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Exhibit Number :
Reference No. : ORA-02 Atch
Commissioner : M.Florio
ALJ : D.Long
K. Bemesderfer
Witness P. Sabino

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Attachments Supporting Testimony of P. Sabino on Southern California Gas and San Diego Gas & Electric Company North-South Project

Revenue Requirements
Related Cost Allocation and Rate Design

San Francisco, California
May 8, 2015

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT
(A.13-12-013)

(DATA REQUEST ORA-NSP-SCG-02)

QUESTION 1:

At page 1 of the Application, the Applicants state that “The North-South Project is needed to maintain Southern System reliability and alleviate the potential for curtailments of customers on the Southern System due to a potential mismatch between the demand of such customers and the volume of flowing supplies delivered to the Southern System to meet that demand.

(a) Please describe and define the metrics that demonstrate the need or needs identified by the Applicants in the above statement.

(b) Does the above statement identify two separate primary needs to be met by the North-South Project? If not, please explain. If so, please explain the relationship between the two identified needs to be met, if any.

(c) Please describe the rating criteria used to assess and determine the adequacy of each Project Alternative to be considered in meeting the identified need/s.

(d) Does the second part of the above statement, which reads “alleviate the potential for curtailments of customers on the Southern System due to a potential mismatch…to meet that demand” pertain to, or include, an identified need for risk reduction of the potential for customer curtailments? If so, please describe the target risk reduction and how this risk reduction target was arrived at by the Applicants.

RESPONSE 1:

a. As explained in the direst testimony of Ms. Musich, the need for minimum flows on the Southern System is created by the fact, that unlike other portions of SoCalGas' system, physical flows delivered to the Southern System are needed on a regular basis, and only a portion of the system's needs can be served by flows from other portions of the system. As illustrated in Figure 1 of Ms. Musich's testimony, the Southern System has risen from an annual average of 366 Mdth/d in 2008 to the current 541 Mdth/d level. Conversely, customer deliveries into the Southern System have dropped from an annual average level exceeding 800 Mdth/d in 2008 to 593 Mdth/d in 2013.

   As also addressed by Ms. Musich in her testimony, this mismatch between demand and flowing supplies is further threatened by the potential for significant volumes of gas to flow to Mexico rather than California and the increase in electric generation demand on the Southern System.

b. No. The mission of the System Operator is to maintain safe, reliable service to customers. The Southern System is currently configured in a manner that requires minimum flowing supplies of natural gas from receipt points within the Southern System each day. But the current configuration (together with market conditions) cannot always provide reliable minimum flowing supplies during critical time periods. When supplies are not available into the Southern System (or any other part of the system), the mission to provide reliable service is put into jeopardy and may result in curtailment of service to customers.

c. SoCalGas assesses the projects based on their ability to meet the Purpose and Need as presented in the Proponent's Environmental Assessment.

d. SoCalGas always seeks to reduce the risk of the potential for customer curtailments, but has not quantified a risk reduction target.

QUESTION 2:

At page 2 of the Application, the Applicants state that "the volume of supplies received into the Southern System at Otay Mesa has generally been minimal due to growing demand for domestic supplies exported to Mexico."

(a) Please provide the date when the Otay Mesa receipt point became operational.

(b) Please provide the data on the volume of supplies received into the Southern System at Otay Mesa from the date Otay Mesa became operational to the latest available date and explain why this information indicates that this volume of supplies has been minimal.

(c) Please explain how the Applicants verified the "growing demand for domestic supplies exported to Mexico." Please also provide all supporting data for this verification.

(d) Does the above statement mean that the Applicants attribute the "minimal'" volume of supplies received into the Southern System at Otay Mesa to the "growing demand for domestic supplies exported to Mexico"? If so, please explain how the Applicants reached this conclusion.

(e) Please provide the volumes received at Otay Mesa transported from the Costa Azul Liquefied Natural Gas (LNG) Terminal.

RESPONSE 2:

a. The Otay Mesa receipt point became operational on May 9, 2008.

b. Please see the attached spreadsheet for the volume of supplies received into the Southern System at Otay Mesa from the date Otay Mesa became operational to 9/17/14. The attached file provides the total deliveries in Dths (10,043,000 Dths). It also shows the average daily deliveries for the period in question (4,368 Dths/day) and the number of days deliveries were made at the receipt point (154) as well as the percentage of those delivery days (7%) in relation to the total number of days in the period (2,299 days). These statistics demonstrate that deliveries were not significant.

c. As described in sections II and III of Mr. Chaudhury's direct testimony (pages 1-5), there are numerous sources highlighting the growing demand for domestic U.S. supplies exported to Mexico. Such sources include the Energy Secretary of the Federal Government of Mexico, the U.S. Energy Information Administration, the California Energy Commission, Kinder Morgan—the owner of El Paso Pipeline Company, and consultants, such as, Bentek Energy.

d. The minimal volume of supplies received into the Southern System at Otay Mesa is attributable to market conditions in Mexico and the United States. These market conditions include the growing demand for natural gas in Mexico and increased exports to Mexico.
e. To date SoCalGas has not transported gas supply on the Bajanorte/TGN systems for delivery at Otay Mesa that was purchased by SoCalGas from the Costa Azul LNG terminal. SoCalGas is unable to provide the volumes scheduled by other shippers for delivery at Otay Mesa that were transported from the Costa Azul LNG Terminal because it does not have access to upstream scheduling data on the Bajanorte/TGN systems that are required to determine the volumes sourced from Costa Azul.

QUESTION 3:

At page 2 of the Application, the Applicants state that SoCalGas also has the ability to transport up to 80 MMcfd of supply from its Northern System to the Southern System via Transmission Line 6916, formerly the Questar Southern Trails Pipeline. Please describe how the Applicants considered the role of Line 6916 in determining possible solutions to the need identified in Question 1.

RESPONSE 3:

Line 6916 was factored into the determination of the need for the North-South Project. If Line 6916 were not available, the need for the North-South Project and flowing supplies from Northern receipt points and storage would increase.

QUESTION 4:

At page 3 of the Application, the Applicants state that "The minimum flow requirements on the Southern System vary with the demand on the system. As demand increases, the minimum flow requirements increase and vice versa. Supplies delivered at Blythe and Otay Mesa are needed to support any Southern System customer demand not met by Chino and Prado Stations during peak periods."[3]

(a) Please provide the historical monthly recorded demand on the system from the beginning of the year 2000 through the latest available date. Based on this recorded data, please provide the recorded minimum flow requirements on the Southern System.

(b) Do the Applicants expect the minimum flow requirements on the Southern System to increase from the historical recorded levels in the future? If so, please provide the projected minimum flow requirements for the forecast period relevant to the Applicants' analysis. Please also identify the dates of the forecast period.

(c) Please provide the required amount of capacity, to meet the need(s) identified in your response to Question 1.

(d) Please identify the specific receipt points where gas supplies should be delivered in order to meet the minimum flow requirements on the Southern System.

(e) How much firm receipt point capacity is available at the receipt points discussed in response to Question 4(d)?

(f) Do the minimum flow requirements shown in the Applicants' response to Question 4(a) meet the need to maintain Southern System reliability as identified on page 1 of the application? If not, please explain.

(g) Do the minimum flow requirements in the Applicants' response to Question 4(a) meet the need to "alleviate the potential for curtailments of customers on the Southern System due to a potential mismatch between the demand of such customers and the volume of flowing supplies delivered to the Southern System to meet that demand", as indicated on page 1 of the application? If not, please explain.

RESPONSE 4:

a. Please refer to the attached file for the total daily gas demand on the Southern System for the period January 2011 through April 2014. Note that data for the Southern System demand prior to January 2011 are unavailable.

   Please refer to the attached file for the recorded minimum flow requirements.

b. Yes. SoCalGas believes it is likely that Southern System minimum flow requirements will increase in the future. Please see the direct testimony of Ms. Musich at pages 5-6. Future Southern System minimum requirements will depend on a host of variable factors including weather and demand. SoCalGas has not attempted to forecast future Southern System minimums.

c. Please refer to Response 1 above.

d. Currently, gas supplies needed to meet the Southern System Minimum need to be delivered at El Paso Ehrenberg, North Baja Blythe or Otay Mesa.

e. The Southern Zone has a total receipt point capacity of 1.2 BCFD. El Paso Ehrenberg has a capacity of 1.2 BCFD (temporarily lowered to 1.0 BCFD pending a hydrotest for Line 2000), North Baja has a capacity of 0.6 BCFD and Otay Mesa has a capacity of 0.4 BCFD.

f. Yes.

g. Yes.

QUESTION 5:

Table 1 at page 6 of the Application shows the costs of Southern System Support after the transfer to the System Operator, beginning in September 2009 and through August 2013.

(a) The column labeled as “Purchases” in Table 1 shows significant variations in the purchase amount from the first 12-month period to the next 12-month period and on to the next. Please explain the reason/s for the yearly variations noted.

(b) The column labeled as “SRMA Costs” shows a huge increase in the fourth year (about 3.5 times) compared to the first 3 years. Please explain the reason for the significant increase in the SRMA costs starting at the fourth year.

(c) The column labeled as “IT BTS Ehrenberg Discounts” showed a dramatic increase in the fourth year to $12.1 million compared to zero $ amounts in the first two years. Please explain the reason for the increase in the discounts noted.

RESPONSE 5:

a. See Figure 1 of Ms. Musich’s direct testimony. Customer purchases were falling at the same time that the Southern System minimum was increasing. As a result the frequency and the size of the gap between customer purchases and the minimum increased over the period, which translates into System Operator purchases.

b. The purchases requested by the System Operator almost tripled in the final year compared to the previous year. In addition, the net cost of those purchases (purchase cost at Ehrenberg + BTS transport – citygate sale) increased in the fourth year.

c. The utility did not employ a BTS discount strategy until December 2011. The fourth year is the only one in which the utility discounted its BTS4 rate at Ehrenberg throughout the year. Without such discounts, the increase in SRMA costs noted in (b) would have been even higher because customers would have purchased even less gas at Ehrenberg absent a discounted BTS transport rate from Ehrenberg to the citygate.

QUESTION 6:

At page 6 of the Application, the Applicants state "In order for Gas Acquisition to meet their obligations for the southern system minimum under the MILC, Gas Acquisition purchased El Paso South Mainline capacity to Ehrenberg at a 15 cent/dth reservation charge premium over other interstate pipeline alternatives."[4] MILC stands for Memorandum in Lieu of Contract. Applicants state that this translates to a $16 million per year cost impact.[5]

(a) Please provide the basis for stating that El Paso South Mainline capacity purchased by Gas Acquisition was "at a 15 cent/dth reservation charge premium over other interstate pipeline alternatives." Which interstate pipeline capacity alternatives did Gas Acquisition consider? Do any of those alternatives deliver to Ehrenberg, or elsewhere on the SCG Southern System?

(b) Please provide the calculation for the $16 million a year impact, including any assumptions.

(c) Do the Applicants expect the North-South Project, or an Alternative Project to be determined, to eliminate the need for a Gas Acquisition MILC? If not, please explain.

(d) How much of an increase in present rates would SoCalGas/SDG&E's proposed project have for customers in the Southern System and all customers, both at the backbone transmission level and at the end-use customer level?

RESPONSE 6:

a. Generally, when Gas Acquisition re-contracts for interstate pipeline capacity, it analyzes a number of alternatives and assesses the market rate for each of those alternatives. For purposes of fulfilling its obligation under the MILC, Gas Acquisition considered capacity on the Kern River, Transwestern, and El Paso pipelines, with only El Paso capacity being able to deliver to Ehrenberg and only El Paso being able to deliver from a supply basin to the SoCalGas Southern System. Gas Acquisition's contracts executed closest to the time when this Application was prepared were directly with El Paso. The contracted capacity with an Ehrenberg delivery point has a 40¢/dth reservation rate, and the capacity with a Topock delivery point has a 23¢/dth reservation rate, resulting in a 17¢/dth premium for Ehrenberg capacity. The15¢/dth market premium discussed in the Application is conservative compared to this 17¢/dth difference.

b. The calculation for the $16 million a year impact is shown in footnote 9 on page 6 of the Application: $0.15/dth x 300 Mdth/day x 365 days = $16 million.
   - 15¢/dth = reservation charge premium discussed in (a)
   - 300 Mdth/day = approximate volume contracted at Ehrenberg that is paying the premium
   - 365 days = number of days in a year

   While the actual product of these numbers is $16.425 million, it was rounded to $16 million in the footnote since it is an approximation.

c. Yes. If the North-South Project is built there will probably be no need for a MILC.

d. The proposed increase in rates can be found in the direct testimony of Mr. Joseph Mock on page 2, Table 1.

QUESTION 7:

At page 7 of the Application, Applicants state that "Increases in cost of Southern System reliability are expected by SoCalGas to continue." Please provide all the SoCalGas analysis upon which this statement is based.

RESPONSE 7:

SoCalGas does not have any additional analysis beyond what is provided in our testimony, workpapers, and application.

<u>QUESTION 8:</u>

At page 7 of the Application, Applicants state "Customer deliveries are expected to continue to drop as supplies on El Paso's South Mainline are diverted to high-value Mexican markets."7

a. Please provide all the SoCalGas analysis upon which this statement is based.

b. What does the phrase "high-value Mexican market" mean? Is the Mexican market considered "high-value" because of Mexican purchases of firm interstate capacity on El Paso, and other interstate pipelines?

<u>RESPONSE 8:</u>

a. The term 'high value' as used refers to price premiums generally paid by the Mexican government for its gas purchases through Pemex. [1] The statement is not based on any analyses done by SoCalGas. Rather it is based on publicly available information about the structure of the natural gas market in Mexico. The gas sales prices in Mexico are simply set by the government. As an example of natural gas price premium paid by the Mexican government, Francisco Salazar, the President of the Mexico's Energy Regulatory Commission (CRE), in an interview in October 2013, mentioned that in February 2013 Pemex Gas "paid upwards of US$21/MM BTU for natural gas in LNG cargos, when, in the U.S. the same gas was at $4" (http://www.energia.com/wp-content/uploads/2013/12/2013-111-30-Interview-with-Francisco-Salazar_v2.pdf, page 6).

b. See response to 8a above.

[1] Pemex is Mexico's state oil and gas monopoly and controls exploration, processing and sales.

QUESTION 9:

At page 7 of the Application, Applicants state "Increasing Mexican exports may reduce flow into Blythe."[8] Please provide all the SoCalGas analysis upon which this statement is based.

RESPONSE 9:

Section III of Mr. Chaudhury's testimony (pages 3-5) contains analysis of potential natural gas exports to Mexico via the El Paso South Mainline, including information on El Paso's recently completed new laterals/expansion of laterals off of South Mainline to facilitate export to Mexico. These additional exports to Mexico will directly compete with available supplies into Ehrenberg. As entities serving the new gas load in Mexico sign long term contracts for capacity with El Paso, the likely result will be substantially lower flowing supplies available to reach Ehrenberg.

QUESTION 10:

At page 8 of the Application, Applicants state "Essentially all of the flowing supplies that arrive at Southern System receipt points are sourced from one pipeline – El Paso. (footnote omitted) Southern System customers have faced reliability problems in the past because of this situation, including a Southern System curtailment in February of 2011 brought about by force majeure conditions upstream of the SoCalGas system, several recent supply related near misses, and operational issues that have created reliability concerns."9 In a footnote, Applicants state that Transportadora de Gas Natural de Baja California (TGN) also has the capability to deliver supply at Otay Mesa but that receipt point is not utilized by the Applicants' customers for economic reasons.

(a) Please identify all the Southern System receipt points where El Paso deliveries of flowing supplies are made. Are these identical to the specific receipt points in your response to Question 4(d) where gas supplies should be delivered in order to meet the minimum flow requirements on the Southern System?

(b) Please explain whether TGN has the capability to deliver supply at the same Southern System receipt points where El Paso delivers flowing supplies.

(c) Please define what is meant by "economic reasons".

(d) Please explain whether "economic reasons" pertain to the higher rates charged by TGN for deliveries to Otay Mesa.

(e) Please explain whether the Applicants believe the TGN pipe through the Otay Mesa receipt point could also meet Southern System minimum requirements needed to maintain system reliability if economic reasons were not a factor.

(f) Please provide details regarding whether the Southern System curtailment in February of 2011 was an emergency curtailment, the time duration and frequency of occurrence, the magnitude of demand curtailment, the number of customers affected by the curtailment and customer type, and the reasons that necessitated the curtailment (i.e., shortfall in gas supply to the Southern System, insufficient pipeline capacity, or other reasons).

(g) Please provide details to explain the clause, "several recent supply near misses and operational issues that have created reliability concerns."

(h) Please explain if during the supply events in Question 10(g) also impacted other natural gas suppliers in other regions or coming off of other pipelines than those identified in Question 10(g).

RESPONSE 10:

a. The Southern System receipt points are Ehrenberg, North Baja, and Otay Mesa. The supplies delivered into all of the Southern receipt points originate from El Paso, but may arrive via an intermediate pipeline.

b. Any supplies delivered from TGN to Otay Mesa either arrived there via El Paso to North Baja to Baja Norte to TGN or else from Costa de Azul to TGN.

c. Gas delivered at Otay Mesa pays the same costs as gas delivered at Ehrenberg, plus the additional costs to get through the three pipelines described in Response 10b above. LNG from Costa Azul does not arrive because the price of LNG is considerably higher than the price of domestic natural gas.

d. See Response 10c.

e. If economic reasons were not a factor, gas delivered at Otay Mesa could go towards meeting the Southern System Minimum requirements.

f. Please refer to SoCalGas Advice Letter 4207.

g. Please refer to Section V of the direct testimony of Ms. Musich.

h. Please refer to Section V of the direct testimony of Ms. Musich.

QUESTION 11:

At page 8 of the above subject, Applicants state "As deliveries to Mexico from the El Paso system increase, supplies into Blythe are going to become more scarce and expensive. This decrease in available supplies at Blythe will make it more difficult to find supplies at any price when problems occur in the supply basins or on interstate pipelines serving Southern California."[10]

(a) In the statements above, do Applicants mean that the expected decrease in available supplies into Blythe would be attributable solely to expected increases in deliveries to Mexico from the El Paso system? Please explain your response.

(b) If some of the Mexican projects expected to result in potential increased deliveries to Mexico do not materialize for whatever reason, then does the need for the North-South Project identified in response to Question 1(a) go away? Please explain your response.

(c) Had Applicants, or other purchasers on behalf of California customers, obtained additional firm capacity on El Paso's southern system prior to purchase of capacity by Mexican customers, would the need for the North-South project been reduced?

RESPONSE 11:

(a) In the statement above, SoCalGas/SDG&E do not mean that the expected decrease in available supply into Blythe would be attributable solely to expected increases in deliveries to Mexico from the El Paso system. However, the expected increases in deliveries to Mexico from the El Paso system could be a significant contributor to the expected decrease in available supply into Blythe.

(b) Ms. Musich's direct testimony discusses the current reliability issues facing the Southern System. So, the need for North-South Project does not go away under the hypothetical that some of the Mexican projects expected to result in potential deliveries to Mexico do not materialize for whatever reason. However, as explained in Mr. Chaudhury's direct testimony, multiple and disparate sources think that the export growth to Mexico will materialize, including the U.S. Energy Information Administration, the Federal Government of Mexico, and the El Paso Pipeline Company.

(c) The North South project will enable the delivery of physical supply to the Southern System. Owning capacity on the El Paso system does not insure someone will actually move physical gas on that capacity or that there will not be upstream supply or maintenance issues preventing that supply from reaching the SoCalGas/SDG&E system.

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(A.13-12-013)
(DATA REQUEST ORA-NSP-SCG-02)

QUESTION 12:

At page 8 of the Application, Applicants state that “At times the System Operator is already practically the only party delivering supplies to the Southern System. Combined with the potential for upstream problems on the El Paso system, this is not a recipe for reliable service to Southern System customers.[11]

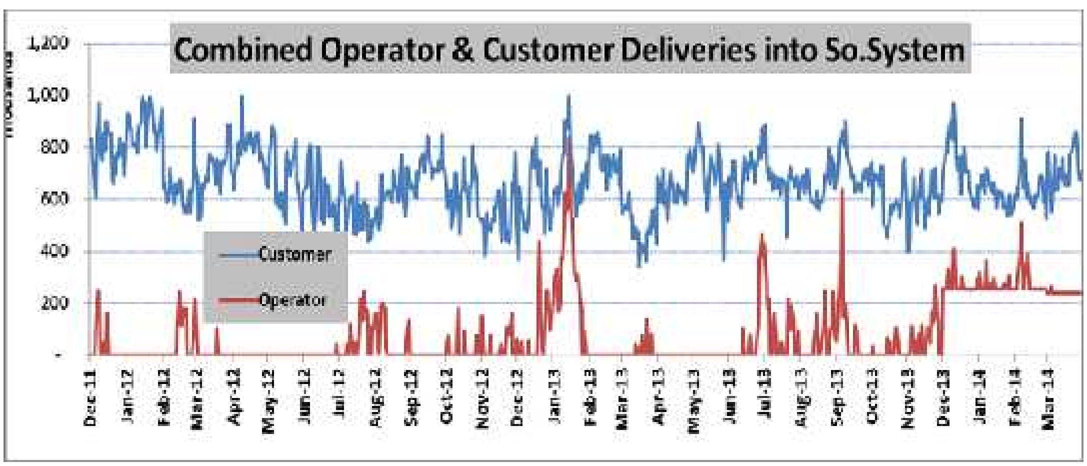
(a) Please identify the specific time period or periods when the situation described has occurred.

(b) Please describe the tools the System Operator used to address the situations asked about in question 12(a).

(c) Did any of the situations asked about in question 12(a) result in any curtailment or curtailments? If so, please provide the details of each curtailment.

RESPONSE 12:

a.



b. The system operator uses both spot gas purchases and baseload contracts
c. Please refer to the following SoCalGas Advice Letters.

Attachments to ORA-NSP-SCG-02

DailyActDeliveriesOt
ay spreadsheet.xlsx

Attachment to
Response to ORA Dat

Southern System
Min(2004 to 2013).xl

4207.pdf

4576.pdf

4603.pdf

4604.pdf

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT
(A.13-12-013)

(Data Request DRA-ORA-NSP-SCG-03)

QUESTION 1:

At page 9 of the application, Applicants state “SoCalGas and SDG&E have looked at a number of potential non-physical solutions to the impending supply-related Southern System cost and reliability problems. None of these potential non-physical solutions provide the tools we need.”

(a) Please identify all the potential non-physical solutions to the impending supply-related Southern System cost and reliability problems “looked at” by Applicants.

(b) Please describe the analysis performed by the Applicants in considering or “looking at” each of the identified potential solutions in response to Question 1(a).

(c) Please describe the evaluation criteria used by the Applicants to perform the analysis described in response to Question 1(b). If there is a threshold that needs to be met with respect to any of the criteria, then please indicate so.

(d) Please provide the results of the analysis and evaluation performed by the Applicants to consider each the non-physical solutions.

(e) Based on the results of the analysis, please discuss how the Applicants reached the conclusion that “None of these potential non-physical solutions provide the tools we need.”

RESPONSE 1:

a-e) Please refer to the December 20, 2013 testimony of Ms. Musich (Section VII) and Mr. Bisi (Section VII).

QUESTION 2:

At page 9 of the Application, Applicants state "One potential option for dealing with future Southern System supply issues is for SoCalGas to contract for basin supplies and interstate capacity to meet anticipated Southern System flow requirements. But this option would not provide the needed reliability benefits. Even with basin supplies and matching interstate capacity, Southern System customers would be at the mercy of supply-related problems outside of California, just as they are today. Even after substantial expenditures to lock in long-term supplies and interstate transportation, we would essentially be in the same situation we are in today, at least from a reliability standpoint. And the cost of this option is likely to be substantially greater over time than the proposed North-South Project."

(a) Please explain how the option of locking-in long term supplies and interstate transportation would not provide the needed reliability benefits.

(b) Was this option subject to the evaluation criteria in your response to Question 1(c)? If so, please describe the results of the analysis.

(c) Please describe your analysis and assumptions to reach the view that "the cost of this option is likely to be substantially greater over time than the proposed North-South Project."

(d) In terms of MMcfd and as a percentage, how much of the natural gas supplies consumed in the Southern System come from outside of California? From inside of California?

(e) Please explain how the presence of an intrastate pipeline such as the North-South project would prevent Southern System customers from being "at the mercy of supply-related problems outside of California." Please describe how the presence of the North-South project would have changed Applicants' ability to handle "supply-related problems outside of California" such as occurred on February 4-6 (5)?, 2014.

RESPONSE 2:

a) Even with basin supplies and matching interstate capacity, Southern System customers would be at the mercy of supply-related problems outside of California, just as they are today. Even after substantial expenditures to lock in long-term supplies and interstate transportation, we would essentially be in the same situation we are in today, at least from a reliability standpoint.

b) Yes

c) The analysis we performed was very similar to that performed by Cathy Yap in her August 15, 2014 testimony on behalf of the Southern California Generation Coalition (SCGC), who calculated a cost of $17.5 million/year to hold 255 MMcf/d of long-term El Paso capacity to the Permian basin. This analysis appears roughly correct using forward curves in August of 2014 for the year 2020. But the SoCalGas/SDG&E testimony proposes that 800 MMcf/d of long-term capacity is needed, not 255 MMcfd, which would increase the costs of the SCGC option to $55 million/year (800/255 x $17.5).

SoCalGas still prefers its infrastructure option for several reasons. First, the cost of the North-South pipeline project is known and fixed, whereas the cost of the SCGC option would change based on market conditions. When SoCalGas did a very similar analysis using forward curves in October 2013 for the year 2018 (the latest publicly available at the time) it estimated a cost of $100 million/year.

Second, both the SoCalGas and SCGC analyses assume current El Paso tariffs as the cost of the interstate capacity. But El Paso's South Mainline is almost fully subscribed; it is uncertain that significant amounts of additional capacity can be subscribed at those rates. Any incremental capacity made available by El Paso could require significant investments on their part and incremental rates that could be higher than those used in both analyses.

Third, assuming the gas the SoCalGas System Operator would be purchasing is re-sold to 3rd parties, the SCGC option requires the SoCalGas System Operator to become the second largest gas purchaser in Southern California, next to its own Gas Acquisition department. Together, these entities would be purchasing almost 2 Bcf/d of gas, or 70% of the Southern California market.

d) Practically, all the gas consumed in the Southern System comes from outside California, with the very small exception of approximately 1 MMcfd of in-state biogas. Out-of-state supplies delivered to the Southern System averaged approximately 640 MMcfd in 2013.

e) The North South pipeline would provide SoCalGas/SDG&E customers on the Southern System access to all of the supply basins plus storage to Northern System customers, reducing the likelihood of problems, like that experienced on February 4-6, 2014. If the North South pipeline were in place, as well as the Low Operational Flow Order proposed in A.14-06-021, SoCalGas/SDG&E would expect adequate supplies to meet Southern system demand up to our system design criteria. Those supplies could be delivered at ANY receipt point and then transported to the Southern System.

QUESTION 3:

At page 10 of the Application, Applicants state SoCalGas and SDG&E also considered the merits of supplementing or replacing the existing System Operator tools with a minimum flowing supply requirement for all end use customers.3 Further, Applicants state "there may be merit to requiring all end use customers to bring some portion of their gas usage into the Southern System. But this would be too small a bandage for too great a potential wound. If SoCalGas is not able to obtain flowing supplies at Blythe, then it is unlikely that our customers will be able to do so either, no matter how large the potential financial penalty for noncompliance. Only a physical upgrade that enables storage gas to reach the Southern System will provide Southern System customers with the same level of reliability as customers located on the rest of the SoCalGas and SDG&E system."

(a) Please describe the analysis performed by the Applicants to consider the merits of supplementing or replacing the existing System Operator tools with a minimum flowing supply requirement for all end-use customers, including any consultation made with the end-use customers. If no analysis was performed nor any customer consultation conducted, then please indicate so and describe the basis for eliminating this option from further consideration.

(b) Please provide the basis for the Applicants' statement that "Only a physical upgrade that enables storage gas to reach the Southern System will provide Southern System customers with the same level of reliability as customers located on the rest of the SoCalGas and SDG&E system."

RESPONSE 3:

a) SoCalGas' previous Southern System Minimum Flowing Supply Requirement proposal was described in the direct testimony of Rodger Schwecke filed for A.08-02-001 (December 5, 2008), at pp. 17-22, which is available at the following link: http://www.socalgas.com/regulatory/A0802001.shtml

   This proposal was withdrawn by SoCalGas pursuant to the 2009 BCAP Phase 1 Settlement adopted by the Commission in D.08-12-020.
   Please refer to the December 20, 2103 testimony of Ms. Musich (Section VII.C.) which further addresses the merits of a Southern System Minimum Flow Requirement.

b) Please see the response to Question 2e.

QUESTION 4:

At page 11 of the Application, Applicants state “Southern System customers pay the same rates as SoCalGas customers located elsewhere. These customers deserve the same level of reliability as customers elsewhere on our integrated transmission system. To achieve this, Southern System customers need to have access to supplies from SoCalGas’ storage and other receipt points, and such access can only be achieved through physical upgrades.”

