

# **Chapter 7. Natural Gas Facilities and Transmission Pipelines**

## **FOCUS OF THE REVISED DRAFT EIR/EIS ANALYSIS**

This chapter updates the 1995 DEIR/EIS assessment of Delta Wetlands Project effects on PG&E natural gas facilities and transmission pipelines. During the Delta Wetlands water right hearing, PG&E presented testimony regarding its easements and natural gas pipelines that cross Bacon Island. The testimony focused on the ways in which proposed Delta Wetlands water storage operations could:

- adversely affect PG&E's ability to use its easements,
- decrease the useful life of the pipelines,
- require additional pipeline maintenance,
- increase the threat of pipeline damage,
- reduce or inhibit pipeline access for routine or emergency repairs, and
- interrupt gas supply.

The future use of PG&E's easement is a private property rights dispute. The real property issues are not addressed in this REIR/EIS. Issues related to the operation and maintenance of the pipeline on Bacon Island and the possibility of impacts on regional natural gas service are considered potential environmental effects that require explanation and analysis. This chapter updates and supplements the discussions of the Bacon Island pipeline issues originally described in Chapter 3E, "Utilities and Highways", of the 1995 DEIR/EIS.

### **Summary of Issues Addressed in This Chapter**

The analysis presented in this chapter addresses the following questions:

- What effect will reservoir operations have on the integrity, operation, and maintenance of PG&E's natural gas pipelines across Bacon Island?
- What effect will reservoir operations have on emergency access to the pipeline?

## Sources of Information

Information used to prepare this chapter is taken from comments on the 1995 DEIR/EIS and from evidence and testimony provided by PG&E and Delta Wetlands at the water right hearing. In addition, data from the U.S. Department of Transportation (DOT), Office of Pipeline Safety (U.S. Department of Transportation 1999), were used in this assessment.

## Definition of Terms

The discussion of gas facilities and pipelines in this chapter includes some terms that may not be familiar to all readers. The following are definitions of these terms as they are used in this chapter:

- *Anticorrosion Coating:* The coating of pipelines with paint, epoxy, or other materials to prevent contact of dissimilar metals. The barrier prevents establishment of a corrosion current and corrosion of the pipe.
- *Bending Load:* The result when the opposite ends of an item are forced together (as when a sheet of paper is folded). Pipelines can be subject to this type of load.
- *Cathodic Protection System:* A process used to prevent pipeline corrosion by passing an electric current through the pipe. When dissimilar metals (the pipeline and soil minerals) are placed in solution together, a corrosion current is established. The cathodic protection system creates an opposite current to minimize corrosion.
- *Firm Storage Capacity:* An amount equivalent to guaranteed storage capacity. Utility rates usually vary based on guarantee of service. The first priority is to meet firm demands; consequently, this demand is most expensive. Demands that can be met with less reliability are less expensive.
- *Internal Inspection:* A process required for pipelines. A robotic device, commonly called a "pig", is sent along the inside of the pipe. The pig measures the resistance of electrical current from the pipe to the ground. Areas with abnormally low resistance indicate damage to the pipe's anticorrosion coating.
- *Load Center:* In the utility business, a concentration of demand or users. For example, the Sacramento metropolitan area is a load center. The area consists of a large group of residential, municipal, and industrial users. The cumulative demand of the load center is considered when utility transmission and storage facilities are developed.
- *Pipeline Balancing:* The process of distributing pipeline capacity to efficiently provide service to competing load centers.

- *Shear Load:* The result when force is applied perpendicular to or on opposite sides of an item (as when a sheet of paper is cut with scissors). Pipelines can be subject to this type of load.
- *Third Party:* An entity that affects a property, but is not the owner of the property (first party) or an agent of the owner (second party).
- *Unbundled Rates:* The individual rates for separate service components of a particular utility. For example, natural gas utilities can be broken down into separate service components such as gas procurement, transportation, storage, and delivery, with distinct rate schedules for each service. Deregulation of the utility industry has allowed this unbundling of services to promote market competition.

## AFFECTED ENVIRONMENT

PG&E owns two high-pressure gas transmission pipelines that cross Bacon Island (Figure 7-1). Line 57-B, constructed in 1974, serves as an input and output conduit for gas stored in the McDonald Island Storage Field; Line 57-A has been removed from operation and has been capped. However, Line 57-A could be used in the future.

### Natural Gas Service

Line 57-B connects PG&E's interstate and intrastate gas transmission and distribution system to the utility's underground natural gas storage facility under McDonald Island (Figure 7-2). The McDonald Island Storage Field is used primarily to supply gas to the Bay Area and Sacramento/Stockton load centers when other resources, such as gas production fields in Canada and the southwestern United States, are inadequate to meet instantaneous (i.e., peak) demands. The McDonald Island storage facility has supplied gas for up to one-third of PG&E's customers during peak demand periods (Stoutamore pers. comm.).

In 1996, PG&E and other natural gas industry representatives adopted the Gas Accord Settlement. This settlement is the result of an extensive negotiation process that PG&E initiated several years ago. The settlement parties, representing a diverse cross-section of natural gas industry participants, have achieved a far-reaching and comprehensive settlement that restructures PG&E's natural gas services, redefines its role in the gas market, and establishes guaranteed transmission rates. The Gas Accord significantly increases competition and economic efficiency in the Northern California gas industry. It enables customers and marketers to participate fully in the increasingly deregulated, inter-regional natural gas markets, with the goal of achieving lower energy prices through increased competition and customer choice. The accord provides for guaranteed, unbundled, cost-based transmission rates.

