COMPARATIVE ANALYSIS OF FUTURE GAS AND ELECTRIC INFRASTRUCTURE OPTIONS IN THE CALIFORNIA/MEXICO BORDER REGION

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Abstract

The report is based on information collected in 2007 and explores the potential effects that planned expansion of commercial liquefied natural gas (LNG) terminal and storage facilities at Costa Azul in Baja California (Baja), Mexico might have upon future energy infrastructure development in the California-Mexico border region. Expansion of the LNG terminal to 2.5 billion cubic feet per day (Bcfd), as approved by regulators in Mexico, could be completed within several years. This expanded LNG capacity will far exceed natural gas demand in Baja, and the resulting surplus could be used to fuel 8,500 megawattts (MW) or more of new gas-fired generation for use by the California market. An evaluation of the following two conceptual trajectories for future growth of energy infrastructure in the California-Mexico border region is performed: large-scale development of natural gas-fired electric generation in Baja with expansion of the electric transmission infrastructure across the border to export power to the U.S. market and development of new gas-fired generating facilities near load centers in Southern California fueled by gas exports from Baja. Hybrid combinations of these two scenarios are also considered. The options are compared on the basis of their capital costs and feasibility, as well as related reliability/security, environmental, regulatory, and policy considerations, and other factors.

Keywords: Power plants, gas-fired generation, electric transmission, natural gas transmission, pipelines, demand forecasts, supply forecasts, LNG terminals, California/Mexico border region, Baja, Southern California, electric infrastructure expansion, natural gas infrastructure expansion, pipeline precedent agreements, submarine cables, HVDC

Executive Summary

The current construction of large-scale commercial liquefied natural gas (LNG) terminal and storage facilities on the coast of Baja, Mexico, creates an opportunity to shape the direction of gas and electric infrastructure growth in the California-Mexico border region. The California Energy Commission (Energy Commission) clearly recognized this in making its 2005 Integrated Energy Policy Report recommendation that California should work to establish cross-border bi-national energy planning and development policies in the border region. This recommendation takes on increased importance in the current LNG infrastructure expansion environment.

This report continues an analysis of energy infrastructure in the border region, as commissioned by the Energy Commission in 2007. KEMA Incorporated has been serving as the lead consultant for this work. An initial phase examined the potential for development of wind renewable energy resources in northern Baja and the transmission for export of such resources to California.[1] A second phase addressed existing energy (gas and electric) infrastructure, currently proposed expansion plans, and growth projections in the California/Mexico border region.[2] That phase showed that a large surplus of natural gas will develop in Baja over the next few years as a result of LNG expansion but did not analyze its potential impact on future gas and electric infrastructure expansion scenarios. The third phase of analysis, addressed in this report, identifies and compares possible long-term options/scenarios for energy infrastructure development in Baja and Southern California that arise from the expansion of LNG capacity in Baja. Given the recent approval by Mexico for expansion of the Costa Azul LNG project to 2.5 Bcfd,[3] the analysis for such regional infrastructure has increased in importance.

Given the natural gas surplus in Baja created by this LNG expansion, the Energy Commission seeks to explore the following two potential trajectories for future growth of energy infrastructure in the border region: large-scale development of natural gas-fired electric generation (EG) in Baja with expansion of the electric transmission infrastructure across the border to export power to the U.S. market and development of new gas-fired generating facilities near load centers in Southern California fueled by gas exports from Baja. Both scenarios are developed in this report and assume that all components of the projected Baja natural gas demand, including internal Comisión Federal de Electricidad (CFE)-owned gas-fired generation expansion, will be served from Costa Azul throughput before any remaining LNG is used for export (for example, for either gas or electricity export).

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[1] Korinek, David; DeMetro, James; Puga, Nicolas. *Challenges and Opportunities to Deliver Renewable Energy From Baja California Norte to California*: California Energy Commission. Publication number: CEC-600-2008-004, June 2008.

[2] Korinek, David; DeMetro, James; Puga, Nicolas. *Current Status, Plans and Constraints Related to Expansion of Natural Gas-Fired Power Plants, Pipelines and Bulk Electric Transmission in the California/Mexico Border Region*, California Energy Commission Publication number: CEC-600-2008-008, August 2008.

[3] In October 2007, Mexico's energy regulator, the Comisión Reguladora de Energía (CRE), approved Sempra LNG's proposed expansion of the Costa Azul LNG project to peak send-out capacity of 2.6 billion cubic feet per day (Bcfd) or 2.5 Bcfd nominal send-out capacity, an increase of 1.5 Bcfd above its previously approved capacity.

It is appropriate to view both the Baja generation scenario and the California generation scenario as "bookends" to a range of gas and electric infrastructure options. The same quantity of surplus gas used in these two scenarios could also support a mix of generation expansion in Baja and Southern California, rather than exclusively one side of the border. The analysis of these bookend scenarios should also help to inform the evaluation of such potential hybrids. Another scenario not explicitly considered is simply assuming the LNG surplus from Baja will flow into the U.S. market and displace other natural gas sources to the region. This could be viewed as the "default scenario" (for example, what may evolve in the absence of any proactive effort by policy makers or regulators).

This report compares the feasibility and scope of the Baja generation scenario versus the California generation scenario. Some of the key factors considered in this comparative analysis include:

- The capital cost of new gas and electric transmission expansion.
- The proximity of new generation to Southern California load centers.
- The delivery capability of the conceptual electric transmission infrastructure for both fossil-fueled generation and renewables.
- Burden of investment to ratepayers, private investors, and/or government.
- Reliability effects on customers of the resulting energy delivery system.
- Related environmental impacts.
- Vulnerability to transport congestion.
- Vulnerability to fires, earthquakes, and other natural disruptions.
- Flexibility to upgrade existing and future lines and corridors.
- Changes needed to laws and policies to allow the new infrastructure or upgrades.
- Time frame to construct the infrastructure.
- Security of each infrastructure scenario in terms of:
    - Potential expropriation.
    - Potential terrorism.

The study concludes that generation expansion supplied by the surplus LNG is feasible on either side of the border, both resulting in the export of energy (gas or electricity) from Mexico to California. The full 2.5 Bcfd (nominal) expansion at Costa Azul could support more than 8,500 MW of new electric generation to the California market. However, the report concludes that the level of Costa Azul gas throughput needed to support such generation development is unlikely to occur before 2015. Electric transmission infrastructure investment on the order of $3.7 billion –$6.6 billion (in 2012 dollars) would be required to deliver the full 8,500 MW of electric power to Southern California load centers. The low end of this range assumes all of the new gas-fired generation would be added in California. The high end of the range assumes all the generation would be added in Baja, Mexico. The cost of "hybrid" expansion plans, which build a portion of such generation in both California and Mexico, would fall somewhere within this range. Gas transmission infrastructure costs in both scenarios are expected to be negligible in comparison to the electric infrastructure costs.

This evaluation is intended to assist the Energy Commission in developing a strategy regarding energy exports from Baja as part of an overall energy policy for the border region. It is hoped that the results of this investigation will serve to inform public policy makers, regulators, utilities, energy developers, and other stakeholders about the feasibility, costs, and constraints faced by such infrastructure expansion options. This in turn can guide related regulatory strategy and help shape policy making for the border region in the most mutually beneficial manner for both California and Mexico.

CHAPTER 1:
Impacts of Costa Azul LNG Terminal on Border Region Natural Gas Supply and Infrastructure

Construction of commercial LNG terminal and storage facilities is currently occurring in various parts of North America, including Baja, the mainland of Mexico, and the Gulf States region in the U.S. By 2020 the Energy Commission projects worldwide volume of LNG trades will reach 41 to 62 Bcfd, with North American trade volumes on the order of 12.3 Bcfd.[4] Sempra Energy's Costa Azul LNG terminal on the coast of Baja, with a nominal capacity of 2.5 Bcfd, will provide more than 20 percent of the total North American volume. Relative to natural gas demand in California, the capacity of Costa Azul roughly equals the current average daily requirements of the entire Southern California Gas Company system.[5] This is clearly a significant infrastructure development event for the California/Mexico border region.

Mexico currently projects that its national growth in natural gas demand will outpace planned supply capacity by 2.2 Bcfd by the end of 2015.[6] Most of the projected demand is in Mexico's mainland, not in the Baja region. Due to the great distances involved, there are no existing or planned gas pipelines between Baja and the mainland natural gas system. On the other hand, Baja shares a common border with the State of California and is close to major Southern California load centers. For example, San Diego is only about 50 miles north of Costa Azul, and Los Angeles is roughly 100 miles further north. Thus, Costa Azul is well situated to serve the energy needs of the entire California/Mexico border region. In fact, as a result of the Costa Azul project, Mexican energy policymakers anticipate a significant increase in energy exports from Baja to the U.S.[7]

Estimate of Natural Gas Surplus in Baja California

As shown in Table 1, there is a projected natural gas surplus of roughly 0.3-0.4 Bcfd under Peak Demand conditions in Baja upon completion of Costa Azul LNG Phase 1, and 1.8 Bcfd after completion of the Costa Azul Phase 2 expansion. Even without the Phase 2 expansion, the LNG capacity/supply associated with Phase 1 exceeds the average daily demand in Baja by nearly 0.7 Bcfd through 2014.

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[4] *The Outlook for Global Trade in Liquefied Natural Gas Projections to the Year 2020*, CEC-200-2007-017, August 2007, pages 2 & 45.

[5] At a meeting with Roger Schwecke and Herbert Emmrich, Southern California Gas Company, May 29, 2007, the company quoted average daily demand of 2.5 Bcfd and all-time peak demand of 5.3 Bcfd.

[6] Presentation by Dr. Aldo Flores Quiroga, Director General for International Affairs, Ministry of Energy (SENER), at Border Energy Forum XIV, San Diego, CA., October 18, 2007.

[7] Personal interview with Dr. Aldo Flores Quiroga, SENER, October 18, 2007.

Table 1: Baja California Natural Gas Demand (MMcfd)
(Excluding Pipeline System Losses)

	2008	2009	2010	2011	2012	2013	2014	2015
Costa Azul Nominal Output[8]	500	1,000	1,000	1,000	1,000	1,000	1,000	2,500
Baja EG Peak Demand[9]	445	540	560	605	605	655	655	700
Baja Non-EG Peak Demand[10]	26	36	37	41	42	45	47	51
Baja Peak Demand (Total)	471	576	597	646	647	700	702	751
Surplus Capacity *(On Peak)*	***29***	***424***	***403***	***354***	***353***	***300***	***298***	***1,800***
Ave Daily EG Demand[11]	270	282	289	297	301	306	304	303
Ave Daily Non-EG Demand[12]	16	19	19	20	20	21	22	22
Ave Daily Demand (Total)	286	301	308	317	321	327	326	325
Surplus Capacity *(Average)*	***214***	***699***	***692***	***683***	***679***	***673***	***674***	***2,175***

Source: KEMA

The estimated surplus is based solely on Costa Azul terminal capacity and does not consider other factors such as the status of offshore LNG supply contracts or delays in global development of LNG sources that might affect the throughput of Costa Azul. KEMA's experience is that such issues could delay full availability of the projected surplus from Costa Azul Phase 2 until the 2015 timeframe. As discussed later in this report, utilization of the projected Baja natural gas surplus to fuel new electric power plants for supply of California's electricity needs would require significant electric infrastructure additions that would also take until 2015 or longer to complete. In the meantime, any surplus gas available from Costa Azul could be delivered to the U.S. market via pipeline facilities, displacing other sources of natural gas to the Southern California region.

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[8] Assumes full Phase I supply available in early 2009 and Phase II supply and capacity available 2015.

[9] Estimated peak natural gas demand including reserve based on *Prospectiva del Mercado de Gas Natural 2006 – 2015*, SENER, Cuadro A.3.1-Demanda nacional de gas natural por estado, 1995-2015, Anexo 3.

[10] Based on multiplying the average daily non-EG demand from *Prospectiva del Mercado de Gas Natural 2006 - 2015*, SENER, Cuadro A.3.1-Demanda nacional de gas natural por estado, 1995-2015, Anexo 3" by the ratio of Peak to Average EG demand.

[11] *Prospectiva del Mercado de Gas Natural 2006 - 2015*, SENER, Cuadro A.3.1-Demanda nacional de gas natural por estado, 1995-2015, Anexo 3.