(a) Please describe and compare the level of reliability received by the “Southern System customers” with the reliability received by other “SoCalGas customers located elsewhere”.
(b) Do Southern System customers currently have access to supplies from SoCalGas storage? If so, please compare “Southern System customers” with “SoCalGas customers located elsewhere”. In this comparison, please explain how much access each group of these customers has to supplies from SoCalGas storage. . If not, please explain why Southern System customers have no access to SoCalGas storage supplies.
(c) Do “Southern System customers” pay for any SoCalGas storage costs in their rates? If so, are such payments equal to those paid for by “SoCalGas customers located elsewhere”?

RESPONSE 4:

a) Under the status quo, Southern System customers receive relatively the same level of reliability as other customers. This is only because of the MILC agreement in place and the significant quantities of gas purchased at Ehrenberg by the System Operator to avoid curtailments of those customers. SoCalGas believes that level of service is unsustainable, however, if supplies at Ehrenberg become less reliable and available due to competing demands for that supply in Mexico. In other words, without an infrastructure investment such as the North-South pipeline, curtailments of Southern System customers would become common, whereas end-use curtailment would remain an uncommon event on other parts of the system.

b) No, Southern System customers do not have physical access to storage.

c) Yes. Yes.

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SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT
(A.13-12-013)

(Data Request DRA-ORA-NSP-SCG-03)

QUESTION 5:

At page 11 of the Application, Applicants state "SoCalGas and SDG&E examined three infrastructure alternatives: (1) River Route, (2) Cross Desert, and (3) the North-South Project. All three alternatives would add approximately 800 MMcfd of North-to-South flow capacity on the SoCalGas system, which would effectively eliminate the Southern System minimum flow requirement."6 At page 22 of the Application, Applicants state that they considered each of the non-physical and physical alternatives to the North-South Project. Please provide a side by side comparison of each infrastructure alternative examined by the Applicants, and each non-physical alternative considered, including:

(a) the direct cost per mile (i.e., costs of material and equipment, total construction, other direct costs) and indirect cost per mile (i.e., engineering, design, survey, land and Right of Way acquisition, regulatory permits, construction management, overheads).

(b) the resulting total rate (in $/Dth) to all SCG/SDG&E customers of each infrastructure alternative.

(c) any contingency costs included in the estimates.

(d) the timing/scheduling for each infrastructure alternative.

(e) the major pipeline and station components and key characteristics of each infrastructure alternative.

(f) How each infrastructure alternative would meet the system reliability needs and the potential for curtailment of customers on the Southern System.

(g) How each alternative provides Southern System customers with access to storage supplies.

(h) How each alternative provides access to the specific receipt points necessary to meet the Southern System reliability. If access to more receipt points are provided by the alternative, then indicate so.

(i) How much each alternative would expand or increase SoCalGas firm backbone capacity.
(j) How each alternative would address force majeure conditions in supply basins and impact Southern System reliability.

(k) How each alternative would address any operational problems on the interstate pipelines serving Southern California.

(l) The class location, by number of miles, for each of the alternatives.

(m) Why was 800 MMcdf of capacity determined to be the need for the projects. Were any other sizes considered? Please provide all supporting analysis.

(n)Please provide ORA with a copy of the active Excel spreadsheets that will be used in the calculations to produce the side by side comparison.

RESPONSE 5:

(a) The cost estimates provided for the River Route and Cross Desert alternatives are based on a factored estimate of the direct costs of the North-South project. As these physical alternatives did not meet the project objectives, a factored cost estimating approach was used to allow cost comparison between alternatives.

The following tables provide the comparison of direct costs, direct costs per mile, direct costs per thousand horsepower by SoCalGas physical alternative. Engineering, design, survey, land and Right-of-way acquisition, regulatory permits, and construction management are identified in the application as direct costs and are addressed in David Buczkowski's testimony. Overheads and escalation are defined and addressed in Garry Yee's testimony.

Alternative Projects Comparison
Pipeline ($ Million)

	North-South (As Filed)	River Route (Factored)	Cross Desert (Factored)
Direct Cost[1]	$518	$560	$1,120
$ Million/Mile	$5.7	$5.6	$5.6
Overheads[2]	$29	$32	$64
Escalation[2]	$47	$67	$133

[1]For additional direct cost information, please reference David Buczkowski's direct testimony in A.13-12-013.

[2]For additional overhead and escalation information, please reference Garry Yee's direct testimony in A.13-12-013.

Alternative Projects Comparison Compressor Station ($ Million)			
	North-South (As Filed)	River Route (Factored)	Cross Desert (Factored)
Direct Cost[1]	$111	N/A	$123
$/HP	$3,696.7	N/A	$3,500.0
Cross Desert Compressor costs exclude $ for ERC's			
Overheads[2]	$7	N/A	$8
Escalation[2]	$9	N/A	$15
[1]For additional direct cost information, please reference David Buczkowski's direct testimony in A.13-12-013.			
[2]For additional overhead and escalation information, please reference Garry Yee's direct testimony in A.13-12-013.			

(b) The following tables replicate Table 1 found in the Direct Testimony of Mr. Mock. Table 1 shows the BTS revenue and rate impact of the proposed North-South project and is the same table found on page 2 of Mr. Mock's direct testimony; whereas Table 2 is the BTS revenue and rate impacts of the River route and Table 3 is the BTS revenue and rate impacts of the Cross Desert route. See Column F for the BTS rate in $/dth format.

TABLE 1
Illustrative BTS Revenue and Rate Impacts

Year	Current BTS Revenue Requirement $ Millions	North-South Project Revenue Requirement $ Millions	Total BTS Revenue Requirement $ Millions	Current BTS SFV Rate $/dth/d	North-South Project BTS Rate Impact $/dth/d	Total BTS SFV Rate $/dth/d
	A	B	C = A + B	D	E	F = D + E
2019*	$149.6	$71.3	$220.9	$0.138	$0.066	**$0.203**
2020	$149.6	$125.0	$274.6	$0.138	$0.115	**$0.253**
2021	$149.6	$117.6	$267.2	$0.138	$0.108	**$0.246**
2022	$149.6	$113.7	$263.3	$0.138	$0.105	**$0.242**
2023	$149.6	$109.9	$259.5	$0.138	$0.101	**$0.239**

*2019 Revenue Requirement of $5.9MM is grossed-up to $71.3MM in order to recover the amount over 1 month due to the estimated in-service date of November 30, 2019.

TABLE 2
Illustrative BTS Revenue and Rate Impacts

Year	Current BTS Revenue Requirement $ Millions	River Route Project Revenue Requirement $ Millions	Total BTS Revenue Requirement $ Millions	Current BTS SFV Rate $/dth/d	River Route Project BTS Rate Impact $/dth/d	Total BTS SFV Rate $/dth/d
	A	B	C = A + B	D	E	F = D + E
2019	$149.6	$0.0	$149.6	$0.138	$0.000	**$0.138**
2020*	$149.6	$64.1	$213.7	$0.138	$0.059	**$0.197**
2021	$149.6	$113.6	$263.2	$0.138	$0.104	**$0.242**
2022	$149.6	$106.9	$256.5	$0.138	$0.098	**$0.236**
2023	$149.6	$103.4	$253.0	$0.138	$0.095	**$0.233**

*2020 Revenue Requirement of $5.3MM is grossed-up to $64.1MM in order to recover the amount over 1 month due to the estimated in-service date of November 30, 2020.

TABLE 3
Illustrative BTS Revenue and Rate Impacts

Year	Current BTS Revenue Requirement $ Millions	Cross Desert Project Revenue Requirement $ Millions	Total BTS Revenue Requirement $ Millions	Current BTS SFV Rate $/dth/d	Cross Desert Project BTS Rate Impact $/dth/d	Total BTS SFV Rate $/dth/d
	A	B	C = A + B	D	E	F = D + E
2019	$149.6	$0.0	$149.6	$0.138	$0.000	**$0.138**
2020*	$149.6	$143.5	$293.1	$0.138	$0.132	**$0.270**
2021	$149.6	$253.5	$403.1	$0.138	$0.233	**$0.371**
2022	$149.6	$238.6	$388.2	$0.138	$0.220	**$0.357**
2023	$149.6	$230.7	$380.3	$0.138	$0.212	**$0.350**

*2020 Revenue Requirement of $12.0MM is grossed-up to $143.5MM in order to recover the amount over 1 month due to the estimated in-service date of November 30, 2020.

(c) The North-South Project costs include approximately 8% contingency. The River Route and Cross Desert factored estimates were based on the North-South cost estimate that includes this approximate 8% contingency.

(d) Because the alternatives did not meet the project objectives, extensive analysis was not performed on these projects, including development of a schedule. Based on the North-South Project, we assume these alternative projects will take at least 6 years to complete from the decision to pursue each alternative.

(e) River Route – We assume the River Route components and characteristics would be similar to the North-South pipeline. The alternative will have an installation of 100 miles of 36-inch pipeline including pipe fittings, mainline valves with remote ops and line break controls, SCADA, pipeline Intrusion Monitoring, and Methane Detection. There will be launchers and receivers at each end. The pipelines will have to interconnect with PLS stations and two existing compressor stations.
Cross Desert – We assume the Cross Desert pipeline and compressor station components would be similar to the North-South pipelines and compressor station. 35,000 HP Compressor Station, 200 miles 36-inch pipeline, pipe fittings, mainline valves with remote Ops and line break controls, SCADA, Pipeline Intrusion Monitoring, and Methane Detection. The pipelines will have to interconnect with a new compressor station and multiple Pressure Limiting Stations.

(f) Each alternative would provide 800 MMcfd of supply to the Southern System, a volume sufficient to meet the design criteria described on page 8 of the Prepared Direct Testimony of David M. Bisi in A.13-12-013. Because each alternative has the capability to deliver supply to the Southern System, the potential for customer curtailment on the Southern System resulting from a lack of gas supply is diminished.

(g) The North-South Project and Cross Desert Project provide physical access to storage supplies for the Southern System; the River Route does not. Please refer to pages 9 – 14 of the Prepared Direct Testimony of David M. Bisi in A.13-12-013.

(h) Please refer to pages 9 – 14 of the Prepared Direct Testimony of David M. Bisi in A.13-12-013, where access to receipt points for each of the pipelines are specified.

(i) Please refer to page 15, lines 13 – 17 of the Prepared Direct Testimony of David M. Bisi in A.13-12-013.

(j) The North-South Project and the Cross Desert Project provide access to many more receipt points than the River Route Pipeline, and therefore would provide a higher level of insurance against disruptions caused by force majeure conditions in supply basins than the River Route alternative. However, all three alternatives provide a higher level of insurance against such disruptions relative to the present situation, where the Southern System is essentially dependent upon supplies delivered on the El Paso pipeline from the Permian and San Juan Basins.

(k) Please refer to Response 5(j) above.

(l) As previously stated, these physical alternatives did not meet our project objectives, therefore extensive analysis was not performed on these projects including development of detailed pipeline alignment and identification of class location, by number of miles. It is assumed that the majority of miles for either alternative would be in class 1 or class 2.

(m)Please refer to Response 5(f) above.

(n) See Attached Excel spreadsheets:

Project Alternatives Costs - Simplified.xlsx

QUESTION 6:

At page 12 of the Application, Applicants indicate that the North-South Project would expand SoCalGas' firm backbone capacity from 3,875 MMcf/d to 4,175 MMcf/d, or by 300 MMcf/d. Please explain whether the expansion of SoCalGas firm backbone capacity is a necessary element to meet the need to maintain Southern System reliability. Does this 300 MMcf/d expansion of firm backbone capacity increase access of Southern System customers to SoCalGas storage gas? Please explain in detail.

RESPONSE 6:

Please refer to page 15, lines 18 – 20, and page 16, lines 1 -2, of the Prepared Direct Testimony of David M. Bisi in A.13-12-013. The expansion of receipt capacity provided by the North-South Project and its alternatives is not necessary to maintain Southern System reliability, nor is it needed to provide access to storage supplies.

QUESTION 7:

At page 22 of the Application, Applicants state that they considered each of the nonphysical and physical alternatives to the North-South Project listed. In addition, the Applicants also considered each of the following: (1) Do nothing and rely on existing System Operator tools (2) A minimum Southern System flow requirement, either for all customers, or just for customers on the Southern System (3) A "low" OFO procedure, similar to the one proposed by SoCalGas in its 2009 BCAP proceeding; and (4) Tighter balancing requirements.

a. Please provide a side by side comparison of items (1) thru (4) similar to the one prepared in response to Question 5 above for the physical and non-physical alternatives, as may be applicable to these four items considered by the Applicants.

b. Please provide ORA with a copy of the active Excel spreadsheets that will be used in the calculations to produce the side by side comparison.

c. Please indicate whether Applicants considered the "low" OFO/EFO procedure and the tighter balancing requirements it has proposed in A.14-06-021 as a nonphysical alternative to the North-South Project. If so, please also include it in the side by side comparison requested in Question 7(a).

RESPONSE 7:

a) The cost of option 1 in the September 2013-August 2014 period was **$32 million**: $12.9 million of System Operator purchases costs $3 million of BTS discount costs, and $16 million of Gas Acquisition capacity premium expense of 300 MMcfd of firm El Paso capacity rights at Ehrenberg. As Mexico demand competes for supplies at Ehrenberg, SoCalGas believes this annual cost of the Southern System problem will increase significantly. In addition, curtailments are likely to increase, which could result in curtailment related costs to shippers and end-use customers.

The overall annual cost of option 2 would likely be very similar to that of option 1, though the portion of those costs noncore customers would pay to SoCalGas and SDG&E would likely change. ~~Presuming that the MILC is still in effect,~~ Gas Acquisition would continue to purchase El Paso Ehrenberg capacity at a premium, and the costs of purchasing noncore supplies currently borne by the System Operator would be shifted to end-use customers. Curtailment costs for shippers and end-use customers would likely be similar under the two options as well.

Option 3 is designed to resolve a different problem than the North-South project. A low OFO/EFO requirement will help bring supplies into our system as a whole during times of system stress, but those requirements can be satisfied by deliveries anywhere on our system or via firm storage withdrawals. This would not enable storage supplies to reach the Southern System, or to provide Southern System customers with access to any additional receipt points.

Option 4 is too vague to analyze.

b) Please see Response 7(a) above.

c) No. SoCalGas/SDG&E consider the Low OFO procedure to be essential to system integrity, independent from the North South project and general system integrity. The Low OFO procedure deals with inadequate supplies on the system as a whole. If the North-South pipeline is installed, it will allow additional gas that is now arriving at Northern System receipt points because of the Low OFO procedures to reach the customers on the Southern System.

QUESTION 8:

Have applicants considered expanding such existing "storage gas" facilities as listed in response to Question 4, or constructing new "storage gas" facilities that could deliver gas directly to the Southern System, as an alternative to the North-South project? If so, please provide such analysis, and please provide a side by side comparison similar to the ones prepared above for Questions 5 and 7. If not, please explain why not.

RESPONSE 8:

Please refer to our Response Q6.3 to the 6th Data Request of SCGC in A.13-12-013, and our Response Q7.1 from the 7th Data Request of SCGC in A.13-12-013.

QUESTION 9:

On August 15, 2014, three interstate pipeline companies filed testimonies in this proceeding that provide alternative pipeline solutions to the Southern System reliability problem described by the Applicants in A.13-12-013. Transwestern Pipeline Company, the El Paso Natural Gas Company, and TransCanada each propose alternatives to the North-South Project proposed by SoCalGas/SDG&E. Please provide a side by side comparison of the three alternative pipelines similar to the one prepared in response to Question 5 above for the physical and nonphysical alternatives, including the Applicants alternatives. Please provide ORA with a copy of the active Excel spreadsheets that will be used in the calculations to produce the side by side comparison.

RESPONSE 9:

Microsoft Excel
97-2003 Worksheet

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT
(A.13-12-013)

(DATA REQUEST ORA-NSP-SCG-06)

QUESTION 1:

The Updated Testimony of Mr. Jimmie I. Cho states at page 2: "As discussed by Mr. Bisi, one portion of our interconnected transmission system – SoCalGas' Southern Transmission System (Southern System) – requires minimum flowing supplies each day. This is because the Southern System can only receive a relatively small amount of flowing supplies from other parts of our system, and no supplies from storage. Without these minimum supplies, reliability would be compromised, and customers on the Southern System would face supply-based curtailments on a regular basis. This situation creates unique operational and reliability issues for the Southern System." Further , the Updated Testimony of Mr. David Bisi states at page 7: "Unlike other parts of SoCalGas' system, the Southern System requires minimum flow volumes at the Blythe and/or Otay Mesa receipt points to maintain service to its customers in the Imperial Valley and San Diego load centers and other communities in San Bernardino and Riverside Counties. While supplies from the Chino and Prado Stations and from Line 6916 can flow eastward, these facilities provide only a limited amount of supplies to meet the demand of the Southern System during peak periods. Additionally, due to the telescoping operating pressures of the Southern System pipelines, the higher MinOPs of the pipelines east of Moreno Station restrict further eastward flow. Similarly, supplies delivered via Line 6916 cannot flow east of the Cabazon area. In other words, supplies delivered at the pipeline MAOP from Chino and Prado Stations and from Line 6916 are at lower pressures than the MinOPs on the eastern portion of the Southern Transmission System. As a result, the remaining supply needed to meet Southern System demand must be delivered from El Paso or North Baja at the Blythe receipt point, and/or from TGN at the Otay Mesa receipt point, in order to maintain service to both core and noncore customers on the Southern System." The term MinOPs refers to Minimum Operating Pressures while MAOP refers to Maximum Allowable Operating Pressures as those acronyms are spelled out on page 6 of Mr. Bisi's Testimony.

Q1a. Please explain whether there is a system-wide reliability issue for the operationally integrated SoCalGas/SDG&E gas transmission system.[1]

Q1b. Please explain whether the Southern System has experienced any curtailment of service in the past as reliability was compromised, and if so, provide the historical recorded curtailment numbers for each recorded occurrence.

Q1c. If no curtailments of service have occurred as a result of the Southern System reliability issue, then describe how the existence of the reliability issue manifests itself in terms of gas transmission system operations.

RESPONSE 1:

1a. The reliability of a system is a function of both the physical infrastructure and the available flowing gas supply. Both are necessary to provide reliable service. SoCalGas and SDG&E do have other parts of its combined gas transmission system that lack sufficient physical infrastructure to provide reliable service to our customers in the event of pipeline outages. However, the North-South Project is intended to address the other component that comprises reliability for the Southern System – a lack of gas supply – and in that regard, there are no other areas on the combined SoCalGas and SDG&E system that have this same reliability issue. In addition, SoCalGas and SDG&E have filed a separate application (A.14-06-021) which proposes new low Operational Flow Order and Emergency Flow Order requirements to help ensure reliable operations during times of system stress when deliveries from customers and marketers are much lower than usage.

1b. There have been two curtailments of service in the past due to a lack of available supply on the SoCalGas Southern System.

On February 3, 2011 a Southern System curtailment was called due to a lack of supply from upstream pipelines. The estimated load reduction was 200 MMcfd.

On February 6, 2014 an emergency curtailment of the Southern System was called that was expanded later that day to a systemwide emergency. The estimated load reduction for this event was approximately 300 MMcfd.

1c. N/A

<u>QUESTION 2:</u>

SoCalGas filed Advice Letters (AL) 4207 in Feb 2011 and AL 4604 in Feb 2014 which provided notice of emergency curtailments on those dates pursuant to D.91- 09-026. Please explain whether the curtailments noticed in AL 4207 and AL 4604 were the result of problems attributed to the Southern System reliability issue described in the SoCalGas/SDG&E Application (A.) 13-12-013. If SoCalGas filed other ALs regarding curtailment of service due to the Southern System reliability issue, please identify them and provide a copy.

<u>RESPONSE 2:</u>

The February 3, 2011 curtailment was caused by supply-related problems outside of California on the El Paso system that diminished supply being provided to the Southern System. The diminished supply could not meet Southern System demand resulting in severe drafting of the pipeline network requiring that a curtailment order be issued.

The February 6, 2014 curtailment was required due to inadequate quantities of gas being delivered to both the Southern System receipt points and to receipt points serving the rest of the SoCalGas system. The lack of supply combined with high electric demand on both the Southern System and the rest of the SoCalGas system resulted in the emergency curtailment orders.

These are the only advice letters regarding curtailment of service filed by SoCalGas regarding curtailment of service due to the Southern System reliability issue.

QUESTION 3:

The 2014 California Gas Report (CGR) does not indicate any recorded curtailment numbers in the period 2009-2013 nor does it indicate any forecast curtailments from 2014 going forward through 2035 under average and cold temperature conditions for both SoCalGas and SDG&E.

(a) Please explain why the 2014 CGR does not show any curtailment numbers in the record years 2009-2013.

(b) Please explain why the 2014 CGR does not show any forecast curtailment numbers in the forecast period from 2014 going forward through 2035. Please explain any assumptions being made in the period going forward.

RESPONSE 3:

(a) The 2014 CGR does not explicitly show any curtailment numbers in the recorded years 2009-2013 because, during some curtailment events, the estimate of the curtailed volume is not available. Over the last five years, SoCalGas/SDG&E curtailed noncore transportation service 11 times. The details of each curtailment is described below:

February 3, 2011: An estimated curtailment of 200 MMcfd.
October 1-2, 2011: All noncore service; noncore customers were allowed to maintain service under an operating emergency by delivery of supply at Otay Mesa system receipt point. No estimate of curtailment is available.
October 8-9, 2011: same as October 1-2, 2011.
October 15-16. 2011: same as October 1-2, 2011.
October 22-23, 2011: same as October 1-2, 2011.
October 29-30, 2011: same as October 1-2, 2011.
November 5-6, 2011: same as October 1-2, 2011.
November 12-13, 2011: same as October 1-2, 2011.
November 19-20, 2011: same as October 1-2, 2011.
December 27, 2012: no estimate of curtailment is available.
February 6, 2014: approximately 300 MMcfd curtailed.

While the 2014 CGR does not explicitly show any curtailment numbers in the recorded years 2009-2013, it is important to understand that noncore customer usage data implicitly captures the effects of any curtailment events.

(b) The 2014 CGR does not show any forecast curtailment numbers in the forecast period from 2014 going forward through 2035 because, on a system-wide basis, the pipeline capacity available to supply gas exceeds the forecasted annual gas demand during the forecast period under average and cold temperature conditions for both SoCalGas and SDG&E.

QUESTION 4:

ORA understands that SoCalGas and SDG&E regularly submits the Gas Utility Monthly Survey (GUMS) forms to the Commission consistent with the requirements of Commission Decisions 91-11-025 and 92-07-025, Resolution G-3044 and the Commission's follow-up letters to the other investor owned utilities within California. The information in GUMS reports is considered confidential information pursuant to PUC Code Section 583 & General Order 66-C. Please explain whether SoCalGas/SDG&E has reported any curtailment numbers attributed to the Southern System reliability issue in any of the GUMS reports submitted. If so, please identify the months for which submissions were made regarding curtailments and any other reliability issues. If the Southern System reliability issue is not reported nor shown in the GUMS reports curtailment numbers, then please explain why.

RESPONSE 4:

SoCalGas has not provided curtailment numbers attributed to the Southern System reliability issue in any of the GUMS reports submitted to the Commission. The curtailment numbers are not reflected in the GUMS reports due to the fact that curtailment volumes are not identified by market segment as presented in the GUMS report.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT
(A.13-12-013)

(DATA REQUEST ORA-NSP-SCG-08)

QUESTION 1:

The Response to ORA-NSP-SCG-02 Question 11(c) in the above subject proceeding reads: "The North South project will enable the delivery of physical supply to the Southern System. Owning capacity on the El Paso system does not insure someone will actually move physical gas on that capacity or that there will not be upstream supply or maintenance issues preventing that supply from reaching the SoCalGas/SDG&E system."

(a) Please explain what measures would "insure someone would will actually move physical gas on that capacity" such that gas would be delivered to the SoCalGas system in order to deliver gas to the Southern System.

(b) Are these measures described in question (a) above different for gas delivered to the Southern System over the North-South system than for gas delivered to the Southern System directly on interstate pipelines, including, but not limited to, El Paso?

(c) Does the type of capacity owned by shippers on interstate pipelines impact whether such capacity is available for use to transport to the SoCalGas/SDG&E system? Please explain.

(d) Please explain what "upstream supply or maintenance issues" can prevent "supply from reaching the SoCalGas/SDG&E system."

RESPONSE 1:

a) SoCalGas has no means to require customers to use interstate capacity or to deliver gas at any particular receipt point on the integrated SoCalGas/SDG&E gas transmission system. SoCalGas cannot control transactions on interstate pipelines, and SoCalGas offers its customers a "postage-stamp" rate model for transportation services, whereby supplies are transported from any receipt point at the same cost. This enables our customers to acquire the most economic gas supplies needed for their operations.

b) Yes. The North-South Project will be part of the integrated SoCalGas/SDG&E gas transmission system. As part of our integrated intrastate system, flows on the North-South project will not be dependent upon upstream nominations, and they will not be subject to the same force majeure concerns as interstate flows into Blythe.

c) As stated in response 1(a), SoCalGas offers a "postage stamp" rate model for transportation, allowing supplies to be transported from any receipt point at the same cost. With that said, SoCalGas does not have knowledge of a shipper's firm or interruptible capacity rights on an upstream pipeline and is thus unaware of how that effects the utilization of the receipt points. SoCalGas is merely aware of the amount of gas and the receipt point the gas is scheduled from upstream pipelines.

d) Upstream supply or maintenance issues that can prevent supply from reaching the SoCalGas/SDG&E system include planned or unplanned pipeline outages and gas production declines due to well freeze-offs, icy roads, rolling electric blackouts or customer curtailments. Freeze-offs routinely occur in very cold weather, and have affected at least some of the five production basins serving the Southwest in five of the last six recent cold weather events (FERC and NERC Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011, p. 9).

QUESTION 2:

The Response to SCGC-4 Question 4.16 (referencing Testimony of Beth Musich, p. 10, lines 9-16) in the above subject proceeding reads: "SoCalGas and SDG&E do not believe that either the North-South Pipeline nor deliveries from Honor Rancho would have been able to support the Southern System on December 9, 2013. SoCalGas and SDG&E were short of supply across their entire system during that event, and there were no supplies available on its Northern System to transport to the Southern System."

(a) Please explain what measures SoCalGas believes could have been taken, by SoCalGas, third party shippers, customers, or the Commission, to have ensured that gas was available to the Southern System on December 9, 2013.

(b) Please explain why such measures do not require construction of the North-South Pipeline.

(c) Please explain whether, and if so, how, SoCalGas intends to propose that the Commission adopt such measures in other proceedings.

RESPONSE 2:

a) Issuing a Low Operational Flow Order (OFO). Partly in response to the December 9, 2013 incident, SoCalGas and SDG&E proposed in A.14-06-021 a Low OFO protocol to provide incentives to balancing agents to ensure delivery of adequate supply to the SoCalGas/SDG&E system or incur non-compliance charges. A.14-06-021 is currently pending before the Commission.

b) The North-South Project will only move gas supply already on the SoCalGas/SDG&E system to other parts of the SoCalGas/SDG&E system. It does not provide a solution to the problem of customers and shippers delivering less gas into the system than they are burning during times of system stress. The North-South Project and our proposed low OFO requirements solve different operational problems.

c) Please refer to Response 2a of this data request.

QUESTION 3:

The Response to ORA-NSP-SCG-2 Question 6(c) reads: "Yes. If the North-South Project is built there will probably be no need for a MILC." This is the SoCalGas/SDG&E Response to the question: "Do the Applicants expect the North-South Project, or an Alternative Project to be determined, to eliminate the need for a Gas Acquisition MILC? If not, please explain."

(a) Please provide all the underlying assumptions regarding your response to item (a) above should SoCalGas/SDG&E assert that only the North-South project can effectively address the Southern System reliability issue and the expectation that the need for a Gas Acquisition MILC will be eliminated with the North-South project.

(b) Assuming the North-South Project is built as now proposed, please explain whether, and if so, how, SoCalGas/SDG&E expects to continue to use the System Operator tools to address the Southern System reliability issue.

RESPONSE 3:

a) As explained in the testimony of Mr. Bisi, if the revised North-South Project is constructed, SoCalGas will need a limited amount of flowing supplies at Blythe—100 MMcf/d or less—only under extremely high sendout conditions. Given this fact, SoCalGas and SDG&E do not anticipate a need for continuing a MILC with Gas Acquisition, at least in its current form.

b) If the North-South Project is built as now proposed, SoCalGas would need to utilize the current System Operator tools only under the unlikely event that customers and shippers are not delivering at least 100 MMcfd of supply at Blythe under a high sendout condition.

<u>QUESTION 4:</u>

Given the deleted project component of the original North-South project (i.e. Whitewater), please explain whether there are still any physical infrastructure alternatives that were considered by SoCalGas/SDG&E that are comparable to the reduced scope of the project. If so, please provide a side by side comparison of each infrastructure alternative examined by the Applicants in considering the reduced scope of the North- South project. If not, please state whether the previous (1) River Route and (2) Cross Desert options are no longer infrastructure alternatives.

