PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Executive Division Resolution GSRB-1
December 5, 2024

R E S O L U T I O N

RESOLUTION GSRB-1: GRANT'S PACIFIC GAS AND ELECTRIC COMPANY REQUEST FOR WAIVER OF A CLASS LOCATION CHANGE FOR A 491.4 FOOT SEGMENT OF A NATURAL GAS TRANSMISSION PIPELINE

SUMMARY

In this Resolution, the California Public Utilities Commission (Commission) grants Pacific Gas and Electric Company's (PG&E) request for a waiver of 49 Code of Federal Regulations (CFR) §§ 192.611(a) and (d) and 49 CFR § 192.619(a)[1] for one intrastate natural gas transmission pipeline segment totaling 419.1 feet in a rural, sparsely located area of San Bernardino County. The waiver allows PG&E to use various integrity management procedures and enhanced integrity management tools instead of replacing the pipeline segment, reducing operating pressure, or conducting a pressure test. This Resolution also imposes a number of conditions that PG&E must meet on an ongoing basis in order for the waiver to continue to be valid.

BACKGROUND

On October 20, 2023, PG&E submitted a request to the Commission's Safety and Enforcement Division (SED) Gas Safety and Reliability Branch (GSRB) seeking a waiver of certain regulations in 49 CFR §§ 192.611 and 192.619 for a 0.079375 miles (419.1 feet) segment of 34" diameter intrastate natural gas transmission pipeline. The pipeline segment is located in a rural, sparsely populated area of San Bernardino County, near the town of Boron. PG&E states that the Class Location of the segment increased from a Class 1 designation to Class 3 on November 8, 2022, due to the expanded (overflow) unpaved parking area adjacent to an existing improved (paved) truck stop parking lot.

Under 49 CFR § 192.611, a change in class location designation requires an operator to replace the segment of pipe or reduce the maximum allowable operating pressure.

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[1] Title 49 CFR §§ 190 through 199 are incorporated by reference in General Order 112-F.

49 CFR § 192.619 specifies the design pressures needed for each class location designation.

DISCUSSION

General Order (GO) 112-F is the "State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems."[2] The rules build upon the Federal Pipeline Safety Regulations, specifically, 49 CFR §§ 191, 192, 193, and 199.[3] Section 101.3 of GO 112-F allows for a utility, in special circumstances, to submit an application to waive compliance with specific rules in accordance with Section 3(e) of the Natural Gas Pipeline Safety Act of 1968.

PG&E submitted its request for waiver in accordance with the Pipeline and Hazardous Materials Safety Administration's (PHMSA) "Criteria for Considering Class Location Waiver Requests."[4] PG&E's request included the following information addressing the PHMSA criteria:

- Instead of replacing the segment of pipe, reducing the pressure, or performing a commensurate pressure test as required by 49 CFR §192.611, PG&E would implement enhanced integrity management procedures and use enhanced integrity management tools such as in-line inspection to mitigate risks.
- The 419.1-foot segment is part of a 43.63 mile inspection area. To replace this segment, PG&E would have to blowdown a significant section of the pipeline. This would release to atmosphere the entire contents (pure natural gas) of the section between nearest mainline valves of the segment at issue. These blowdown emissions are a short-lived climate pollutant and a lost resource that result in a pass-through financial cost to PG&E's customers. Further, PG&E would cause significant impacts to vegetation and soils to that short segment during excavation in order to replace and test pipe.
- Data confirming that the pipe design and construction met acceptable PHMSA criteria.

[2] GO 112-F, Section 101.1.

[3] GO 112-F, Section 101.2.

[4] Attachment 1 provides PG&E's detailed responses to the criteria.

- The segment has no history of pressure test failures and was last tested on March 9, 2012.
- The segment has a 40-inch depth of cover and there are no identified unstable soil conditions.
- There is no history of leaks, failures or systemic programs with the segment and the maximum preceding 5-year high pressure is noted as 830 pounds per square inch gauge (psig).
- The pipeline segment is included in PG&E's Transmission Integrity Management Program (TIMP). The last integrity inspection, using in line inspection, was conducted in 2021.