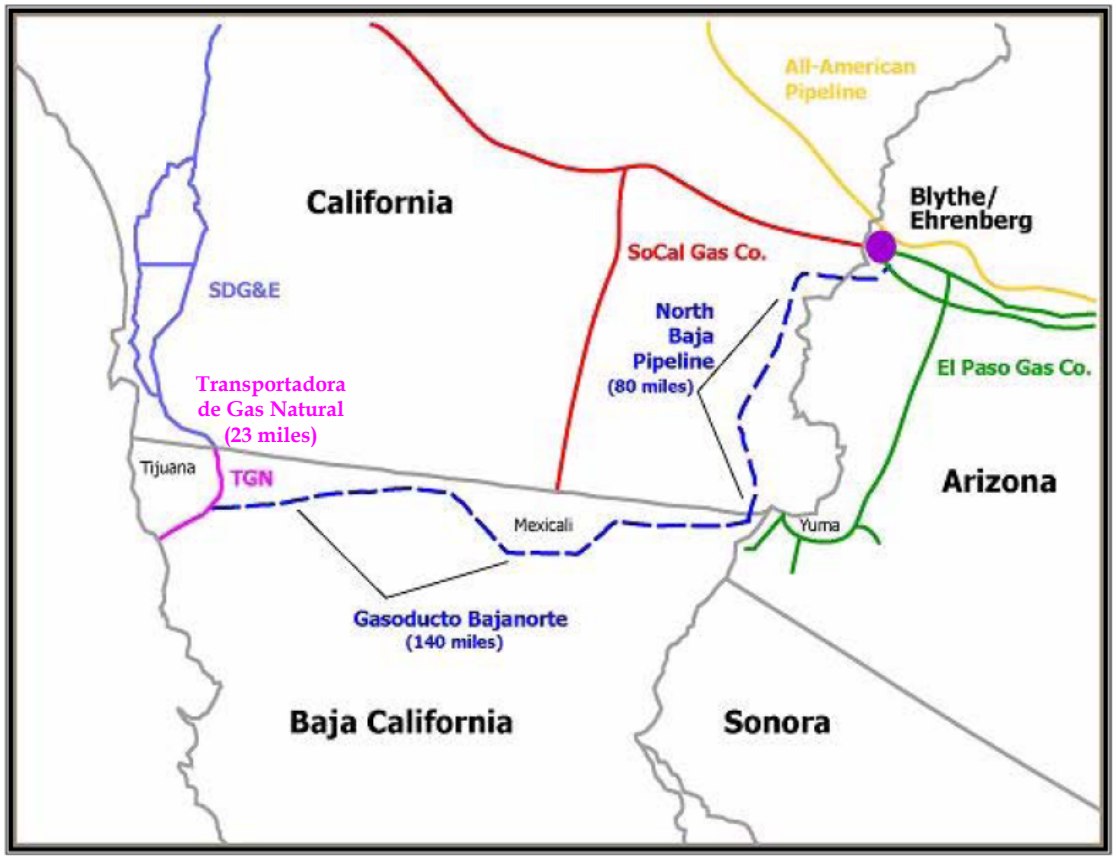
[12] Ibid.

Expansion of Natural Gas Pipelines in the Border Region

The eventual configuration and capability of the North Baja Pipeline (NBP) and the Baja natural gas pipeline system are critical factors in evaluating strategies for development of new power plants to serve electric load centers in Southern California. The capability of the pipeline system to provide an alternate path to deliver U.S.-sourced supplies in the event of disruption or diversion of LNG supplies would also be a critical consideration in developing the details of an overall approach. Furthermore, the ability to deliver either U.S.—or the LNG-sourced gas supplies northbound through Otay Mesa will provide significant benefits to the Southern California Gas Company (SoCalGas) transmission system as discussed on page 7 of this report.

Baja currently receives all of its natural gas supplies from U.S. sources delivered primarily via a pipeline system that includes the North Baja Pipeline (NBP), Gasoducto Baja Norte (GBN), and Transportadora de Gas Natural (TGN) as shown in Figure 1. Gas supplies enter NBP at Blythe/Erhenberg and flow south into Mexico, then west on GBN and TGN. NBP and GBN are certificated to transport approximately 500 million cubic feet per day (MMcfd) and TGN is certificated to transport 300 MMcfd. This pipeline system is a summer peaking, and existing Baja gas demand consists almost entirely of gas-fired power plants located in Mexicali and Rosarito.

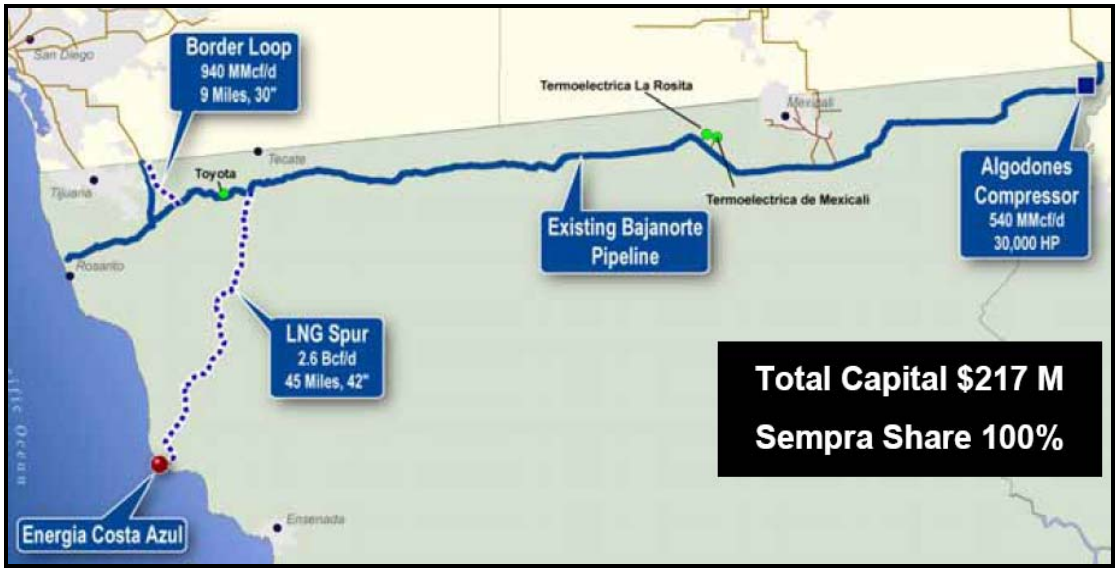
Figure 1: Natural Gas Pipelines in Border Region



Source: Sempra

Along with the initial phase of Costa Azul LNG facility construction, Sempra is constructing a pipeline spur from Costa Azul and sponsoring other upgrades of the GBN/TGN/NBP pipeline system as shown in Figure 2.

Figure 2: Gasoducto Baja Norte Expansion



Source: Sempra

Pipeline owners have also published plans for the expansion of Baja's natural gas pipelines. In total, the following pipeline projects are being done in conjunction with construction of the initial phase of the Costa Azul LNG terminal project:

Costa Azul Spur

- Add 45-mile, 42-inch LNG spur from Costa Azul to GBN with a capacity of 2.6 Bcfd

Gasoducto Baja Norte (GBN)

- Modify existing system to allow for the bi-directional flow of gas
- Add 9-mile, 30-inch border loop (part of TGN) from GBN to Otay Mesa (SDG&E) with a capacity of 940 MMcfd
- Additional compression at Algodones to deliver 550 MMcfd northbound to NBP

North Baja Pipeline (NBP)

- Modify existing system to allow for the bi-directional flow of gas with capacity to deliver up to 614,000 Dekatherms per day (Dthd) on a firm basis from Mexico to markets in California and Arizona
- Add 2.1-mile, 36-inch pipeline and new meter station to connect directly with SoCalGas at Blythe
- Add 46-mile, 16-inch lateral pipeline from its mainline to the Imperial Irrigation District's (IID) El Centro Generating with capacity to transport up to 110,000 Dthd or approximately 100 MMcfd.

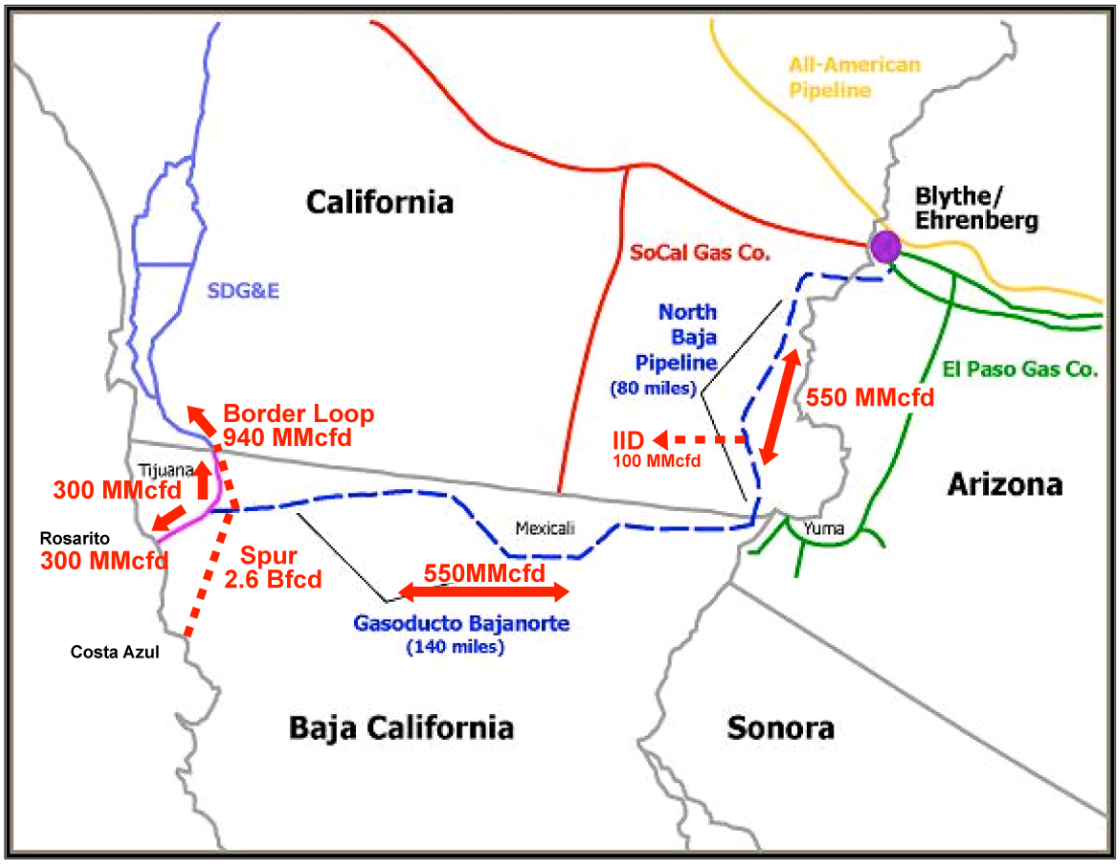
These additions and upgrades will result in the pipeline delivery capacities shown in Table 2 and Figure 3.

Table 2: Theoretical Pipeline Capacities After Costa Azul (Phase 1)

Pipeline Segment & Flow Direction	Pipeline Capacity
North Baja Pipeline (NBP)	
North	575 MMcfd
South	195 MMcfd
Gasoducto Baja Norte (GBN)	
East of LNG spur to NBP	550 MMcfd
West of LNG spur to TGN	500 MMcfd
Transportadora de Gas Natural (TGN)	
Border Loop	400 MMcfd firm *(940 MMcfd total)*
GBN to Rosarito	300 MMcfd
GBN to Tijuana	300 MMcfd

Source: KEMA

Figure 3: Physical Pipeline Capacities after Costa Azul (Phase 1)



Source: Sempra (Edited)

Pipeline Spur From Costa Azul to GBN

The 45-mile spur being built in 2008 as part of Phase 1 of Costa Azul will be capable of a peak capacity 2.6 Bcfd, in anticipation of the future Phase 2 of development of the LNG terminal capacity at Costa Azul. There has also been discussion about adding a spur from this pipeline to Ensenada at some time in the future to serve forecasted CFE generation expansion in that area.

GBN Pipeline

Upon completion of the upgrades, GBN will be bi-directional and will have the capacity to transport approximately 550 MMcfd of natural gas from the LNG spur to NBP. There is also capacity to transport approximately 500 MMcfd from the LNG spur west to TGN; however, that path is limited by the 300 MMcfd of transport capacity of the existing TGN pipeline. Also, NBP will be delivering (primarily by displacement) approximately 200 MMcfd to GBN of U.S.-sourced gas supplies for existing customers.

NBP

On October 2, 2007, the U.S. Federal Energy Regulatory Commission (FERC) issued a certificate to NBP for all three phases of its expansion application. NBP expansion phases I and IA are intended to coincide with Phase 1 of the Costa Azul project.

Phase I will enable bi-directional flow on the NBP system as well as enable it to receive and transport up to 550 MMcfd from Mexico to markets in California and Arizona. In addition, 200 MMcfd of U.S. supply will continue to be delivered to customers in Mexico.

A new pipeline stub is also planned from NBP to IID in the vicinity of its El Centro Generation Plant, as shown in Figure 3. This extension will have firm capacity of 100 MMcfd, which is sufficient to supply about 500 MW of new generation capacity in IID.[13]

Transportadora de Gas Natural

Sempra is constructing the Border Loop, which is a new 940 MMcfd-capacity pipeline from GBN to Otay Mesa. Sempra is incurring the cost to upgrade San Diego Gas & Electric (SDG&E) pipeline facilities to be able to deliver 400 MMcfd of that capacity into SDG&E on a firm basis. The capacity of the 940 MMcfd Border Loop is in addition to the existing 300 MMcfd of TGN capacity. Use of this full 940 MMcfd would require completion of the capacity expansion plans at Costa Azul, as well as additional delivery capability related to upgrades of the GBN system.

It appears that TGN itself will continue to be certificated for 300 MMcfd, as there has been no filing to date for upgrade of the TGN system with Mexican regulators. Although GBN is a 500 MMcfd pipeline with an interconnection to TGN, firm contracts with customers upstream on GBN result in significantly less than 300 MMcfd of firm delivery capability from GBN to TGN. Therefore, the TGN system is not able to fully utilize its certificated capacity today without significant deliveries from the SDG&E system through Otay Mesa.

Impact of Pipeline Expansion on Delivery Capacity

The impact of the Costa Azul LNG facility and the associated pipeline expansions on delivery capacity in Baja is a function of various factors. Since the addition of Costa Azul means the entire NBP/GBN/TGN system can now be fed from both ends, the capability of the system to deliver volumes to Baja customers will be determined by the physical capabilities of the pipes (Figure 3) as well as the following factors:

- The level of firm LNG deliveries to Costa Azul
- The location of future power generation plants in Baja
- The level and location of contracted quantities of gas flowing north to the U.S.
- The level and location of the contracted quantities of gas flowing south to Mexico.