<u>RESPONSE 4:</u>

There are no other physical infrastructure alternatives that are comparable to the modified North-South Project. The River Route and Cross Desert option are not viable alternatives for the reasons expressed in our testimony. The revised scope of the North-South Project does not change this fact.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT
(A.13-12-013)

(DATA REQUEST ORA-NSP-SCG-09)

QUESTION 1:

In Response to ORA-NSP-SCG-06 Question1a, SoCalGas states that the "North-South Project is intended to address the other component that comprises reliability for the Southern System – a lack of gas supply – and in that regard, there are no other areas on the combined SoCalGas and SDG&E system that have this same reliability issue." In addition, at page 13 of the Updated Direct Testimony of Ms. Gwen Marelli under the heading caption "Efforts By SOCALGAS To Mitigate the Southern System Problem," the Testimony provides a brief description of the "efforts" by SoCalGas above and beyond spot purchases and sales, which include the following:

(i) baseload contracts for Southern System support;
(ii) enabling the System Operator to move supplies from Blythe to Otay Mesa;
(iii) the Commission-authorized Memorandum in Lieu of Contract (MILCs) with Gas Acquisition;
(iv) Backbone Transportation Service (BTS) discounts; and
(v) Addition of Line 6916.

In Ms. Marelli's Updated Testimony, SoCalGas includes a section captioned "These Mitigation Efforts Will Not Solve the Southern System Problem," stating (Gwen Marelli Direct Testimony, p. 16): "Each of the mitigation efforts described above, other than the addition of Line 6916, is a short-term effort to reduce the cost of providing Southern System support for our customers. None of these efforts will deal with the long-term Southern System support issues described above and in the testimony of Mr. Morrow. As can be seen in Figure 3, at times the System Operator is delivering the majority of supplies to the Southern System. …

"As gas supplies at Blythe and Otay Mesa become more scarce and more expensive, BTS discounts, baseload contracts, and even future MILCs with Gas Acquisition will not solve the reliability and cost issues we will be facing."

Q1a. If an analysis of the "efforts" was previously reviewed by SoCalGas, and were included elsewhere in the SoCalGas Application, then please provide the relevant cite reference to them. Otherwise, please provide the analysis of the "efforts" by SoCalGas that enabled SoCalGas to conclude that each of the mitigation efforts (as described in the above Updated Testimony of Ms. Marelli) will not solve the reliability issue for the Southern System and is a "short-term" effort, including an explanation of the use of the term "short-term" in this context.

Q1b. Please explain whether SoCalGas relied on a specific forecast assumption of gas supplies at Blythe and Otay Mesa in the statement "[a]s gas supplies at Blythe and Otay Mesa become more scarce and more expensive…". If so, please provide the forecast relied upon by SoCalGas and state the assumptions under that forecast scenario. If no specific forecast was relied upon, then please explain the basis for the above statement, including any assumptions being made.

Q1c. SoCalGas refers to the Southern System support issues as "long term" in the above referenced statements from Ms. Marelli's Updated Testimony. Please explain the meaning of "long-term" as it refers to the Southern System support issues, and state any SoCalGas' assumptions regarding the Southern System support issues being considered a "long term" reliability issue. Does SoCalGas assume the lack of gas supplies into the Southern System will continue to persist in the long term absent a physical infrastructure such as the North-South Project built?

<u>RESPONSE 1:</u>

a. The mitigation efforts described by Ms. Marelli are "short-term" because they rely on the economic availability of supply at Ehrenberg. Due to the expansions of demand for natural gas in Mexico described by Mr. Chaudhury, SoCalGas and SDG&E do not believe such supply will be economically available after 2020. For example, SoCalGas will not be able to obtain baseload supplies at Ehrenberg for SoCalGas border + 8 cents, +20 cents, or even +30 cents. Gas Acquisition will not be able to justify the extremely expensive long-term contract and supply commitments necessary to fulfill its current obligations under the MILC. The cost of supply at Ehrenberg will become so high that it will be uneconomical to deliver such supply to the Los Angeles citygate even if the BTS rate for transport of such gas on the Southern System is discounted all the way down to zero.

   Furthermore, the mitigation efforts are short-term because they do not provide Southern System customers the reliability afforded other customers throughout the system. They are susceptible to flowing supply failures of El Paso's Southern System supplies. Whereas other parts of the system can be protected against potential flowing supply failures with storage, SoCalGas' Southern System customers will not have effective access to storage without the long-term solution represented by the North-South pipeline proposal.

   SoCalGas and SDG&E have historically had problems with supply reliability during cold weather events that periodically affect the Southwest US. These problems resulted in the curtailment of end use customers in 1989 and again in

2011. These supply problems have been documented by the Federal Energy Regulatory Commission (FERC) in the FERC/NERC Staff Report on the 2011 Southwest Cold Weather Event.

b. Ms. Marelli relied on the forecast provided by Mr. Sharim Chaudhury on pages 5 and 6 of his direct testimony. The utility believes the forecasted increase of exports into Mexico via El Paso South Mainline shown on those pages will lead to a corresponding decrease in the availability of economic supplies available to SoCalGas at Ehrenberg.

c. SoCalGas and SDG&E define long term as beyond 2020. Yes, SoCalGas believes the lack of gas supplies into the Southern System will persist in the 2020-2040 period absent a physical infrastructure such as the North-South Project.

QUESTION 2:

In Response to ORA-NSP-SCG-06 Question 1b, SoCalGas describes only two curtailments of service in the past due to a lack of available supply on the SoCalGas Southern System. In Response to ORA-NSP-SCG-06 Question 1b, and in a similar Response to TURN DR3 Question 2, SoCalGas states that the Southern System experienced two curtailments in the last ten years which affected transportation service to noncore customers. The two identified curtailment events occurred on specific dates of February 3, 2011 and February 6, 2014. The estimated load reduction for the first event was 200 MMcfd while the same was approximately 300 MMcfd for the second event. On page 12 of Ms. Marelli's Updated Testimony, SoCalGas describes some instances of reduced receipt point capacity on Blythe and states: "If, however, the North-South Project had been in service, Gas Control could have simply moved gas from our Honor Rancho storage field or a variety of northern sources including our Kramer Junction, Needles, and Topock receipt points. This project will allow us to deal with rapidly changing operational concerns, reducing the risk of curtailment for our noncore customers."

Q2a. Except for Line 6916 which went into service on December 20, 2012 and the later approval of AL 4517 dated July 2, 2013, per Marelli Updated Testimony in A.13-12-013 dated Nov.12, 2014, pp.15-16, it appears to ORA that at least the other mitigation "efforts" described by SoCalGas were already in place and available for use when the two identified curtailment events due to a lack of gas supply on the SoCalGas Southern System occurred on February 3, 2011 and February 6, 2014. If ORA understands this correctly, then is it accurate to say that the two curtailment events described occurred despite employing all the mitigation "efforts" that were above and beyond the spot purchases and sales by SoCalGas? Please explain in particular how useful the MILC and the baseload contract efforts were in terms of providing reliable gas supplies during the two identified curtailment events in Feb. 2011 and Feb. 2014. If these two efforts did not meet expectations in terms of providing gas supplies to the Southern System, then please explain.

Q2b. Assume hypothetically that the proposed North-South Project (as updated) had been in existence and in service during the period when the above described two curtailment events occurred. Assume further that the MILC and the baseload contracts were not in place but SoCalGas is able to engage in spot purchase and sales. Please describe if and how the North-South Project would have enabled SoCalGas to deal with the "lack of gas supply" situations it faced on Feb. 3, 2011 and Feb.6, 2014 on the Southern System. Based on the hypothetical, would the North-South Project have enabled gas supplies to flow on the Southern System and prevented the two curtailment events from occurring? If so, please explain how.

Q2c. In Response to TURN DR3 Question 2 regarding the estimated curtailed volumes during the curtailment event on Feb. 6, 2014, SoCalGas and SDG&E state that they “do not know how much each of those generators would have burned absent the curtailment orders, and therefore cannot reasonably estimate the curtailed volumes and their respective firm and interruptible portions.” However, in Response to ORA-NSP-SCG-06 Question 1b, the utilities state that the estimated load reduction for this event was approximately 300 MMcfd. Please explain:
1) How SoCalGas and SDG&E calculated the load reduction for this event;
2) Whether the load reduction included any curtailed generation, and if so, how much;

RESPONSE 2:

a) On February 6, 2014 the Memorandum in Lieu Of Contracts (MILC) with Gas Acquisition and the baseload contracts delivered the agreed supplies at Ehrenberg. On February 3, 2011 SoCalGas was not yet authorized to purchase baseload contracts for Southern System support. Moreover, the Commission did not authorize the MILC with Gas Acquisition until 2012.

b) The curtailment events on February 3, 2011 would have been avoided had the North-South Project been in existence and SoCalGas was able to engage in spot purchase and sales from non-southern system receipt points and storage to support Southern System reliability. The curtailment event on February 6, 2014 would not have been avoided even if the North-South Project been available and SoCalGas was able to engage in spot purchase and sales from non-southern system receipt points and storage to support Southern System Reliability. This problem would be avoided in the future by the adoption of the Low OFO/EFO proposal as presented in A.14-06-021.

c) On February 6, 2014 at 6:25 a.m., Gas Control contacted CAISO regarding an increased EG burn. CAISO indicated that the increase in EG burn was going to track an initial forecast, submitted to Gas Control the previous evening that was not accepted, which was approximately 280 MMcf higher on the SoCalGas system and 215 MMcf higher on the SDG&E system than the previous day’s (2/5/14) burn. Gas Control had not anticipated nor had been forewarned of this very large increase in expected EG burn and therefore had not requested additional gas to meet this additional load nor had made plans to curtail load had additional supply not been available. Gas Control was forecasting EG loads for February 6 at levels equivalent to February 5 with an ability to meet an increased demand of up to 200 MMcfd on the system. With storage withdrawal already at maximum and combined with low out-of-state receipts, the increase in load beyond 200 MMcfd, approximately 300 MMcfd, could not be sustained without curtailment of lower priority load located both on the Southern System and also system wide.

QUESTION 3:

In Response to ORA-NSP-SCG-06 Question 3(a), SoCalGas and SDG&E state that over the last five years, the noncore transportation service was curtailed 11 times, including the Feb. 3, 2011 and Feb. 6, 2014 curtailment events previously described in Question 2 of this data request.

Q3a. Please list and explain in detail the additional nine (9) curtailment events, including dates, amounts of capacity curtailed, length of curtailment, and efforts made by SoCalGas and SDG&E to respond to the curtailment.

Q3b. Please clarify whether the additional nine (9) curtailment event dates identified in the Response to ORA are likewise attributed to a lack of available gas supply on the SoCalGas Southern System, and therefore, are similar in nature to the Feb.3, 2011 and Feb.6, 2014 curtailment events. If not, then please specify the reason(s) associated with these other curtailments and confirm whether these nine other curtailments of service could not be attributed to the Southern System reliability issue.

Q3c. Please clarify whether SoCalGas had filed any advice letters regarding the curtailment of service on the dates identified in the Response to ORA-06 Question 3b. If no advice letters were filed, then please explain why it was not necessary to file them.

Q3d. During any of the additional nine (9) curtailment events, were the other mitigation “efforts” described by SoCalGas on page 16 of Ms. Marelli’s testimony already in place and available for use except for Line 6916 which went into service on December 20, 2012 and the later approval of AL 4517? If so, then please provide a list identifying which ones. Please answer the questions in 2a of this data request for this list.

Q3e. Please answer the hypothetical questions in 2b for the list of curtailments provided in response to question 3d.

RESPONSE 3:

a) The dates (which comprise the duration) for the nine curtailment events referenced herein were previously provided to ORA in response to Question 3a of ORA-NSP-SoCalGas-06. As SoCalGas and SDG&E stated in its response to Question 3a, noncore customers were allowed to maintain service under an operating emergency by delivery of supply at the Otay Mesa receipt point, and no estimate of curtailment volumes are available.

b) They are not. The nine SDG&E curtailment events identified in response to ORA-NSP-SoCalGas-06 Question 3a were necessary to perform pipeline safety-related work on SDG&E Transmission Line 3010, and resulted in a capacity reduction on the SDG&E system.

c) These nine curtailment events were on the SDG&E system. SDG&E is not required to file an advice letter for curtailment events ordered on its system.

d) No. The nine SDG&E curtailment events referenced were the result of pipeline-safety related work. The mitigation efforts SoCalGas is authorized to make do not apply for this situation.

e) The North-South Project is not designed to improve the capacity of the SDG&E system, and therefore access to SoCalGas storage supplies afforded by the North-South Pipeline would not have prevented these nine curtailment events.

QUESTION 4:

Page 17 of Ms. Marelli's Updated Testimony states: "By contrast, Line 6916 is a true long-term reliability solution that decreases the Southern system minimum. But with a capacity of up to 80 MMcfd, Line 6916 is only part of the solution. For the reasons I will now discuss, additional physical solutions to the Southern System problem are necessary in order to provide Southern System customers with the reliability they deserve at a reasonable cost." In Response to TURN DR4 Question 2, SoCalGas states: "Yes, SoCalGas briefly considered improving Line 6916 as an alternative to the North-South project. However, without further improvement to the transmission system, volumes transported on Line 6916 would be limited to those delivered at our Topock receipt point, which currently has a receipt capacity of 540 MMcfd and is frequently not fully utilized. SoCalGas and SDG&E do not believe it is prudent to simply trade a dependency on supply at Blythe for a dependency on supply at Topock. This improvement would therefore not provide the level of reliability necessary to support the Southern System, either in terms of volume or supply diversity."

Q4a. Please explain what SoCalGas means by "SoCalGas briefly considered improving Line 6916 as an alternative to the North-South project." Briefly describe the options to improving Line 6916 that were considered by SoCalGas and the reasons behind dropping consideration of those options.

Q4b. Please explain in detail and quantify the statement "Topock receipt point …[is] frequently not fully utilized." Please provide an estimate of usage of the Topock receipt point over the next ten years if:
1) Line 6916 remains unchanged and North-South is constructed;
2) Line 6916 remains unchanged and North-South is not constructed;
3) Line 6916 is improved and North-South is not constructed.

RESPONSE 4:

a) SoCalGas and SDG&E examined whether Line 6916 could be improved to serve as an alternate to the North-South Project. We found that significant improvement was required in terms of new pipeline and compression. Because an improved Line 6916 would provide less benefit than the River Route Pipeline alternative we presented in our testimony, and yet cost more due to the expanded pipeline length and need for compression, we did not include it as a viable alternative in our application.

b) SoCalGas and SDG&E have no such forecast available.

QUESTION 5:

On pages 7-8 of the SoCalGas/SDG&E Application, the Applicants claim increasing threats to the Southern System reliability on top of the increased possibility of higher system reliability costs. On pages 17-19 of Ms. Marelli's Updated Testimony, the Applicants state they have looked at a number of potential non-physical solutions to the SoCalGas Southern System reliability issues and that "Non-Physical Solutions will not solve the Problem." On page 21 of Ms. Marelli's Updated Testimony, Applicants state their belief that without access to SoCalGas storage fields, the Southern System customers will continue to be dependent on a single receipt point Blythe: "Southern System customers need to have access to supplies from SoCalGas storage field and other receipt points, and such access can only be achieved through physical upgrades." In Response to ORA-NSP-SCG-03 Question 4, SoCalGas states that Southern System customers do not have physical access to SoCalGas storage supplies. On p. 10 of its Application, SoCalGas and SDG&E state they considered the merits of supplementing or replacing the existing System Operator tools with a minimum flowing supply requirement for all end-use customers. Given the "increasing threats to the Southern System reliability," please explain whether SoCalGas should now explore a proposed Southern System minimum flowing supply requirement for all end-use customers. If not, then please explain the basis for the statement on p. 10 of the Application "But we do not believe that the time is ripe for such a proposal." Why is the time not ripe for such a proposal now?

RESPONSE 5:

SoCalGas and SDG&E believe that, customers would not be able to acquire supplies on the Southern System in times of stress like the Southwest Cold Weather Event of February 1 – 5, 2011 any more readily or easily than the System Operator would. Therefore, SoCalGas and SDG&E do not view a Southern System customer flow order as a viable solution to this problem.

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SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT
(A.13-12-013)

(DATA REQUEST ORA-NSP-SCG-09)

QUESTION 6:

The Direct Testimony of Sharim Chaudhury, pp. 1-3, cites to multiple forecasts that predict substantial increases in exports of natural gas from the US to Mexico. Although the cite references are indicated in footnotes 1 to 8 of the Chaudhury testimony, including the Prospectiva del Mercado de Gas Natural 2009-2024 [Natural Gas Market Outlook 2009-2024], pages 116,118,131; Secretary of Energy (SENER), Federal Government of Mexico, 2010, the Bentek Material, and the Kinder Morgan Presentations, ORA could not get to most of these cites except the ones for the US EIA. Please provide ORA with an active link to the materials cited on footnotes 1 through 8 of this testimony, or alternatively, provide pdf or hard-copies of the materials.

RESPONSE 6:

Footnote 1: http://www.sener.gob.mx/res/PE_y_DT/pub/Prospectiva_gasnatural_2009-2024.pdf

Footnote 2: http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf

Footnote 3: http://www.eia.gov/forecasts/aeo/er/

Footnote 4: The CEC's "2013 Integrated Energy Policy Report, Draft Lead Commissioner Report, October 2013" has been superseded by the final 2013 IEPR released in January 2015. See page 248 of the 2013 IEPR: http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF.pdf

Footnote 5: The May 2013 Bentek overview report is no longer available online. SoCalGas has scanned its hardcopy as an electronic pdf file. See page 5 of the accompanying file "North-South ORA-NSP-SCG-09 Q6 footnote5.pdf".

Footnote 6: http://ir.kindermorgan.com/sites/kindermorgan.investorhq.businesswire.com/files/event/additional/0827_MS_KD.pdf

Footnote 7: http://ir.kindermorgan.com/press-release/all/kinder-morgan-energy-partners-increases-quarterly-distribution-132-unit

Footnote 8: (The same footnote link shown in direct testimony remains active): http://www.bentekenergy.com//BentekTopStories.aspx?e=3&rpt=136&dt=7/10/2013

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QUESTION 7:

At p.5 of the Direct Testimony of Sharim Chaudhury, SoCalGas states: "During 2012 the daily gas flows from the US to Mexico via the El Paso South Mainline averaged approximately 637 MMcfd. [Cite to Footnote 13] As a result of these referenced projects, this gas flow may increase to as much as 1,200 MMcfd by the end of 2014, [Cite to Footnote 14] and to as much as 1,653 MMcfd by the end of 2025."[Cite to Footnote 15] ORA understands that the 1,200 MMcfd figure by the end of 2014 is only an estimate based on information available at the time of the SoCalGas testimony.

Please provide the actual gas flow from the US to Mexico via the El Paso South Mainline at the end of 2014. Based on the actual gas flow, please confirm whether the projected 1,653 MMcfd by the end of 2025 is still forecast, and if not, please provide an updated figure.

RESPONSE 7:

The average daily gas flow from the US to Mexico via the El Paso South Mainline was 906 MMcfd from July 1, 2014 through December 31, 2014. The average daily flow was 823 MMcfd in December 2014 while it was 1,020 MMcfd in July 2014.

The projected 1,653 MMcfd forecast by the end of 2025 still holds because the 2025 forecast was based on the planned future gas-fired power plants in Mexico, both new and converted from fuel oil, that are likely to rely on gas delivered from the El Paso South Mainline (see the Direct Testimony of Sharim Chaudhury, page 4, lines 14-18). As pointed out in Mr. Chaudhury's Direct Testimony, footnote 16, this 2025 forecast is likely to understate the gas export of Mexico via the South Mainline since the forecast reflects gas demand for gas-fired power plants only and do not include any gas demand for potential growth in Mexico's industrial sector.

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SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT
(A.13-12-013)

(DATA REQUEST ORA-NSP-SCG-11)

QUESTION 1:

At page 11 of the Application, Applicants state "Southern System customers pay the same rates as SoCalGas customers located elsewhere." In Response to ORA-NSP-SCG-03 Question 4b, SoCalGas states that Southern System customers do not have physical access to SoCalGas storage supplies. Further, in the same Response, Applicants state Southern System customers pay for SoCalGas storage costs in their rates and the payments are equal to those paid for by SoCalGas customers located elsewhere on the system. Given that Southern System customers have no physical access to SoCalGas storage supplies, please describe the specific storage service paid for by the Southern System customers in their rates. In your response, please specify the amount (in dollar terms) that is being charged to and paid for by Southern System customers in their rates
(in cents per therms).

RESPONSE 1:

SoCalGas and SDG&E core customers pay for storage (as opposed to Southern System) reliability service and both SoCalGas and SDG&E core and noncore customers pay for load balancing service which are recovered in their transportation rates. The following is the aggregate amount of dollars currently allocated to the Core Storage Reliability and Load Balancing functions. These costs are not allocated to customers based on their location on the system.

Core Storage Reliability - $52.8 million
Load Balancing - $10.3 million

Given the aggregate storage service dollars provided above, core customers' transportation rates include, on average, approximately 1 cent per therm for core reliability. Core and noncore customers' transportation rates include, on average, approximately 0.1 cent per therm for storage load balancing services.

Additionally, SoCalGas and SDG&E noncore customers can contract for unbundled storage service. Unbundled storage is not included in transportation rates, but is available to all customers regardless of their location on the system. The following is the aggregate amount of dollars currently allocated to the Unbundled Storage function.

Unbundled Storage - $26.5 million

QUESTION 2:

Please explain whether SoCalGas/SDG&E has explored obtaining gas supplies from any independent storage providers, including any outside of the service territories of SoCalGas/SDG&E. If so, please describe those efforts to take gas supplies from independent gas storage providers and the result. If not, please explain why not.

RESPONSE 2:

Within the SoCalGas and SDG&E service territories, there are no independent gas storage providers. SoCalGas owns and operates all underground natural gas storage facilities in southern California.

Storage supplies from providers outside of the SoCalGas and SDG&E service territories would only provide the same level of benefit to our system reliability as delivered pipeline flowing supplies would. For the reasons presented in our prepared direct testimony, SoCalGas and SDG&E believe the physical solution comprised of the North-South Project is a better solution for our system.

QUESTION 3:

At p. 21 of Ms. Marelli's Updated Testimony dated Nov. 12, 2014, SoCalGas/SDG&E state that three infrastructure alternatives were examined and that all three alternatives would add approximately 800 MMcfd of North-to-South flow capacity on the SoCalGas system. SoCalGas/SDG&E state this would effectively eliminate the Southern System minimum flow requirement. Further, Applicants explain that the provision of access to supplies from storage and additional receipt points (Wheeler Ridge, Kern River Station, and Kramer Junction), would increase the reliability of service to Southern System customers, and that this is the primary reason for proposing the North-South Project, and the reason that contractual alternatives do not work. At p. 22 of Ms. Marelli's Updated Testimony, Applicants explain that the North-South Project would expand SoCalGas' firm backbone capacity from 3,875 MMcfd to 4,175 MMcfd.

QUESTION 3a:

Please confirm whether the reduced scope of the proposed North-South Project as updated on Nov. 12, 2014 by SoCalGas/SDG&E, would still add approximately 800 MMcfd of North-to-South flow capacity on the SoCalGas system and eliminate the Southern System minimum flow requirement, similar to the original proposed Project. If not, please explain.

QUESTION 3b:

Please confirm whether any of the current proposed alternatives to the North-South Projects provided by EPNG, Transwestern, and TransCanada/North Baja, if adopted, could provide the necessary equivalent North-to-South flow capacity on the SoCalGas system and effectively eliminate the Southern System minimum flow requirement. If not, please explain.

QUESTION 3C:

In order to address the Southern System reliability issues in A.13-12-013, please explain if it is absolutely necessary to eliminate the Southern System minimum flow requirement. If not, please explain.

QUESTION 3D:

What are the advantages of eliminating the Southern System minimum flow requirement? Please explain. Are there disadvantages of eliminating the Southern System
minimum flow requirement? Please explain.

QUESTION 3E:

Why would construction and operation of the North-South Project categorically allow for the elimination of the Southern System minimum flow requirement? If the North-South Gas pipeline was authorized, built, and put into service; and then became non-operational; would a Southern System minimum flow requirement be necessary?

QUESTION 3F:

Please identify which SoCalGas storage facilities could be accessed by Southern System customers if the North-South Project were built. If the North-South Project had been built and was in operation, then please explain whether the access to the identified SoCalGas storage facilities would have prevented the two curtailment of service events in the Southern System that occurred on February 3, 2011, and February 6, 2014, described in SoCalGas/SDG&E Response to ORA-NSP-06 Question 1a.

QUESTION 3G:

If the North-South Project had been built and was in operation, then please explain whether the access to the identified SoCalGas storage facilities would have prevented the nine additional curtailment of service events described in response to ORA-NSP-SCG-06 Question 3(a). Please explain why or why not.

QUESTION 3H:

Please explain whether access to the additional receipt points (Wheeler Ridge, Kern River Station, and Kramer Junction) would have prevented the two curtailment of service events in the Southern System described in SoCalGas/SDG&E Response to ORANSP-06 Question 1a.

QUESTION 3I:

Would access to the additional receipt points (Wheeler Ridge, Kern River Station, and Kramer Junction) have prevented the nine additional curtailment of service events described in response to ORA-NSP-SCG-06 Question 3(a)? Please explain why or why not?

QUESTION 3J:

Please explain whether the expansion of the SoCalGas' firm backbone capacity from 3,875 MMcfd to 4,175 MMcfd is necessary in order to address the Southern System reliability issues in A.13-12-013. Please explain the need for and use of the SoCalGas expanded firm backbone capacity for purposes of addressing the Southern System reliability issues.

RESPONSE 3:

a) The reduced scope of the North-South Project, i.e. the elimination of the Whitewater pipeline, does not alter the 800 MMcfd capacity of the remaining components (the Adelanto compressor station and the Adelanto-Moreno pipeline). However, per our testimony, this 800 MMcfd is not able to be transported to all areas of our Southern System under all demand conditions, and will require the delivery of 100 MMcfd of supply at Blythe under the demand scenario used in our application.

b) The North-South Project will provide flowing supplies to the Southern System. The proposed alternatives to the North-South Project would not provide flowing supplies, just the ability for shippers on the pipeline to flow gas to the Southern System if they choose to on a particular day – just as the ability is there today with the existing El Paso pipeline connected at Blythe. Therefore, proposed alternatives to the North-South Project are not equivalent and will not eliminate the Southern System minimum flow requirement.

c) SoCalGas and SDG&E believe it is in the best interest of our customers to have a gas transmission system that is not dependent upon either having supply delivered at a specific location or face customer curtailment and jeopardize system integrity. In that regard, we believe that a Southern System minimum flow requirement has been relied upon for far too long, and that it is necessary to propose a physical alternative to replace it for the reasons specified in our application.

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d) Please refer to Response 3c of this data request for the advantages. In regards to disadvantages, the cost of the physical solution may appear to be unattractive in comparison to maintaining a minimum supply requirement or relying upon supply contracts. However, if the status quo were to continue, then the risk of customer curtailment must also be accepted when those supplies are unavailable.

e) As explained in our testimony (Updated Direct Testimony of David M. Bisi, pages 6-7), the Southern System minimum flow requirement is necessary because customers and shippers often choose not to deliver gas supply to our Blythe and Otay Mesa receipt points for economic reasons. SoCalGas has limited capacity to support the Southern System with supply delivered to our other receipt points, and so it must specify a minimum flow requirement based on customer demand on the Southern System in order to maintain system integrity and avoid customer curtailments.

   Because the North-South Project will provide access to gas delivered at those other receipt points, as well as storage supplies, for the Southern System, SoCalGas no longer would have a need to have more than 100 MMcfd of supply delivered at Blythe, and that would only be under an extreme high-sendout condition.

