operate at reduced pressure. However, operation at full pressure is not allowed until the integrity of the affected pipeline, adjacent pipelines, and associated pipelines are confirmed by the operator and approved by the regulator. This process is very slow as is evidenced by the fact that the affected EPNG lines are still not allowed to operate at full MAOP even 18 months after the incident. In addition, EPNG was unaware of the new policy by the Office of Pipeline Safety and had full expectations to get the pipelines back in service in short order. It is our opinion, based on discussions with personnel, that EPNG did everything possible to expedite returning the pipelines to service. This is exemplified in a memo from William Healy to Richard Lopez (inspector with the Southwest Region of the Office of Pipeline Safety) dated December 29, 2000. In the memo, Mr. Healy describes the company's plan to expedite work so that the lines can be returned to full operating pressure before the winter season begins. There are other examples in Response to Data Requests from Various Parties Nos. 36 and 39, dated January 14, 2002.

6.5 Conclusions with Respect to the Carlsbad Incident

It is our opinion that the Carlsbad incident has had profound affects on the operation of the pipeline system. This affect has manifested itself in two ways. First, there is the direct effect of reduced operation of certain facilities as explained above. Second, there is the effect of operation of a pipeline system in the aftermath of a significant incident. The CAO imposes strict limitations on the line pressures at which EPNG can operate the affected portions of its pipeline and threatens civil penalties for violations.

We believe the company's approach was prudent and responsible. Pipeline operators must always balance safety of the public, their employees and the environment with cost elements as well as the deliverability of the pipeline system. It is our opinion that EPNG has managed these elements appropriately.

7.0 Maintenance

Maintenance events have by far the largest EPNG-controllable impact on operations; therefore we reviewed these events in detail.

7.1 Process for Scheduling Maintenance

We reviewed the maintenance scheduling process for both planned and unplanned maintenance events and interviewed personnel responsible for maintenance planning and tracking. The processes are described in Response to Request 30 from the Joint First Set of Data Requests from Various Parties (“Request No. 30”), for planned maintenance and Response to Data Request 31 from the Joint First Set of Data Requests from Various Parties (“Request No. 31”) for unplanned maintenance.

The quarterly, monthly and daily reviews of maintenance are a “best practice” in the industry. The statement that “every effort is made to perform maintenance in a manner that minimizes the impact to shipper” (contained in Request No. 30) is supported, in our opinion, by the discussions below in Sections 7.3 and 7.4.

The process for unplanned maintenance is standard for the industry. The ability for “any employee on site...to remove a pipeline component from service” (contained in Request No. 31) is a best practice in the industry and demonstrates EPNG’s commitment to providing safe and reliable service. The process reflects both the minimization of unscheduled maintenance as well as the expediting of maintenance when an opportunity arises due to an unscheduled outage.

Planned and unplanned maintenance activities are consistent with the American Society of Mechanical Engineers Standard B31.8S, (Integrity Management Program) for responding to conditions affecting the integrity of pipeline facilities. This includes provisions for evaluating anomalies identified during pig runs and elapsed time guidelines for investigation and repair of anomalies.

7.2 Review of Maintenance Events During the Relevant Period

Maintenance events for the relevant period were reviewed to evaluate the prudence of the company's actions. We reviewed each of the maintenance events taken during the relevant period. We reviewed company records including Exhibit EPNG-18, El Paso Natural Gas Co. Shutdown Schedule; EPNG-67, Available Capacity Provided by Gas Control to Scheduling, as amended; EPNG-13002, the Operations Control Reports and the Coordinators Logs in EPNG-10001. We discussed many of the events with company personnel and are satisfied that the company acted in a prudent and responsible manner.

7.3 Review of Maintenance Events Discussed by Mr. Yoho

Mr. Yoho asserts that five maintenance outages could have been performed at times other than the relevant period. We do not believe Mr. Yoho's criticisms are valid. We describe why we believe he is criticism is without foundation below.

Two of these caused a more significant impact to available capacity: Window Rock and Cornudas B. A narrative history of the maintenance planning and the work conducted at Window Rock and Cornudas was provided in Response to Request No. 16 from the Joint Third Set of Data Requests From Various Parties. We discuss each of the five below.

7.3.1 Window Rock

The Window Rock outage was planned for the summer of 2000. Delivery of material and equipment caused a postponement until late October. Due to unscheduled maintenance at another station, this project was again delayed until started on November 2nd. Discussions were held in order to confirm doing the project in a shoulder month or waiting several months to after the heating season. EPNG had been experiencing increasing numbers of compressor unit trips and it was decided that the risk associated with problems with the units during the upcoming winter months was greater than the risk of restricting capacity early in a shoulder month.