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[13] SoCalGas' Line 6902 is currently the only transmission line serving the Imperial Valley. SoCalGas is planning to expand the line's capacity to 150 MMcfd.

For the Phase I of the project, approximately 575 MMcfd (614,000 Dthd) is contracted to flow east and north on GBN and NBP and 195 MMcfd (208,000 Dthd) remains contracted to flow south and west on these pipelines. While this "gross" volume far exceeds the physical capability of the system (Phase I) to deliver volumes into Baja, the "net" level is within pipeline capability because part of the U.S.-sourced gas being scheduled to Baja will displace (be exchanged with) LNG-sourced gas being scheduled to the U.S. As a result, the full contracted bidirectional volumes can be delivered without the need for all of the gas to physically flow on NBP and GBN. In addition, construction of the planned CFE power plant in Ensenada, Mexico will help meet the projected power demand in Baja without utilizing any of the Phase I cross-Baja pipeline capacity since the plant will be served directly from Costa Azul via the new 45-mile radial spur.

The location of the interconnection of the 45-mile LNG spur and the GBN system also has significant benefits. Assuming sufficient volumes and pressures will result from Costa Azul, at least 500 MMcfd could theoretically flow east to Mexicali and into NBP and an additional 500 MMcfd could flow west on GBN towards Rosarito and Tijuana. Furthermore, although the new Border Loop does not add to the mainline capacity in Baja, it still adds substantial flexibility in that it will be capable of delivering up to 940 MMcfd to SDG&E through Otay Mesa (of which 400 MMcfd will be available on a firm basis).

Although current gas demand at Rosarito projected to be 150 MMcfd, the existing TGN system is capable of delivering an additional 150 MMcfd to the Rosarito area, which could support approximately 900 MW of additional combined-cycle generation (above and beyond CFE's current generation expansion forecast) without any additional pipeline facilities beyond those planned for Phase I of Costa Azul. In addition, remaining capacity on GBN and TGN could deliver up to 145 MMcfd flowing north to Tijuana which could fuel an additional 875 MW of combined-cycle generation in the Tijuana area.[14]

Existing contracted capacity to meet natural gas demand served by GBN in eastern Baja is 357 MMcfd. Total capacity on this section of GBN is approximately 550 MMcfd. Through the forecast period, 642 MW of new gas-fired electric generation is planned primarily in the Mexicali region. Based on expected heat rates, this new generation represents additional natural gas demand of approximately 125 MMcfd, which leaves 68 MMcfd of capacity—sufficient to fuel a new 400 MW combined-cycle power plant.

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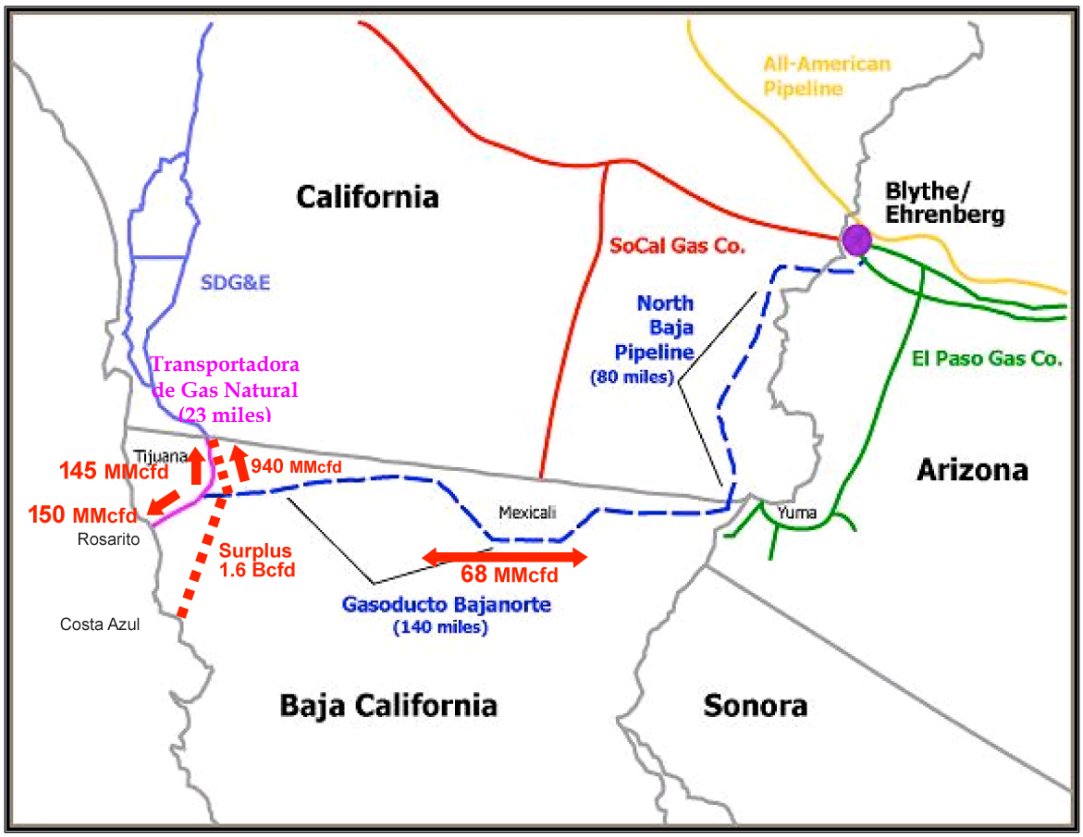
[14] Given the configuration of TGN and the location where deliveries from GBN are made, it is theoretically possible to flow an additional 300 MMcfd west to Rosarito and 300 MMcfd north to Tijuana with modest expansion of pipeline infrastructure in the Tijuana/Rosarito area with the completion of Costa Azul Phase 1. In KEMA's opinion such an increase in capacity could be accomplished by completing a 23-mile loop of the TGN pipeline at a cost of approximately $80 million to $90 million. It should be noted that TGN has made no filing in Mexico for such new facilities or to recertify its transport capacity.

A summary of the "surplus" pipeline capacities available in Phase 1 for all other uses (after meeting internal Baja demand projections) is shown in Figure 4.

Figure 4: Surplus Pipeline Capacities Within Baja (Phase 1) Based on Baja's 2015 Natural Gas Peak Demand Forecast



Source: Sempra (Edited)

Based on the surplus pipeline capacities, sufficient gas would be available to supply new generation (above and beyond CFE's requirements) in the approximate amounts and locations shown in Table 3. The generation shown in Table 3 represents potential development only, not actual plans. Furthermore, Table 3 reflects potential generation expansion based solely on surplus gas pipeline capacities and does not take into account any other factors that bear on plant siting (for example, land and cooling water availability, emission constraints, etc.).

Table 3: Potential Generation Capacity Additions (Phase 1)

Geographic Area	Surplus Pipeline Capacity (MMcfd)	Corresponding Amount of Gas-fired Generation (MW)
Tijuana	145	875
Rosarito	150	900
GBP corridor *(from LNG tap to Mexicali)*	68	400
Total	363	2,175

Source: KEMA

Due to the confidentiality of contract negotiations between Costa Azul, pipeline owners and pipeline customers in Mexico, it is unknown if any or how much of the surplus gas from Phase 1 will be used for new power plant development in Baja. For the current report, it is assumed that any generation developed in Baja for export in Phase 1 would either be interconnected with CFE at 230 kilovolt (kV) (and subsequently wheeled to the U.S. market) or would connect directly with SDG&E-owned substations along the California/Mexico border. Therefore, further analysis of electric transmission infrastructure requirements was not performed for Phase 1.

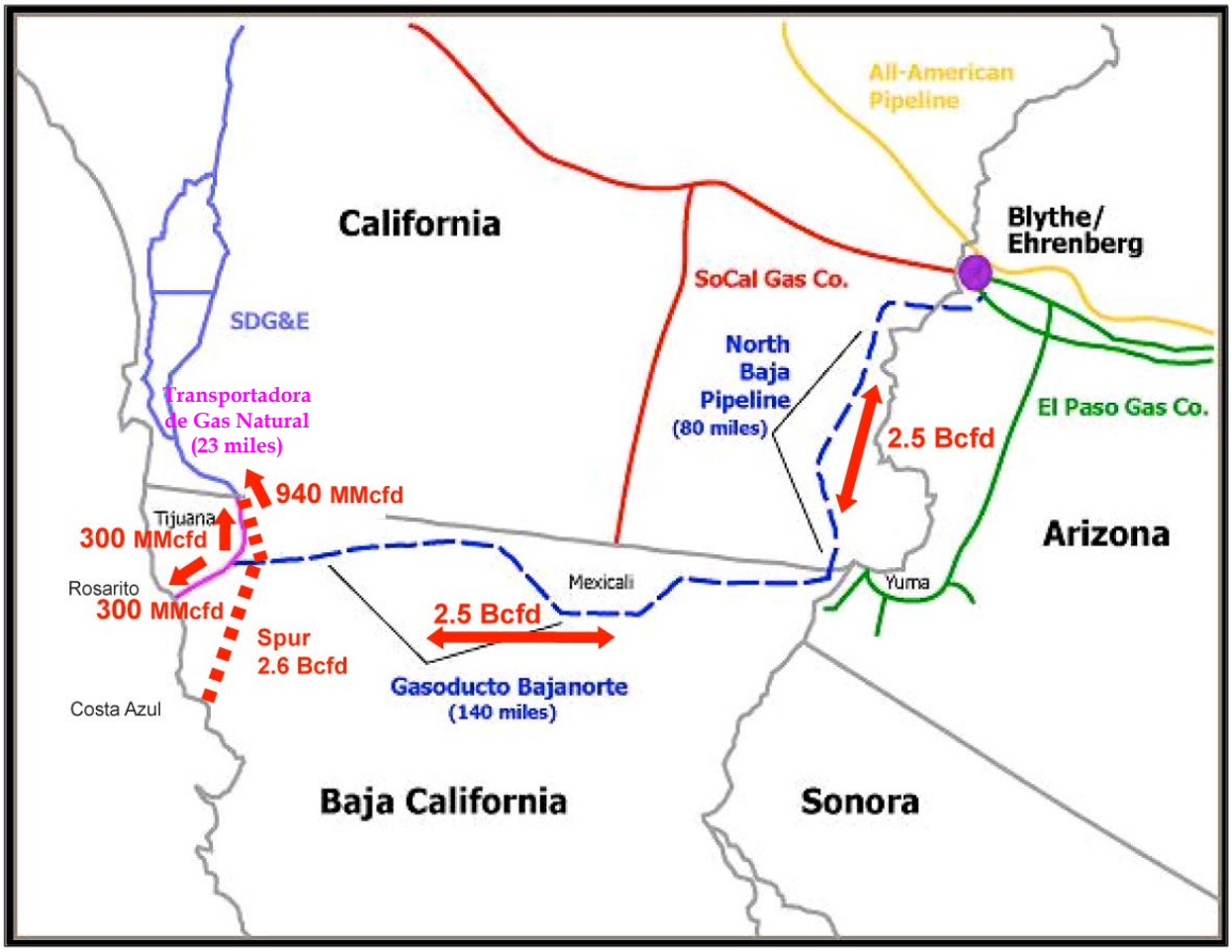
Impacts of Costa Azul Phase 2 on Border Region Pipeline System

The development of the Costa Azul LNG terminal and the associated pipeline upgrades for Phases 1 and 2 will create significant capacity to deliver gas supplies into the border region. In addition to the planned capacity of the LNG, both NBP and presumably GBN will be able to transport up to 2.5 Bcfd. How GBN will be reconfigured to deliver this amount is unknown at this time. Upgrades to GBN will be based on the location (receipt and delivery points) and volumes committed. Unlike in the U.S., there is no public disclosure of applications under the Mexican regulatory system until the application is approved. While it is highly likely that GBN will be able to deliver the full send-out capability of the Costa Azul terminal, it is not clear what level of capability it will have for delivery of U.S.-sourced gas received from NBP, although this report assumes that such deliveries could occur.

Phase 2 of Costa Azul will increase the nominal, firm send-out capacity from 1 Bcfd to 2.5 Bcfd. The Costa Azul LNG terminal and the NBP have received approvals to proceed with construction of Phase 2. The GBP has an application pending. There is no application for upgrade of the TGN Pipeline for Phase 2. The Border Loop is considered to be part of TGN and is part of the Phase I project. The expected pipeline capacities after the Phase 2 expansion are shown in Figure 5.

On May 15, 2006 Sempra LNG issued a press release announcing it had received bids totaling 2.9 Bcfd for Phase 2 of Costa Azul. This amount is almost twice the planned incremental send-out capacity of 1.5 Bcfd. To date, however, there has been no information regarding the status of negotiations or identification of customers and volumes for Phase 2. Sempra indicated in its press release that the ultimate size and scope of Phase 2 will depend upon the outcome of the negotiations of the commercial agreements. Since these negotiations are confidential, it is not known how closely they might align with either of the infrastructure scenarios contemplated in this report. In fact, some of the bids may align with the Baja Generation Scenario and other bids with the California Generation Scenario. Which of these negotiations are ultimately successful in this process will depend largely on commercial criteria beyond the scope of this report.