The Gas Accord allows continued operational integration of PG&E's gas storage and transmission facilities. PG&E will reserve firm storage capacity for pipeline balancing services. PG&E's Core Procurement Department will contract for a portion of the utility's firm storage capacity on behalf of the core (PG&E's customers). The remaining storage capacity will be marketed in an unbundled storage program that requires PG&E to provide storage to third parties. The McDonald Island Storage Field is PG&E's largest underground natural gas storage facility, and Line 57-B is the only link between the storage field and the PG&E distribution system. Under the new Gas Accord, PG&E's role as a storer of natural gas will increase; consequently, PG&E's use of the McDonald Island Storage Field and reliance on Line 57-B will also increase.

### **Pipeline Design Criteria**

The DOT Office of Pipeline Safety comprehensively regulates the design, construction, testing, operation, and maintenance of natural gas pipelines and associated facilities in accordance with 49 CFR 192. The following general requirements govern the use of natural gas pipelines:

- The materials for the pipe and components for use in pipelines must maintain structural integrity under temperature and other environmental conditions that may be anticipated. They must be chemically compatible with any gas that they transport.
- The pipe must be designed with sufficient wall thickness or installed with adequate protection to withstand anticipated external pressures or loads.
- Each pipeline component must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability.
- The pipeline must be protected from external corrosion by an external protective coating and a cathodic protection system.
- Before a new, repaired, or relocated pipeline can be placed into service, it must be tested to substantiate its maximum allowable operating pressure and to confirm that each leak has been located and eliminated.
- The operator shall prepare and follow a manual of written procedures for conducting operations and maintenance activities, responding to emergencies, and handling abnormal conditions.
- The operator shall have a patrol program to observe surface conditions on and adjacent to the pipeline right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.
- A pipeline that is abandoned in place or deactivated must be disconnected from all gas sources, purged of gas, and sealed at the ends.

Line 57-A is 18 inches in diameter and Line 57-B has a diameter of 22 inches. Both pipelines are buried as they cross Bacon Island and are designed to operate under temporarily flooded conditions or in saturated soils. The pipelines as constructed are engineered and built to withstand more than the external pressure that would be applied by the load, or weight, of water under full reservoir conditions. Normal operation or integrity of a pipeline would not be impaired by the pressure of overlying water in a full reservoir. According to PG&E's easements, Line 57-A is buried at a minimum of 4 feet and as much as 8 feet below the ground surface; Line 57-B is buried at a minimum of 3.5 feet below the ground surface. Line 57-A has concrete weights, except along approximately 900 feet on the west side of the island, where the pipeline is concrete coated. Line 57-B is entirely concrete coated. Concrete coating and weighting prevents the pipeline from floating out of the trench when inundated or when saturated soils would not have the strength to resist the pipeline's buoyancy. Line 57-B is currently rated for pressures up to 2,160 pounds per square inch (psi) and can convey approximately 1.25 billion cubic feet per day (Bcf/day). As mentioned previously, Line 57-A has been removed from operation and has been capped.

### Pipeline Safety

Historically, natural gas transmission and distribution lines and associated facilities have had a very low probability of a full-scale rupture that could lead to an explosion resulting in property damage or fatalities. The most recent data available from the DOT Office of Pipeline Safety for 1985 through 1999 (U.S. Department of Transportation 1999) indicate the following:

- Approximately 1.7 million miles of natural gas transmission and distribution pipelines are present in the United States; these lines are subject to DOT jurisdiction. Transmission pipelines include pipelines of similar diameter and operating pressure to the PG&E pipeline crossing Bacon Island. Distribution pipelines are smaller in diameter and operated at a lower pressure than the PG&E pipeline crossing Bacon Island.
- During the data collection period, 1,302 reportable incidents (significant leaks) occurred in the nation on natural gas transmission projects similar to the proposed project. The causes of the leaks were identified as follows (totals less than 100% because of rounding):
  - 527 incidents (40%) were related to various construction or operating errors, or to other unspecified causes (e.g., improper welding or maintenance);
  - 368 incidents (28%) were caused by a third party, such as agricultural operations, and 62 of these occurred on pipelines that were unmarked;
  - 300 incidents (23%) were caused by corrosion, and 261 of these were related to uncoated pipelines; and
  - 107 incidents (8%) were caused by natural or geologic forces (8 by subsidence, 4 by flooding, and 3 by channel scour).

- Of the 1,302 incidents:
  - 880 (68%) were on projects constructed before the current Minimum Federal Safety Standards (CFR 49 Part 192) were promulgated in 1970 (35 FR 13257), and therefore on pipelines greater than 30 years old.
  - Most leaks were repaired or made safe in less than 1 day:
    - 540 leaks (41%) were repaired or made safe in less than 1 hour;
    - 1,062 leaks (81% inclusive) were repaired or made safe in 3 hours or less; and
    - 36 leaks (less than 3%) took 24 hours or longer to repair or make safe.
  - 35 incidents were reported in California.

From the DOT data presented above, it can be concluded that the transmission pipelines that are least prone to leaks or other accidents are those that have been constructed since 1970 and operated in accordance with minimum federal safety standards, are coated to prevent corrosion, and are well marked. In the Delta region of California, where there is risk of subsidence, flooding, channel scour, and seismic activity, no incidents of pipeline rupture or leak related to natural forces have been reported. In addition, no incidents related to corrosion or outside forces were reported. The only incident reported occurred at an above-ground metering facility where a seal failed on an odorant pump.