   Should the North-South Project be constructed and then temporarily removed from service, SoCalGas would again need a minimum level of supply delivered at Blythe or Otay Mesa for the duration of the outage.

f) As explained in the Updated Direct Testimony of David M. Bisi at page 12, the North-South Project would be able to access withdrawal supplies from our Honor Rancho storage field. The curtailment events on February 3, 2011 and February 6, 2014 were the result of gas supply shortages across the entire system. Storage supplies from SoCalGas' Honor Rancho facilities were needed to substitute for these lost supplies, and therefore would have been unavailable to transport to the Southern System via the North-South Project in order to prevent these two curtailment events.

g) The nine curtailment events identified in response to ORA-NSP-SoCalGas-06 Question 3a were necessary to perform pipeline safety-related work on SDG&E Transmission Line 3010, and resulted in a capacity reduction on the SDG&E system. The North-South Project is not designed to improve the capacity of the SDG&E system, and therefore access to SoCalGas storage supplies afforded by the North-South Pipeline would not have prevented these nine curtailment events.

h) No, for the same reasons described in response to Question 3f of this data request.

i) No, for the same reasons described in response to Question 3g of this data request.

j) No, the expansion of SoCalGas' firm receipt capacity is not necessary in order to directly address the Southern System reliability issues. However, the expansion of firm receipt capacity is beneficial because it increases opportunities for shippers to bring additional supplies into the northern zone whenever these are the least costly. Please refer to Section V of the Updated Direct Testimony of David M. Bisi.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT
(A.13-12-013)
(4th DATA REQUEST FROM SOUTHERN CALIFORNIA GAS COALITION)

QUESTION 4.1:

4.1. With respect to the testimony on page 4, lines 3-8:

- 4.1.1. What portion of 2011 southern system minimum flows was represented by the core's requirements on an annual average basis, lowest daily share basis, and highest daily share basis?
- 4.1.2. What portion of 2011 southern system minimum flows was represented by the noncore's requirements on an annual average basis, lowest daily share basis, and highest daily share basis?
- 4.1.3. What portion of 2011 southern system minimum flows was represented by the electric generation requirements on an annual average basis, lowest daily share basis, and highest daily share basis?
- 4.1.4. What portion of 2012 southern system minimum flows was represented by the core's requirements on an annual average basis, lowest daily share basis, and highest daily share basis?
- 4.1.5. What portion of 2012 southern system minimum flows was represented by the noncore's requirements on an annual average basis, lowest daily share basis, and highest daily share basis?
- 4.1.6. What portion of 2012 southern system minimum flows was represented by the electric generation requirements on an annual average basis, lowest daily share basis, and highest daily share basis?
- 4.1.7. What portion of 2013 southern system minimum flows was represented by the core's requirements on an annual average basis, lowest daily share basis, and highest daily share basis?
- 4.1.8. What portion of 2013 southern system minimum flows was represented by the noncore's requirements on an annual average basis, lowest daily share basis, and highest daily share basis?

4.1.9. What portion of 2013 southern system minimum flows was represented by the electric generation requirements on an annual average basis, lowest daily share basis, and highest daily share basis?

4.1.10. What was the term of the capacity rights on the El Paso Southern Mainline to Ehrenberg that Gas Acquisition purchased?

4.1.11. When were the capacity rights for Ehrenberg purchased by Gas Acquisition?

4.1.12. Were those capacity rights purchased directly from El Paso or were they brokered capacity?

4.1.13. Which other pipelines did Gas Acquisition compare the price of Ehrenberg capacity to?

4.1.14. Were those comparison capacity rights to be purchased directly from the corresponding pipeline or were they to be brokered capacity?

<u>RESPONSE 4.1:</u>

4.1.1 – 4.1.9 SoCalGas and SDG&E object to these questions on the grounds that they requests confidential customer-specific information.

4.1.10 November 1, 2013 through October 31, 2018.

4.1.11 The Expedited Advice Letter was approved by the CPUC on June 13, 2013, and FERC approval was received July 17, 2013.

4.1.12 Directly from El Paso.

4.1.13 None

4.1.14 N/A

QUESTION 4.2:

4.2. With respect to the testimony on page 4, lines 9-12:

4.2.1. What portion of 2008 southern system minimum flows was represented by the core's requirements on an annual average basis, lowest daily share basis, and highest daily share basis?

4.2.2. What portion of 2008 southern system minimum flows was represented by the noncore's requirements on an annual average basis, lowest daily share basis, and highest daily share basis?

4.2.3. What portion of 2008 southern system minimum flows was represented by the electric generation requirements on an annual average basis, lowest daily share basis, and highest daily share basis?

RESPONSE 4.2:

SoCalGas and SDG&E object to these questions on the grounds that they request confidential customer-specific information.

QUESTION 4.3:

4.3. Please provide the workpapers including all data for Figure 1.

RESPONSE 4.3:

Please refer to SoCalGas/SDG&E response to SCGC Data Request #1 which provides the workpapers for Witness Musich.

QUESTION 4.4:

4.4. With respect to the testimony on page 5, lines 8-9:

- 4.4.1. Please provide SoCalGas' forecast of "greater volumes of Southern System support purchases" for the year 2014.
- 4.4.2. Please provide SoCalGas' forecast of "greater volumes of Southern System support purchases" for the year 2015.
- 4.4.3. Please provide SoCalGas' forecast of "greater volumes of Southern System support purchases" for the year 2016.

RESPONSE 4.4:

4.4.1 No such forecast exists.

4.4.2 No such forecast exists.

4.4.3 No such forecast exists.

QUESTION 4.5:

4.5. With respect to the testimony on page 6, lines 1-2:

- 4.5.1. Please provide SoCalGas' forecast of increased prices during 2014-2016 for natural gas supplies that would be available to the System Operator for Southern System support purchases.
- 4.5.2. Please identify the gas producing areas from which those supplies would be expected to flow.

RESPONSE 4.5:

4.5.1 No such forecast exists.

4.5.2 N/A

QUESTION 4.6:

4.6. Please provide the workpapers including all data for Figure 2.

RESPONSE 4.6:

Please refer to SoCalGas/SDG&E response to SCGC Data Request #1 which provides the workpapers for Witness Musich.

QUESTION 4.7:

4.7. With respect to the testimony on page 7, lines 6-16:

4.7.1. Please identify each of the electric generation projects that is included in the "number of gas-fired generation projects proposed for our service territories."

Please identify the proposed capacity and location of each of these projects

RESPONSE 4.7:

SoCalGas and SDG&E object to this request on the grounds that it is unreasonably burdensome. Information about proposed gas-fired electric generation projects is equally available to SCGC on the California Energy Commission (CEC) website, in public filings at the CEC, and in a variety of public sources such as newspapers.

QUESTION 4.8:

4.8. If a project obtains the required permits from the CEC, does this guarantee that the project will be completed and brought on line?

RESPONSE 4.8:

Please see our response to question 4.7. In addition, questions regarding the scope and nature of CEC permits are more properly addressed to the CEC and the parties obtaining those permits.

QUESTION 4.9:

4.9. With respect to the testimony on page 8, lines 6-10:

- 4.9.1. Please identify the producing basins that experienced the well freeze-offs during this period.
- 4.9.2. What were the delivery levels at each of the receipt points into SoCalGas' system during the period, February 1-5, 2011?
- 4.9.3. How much gas was withdrawn from storage during this period?

RESPONSE 4.9:

4.9.1 Please see: http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf

4.9.2 Data is available on SoCalGas Envoy website at https://scgenvoy.sempra.com/

4.9.3. Data is available on SoCalGas Envoy website at https://scgenvoy.sempra.com/

QUESTION 4.10:

4.10. With respect to the testimony on page 8 lines 11-21:

4.10.1. What steps did the System Operator take to procure additional volumes for February 2, 2011?

4.10.2. What volume of gas did the System Operator procure for that date?

4.10.3. What occurrences took place that led the System Operator to conclude that "supplies were being bid away by East-of-California customers served by the apparently more distressed El Paso system"?

4.10.4. What was the demand on the Southern System on February 2, 2011?

4.10.5. What was the amount of flowing gas that SoCalGas was able to divert from the northern part of the system into the Southern System through Chino and/or Prada Stations on that date?

RESPONSE 4.10:

4.10.1 Please refer to SoCalGas Advice Letter 4282.

4.10.2 Please refer to SoCalGas Advice Letter 4282.

4.10.3 Please refer to Response 4.9.1. The Hub was unable to obtain all of the supplies requested by the System Operator.

4.10.4 For the purposes of this response, SoCalGas and SDG&E define the "Southern System" as the area on its gas transmission system east of Moreno Station, including the Rainbow Corridor and San Diego. The Southern System demand on 2/2/2011 is estimated at 991 MMcfd.

4.10.5 SoCalGas was able to transport 190 million cubic feet (MMCF) of gas to the Southern System via the Chino and Prado crossovers on 2/2/2011.

QUESTION 4.11:

4.11. With respect to the testimony on page 9, lines 5-8:

4.11.1. If the North-South Pipeline were in place, how long would it take to deliver gas from Honor Rancho into the Southern System?

4.11.2. How much gas would be available from Honor Rancho in MDth/day to deliver into the Southern System?

4.11.3. How many days could Honor Rancho sustain this level of withdrawal?

RESPONSE 4.11:

4.11.1 When SoCalGas and SDG&E see a shortfall in supply on the Southern System via the scheduling process, Honor Rancho can contribute to the planned mix of supplies on the Northern System that can be transported on the North-South Pipeline.

4.11.2 Please refer to Response 2.10.1 to SCGC's 2nd Data Request in A.13-12-013.

4.11.3 The Honor Rancho storage field can sustain its maximum deliverability for approximately 20 days, assuming full storage inventory and that it is not replenished.

QUESTION 4.12:

4.12. With respect to the testimony on page 9, lines 11-16:

4.12.1. What was the core gas requirement on the Southern System during January 14-15, 2013?

4.12.2. What was the noncore gas requirement on the Southern System during January 14-15, 2013?

4.12.3. What was the electric generation gas requirement on the Southern System during this period?

4.12.4. What volume of gas was brought into SoCalGas' system through Otay Mesa during this period?

4.12.5. What was the amount of flowing gas that SoCalGas was able to divert from the northern part of the system into the Southern System through Chino and/or Prada Stations during this period?

4.12.6. What volume of gas was brought in across Line 6916 during this period?

RESPONSE 4.12:

For the purposes of this response, SoCalGas and SDG&E define the "Southern System" as the area on its gas transmission system east of Moreno Station, including the Rainbow Corridor and San Diego, and "requirement" as meaning demand.

4.12.1 SoCalGas and SDG&E do not estimate separately the core and non-EG noncore Southern System demand. The total core and non-EG noncore demand during this period is estimated at 693 MMCF on 1/14/13 and 686 MMCF on 1/15/13.

4.12.2 Please refer to Response 4.12.1.

4.12.3 The Southern System electric generation demand during this period was 343 MMCF on 1/14/2013 and 314 MMCF on 1/15/2013.

4.12.4 Volumes delivered at Otay Mesa during this period are available on Envoy.

4.12.5 SoCalGas transported 49 MMCF on 1/14/2013 and 45 MMCF on 1/15/2013 to the Southern System via the Chino and Prado crossovers.

4.12.6 SoCalGas transported 73 MMCF on 1/14/2013 and 66 MMCF on 1/15/2013 on L6916.

QUESTION 4.13:

4.13. With respect to the testimony on page 9, lines 18-20:

- 4.13.1. What was the core gas requirement on the Southern System during June 29-July 3, 2013?
- 4.13.2. What was the noncore gas requirement on the Southern System during June 29-July 3, 2013?
- 4.13.3. What was the electric generation gas requirement on the Southern System during this period?
- 4.13.4. What volume of gas was brought into SoCalGas' system through Otay Mesa during this period?
- 4.13.5. What was the amount of flowing gas that SoCalGas was able to divert from the northern part of the system into the Southern System through Chino and/or Prada Stations during this period?
- 4.13.6. What volume of gas was brought in across Line 6916 during this period?

RESPONSE 4.13:

For the purposes of this response, SoCalGas and SDG&E define the "Southern System" as the area on its gas transmission system east of Moreno Station, including the Rainbow Corridor and San Diego, and "requirement" as meaning demand.

4.13.1 SoCalGas and SDG&E do not estimate separately the core and non-EG noncore Southern System demand. The total core and non-EG noncore demand during this period is estimated at 273 MMCF on 6/29/2013, 277 MMCF on 6/30/2013, 300 MMCF on 7/1/2013, 304 MMCF on 7/2/2013, and 307 MMCF on 7/3/2013.

4.13.2 Please refer to Response 4.13.1.

4.13.3 The Southern System electric generation demand during this period was 416 MMCF on 6/29/2013, 394 MMCF on 6/30/2013, 464 MMCF on 7/1/2013, 426 MMCF on 7/2/2013, and 329 MMCF on 7/3/2013.

4.13.4 Please refer to Response 4.12.4.

4.13.5 SoCalGas transported no volumes to the Southern System via the Chino and Prado crossovers during this period.

4.13.6 SoCalGas transported 52 MMCF on 6/29/2013, 50 MMCF on 6/30/2013, 55 MMCF on 7/1/2013, 55 MMCF on 7/2/2013, and 52 MMCF on 7/3/2013 on L6916.

QUESTION 4.14:

4.14. With respect to the testimony on page 9, lines 20-23:

4.14.1. What was the core gas requirement on the Southern System during August 29-September 6, 2013?

4.14.2. What was the noncore gas requirement on the Southern System during August 29-September 6, 2013?

4.14.3. What was the electric generation gas requirement on the Southern System during this period?

4.14.4. What volume of gas was brought into SoCalGas' system through Otay Mesa during this period?

4.14.5. What was the amount of flowing gas that SoCalGas was able to divert from the northern part of the system into the Southern System through Chino and/or Prada Stations during this period?

4.14.6. What volume of gas was brought in across Line 6916 during this period?

RESPONSE 4.14:

For the purposes of this response, SoCalGas and SDG&E define the "Southern System" as the area on its gas transmission system east of Moreno Station, including the Rainbow Corridor and San Diego, and "requirement" as meaning demand.

4.14.1 SoCalGas and SDG&E do not estimate separately the core and non-EG noncore Southern System demand. The total core and non-EG noncore demand during this period is estimated at 236 MMCF on 8/29/13, 183 MMCF on 8/30/13, 194 MMCF on 8/31/13, 213 MMCF on 9/1/13, 242 MMCF on 9/2/13, 240 MMCF on 9/3/13, 246 MMCF on 9/4/13, 240 MMCF on 9/5/13, and 239 MMCF on 9/6/13

4.14.2 Please refer to Response 4.14.1.

4.14.3 The Southern System electric generation demand during this period was 503 MMCF on 8/29/13, 606 MMCF on 8/30/13, 451 MMCF on 8/31/13, 436 MMCF on 9/1/13, 445 MMCF on 9/2/13, 537 MMCF on 9/3/13, 574 MMCF on 9/4/13, 575 MMCF on 9/5/13, and 515 MMCF on 9/6/13.

4.14.4 Please refer to Response 4.13.4.

4.14.5 SoCalGas transported 0 MMCF on 8/29/13, 23 MMCF on 8/30/13, 0 MMCF on 8/31/13, 0 MMCF on 9/1/13, 0 MMCF on 9/2/13, 4 MMCF on 9/3/13, 3 MMCF on 9/4/13, 0 MMCF on 9/5/13, and 0 MMCF on 9/6/13 to the Southern System via the Chino and Prado crossovers during this period.

4.14.6 SoCalGas transported 53 MMCF on 8/29/13, 60 MMCF on 8/30/13, 60 MMCF on 8/31/13, 60 MMCF on 9/1/13, 41 MMCF on 9/2/13, 46 MMCF on 9/3/13, 52 MMCF on 9/4/13, 46 MMCF on 9/5/13, and 32 MMCF on 9/6/13 on L6916.

QUESTION 4.15:

4.15. With respect to the testimony on page 10, lines 2-19:

4.15.1. What was the core gas requirement on the Southern System during December 6-11, 2013?

4.15.2. What was the noncore gas requirement on the Southern System during December 6-11, 2013?

4.15.3. What was the electric generation gas requirement on the Southern System during this period?

4.15.4. What volume of gas was brought into SoCalGas' system through Otay Mesa during this period?

4.15.5. What was the amount of flowing gas that SoCalGas was able to divert from the northern part of the system into the Southern System through Chino and/or Prada Stations during this period?

4.15.6. What volume of gas was brought in across Line 6916 during this period?

RESPONSE 4.15:

For the purposes of this response, SoCalGas and SDG&E define the "Southern System" as the area on its gas transmission system east of Moreno Station, including the Rainbow Corridor and San Diego, and "requirement" as meaning demand.

4.15.1 SoCalGas and SDG&E do not estimate separately the core and non-EG noncore Southern System demand. The total core and non-EG noncore demand during this period is estimated at 484 MMCF on 12/6/13, 499 MMCF on 12/7/13, 568 MMCF on 12/8/13, 638 MMCF on 12/9/13, 490 MMCF on 12/10/13, and 494 MMCF on 12/11/13

4.15.2 Please refer to Response 4.15.1.

4.15.3 The Southern System electric generation demand during this period was 347 MMCF on 12/6/13, 338 MMCF on 12/7/13, 418 MMCF on 12/8/13, 284 MMCF on 12/9/13, 291 MMCF on 12/10/13, and 360 MMCF on 12/11/13.

4.15.4 Please refer to Response 4.14.4.

4.15.5 SoCalGas transported no volumes to the Southern System via the Chino and Prado crossovers during this period.

4.15.6 SoCalGas transported 32 MMCF on 12/6/13, 30 MMCF on 12/7/13, 49 MMCF on 12/8/13, 32 MMCF on 12/9/13, 38 MMCF on 12/10/13, and 49 MMCF on 12/11/13 on L6916.

QUESTION 4.16:

4.16. With respect to the testimony on page 10, lines 9-16:

4.16.1. If the North-South Pipeline were in place, how long would it have taken to deliver gas from Honor Rancho into the Southern System in response to the unexpected shortfall on December 9?

4.16.2. How much gas would have been available from Honor Rancho to deliver into the Southern System on that date?

RESPONSE 4.16:

With respect to the testimony on page 10, lines 9-16, SoCalGas and SDG&E do not believe that either the North-South Pipeline nor deliveries from Honor Rancho would have been able to support the Southern System on December 9, 2013. SoCalGas and SDG&E were short of supply across their entire system during that event, and there were no supplies available on its Northern System to transport to the Southern System.

QUESTION 4.17:

4.17. Please provide the workpapers including all data for Figure 3.

RESPONSE 4.17:

Please refer to SoCalGas/SDG&E response to SCGC Data Request #1 which provides the workpapers for Witness Musich.

QUESTION 4.18:

4.18. With respect to the testimony on page 16, lines 13-15:

4.18.1. Is it this witnesses' belief that if firm capacity were maintained on El Paso for delivery at Blythe, the capacity holder would be unable to obtain supplies of gas to deliver to Blythe under all circumstances?

4.18.2. If the answer to the previous question is "yes," please provide a copy of all studies, reports, analyses, and communications that supports the witnesses' belief.

4.18.3. Is it this witnesses' belief that if firm capacity were maintained on El Paso for delivery at Blythe, the capacity holder would be unable to obtain supplies of gas to deliver to Blythe under extreme weather circumstances?

4.18.4. If the answer to the previous question is "yes," please define extreme weather circumstances and provide a copy of all studies, reports, analyses, and communications that supports the witnesses' belief.

4.18.5. Is it this witnesses' belief that if firm capacity were maintained on El Paso for delivery at Blythe, the capacity holder would be only able to obtain supplies of expensive gas to deliver to Blythe?

4.18.6. If the answer to the previous question is "yes," please define what would constitute expensive gas and provide a copy of all studies, reports, analyses, and communications that supports the witnesses' belief.

RESPONSE 4.18:

SoCalGas and SDG&E object to these questions on the grounds that they are ambiguous and confusing. The questions do not appear to have a direct relationship to the referenced testimony. In addition, the questions ask about a particular witnesses' personal beliefs, then request studies, analyses, etc. from SoCalGas and SDG&E to back up those personal beliefs. Without waiving these objections, and subject thereto, SoCalGas and SDG&E respond as follows:

Yes, SoCalGas and SDG&E believe there is the potential for both supply and capacity curtailments on upstream pipelines. SoCalGas and SDG&E do not have any studies or analyses forecasting future curtailments and other problems on upstream pipelines. Past operational information for the upstream interstate pipelines is equally available to SCGC.

QUESTION 4.19:

4.19. With respect to the testimony on page 17, lines 11-20:

4.19.1. How much capacity does SoCalGas believe it would need to hold under a scenario where SoCalGas would "contract for basin supplies and interstate capacity to meet anticipated Southern System flow requirements"?

4.19.2. What is the estimated cost associated with holding this level of interstate capacity?

4.19.3. What is the estimated cost associated with holding basin supply contracts for this level of capacity?

4.19.4. How many times has gas been shut in on the basins serving El Paso's Southern Mainline during the last five years?

RESPONSE 4.19:

4.19.1 Based on the forecast presented in the TCAP, we expect future capacity needs to be at least equivalent to current needs.

4.19.2 Please refer to El Paso tariffs.

4.19.3 SoCalGas has not estimated the premiums necessary for long term supplies to support the Southern System.

4.19.4 SoCalGas does not have the requested information about El Paso's system operations. To the extent this information is public it is equally available to SCGC.

QUESTION 4.20:

4.20. With respect to the testimony on page 21, line 24, and page 22, lines 1-2:

4.20.1. How many times has service been curtailed simultaneously on El Paso's Northern Mainline, El Paso's Southern Mainline, Transwestern, and Questar during the last five years?

4.20.2. How many times has gas been shut in simultaneously on the basins serving El Paso's Northern Mainline, El Paso's Southern Mainline, Transwestern, and Questar during the last five years?

RESPONSE 4.20:

4.20.1 SoCalGas and SDG&E object to the question on the grounds that it appears to be misstating the referenced testimony. The referenced testimony does not indicate that all supply basins will be shut in simultaneously. SoCalGas and SDG&E also object to this question on the grounds that it is unreasonably burdensome because it requests interstate pipeline operational information that is equally available to SCGC.

4.20.2 Please refer to Response 4.20.1.

QUESTION 4.21:

4.21. With respect to the testimony on page 22, lines 3-9:

4.21.1. Please explain why the witness believes an option to "fully use existing Southern Zone receipt capabilities" would be valuable given her testimony that supplies delivered at this receipt point will be unavailable in the future.

RESPONSE 4.21:

4.21.1 Please refer to Response 2.11.5 to SCGC's 2nd Data Request in A.13-12-013.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT
(A.13-12-013)

(10TH DATA REQUEST FROM SOUTHERN CALIFORNIA GAS COALITION)

QUESTION 10.1:

10.1. With respect to the testimony on page 8, lines 11-21 and page 9, lines 1-4:

- 10.1.1. If the North-South Pipeline were in place, would SoCalGas have been able to deliver sufficient supplies into the Southern System to avoid the severe drafting of the pipeline system on February 2, 2011?
- 10.1.2. Would deliveries across the North-South pipeline been sufficient to eliminate the need to deliver gas through Otay Mesa on February 2, 2011?
- 10.1.3. How much gas would have been available from Honor Rancho to deliver into the Southern System on that date?
- 10.1.4. If the North-South Pipeline were in place, would SoCalGas have been able to deliver sufficient supplies into the Southern System to avoid the curtailment on February 3, 2011?
- 10.1.5. Would deliveries across the North-South pipeline been sufficient to eliminate the need to deliver gas through Otay Mesa on February 3, 2011?
- 10.1.6. How much gas would have been available from Honor Rancho to deliver into the Southern System on that date?

RESPONSE 10.1:

With respect to the testimony on page 8 lines 11-21 and page 9, lines 1-4, SoCalGas and SDG&E do not believe that either the North-South pipeline or deliveries from Honor Rancho would have been able to support the Southern System on February 2 and 3, 2011. SoCalGas and SDG&E were short of supply across their entire system during that even, and there were no supplies available on its Northern System to transport to the Southern System. Because our Southern System is not interconnected to the same extent as the rest of our transmission system, when we have overall supply issues, the first place we notice that is on the Southern System, and that lack of interconnectedness limits our options. SoCalGas and SDG&E recently filed an application proposing a “low OFO” procedure would help in these instances of overall system supply shortages. If the low OFO procedure were in place and adequate supplies were delivered, the North-South pipeline would allow customers to deliver their supplies at the receipt point of their choice and allow SoCalGas & SDG&E to deliver that supply throughout the system.

QUESTION 10.2:

10.2. With respect to the testimony on page 9, lines 11-16:

- 10.2.1. If the North-South Pipeline were in place, would SoCalGas have been able to deliver sufficient supplies into the Southern System to eliminate the curtailment watch on January 14, 2013?
- 10.2.2. How much gas would have been available from Honor Rancho to deliver into the Southern System on that date?
- 10.2.3. If the North-South Pipeline were in place, would SoCalGas have been able to deliver sufficient supplies into the Southern System to eliminate the curtailment watch on January 15, 2013?
- 10.2.4. Would deliveries across the North-South pipeline been sufficient to eliminate the need to deliver gas through Otay Mesa on January 15, 2013?
- 10.2.5. How much gas would have been available from Honor Rancho to deliver into the Southern System on that date?
- 10.2.6. Would deliveries across the North-South pipeline been sufficient to eliminate the need to deliver gas through Otay Mesa on January 16, 2013?
- 10.2.7. How much gas would have been available from Honor Rancho to deliver into the Southern System on that date?

RESPONSE 10.2:

With respect to the testimony on page 9, lines 11-16, SoCalGas and SDG&E do not believe that either the North-South pipeline nor deliveries from Honor Rancho would have been sufficient to eliminate the curtailment watch or to avoid purchases at the Otay Mesa receipt point. During this event, the level of demand on the Southern System, particularly in the Rainbow Corridor and in San Diego, was very high. In fact, the San Diego demand on January 14 and 15 was 659 and 639 MMcfd, respectively, which exceed the 630 MMcfd capacity of SDG&E system. While SoCalGas had ample supply available on its Northern System, additional supply delivered at Moreno via the North-South pipeline could not be redelivered through the Rainbow Corridor to the SDG&E system – the SDG&E system was simply out of capacity.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT
(A.13-12-013)
(1ST DATA REQUEST FROM TRANSWESTERN PIPELINE)

QUESTION 1:

With reference to the Direct Testimony of Sharim Chaudhury:

a. With respect the statements on page 4 that 6,561 MWs of gas-fired power plants are expected to come on line by 2019, and that 8,831 MWs of gas-firedt power plants are expected to come on line by 2025, please provide the list of projects included in these numbers. For each individual project please provide the project's name, capacity in MW, and projected in-service date.

b. With respect to the chart on page 6, please provide projections of potential gas exports for each of the years between 2014 and 2019.

RESPONSE 1:

a. The attached page (page 8 from the EPNG Business Update, February 2013) contains the requested information about each individual project, capacity in MW, and projected in-service date.

EPNG Business
Update, February 20

b. The projections of potential gas exports for each of the years between 2014 and 2019 are shown below. The projections are based on the methodologies described in foot notes 12 and 15, page 5, of Mr. Chaudhury's Direct Testimony. As pointed out in footnote 16, page 5 of the same testimony, the 2015 through 2025 potential gas exports to Mexico reflects demand for gas-fired power plants only and do not include any potential exports to meet growth in Mexico's industrial and residential sector due to unavailability of data for these sectors.

Potential Gas Export From the U.S. to Mexico Via the El Paso South Mainline				
To Meet Potential Power Plant Gas Demand (MMcfd)				
2015	844			
2016	1,033			
2017	1,200			
2018	1,286			

QUESTION 2:

With reference to the Direct Testimony of David M. Bisi:

a. On pages 12 and 13 the testimony states that gas supplies cannot be transported east from Newberry to North and South Needles. Given that statement, does SoCalGas agree with El Paso's witness Sanabric that El Paso's proposed project would be able to transport gas supplies from SoCalGas' storage to SoCalGas' southern system at Ehrenberg? If the answer is yes, please explain how such transportation would be possible without transporting gas from Newberry east to North or South Needles.

RESPONSE 2:

Please refer to EPNG's Response to Question 23 of SoCalGas' and SDG&E's 1st Data Request in A.13-12-013 (attached). The SoCalGas system interconnects with the common Kern/Mojave pipeline as described in EPNG's response. However, questions regarding the operations and capabilities of Kern/Mojave should be directed to EPNG, not SoCalGas and SDG&E. SoCalGas and SDG&E believe that the services described by EPNG (i.e., transporting SoCalGas storage supplies on EPNG's proposed project) would likely require significant additional capital improvements on the SoCalGas system. But we have not yet analyzed what those improvements would be or how much they would cost.

2014-10-30 EPNG
Responses to SoCal-N

QUESTION 3:

With reference to the Direct Testimony of Beth Musich:

a. On page 5 the testimony states: “Southern System support costs have been rising during the past five years. SoCalGas and SDG&E expect this trend to continue.” Did SoCalGas conduct any analysis of the likely range of these system support costs for the period 2014 through 2019? If the answer is yes, please explain how the analysis was conducted and provide the results thereof.

RESPONSE 3:

No.

A.13-12-013

SOCALGAS AND SDG&E NORTH-SOUTH (NSP) PROJECT

RESPONSE TO SECOND SET OF DATA REQUESTS TO TRANSWESTERN PIPELINE COMPANY, LLC FROM CALIFORNIA PUBLICE UTILITY COMISSION (CPUC) OFFICE OF RATEPAYER ADVOCATES (ORA)

Request 2-1:

On November 12, 2014, SoCalGas/SDG&E updated their filing in A.13-12-013 for the proposed North-South Project (NSP) where the Moreno-Whitewater pipeline component of the NSP was removed. In light of this change in the length and scope of the North-South Project, several parties provided updated testimonies in A.13-12-013. ORA's understanding is that TW did not provide an update to its testimony in A.13-12-013 on March 23, 2015.

(a) Please confirm that Transwestern (TW) is not proposing to revise the TW Project alternative to the North-South Project as described in its August 15, 2014 Testimony, and that the estimated costs and revenue requirements remain unchanged as shown in Tables 1, 2, 3, and 5 therein. Otherwise, if the scope and estimated costs of the TW Project alternative have changed, then please explain and provide the changes and corresponding supporting Workpapers.

(b) Please describe how much contingency is built in to the current cost estimates for the TW Project alternative.