Figure 5: Mainline Capacities After Costa Azul (Phase 2)



Source: Sempra (Edited)

Appendix A lists the customers for Phase 2 that were identified by NBP in its FERC filing for pipeline expansion. However, the intended use of such delivery rights by the respective customers is unknown. A public list of bidders is not available from Costa Azul's Phase 2 expansion auction, but it can be assumed that many of the bidders shown in Appendix A also participated in the Sempra auction (that is, the two largest customers, Chevron USA and Coral Energy respectively account for about 1 Bcfd and 500 MMcfd of the expansion capacity). These volumes were originally anticipated to originate from Chevron's Mar Adentro LNG terminal, which has been cancelled by Chevron. NBP indicates, however, that these customers have not terminated their previous agreements. Presumably, since there was no update by NBP of its FERC application before it received its certificate, these agreements are still in effect. However, it is unknown whether these two customers also nominated these volumes during the Phase 2 Costa Azul capacity auction.

Since Phase 1 volumes of Costa Azul are more than sufficient to meet forecasted natural gas demand in Baja, the incremental volumes from Phase 2 could be exported to U.S. markets. These volumes could be delivered to El Paso and redelivered (via backhaul) to upstream markets or delivered to SoCalGas at Blythe and through the Border Loop at Otay Mesa for redelivery to markets in California. NBP has indicated that in the future it may also construct a lateral of approximately 80 MMcfd to supply directly into the Yuma, Arizona area.

Increase in Useable Pipeline Capacity South of Moreno

A significant development associated with the Costa Azul LNG terminal is the ability to inject gas into the SDG&E pipeline system from the south through Otay Mesa.[15] The Border Loop pipeline from GBP to Otay Mesa will have capacity to deliver up to 940 MMcfd to SDG&E at Otay Mesa. However, of this total, only about 400 MMcfd could be delivered on a firm basis, given the gas demand characteristics of the San Diego gas system. Based on KEMA's analysis, 400 MMcfd of firm delivery would release significant capacity along the Moreno-Rainbow corridor, which currently supplies the majority of SDG&E gas needs from the north. Reducing the delivery of gas through the Moreno-Rainbow corridor to SDG&E will enable the Moreno-Rainbow pipeline to operate at lower minimum pressures and allow more gas to be taken off the pipeline between Moreno and Rainbow. With 400 MMcfd of firm supply at Otay Mesa, 1 Bcfd of capacity will be available on the Moreno-Rainbow pipeline. After meeting existing demand this leaves approximately 600 MMcfd of useable capacity along the Moreno-Rainbow corridor, which could be used to serve about 3,200MW of new generating capacity along the corridor (assuming an average heat rate of 7,500 BTU/kwH). Such deliveries would depend on the ability of SoCalGas and/or SDG&E to contract for 400 MMcfd of firm deliveries to Otay Mesa from the south, and it is unknown if these companies have explored this option. However, for this purpose, the source of supply for firm gas deliveries at Otay Mesa could be either Baja LNG or U.S. gas suppliers (for example, from Blythe).

[15] Generic references to Otay Mesa in this report refer to the southernmost edge of SDG&E's service area, and do not refer to the Otay Mesa Generating Project (OMGP), which is presently under construction about 1.5 miles north of the international border. Licensing documents filed with the Energy Commission indicate that the OMGP plant will be supplied via a new 2 mile stub from SDG&E's high pressure gas pipeline system. The plant developer (Calpine) also has a presidential permit that would allow it to connect to the proposed Border Loop pipeline, but has no plans to do so at this time.

CHAPTER 2:
Analysis of the Baja Generation Expansion Scenario

Given the natural gas surplus in Baja created by the LNG supply and infrastructure expansion associated with Costa Azul, the remainder of this report seeks to explore the following two potential trajectories for future growth of electric infrastructure in the border region: (a) large-scale development of natural gas-fired electric generation in Baja with expansion of the electric transmission infrastructure across the border in order to export power to the U.S. market, and (b) development of new gas-fired generating facilities near load centers in Southern California fueled by gas exports from Baja. The first scenario, Baja generation expansion, is addressed in Chapter 2. The second scenario, new gas-fired generation in Southern California, is addressed in Chapter 3. Both scenarios assume that all components of the projected Baja natural gas demand, including internal Comisión Federal de Electricidad (CFE)-owned gas-fired generation expansion, will be served from Costa Azul throughput before any remaining LNG is used for export purposes (for example, for either gas or electricity export).

If the total 1.5 Bcfd increment of surplus natural gas created by Costa Azul Phase 2 is used to supply new electric generation projects, it could fuel an additional 8,500 MW of generation in Baja.[16] As a point of reference, this is comparable to the amount of generation currently connected to the Palo Verde Hub in Arizona. As previously noted, it is possible that more than 2,000 MW of new generation (above and beyond CFE's generation requirements) could also be supported by surplus gas capacity from Costa Azul Phase 1. For the purpose of this study, it is assumed that any portion of this potential generating capacity developed for export in Phase 1 would either interconnect with the existing CFE system and wheel to California or would use lower voltage (for example, 230 kV) generator tie-lines connecting directly into the California Independent System Operator-controlled grid.

Plant siting and electric transmission requirements for 8,500 MW of new gas-fired generation in Phase 2 would present significant challenges, including:

- The ability to mitigate the environmental impacts.
- The significant volume(s) of cooling water required.
- The cost and environmental impacts of extensive electric transmission infrastructure needed to deliver the generation to remote load centers.

Power plant cooling water requirements, in particular, pose a major siting issue in Baja. As discussed in Appendix E, limitations on sources of cooling water in Baja favor siting of new gas-fired power plants along Baja's coastline, particularly along the Pacific coast.[17] The most practical location to site such generation would be in the proximity of Costa Azul, based on the access to both fuel and cooling water.

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[16] Assumes an average heat rate of approximately 7,500 BTU/kwh.

[17] The relatively cool ambient water temperatures along the Pacific Coast make it much more suitable for power plant development than along the eastern coast of Baja where high ambient water temperatures are common, especially during summer months.

The balance of this chapter develops and compares two competing approaches for siting of 8,500 MW of new generation in Phase 2 of Costa Azul. One concept looks at siting all of this generation in Baja. The other concept looks at siting all of the generation north of the Mexico border in California, as close as practical to major load centers. Some hybrid approaches are also considered at a conceptual level.

Electric Transmission Requirements for Export of Large-Scale Generation Output From Baja California

Export of 8,500 MW of generation from Baja to the U.S. would require substantial investment in electric transmission infrastructure on both sides of the border. Furthermore, since the Southern California load centers immediately adjacent to the border with Mexico (these are, San Diego and the Imperial Valley) do not have sufficient demand to absorb 8,500 MW of exports from Baja, the electric transmission plan of service must extend to the greater Los Angeles load center. It is anticipated that if such an infrastructure were to be built, the resulting new generation would displace older, less efficient generation as well as support demand growth in California.

Developing a transmission plan of service on this scale entails a lengthy process. Sponsors of major transmission proposals typically conduct an independent engineering study to develop a conceptual plan of service. Next, pursuant to transmission planning protocols utilized in the Western Electricity Coordinating Council (WECC),[18] the sponsor(s) would then initiate a request for formation of a regional study group. The WECC study process involves detailed modeling and simulation of the proposed project and the interconnected system. Any WECC stakeholder may participate in the regional study group process and, if they desire to do so, submit recommendations on alternatives or variations to the plan of service. In addition to the WECC planning process, the U.S. detailed generator interconnection studies need to be conducted pursuant to the FERC-filed tariffs of each affected utility. Such interconnection studies often identify further refinements to the transmission plan of service.

Such detailed analysis is well beyond the scope of this study. Therefore, KEMA has applied engineering judgment and experience to present a conceptual plan of service for exporting 8,500 MW from the Costa Azul area to major load centers in Southern California. The key assumptions used were:

- Transmission facilities of at least 500 kilovolts (kV) alternating current (AC) and/or 500 kV high-voltage direct current (HVDC) are required to export this amount of generating capacity. It is impractical to expand the existing transmission infrastructure in Baja, which operates at 230 kV and below, to export as much as 8,500 MW. Higher voltage transmission facilities, such as 500 kV AC and/or HVDC,[19] would be required.

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[18] All of the utilities in the California/Mexico border region, including CFE, are members of the WECC.

[19] HVDC line design typically utilizes a "bi-pole" configuration with one conductor operating as the positive (+) pole and a second conductor operating as the negative (-) pole. Full capacity operation of the line requires both poles to be in operation, but it may be possible to deliver partial capacity even with one pole inoperable.

The typical power delivery capacity of such lines is on the order of 1,500-2,000 MW per circuit in the case of 500 kV AC lines. Overhead 500 kV HVDC "Bi-pole"[20] lines are capable of delivering 2,000-3,000 MW. Both types of transmission already exist in California but have yet to be built in Baja. Another option would be to utilize 500 kV HVDC cable offshore from the Pacific coastline. Such submersible cables are referred to as submarine cables due to their underwater location. Bi-pole HVDC submarine line ratings are currently available up to about 1,500 MW at 500 kV, which may require two cables per pole. A number of 500 kV HVDC submarine cables projects have been successfully installed in Europe, Asia, and the United States (another is now certified across San Francisco Bay).

- The transmission plan of service should provide for export of the full capacity of the Costa Azul generation as a "firm resource" to California (that is, non-firm, curtailable exports are not the design objective). Pursuant to California Independent System Operator (California ISO) criteria up to 1,100 MW of generation tripping is allowed for single-contingency events on the transmission system and up to 1,400 MW of generation dropping is allowed for double-contingency events (for example, outage of a double-circuit AC line or both poles of an HVDC line). However, KEMA's goal is to present a potential transmission plan that is not dependent on generation tripping for single contingencies.
- It is not necessary for the Costa Azul electric infrastructure to connect with the CFE system to export electricity to the U.S.
- Significant facility upgrades (including lower voltage facilities) will also be required in the utility systems at the receiving end of new transmission lines from Baja. This could include upgrades of thermal delivery capability, short-circuit withstand capability, protective systems, mitigation of physical space limits in existing substations, etc.
- Due to overland corridor constraints, particularly north of the international border, one or more offshore submarine transmission lines would need to be included in the plan of service if the overall size of the Baja generating complex exceeds 3,000 MW. An inland underground transmission option is not feasible at 500 kV because such cables are so bulky they must be transported from the factory to the installation site by ocean-going vessels (these vessels are also used to spool the cables onto the ocean floor).[21]

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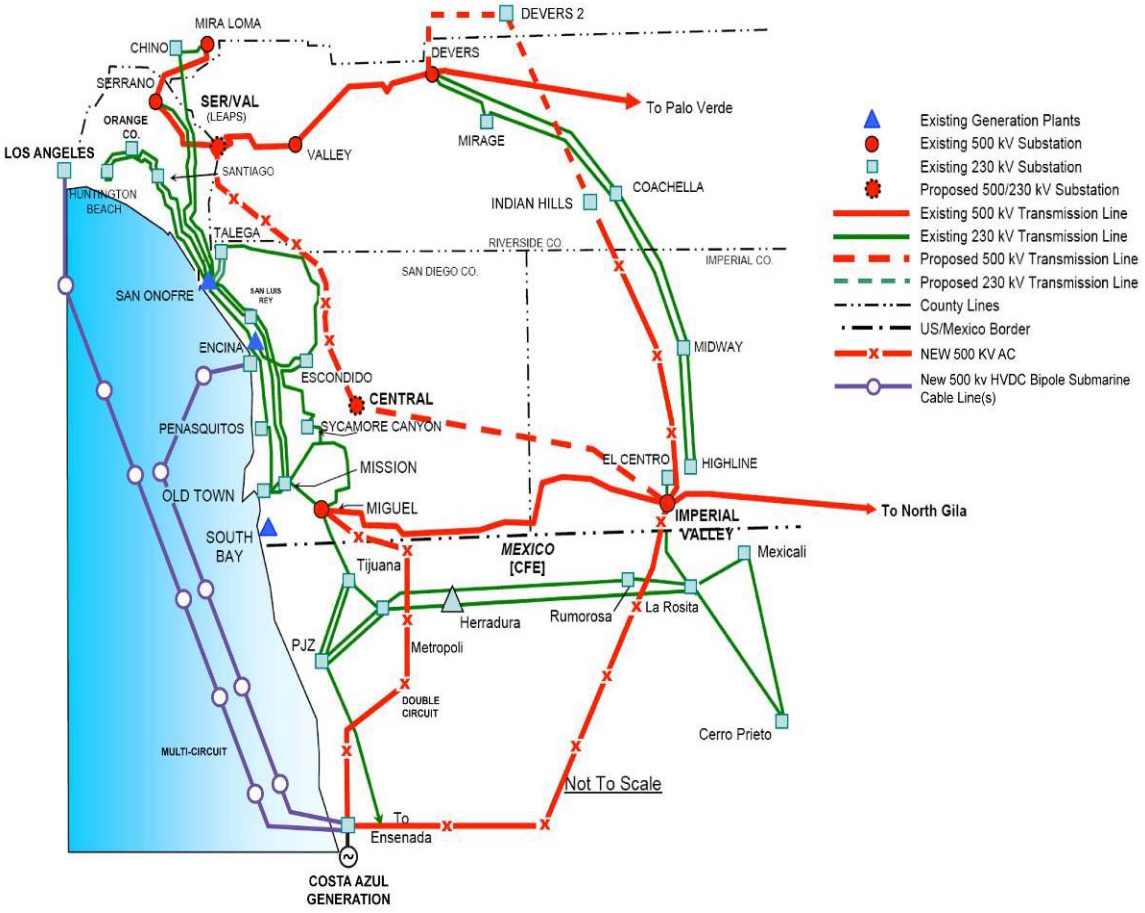
[20] HVDC lines can be built in either Monopole or Bi-pole design. Monopole lines use one "energized" conductor and a second "neutral" conductor as the return path for the circuit. Bi-pole lines utilize two energized conductors at opposite polarities (positive and negative voltages).