Based on its review, GSRB staff determined that this pipeline segment meets the criteria that the Office of Pipeline Safety (OPS) uses in considering whether to grant class location change waiver/permit requests. In making this decision, GSRB staff considered the following factors:

- This segment is not changing to a Class 4 location.
- This segment is not a bare pipe.
- This segment does not contain wrinkle bends.
- This segment is not operating above 72% specified minimum yield strength (SMYS).
- This segment was hydrostatic tested to at least 1.25 x MAOP.
- This segment was in-line inspected in 2021 with no significant anomalies identified that indicate systemic problems.
- This segment and its 43.63 miles of inspection area will be included in the PG&E's Integrity Management Program and periodically inspected with an in-line inspection (ILI) technique.

GSRB staff also concluded that integrity management technology, such as ILI, could identify and mitigate integrity issues that could threaten the pipeline segment and cause failure.

Based on these considerations, GSRB determined that granting PG&E's request to waive 49 CFR § 192.611(a) and (d) and 49 CFR § 192.619(a) for this 419.1-foot segment is not inconsistent with gas pipeline safety if additional operations and maintenance conditions are implemented by PG&E, as specified in "Detail State Waiver Conditions".[5] These conditions are summarized below:

1. **Current Status of Pipe in the Ground**

   To ensure that key characteristics of the pipe currently installed in the ***State Waiver segment*** are known, CPUC requires records that PG&E confirm pipe specifications, successful pressure tests, and girth weld non-destructive tests. Should records be unavailable or unacceptable, PG&E must complete additional activities as detailed in the State Waiver. If these additional activities are not completed or should pipe be discovered that does not meet specific requirements of eligibility, the ***State Waiver segment*** must be replaced.

2. **Operating Conditions**

   The ***State Waiver inspection area*** must continue to be operated at or below the existing MAOP of 861 pounds per square inch gauge (psig) until a restoration or uprating plan has been approved. PG&E's operations, and maintenance manual (O&M), IM program, and damage prevention (DP) program must be modified to implement the State Waiver conditions. In addition, CPUC must approve any long-term flow reversals that would impact the ***State Waiver segment***.

3. **Threat Management**

   Threats are factors that can lead to the failure of a pipeline. Activities are required to identify, assess, remediate, and monitor threats to the pipeline.

   a) **General activities.** PG&E must perform annual data integration and identification of threats to which the ***State Waiver inspection area*** is susceptible. These activities must include periodic integrity assessments at defined intervals with specific inline inspection (ILI) tools, strict anomaly repair criteria, and appropriate environmental assessment and permitting.

   b) **External corrosion control requirements.** The State Waiver requires additional activities to monitor and mitigate external corrosion. These activities include installation and annual monitoring of cathodic protection (CP) test stations, periodic

[5] See Attachment 2 to this Resolution.

close interval surveys (CIS), and clearing or remediating shorted casings that may impede CP effectiveness. These activities ensure the appropriate level of CP is reaching the pipeline in areas where coating loss or damage has occurred in order to prevent or mitigate external corrosion. In addition, PG&E is required to develop and implement a plan that identifies and remediates interference from alternating or direct current (AC/DC) sources (such as high-voltage powerlines) that could adversely impact the effectiveness of CP.

c) **Internal corrosion control requirements.** The State Waiver includes gas quality specifications to mitigate internal corrosion because internal corrosion is highly dependent on the quality of the gas transported within the pipeline.

d) **Stress corrosion cracking requirements.** To ensure that stress cracking corrosion (SCC) is discovered and remediated, any time a pipe segment is exposed during an excavation, PG&E must examine coating to determine type and condition. If the coating is in poor condition, PG&E must conduct additional SCC analysis. If SCC is confirmed, PG&E must implement additional remediation and mitigation.

e) **Pipe seam requirements.** PG&E must perform an engineering integrity analysis to determine susceptibility to seam threats. PG&E must re-pressure test any ***State Waiver segment*** with an identified seam to ensure the issue is not systemic in nature.

f) **External pipe stress requirements.** Upon identification of any source of external stress on the pipeline (such as soil movement), PG&E must develop procedures to evaluate and periodically monitor these stresses.

g) **Third-party specific requirements.** To assist in identifying the pipeline location and minimizing the chance of accidental pipeline strikes, PG&E must install and maintain line- of-site markers for the pipeline. PG&E must perform mitigation activities for any location where a depth-of-cover survey shows insufficient soil cover.