(c) Please describe the base year of the TW Project alternative and how much inflation is built in to the current cost estimates.

Response:

(a) Transwestern is not proposing to revise the TW Project alternative to the North-South Project at this time. Transwestern has not performed or paid any third party(s) to have additional or updated studies to determine if the estimated costs have changed.

(b) Transwestern included 5% contingency in its current cost estimate

(c) Transwestern included 4.5% escalation to account for inflation

A.13-12-013

SOCALGAS AND SDG&E NORTH-SOUTH (NSP) PROJECT

RESPONSE TO SECOND SET OF DATA REQUESTS TO TRANSWESTERN PIPELINE COMPANY, LLC FROM CALIFORNIA PUBLICE UTILITY COMISSION (CPUC) OFFICE OF RATEPAYER ADVOCATES (ORA)

Request 2-2:

At page 5 of the above subject Testimony, witness Hearn states "I will provide any additional relevant details about the proposed pipeline route in my supplemental testimony." Further at page 6 of the above subject, witness Hearn states "I will provide additional details about this incremental compression in my supplemental testimony."

(a) Please confirm whether any of these supplemental testimonies were provided since the August 15, 2014 filing, and if so, please provide them to ORA.

(b) If not, is Mr. Hearn referring to the testimony currently scheduled for May 6, 2015?

Response:

(a) Transwestern has not provided supplemental testimonies. It was anticipated that given firm interest in Transwestern's project additional engineering and cost studies would be performed. Transwestern is optimistic this may still occur.

(b) No. Please see (a).

SOCALGAS AND SDG&E NORTH-SOUTH (NSP) PROJECT

RESPONSE TO SECOND SET OF DATA REQUESTS TO TRANSWESTERN PIPELINE COMPANY, LLC FROM CALIFORNIA PUBLICE UTILITY COMISSION (CPUC) OFFICE OF RATEPAYER ADVOCATES (ORA)

Request 2-3:

At pages 5-6 of the above subject, TW describes the proposed Needles-Ehrenberg pipeline as consisting of two phases: Phase I consists of approximately 120 miles of new 30-inch diameter pipeline running in a north-south direction in western Arizona. Phase I pipeline would have a capacity of 500 MMcfd under a Maximum Allowable Operating Pressure (MAOP) of 1,300 pounds per square inch (psig), and a 600 psig design delivery pressure without need for any additional compression beyond that already in place. Phase II consists of the addition of 16,000 horsepower (hp) of compression to be installed near the pipeline's northern interconnect point. When completed, TW describes the Phase II compression as increasing the pipeline's capacity by 300 MMcf/d, for a cumulative capacity of 800 MMcf/d. Table 4 on page 10 of the above subject 5 provides an example of the Phase I project timeline, indicating a project in-service date of May 2017.

(a) Other than Phase II, please state if there are any other facilities that TW would need to construct to bring the TW Project alternative in-service? If so, please so state.

(b) Please describe the proposed delivery location for the TW Project alternative. Please explain whether the proposed delivery location entails any additional costs or would require expansion of a SoCalGas backbone transmission receipt point capacity.

(c) Please clarify whether the 500 MMcf/d is the minimum design flow for the TW Project alternative, and if not, please state the minimum design flow for the TW Project alternative.

(d) Please confirm that the TW Project is contingent upon TW signing contracts for firm transportation for the capacity of Phase I of TW Project, or upon some different measure of market interest in the TW Project.

(e) Please state whether Phase II is an absolute must do for the TW Project alternative which has to be implemented following Phase I, and if so, indicate the estimated project in-service date for Phase II of the TW Project alternative.

(f) Please describe the various gas basin sources made possible with a TW Project alternative, and whether the TW Project alternative enables access to any new gas supply sources previously inaccessible to SoCalGas.

(g) ORA understands that the TW Project alternative is a new interstate pipeline to be built. Please explain what would be required in order for the TW Project alternative project to reach critical size for viability, including the need for anchor shippers.

(h) If the TW Project alternative has uncontracted capacity, then please state the identity of the party who will be at risk for any unsubscribed capacity.

(i) Please describe the available contract term length (in years) of a precedent agreement with TW in relation to the TW Project alternative.

Response:

(a) No other additional facilities are needed.

(b) It is anticipated the delivery location would be at a custody transfer rated metering facility on the Arizona side of the Colorado River with the necessary piping to tap the SoCalGas backbone transmission system. The proposed delivery location and corresponding piping and tap are included in the estimated direct capital costs.

(c) 500 MMcf/d is not the minimum design flow for the Needles-Ehrenberg Pipeline. The minimum design flow will be a function of the size of the meter installed at the delivery location. If necessary, a low flow meter could be installed to accommodate extremely low flows.

(d) The Transwestern proposed Needles-Ehrenberg Pipeline project is contingent on necessary economic support. This may come in the form of firm transportation agreements or capital reimbursable agreements.

(e) Phase II is not an absolute must do.

(f) Transwestern's Needles-Ehrenberg Pipeline project will provide access to Rocky Mountain, Permian, San Juan and Midcontinent supply basins.

(g) The determination of whether to proceed with the project relies on a number of variables to include: capacity sold, rate, term, interested parties, etc. There is no firm rule for determining the amount of risk a company may accept.

(h) Transwestern would be the party at risk for any unsubscribed capacity.

(i) Transwestern has not designed the parameters of the necessary open season and precedent agreements, but will consider varying terms depending on whether a party is willing to be an anchor shipper and the magnitude of their capacity commitment.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT

(A.13-12-013)

(OFFICE OF RATEPAYER ADVOCATES DATA REQUEST NO. ORA-NSP-EPNG-01)

GENERAL OBJECTIONS:

El Paso Natural Gas Company, L.L.C. (EPNG) objects to each question to the extent that it seeks information protected by the attorney-client privilege, the attorney work product doctrine, or any other applicable privilege or evidentiary doctrine. No information protected by such privileges or evidentiary doctrines will be knowingly disclosed.

ORA DATA REQUEST NO. ORA-NSP-EPNG-01 – QUESTION 1:

Please provide all workpapers and active excel spreadsheets in support of the above subject, including but not limited to, those used to arrive at the numbers shown in Tables 1 and 2. Excel spreadsheets should not contain hard-coded numbers but instead should have the formulas that were used to arrive at the calculations shown in the workpapers in support of the testimony that will enable ORA to replicate the numbers.

RESPONSE TO ORA DATA REQUEST NO. ORA-NSP-EPNG-01:

Response to Data Depicted in Table 1:

EPNG objects to Data Request No. ORA-NSP-EPNG-01 inasmuch as it relates to the data presented in Table 1 of the Prepared Intervenor Testimony of Anthony M. Sanabria in this proceeding. The derivation of the data contained in Table 1 is not relevant to the subject matter involved in Application 13-12-013 and not reasonably calculated to lead to the discovery of admissible evidence. Moreover, EPNG's provision of the confidential and proprietary economic models used to derive the data contained in Table 1 would be intrusive as that term is used in CPUC Rules of Practice and Procedure, Rule 10.1 **Discovery**.

Without waiving the foregoing objections, EPNG states that the Annual Revenue Requirements set forth in the Prepared Intervenor Testimony of Anthony M. Sanabria are firm (subject to approval by the appropriate management, management committee, and/or board of directors of EPNG and/or its parent companies). EPNG is willing to accept all financial risk if its project costs increase and would not seek to increase the Annual Revenue Requirements set forth in Table 1.

Date: September 22, 2014
Prepared by: Anthony M. Sanabria, Account Director, Business Development,
719-667-7582; Anthony_Sanabria@kindermorgan.com
Supervisor: Gregory W. Ruben, Vice President, Business Development

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
NORTH-SOUTH PROJECT REVENUE REQUIREMENT

(A.13-12-013)

(OFFICE OF RATEPAYER ADVOCATES DATA REQUEST NO. ORA-NSP-EPNG-01)

Response to Data Depicted in Table 2:

EPNG's Pipeline and Supply Reliability data presented in Table 2 of the Prepared Intervenor Testimony of Anthony M. Sanabria in this proceeding was calculated by summing the scheduled volumes from nomination cycles 1 through 4. The total scheduled volumes were compared to the sum of third party reductions (i.e., the inability of a third party to provide the gas as nominated), underperformance (i.e. cuts because a receipt into the pipeline is not providing gas at a rate to meet the nomination), and pipeline reductions (i.e., cuts based on a pipeline specific event – the only cut directly attributable to EPNG directly). The sum of these three categories of reductions was divided by the sum of total scheduled gas to derive the total reliability. Pipeline reliability is the sum of the pipeline related cuts divided by the sum of total scheduled gas.

The sum across all four cycles was used to capture all relevant nominations and cuts. Using only one cycle might miss significant cuts in a different cycle. Averaging across the cycles might also weight the result favorably or unfavorably with large or small reductions in one cycle that were not apparent in another cycle.

For reference, the same calculations are provided in the accompanying spreadsheet for each of the four cycles. The source of this data is from EPNG's Electronic Bulletin Board (EBB). The information is a mix of public and private data. The scheduled volumes by cycle are available on the EBB, but the capacity reductions – particularly by category – would not be available. Individual shippers would have access to this information for their own nominations.

Date: September 22, 2014
Prepared by: Aaron Purdy, Manager Account Services – Business Management,
719-520-4374, Aaron_Purdy@kindermorgan.com
Supervisor: George Wayne, Jr., Director, Account Services – Business Management

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 904 G) For Authority To Recover North-South Project Revenue Requirement In Customer Rates And For Approval Of Related Cost Allocation And Rate Design Proposals	APPLICATION 13-12-013 Filed December 20, 2013

**RESPONSES OF EL PASO NATURAL GAS COMPANY, L.L.C.
TO THE SECOND SET OF DATA REQUESTS OF
THE OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION**

Question 1: At page 3 of the above subject, witness Sanabria states that the revised North-South Project which no longer includes 31 miles of pipeline between Moreno and Whitewater, “will not have an impact on the cost, timing or design of the alternative project outlined” in his initial testimony. At page 5 of the initial testimony, witness Sanabria states “EPNG’s alternative would involve the looping of its Havasu Crossover in La Paz County, Arizona with a 42-inch diameter pipeline and the installation of compression facilities along the pipeline loop in Arizona.” At page 7 of the initial testimony, witness Sanabria states “EPNG notes that is proposal is scalable and can be adjusted to meet various levels of capacity increase up to the 800 Mdth/day design capacity associated with SoCalGas/SDG&E’s project depending on the alternative design proposal that is selected.” At page 5 of the above subject updated testimony, Table 1 provides a comparison of Revised North-South Project and the EPNG Alternatives. Three EPNG options are indicated for MDQs of 300, 550, and 800 Mdth/day.

(a) Please explain what would be required in order for the EPNG alternative selected to reach critical size for viability, including how much firm capacity must be subscribed by anchor shippers.

Response to Office of Ratepayer Advocates Data Request 1(a):
The scalability of EPNG’s Proposed Alternative is based upon the ability to add additional compression and metering to a planned loop of EPNG’s Havasu Crossover as detailed in the Prepared Intervenor Testimony of Anthony M. Sanabria. EPNG has received full subscription of the capacity supporting the looping of the Havasu Crossover. Each option would require full subscription of the listed capacity, for the term specified, in order for the annual revenue requirements shown in Table 1 on page 7 of the revised testimony of witness Sanabria to apply. EPNG is willing to consider additional options based on varying commercial terms such as volume, term, etc., in order to accommodate the needs of SoCalGas/SDG&E.

Date: April 14, 2015
Prepared by: Anthony M. Sanabria, Account Director, Business Development
Supervisor: Gregory W. Ruben, Vice President, Business Development

(b) Please explain if there are any other facilities that EPNG would need to construct to bring the EPNG alternative in-service. If so, please so state.

Response to Office of Ratepayer Advocates Data Request 1(b):
The current design proposed by EPNG requires the installation of approximately 100 miles of 42” pipe as a loop of the existing Havasu Crossover pipeline in Mohave and La Paz Counties, Arizona. This build is supported by the fully subscribed Open Season dated February 19, 2014. Additional compression would be added at existing EPNG stations in Arizona to effectuate the transport of natural gas from the Topock Meter Station in Mohave County, Arizona (the current interconnect with SoCalGas’ Northern System and other interstate pipelines) to the Ehrenberg Meter Station in La Paz County, Arizona (the current interconnect with SoCalGas’ Southern System). Enhancements to the current natural gas metering between SoCalGas and EPNG is also required to

facilitate this project. EPNG does not anticipate any other facilities would be required to effectuate the service described in the Prepared Intervenor Testimony of Anthony M. Sanabria.

Date: April 14, 2015
Prepared by: Anthony M. Sanabria, Account Director, Business Development
Supervisor: Gregory W. Ruben, Vice President, Business Development

(c) If the EPNG alternative was built, would this result in the need to construct additional facilities at a later time? If so, what facilities would be needed and why?

Response to Office of Ratepayer Advocates Data Request 1(c):
No.

Date: April 14, 2015
Prepared by: Anthony M. Sanabria, Account Director, Business Development
Supervisor: Gregory W. Ruben, Vice President, Business Development

(d) Please describe the proposed delivery location for the EPNG alternative. Please explain whether the proposed delivery location entails any additional costs or would require expansion of a SoCalGas backbone transmission receipt point capacity.

Response to Office of Ratepayer Advocates Data Request 1(c):
EPNG's current proposal is to transport natural gas to SoCalGas' Southern System at the existing interconnect between SoCalGas and EPNG at the Ehrenberg Meter Station in La Paz County, Arizona. Based on previous historical volumes delivered and SoCalGas' comments on the River Route on deliveries to this location, it is assumed that SoCalGas would not need to construct any additional facilities.

Date: April 14, 2015
Prepared by: Anthony M. Sanabria, Account Director, Business Development
Supervisor: Gregory W. Ruben, Vice President, Business Development

Question 2: Please describe the average pipeline cost in $ per mile of the EPNG alternatives, and the average cost in $ per horsepower of compression associated with the EPNG alternatives.

Response to Office of Ratepayer Advocates Data Request 2:

The total projected pipeline and compression costs for EPNG's proposed project range from $426,533,200 to $486,125,200. This includes costs for both the capacity awarded by EPNG in its February 19, 2014 open season and the capacity that would be used to serve SoCalGas. EPNG's estimate includes costs for 100 miles of 42" pipeline and 22,300 to 64,000 horsepower in compression. All costs reflect 2014 dollars.

Date: April 14, 2015
Prepared by: Anthony M. Sanabria, Account Director, Business Development
Supervisor: Gregory W. Ruben, Vice President, Business Development

Question 3: In Response to ORA-EPNG-01 Question 1, EPNG states "EPNG is willing to accept all financial risk if its project costs increase and would not seek to increase the Annual Revenue Requirements set forth in Table 1." Please explain the meaning of "all financial risk." Is it fair to assume that project cost increases for whatever reason will be covered by the term "all financial risk,"? If not, please explain in detail.

Response to Office of Ratepayer Advocates Data Request 3:
Unlike SoCal's North-South Project, EPNG's Annual Revenue Requirements are fixed.

As previously stated in Data Request No. 1, EPNG's Annual Revenue Requirements set forth in the Prepared Intervenor Testimony of Anthony M. Sanabria are firm (subject to approval by the appropriate management, management committee, and/or board of directors of EPNG and/or its parent companies). EPNG is willing to accept the financial risk of any increase in project costs and would not seek to increase the Annual Revenue Requirements set forth in Table 1.

Date: April 14, 2015
Prepared by: Anthony M. Sanabria, Account Director, Business Development
Supervisor: Gregory W. Ruben, Vice President, Business Development

NAVIGANT

NGMarket notes

A publication by Navigant's Energy Practice » October 2014

Contents

"Fracking 101"

Along with the abundance of shale gas across the country, there has been an abundance of news stories discussing hydraulic fracturing, or "fracking," as it is commonly referred to. The term is used frequently, and often improperly.

Fracking is not drilling. Nor are there "fracking pipelines." And, new terminology has started to become part of the vernacular - those objecting to the process are often referred to as "fracking foes" or even "fractivists."

Hydraulic fracturing is the injection of water and additives under high pressure into a potential oil and/or gas bearing formation, deep in the ground. The liquid fractures the rock or shale in which the oil or gas is held, and the tiny fissures are held open by the "proppants," such as sand, that enable the oil and gas to flow. Almost every well drilled in the world since the 1940s has been hydraulically fractured. Very little oil or gas would flow without it. So, if this process has been in place for decades, why is there all this sudden attention?

The advent of horizontal drilling (which essentially turns the corner on a well that is at first vertically drilled and then drilling horizontally within the formation, rather than just vertically through it), provides the well bore with much greater exposure to the producing formation. There has been a major shift from recovering oil and gas held primarily in sandstone, which makes up the bulk of conventional production, to recovering reserves in shale formations, deep underground. This increased exposure to the reservoirs that hold the resource usually requires more fluids. By more we mean ***a lot* more** fluid, primarily water and additives—many multiples per well compared to what has historically been used in previous wells simply drilled vertically through the formation. So much more water is used in hydraulically fractured wells that the amount of water and additives being used has become a primary point of contention, and highlighted the need for best practices, including the recycling of water and other fluids. Additionally, drilling is now taking place in areas where little production took place previously. Also, there are more people closer to hydraulic fracturing activity who are less familiar with this process than those living in historical oil and gas producing states, like Texas and Louisiana where regional oil and gas production has been going on for decades.

If hydraulic fracturing is actually as hazardous as some news headlines would lead you to believe, then why does the industry continue the practice? The answer lies somewhere in the middle, in that that while hydraulic fracturing incurs risk, so do so many other aspects of developing or generating energy. Coal, nuclear power, and even wind and solar carry with them certain costs and indeed risks to the environment that are inherent in their harnessing for human consumption. The bottom line is that energy, in most all forms, can be dangerous in some parts of its path from initial development or production to delivery to the end-user and through to the resultant emissions or other effects after the resource has been consumed.

One recent headline identified a study that de-links the matter of hydraulic fracturing impacting ground water by explaining that it is not hydraulic fracturing but rather poor well completions that are the likely cause of the ground water issues. Completion work on these wells takes place independent of any hydraulic fracturing activity, yet the majority of the blame is often ascribed to hydraulic fracturing. Proper well completion practices themselves are well understood within the industry but are in fact separate from the initial drilling activity. Well completion, which has taken place since the very first producing well, should not be confused with hydraulic fracturing.

In our estimation, shale production is expected to grow from providing just 7 percent of the natural gas produced in the U.S. in 2007, to almost 60 percent by the end of this decade. Without natural gas production from shale, through the combined breakthroughs of horizontal drilling and hydraulic fracturing technologies, the U.S., at this point, would be facing a very different, and very bleak, energy future.

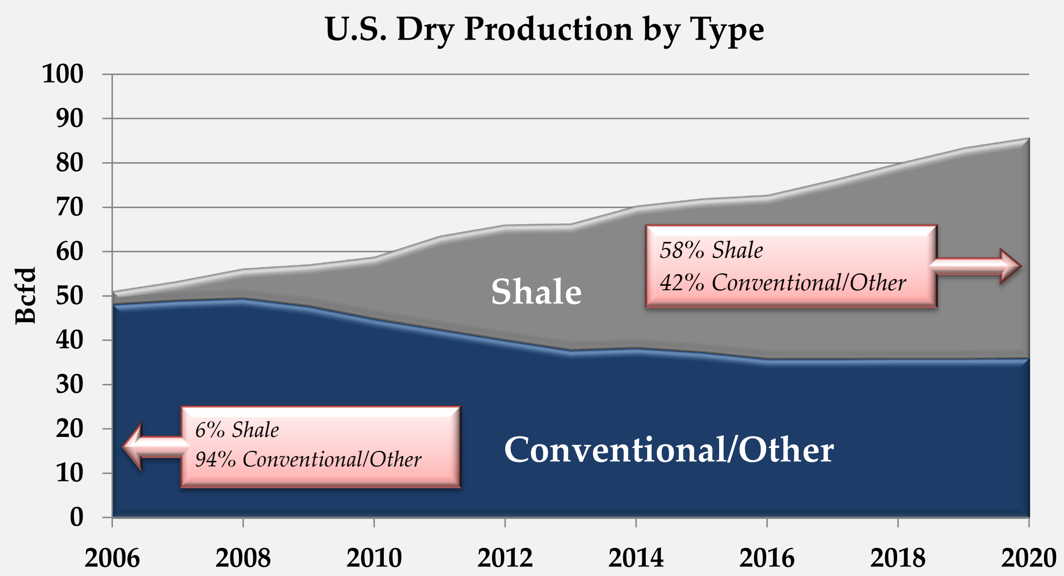
The result of utilizing horizontal drilling and hydraulic fracturing together, however, is that in just the past six years, North America has gone from a future of supply shortages, concerns over energy security, and increasing imports of natural gas, to having now dozens of multi-billion dollar facilities proposed to export surplus U.S. natural gas to the rest of the world (See Figure 2). A similar phenomenon is happening with oil, as pressure is being put on U.S. regulators to consider the reduction or removal of the federal ban on oil exports, owing to production increases from unconventional reserves through hydraulic fracturing. Thus, it is possible that the United States could become an energy independent nation—not to say there won't continue to be imports occurring, primarily to serve U.S. refineries that lack secure supplies to meet the local production requirements and that require oil from Mexico and Venezuela and Canada to continue to operate. It is, however, likely that within the next decade the U.S. will export more gas petroleum products than it imports. The export of surplus natural gas and the reduced need to import oil is beneficial not only for the country's balance of trade, but also for job creation across the country – as reflected in the recent improvements in the U.S. economy and falling unemployment levels.

As with everything in the energy sector, there is a balance to be struck. And, in the case of hydraulic fracturing, the balance is between the concerns of those who question this new technology, and the positive impact it is expected to have on the U.S. economy going forward. The country is just in the beginning stages of its energy renaissance. Navigant's recently released *North American Natural Gas Outlook – Summer 2014* indicates continued growth in the production of oil and natural gas, and this growth is expected to help provide a more secure energy future for North America, while enabling the U.S. to be a significant part of the worldwide movement to provide access to low-cost energy, and higher living standards, to an increasing number of people around the world. While the pros and cons of fracking continue to be debated in news headlines and state legislatures, the chances are we will all continue to benefit from it. Peaceful coexistence between oil and gas production and urban communities is possible, as best practices in the field become the recognized norm and we move toward the realization of the net benefits of developing these tremendous underground resources.

— *Bob Gibb*

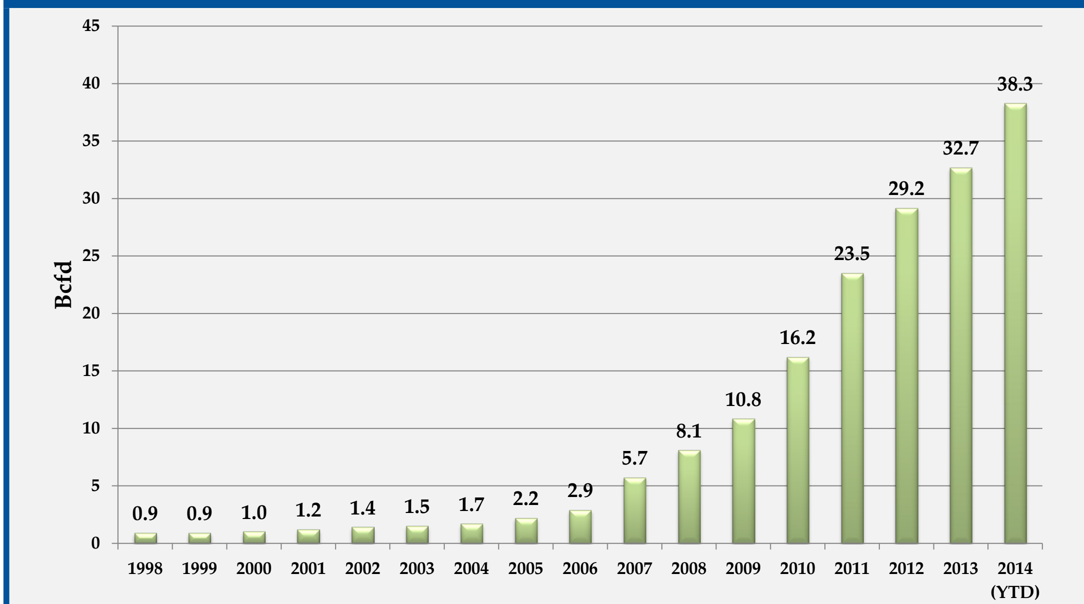
About the Author »
Bob Gibb, is an Associate Director in Navigant's Energy Practice.

FIGURE 1. NAVIGANT'S U.S. FORECAST GAS SHALE PRODUCTION TO 2020



Source: Platts, Navigant's *North American Natural Gas Market Outlook, Mid-Year 2014*

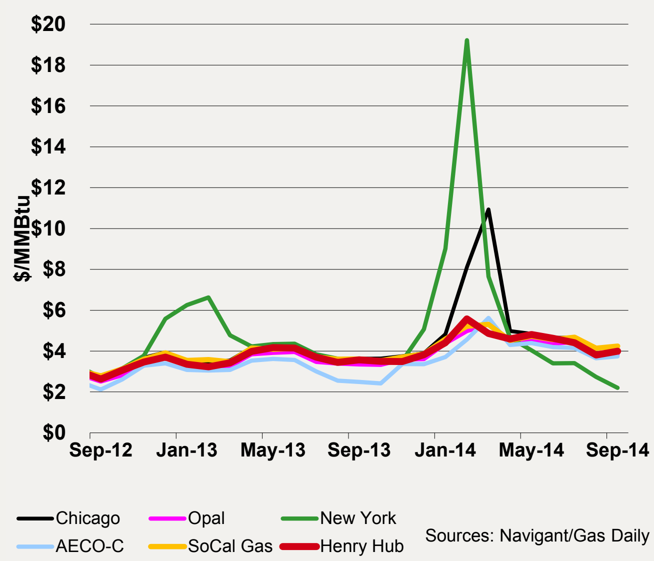
FIGURE 2. U.S. HISTORICAL ANNUAL AVERAGE DRY GAS PRODUCTION



Source: Platts, Navigant's *North American Natural Gas Market Outlook, Mid-Year 2014*

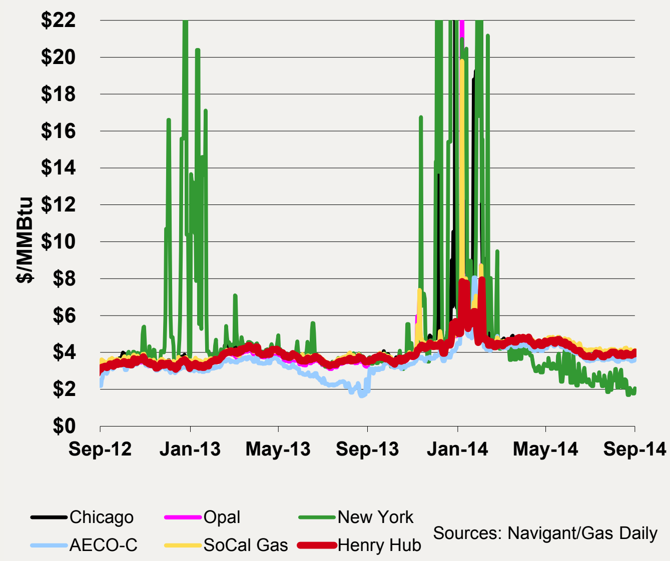
Natural Gas Market Charts

MONTHLY GAS INDEX PRICE



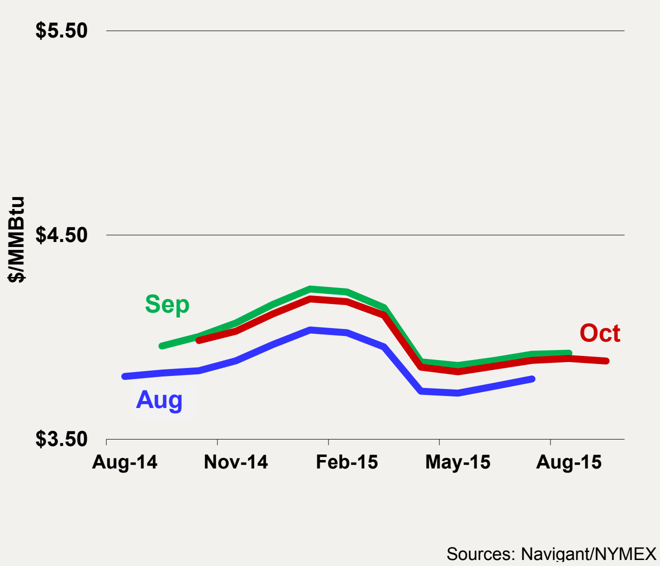
Monthly index gas price increased 5% last month, with Henry Hub at $3.99/MMBtu for September versus $3.81 for August.
The September 2014 price exceeded the September 2013 price of $3.57/MMBtu by $0.42/MMBtu.