[21] Truck delivery of short lengths of 500 kV underground cable (for example, up to one-third mile) are possible, but longer overland installations are impractical and prone to increased failure rates due to the number of splices involved.

- The following previously proposed transmission projects were assumed to be completed according to the plan(s) of service envisioned by their respective proponents:
  - SDG&E's Sunrise Powerlink
  - Los Angeles Department of Water and Power's (LADWP) Green Path North
  - Nevada Hydro's LEAPS transmission
  - IID's Indian Hills – Devers 2 line (500 kV).

Based on the above assumptions, KEMA presents a conceptual electric transmission plan of service in Figure 6.

Figure 6: Conceptual Electric Transmission Plan for Baja Generation Scenario (Costa Azul Phase 2)



Source: SDG&E Sunrise Powerlink Amended Application, CPUC A.05-12-014, Appendix ll, 12-14-05 (Edited)

The plan of service shown in Figure 6 includes the following major elements:

- Up to three bi-pole 500 kV HVDC submarine lines from Costa Azul to the Los Angeles area, (each rated approximately 1,500 MW) terminated in the vicinity of the Alamitos, Haynes, and/or Long Beach generating stations.
- A bi-pole 500 kV HVDC submarine line from Costa Azul to San Diego (rated approximately 1,500 MW) terminated in the vicinity of the Encina generating station
- A double-circuit 500 kV AC overhead line from Costa Azul to Miguel Substation in the SDG&E system
- A single-circuit 500 kV AC overhead line from Costa Azul to Imperial Valley Substation in the SDG&E system, and continuing northward from Imperial Valley to IID's proposed Indian Hills 500 kV Substation
- A single-circuit 500 kV AC line from SDG&E's proposed Central Substation[22] to the southern terminus of Nevada Hydro's proposed LEAPS 500 kV transmission system[23]
- A 500 kV AC switchyard and sending-end HVDC terminals at Costa Azul[24]
- Receiving-end HVDC terminals in the Los Angeles and San Diego areas.

KEMA's order of magnitude cost estimate for the electric transmission plan of service described above is $6.6 billion (2012 dollars). An itemization of the components of this cost estimate is provided in Appendix C, along with unit cost assumptions. More than 50 percent of this total cost is attributable to the submarine cable lines. As shown in Table 4, one HVDC submarine line could be eliminated for each 1,500 MW decrement in new Baja generation.

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[22] SDG&E filed CPUC application for the Sunrise Powerlink specifies a preferred location for a new 500 kV Central Substation a few miles southeast of Warner Springs, California.

[23] Nevada Hydro's interconnection application(s) for the proposed LEAPS project filed with the California ISO call(s) for a southern 500 kV terminus with SDG&E in the vicinity of USMC Camp Pendleton and a northern 500 kV terminus with SCE approximately midway between Valley Substation and Serrano Substation.

[24] A variety of options are possible for connection of generators at Costa Azul to the 500 kV AC switchyard and HVDC system. It is beyond the scope of this study to formulate a detailed substation plan of service at Costa Azul, but the conceptual 500 kV plan of service can accommodate at least five 1,200MW step-up transformer banks at Costa Azul and a 500 kV AC source/tie for each HVDC line. Alternatively, if one or more large generating plants are located remote from the switchyard, they could be connected to the 500 kV switchyard via 500 kV gen-ties. In this case, the step-up banks would be located at the sending end of the gen-tie(s).

Table 4: Transmission Cost vs. Baja Generation Capacity

New Generation Capacity (MW)	Number of HVDC Submarine Lines Required	Electric Transmission Capital Cost ($x10^9)
~8,500	4	6.6
~7,500	3	5.2
~6,000	2	3.8
~4,500	1	2.4
~3,000	0	1.5

Costs (in 2012 dollars) are approximate.
Source: KEMA

As previously noted, it is not necessary from either a technical or legal perspective for this electric transmission infrastructure to connect with the CFE system. The power plant switchyard and transmission ties up to the U.S./Mexico border can be financed, owned, and operated by a private entity under the laws and regulations of Mexico. In fact, there is precedent for such facilities to be added to the California ISO-controlled grid.[25] On the other hand, if one or more interconnection points with the CFE system were added, current Mexican regulations would prohibit private ownership of this AC transmission. Under current Mexican law (that is, Reglamento de la LSPEE), ownership of the cross-border AC transmission infrastructure thus interconnected would have to be transferred to CFE and incorporated into CFE's Baja del Norte control area. The implementing rules and regulations of the LSPEE address the matter of compensation for the transfer of ownership of third-party construction generation interconnection facilities to CFE and rules for the provision of wheeling service by CFE. The impacts on the plan of service and capital costs from adding any point(s) of interconnection within CFE are unknown, but clearly such interconnection would have reliability benefits for CFE's Baja control area.

It is also conceivable that a hybrid plan of service could be used in which part of the new generation is delivered over privately owned HVDC 500 kV gen-ties to the U.S.[26] with the rest wheeled over 500 kV AC transmission interconnected with CFE. In this case, only the AC portion of the transmission plan would be subject to the transfer of ownership and operating cost regulations of Mexico, as previously discussed.

In any case, given the potential reliability benefits of such interconnection(s) to CFE Baja electric operations, policy makers and regulators in Mexico may want to investigate options to facilitate the development of such infrastructure.

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[25] Radial 230 kV generator tie-lines from both the Termoelectrico de Mexicali and La Rosita power plants in Baja with the U.S. are under California ISO control.

[26] A precedent for such an arrangement exists with the La Rosita generating plant in Mexicali, where part of the plant output is injected into CFE's system and another portion is delivered over the gen-ties to the U.S.

CHAPTER 3:
Analysis of the California Generation Expansion Scenario

The goal of this scenario is to identify an electric infrastructure plan capable of integrating new generation as close as possible to load centers in Southern California and supplied by surplus natural gas from Costa Azul Phase 2. Siting new generation close to major load centers minimizes delivery losses and capital costs for constructing the associated electric transmission infrastructure. From a gas supply perspective it is also economically efficient to site new generating plants along sections of the natural gas system that have surplus capacity. Based on KEMA's analysis, after completion of the pipeline upgrades planned in conjunction with the Costa Azul Phase 2, Southern California pipeline capacity would support a conceptual generation expansion plan as shown in Table 5.

Table 5: Conceptual Generation Sites in Southern California

	Potential Capacity (MW)	Approximate Distance to Following Load Centers (Miles)	
		Los Angeles	San Diego
Moreno South	3,200	60	75
Blythe South	4,800	200	150
El Centro Area	500	150	100

Source: KEMA

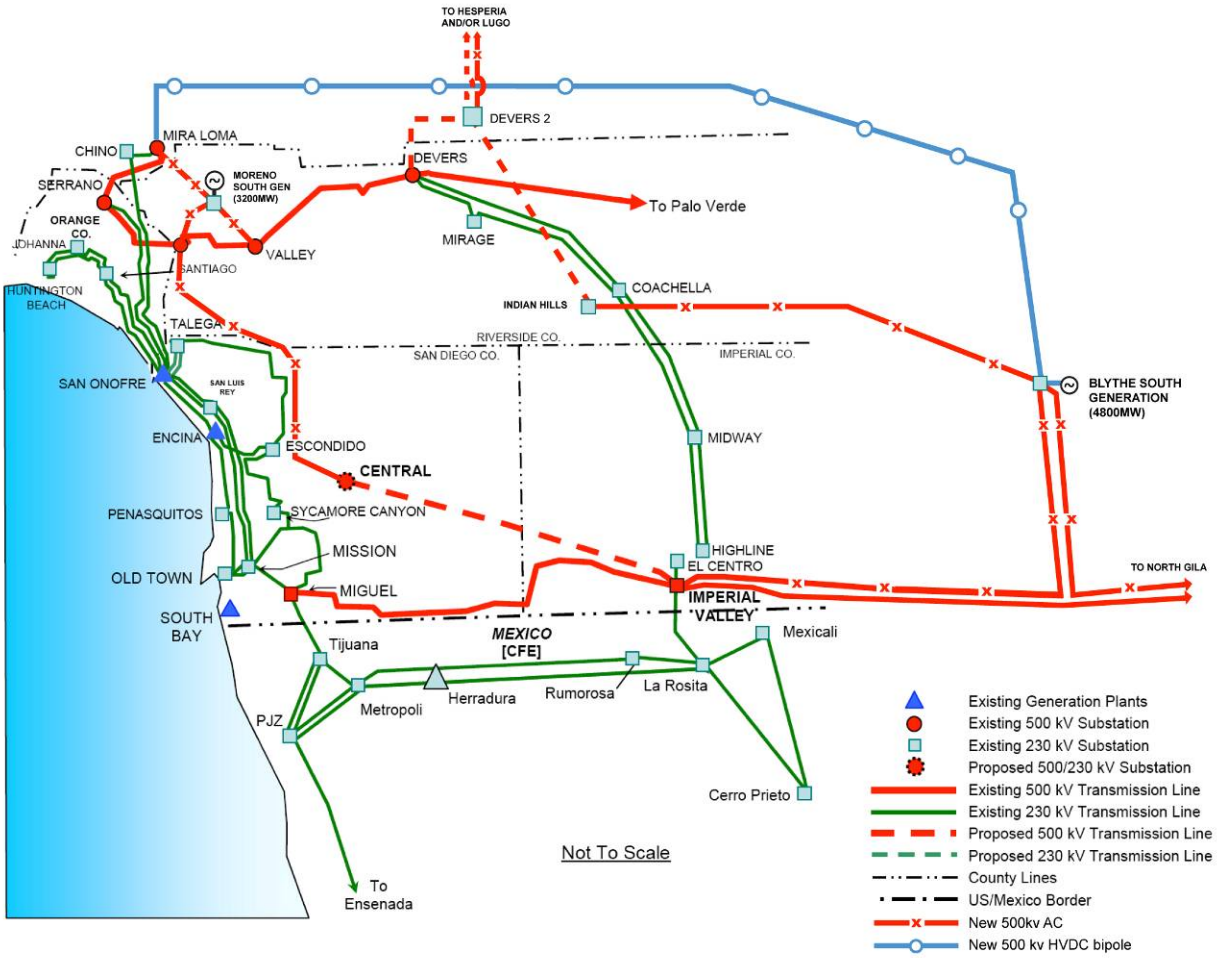
The increase in LNG capacity from the 1.5 Bcfd expansion of Costa Azul is sufficient to fuel all of this 8,500 MW of new generation, assuming an average heat rate of 7,500 BTU/kwh. Some of this potential generation capacity may already be reflected in the development plans and proposals identified in Appendix B. Also, part of the Blythe South capacity could actually be sited along the SoCalGas pipeline infrastructure to the west of Blythe and be integrated into the Blythe South transmission plan presented on pages 26 and 27 of this report. Lastly, while El Centro area generation is shown in Table 5, it is assumed the generation will supply load within the IID system and not distant load centers. Therefore, no specific transmission was considered for this 500 MW of capacity.

Although some of the generation proposals listed in Appendix B are located in the San Diego area, potential generation expansion in San Diego is not included in Table 5 since the planned pipeline upgrades in the border region will primarily change the direction of gas flow into San Diego (south vs. north), but have little impact on the overall firm delivery limit into San Diego. Furthermore, it seems unlikely that any significant amount of additional emissions credits/offsets can be procured in the San Diego area to support major new power plant expansion (except for those that become available through retirement of older generating facilities in the load pocket, in which case the new generating capacity would essentially just replace old capacity). In any case, if 3,200 MW of new generation is supplied between Moreno and Rainbow, the remaining southbound delivery capability at Rainbow together with the firm northbound capability being added at Otay Mesa would be approximately the same as the

existing firm pipeline capacity into SDG&E. This does not preclude the possibility of shifting some of the 3,200 MW of generation expansion from Moreno South into SDG&E, if suitable plant sites and emission credits/offsets can be identified to support such development.

A conceptual electric transmission plan of service to deliver the generation shown in Table 5 into the Los Angeles and San Diego load centers is presented in Figure 7. This plan of service is based on comparable assumptions to those already described in the Baja generation expansion scenario.[27]

Figure 7: Conceptual Electric Transmission Plan for California Generation Scenario (Costa Azul Phase 2)



Source: SDG&E Sunrise Powerlink Amended Application, CPUC A.05-12-014, Appendix II, 12-14-05 (Edited)

[27] No electric infrastructure additions were considered for the 500 MW increment of IID generating capacity, which is assumed to tie directly into IID's lower voltage grid.

The plan of service shown in Figure 7 includes the following major elements:

- A bi-pole 500 kV HVDC overhead line from Blythe South to greater Los Angeles (rated 2,000-3,000 MW) with its western terminus in the vicinity of Mira Loma Substation
- A double-circuit 500 kV AC overhead line from Blythe South to the existing North Gila – Imperial Valley 500 kV corridor. From that point, the line would split into new 500 kV circuits into both North Gila and Imperial Valley
- A single-circuit 500 kV AC line from Blythe South to IID's Indian Hills Substation
- A second 500 kV AC line from Devers 2 to Hesperia and/or Lugo Substation(s), paralleling LADWP's proposed Green Path North line
- A single-circuit 500 kV AC line from SDG&E's proposed Central Substation[28] to the southern terminus of Nevada Hydro's proposed LEAPS 500 kV transmission system[29]
- A 500 kV AC switchyard and sending-end HVDC terminals at the new Blythe South generation site, as well as new 500 kV AC switchyards at the new Moreno South and Blythe South generation sites
- A second Valley-LEAPS 500 kV line, looping through the new Moreno South 500 kV switchyard[30]
- A new single-circuit 500 kV AC line from Moreno South to Mira Loma Substation.