4. Consequence Mitigation

To ensure quick response and reduce adverse outcomes in the event of a failure, each side (upstream and downstream) of the ***State Waiver segment*** must have and maintain operable automatic shutdown valves (ASV) or remote-controlled valves (RCV). PG&E must monitor valves through a control room with a supervisory control and data acquisition (SCADA) system. In addition to the mainline valves, should a crossover or lateral connect between the valve locations, additional isolation valves may be required. To ensure a leak is discovered promptly, leakage surveys are required twice a year.

5. Gas Leakage Surveys and Remediation

PG&E must conduct leakage surveys more frequently than is presently required in 49 CFR 192.706. Gas leakage surveys using instrumented gas leakage detection equipment must be conducted along the ***State Waiver segment*** and at all valves, flanges, pipeline tie-ins with valves and flanges, and ILI launcher and receiver facilities in the ***State Waiver inspection area*** at least twice each calendar year, at intervals not to exceed 7½ months. The type of leak detection equipment used, survey findings, and remediation of all instrumented gas leakage surveys must be documented by PG&E.

6. Post Leak or Failure

If an in-service leak should occur, the leak must be graded and remediated. In addition, for all in-service or pressure test leak/failure(s), PG&E must conduct a root cause analysis to determine the cause. If the cause is determined to be systemic in nature, PG&E must implement a remediation plan or replace the ***State Waiver segment***.

7. Class Location Study and Potential Extension of State Waiver Segment

PG&E must conduct a class location study annually. This allows PG&E to quickly identify extended locations that must comply with the ***State Waiver segment*** requirements. PG&E may extend the ***State Waiver segment*** with proper notification, update of the Final Environmental Assessment (FEA), and implementation of all requirements in the State Waiver.

8. CPUC Oversite and Management

CPUC maintains oversight and management of the State Waiver. This includes annual meetings with executive level officers on State Waiver implementation status, written certification of the State Waiver, State Waiver required notification of planned activities, notification of root cause analysis results, and notification prior to certain excavation activities so that CPUC may observe.

9. Documentation

PG&E must maintain documentation that supports compliance with State Waiver conditions for the life of the pipeline.

In granting this waiver, PG&E is reminded that:

1. The waiver only applies to the 419.1-foot segment identified in PG&E's request and does not extend to any other pipe segments in the 43.63 miles of inspection area or other facilities.
2. This waiver is effective upon approval by the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), or if there is no action by PHMSA, 60 days after the receipt of waiver from State Agency.
3. This waiver requires PG&E to implement additional operations and maintenance conditions recommended by GSRB on the 419.1-foot segment and the 43.63 miles of inspection area identified in PG&E's request. These conditions, specified in the "Detail State Waiver Conditions" and included as Attachment 2 to this Resolution, are intended to decrease the likelihood of a release of gas. These additional preventative measures would help prevent leaks and ruptures, demonstrating that the State Waiver is not inconsistent with pipeline safety.

SED and the Commission retain discretion to rescind the right to delay inspection or other required activity. Further, SED or the Commission may cancel or modify the permission given in this Resolution at any time.

COMMENTS ON DRAFT RESOLUTION

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this resolution was neither waived or reduced. Accordingly, this draft resolution was mailed for comments, and will be placed on the Commission's agenda no earlier than 30 days from today. Comments were provided on ____________ by ________________.

FINDINGS AND CONCLUSIONS

1. On October 20, 2023, PG&E submitted a request to the Commission's Safety and Enforcement Division (SED) Gas Safety and Reliability Branch (GSRB) seeking a waiver of certain regulations in 49 CFR §§ 192.611 and 192.619 for a 0.079375 miles (419.1 feet) segment of 34" diameter intrastate natural gas transmission pipeline located in a rural, sparsely populated area of San Bernadino County, near the town of Boron.
2. General Order 112-F, Part 101.3 allows for a utility, in special circumstances, to submit an application to waive compliance with specific rules in accordance with Section 3(e) of the Natural Gas Pipeline Safety Act of 1968.
3. The information provided in PG&E's waiver request meets the criteria that the Office of Pipeline Safety (OPS) uses in considering whether to grant class location change waiver/permit requests.
4. PG&E's request to waive 49 CFR § 192.611(a) and (d) and 49 CFR § 192.619(a) for the 419.1-foot segment is not inconsistent with gas pipeline safety if additional operations and maintenance conditions are implemented by PG&E, as specified in "Detail State Waiver Conditions."
5. SED notified PHMSA of its intent to approve PG&E's requested waiver.