## **IMPACT ASSESSMENT METHODOLOGY**

### **Analytical Approach and Impact Mechanisms**

Impacts on natural gas facilities and service were assessed based on the ways in which construction and operation of the Delta Wetlands Project alternatives would benefit or adversely affect the existing utility infrastructure or service. Effects of the project alternatives on gas transmission lines and facilities on the project islands were determined through correspondence with the affected utility company and other experts. Under the Delta Wetlands Project, Bacon Island, which is now used for agricultural operations, would be used for reservoir storage. The levees around the island would be reinforced and the island would be inundated when water is available for diversion from the Delta. Flooding the island and improving the project levees may affect the conditions under which the existing gas pipeline is operated and maintained.

## Criteria for Determining Impact Significance

An alternative is considered to have a significant impact on the gas facilities and services if, when compared to existing conditions, it would:

- result in a substantial disruption to existing natural gas service;
- increase risk of structural failure of gas facilities and pipelines;
- result in a need for substantial alterations to, or increased maintenance of, natural gas facilities; or
- result in increased demand for existing emergency services beyond their current capacity.

An alternative is considered to have a beneficial effect if it would improve the existing utility infrastructure when compared to existing conditions.

## ENVIRONMENTAL CONSEQUENCES

Flooding of the PG&E easement on Bacon Island under proposed Delta Wetlands Project operations would not increase the risk of structural failure of the operating gas pipeline or cause a physical change in PG&E's ability to supply gas to Bay Area or Sacramento/Stockton load centers. Flooding the island would probably change the manner in which PG&E monitors its pipelines and repairs leaks to the pipeline. These impacts are discussed below; Table 7-1 provides a comparison between the 1995 EIR/EIS and REIR/EIS impact conclusions.

### Risk of Pipeline Leak or Rupture Resulting from Island Inundation

In the long term, the risk of pipeline leak or rupture, which is generally caused by corrosion, ground settlement, or physical damage from ground-disturbing equipment (e.g., farm equipment), would not increase under proposed project operation. The risk of pipeline rupture would decline because implementation of the Delta Wetlands Project would substantially reduce ground-disturbing activities by eliminating agricultural practices such as installation of internal drainage ditches that may cross the pipeline easement on Bacon Island. However, as described in the next section, risks to the pipeline could increase during Delta Wetlands' construction of levees.

The pipelines across Bacon Island would not require major structural modification for use under the submerged conditions caused by implementation of the proposed project. The operating

gas pipeline (Line 57-B) on Bacon Island is concrete coated to prevent it from floating when the land is flooded or when the overlying soils are not strong enough when saturated to overcome pipeline buoyancy. The soils along the easement are already likely to be saturated at the depth of the pipeline because of a high water table.

The currently unused pipeline (Line 57-A) on Bacon Island may need additional weighting before the island is flooded to prevent the line from floating (Grimm pers. comm.). As mentioned previously, Line 57-A has concrete weights, except for approximately 900 feet on the west side of the island where the pipe is concrete coated. Under inundated conditions, Line 57-A could float, resulting in unanticipated bending loads that could damage its anticorrosion coating and disrupt the cathodic protection system. Therefore, inundating the island without proper weighting may substantially damage Line 57-A. Although Line 57-A is not used now, PG&E may choose to use it in the future. The need to weight the pipeline is considered a substantial alteration to the existing system. This impact is considered significant and the following mitigation is recommended.

**Mitigation Measure: Securely Anchor Line 57-A before Bacon Island Flooding.** Delta Wetlands shall reimburse PG&E for engineering studies, materials, and construction expenses to securely anchor Line 57-A before reservoir operations begin on Bacon Island.

### **Risk of Pipeline Leak or Rupture Resulting from Levee Improvements**

The proposed levee buttressing could locally increase the rates of levee settlement or subsidence where the gas pipelines penetrate the Bacon Island exterior levees. Levee settlement or subsidence could increase the shear or bending loads on the pipeline, depending on the location of the pipeline with respect to the compressible levee foundation materials.

Under existing conditions, PG&E is required to maintain these pipelines at levee crossings and to improve or modify the lines in response to ongoing levee repair activities. PG&E designs and installs pipelines in the Delta region with an understanding of internal island subsidence problems (see Chapter 3D in the 1995 EIR/EIS for a discussion of subsidence in the central Delta) and of ongoing levee maintenance activities that can increase risks of pipeline failure through differential settlement and line exposure. PG&E commonly practices corrective measures necessary to relieve excessive pipeline stress resulting from levee settlement. The levee improvements proposed by Delta Wetlands are greater than those conducted under ongoing levee maintenance activities. As a result, the need for corrective measures and associated costs may increase during levee construction and settlement when compared to existing pipeline maintenance requirements. The potential for substantial pipeline stress resulting from Delta Wetlands levee improvements is considered a significant impact. The following mitigation measures are recommended.