KEMA's order of magnitude cost estimate for the electric transmission plan of service described above is $3.7 billion (2012 dollars). An itemization of the components of this cost estimate is provided in Appendix C, along with unit cost assumptions.

The electrical performance of the conceptual transmission plans described in this report would need to be verified through detailed transmission planning simulations (power flow, stability, short circuit), which are beyond the scope of this study. It is anticipated that such analyses would identify necessary modifications to the plan(s) of service, as well as lower voltage upgrades that would be required at the receiving-end of the new 500 kV lines in order to complete delivery of the additional power into load centers. KEMA has included approximate cost estimates for receiving system upgrades based on engineering judgment.

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[28] SDG&E filed CPUC application for the Sunrise Powerlink specifies a preferred location for a new 500 kV Central Substation a few miles southeast of Warner Springs, CA.

[29] Nevada Hydro's interconnection application(s) for the proposed LEAPS project filed with the California ISO call(s) for a southern 500 kV terminus with SDG&E in the vicinity of USMC Camp Pendleton and a northern 500 kV terminus with SCE approximately midway between Valley Substation and Serrano Substation.

[30] In this context, LEAPS refers to the new 500 kV switchyard proposed by Nevada Hydro at the intersection of the LEAPS northbound generator-tie line with the existing Valley-Serrano 500 kV line.

It should be noted that due to the inland location of the conceptual Southern California generating plant sites described above, it's likely that significant costs would be incurred in meeting plant cooling requirements (including acquisition of related water rights). In addition, significant costs can also be expected for developing emissions offsets or acquiring emissions credits in Southern California. Assessing the feasibility and costs of such plant development requirements on a site by site basis is beyond the scope of this study.

CHAPTER 4:
Comparison of Scenarios

As described on pages 23 and 27 of this report, it is estimated that electric transmission capital investment of $3.7 – $6.6 billion (2012 dollars) would be needed to interconnect and deliver 8,500 MW of electric generation to Southern California load centers. These costs represent two bookend scenarios (100-percent California generation siting vs. 100-percent Baja generation siting), and there are any number of hybrid siting scenarios that could be developed (see Table 6).

Table 6: Sample Hybrid Siting Scenarios

Table 6a. Generation Siting Assumptions		Electric Transmission Capital Cost ($x10^9)
Location	Capacity (MW)	
Blythe South	4,000	3.1
Costa Azul	4,000	2.4
El Centro	500	n/a
Total	***8,500***	***5.5***

Table 6b. Generation Siting Assumptions		Electric Transmission Capital Cost ($x109)
Location	**Capacity (MW)**	
Moreno South	**3,200**	**0.6**
Costa Azul	**4,800**	**3.8**
El Centro	**500**	**n/a**
Total	***8,500***	***4.4***

Approximate costs (2012 dollars), based on Tables 2 and 3 and Appendix C.

Source: KEMA

The costs of such hybrid siting scenarios fall between the two bookend scenarios. However, it must be noted that for the examples in Table 6, no attempt has been made to account for the electrical system interdependencies that could result from overlapping parts of two different generation scenarios. These would also affect the plan of service and capital costs.

One of the Energy Commission's objectives for this scenario study was to locate potential generation as close as possible to the major load centers of Southern California (distances to the load centers from the conceptual in-state generation sites at Blythe South and Moreno South sites were summarized in Table 5). In this regard it is worth noting that generation located at Costa Azul would actually be closer to both Los Angeles and San Diego than generation located at Blythe South, and both Costa Azul and Moreno South are a comparable distance from San

Diego. Furthermore, the proposed HVDC submarine cable lines would inject a portion of the Costa Azul generation directly into the Los Angeles and San Diego areas, avoiding potential congestion constraints into these load centers on the AC system. This suggests that generation at Costa Azul may satisfy the Energy Commission's "proximity to load center" objective as much as the California generation scenario, but further technical study is needed to confirm this observation.

Another objective stated by the Energy Commission for these transmission scenarios is to facilitate delivery of renewable resources. In this regard, the transmission plans in Figure 6 and Figure 7 both provide additional transfer capability into the load centers that could be used for delivery of renewable resources from the border region and the Imperial Valley. This would be especially true in off-peak hours when thermal generation dispatch is reduced, but some renewables (for example, wind resources) are peaking. Both plans include HVDC lines, which unlike AC line actually allow precise "control" of flows over the path. This feature would help to optimize the dispatch between thermal and renewable resources in the border region.

The Energy Commission also raised the question of power delivery capability between California and Arizona. This would be a secondary impact of the conceptual transmission plans for the Baja and California generation scenarios, and can only be quantified through technical studies. However, since the plan shown in Figure 7 would add a new 500 kV line between Blythe South and the North Gila Substation in Arizona, it is clear that additional import/export capability with Arizona would be available. Arizona Public Service (APS) is currently proposing a second 500 kV line from Hassayampa to North Gila. If this new APS line is built, along with the transmission plan shown in Figure 7, the combination would result in a new 500 kV path all the way from the Palo Verde Hub in Arizona to the greater Los Angeles area.

Other points of comparison requested by the Energy Commission are included in Appendix C in an effort to better understand the pros and cons of the Baja and California generation scenarios, respectively. However, the conceptual estimates of capital costs and the pros and cons provided in Appendix D are not sufficient to choose a preferred scenario. Such a recommendation would require a detailed benefit-cost analysis. Developing a meaningful benefit-cost analysis would first require the type of detailed WECC regional planning and FERC-approved generator interconnection study processes mentioned earlier in this report. Such technical studies would need to be performed for each scenario, hybrid, and blend of interest in order to determine a set of technically proven electrical plans and their associated capital cost estimates. However, even that would not provide an adequate basis for accurate benefit-cost analysis. A complete analysis would need to include detailed multi-year production cost modeling[31] and gas market clearing price simulations for each scenario of interest. Until such work is done, it is impossible to determine with any certainty if either the Baja generation expansion scenario, the California generation expansion scenario—or a hybrid scenario—would result in a net savings to ratepayers. Such generation expansion scenarios should also be benchmarked against simply allowing surplus natural gas exports from Baja LNG to displace other sources of natural gas in the U.S.

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[31] In order to accurately compare the economic impact of the infrastructure scenarios in question, the production cost assessment must be done with a tool that accurately models connectivity and flows on the electric transmission system.

CHAPTER 5:
Conclusions and Action Items

The addition of the Costa Azul LNG terminal located only 50 miles south of the California-Mexico Border, with 2.5 Bcfd of planned throughput, provides a significant opportunity to shape future gas and electric infrastructure expansion in the border region. Absent a clear regulatory and governmental strategy in this regard, decisions regarding such infrastructure development will default to private investors. It is unlikely that private investment decisions alone would achieve the greatest level of public benefit for the border region. Regulators and governmental agencies on both sides of the border can increase the public benefits to the region by taking a proactive role in shaping the direction of this future infrastructure.

Although Costa Azul has received regulatory approval from Mexico to expand from its terminal capacity from 1.0 Bcfd to 2.5 Bcfd nominal (2.6 Bcfd peak) as early as 2010, in KEMA's opinion the projected rate of development of global LNG supply is unlikely to support expansion to the full 2.5 Bcfd volume under winter peak gas demand conditions until the 2015 timeframe. However, the full volume may be available much sooner during summer demand conditions.

Costa Azul's Phase 1 capacity (1.0 Bcfd) exceeds the demand forecast of natural gas markets within Baja, and there are no plans to export any natural gas from Baja to the mainland of Mexico. Therefore, all of the incremental 1.5 Bcfd of LNG capacity expected from Costa Azul Phase 2 will be surplus to Baja's energy needs and is available for export to U.S. markets through the forecast period. If this surplus is used to fuel new electric generation projects, it could supply approximately 8,500 MW of new capacity.

Electric transmission infrastructure investment on the order of $3.7 billion to $6.6 billion (in 2012 dollars) would be required to deliver the full 8,500 MW of electric power to Southern California load centers. Furthermore, there is a large differential in estimated electric transmission expansion capital costs for the Baja generation scenario vs. the California generation scenario at the 8,500 MW level. However, electric transmission costs for the Baja generation scenario drop off quickly at lower levels of generation expansion, which could eliminate that differential. Detailed multi-year production cost modeling[32] and gas market clearing price simulations would need to be conducted at various levels of generation expansion up to 8,500 MW in both Baja and California to determine if there is a generation plan with net savings to ratepayers. The cost and benefits of such scenarios should also be benchmarked against simply allowing surplus natural gas exports from Baja to displace other sources of natural gas in the U.S.

The licensing and construction of such electric transmission infrastructure could take significant time, on the order of 6 to 8 years, regardless of whether the generation is constructed in Baja or Southern California. More complicated licensing coordination would be involved with the Baja generation scenario because it requires licensing of new transmission in both Mexico and the U.S., but there is adequate past precedent for such bi-national projects. However, there is no

[32] Ibid.

past precedent for licensing of offshore submarine cables running parallel to the coast of either California or Mexico, as envisioned in the Baja generation scenario. This could introduce added transmission licensing delays and costs for environmental mitigation.

The scale of privately funded electric system upgrades contemplated in Baja generation scenario is unprecedented under Mexican regulations and, if interconnected to CFE's facilities, would dramatically reshape the electric grid in Baja. In light of the significant benefits to the reliability of CFE's electric grid in Baja that could accrue from such interconnection facilities, it would be in Mexico's interest to consider incentives for the development of such infrastructure. This matter should be considered by the pertinent Mexican energy agencies.

Assuming that comparable environmental standards and mitigation measures would be adopted by new electric generation projects in either Baja or Southern California, the siting/licensing/construction lead times and development costs of generation facilities added on either side of the border would be similar. However, any requirements for special power plant cooling facilities (for example, dry cooling towers) could add substantial costs for plants built either to the north or the south of the border and can only be determined on a site-by-site basis.

Severe constraints on cooling water resources in Baja would favor locating any major new electric generating plants along the Pacific Coast. For easiest access to LNG, the preferable location would be in the proximity of the Costa Azul terminal. Likewise, the cost involved in acquiring cooling water, using dry cooling and emission offsets in the California generation scenario are unknown but could be substantial.

The desired mix of future gas-fired generation vs. renewable resources in the overall resource portfolio for the state of California should be assessed to determine what weight to place on development of new gas-fired generation fueled by the Baja LNG surplus in coming decades. Such an assessment needs to recognize that inherent differences in the dispatch characteristics of fossil vs. renewable generation may allow shared use of some components of the related electric transmission infrastructure.

GLOSSARY

AC	alternating current
AFC	Application for Certification
APS	Arizona Public Service
Bcfd	Billion cubic feet per day
BTU	British thermal unit
CFE	Comisión Federal de Electricidad
Dthd	Dekatherms per day
EG	electric generation
FERC	Federal Energy Regulatory Commission
GBN	Gasoducto Baja Norte
HVDC	high-voltage direct current
IID	Imperial Irrigation District
CALIFORNIA ISO	California Independent System Operator
kV	Kilovolt
LADWP	Los Angeles Department of Water and Power
LNG	Liquefied Natural Gas
MMcfd	Million cubic feet per day
MW	Megawatt
NBP	North Baja Pipeline
PTO	Participating Transmission Owner
ROW	Right-of-way
SDG&E	San Diego Gas & Electric
SoCalGas	Southern California Gas Company
TGN	Transportadora de Gas Natural
WECC	Western Electricity Coordinating Council

APPENDIX A:

Customer Precedent Agreements Identified In NGP'S FERC Filing for Phase 2

North Baja Pipeline Expansion Project Precedent Agreements		
	Quantity (Dthd)	
Phase/Shipper	***Annual***	***Delivery Path***
Phase I Northbound		
Coral Energy Resources, LP	212,000	U.S.-Mexico border to El Paso Natural Gas Company[a] (El Paso)
Sempra Energy LNG Marketing Corp.	100,000	U S. -Mexico border to El Paso [a]
Existing Shippers b	302,000	U.S.-Mexico border to El Paso [a]
Total Phase J Northbound	614,000	
Phase I-A HO Lateral		
Imperial Irrigation District	110,000	Ogilby Meter Station to El Centro Generating Station
Phase II Northbound		
Chevron USA, Inc.	1,070,000[c]	U.S.-Mexico border to El Paso [a]
Coral Energy Resources, LP	530,000[c]	U.S.-Mexico border to El Paso [a]
Sempra Energy LNG Marketing Corp.	200,000	U.S.-Mexico border to El Paso [a]
Total Phase II Northbound	1,800,000	
Total Northbound Phases (2010)	2,384,000[d]	
Unsubscribed Northbound Capacity	548,000	

[a] Deliveries to Southern California Gas Company would fall within the path.

[b] Several existing shippers reversed the primary path from southbound to northbound for a total 302,000 Dthd (283.57 MMcfd). In 2010, this volume is reduced to 272,000 Dthd (255.40 MMcfd).

[c] Although these volumes were anticipated to be transported from the Mar Adentro terminal, the shippers have not terminated their precedent agreements for transportation capacity on Phase II of *the* North Baja Pipeline Expansion Project.

[d] Reflects the reduction in Phase I volumes described in footnote b,

Note: All precedent agreement terms are for 20 years.