When the maintenance began, capacity restriction was estimated at 480 MMCFD. On November 2, Window Rock Stations A and B were taken off-line as set forth in EPNG-67 (Wilcox-67)). On November 3, EPNG increased capacity by 230 MMCFD. On November 4, capacity was increased by 50 MMCFD. On November 12, capacity was increased by 100 MMCFD as six units of Window Rock B were returned to service. On November 16, the remaining units at the Window Rock station were returned to service resulting in another 100 MMCFD of additional capacity being available.

The company increased available capacity five times during the outage. It is evident that EPNG made capacity available to its shippers when it could be made available. We believe that EPNG acted in a prudent and responsible manner taking the outage.

7.3.2 Cornudas B

Mr Yoho refers to EBB 3428. EPNG had been experiencing problems with the regenerator since 1986. The unit had been inspected and repaired numerous times. In August, the company made the decision to convert the unit to simple cycle. There were delays in procurement and it was decided the work could not be conducted prior to the winter months. A PLC replacement project was rescheduled to early March and the plans were then to combine the simple cycle installation and the PLC project into one outage to minimize downtime of the units. It is evident that EPNG tried to schedule the work to minimize the impact on shippers by deferring the work and combining two projects during a single outage and that EPNG acted prudently in considering other maintenance activity in adjacent stations.

During this outage it should also be noted that EPNG combined other work events in the station that required outages, to correspond with this outage. These outages were: Office of Pipeline Safety required emergency shutdown device check (1 day), the Office of Pipeline Safety required relief valve checks (1 day), and the regenerator repairs (3 days). Combining of all these events into one scheduled outage minimized the potential for

throughput constraints, even though the system did not experience any constraints during this outage. Overall, we believe the actions taken by the company were prudent and responsible.

7.3.3 Hackberry

Mr. Yoho refers to EBB 3298. Exhaust bellows at Hackberry were cracked and exhaust was venting into the compressor building. This created an employee safety concern that required the work to be done expeditiously. We believe that EPNG acted in a prudent and responsible manner taking the outage and addressing the safety concern.

7.3.4 Pecos

Mr. Yoho refers to two EBB notices; EBB 3416 and 3443. The first, EBB 3416, related to problems encountered at the Cornudas A station, resulting in constraints at Pecos. Cornudas was experiencing overspeed trips, high exhaust temperatures and larger volumes in the inlet scrubbers, all resulting from contaminants introduced into the system as a result of pigging conducted under the Office Of Pipeline Safety CAO. This outage involving reducing speed of the Cornudas turbines was taken to accommodate a pigging run scheduled Feb 2 between Guadalupe and Cornudas stations. We believe that EPNG acted in a prudent and responsible manner addressing these safety concerns.

The second, EBB 3443, related to similar problems at Cornudas A, caused by earlier pigging. Maintenance was required to remove liquids and contaminants that had accumulated in the fuel nozzels and the inlet scrubber filters. This was coordinated with a one-day outage needed to accomplish an Office of Pipeline Safety required inspection. This resulted in saving a day of downtime at a later date to conduct the compliance inspection. We believe that EPNG acted in a prudent and responsible manner taking the outage.

7.4 Rescheduled Maintenance (Maintenance Deferred)

In addition to the events we reviewed that were scheduled, we looked at those events that were rescheduled or on hold, due to the issues relative to capacity constraints through Pecos and other locations.

In an e-mail from Charlie Mathis dated December 8, 2000, to Bud Wilcox, it is shown that several scheduled maintenance events were rescheduled or put on hold due to the pressure restrictions at Pecos (and due to high demand). In our opinion, this memo is indicative of the fact that EPNG made efforts to defer outages to maintain as much throughput as possible while addressing the requirements of Office of Pipeline Safety CAO.

We also looked at the EBB postings during the relevant period. The following sample of postings is referenced to again support the fact that maintenance was rescheduled or eliminated or efforts made to minimize throughput reductions during the relevant period.

Nov 3 – Window Rock reductions reduced

Nov 7 – Pigging without capacity reductions

Nov 11 – Window Rock partially on-line, 3-days early

Nov 28 – Cornudas B down but will not affect capacity

Dec 4 – Waha turbine shutdown due to other unit failure

Dec 5 – Delay of pigging due to impact on markets

Dec 5 – Delay of work at Wenden, Hackberry and Dutch Flat delayed due to demand

Dec 8 – Bondad work done when volumes are low

Dec 8 – Line 1200 work done 5-7 days early restoring capacity

Dec 13 – Waha work done now because of no demand for turbines

7.5 Conclusions with Respect to Maintenance

In our opinion, all of these events and outages, as well as the decisions to defer maintenance were reasonable and prudent and showed a commitment to operation of a

safe and reliable system. Additionally, based on operating history, personal experience and the risk to safety associated with these events, we believe EPNG acted responsibly.