DAILY GAS PRICE



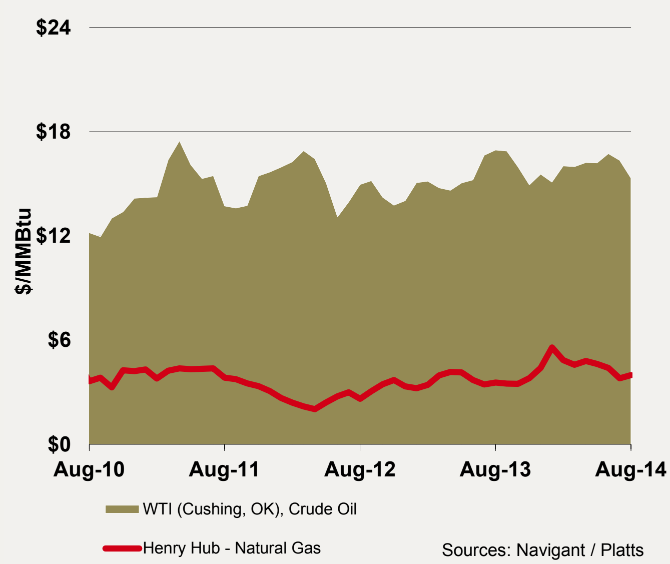
The daily spot prices ended September unchanged versus the end of August with Henry Hub at $4.02/MMBtu. Prices in New York averaged $1.65 below Henry Hub during September, versus a difference of $1.45 during August.

NYMEX FUTURES SETTLEMENT PRICES AT CLOSE



The average 12-month strip price decreased slightly by four cents, or up 1%, to $3.98/MMbtu for the strip starting October 2014.

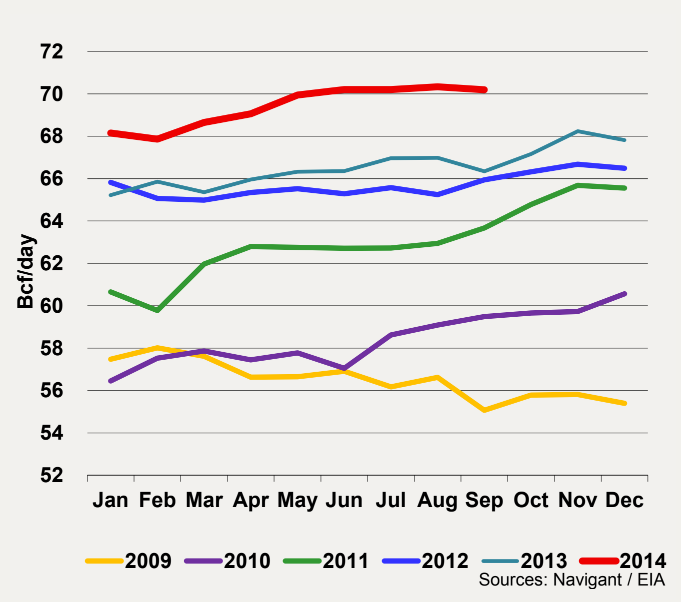
MONTHLY PRICES: OIL AND NATURAL GAS GULF COAST



The most recent gas/oil price ratio fell to 3.8 times, with Henry Hub natural gas price at $3.99 versus WTI crude oil price at $15.33.
The ratio one year prior was 4.7 times.

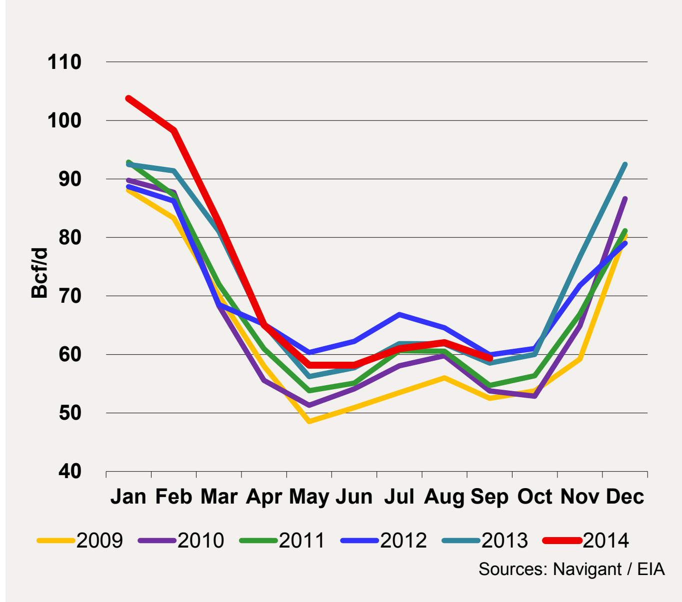
Natural Gas Market Charts

U.S. DRY GAS PRODUCTION



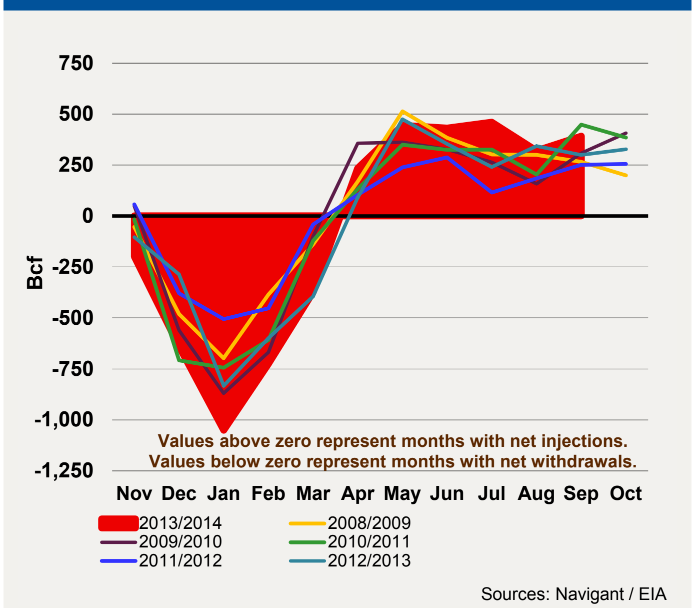
U.S. dry gas production remained steady at 70 Bcfd.

U.S. MONTHLY NATURAL GAS DEMAND



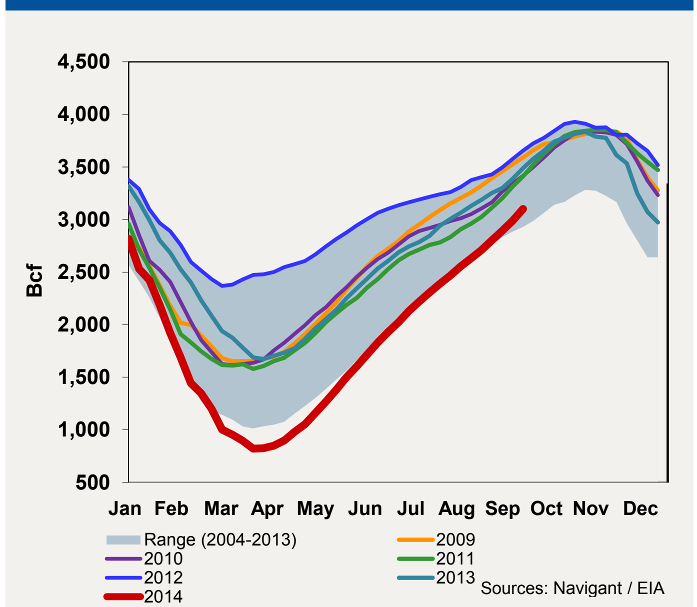
U.S. gas demand had a strong September and exceeded ten of the last eleven years at this time.

MONTHLY U.S. STORAGE ACTIVITY



U.S. storage injection levels were strong in September, at 391 Bcf, higher than eight of the last ten years at this time.

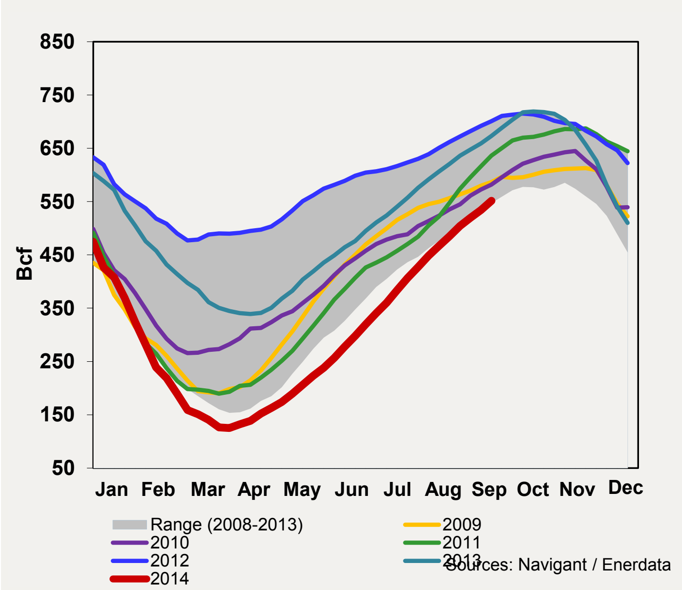
U.S. GAS STORAGE



U.S. storage inventories in September continued farther into range at this time for the last ten years, at 3,100 Bcf.

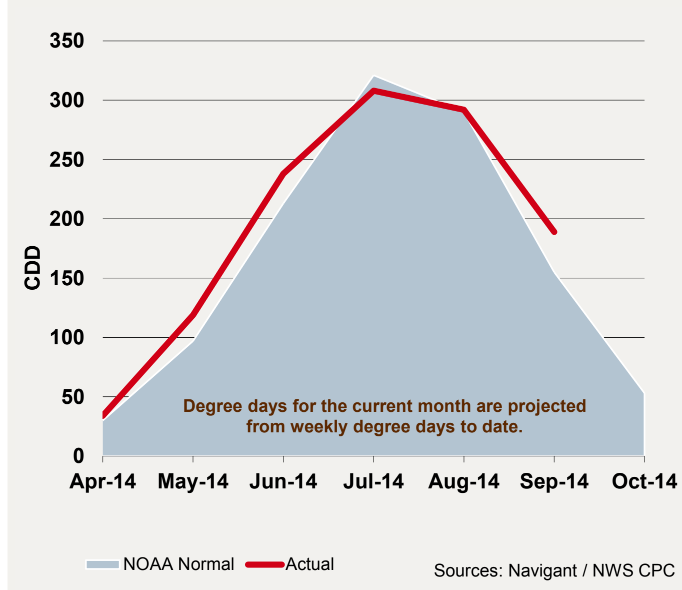
Natural Gas Market Charts

CANADA GAS STORAGE



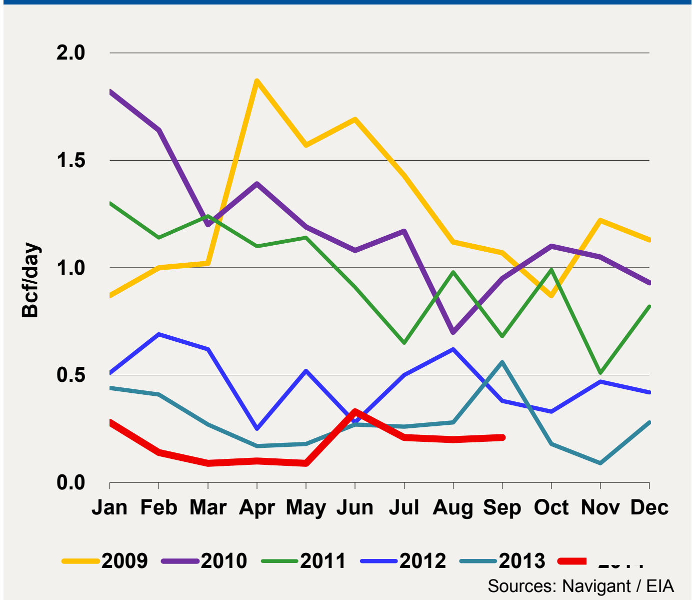
Canadian storage injections in August helped move storage levels closer to the range for the last six years at this time, at 463 Bcf versus 477 Bcf in 2008.

U.S. POPULATION-WEIGHTED CDD



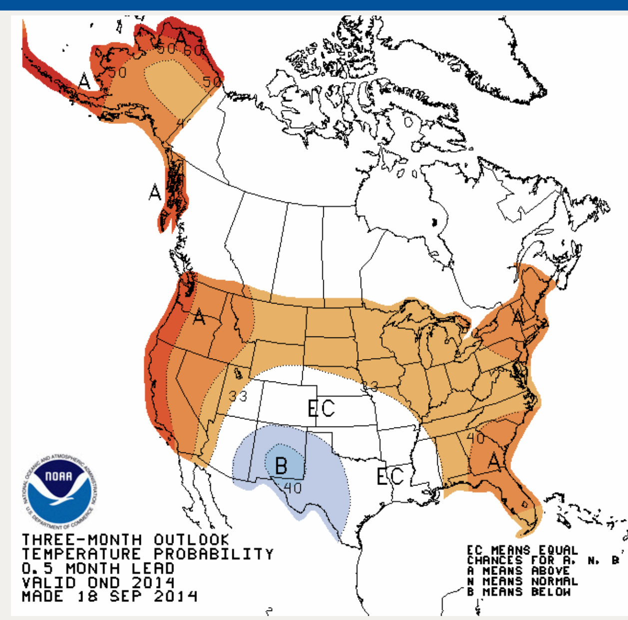
Near-normal temperatures in August brought season-to-date cooling degree days down to 4% above normal.

U.S. LNG IMPORTS



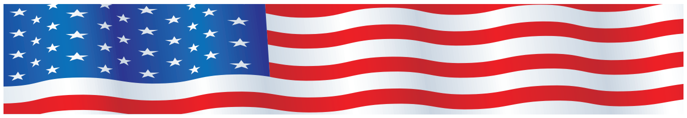
U.S. shale gas production remained steady at the recent high of 38.2 Bcfd.

U.S. TEMPERATURE OUTLOOK



The temperature outlook is for above normal temperatures for most of the western continental U.S., and for the Atlanctic Coast states down through northern Florida. Below normal temperatures are favored for the central Great Plains southwest through central New Mexico.

Legislative and Regulatory Highlights



Maryland

Dominion Cove Point LNG Receives FERC Authorization for Construction and Operation

On September 29, the Federal Energy Regulatory Commission announced the authorization of Dominion Cove Point LNG, LP to construct and operate its proposed LNG liquefaction terminal in Calvert County, Maryland. FERC's order included 79 conditions to mitigate potential adverse environmental effects. In addition to the terminal siting approval, FERC also approved ancillary projects on the Dominion system to accommodate the delivery of gas to the terminal. On September 30, Dominion notified FERC that it accepted the order and all of its conditions. The terminal will be able to liquefy and export about 5.75 million tons per year of LNG via ships docked at its existing offshore pier. Construction is proposed to start in 2016, with an in-service date of March 2017.

Northwest

Jordan Cove LNG Developer Veresen to Acquire 50% of Ruby Pipeline

On September 22, Veresen Inc. announced its execution of an agreement to purchase for $1.425 billion Global Infrastructure Partners' 50% interest in the 1.5 Bcfd capacity, 680-mile, 42-inch Ruby Pipeline connecting the Opal hub in Wyoming with the Malin hub in Oregon. Kinder Morgan, affiliate of Ruby Pipeline's other 50% owner, El Paso Pipeline Partners, will continue to operate Ruby on a day-to-day basis. There is currently about 0.4 Bcfd of uncontracted capacity on Ruby, as well as another 0.5 Bcfd of expansion capacity available with compression. The proposed Pacific Connector Gas Pipeline, from Malin to the proposed Jordan Cove LNG export terminal in Coos Bay, Oregon is also 50% owned by Veresen. Veresen expects the Ruby Pipeline to provide "significant upside" associated with its Jordan Cove LNG project.

British Columbia

Province of British Columbia Approves Allowances Totaling $120 Million in Latest Infrastructure Development Credits

On September 17, the Province of British Columbia announced that it had approved a 13th installment of its royalty credit program, begun in 2004, to foster infrastructure projects for natural gas development. The latest approval, for $120 million, will be used to help fund 17 road and pipeline projects, focused in the Montney play area of northeast B.C. To date, the royalty credit program has helped in the development of 220 infrastructure projects representing about $2 billion in private capital investment.

Woodfibre LNG Signs MOU for LNG Sales Agreement with Chinese Firm

On September 25, the Office of the Premiere of British Columbia reported that Woodfibre LNG, which is developing a liquefaction terminal in Squamish, executed a Memorandum of Understanding with Guangzhou Gas of China for the potential off-take of one million tons per year of LNG. The preliminary agreement calls for a 25-year term, beginning in 2017. The Woodfibre project is planned for a brownfield site with a deep-water port and existing electric and gas infrastructure. Five Guangdong province cities have sister-city relationships with B.C. cities (including Guangzhou and Vancouver), and the two provinces have been sister-provinces and worked together to develop trade for two decades.

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NG Market Notes is a publication of Navigant's Global Oil & Gas Practice. Navigant's NG Market Notes newsletter focuses on the North American natural gas market - serving utilities and public entities, independent power producers, natural gas producers, pipelines, LNG developers, large industrial end-users and financial services companies.

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Navigant's Energy Practice includes more than 370 experts focused on issues across the entire energy value chain including renewables, climate change, energy efficiency, demand response, emerging technologies, global oil and gas, generation, resource procurement, transmission, markets, performance improvement, fuel sourcing, rates and regulation, as well as providing energy market research reports in the areas of clean technologies, smart grid and emerging energy-related markets. More information about Navigant's Energy Practice can be found at navigant.com/energy.

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MEXICO'S NEW ENERGY LANDSCAPE

March 2015

CONTENTS

OVERVIEW

Mexico's entire energy sector is undergoing unprecedented liberalization and reform, creating important opportunities for foreign production, power and midstream companies. This sweeping restructuring effort will leave no area of the Mexican energy industry untouched. The latest liberalization will open the exploration and production (E&P) sector to private investment, leading to crude oil production growth from fields that have some of the lowest breakeven costs in the world.

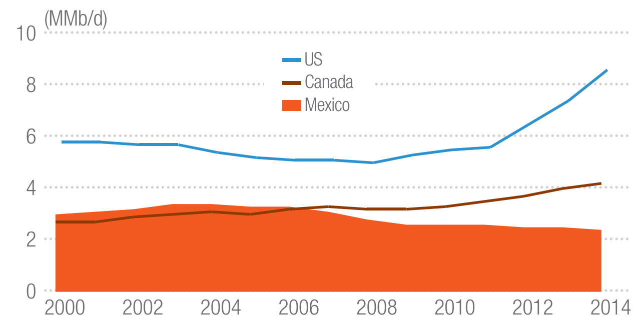
Mexico also is in the process of creating a wholesale power market, with massive additions of gas-fired power generation planned over the next decade. To fuel this power generation growth, the country has embarked on a $12 billion expansion of its natural gas pipeline network with several large new import projects at the US border. Mexico is expected to increase reliance on US natural gas to feed its new pipelines, supply its growth in power generation and support a renaissance of its industrial sector.

Mexico's energy regulatory structure is being reconfigured, and its state-owned energy businesses are being reorganized. Forecasting the effects of the many changes in Mexico's energy sector will be challenging, but there are a few important trends emerging and some likely outcomes that this paper will address. Bentek also includes ongoing forecasts of Mexico's supply and demand fundamentals in its CellCast, Market Call and other products[1].

One trend that has been in place for several years is declining oil, gas and natural gas liquids (NGLs) production. Mexico hopes the latest liberalization of its E&P sector will reverse production declines and lead to a period of growth. Oil and gas production has been falling steadily over the past decade in deep contrast with the energy boom in the United States and Canada. Crude oil production in Mexico averaged 2.4 MMb/d in 2014, down almost 30% or 1 MMb/d from the peak of 3.4 MMb/d reached in 2004. Despite the production declines, Mexico continues to be one of the largest crude oil exporters globally. However, lower crude oil production has translated into lower crude export volumes, which have negatively impacted the revenues of the Mexican government. Declining production has also driven domestic prices for natural gas, liquefied petroleum gas (LPG), electricity and refined products, such as motor gasoline and diesel, higher as the country increasingly relies on imports to satisfy the domestic demand for these products. High domestic energy prices have negatively impacted Mexican households and the competitiveness of the industrial sector.

In an effort to reverse production declines, the Mexican government, under the mandate of President Enrique Peña Nieto, proclaimed a constitutional reform that modified three articles of the country's constitution. The president signed this reform into law on December 20, 2013, a few days after it was approved by the Mexican Congress and 25 out of the 31 state legislatures. In August 2014, the president signed secondary legislation, consisting of nine new laws and amendments to 12 existing laws to implement the Constitutional changes. The changes allow for private investments, foreign and domestic, across the oil and gas value chain and end the 76-year monopoly of state-owned energy company Petróleos Mexicanos (PEMEX), which has had sole rights to engage in exploration, production, processing, refining and commercialization of hydrocarbons since President Lazaro Cardenas nationalized the oil industry in 1938.

GRAPH 1: NORTH AMERICAN CRUDE OIL PRODUCTION



Source: EIA, IEA, SENER

Mexico currently is starting the process of allowing private capital to unlock the country's vast oil and gas reserves. As a first step in this process, the Mexican government is scheduled to award 14 blocks in the shallow waters of the Gulf of Mexico this summer. More than 22 companies already have registered and paid the fees to access a data room to support the due diligence in this bidding process. Large, multinational energy companies and independent producers alike will now have the ability to engage in exploration and extraction activities in areas that could provide some of the lowest breakeven costs in the world. Mexico's processing, fractionation and refining complexes have changed little in recent years, but liberalization will create investment opportunities for midstream and downstream companies. As private investment leads to production in new areas, the country will have to develop gathering and transportation systems to connect this new supply to markets.

Another important trend in Mexico is rapid power generation growth and natural gas demand growth as the power sector reduces its reliance on expensive fuel oil. The power market currently is dominated by government utility Comisión Federal de Electricidad (CFE). Mexico allowed independent power producers (IPPs) to generate electricity starting in 1992, but they were forced to sell their power to the CFE. Although generation from IPPs has increased over the past decade, electricity prices also have increased. To help drive prices lower, the

1 For more information contact Bentek Energy at info@bentekenergy.com or at 1-888-251-1264.

energy reform will reward low-cost power production by allowing IPPs to sell electricity under the same terms and conditions as the CFE in a wholesale market. Energy reforms also will include the country's first Independent System Operator (ISO), which will economically dispatch power plants until demand is satisfied, setting the spot price for electricity starting in 2016.

The CFE and IPPs have proposed a large number of new gas-fired power projects and gas conversions of existing fuel oil plants.

In an effort to provide fuel for these plants, Mexico also is embarking on one of the largest pipeline construction periods in its history. Bentek is currently tracking more than 22 pipeline projects in Mexico. These projects include a number of new or expanded US border crossings to facilitate increased natural gas imports from the US. The US exported 2.0 Bcf/d of natural gas to Mexico in 2014, more than twice the volumes recorded for 2010. US natural gas exports to Mexico are likely to continue growing over the next decade to fuel the country's demand growth in the power, industrial and residential and commercial sectors. Rising imports from the US will help displace more expensive liquefied natural gas (LNG) imports at Mexico's three import terminals.

This paper provides transparency about the many changes taking place in Mexico and the likely impacts on energy market fundamentals. Understanding Mexico's new energy landscape will be imperative if private companies plan to take advantage of the opportunities Mexican energy reform will create and the challenges the industry will likely face.

INDUSTRY REGULATORS AND STATE PRODUCTIVE ENTERPRISES

Mexico is in the process of changing the structure of its government-owned energy businesses, PEMEX and the CFE, as well as the regulatory framework and regulatory bodies that oversee the industry. PEMEX and the CFE will become State Productive Enterprises (SPEs) that must make autonomous, commercially driven decisions to remain competitive. To ensure transparency and stimulate competition, the reform has also reorganized and strengthened the government agencies that regulate the industry. These agencies include the Ministry of Energy (SENER), the Ministry of Finance (SHCP), the National Hydrocarbons Commission (CNH), and the Energy Regulatory Commission (CRE). The reform also created a national agency for industrial safety and environmental protection, as well as two new organs to operate the wholesale power market and the national natural gas transportation and storage systems.

The government proclaimed the constitutional reform in December 2013, but the rules that will govern the industry are still under development. Companies interested in entering Mexico's energy market will be impacted by the decisions these regulators make and will also compete head-to-head with two of the most powerful enterprises in the country. Understanding the roles and responsibilities of these organizations will be imperative for doing business in the Mexico. This section reviews the main regulators and the two SPEs that participate in Mexico's new energy landscape.

SENER – Secretaría de Energía
Ministry of Energy

SENER dictates Mexico's energy policy, and is analogous to the US Department of Energy (DOE). SENER is organized in two subsectors: (1) hydrocarbons, which includes crude oil, gas, NGLs, refined products and basic petrochemicals; and (2) electricity. SENER's responsibilities in the area of hydrocarbons include providing the permits to refine crude oil, treat natural gas and import/export refined products; selecting areas to be tendered for exploration and extraction (E&E); granting and revoking leases; and designing the E&E contracts and terms for the bid. In the area of electricity, SENER directs the planning and expansion of the national grid, and determines the requirements to issue Clean Energy Certificates, among other responsibilities. The SENER publishes monthly and annual statistics for the energy industry, similar to the US Energy Information Administration (EIA).

SHCP – Secretaria de Hacienda y Crédito Público
Ministry of Finance

The SHCP defines the economic and fiscal terms of each E&E contract, and oversees cost accounting. The head of the SHCP is comparable to the Secretary of the Treasury in the US.

FMP – Fondo Mexicano del Petróleo para la Estabilización y el Desarrollo
Mexican Petroleum Fund

The FMP will be in charge of paying amounts due on E&E contracts and managing the state oil revenues, such as duties and royalties, but not taxes.

CNH – Comisión Nacional de Hidrocarburos
National Hydrocarbons Commission

The CNH regulates Mexico's upstream sector and is the technical expert in this segment. The CNH performs the bidding process, signs, manages and oversees E&E contracts, authorizes drilling and seismic studies, and manages the National Petroleum Information Center.

CRE – Comisión Reguladora de Energía
Energy Regulatory Commission
The CRE regulates Mexico's midstream sector, including the transportation and storage of natural gas, LPG and electricity. This regulatory entity is comparable to the US Federal Energy Regulatory Commission (FERC). The CRE establishes the tariffs for regulated services, and provides the permits to commercialize, transport, store and distribute hydrocarbons, refined products, and electricity.

ASEA – Agencia de Seguridad, Energía y Ambiente
National Agency for Industrial Safety and Environmental Protection of the Hydrocarbons Sector
The energy reform created the ASEA to regulate and supervise industrial and operative safety. The ASEA is also responsible for protecting the environment, and is an administrative agency of the Ministry of Environment and Natural Resources. The agency will carry out inspections to verify compliance with federal environmental laws, will perform root cause analysis of accidents, and may impose fines and shutdown regulated activities. The ASEA will oversee E&E, oil refining, gas processing, pipeline transportation and storage, waste management, pollutant emissions controls, among others. In the US, the scope of the ASEA is covered by various regulators, including the Environmental Protection Agency (EPA), the Occupational Safety and Health Administration (OSHA), and the Department of Transportation's (DOT's) Pipeline and Hazardous Materials Safety Administration (PHMSA).

PEMEX – Petróleos Mexicanos
Pemex is a State Productive Enterprise, and is Mexico's only vertically integrated oil and gas company. PEMEX is currently undergoing a reorganization that was approved in Nov. 2014 which reduces the number of subsidiaries to two: Exploración y Producción, which will handle all upstream activities, and Transformación Industrial, which includes gas processing, NGL fractionation, crude oil refining, and petrochemical production.

PMI Comercio Internacional
PMI is a group of trading and logistics affiliates of PEMEX responsible for commercializing the company's crude oil and refined products in the global market.

MexGas Supply (formerly MGI Supply)
MexGas Supply is an indirect subsidiary of PEMEX responsible for commercializing natural gas and NGLs in the global market. This entity holds PEMEX's natural gas transportation contracts on US pipelines, and it was previously called MGI Supply.