Source: Final Environmental Impact Statement on North Baja Pipeline Expansion Project, Docket Nos. CP06-61-000 filed at the FERC on June 8, 2007

APPENDIX B:
Proposed Gas-Fired Power Plants in the Border Region

Table B-1: Proposed Baja California Plants

Name	Intended Market	Location	Status	Capacity (MW)	In-Service Date
AES Rosarito Combined Cycle[1]	Export to AES NewEnergy, Inc.	Playas de Rosarito – Presidente Juárez Site	CRE Permit E/202/EXP/2001 Cancelled	556	NA
Energía de Mexicali[1]	Export to Integral Energy Services	Mexicali	CRE Permit E/163/EXP/2000 Unknown	258	Unknown
Generadora del Desierto[1]	Possibly California	San Luis Rio Colorado, Sonora	Under Construction	601	2008
Baja California Combined Cycle	CFE	Playas de Rosarito – Presidente Juárez Site	Under bid	252	2009
Baja California II GT	CFE	San Luis Rio Colorado, Sonora	Programmed[3]	220	2009
Pres. Juarez GCT/CC Conversion	CFE	Playas de Rosarito – Presidente Juárez Site	Programmed[3]	90	2010
Cierro Prieto V Geothermal	CFE	Cierro Prieto	Programmed[3]	100	2010
Baja California III	CFE	Ensenada	Programmed[3]	279	2011
Baja California IV	CFE	Playas de Rosarito – Presidente Juárez Site	Programmed[3]	280	2013
Baja California V [2]	CFE	San Luis Rio Colorado, Sonora	Programmed[3]	271	2013
Baja California VI[2] GT	CFE	Mexicali	Programmed[3]	151	2015

Sources: (1) Comisión Reguladora de Energía website.
(2) Either new generating plant or PPA – CFE POISE 2007-2016
(3) Comisión Federal de Electricidad - POISE 2007-2016

Table B-2: Proposed California Plants

Name	Location	Status	Capacity (MW)	In-Service Date
Blythe II Combined Cycle	Riverside County	On Hold	520	n/a
Sun Valley Energy Project (Peaker)	Riverside County (near Romoland)	Currently in Application for Certification (AFC) Process	500	12/08
Orange Grove Energy	San Diego County (near Pala)	Currently in AFC	100	7/08
Sentinel Peaker	Riverside County (near Palm Springs)	Currently in AFC	850	5/10
MMC Chula Vista Expansion	San Diego County	Currently in AFC	100	12/09
South Bay Replacement Combined Cycle	San Diego County	Currently in AFC	620 (less the capacity of the existing South Bay plant)	Unknown
Carlsbad – NRG (Removes Encina 1, 2 &3)	San Diego County	Currently in AFC	558 (less the capacity of Encina 1, 2 &3)	Unknown
Larkspur 3	San Diego County (near Border)	Currently in AFC	47	Suspended
San Diego Community Power – ENPEX	San Diego County (near Sycamore Canyon)	Disclosed, but no AFC to date	750	Unknown

Source: California Energy Commission – Energy Facility Status (October 9, 2007)

APPENDIX C:
Capital Cost of Electric Transmission Infrastructure

Table C-1: Baja Generation Scenario
(U.S. Dollars x 1 Million)

Line Section	Miles[1]	Line Type	Cost per Mi.[2]	Cost of Line Segment	Termination Components		Total Line Cost *(2006 dollars)*	Total Line Cost[10] *(2012 dollars)*
					Description	Cost		
Costa Azul – Los Angeles[4]	154 per line	500 kV HVDC Submarine Cable[3]	2.615	402.7 per line	Costa Azul HVDC Term.	200 per line	1,052.7 per line	1,332.0 per line
					Los Angeles HVDC Term.	200 per line		
					Receiving system upgrades (TBD)[33]	250 per line		
Costa Azul – San Diego[5]	94	500 kV HVDC Submarine Cable[3]	2.615	245.8	Costa Azul HVDC Term.	200	895.8	
					San Diego HVDC Term.	200		
					Receiving system upgrades (TBD)	250		
Costa Azul – Miguel	68[6]	500 kV AC (dbl. ckt.)[9]	3.17	215.6	Costa Azul line terminals (two)	4.6	505.2	
					Miguel line terminals (gas insulated sub)	10.0		
					Receiving system upgrades	250		
					Modifications to adjacent CFE facilities	25		
Costa Azul – Imperial Valley Sub	109	500 kV AC	2.15	234.4	Costa Azul line terminal	2.3	264.0	
					Imperial Valley. line terminal	2.3		
					Modifications to adjacent CFE facilities	25		

[33] Conversion of an existing 230 kV transmission path between Alamitos and Serrano to 500 kV may be justified as part of this expansion.

Imperial Valley Sub – Indian Hills	86	500 kV AC	2.15	184.9	Imperial Valley line terminal	2.3	214.5	
					Indian Hills line terminal	2.3		
					Modifications to adjacent IID facilities	25		
Central Sub – LEAPS[7]	68[6]	500 kV AC	2.15	146.2	Central line terminal	2.3	185.8	
					LEAPS terminal	2.3		
					Series Compensation	10.0		
					Modifications to adjacent SDG&E facilities	25		
Costa Azul Switchyard[8]	n/a	500 kV AC	n/a	n/a	Site preparation	10.0	27.0	
					5 substation bays, in Breaker-and-a-half layout	17.0		
Grand Total							5,250.4	6,643.5

Footnotes:

1) Adds 15% to point to point distance (except as noted) to account for routing variations, etc.
2) Includes land and construction costs; excludes licensing and environmental costs.
3) Assumes 3,000 MW, bi-pole configuration.
4) Assumes termination in vicinity of Alamitos, Haynes and/or Long Beach Generating Stations.
5) Assumes termination in vicinity of Encina Generating Station.
6) Adds 35% to straight line distance to account for routing variations (increased factor due to proximity of potential routes to greater San Diego and/or Tijuana metropolitan areas)
7) Assumes Central Sub location proposed by SDG&E in Sunrise Powerlink filing and receiving-end termination at the southernmost point of proposed LEAPS 500 kV transmission system.
8) Excludes lower voltage facilities, step-up transformer costs and HVDC terminals
9) Cost per mile assumes double-circuit construction (corridor width and cost would increase if two single-circuit lines are utilized).
10) Assumes annual escalation factor of 4%.

Source: KEMA

Table C-2: California Generation Scenario
(U.S. Dollars x 1 Million)

Line Section	Miles[1]	Line Type	Cost per Mi.[2]	Cost of Line Segment	Termination Components		Total Line Cost *(2006 dollars)*	Total Line Cost[10] *(2012 dollars)*
					Description	Cost		
Blythe South – Mira Loma	196	500 kV HVDC Line[3]	1.810	354.8	Blythe South HVDC Terminal	200	1,104.8	
					Mira Loma HVDC Terminal	200		
					Receiving system upgrades (TBD)	250		
Blythe South – Devers 2	132	500 kV Dbl. Ckt AC Line	2.720	359.0	Blythe South line terminals (two)	4.6	388.2	
					Devers 2 line terminals (two)	4.6		
					Series compensation (one per circuit)	20		
Blythe South – North Gila	46[4]	500 kV AC	2.15	98.9	Blythe South line terminals	2.3	153.5	
					North Gila line terminal	2.3		
					Receiving system upgrades (TBD)	50		
North Gila – Imperial Valley Sub	95	500 kV AC	2.15	204.3	North Gila line terminal	2.3	218.9	
					I.V. line terminal	2.3		
					Series compensation	10		
Imperial Valley Sub – Indian Hills	86	500 kV AC	2.15	184.9	I.V. line terminal	2.3	214.5	
					Indian Hills line terminal	2.3		
					Modifications to adjacent IID facilities	25		
Valley Sub – Moreno South	11[5]	500 kV AC	2.15	23.7	Valley line terminal (Gas insulated sub)	10	185.8	
					Moreno South line terminal	2.3		
Moreno South – LEAPS[6]	27[5]	500 kV AC	2.15	58.1	Moreno South line terminal	2.3	62.7	
					LEAPS North line terminal	2.3		
Moreno South – Mira Loma[7]	34[5]	500 kV	2.15	73.1	Moreno South line terminal	2.3	77.7	
					Mira Loma line terminal	2.3		
					Receiving system upgrades (TBD)	150		

Central Sub – LEAPS South[8]	68[7]	500 kV AC	2.15	146.2	Central line terminal	2.3	185.8	
					LEAPS terminal	2.3		
					Series Compensation	10.0		
					Modifications to adjacent SDG&E facilities	25		
Devers 2 to Hesperia/Lugo	75[11]	500 kV AC	2.15	161.3	Devers 2 terminal	2.3	165.7	
					Hesperia terminal	2.3		
Blythe South Switchyard[9]	n/a	500 kV AC	n/a	n/a	Site preparation	10.0	23.6	
					4 substation bays, in Breaker-and-a-half layout	13.6		
Moreno South Switchyard[10]	n/a	500 kV AC	n/a	n/a	Site preparation	8.0	18.2	
					3 substation bays, in Breaker-and-a-half layout	10.2		
Imperial Valley Switchyard[10]	n/a	500 kV AC	n/a	n/a	Site preparation	6.0	12.8	
					2 substation bays, in Breaker-and-a-half layout	6.8		
Grand Total							2,957.8	3,743.3

Footnotes:

1) Adds 15% to point to point distance (except as noted) to account for routing variations, etc.

2) Includes land and construction costs; excludes licensing and environmental costs.
3) Assumes 2,000 MW, bi-pole configuration.
4) Assumes one-half of distance from Blythe, CA to North Gila Substation, due to range of possible generating plant sites along the NGP.
5) Assumes Moreno South plant location approximately one-half of distance from Moreno to Valley Substation, along the Moreno-Rainbow pipeline.
6) Assumes receiving-end termination at the northernmost point of proposed LEAPS 500kV transmission system.
7) Adds 35% to straight line distance to account for routing variations (increased factor due to proximity of potential routes to San Diego or Riverside metropolitan areas)
8) Assumes Central Sub location proposed by SDG&E in Sunrise Powerlink filing and receiving-end termination at the southernmost point of proposed LEAPS 500kV transmission system.
9) Excludes lower voltage facilities, step-up transformer costs and HVDC terminals.
10) Excludes lower voltage facilities, and step-up transformer costs.
11) Adds 50% to straight line distance to account for routing around Angeles National Forest.
12) Assumes annual escalation factor of 4%.

Source: KEMA

Table C-3: Unit Cost Assumptions

Transmission Line Unit Cost-AC System/Per Mile	**Unit cost in $1,000**		
1 -Project Unit Cost- Transmission Line	Right-of-Way (ROW) or Land cost	Construction cost	Total
Canada-British Columbia/Alberta/Pacific Northwest/Nevada			
500 kV Single Circuit cost per mile	300	1,700	2,000
500 kV Double Circuit Line(1.6 times Single Circuit Line construction cost)	300	2,720	3,020
765 kV Single Circuit Transmission Line construction cost(1.3 times the construction cost of 500 kV double circuit line)	300	3,536	3,836
230 kV transmission line single circuit	300	1,000	1,300
230 kV transmission line double circuit(1.6 times single circuit)	300	1,600	1,900
Bi-Pole HVDC Transmission line +/- 500 kV (0.8 times the construction cost of single circuit 500 kV line)	300	1,360	1,660
BCTC 500 kV SCTL line cost Canadian $2.4 million per mile, assuming 0.956 conversion rate			2,200
California 500 kV Single Circuit cost (CA Row or land cost 1.5 times Pacific Northwest)	450	1,700	2,150
500 kV Double Circuit Transmission Line (CA Row or land cost 1.5 times Pacific Northwest and 1.6 times the construction cost of single circuit 500 kV line[1]*)	450	2,720	3,170
765 kV Single Circuit Line (Land or ROW CA 1.5 times the Row cost in Northwest and 1.3 times the construction cost for double circuit 500 kV line in California)	450	3,536	3,986
230 kV transmission line single circuit	300	1,000	1,300
230 kV transmission line double circuit (0.6 times single circuit)	300	1,600	1,900
Bi-Pole HVDC Transmission line +/- 500 kV *Over Land* (0.8 times the construction cost of single circuit)	450	1,360	1,810
DC line – Bi-pole (Submarine Cable)			
DC Line Bi-Pole -two cables (Submarine Cable -See Breeze Option)			2,615
II -Local Area Transmission Reinforcement cost			
Reconductor existing 500 kV line			1,000
Reconductor existing 230 kV line Single circuit			500
III-Terminal Equipment AC System			
500 kV complete BAAH Bay (3 Breakers for two element termination) 1,500 kV with two breakers			3,400
500 kV Breaker			2,300
765 kV complete BAAH Bay (3 Breakers for two element termination) 230 kV breaker			1,100
			4,420
			1,000
500/230 kV, 1,134 MVA bank (Three Single Phase Units $8 million/phase)			24,000
765/500 kV or 765/230 kV, 1134 MVA bank (Three Single Phase Units $8 million/phase) 230/115V or below bank			31,200
500 kV Series Compensation per bank			10,000
765 kV series compensation 1.3 times cost of 500 kV bank			13,000
Reactive Support +/-300 MVAR SVC @ S100/KVAR			30,000

IV -HVDC Station Equipment	
Converter Bi-Pole 1,500 MW (See Breeze WCC project I) Allston	200,000
Martin	120,000
Newark	120,000
Converter Bi-Pole 3,000 MW (one at each terminal) Frontier line project	500,000

Source: WECC Regional Planning Study, Draft Technical Analysis Subcommittee Report, Canada/Pacific Northwest to California Transmission Project, October 17, 2007.