8.0 Managing the Transient Factors

The company is responsible for operating the system safely while delivering gas in conformance with confirmed nominations, despite the fact that EPNG does not control the time and way in which these factors introduce transients into the system. The manifestation of these factors in day-to-day operation is best exemplified through a set of examples.

Example 1 – Pecos Compressor Station – System Test - January 25, 2001

The following summary of a real day in the life of the EPNG pipeline demonstrates the following facts:

- 1) The system was pulling the maximum amount of gas from Pecos on the downstream side. This means that as much capacity was made available for deliveries of gas to California as could be under the conditions on the pipeline this day.
- 2) The compressor stations upstream of Pecos were pushing the maximum amount of gas into Pecos from the upstream side.
- 3) Near maximum utilization of horsepower was realized throughout the day as evidenced by having achieved maximum differential pressure across the compressors.
- 4) The Office of Pipeline Safety's Corrective Action Order constrains the maximum achievable throughput at Pecos.

The company had been operating to achieve scheduled volumes of 920 to 930 MMCF through the Pecos station in December and January. A decision was made to try and push the operating throughput to 980 MMCF.

The day began at 7:00 AM with conditions being conducive to testing of the system in the Pecos area. The objective was to pull as much gas as possible out of Pecos on the downstream side and at the same time push as much gas as possible into Pecos from the

upstream side. The night before, units at two upstream stations, Eunice and Keystone were put online to begin pushing gas to raise the pressure and pack the lines upstream of Pecos to maximize volume into Pecos.

The total line-pack was at 6368 MMCF, indicative of a reasonably full pipeline (6500 MMCF is indicative of a reasonably full line). Washington Ranch, just downstream of Pecos was injecting into storage at a rate of 113 MMCFD, near the maximum, which is approximately 130 MMCFD, with the CAO pressure restrictions in place. The suction pressure at Pecos began the day at 456 psig with a corresponding discharge of 612 psig. Within several hours the Pecos discharge pressure was in excess of 626 psig.

Two cleaning pigs were launched into the 1110 Line near Carlsbad, one at 7:02 AM and a second at 7:30 AM. The pigs were received at Guadalupe at 12:30 PM and 1:00 PM. However, the use of these cleaning pigs did not have any adverse affect on capacity as evidenced by observing that the pressures at Pecos discharge did not change.

By mid-afternoon the discharge pressure was in excess of 630 psig. Injection at Washington Ranch was trimmed to 100 MCF at 11:35 PM.

Early in the morning, beginning at 3:30 AM units at the up-stream compressor stations, Eunice and Keystone had reached the MAOP and began going off-line due to high discharge pressures. Eunice dropped a unit at 3:30 AM and then Keystone and Eunice each dropped a unit at 7:45 AM on January 26 (the beginning of the next gas day). These trips provide clear evidence that the compressor stations upstream of Pecos were pushing the maximum amount of gas into Pecos from the upstream side.

The differential pressure across the Pecos station was at near maximum (150 or greater) for the entire day. The achievement of near maximum pressure differential for these compressor units demonstrates maximum use of the horsepower throughout the day.

At the end of the day, 7:00 AM January 26, the suction pressure at Pecos was at 480 with a corresponding discharge pressure of 647 (this is the discharge set point value). Actual volumes through Pecos reached 935 MMCF. Total line pack ended the day at 6231 MMFC, a decrease of over 137 MMCF. The fact that line-pack decreased a significant amount while at the same time gas was injected into storage, while moving as much gas to the west as physically possible, validates the magnitude of the pull. The system was pulling a maximum amount of gas from Pecos on the downstream side as evidenced by injection into storage.

The results of the day demonstrated that the maximum achievable throughput when constrained by the Office of Pipeline Safety, Corrective Action Order that limits pressure upstream of Pecos to 538 psig, is approximately 930 MMCF. In addition, this test of the system validated the past schedule range of 920 to 930 MMCF.

The chronology is based on exhibits previously provided for this case.

Example 2 – Pecos River Station – Smart Pigging - December 8, 2000

The following summary of another real day in the life of the EPNG pipeline demonstrates the following facts:

- 1) Maintenance was postponed to minimize the impact of outages.
- 2) Schedule can be met while performing maintenance.