**Mitigation Measure: Monitor Locations Where Gas Pipelines Cross Bacon Island Levees during and after Levee Construction.** During levee strengthening, Delta Wetlands engineers will install equipment to monitor levee settlement and subsidence rates. After levee completion, Delta Wetlands will conduct weekly inspections to check for potential problems at the gas pipeline crossings, including concerns about levee stability, settlement, and subsidence. If the weekly inspection indicates that settlement, erosion, or slumping at the gas pipelines has occurred, Delta Wetlands will notify PG&E and will implement corrective measures to mitigate any decrease in levee stability near the gas lines (see below).

**Mitigation Measure: Implement Corrective Measures to Reduce Risk of Pipeline Failure during Levee Construction.** Delta Wetlands shall reimburse PG&E for the incremental increase in maintenance costs associated with installation of new pipeline segments under Bacon Island levees or implementation of other appropriate corrective measures, which would prevent damage to the gas pipeline from increased bending or shear loads at levee crossings during levee construction and settlement.

### **Potential Interference with Pipeline Inspection Procedures**

As part of its pipeline operation, inspection, and maintenance procedures required by federal and state regulations (49 CFR 192 and California Public Utilities Commission [CPUC] General Order 112), PG&E conducts annual aerial and walking inspections along the pipeline route to check for small leaks, evidence of internal or external corrosion, or easement encroachment (e.g., new drainage ditches). Valves are also regularly monitored for pressure fluctuations that could be caused by leaks (Grimm pers. comm.). Implementation of the Delta Wetlands Project would not alter PG&E's methods for routine inspection of the pipeline. Walking inspections for minor leaks would have to be scheduled during dry periods, or inspections could be conducted by boat when the island is flooded. To ensure that PG&E has access to the line for annual inspections under wet as well as dry conditions, the following mitigation is recommended.

**Mitigation Measure: Provide Adequate Facilities on Bacon Island for Annual Pipeline Inspection.** Delta Wetlands shall provide a suitable ramp and turnaround facilities to launch a boat for regular pipeline inspections, and should provide a suitable staging area for equipment and materials needed for gas pipeline repairs.

PG&E also monitors the pipelines using internal inspection and cathodic protection testing. No valves are located on Bacon Island, and internal inspection ("pigging") could occur regardless of dry or wet conditions. Flooding the island would inundate cathodic protection test stations, rendering them unusable. The cathodic protection test stations would need to be relocated before flooding of Bacon Island. This impact is considered significant and the following mitigation is recommended.

**Mitigation Measure: Relocate Cathodic Protection Test Stations before Bacon Island Flooding.** Delta Wetlands shall reimburse PG&E for engineering studies, materials, and construction expenses to relocate cathodic protection test stations to the perimeter levee system, and shall grant PG&E an easement to access the relocated cathodic protection test stations.

### **Potential Delay in Emergency Repairs and Unscheduled Interruption of Service**

As described previously, the risk is very low that a pipeline leak or rupture would occur on Bacon Island, and if a leak or rupture occurred, it is equally likely to occur under dry conditions as under wet (i.e., full or partial-storage) conditions. This conclusion is based on the following considerations:

- Pipeline ruptures or leaks on Bacon Island under the proposed project would be caused by internal or external corrosion or levee settlement or subsidence loads. In recent years, no pipeline ruptures in the Delta have been caused by these modes (U.S. Department of Transportation 1999). PG&E more often must respond to leaks caused by farm equipment; emergency repairs in the Delta caused by ground-disturbing equipment generally occur once or twice a year (Warner pers. comm.).
- Annual inspections to detect small leaks, identify internal or external pipeline corrosion, identify potential levee subsidence or settlement problems, and prevent future pipeline ruptures or substantial pipeline leaks in those areas by prescribing immediate repair work will still be conducted in accordance with federal and state regulations.
- Based on modeling of water storage operations for the proposed project (see Chapter 3), it is estimated that Bacon Island would be at full storage (filled by the end of December) fewer than 50% of winters, and the reservoir islands would be empty in 437 of the 864 months simulated for the 72-year hydrologic record, or approximately 51% of the time. Therefore, opportunities for repair and replacement of damaged pipeline segments under dry conditions will occur about 50% of the time.

If repairs are needed during flooded conditions on Bacon Island, the Delta Wetlands Project could increase the cost of repair operations, extend the time required by PG&E to make necessary repairs, and possibly increase the duration of service curtailments. The following sections describe the emergency repair procedures and the effects on service under existing conditions and with the Delta Wetlands Project in operation.

## Existing Conditions

**Emergency Repair Procedures.** PG&E is required by the CPUC (CPUC General Order 112(e), which adopts 49 CFR 192) to maintain an emergency-preparedness plan. As described in the hearing testimony, PG&E has a supply of materials and specially trained welders and equipment operators for emergency shallow-water repairs of its pipeline facilities. PG&E's testimony also states that the pipelines crossing Bacon Island are under water most of the time because of shallow groundwater, and that those conditions require special procedures to facilitate repairs.

PG&E stated that it could probably mobilize crews within several weeks under existing (i.e., dry) conditions. The time required for repair cannot be estimated without knowing the conditions that led to the rupture and the extent of the rupture; PG&E would assess both of these factors after excavating and inspecting the damaged portion of the pipeline. To respond to a pipeline failure on Bacon Island under existing conditions, PG&E would:

- shut off gas flowing through the line at the nearest valves (on McDonald Island, 2.9 miles east of the east side of Bacon Island, and 5.2 miles west of the west side of Bacon Island) and isolate the pipeline segment;
- release gas within the pipeline section that crosses the island at one of the shut-off valves; and
- drive equipment to the leak site, excavate the pipeline, dewater the working pit (because of shallow groundwater levels, some dewatering is probably necessary even during the summer), cut out the damaged section, weld a new section in place, and test the pipeline (Warner pers. comm.).