THEREFORE, IT IS ORDERED THAT:

1. Pacific Gas and Electric Company's request for a waiver of 49 CFR §192.611(a) and 49 CFR §192.619(a) and (d) for a 0.079375 miles (419.1 feet) segment of 34" diameter intrastate natural gas transmission pipeline located in a rural, sparsely populated area of San Bernadino County, near the town of Boron, is granted.
2. The waiver granted herein does not extend to activities or facilities not set forth in this Resolution.
3. Pacific Gas and Electric Company shall implement the additional operations and maintenance conditions specified in Attachment 2, "Detail State Waiver Conditions".
4. The Commission or the Safety and Enforcement Division may rescind, cancel or modify the permission given in this Resolution at any time.
5. This Resolution shall be submitted to The Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) for the required 60 days' notice in accordance with Section 3.3.2 of the PHMSA State Program Guidelines.
6. This waiver is effective upon approval by The Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), or if there is no action by PHMSA, 60 days after the receipt of waiver from the Commission.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on December 5, 2024 the following Commissioners voting favorably thereon:

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Rachel Peterson
Executive Director

ATTACHMENT 1

PG&E detailed responses to the criteria for considering class location change

Attachment 1 - PG&E detailed responses to the criteria for considering class location change

CRITERIA	ACCEPTANCE CRITERIA	OPERATOR RESPONSE
CLASS LOCATION		
Class Location Change		Class 1 to Class 3
PIPE DESIGN AND CONSTRUCTION		
Pipe Manufacturer	Requires Substantial Justification – Pipe manufactured prior to 1954.	Consolidated Western. API 5L pipe from 6/15/1950.
Pipe Material	Welded steel pipe with toughness meeting the current requirements of ASME B31.8 or pipe of known toughness.	Steel Pipe of low or unknown toughness where the operator has addressed this risk in accordance with 49 CFR 192.624. 49 CFR 192.624, Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.
Design Stress	Less than or equal to 72% of SMYS.	Yes – 69.7%
Pipe Girth Welds	Records exist[1] that demonstrate that the girth welds were volumetrically inspected during construction.	X-ray records consistent with federal inspection requirements; Richardson X-Ray Service – June 2, 1950, and Richardson X-Ray Service – November 28 1950.
Pipe Coating	Fusion Bonded Epoxy, Multi-layer Epoxy	FBE, Epoxy, HAA
PRESSURE TESTING		
Test Pressure	Tested to at least 90% SMYS and 1.25 times MAOP.	Tested on 3/9/2012 with water for 8.3 hours to 1137psig and spike tested for 30 min to 1,223 psig, which is greater than 1.25XMAOP.
Test Failures	No history of pressure test failures.	None.
ENVIRONMENTAL CONSIDERATIONS		
Depth of Cover	Cover meeting the requirements of 49 CFR 192.327 (a). Class 1, 30". Class 3, 36" – normal soil. Consolidated Rock Class 1 – 18", Class 3 24 inches.	40"

[1] Records could include purchasing or other records, actual NDE reports or radiographs are not required.

CRITERIA	ACCEPTANCE CRITERIA	OPERATOR RESPONSE
Local Geology	Located in stable soil.	ILI IMU did not capture any bending strain at this location. PG&E's geohazard monitoring and management program has also not identified any unstable soil conditions which is also reflected in the threat identification results.
OPERATIONAL CONSIDERATIONS		
Leaks and Failures	No history of leaks, failures, or systemic problems on similar system pipe that is found in the special permit inspection area.[2]	None
Service	Gas stream constituents meet requirements in 49 CFR 192.620(d)(5)(v).	Natural Gas
Pressure Fluctuations	Light to moderate pressure spectrum	Maximum preceding 5 year high pressure is noted as 830 psig.
Cathodic Protection	Requirements of 49 CFR Part 192, Subpart I have been met for entire life of the pipeline with no evidence of coating damage due to excessive current.	CP records over last 5 years are compliant with Subpart I. As stated within the inspection history, there were no remedial activities required due to corrosion.
Safety Related Conditions Reports	No SRCR's related to line pipe integrity in the special permit inspection area containing special permit segment.	N/A - none.
INTEGRITY MANAGEMENT PROGRAM		
Program	Up to 25 miles of pipe either side of the waiver location must be included in the pipeline company's Integrity Management Program and periodically inspected with an in-line inspection technique	Pipeline section is included in the TIMP. Last integrity inspection in 2021 via ILI.
ILI Time Frame	The special permit segment must be piggable. If ILI is performed after special permit application, the special permit is contingent on completion of the inspection and repairs as specified in the special permit conditions.	Last inspections conducted as follows: Geometry Run: 3/5/2021,MFL-A Run: 3/6/2021 MFL-C Run: 3/8/2021 EMAT Run: 3/9/2021