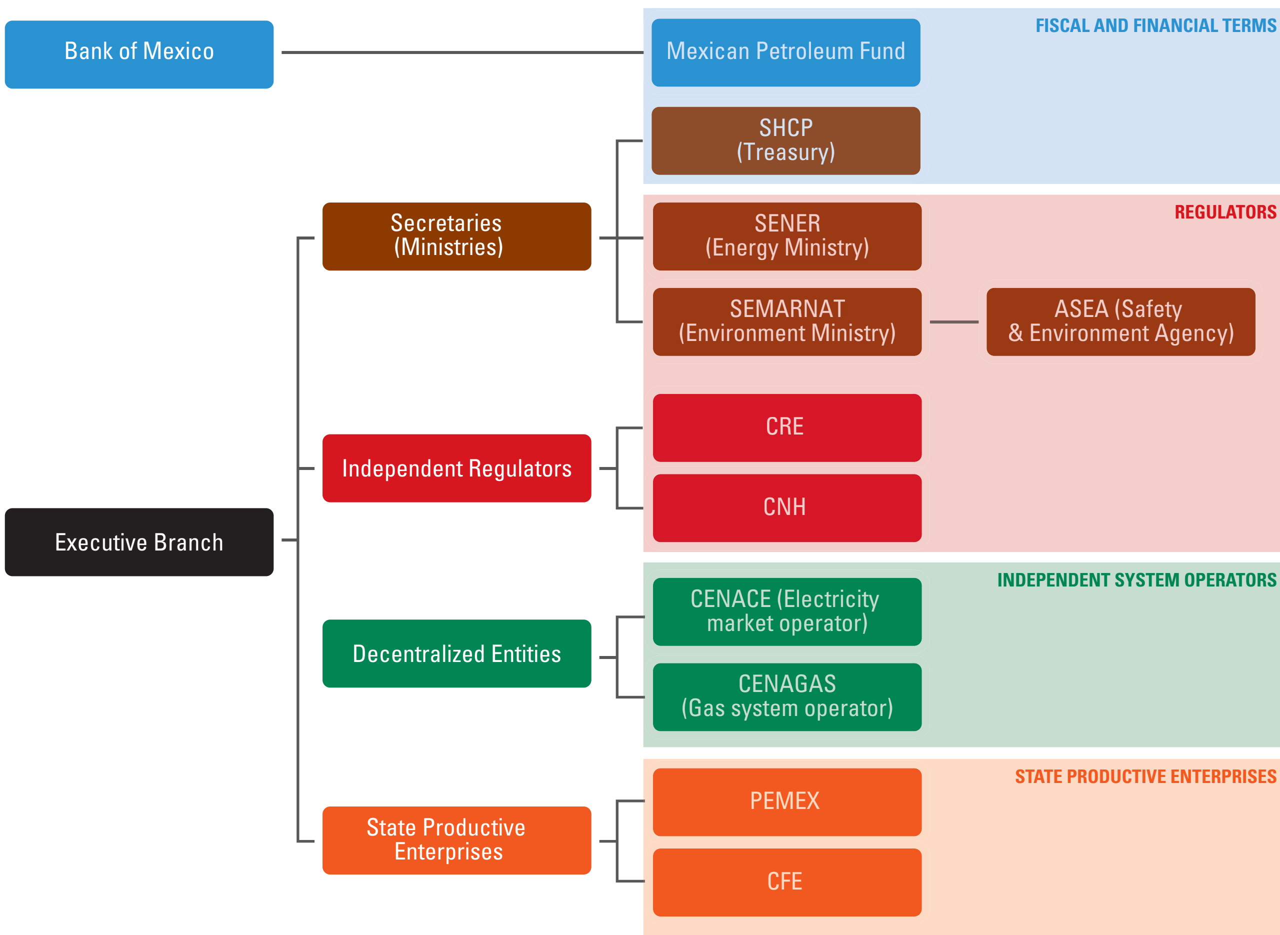
CFE – Comisión Federal de Electricidad
Federal Electricity Commission
The CFE is a State Productive Enterprise and is currently Mexico's only electric utility. The CFE generates, transmits, markets and distributes power. The CFE operates more than 50 GW of power generation, representing roughly 85% of the country's total nameplate capacity, and maintains the transmission grids and distribution networks.

CENACE – Centro Nacional de Control de Energía
National Center for the Control of Energy
The energy reform created CENACE to operate Mexico's dispatch system. CENACE will be responsible for wholesale market operations and will set the spot price by taking into account the daily operating costs submitted by generators, similar to an Independent System Operator (ISO) in the United States.

CENAGAS – Centro Nacional de Control de Gas Natural
National Center for Natural Gas Control
CENAGAS will operate Mexico's national natural gas transportation pipelines and storage system. PEMEX is currently in the process of transferring these operations to CENAGAS.

The following chart summarizes the relationship between the regulators and SPEs that participate in Mexico's energy industry.

CHART 1. INDUSTRY REGULATORS AND STATE PRODUCTIVE ENTERPRISES



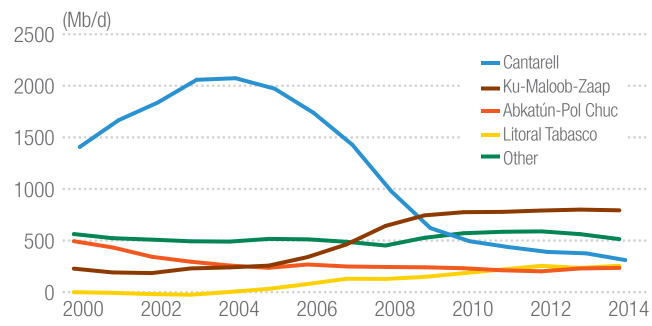
Source: Platts, CRE

UPSTREAM DEVELOPMENTS

Mexico has large oil and gas resources but PEMEX does not have the technology, experience or the capital to reverse Mexico's production declines by unlocking unconventional resources onshore or expanding expensive deepwater exploration and production in the Gulf. Mexico's upstream industry has developed primarily in four states located along the Gulf Coast: Tamaulipas, Veracruz, Tabasco and Chiapas. PEMEX's exploration and production activities have primarily targeted crude oil, and only two of the company's 12 producing assets target natural gas.

Current production is primarily extracted from the shallow waters of the Gulf of Mexico in the Bay of Campeche, and in onshore basins through conventional extraction techniques. These areas represent 75% of the country's total oil and gas production. The energy reform will help unlock resources as it allows private companies to invest capital to participate in hydrocarbon exploration and extraction projects. The reform will also allow PEMEX to partner with these companies to develop the technical know-how to extract hydrocarbons from deepwater and shale plays. The Mexican government will award the first E&E contracts this summer, and more than 22 companies have paid the fees and registered to participate in the first tender.

GRAPH 2: CRUDE OIL PRODUCTION BY ASSET

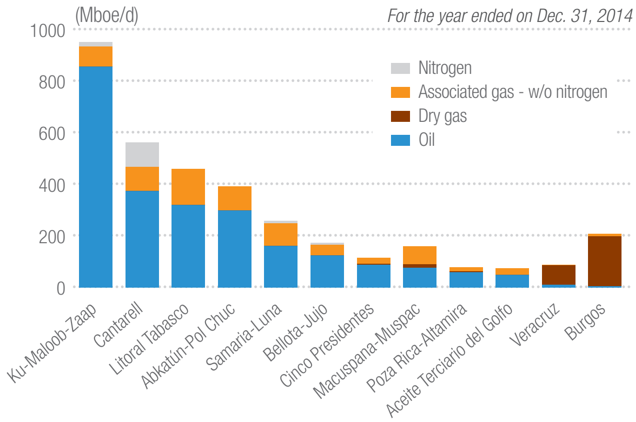


Source: SENER

A study published by Standard and Poor's (S&P) in December 2014 estimated that PEMEX's average production cost, including extracting, finding, and development costs, is about $22.82 per barrel. Like Platts, S&P is owned by McGraw-Hill Financial. As *Graph 2* shows, PEMEX's largest producing asset is Ku-Maloob-Zap (KMZ), which is the name of three fields that have produced relatively flat crude oil volumes of 850 Mb/d since 2008. Production from KMZ, however, is only a fraction of the volumes the nearby asset of Cantarell once produced. In 2004, Cantarell was the world's second most prolific

MAP 1: MEXICO'S MAIN PRODUCING REGIONS

GRAPH 3: OIL AND GAS PRODUCTION



Source: Bentek, SENER

field, only behind the Ghawar deposit in Saudi Arabia. PEMEX started to inject nitrogen into Cantarell in 2000 to enhance oil recovery, and this helped push production to a high of 2.2 MMb/d in 2003 and 2004. However, production has quickly declined since, and it averaged 375 Mb/d in 2014. Growing production from Litoral Tabasco has partially offset Cantarell's declines.

Natural gas production in Mexico is primarily recovered in association with crude oil (*Graph 3*). In 2014, PEMEX produced an average of 6.5 Bcf/d, and 70% was associated gas. As a result, the majority of Mexico's gas is recovered in the shallow waters of the Gulf, which amounted to 4.8 Bcf/d in 2014. This volume includes 770 MMcf/d of nitrogen because PEMEX has been using this product to enhance oil recovery, particularly in Cantarell and KMZ. Total dry gas supply, after treating and processing, shrank to 4.5 Bcf/d in 2014.

The Burgos basin, which in part holds an extension of the Eagle Ford shale, is currently PEMEX's largest gas producing asset. Burgos produced 1.1 Bcf/d in 2014. This volume is 20% lower than the 1.5 Bcf/d recorded in 2009. PEMEX recovers almost no oil from Burgos, but NGL recovery has averaged 40 Mb/d since 2010.

Mexico ranks sixth in the world in terms of shale gas and eighth in terms of shale oil according to data published by the EIA in June 2013. Aceite Tercario del Golfo, commonly known as Chicontepec, is the largest shale play in Mexico in terms of its reserves. However, oil and gas production from this asset averaged only 50 Mb/d and 150 MMcf/d, respectively, in 2015. Operators applying horizontal drilling and hydraulic fracturing techniques in Mexico's unconventional plays have the potential to unlock production from this play.

On August 13, 2014, the SENER assigned PEMEX the fields it was allowed to retain, culminating a process known as Round Zero. On this day, the CNH also revealed the areas that will be tendered in 2015 in a process called Round One. Round One has opened up for tender 14 blocks for the exploration of oil and gas in the shallows waters of the Gulf. The CNH has scheduled to open the bids and award the blocks on July 15, 2015 – which is also the deadline to submit the bids. The CNH opened the data room to support this tender on January 20, 2015. The fees associated with registering in the bidding process and accessing this data room amount to roughly US$380,000.

As of February 6, the CNH had granted access to the data room to 22 companies, including ExxonMobil, Chevron, BG Group, Shell, ENI, Total, Statoil, and BHP Billiton, among others. On February 27, the CNH issued a call for bids and opened the data room to support a second list of tenders. This time, the government is offering five blocks for the extraction of oil and gas, also in shallow waters. The CNH has set Sep. 30 as the date for companies to submit their bids. On this same day, the government will also open and award the bids.

Last year, the CNH had discussed tentative plans to issue additional calls for bids for blocks in unconventional shale plays, conventional onshore fields, and deepwater blocks by the end of 2015. However, the CNH has postponed the process in the midst of lower oil prices, and it has yet to issue a new schedule.

PEMEX's low costs indicate that developed areas such as the shallow waters are still attractive to private companies in today's price environment. Deepwater and unconventional fields, particularly in the northern area that are not connected to existing infrastructure, may take longer to develop. It is important to note that the location of the initial resource offering indicates that crude oil production rather than shale gas will be the main target of liberalization in the initial stages.

MIDSTREAM AND DOWNSTREAM INFRASTRUCTURE

The energy reform will also impact a number of other sectors of Mexico's energy industry, including crude oil refineries, pipelines, processing plants, fractionators, and steam crackers, among other assets. Historically, these assets have been mostly owned and controlled by PEMEX. This section provides an overview of some of the energy infrastructure currently in place in the country.

Crude oil refining and exports

PEMEX owns and operates six refineries in Mexico with combined nameplate capacity of 1.7 MMb/d, which is significantly lower than domestic crude oil production that averaged 2.4 MMb/d in 2014. These refineries are designed to take primarily the country's light and extra-light domestic production, called Isthmus and Olmeca, respectively, which are produced in Litoral Tabasco and Onshore. PEMEX had discussed plans of building a new refinery, dubbed Bicentenario, adjacent to its Tula refinery. The company canceled this project in 2014, and instead announced plans to invest US$15 billion to upgrade three existing refineries. However, the company issued a press release on February 16 announcing cuts in its projected capital expenditures (CAPEX) for 2015, and these refinery upgrades have been delayed.

PMI Comercio Internacional is responsible for commercializing the company's crude oil and refined products. The company has access to five terminals to export crude, which are primarily located along the Gulf Coast. One of these export terminals is in the open sea, 100 miles away from Ciudad del Carmen in Campeche, and only one is on the West Coast. Mexico does not currently have international oil pipeline connections. In 2014, Mexico's crude oil exports averaged 1.1 MMb/d, and the United States imported 0.8 MMb/d or roughly 70% of this volume. Spain was the second largest importer of Mexican crude with 160 Mb/d, followed by India with 81 Mb/d.

The crude produced from Mexico's Campeche Bay is typically of low API gravity, ideal for US refineries on the US Gulf Coast with coking capacity. The US is, by far, the largest consumer of heavy Mexican crude globally. Given the strong relationship between the two countries, PMI owns half of the Deer Park refinery in Texas in a joint venture (JV) with Shell. This refinery is the sixth largest in the US and is designed to take heavy sour crude. More than half of the crude oil this refinery processes is imported Maya from Mexico.

In January 2015, PEMEX submitted a proposal to the US Department of Commerce's Bureau of Industry

MAP 2: PEMEX'S INDUSTRIAL TRANSFORMATION FACILITIES AND MEXICO'S LNG TERMINALS

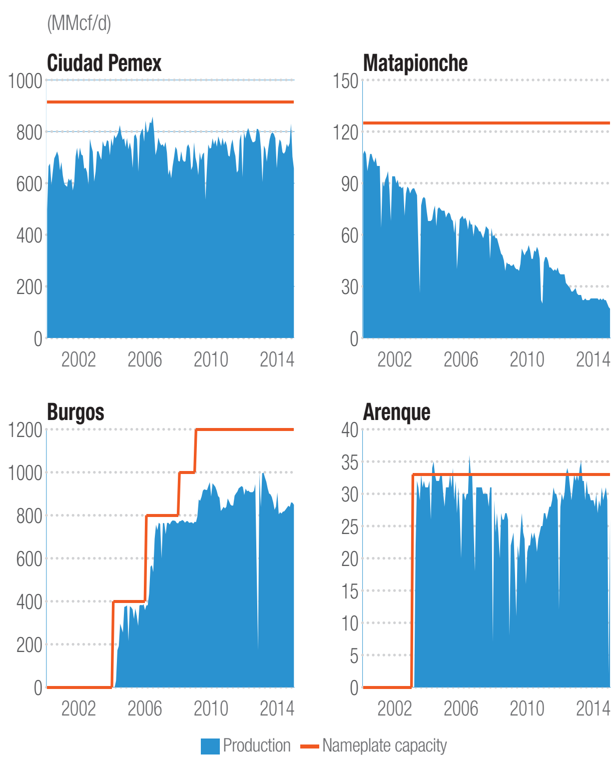
and Security (BIS) for an exchange of crude. PEMEX has proposed to exchange up to 100 Mb/d of light crude and condensate from the US with the intention of blending it with Mexican grades to increase production of gasoline and distillates in three refineries that are configured for cracking. In exchange, Mexico would continue to export heavy crude to be refined in the US. In February, 21 senators pressed the Obama administration to approve the exchange, and submitted a letter proposing to apply to Mexico President Ronald Reagan's decision to allow oil exports to Canada for domestic consumption since 1985.

Global heavy oil production, with the exception of production from Canada's oil sands, is in decline as producers, particularly in the US, target shale oil formations that produce light and ultra-light crude. Mexican crude is well positioned as US refineries will continue to source heavy crude despite the growth of discounted, light barrels in North America.

Gas processing

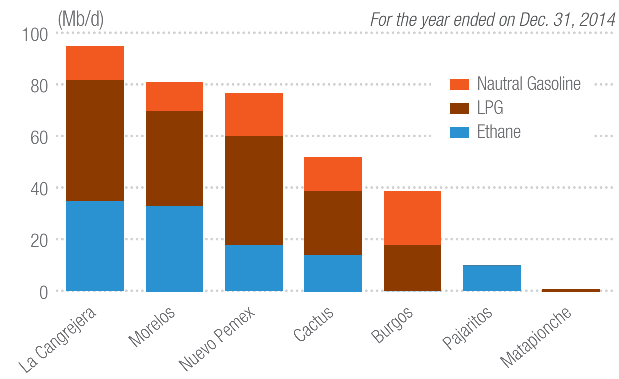
Gas processing in Mexico has changed little in recent years. PEMEX operates nine processing complexes that have combined sweetening capacity of 4.5 Bcf/d to treat sour natural gas and 5.9 Bcf/d of cryogenic capacity to recover NGLs. Utilization rates for cryogenic processing plants averaged 62% in 2014. As Graph 4 shows, Ciudad Pemex and Areneque experienced the highest utilization

GRAPH 4: DRY GAS PRODUCTION FOR SELECTED PLANTS



Source: Bentek, SENER

GRAPH 5: NGL PRODUCTION BY FRACTIONATOR



Source: SENER

rates, slightly above 80%, while utilization rates at Matapionche were only 17%.

PEMEX built the majority of its processing capacity between the 1950s and the 1970s, and in the past decade, it has added capacity in only three plants. PEMEX completed its most recent processing expansion in 2012 at its Poza Rica plant to support growing production from Chicontepec. In 2009, PEMEX completed the third and final phase of its Burgos processing plant, which has a nameplate capacity of 1.2 Bcf/d. In 2003, PEMEX completed its Arenque processing plant, the smallest in the country. Arenque has a nameplate capacity of 33 MMcf/d, and has run at an average utilization rate of 88% since it was commissioned.

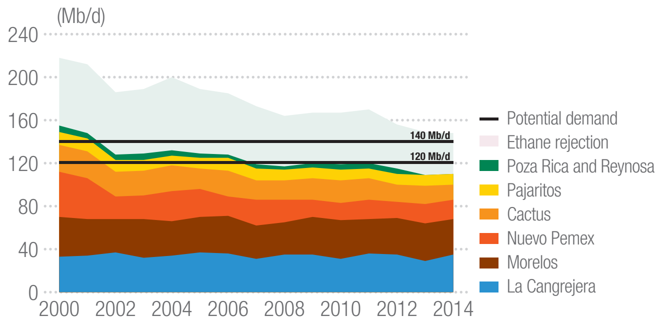
Natural gas liquids fractionation

NGL recovery in Mexico has declined in the past decade, following the declines in crude oil production. PEMEX separates y-grade into purity NGL products in nine fractionators that are mostly located at the same sites as the processing plants. Fractionation, however, also takes place at the Madero refinery and at PEMEX's three petrochemical complexes. PEMEX fractionators have a combined C2+ capacity of 587 Mb/d and produced an average 360 Mb/d in 2014. As *Graph 5* shows, La Cangrejera and Morelos are currently the largest fractionators by throughput. NGLs produced at these two fractionator complexes have remained relatively steady over the past decade while production from Nuevo Pemex and Cactus has consistently declined over the same time period. The Burgos fractionator has partially offset the declines. However, the Burgos complex is not designed to recover ethane.

Ethane cracking

The first greenfield steam cracker that will take advantage of the low-ethane prices spurred by North America's shale boom will be located in Mexico and is scheduled to start operations at the end of this

GRAPH 6: ETHANE PRODUCTION



Source: SENER

year. Braskem-Idesa is currently constructing the 2,310 MMlb/yr Etileno XXI complex that will house one steam cracker and two downstream polyethylene (PE) facilities. Bentek estimates that this plant will require 60 Mb/d of ethane, which will double Mexico's ethane demand. The company has signed a 20-year supply agreement with PEMEX, linked to ethane prices at Mont Belvieu and gas prices at Henry Hub.

PEMEX currently operates three steam crackers at the petrochemical complexes of La Cangrejera, Morelos and Pajaritos, all located in an area known as Coatzacoalcos, in the state of Veracruz. These crackers have a combined nameplate capacity of 3,045 MMlb/yr and are designed to crack ethane for 100% of their feedslate. Bentek estimates that these units would require roughly 80 Mb/d of ethane in total when running at 95% utilization. Actual demand from these crackers, however, is closer to 60 Mb/d. The average utilization rate of PEMEX's steam crackers has fallen from a peak of 84% in 2009 to 71% in 2014 as ethylene production from Pajaritos has steadily declined since 2007. It is worth noting that Pajaritos has not produced ethylene from October 2014 according to data published by the SENER with data up until the end of January.

Although current production is sufficient to support existing petrochemical demand, PEMEX may be short ethane when Etileno XXI starts operating. To mitigate this risk, PEMEX has disclosed plans to increase ethane recovery capabilities in its Ciudad Pemex processing complex, which is not producing NGLs currently. Additionally, Gasoductos de Chihuahua, a 50/50 JV between PEMEX and IEnova (a subsidiary of Sempra International), is developing a 140-mile ethane pipeline to connect the Cactus, Nuevo Pemex and Ciudad Pemex complexes to Coatzacoalcos. However, as *Graph 6* shows, the supply for ethane could be very tight once Etileno XXI comes online, even after taking into account the ethane that is currently being rejected in the gas stream.

One of the goals of the energy reform is to make the country's manufacturing industry more competitive. Mexico is a net importer of polyethylene, and Platts' *Global Polyethylene Outlook* expects demand for this resin to increase with the country's GDP growth. Potential ethane shortages, however, could defer investments in additional ethylene production facilities. In fact, if the declines in ethane production persist, PEMEX is at risk of being forced to operate its crackers at even lower utilization rates. The existing steam crackers are conveniently located near the LPG import terminal of Pajaritos. Hence, PEMEX could consider importing ethane through this port, or adding feedstock flexibility to one of its units to take propane and butane. With the expectation that NGL production will increase while LPG domestic demand declines, propane and butane could become feasible feedstock in Mexico's petrochemical industry.

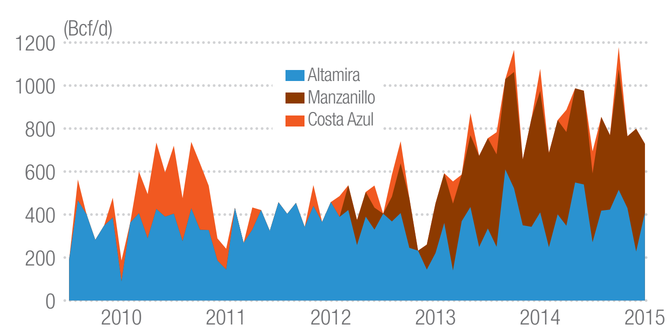
Liquefied natural gas imports

Mexico has continued to increase LNG imports over the last several years due to persistent pipeline constraints, declining dry gas production, and increasing natural gas demand. Growing US pipeline imports eventually will displace LNG imports and may even lead to LNG exports.

Mexico can import LNG at three facilities: Costa Azul in Baja California, Manzanillo on the West Coast of central Mexico, and Altamira on the Gulf Coast. These facilities have a combined regasification capacity of 16.1 million metric tons per annum (mtpa) or 2.0 Bcf/d. Mexico first began LNG imports in 2006 and imports have increased consistently every year. In 2014, Mexico imported just under 0.9 Bcf/d, representing roughly 12% of Mexico's total gas supply, an 18% increase year-over-year. Although Costa Azul is the country's largest import terminal, Manzanillo and Altamira have been the prime receivers of LNG imports.

Sempra's 1-Bcf/d Costa Azul terminal, located in Ensenada, Baja California, near Tijuana, was the second LNG import terminal completed in Mexico, starting operations in 2008 and serving growing demand in Baja California and California. The terminal imported just over 200 MMcf/d in 2010 and accounted for 38% of Mexico's total LNG supply that year. However, as *Graph 7* shows, the US shale boom shortened Costa Azul's useful

GRAPH 7: LNG IMPORTS



Source: Bentek

life, and imports at this terminal fell to 35 MMcf/d in 2014, accounting for a mere 4% of Mexico's total LNG imports that year. Growing US production reversed gas flows between Costa Azul and the US. As a result, Sempra renegotiated its long-term supply contract with Indonesia's Tangguh LNG and re-sold the vast majority of the supply to Japanese buyers. This displacement of Mexican LNG supplies into the Asian markets mirrored much of the displacement that was occurring in the US during the same timeframe.

Manzanillo is Mexico's newest LNG import terminal, completed in 2012, and primarily sells gas to the CFE and to PEMEX to supply power and industrial load in the constrained Guadalajara and Mexico City areas. The terminal is a joint venture between Samsung (37.5%), Mitsui (37.5%), and KOGAS (25%). It has a long-term supply contract with Peru LNG that started at 90 MMcf/d in 2012 and ramped up to 500 MMcf/d in 2015. Manzanillo imported 450 MMcf/d in 2014, representing a 90% utilization rate and providing 51% of the country's total LNG supply. The terminal also imports spot cargoes at the Japan-Korea Marker (JKM) spot price plus a fixed component, which makes Manzanillo spot imports some of the most expensive in the world.

The Altamira import terminal, a joint-venture between Royal Dutch Shell (50%), Total (25%), and Mitsui (25%), was the country's first LNG import terminal, completed in 2006. Altamira primarily supports the CFE's gas-fired power plants in the northeastern portion of the country. The terminal is primarily supplied under two long-term supply contracts with Nigeria LNG and Qatargas and it imported about 340 MMcf/d in 2014, representing a 70% utilization rate and providing 45% of the country's LNG supply.

As LNG imports begin to taper with the influx of US pipeline imports, market participants in Mexico are increasingly exploring the viability of exporting LNG. PEMEX announced plans last November to develop a $6 billion LNG liquefaction plant to be operational in 2020. The company is seeking to partner with third-party investors to develop the project. PEMEX has not yet selected the location for this terminal, but it is expected to be close to its Salina Cruz refinery on the West Coast in southern Mexico. The greenfield project will require an expansion of the 90 MMcf/d Transoceanic Pipeline, a 100-mile line that connects the refinery with Pajaritos, which is located in the Coatzacoalcos area and is well connected to the company's main producing assets along the Gulf Coast. However, the South Central area of Mexico is already highly supply-constrained and would require substantial growth in both domestic production as well as new connectivity to US gas supplies in order for this project to become a reality. Therefore, any LNG

MAP 3: MEXICO'S CURRENT AND PROPOSED NATURAL GAS INFRASTRUCTURE

exports from this terminal would not likely occur until the mid-to-late 2020s.

Similarly, on Feb. 19, PEMEX, Sempra LNG, and IEnova signed a memorandum of understanding (MOU) to coordinate development of a 2 mtpa natural gas liquefaction project at Costa Azul. The project would require 270 MMcf/d of gas. However, Bentek's analysis suggests that the current gas pipeline network connecting the US to Costa Azul would likely be unable to deliver the required gas supply over the long term due to capacity constraints on the El Paso pipeline and growing gas demand in the Southwest US. Therefore, the project would likely need to include a new supply pipeline, which would increase the cost of the project. Furthermore, the drop in global oil prices has significantly reduced global CAPEX budgets, which will limit capital available for new LNG export projects.

Natural gas pipelines

Mexico is embarking on one of the largest pipeline construction periods in its history in an effort to bring natural gas to dozens of new gas-fired power plants, as well as new areas of the country that currently rely heavily on fuel oil. Multiple new gas pipelines are planned for the northwestern quadrant of the country, which does not currently have adequate access to domestic natural gas production. The largest proposed pipeline system is Los Ramones pipeline, which extends roughly 650 miles from the South Texas border to northeastern Mexico.

Mexico's most important natural gas transportation system currently is the Sistema Nacional de Gasoductos (SNG), which has a nameplate capacity of 5.0 Bcf/d and is composed of roughly 5,400 miles of pipeline. PEMEX used to own and operate this system, but the energy reform has created CENAGAS to operate the capacity on this system. PEMEX is also in the process of transferring to CENAGAS the operations of a smaller, 212-mile, 1,054-MMcf/d system called Sistema Naco Hermosillo (SNH). The SNH is not currently connected to the SNG, and it receives its supply primarily from Kinder Morgan's El Paso Natural Gas (EPNG) in Arizona.

Private companies also own and operate gas pipeline systems in Mexico and are regulated by the CRE. Mexico's largest independent pipeline company is Fermaca, but other multinational companies such as Sempra International (operating in Mexico under its subsidiary, IEnova), TransCanada, GDF Suez, and Kinder Morgan participate in this country.

Mexico's reliance on imported LNG is largely due to pipeline constraints that limit access to US pipeline gas. The completion of the Los Ramones I pipeline this year alleviated some constraints limiting US imports. Los Ramones receives gas from South Texas via the recently completed NET Mexico pipeline, and delivers the gas to the SNG in the state of Nuevo Leon. The pipeline commenced service in December 2014 with 1.0 Bcf/d of capacity, and will be expanded to 2.1 Bcf/d later this year when the Los Ramones II – North and Los Ramones II – South extend the system's reach farther downstream to the center of the country.

Bentek is currently tracking more than 22 infrastructure projects to develop greenfield natural gas pipelines in Mexico. As Table 1 shows, The CFE has awarded five tenders for the construction of new transportation assets since October 2014. These five pipelines will represent investments of more than US$2.2 billion dollars and have combined nameplate capacity of 5.7 Bcf/d. Companies such as Sempra, TransCanada, Energy Transfer Partners, and Crestwood have actively participated in this process.