**Effects on Service.** If Line 57-B were damaged and removed from service, PG&E would curtail deliveries to customers if supplies were not adequate to meet demand. PG&E stated in its testimony that, under existing conditions, it distributes natural gas from three sources: the 400 and 401 lines from Canada, the 300 line from southern California, and local production. Additionally, PG&E stated that these sources of gas currently cannot meet the peak gas demand that occurs during cold weather. Line 57-B connects the McDonald Island storage facility to the distribution system to provide peak capacity and redundancy of supply if one of the other sources is interrupted. If the McDonald Island storage facility were not online during a peak-demand period, PG&E would attempt to balance its system and purchase additional gas to minimize service interruptions; however, PG&E's ability to respond to the situation is limited because the pipelines that connect to the gas sources have limited capacity.

Natural gas, like other utility services, has multiple price schedules based on delivery of the service. A supply that is interruptible is less expensive than a firm supply. If gas service must be curtailed, customers with interruptible supplies would be affected first. Customers with interruptible supplies are usually industrial users that can switch to alternative fuels, such as the electricity-generating facilities in Pittsburg, which can switch to fuel oil when natural gas supplies are curtailed (which occurred during the winter of 1997). Many firm-supply customers may not have an

alternative fuel supply. During service interruptions, PG&E would not be able provide alternative service to all customers, and it would be up to customers to meet their individual needs.

## **Delta Wetlands Project Conditions**

**Emergency Repair Procedures.** Under Delta Wetlands Project conditions, the procedure for pipeline repair described previously would still be used when the reservoir island is not flooded (i.e., during dry periods). PG&E testified that a repair conducted when Bacon Island is partially flooded could be completed using similar techniques as under without-project conditions, except that access to the site may require use of a boat or barge, depending on the depth of stored water relative to the height of existing roads across the island. After accessing the site, PG&E could install sheet piles around the damaged area, dewater a work area, and then complete the pipeline repair as if it were under dry conditions (Clapp testimony). However, because of the logistical problems associated with accessing the site and installing sheet piles around a larger area, PG&E would require additional resources and planning time and would incur greater costs using these techniques under flooded conditions than under dry conditions.

Alternatively, as suggested in the water right hearings, underwater repair methods could be used to repair a damaged pipeline. PG&E stated that it is not currently equipped to service pipelines through water with divers and underwater welding equipment (Warner pers. comm.). However, PG&E staff also testified that the utility has a supply of materials and specially trained welders and equipment operators for emergency shallow-water repairs of its pipeline facilities (Clapp testimony). Nevertheless, underwater repair methods would be costly and require specialized equipment and do not appear to be a practical alternative at this time.

The final practicable repair option is to shut down the pipeline, empty the reservoir, and use dry-condition repair techniques. If a significant pipeline leak occurred on Bacon Island during water-storage operations and the leak could not be repaired by installing sheet piles and dewatering a work area, the pipeline would probably have to be shut down until the reservoir could be drawn down and conventional dry-conditions construction techniques could be used. According to Delta Wetlands' testimony, drawing the stored water down at the maximum rate assuming a full reservoir would take at least three weeks, assuming that Delta Wetlands' operational rules would allow discharge at the maximum rate. Additional time would be required to allow the land surface to dry before equipment could be operated on the ground surface, possibly substantially increasing the waiting period before the pipeline could be repaired. This repair technique, in addition to using sheet piling, appears to be the most practical repair method available if an emergency occurred during reservoir operations.

Additionally, the 1995 DEIR/EIS suggested that directional drilling, which is used for pipeline repairs at Delta channel crossings, would be a practical repair solution. When a line fails under a Delta channel, PG&E directionally drills under the channel adjacent to the damaged line and pulls a new pipeline segment. The new pipeline segment is welded into the existing line on both sides of the channel, and the damaged line is sealed (usually filled with concrete) and abandoned in place. However, under closer review, this technique is not a practicable solution to repair the line across Bacon Island. To drill entirely under Bacon Island, the entrance and exits of the bore would

need to be located on the land on Palm Tract and McDonald Island, greatly increasing the bore length (from about 2 miles to 5 miles).

Although technically possible, the construction of a new line under Bacon Island when the reservoir is full would be costly and time-consuming. It could take months to design the new pipeline segment, mobilize the appropriate equipment, obtain the pipe, and secure the necessary permits and leases from the regulatory agencies. For example, the California State Lands Commission requires that detailed engineering plans be prepared and approved before it will grant a lease to cross state lands (the channels adjacent to the Delta Wetlands islands), and the California State Reclamation Board requires that PG&E receive an encroachment permit from the local reclamation district before construction.

Shorter pipeline segments could be installed using directional-drilling techniques by creating temporary gravel islands within Bacon Island. However, the necessary equipment would be difficult to transport to the site. Barges are typically used to move such equipment, but they would not have access to the island interior. A large crane would be required to lift equipment over the levee, from the adjacent channel to the island interior. The storage level (water depth) at the time of repair could limit the size of equipment that could be used, further slowing the repair process. As with a single directional drill, it could take months to design the new pipeline segment, mobilize the appropriate equipment, obtain the pipe, and secure the necessary permits and leases from the regulatory agencies. This does not appear to be a practicable repair technique on Bacon Island.