APPENDIX D:

Comparative Analysis of Energy Infrastructure Options Related to Major Gas-Fired Generation Expansion in California-Baja Border Region

Factor(s)	Option A: Generation Expansion in Baja	Option B: Generation Expansion in California
Capital Cost	Expect comparable power-plant development costs for both options, assuming a generation site location on Pacific Coast of Baja and built to meet California environmental standards (in order to avoid potential objections by interveners in California.) Electric transmission costs estimated at $6.6 billion (2012 dollars). Gas pipeline costs same in both options.	Expect comparable power-plant development costs for both options, except for acquiring water rights and emission offsets/credits. Use of dry cooling and/or treatment of municipal wastewater for cooling will increase costs. Electric transmission costs estimated at $3.7 billion (2012 dollars). Gas pipeline costs same in both options.
Burden of Investment to Ratepayers, Investors and/or Government	Capital cost of all electric transmission upgrades in Baja must be paid by developer & recovered through their own revenue sources. CFE must be given ownership of any transmission facilities that physically interconnect with their system. Unclear if portion of gen-ties physically within the U.S. may be eligible for “Trunk-line” cost treatment under California ISO tariff.	Capital cost of any network transmission upgrades in CA must be paid by developer but can be recovered through California ISO tariff if the owner becomes a Participating Transmission Owner (PTO). “Trunk-line” rate treatment may apply under California ISO tariff, in which case initial construction costs may be borne by local utility and later passed on to gen developers.

Related Environmental Impacts	*Mexican environmental Norms are less stringent and thus impose lower costs – however in order to be able to export plants must meet U.S. emission standards thus bringing costs up to par with U.S.* Little precedent exists on the licensing/environmental impacts of offshore submarine cable running parallel to the coastline in either Mexico or California, but it can be expected to extend the licensing process.	More restrictive emission constraints in Southern California may limit the amount of generation that can be developed at the conceptual sites described in this report.
Relative Levels of Supply Reliability to Customers	*Reliability of overhead lines is comparable in U.S. and Mexico.* *Reliability of submarine cables may be comparable to overhead if they are buried under ocean floor, but repair times will be longer if they fail.*	*Reliability of overhead lines is comparable in U.S. and Mexico.*
Vulnerability to Transport Congestion	No cross-border gas pipeline congestion is expected. The conceptual electric transmission plan of service provided in the report attempts to avoid major congestion constraints, but detailed studies would be required to determine the actual level of congestion exposure.	No cross-border gas pipeline congestion is expected, except for 400MMcfd firm limit on northbound deliveries to Otay Mesa. The conceptual electric transmission plan of service provided in the report attempts to avoid major congestion constraints, but detailed studies would be required to determine the actual level of congestion exposure.

Vulnerability to Fires, Earthquakes and Other Physical Disruptions	Due to proximity to Costa Azul, generation should be less vulnerable to pipeline disruptions. Submarine cables, if buried, should have minimal exposure to physical disruptions, but earthquake exposure would need to be evaluated.	Greater mileage of overhead electric transmission exposed to fires, storms, lightning, live line contact, gunshot damage, earthquakes and landslides.
Flexibility to Upgrade Lines and Expand Corridors	No existing 500 kV electric corridors across border, but it's possible that a radial 500 kV trunk-line to the U.S. may be built by Baja wind developers by 2010. Could provide some upgrade or expansion potential if located in area needed for LNG plan of service. Expandability of submarine cable routes is unknown.	Unknown expansion potential of the two high-pressure gas pipeline routes across border. Transmission plan of service envisions new 500 kV lines in parallel with (a) N.Gila-Imperial Valley, (b) Green Path North, and (c) portion of Valley-Serrano. Potential for expansion of these existing corridors is unknown.
Timeframe to Construct Infrastructure	Requires 500 kV licensing & environmental analysis in both CA and Mexico, including assessment of environmental impact of offshore cable corridors. Therefore, expect 1 year longer to license and construct than Option B. Depending on number of 500 kV HVDC submarine lines required, cable procurement might exceed the annual volume of global cable manufacturing capability and cause delays in project completion.	Assume 6-7 years to license and construct new 500 kV overland lines located within U.S. (all routes to be licensed are in California, expect short section of Blythe South – N. Gila which is in Arizona).

Changes Needed to Laws and Policies to Facilitate Construction or Improvements	Mexican energy officials may wish to reconsider current policies regarding private funding & wheeling cost exposure to developers when facilities interconnect with CFE, due to the potential benefits that could accrue to CFE from revisions to the scope of proposed electric plan of service.	[See related recommendations in *Challenges and Opportunities to Deliver Renewable Energy From Baja California Norte to California*: California Energy Commission. Publication number: CEC-600-2008-004, June 2008.]
Security of Supply, Expropriation.	Power plants, gas pipelines and electric lines in Mexico could be expropriated in the event of a *severe worldwide oil and gas shortage that threatens Mexico's national security.* *However, LNG is not covered by the Mexican constitution, so risk of its expropriation is low.*	There are not electric facilities in Mexico in the plan of service for Option A. *LNG is not covered by the Mexican constitution, so risk of its expropriation is low.*
Security of Supply, Terrorism	Minimal risk to LNG plants, power plants and electric substations in either U.S. or Mexico due to defined security perimeter. Greatest risk is on overhead electric transmission at lines, which are difficult to secure. Minimal risk on submarine lines.	Minimal risk to LNG plants, power plants and electric substations in either U.S. or Mexico due to defined security perimeter. Greatest risk is on overhead electric transmission at lines, which are difficult to secure.
Future Upgradeability	Future improvements in submarine cable technology are likely to make increased cable ratings possible. HVDC terminal equipment can be designed for future expansion.	HVDC terminal equipment can be designed for future expansion.

Backup Pipeline Capacity for Loss of LNG Terminal or Supply	Backup source of natural gas supply to Costa Azul generation from U.S. sources would be needed, along with southbound pipeline capacity, in the event of an extended LNG facility or supply disruption.	Good proximity of Moreno and Blythe to backup U.S. pipeline sources in the event of an extended LNG facility or supply disruption.

Source: KEMA

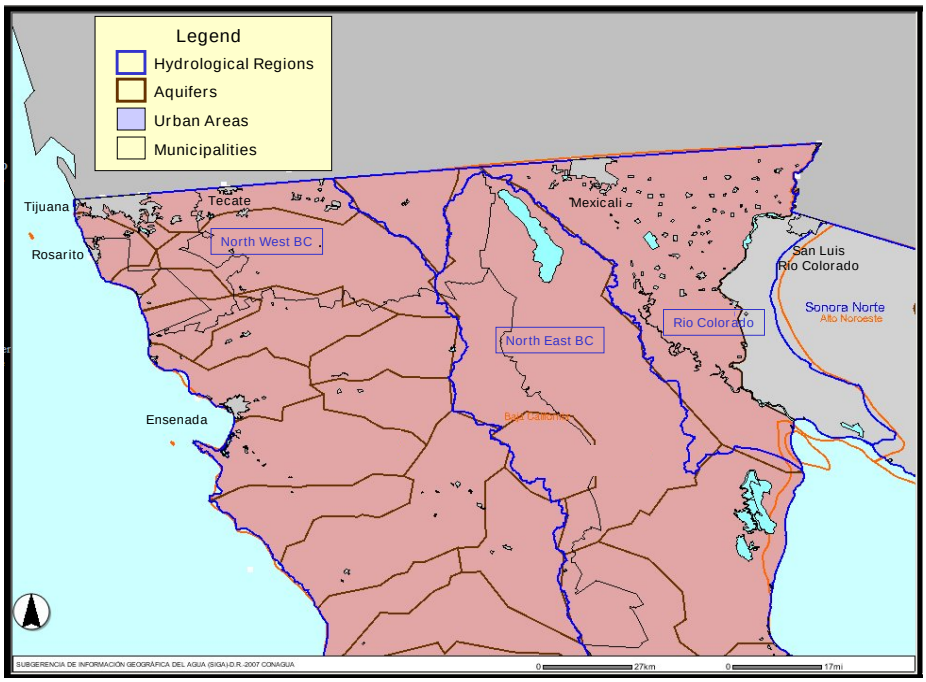
APPENDIX E:

Sources of Cooling Water to Support Large Scale Thermal Generation Expansion in Baja California

Thermal generation of electricity requires the rejection of significant amounts of thermal energy to the environment. Thus, the availability of cooling water is an important consideration in the site selection process for power plants, particularly in extremely hot and dry climates such as that of Northern Baja. Obviously, the preferred approach is if the generating plant is located near a large body of water, such as a river, a lake or the ocean, where large volumes of water are available for cooling. Alternatively, the waste heat can be transferred to the ambient air in large heat exchangers or cooling towers, in which water is evaporated to enhance the cooling process. While such dry air cooling options are readily adapted for use in temperate to cold climates, the high temperatures experienced in the inland areas of Baja during many months of the year typically require the use of cooling water to enhance the plant's economic performance. Even the use of "dry cooling" requires a significant volume of make-up water, although considerably less than conventional once-through water-cooling systems.

The hydrology of the northern Baja region is summarized in Figure E-1.

Figure E-1: Northern Baja California Hydrology



Source: Comisión Nacional del Agua – Sistema de Información Geográfico

Baja possesses few hydrologic resources. Except for the southern terminus of the Colorado River,[34] there are no natural, year-round surface drainage resources in the state. Available surface water is seasonal and experiences high evaporation rates. The presence of lakes, rivers, springs, arroyos and other surface drainages is extremely limited, and annual precipitation for a large part of the state is below 2 inches. For those few areas where rains do occur, precipitation is limited to 8 to 12 inches per year. Therefore, recharging of underground hydrological resources is also limited. Extraction from underground resources is highly restricted, with many fields limited to the supply of water for urban areas. However, agricultural use is permitted in some areas with access to other sources of water, such as the Valley of Mexicali.

Eighty-eight percent of the total fresh water hydrologic resources of Baja are located in the Mexicali Valley, and 57 percent of that water comes from the Colorado River. Of the remaining 43 percent, surface waters account for 63 percent of the volume and underground sources for the remaining 37 percent. In the areas of Tijuana-Rosarito and Tecate most of the water comes from the Colorado River via an aqueduct, with the balance from various underground hydrological sources (wells) and surface water stored in dams. In Tijuana, 94.5 percent of the water comes from the Colorado River, with only 4.4 percent originating in wells and a mere 1.1 percent from surface water.[35]

The hydrological resource map in Figure E-1 shows the three hydrological regions encompassing Northern Baja: Northwest Baja (Ensenada); Northeast Baja (Laguna Salada); and the region simply referred to as the Colorado River, which reaches into Northwestern Sonora State.

The Northwest Baja hydrological region possesses a large hydrological net consisting of rivers and numerous arroyos, but the majority of these are intermittent. The only three reservoirs in the State are located in this region: the Abelardo L. Rodriguez Dam, the El Carrizo Dam and the Emilio Lopez Zamora Dam. These resources are barely sufficient to serve the domestic uses of the growing population, as well as farming and industrial activities. Therefore, the electric generating capacity in this region is clustered on the Pacific Coast of Baja, at Rosarito Beach, where abundant seawater is available for cooling.

The Northeast Baja hydrologic region presents superficial drainages fed by occasional rains that drain in the Sea of Cortez and the Laguna Salada-Arroyo del Diablo field which borders with the east slope of the Juarez Sierra and the west slope of the Cucapah Sierra. Water use in this region is mainly for domestic and farming use.

The Colorado River hydrological region is located in the Northeast area of the State, and it is constituted by the territory located west of the State of Sonora and east of Baja, and the final portion of the Colorado River. The Valley of Mexicali is located within this region. It should be

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[34] It should be noted that 100 percent of the available fresh water from the Colorado River is typically drawn off for agricultural and municipal uses before the river reaches its delta in the Gulf of California.

[35] Tijuana Master Plan for Water and Wastewater Infrastructure, 2001, page 2-27

noted that the La Rosita Generating Complex and the Termoeléctrica de Mexicali generating plant, which are both located in Mexicali, use treated wastewater from the City of Mexicali in order to avoid impacting the sparse water supplies in the area. Even given this reliance on treated wastewater, during siting of these plants local environmental groups argued for the use of dry cooling towers in order to eliminate unnecessary evaporation of such scarce water resources. In fact, no additional recycled water volume is projected to develop in Mexicali in the foreseeable future.

The option to use dry cooling tower technology also would not fully mitigate the cooling water constraint. While evaporatively enhanced "dry cooling" towers require much less water than conventional "wet" cooling towers, both types must purge the dissolved solids (salts) that become increasingly concentrated as the water evaporates. Furthermore, the ongoing discharge of high-salinity effluent that results from the cooling of generating plants in the Mexicali area enters the New River, which flows northbound across the U.S.-Mexico border and then empties into the Salton Sea in the Imperial Valley. Increasing concerns about high water salinity in the bird breeding areas around the Salton Sea could significantly limit further power plant development in the Mexicali area.

Plant siting in desert regions such as Baja could also benefit from a novel approach to extract water from power plant flue gas using membrane technology is currently being pursued as a research and development project by European researchers.[36] Initial research indicates that utilization of such membrane technology on a 400 MW coal-fired plant fitted with a flue gas desulfurization system could potentially recover as much as 20 percent of the moisture content from the flue gases, resulting in recovery of 30 tons of water an hour at the plant. Once recovered this water can serve part of the cooling water requirements of the plant. While it is possible that similar technology could be extended to gas-fired plants, the theoretical level of water extraction would be lower in such applications.[37] However, if the technology is successfully commercialized for gas-fired plants, it could be beneficial to siting and operation of future power plants in desert regions such as Baja and Southern California.

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[36] *Water-Guzzler Turns Water Producer*, Global Contact – KEMA's Quarterly Publication, September 2007.

[37] Personal communication with Frank de Vos, KEMA Netherlands.