The CFE is scheduled to award five more tenders for the construction of gas transportation systems between now and the end of the summer. Bids for the San Isidro – Samalayuca package are due on March 25 and the CFE will announce the winning bid on April 16. The CFE has not yet set the date for the four other contracts, but tentative

TABLE 1. RESULTS FROM RECENT CFE TENDERS

	Ramal Tula	Ojinaga - El Encinto	El Encinto - La Laguna	Waha - Presidio	Waha - San Elizario
Awarded Date	Oct-2014	Nov-2014	Dec-2014	Jan-2015	Jan-2015
Sempra		A	x	x	x
TransCanada		x	x	x	x
Crestwood				x	
ETP/Carso/Mastec		x	x	A	A
Fermaca		x	A		
Operadora Mexicana de Gaseoductos				x	x
Enagas/Elecnor		x	x		
ATCO	A				
Arendal	x				
Capacity (MMcf/d)	485	1,400	1,107	1,350	1,135
CAPEX (Million USD)	$ 48	$ 300	$ 630	$ 643	$ 596

A: awarded; x: submitted a bid

Source: Bentek, CFE

plans indicate that the state productive enterprise plans to award the contracts by the end of July.

Bentek estimates that US pipelines have an aggregate nameplate capacity of roughly 7.5 Bcf/d to deliver natural gas to the Mexican border for export. Four interstate pipelines deliver half of Mexico's total inland gas imports currently: El Paso Natural Gas Pipeline (EPNG), North Baja, Tennessee Gas Pipeline (TGP) and Texas Eastern Transmission (TETCO). Mexico receives the other half of its inland imports from a number of intrastate pipelines and natural gas utilities, including Enterprise's Texas Intrastate system, Kinder Morgan Border Pipeline, Kinder Morgan Texas, OkTex Pipeline, Reef International, San Diego Gas & Electric, SoCal Gas, and West Texas Gas. Most recently, NET Midstream completed NET Mexico in December and Bentek's discussions with the pipeline indicate that the pipelines flowed about 350 MMcf/d that month and peaked as high as 500 MMcf/d. Kinder Morgan completed the Sierrita Pipeline at the end of October, but flows have dropped to zero since November 18 indicating downstream infrastructure issues on the Sonora Pipeline.

Bentek is tracking six projects to expand or build new capacity to deliver dry natural gas to the US/Mexico border that could amount to 5.3 Bcf/d. These projects include the San Elizario and Presidion pipelines, two projects sanctioned by the CFE that will transport a combined 2.5 Bcf/d from the Permian into northwestern Mexico. The CFE has estimated that gas demand in the Northwestern Mexico region, which includes Sonora, Chihuahua, Sinaloa, and Durango, will require 2.2 Bcf/d of incremental supply between now and 2028.

GRAPH 8: US NATURAL GAS PIPELINE EXPORTS TO MEXICO

Source: EIA

As *Graph 8* shows, Mexico's imports of natural gas via pipeline from the US have increased consistently over the past few years. In 2014, Mexico imported an average of 2.0 Bcf/d, up 114% from the 0.9 Bcf/d imported in 2010. Imports via pipeline peaked at 2.2 Bcf/d last September, but volumes have since fallen as gas demand for power generation has been tempered with the start of the winter. Mexico's natural gas imports are seasonal, and typically peak in the summer on increased demand from the electricity sector.

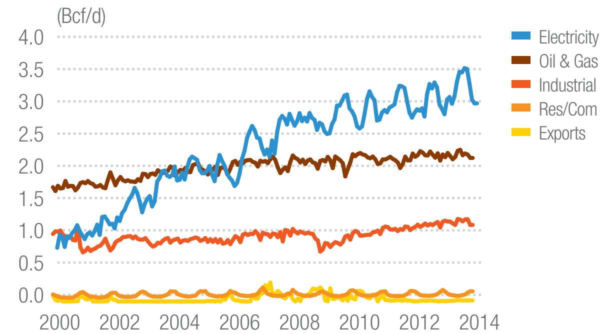
NATURAL GAS SUPPLY

Gas production in Mexico has declined over a period of time when demand for this commodity has increased rapidly. As a result, the country has increasingly relied on imports to satisfy its growing domestic demand.

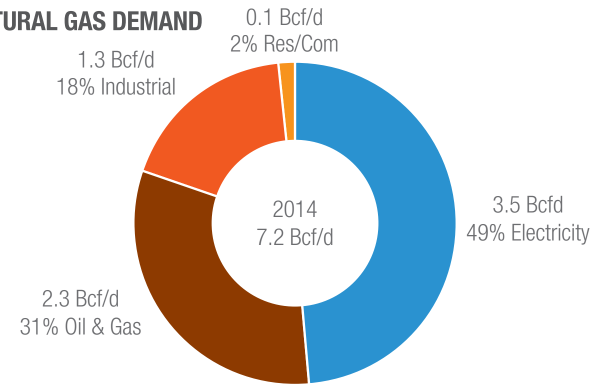
In 2010, natural gas demand in Mexico averaged 6.5 Bcf/d. At that time, dry gas production averaged 5.0 Bcf/d, enough to satisfy just shy of 80% of the country's natural gas needs. Domestic dry gas production, however, has fallen by 12% in the past four years, to 4.4 Bcf/d on average in 2014 and representing roughly 60% of the country's gas needs last year. Conversely, demand has increased by 12% over the same timeframe to 7.2 Bcf/d. The result is an increase in imports from the US via pipelines and overseas via LNG.

As *Graph 9* shows, the US delivered 2.0 Bcf/d of natural gas to Mexico in 2014, up 114% since 2010 and representing 27% of the country's gas needs. Pipeline imports represented only 14% of the country's needs in 2010. Over the past four years, LNG imports have also increased materially, though not as fast as inland imports from the US. In 2014, Mexico's LNG imports averaged 0.9 Bcf/d, up 66% from the 0.5 Bcf/d averaged in 2010. LNG represents roughly 12% of total Mexico's gas supply currently. Natural gas demand is set to increase in Mexico, driven by power generation, while producers target crude oil production. As a result, Mexico will increasingly rely on imports for its natural gas supply.

GRAPH 10: NATURAL GAS DEMAND COMPONENTS



NATURAL GAS DEMAND



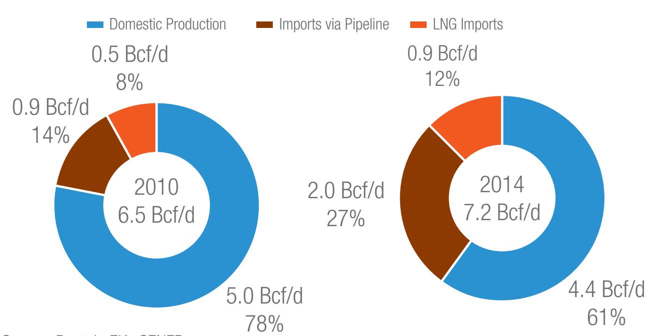
Source: Bentek, SENER

Downstream demand

Natural gas demand is increasing rapidly in Mexico, particularly in the power sector, and this trend is expected to accelerate over the next decade as the country expands its power sector, reduces reliance on expensive fuel oil and increases consumption of cleaner burning natural gas. Demand grew 3.8% in 2014 to 7.2 Bcf/d and has increased consistently over the past decade.

The electricity sector is the largest component of natural gas demand in Mexico, representing 3.5 Bcf/d in 2014 and almost 50% of the country's total gas demand needs that year (*Graph 10*). This source of demand is highly seasonal, peaking in the summer and leveling down in the winter as milder temperatures reduce the need for cooling. The CFE is the country's largest power producer in Mexico and it consumed an average of 1.3 Bcf/d in 2014.

GRAPH 9: NATURAL GAS SUPPLY



Source: Bentek, EIA, SENER

The oil and gas industry represented the second largest component of natural gas demand, with 2.3 Bcf/d representing 31% of the market. Within this sector, production and other upstream operations account for the largest component of gas demand, representing almost 60% of the total gas consumed by the oil and gas industry in 2014. The rest is evenly split between gas processing and transportation, petrochemical production and refining. Average annual demand from the oil and gas sector has remained relatively steady above 2.0 Bcf/d since 2004.

The industrial sector has been the second largest driver of natural gas demand growth over the study period. Industrial consumption averaged 1.3 Bcf/d in 2014, up more than 20% from 2010.

The residential and commercial sector consumed less than 120 MMcf/d in 2013. Although winters in Mexico are materially milder than in the US, natural gas has yet to substantially penetrate the residential and commercial sector. LPG is the country's fuel of choice for cooking and heating, with a penetration of 52% while wood represents 41%, leaving a share of only 7% for natural gas. The residential and commercial sector consumes an average of 215 Mb/d of LPG, which equates to roughly 0.9 Bcf/d. The pipeline build-out planned over the next several years could generate incremental gas demand from the residential, commercial, industrial, and power sectors as this commodity reaches more cities and Mexicans switch from LPG to natural gas.

Demand for gas is somewhat seasonal in Mexico with small peaks in the summers as air conditioning generates peak demand for power from June through September, and winter heating loads are relatively small. Total gas demand in Mexico peaked at 7.7 Bcf/d in October 2014 and fell to a minimum of 6.9 Bcf/d in December 2014, a swing of 0.8 Bcf/d or only an 11% difference between the average demand in those two months.

From a geographic standpoint, the majority of Mexico's gas consumption takes place in the Southeastern portion of the country where activities associated with oil extraction, gas processing, NGL fractionation, and petrochemical production are concentrated. The Northeast represents the second largest demand center, where demand is driven by the electric and industrial sectors.

CONCLUSIONS

The reform and liberalization of Mexico's energy industry will touch nearly every sector of the economy. In 2015, the biggest change will take place in the upstream sector, which is being opened to private investments for the first time since 1938. The CNH is scheduled to award the first 14 blocks for the exploration of hydrocarbons in the shallow waters of the Gulf of Mexico this summer, and it is planning to award five more blocks for production in this same area in the fall.

This liberalization effort will promote investments along the entire oil and gas supply chain, including not only exploration and production, but also gathering, gas processing, NGL fractionation, and crude refining. This effort intends to boost energy production in Mexico and lower electricity prices. However, production will be slow to reverse course in today's low-oil-price environment. Eventually, Mexican oil production will begin to grow again because the country offers companies the opportunity to operate in areas that have some of the world's lowest production costs.

Despite the domestic demand growth for natural gas, Bentek does not expect this commodity to be the focus of private companies participating in the liberalization of Mexico's upstream sector, as companies will be targeting crude oil. In addition, the first blocks that will become available for private exploration and production activities will be far from the new gas pipeline and power plant infrastructure being built in the northwestern and northeastern regions of the country.

Low oil prices may slow down the expectations of Mexico's production growth, but they will not stop the country's growing demand for hydrocarbons. As a result, the United States will likely serve Mexico's increasing demand for natural gas. Mexico needs a growing fuel source for its rapid expansion of gas-fired power generation while the US Permian Basin in West Texas and the Eagle Ford Shale in South Texas need a growing market south of the border. In fact, the majority of the natural gas pipelines completed at the end of 2014 and currently under construction are being designed to move gas south from the US border. The Los Ramones I pipeline, extending from South Texas into Nuevo Leon, started to ease pipeline constraints on the National Gas Pipeline System (SNG) in December 2014 and will serve growing industrial and power generation demand in the Northeast going forward. Kinder Morgan's Sierrita Pipeline, which extends south from El Paso Natural Gas' South Mainline near Tucson, Arizona to the border with Sonora, Mexico will serve a number of new power generation projects and pipelines being built in the northwestern quadrant of the country. The San Elizario and Presidio pipelines in West Texas will bring gas from the Permian Basin to pipelines in the state of Chihuahua. In Mexico, more than 22 pipeline projects will move gas further south, relieving gas transportation constraints and serving demand growth.

The power industry has been the main driver behind these pipeline expansions, but the extension of the country's natural gas transportation system will impact every sector of the country. US gas supply will displace expensive LNG imports at Altamira on the Gulf Coast and eventually at the Manzanillo terminal on Central Mexico's Pacific Coast. The pipeline build out and availability of natural gas will lower energy prices and create opportunities in the agriculture, manufacturing, mining, construction, basic materials, and utilities sectors. The penetration of natural gas will stimulate fuel switching in the power market primarily from fuel oil to natural gas, as well as fuel switching in Mexican households from LPG and wood to natural gas.

These are among the many changes taking place in Mexico. Data and analysis on the Mexican energy sector is needed now more than ever as the country creates new opportunities for foreign companies and increases competition among existing participants.

Contact Bentek Energy at info@bentekenergy.com or at 1-888-251-1264, for detailed forecasts of Mexico's energy supply and demand fundamentals, information on existing and new infrastructure projects, and updates on the ongoing changes in Mexican energy regulation and reform.

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The Economist

Energy in North America

A new Mexican revolution

The country's energy reforms may transform not just the oil and gas business but the whole of its industry—if, as ever, not derailed by politics

Nov 15th 2014 | MEXICO CITY | From the print edition

RECRUITMENT flyers are being handed out in the main square of Los Ramones, a once-sleepy town of tumbleweed and spit-and-sawdust bars 63 miles (100km) south of Mexico's border with the United States. The call is for workers to start building the second stage of a gas pipeline heading south towards central Mexico, even before the first stage of the pipeline has been inaugurated.

The Los Ramones pipeline is the spine of a proposed 10,000km natural-gas transport network that could lead the transformation of Mexico's energy industry. When gas starts to flow down from Texas to Los Ramones along stage one of the pipeline, on December 1st, Mexico's gas market will be physically plugged in to that of the rest of North America for the first time. Emilio Lozoya, the boss of Pemex, the state oil company, points out that this means Mexico will start to benefit from the cheap shale gas that has boosted the prospects of all manner of businesses north of the border.

The implications of this alone could be profound for Mexican industry. About a fifth of the country's power is now generated with dirty and expensive fuel oil which, excluding subsidies, makes the cost of electricity to industrial users 75% higher than in the United States. A greater supply of cheap gas coming down the pipes, coupled with a recent liberalisation of the electricity market to encourage the building of new power plants, could start to drive down power prices for industrial users within two years, officials say. That could make Mexico's most buoyant export businesses, such as carmaking and aerospace, even more competitive.

Yet this is just one part of an energy revolution that is set to sweep Mexico now that its constitution has been changed, and enabling laws have been passed, to end Pemex's 76-year monopoly on oil and gas production. All aspects of the energy market are being opened up. And a country with huge potential reserves—including extensive shale beds that mirror those across the border in the United States, albeit with more legal obstacles—is poised to start exploiting them more efficiently.

In at the shallow end

On or around November 15th the government plans to start the process of inviting private oil companies, domestic and foreign, to bid for the first new exploration blocks, in shallow waters off the Gulf coast. By March next year the global oil majors will get their first glimpse of the tender process for some of the juiciest prospects of all, the mostly untapped deepwater sites in Mexico's part of the Gulf. "Round One" of the tendering process will also include a number of onshore exploration blocks (see map). The government hopes that over the coming four years the successful bidders in this round will invest about $50 billion in the blocks they win.

Besides being able to bid for oil- and gasfields, and to build electricity-generating plants, private firms will be freer to invest in pipelines, ports and other infrastructure—something that cash-strapped Pemex has long failed to do. If all goes to plan, the influx of capital and the fall in energy costs should boost productivity and profits across Mexican industry, lifting the country's hitherto anaemic growth rate—the main objective that President Enrique Peña Nieto had in mind when promoting the energy reforms.

Foreign firms are impressed with the speed at which Mr Peña is pushing through reforms that were all but unthinkable just a few years ago, even amid political turmoil. "Mexico has really captured the imagination of the world energy sector," says Enrique Hidalgo of Exxon Mobil, America's largest oil company. However, potential bidders are still waiting for details of all the technical and financial requirements they will have to sign up for.

Private firms, domestic and foreign, will also be looking for indications that the government is serious about ensuring they can compete fairly against Pemex and another state energy behemoth, the Federal Electricity Commission (CFE). Pemex officials insist they are perfectly happy to see competitors come in: they will have enough on their plates reforming the bloated and inefficient company, and reversing its declining oil output.

The government is conducting a communications blitz to reassure investors that there is plenty of room for new entrants to prosper alongside the two state giants, given the huge amount of untapped reserves the country enjoys, the dire need for new infrastructure and the strong demand for cheaper gas and electricity. The various regulatory bodies that oversee the energy business have been given new mandates to prevent market dominance, notes Francisco Salazar, the head of one of them, the Energy Regulatory Commission. And the national antitrust agency has been given the power to intervene in energy markets.

However, Mexican business leaders wonder how easy it will be for the two state giants to shake off their monopolistic mindset. "The risk is that you think you have a level playing field and you find yourself against two Samsons," says Jaime Williams of the Business Co-ordinating Council, a lobby group.

Officials are also trying to dispel three further clouds of doubt that have been cast over the energy reforms recently. The first is the falling oil price. Pemex officials argue that this may even prove an advantage for Mexico, since its new oil will be relatively cheap to extract. Many of the new exploration blocks will have total costs of perhaps $40-45 dollars a barrel, they say, comfortably below the $77 a barrel at which Texan crude was trading this week. Global firms may thus lose interest in more costly projects in other parts of the world, and turn their attention to Mexico. Even so, if crude prices keep falling, some of Mexico's costlier deepwater and shale-gas prospects may begin to look unattractive.

The second area of concern is violence and lawlessness. These have come back into the spotlight following the murders in September of 43 students in south-western Mexico (see article (http://www.economist.com/news/americas/21632565-questions-about-financing-president-pe-house-add-his-woes-bad-worse)). Jesús Reyes Heroles, a former head of Pemex, notes that global oil companies are used to coping with such risks, though there may now be more attention on potential security threats in some oil-rich states, such as Tamaulipas and Veracruz. And, of course, many other new oilfields will be out at sea.

A third is transparency. Mr Peña has done himself no favours on this score: it emerged this week that he is living in a home owned by a businessman who has bid for big government contracts. The energy-bidding process will be overseen by a variety of ministries and regulators, which should help promote openness—though it may also promote bureaucracy.

Even if Mexico's energy revolution is more of a slow-burner than the government hopes, it has the potential to create large numbers of jobs—with luck, at least some of them in the country's strife-torn south. As its new pipelines eventually reach across not just the northern border but the southern one with Guatemala, they will bring cheap energy to Central America too. For all Mr Peña's current political problems, the risk of his energy reforms being undone looks slim, and the prospects for businesses across the country, and perhaps the whole region, are set to brighten.

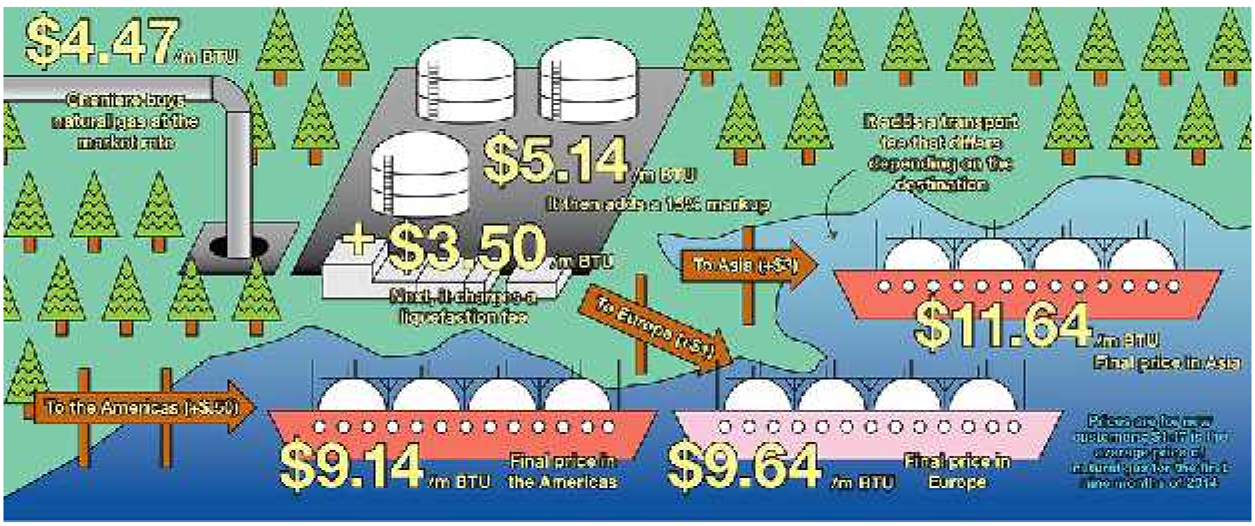
From the print edition: Business

Bloomberg Business

Energy

U.S. Natural Gas Exports Will Fire Up in 2015

By Zain ShaukNovember 06, 2014



On an otherwise barren strip of the Louisiana coast, a crew of more than 4,000 workers has spent the past two years building what will be the largest supercooling facility for natural gas in the U.S. When it's finished late next year, Cheniere Energy's (LNG) Sabine Pass liquefaction terminal will begin chilling natural gas to -260F so it can be loaded onto tankers and sold to customers in Europe and Asia. It will be the first facility to export natural gas from the contiguous U.S.

The first phase of the Sabine Pass project will cost more than $12 billion and seemed unlikely after Cheniere bet the wrong way on the U.S. natural gas market. In 2008 it spent $2 billion to build an import terminal that quickly became useless when abundant natural gas in the U.S. ended demand for imports, cutting the price from $13 per million BTUs to less than $3 in the U.S.

For the next two years, Cheniere's stock price hovered just above $1 a share as the Houston-based company flirted with bankruptcy. In 2010, Chairman and Chief Executive Officer Charif

Souki bet on the shale boom and proposed the export terminal. Despite the risks, he managed to line up billions in financing; that's given Cheniere a two-year head start on the half-dozen other LNG export terminals planned along the Gulf Coast. In 2013, Souki was the highest-paid CEO of a U.S. public company ($142 million), and Cheniere is now poised to become one of the most important exporters in the global LNG market. "The impact we're having on the rest of the world sometimes surprises us," says Souki. "We're going to represent 25 percent of the gas sold to Spain. We're going to feed enough gas to England to heat 1.8 million homes."

Cheniere says it will be the largest buyer of U.S. natural gas by 2020. Its liquefaction plant in Louisiana and another planned for Texas will allow it to ship about 6 percent of all the gas produced in the U.S. It's locked buyers into 20-year contracts based on the cost of natural gas within the U.S., which averaged $4.47 per million BTUs for the first nine months of 2014. For a new customer in Asia, a delivery based on September prices would cost about $11.64, after fees. A customer in Europe would pay about $9.64. "This is the first time that there will be LNG on the market that is truly price-sensitive and totally open to the destination that needs it most," says Souki. "You won't have a few producers able to decide arbitrarily what they want to charge."

Mexican Economy Expanded Modestly in 2014

Data are setback for President Enrique Peña Nieto’s government, which initially had expected stronger growth

The growth data for 2014 were a setback for Mexican President Enrique Pena Nieto, who has undertaken reforms to open up key sectors of the economy and had ambitious targets for growth. *PHOTO: EUROPEAN PRESSPHOTO AGENCY*

By
Juan Montes
Updated Feb. 20, 2015 12:39 p.m. ET

MEXICO CITY—Mexico's economy expanded at a modest pace in 2014, as healthy growth in manufactured exports was offset by mixed activity in the construction sector, weak domestic consumption and ailing oil production.

Gross domestic product grew 2.1% last year, as widely expected, the national statistics agency reported on Friday. That rate compared with 1.4% expansion in 2013.

The data are a setback for President Enrique Peña Nieto's government, which initially had expected 3.9% growth for 2014. The average annual growth in the first two years of Mr. Peña Nieto's administration has been 1.8%, far from the 5% targeted for by the end of the president's term in 2018.

Mr. Peña Nieto's ambitious economic reforms, such as opening up the oil industry, seem not to be impacting growth yet, analysts say. "The economy isn't really moving at a good pace," said Héctor Villarreal, the head of Mexico's Center for Economic and Budget Research, a think tank. "It's clearly insufficient if we want to significantly reduce poverty and move Mexico toward a middle-class country."

During the fourth quarter, Mexico's economy accelerated its growth slightly, supported by the services sector, although data came in below expectations. GDP advanced at an annualized rate of 2.7% from the third quarter. In December alone, the economy shrank 0.3%.

The growth outlook for 2015 has also deteriorated in recent weeks, with many economists lowering estimates after the government announced spending cuts that reflected lower oil prices.

RELATED READING

- How's the Mexican Economy Growing? You'll Have Three Answers (Feb. 19, 2015)
- Central Bank Cuts Mexican Growth Forecasts (Feb. 18, 2015)
- Economists Lower Forecasts for Mexican Growth and Inflation (Feb. 3, 2015)
- Mexico to Cut Planned Spending (Jan. 30, 2015)

Record government spending of 4.5 trillion pesos (around $300 billion) last year, financed by more debt and higher taxes, was the main bet of Finance Minister Luis Videgaray to boost growth. But it didn't deliver the expected results, some experts said.

Despite a 19% increase in infrastructure spending, construction related to civil works contracted 2.7% during 2014, and total investment in nonresidential construction fell around 1.8%. By contrast, private construction strongly picked up during the fourth quarter.

"Mexico's government spends badly," said Leo Zuckerman, a political analyst and columnist. "Public spending is very inefficient in Mexico. Most of the money goes to current expenditure and subsidies, which don't create real wealth." Last year, Mexico spent 60% of the budget on wages, subsidies and other current expenditures, while only 18% was channeled to investments.

Analysts also said a big chunk of investment spending is transferred and handled by state and local governments, where corruption and waste of resources are higher. "I think many governors delayed the execution of some spending last year, waiting until midterm elections approach," said Jonathan Heath, an independent economist. Midterm elections are in June.

The battered southern state of Guerrero, at the epicenter of a major security crisis after the kidnapping and likely murder of 43 college students, received around 76 billion pesos ($5.1 billion) in 2014 from the federal government, but about 75% of that was to pay public servants' wages and other current expenditures, according to data from the Finance Ministry.

Falling oil production also hit Mexico's growth last year. Extraction of oil and gas fell 2.4%, according to the statistics agency, as state-oil firm Petróleos Mexicanos produced on average 100,000 barrels of crude oil less a day in 2014 than in the previous year.

Domestic spending remained weak throughout the year, as across-the board tax increases that came into effect at the beginning of 2014 affected household incomes. The services sector, the best gauge of private consumption, grew 2.2%.

The robust growth in the manufacturing sector, boosted by a steady recovery in the U.S. economy, appeared to be one of the few bright spots last year. Fueled by the thriving auto and so-called maquiladora export-manufacturing industries, manufacturing activity expanded 3.7%.

Growth prospects for 2015 had seemed favorable at the beginning of the year, as the U.S. economy was gaining traction and Mexico sends 80% of its exports north of the border. And the government had expected that legal overhauls to open up the energy and telecom sectors to more competition would start to bear fruit on the economic front.

But tumbling world oil prices forced the government to announce in late January a $8.3 billion spending cut, leading some economists and the central bank to cut their growth estimates. Mexico finances a third of the federal budget through oil.

On Wednesday, the central bank slashed its growth forecast for this year to between 2.5% and 3.5% from the previous 3%-4% estimate. The bank alerted that a second round of cuts could be necessary if oil prices fall further.

The government modified its forecast for 2015 to growth between 3.2% and 4.2% from the initially budgeted 3.7%.

Mexico’s Energy Overhaul Draws Geological-Data Firms

Hunt for oil is on in deep-water areas of the Gulf of Mexico where little exploration has been done

By
Laurence Iliff
April 17, 2015 6:35 p.m. ET

MEXICO CITY—The opening of Mexico’s energy sector to private and foreign companies is drawing dozens of geological-data firms that plan to crisscross the Gulf of Mexico and onshore areas in search petroleum riches that went undiscovered during the eight-decade monopoly of Petróleos Mexicanos.

Mexico’s oil regulator, the National Hydrocarbons Commission, approved four Norwegian companies this week to focus on the oil-rich Gulf of Mexico, including deep-water areas where state-owned Pemex, Mexico’s lone oil producer, has done little exploration and has no production.

Geological-data companies TGS, Petroleum Geo-Services ASA, Dolphin Geophysical and Spectrum ASA will have rights for 12 years to sell information gathered in seven Gulf areas, but copies of their data will be given to the hydrocarbons commission for private review.

The seismic surveys are expected to give a more complete picture of areas that haven’t yet been studied or were surveyed many years ago with less sophisticated technology.

“This is excellent news because it will multiply and potentiate the capacity for exploration,” hydrocarbons Commissioner Edgar Rangel said on Thursday.

The four permits for data-gathering are the first batch in the wake of the energy overhaul last year that opened Mexico’s oil industry to private firms in the hope of reversing a decadelong slide in production.

Mexico is in the early stages of its first round of auctions for oil blocks under the energy overhaul, with the first contracts for shallow-water exploration to be awarded in July.

Pemex has provided its geological data to the hydrocarbons commission, which has set up data rooms for oil and gas companies to analyze the studies before making bids.

In recent decades, Pemex has focused much of its energy on big, shallow-water deposits concentrated in the southern Gulf, several of which are now at peak production or in decline. The end of an era of “easy oil” was a key selling point of the energy overhaul, which leftist parties opposed as a sellout to foreigners.

The four Norwegian firms will conduct two-dimensional geological studies in areas of the Gulf covering about one million square kilometers, according to the commission. Some of the areas overlap, meaning more than one company will have the data.

The commission says there are 22 more firms seeking permission to carry out geological mapping—including more sophisticated three-dimensional studies—that will provide a wealth of data and possibly lead to significant new oil and gas discoveries.