PG&E contends that the only suitable solution to potential adverse effects on its pipelines and potential interruption of service would be construction of new pipelines around the proposed project. The pipeline incident data collected by the DOT, however, do not support this conclusion. Pipelines very rarely fail catastrophically without external forces or third-party actions. Flooding Bacon Island and discontinuing the current agricultural activities would all but eliminate any potential third-party action that could damage the pipeline. Internal inspection, required by federal and state regulations, detects corrosion or abnormalities in the pipeline walls in advance of potential failure. Furthermore, it is a common industry practice to allow small leaks to go unremedied for months while engineering studies are completed and specialized equipment and personnel are mobilized.

In summary, conducting a repair while the reservoir is inundated or drawing the reservoir down before conducting a dry-land repair would take longer and cost more during Delta Wetlands reservoir operations when compared to existing conditions. Without knowing the specifics of the pipeline rupture, it is difficult to determine the magnitude of the effect on PG&E's repair time and associated costs of the additional time needed to plan for a shallow-water repair or the time required to draw down the reservoir.

**Effects on Service.** Inundation of the island under Delta Wetlands Project operations could slow PG&E's response time to repair a pipeline leak and could interrupt service for a longer period than would occur under existing conditions. As described above, a severe leak or pipeline rupture would take longer to repair under flooded reservoir conditions than the existing dry conditions. This delay in repairs could result in longer periods of using alternative gas sources.

## **Impact Conclusion for Potential Delay in Emergency Repair**

As evidenced by the Office of Pipeline Safety data, the long-term risk of catastrophic pipeline failure is very low under existing conditions, and implementation of the project would further reduce the risk to the pipeline from potentially damaging third-party activities. Flooding of Bacon Island could delay and complicate repairs to PG&E's pipeline facilities if a rupture occurred during water-storage operations. Flooding the island would also increase the cost of such repairs. If a repair required an immediate drawdown of the reservoir, it is simulated that all the water could be removed within three weeks (under full-reservoir storage) while appropriate engineering studies are being completed and before repair equipment and personnel could be mobilized. The three-week drawdown estimate assumes that Delta Wetlands discharges from Bacon Island would not be restricted by water quality mitigation measures or other operational constraints. The potential impact on PG&E's operations is an economic one. The incremental costs to PG&E (e.g., lost revenue and purchase cost of alternative supplies) and its customers resulting from an extended time required to repair the pipeline under project conditions cannot be determined but are recognized as a potential economic effect of the Delta Wetlands Project. Because economic effects are not considered environmental impacts under CEQA and NEPA, no significance conclusion is made and no mitigation is identified (see also Chapter 3K, "Economic Conditions and Effects", in the 1995 DEIR/EIS).

## **Cumulative Impacts**

Implementing the Delta Wetlands Project would not contribute significantly to cumulative risk of gas pipeline failure in the Delta. Activities in the Delta that could affect gas pipelines include agricultural activities and levee strengthening or maintenance. Because the Delta Wetlands Project would substantially reduce ground-disturbing activities, it would reduce the cumulative risk to pipelines from third-party activities (e.g., farming). PG&E monitors some levee crossings, including the Bacon Island and McDonald Island levee crossings, using monthly inspections of installed tilt meters at the levee crossings (Clapp testimony). Cumulative risks to gas pipelines at levee crossings in the Delta are considered less-than-significant because PG&E applies monitoring procedures and implements pipeline improvements in response to levee maintenance or settlement on an ongoing basis. Therefore, the cumulative effect on gas pipelines in the Delta is considered less than significant and no mitigation is required.

## **Impact Evaluation of Project Alternatives from the 1995 Draft EIR/EIS**

As described in Chapter 2, Bacon Island would be used for water storage under all three project alternatives evaluated in the 1995 DEIR/EIS. Consequently, effects on PG&E's gas pipeline would be the same under all alternatives. The impacts and mitigation measures described above for the proposed project (Alternative 2 in the 1995 DEIR/EIS) would also apply to Alternatives 1 and 3.

Table 7-1. Comparison between Delta Wetlands Project Impacts on Natural Gas Facilities  
in the 1995 DEIR/EIS and in the 2000 REIR/EIS