[2] For this protocol, the special permit inspection area containing the special permit segment is defined as an area on each side of the waiver location between the launcher and receiver for an in-line inspection tool.

CRITERIA	ACCEPTANCE CRITERIA	OPERATOR RESPONSE
ILI Type	The special permit inspection area that contains the special permit segment must be able to be inspected by ILI using tools applicable to the threats to which the special permit segment is susceptible.	Geometry, MFL-A, MFL-C, EMAT
Direct Assessment (ECDA and SCCDA)	Identify the inspection area containing the proposed waiver location(s). Direct Assessment results for the proposed waiver area (ECDA, SCCDA, and coating)	ECDA: Indirect Inspection testing (IIT): 9/21/2016 Last excavation and direct examination 12/20/2016 SCCDA: Last direct examination 10/25/2016; no findings of SCC were detected, and threat level did not change.
Coating Assessment	Coating in good condition with no evidence of disbondment.	Coating condition is good or excellent.
Damage Prevention	Damage prevention program based on best practices endorsed by the Common Ground Alliance.	PG&E has a Utility Procedure: TD-4412P-05, "Excavation for Damage Prevention Program" and TD-4412S, "Preventing Damage to Underground Facilities." Document references best practices from Common Ground Alliance.
Cracking Threat (Stress Corrosion Cracking, Selective Seam Weld Corrosion or Cracking, Girth Weld Cracking)	Special permit segment is not susceptible to cracking threat.	N/A – No evidence of crack or crack-like defects have been identified on special permit segment.
Geological Threat	Not susceptible to geological threat. (e.g., located in stable soil, not in an earthquake zone, etc.).	ILI IMU did not capture any bending strain at this location. PG&E's geohazard monitoring and management program has also not identified any unstable soil conditions which is also reflected in the threat identification results. Threat identification has not identified this location as susceptible to seismic, landslide or unstable soil conditions. PG&E's Environmental Impact Report also does not note any geological threats.
Integrity Assessment Findings	Corrosion < 30% pipe wall thickness Dents < 2%[3]	None; Refer to ATTACHMENT, "Attachment A - Special Permit - Pipeline Segment Integrity Information - PG&E.xlsx"

[3] Attachment A in the example special permit conditions gives additional criteria for evaluating dents. This document can be accessed on the PHMSA website at the following URL: https://www.phmsa.dot.gov/pipeline/class- location-special-permits/example-class-location-special-permit-typical-condition

CRITERIA	ACCEPTANCE CRITERIA	OPERATOR RESPONSE
	No SCC in the special permit inspection area and the special permit segment is not susceptible to SCC	
INSPECTION AND ENFORCEMENT HISTORY		
Inspection Findings	No enforcement actions in the PHMSA Region under consideration in the last five years.	N/A - None in specific area.
Integrity Management Program Performance	No IMP enforcement cases for the previous 5 years.	No inspection finds related to this section of pipeline.

ATTACHMENT 2

Detail State Waiver Conditions

Attachment 2 - Detail State Waiver Conditions

State Waiver Segments and State Waiver Inspection Areas

This State Waiver and the proposed waiver conditions pertain to the specified ***State Waiver segment*** and corresponding ***State Waiver inspection area*** defined below.

State Waiver Segment:

This State Waiver applies to the ***State Waiver segment*** in **Table 1 – State Waiver Segments** and are identified using the PG&E survey station (SS) references.

Table 1 – State Waiver Segments

State Waiver Segment Number	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (SS)	End Survey Station (SS)	County or Parish, State	No. Dwellings	Year Installed	Seam Type	MAOP (psig)	Pressure Test - Condition 1(b) Required (Yes)	Material - Condition 13(d) Required (Yes)
1	34	300A	419.1	962577.46	962996.56	San Bernardino, CA	0 (OPA)	1950	DSAW	861	Yes	Yes

Note: **DSAW** is a double submerged arc welded longitudinal seam.