This example actually starts on December 5, 2000 with a planned run of a smart pig on Line 1100 between Pecos River and Washington Ranch. The inspection of this line with a smart pig was required by the Office of Pipeline Safety under the Corrective Action Order (CAO). Due to low line pack (6168 MMCF), customer needs for gas, and the fact that the CAO allowed some flexibility on when to run the inspections, it was decided to postpone this event until Thursday afternoon, December 7. Operational history has shown that less gas was typically scheduled during weekends.

December 8th started with scheduled capacity of 930 MMCF through Pecos. Line pack was high at 6404 MMCF (6500 MMCF is the high end of the range). Washington Ranch was idle. The system was, in effect, reasonably full.

The suction pressure at Pecos was 434 psig with a corresponding discharge pressure of 588 psig.

As the day progressed the suction and discharge pressures built up at Pecos. By early afternoon the discharge pressure was in excess of 620 psig and climbing. At 1:51 PM, the section of the line is blocked in by closing upstream and downstream valves. Injection into Washington Ranch also started at this time to begin pulling the pressure down. At 6:00 PM Line 1100 blowdown begins between Pecos River and Washington Ranch in order to make pipeline modifications and run the smart pig.

Pressures continued to remain constant for the rest of the day.

At the end of this day, 7:00 AM December 7, the suction pressure at Pecos was at 464 psig with a corresponding discharge pressure of 627 psig. Actual volumes through Pecos reach 928 MMCFD, or just 2 MMCFD below schedule. Total line pack ended the day at 6595 MMCF, an increase of 95 MMCF.

The results of the day demonstrated that planned maintenance was postponed due to customer needs. In addition, by waiting until later in the week to isolate and blow-down the valve section to be pigged, capacity through Pecos met scheduled deliveries.

The chronology is based on exhibits previously provided for this case.

Example 3 - Pecos River Station – Station Shutdown – January 3, 2001

The following summary of a day selected by Mr. Flanders demonstrates the following facts:

- 1) EPNG's prompt response to an unscheduled maintenance event; and,
- 2) The resulting impact on capacity.

The day began at 7:00 AM with scheduled capacity of 920 MMCF through Pecos. Line pack was at above the high end of the desired range at 6533 MMCF (6500 MMCF is the high end of the range). SoCal did not take all scheduled gas the day before and they agreed to take extra gas (106 MMCF) this day in order to have a two-day balance. Washington Ranch was on injection with both units running in order to maximize the rate of injection. The suction pressure at Pecos was 431 psig with a corresponding discharge pressure of 593 psig.

As the day progressed the suction and discharge pressures built up at Pecos. By late evening the discharge pressure was 644 psig (just 2 psig below set point of 646 psig). At 1:01 AM Pecos station went down due to a regulator seat failure on the first cut fuel regulator causing a low fuel alarm trip on each turbine. A few minutes later a "dominoing" effect began. At 1:14 AM, Keystone went down on high pressure. Eunice began dropping off compressor units at 1:30 AM. Both these stations are upstream of Pecos.

With all units at Pecos down as well as the units at the upstream stations going down, pressure downstream of Pecos began to go down. Injection into Washington Ranch was curtailed to provide more gas flowing to the west. Repairs began immediately. At 3:20

AM, two and a half hours later, Pecos began to be put back on-line. By 3:56 AM all units were running.

At the end of this day, 7:00 AM January 4, the suction pressure at Pecos was 431 psig with a corresponding discharge pressure of 593 psig. Actual volumes through Pecos reached 868 MMFCD, or 52 MMFCD below schedule. Total line pack for the day ended at 6392 MMCF a loss of 140 MMCF.

Based on our evaluation of data from the relevant period, we find no evidence that flows greater than the 930 can be achieved on a sustained basis through Pecos.

The chronology is based on exhibits previously provided for this case.

8.0 Conclusions

We believe the approach the company used to determine available capacity was reasonable and based on sound judgement. We believe the system was operated in a prudent and responsible manner given the environment after the Carlsbad rupture. The system was constrained at Pecos by the Office of Pipeline Safety CAO, thereby limiting capacity and operational flexibility on the Southern portion of the system. EPNG managed the pressures in the system in accordance with the letter and spirit of pipeline safety regulatory requirements and in full consideration of the transient operating conditions, which were largely outside of the control of the company. Based on our evaluation, we conclude that EPNG's method of determining available capacity was sound and appropriate in view of the transient conditions and other restrictions on the EPNG system. Furthermore, based on our review of numerous days of operating data, we believe that EPNG correctly determined the amount of available capacity during the relevant period. In addition, the company made reasonable and prudent judgements in the selection of maintenance events to take during the relevant period, as well as those it deferred. Finally, we believe the company appropriately balanced the needs of end use gas customers with safe, reliable operation.