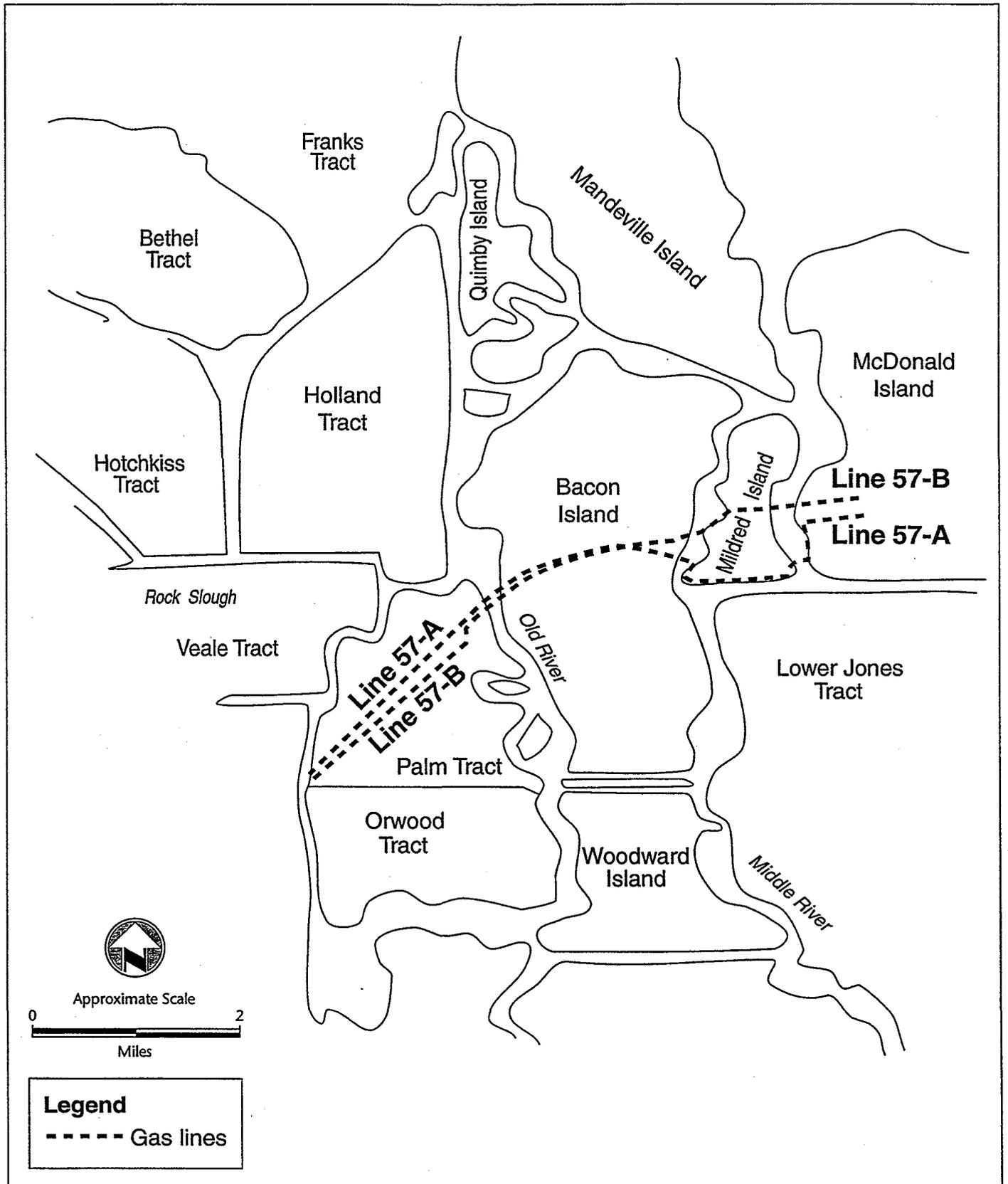
Impacts and Mitigation Measures of 1995 DEIR/EIS Alternatives 1 and 2	Differences between 1995 DEIR/EIS and 2000 REIR/EIS
----	<p><b>Risk of Pipeline Leak or Rupture Resulting from Island Inundation.</b> The risk of pipeline rupture would decline under project conditions because the project would substantially reduce ground-disturbing activities, such as agricultural practices, that could result in line rupture. This effect is considered beneficial. However, Line 57-A may require additional weighting before the island is flooded. The line could float under inundated conditions, resulting in increased risk of damage to this pipeline and the need for pipeline modifications. Therefore, this impact is considered significant and the following mitigation measure is recommended. (S)</p> <ul style="list-style-type: none"> <li>• Securely Anchor Line 57-A before Bacon Island Flooding. (LTS)</li> </ul>
<p><b>Impact E-3:</b> Increase in the Risk to Gas Lines Crossing Exterior Levees on Bacon Island (LTS)</p> <ul style="list-style-type: none"> <li>• No mitigation is required.</li> </ul>	<p><b>Risk of Pipeline Leak or Rupture Resulting from Levee Improvements.</b> Potential settlement issues or increased loads on the pipelines at the levee crossings may require corrective measures during levee construction and settlement. This impact is considered significant and the following mitigation measures are recommended. (S)</p> <ul style="list-style-type: none"> <li>• Monitor Locations Where Gas Pipelines Cross Bacon Island Levees during and after Levee Construction and</li> <li>• Implement Corrective Measures to Reduce Risk of Pipeline Failure during Levee Construction. (LTS)</li> </ul>

Note: S = Significant; SU = Significant and unavoidable; LTS = Less than significant; B = Beneficial.

Table 7-1. Continued

Impacts and Mitigation Measures of 1995 DEIR/EIS Alternatives 1 and 2	Differences between 1995 DEIR/EIS and 2000 REIR/EIS
----	<p><b>Potential Interference with Pipeline Inspection Procedures.</b> To the extent practical, walking inspections would be completed during dry periods; however, PG&amp;E would need to modify its inspection practices during inundated conditions by using a boat rather than a walking inspection. According to PG&amp;E, this represents a substantial alteration in PG&amp;E's maintenance procedures. Additionally, flooding Bacon Island would inundate cathodic protection test stations. This impact is considered significant and the following mitigation measures (described in the text) are recommended to assist PG&amp;E in conducting its routine maintenance and reduce the impact to a less-than-significant level. (S)</p> <ul style="list-style-type: none"> <li>• Provide Adequate Facilities on Bacon Island for Annual Pipeline Inspection.</li> <li>• Relocate Cathodic Protection Test Stations before Bacon Island Flooding. (LTS)</li> </ul>
<p><b>Impact E-4: Increase in PG&amp;E Response Time to Repair a Gas Line Failure on Bacon Island (LTS)</b></p> <ul style="list-style-type: none"> <li>• No mitigation is required.</li> </ul>	<p><b>Potential for Delay in Emergency Repairs and Unscheduled Interruption of Service.</b> Project operations would not preclude routine inspections and emergency repairs. However, reservoir operations on Bacon Island would delay and complicate the repairs of PG&amp;E's pipeline facilities that would be needed if a rupture occurred during water-storage operations. Flooding the island would also increase the cost of such repairs. The potential impact on PG&amp;E's operations is an economic one. The incremental costs, if any, to PG&amp;E and its customers resulting from an extension of time required to repair the pipeline under project conditions are recognized as a potential economic effect of the Delta Wetlands Project. Because economic effects are not considered environmental impacts under the California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA), no significance conclusion is made and no mitigation is identified (see also Chapter 3K, "Economic Conditions and Effects" in the 1995 DEIR/EIS).</p>

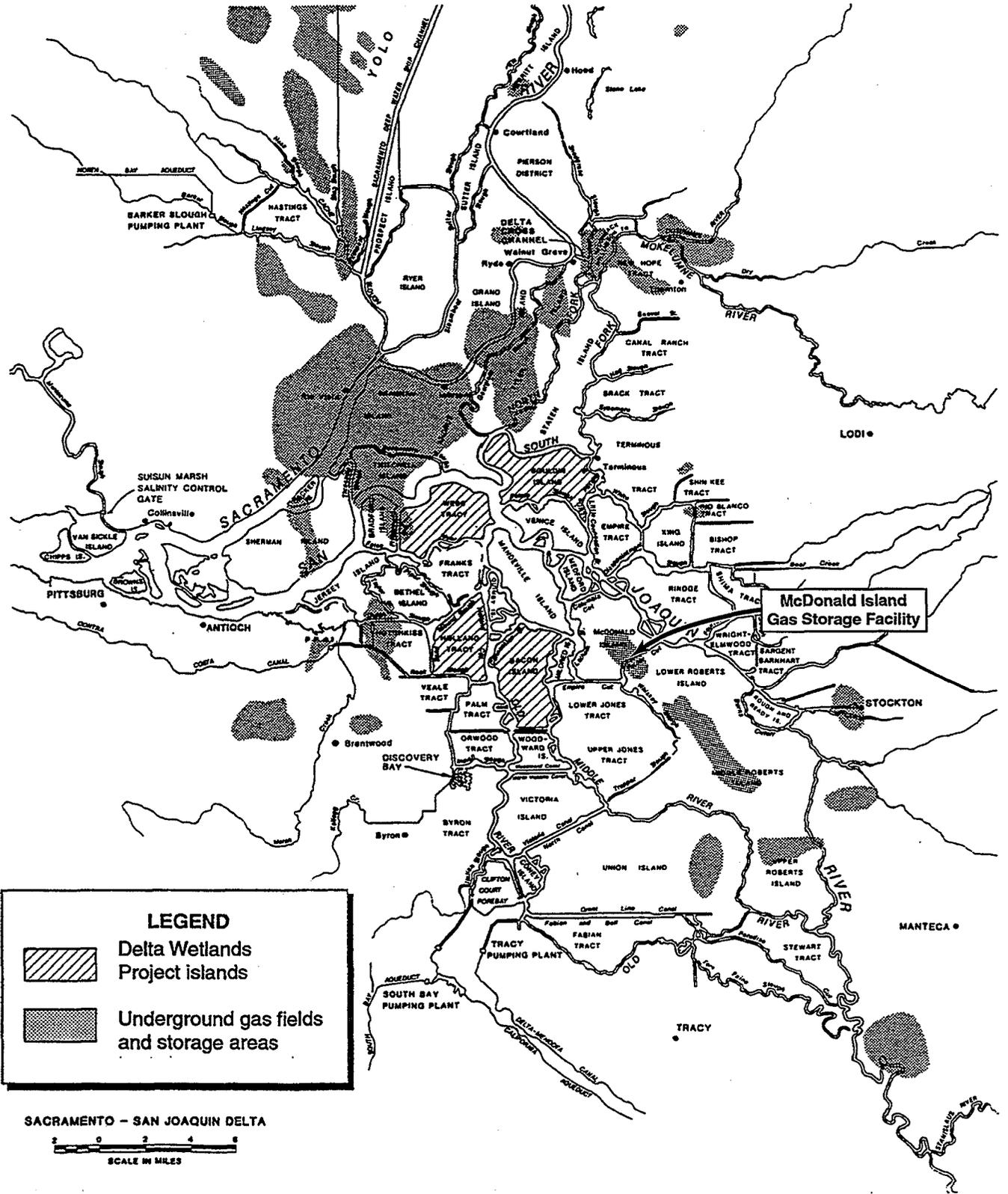
Note: S = Significant; SU = Significant and unavoidable; LTS = Less than significant; B = Beneficial.



Source: Bennett pers. comm., Forkel pers. comm.



Figure 7-1  
Gas Transmission Lines on Bacon Island



Source: DWR 1993.



**Figure 7-2**  
**Underground Gas Fields and Storage Areas**  
**in the Delta Wetlands Project Vicinity**