State Waiver Inspection Area:

The ***State Waiver inspection area*** is defined as the area that extends 220 yards on each side of the centerline as listed in **Table 2 – State Waiver Inspection Areas**.

Table 2 – State Waiver Inspection Areas

State Waiver Inspection Area Number	State Waiver Segment(s) Included	Outside Diameter (inches)	Line Name	Start Survey Station (SS)	End Survey Station (SS)	Length[4] (miles)
1	1	34	300A	842683.77	1073047.43	43.63

Extended State Waiver Segment:

The ***extended State Waiver segment*** is defined as the ***State Waiver segment*** and the five (5) contiguous miles past each endpoint.

Attachment B contains a general map that includes the pipeline route map showing the ***State Waiver segment.***

[4] If the ***State Waiver inspection area*** footage does not extend from in-line inspection launcher to receiver, then the ***State Waiver inspection area*** would need to be extended to include the in-line inspection launcher to receiver.

GSRB Proposed State Waiver Conditions

GSRB staff finds that granting this waiver to PG&E is not inconsistent with pipeline safety if a list of specified waiver conditions is implemented by PG&E. GSRB staff is proposing the following conditions as part of the State Waiver. These proposed State Waiver conditions below are designed to align with other PHMSA approved Class Location Change waivers. Each condition detailed in this section applies to the State Waiver inspection area and the corresponding State Waiver segment unless otherwise noted in the condition.

Proposed Conditions

1) **Condition 1 - Maximum Allowable Operating Pressure**
   a) **Maximum Allowable Operating Pressure**: PG&E must continue to operate each ***State Waiver segment*** and ***State Waiver inspection area*** at or below the existing MAOP of 861 pounds per square inch gauge (psig).
   b) **Pressure Test**: PG&E must identify previous pressure tests for each ***State Waiver segment***. Pressure test records for each ***State Waiver segment*** must meet 49 CFR 192.517(a) and be traceable, verifiable, and complete (TVC)[5] as required in 49 CFR 192.624(a)(1).
      i) PG&E must furnish TVC pressure test records to CPUC within 60 days of the grant of the State Waiver. The pressure test records must be compliant with **Condition 1(b)**.[6] PG&E must receive a "no objection" letter from CPUC that the TVC pressure test records are compliant with 49 CFR 192.517(a), 192.624(a)(1), and 192.619(a)(1) through (a)(4) for a Class 1 location, or PG&E must pressure test each ***State Waiver segment*** in accordance with **Condition 1(b)(ii)**.
      ii) If PG&E does not have a TVC record of a 1.25 times the MAOP hydrotest in accordance with Subpart J, or the ***State Waiver segment*** requires an updated pressure test, the ***State***

[5] TVC procedures and records must follow the following: 1) "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements and Other Related Amendments"; 84 FR 52218 to 52219; October 1, 2019; and 2) PHMSA Advisory Bulletin: Pipeline Safety: Verification of Records; 77 FR 26822; May 7, 2012; https://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf.

[6] The pressure test records must cover the entire length of the ***State Waiver segment***, regardless of when the pipeline, single or multiple pipe joints, or other pipeline components were installed. Affidavits for a pressure test are not acceptable TVC pressure test records.

Waiver segment must be hydrostatically tested[7] to a minimum of 1.39 times the MAOP for eight (8) continuous hours in accordance with 49 CFR Part 192, Subpart J, within 18 months of the grant of this State Waiver.[8]

c) **MAOP Restoration or Uprating of Previously De-rated Pipe**: MAOP restoration or uprating is not approved for this State Waiver.

2) **Condition 2 - Procedure Updates**

Within 90 days of the grant of the State Waiver, PG&E must develop and maintain procedures in accordance with 49 CFR 192.603 and 192.605 that incorporate the State Waiver condition requirements as follows:

a) **Operations and Maintenance Manual**: PG&E must amend the applicable sections of its Operations and Maintenance (O&M) manual(s) and procedures to incorporate the State Waiver conditions.

b) **Integrity Management Program**:

i) PG&E must incorporate each ***State Waiver segment*** into its written integrity management program (IMP) procedures as if the ***State Waiver segment*** is a "covered segment" as defined in 49 CFR 192.903, except for the reporting requirements contained in 49 CFR 192.945.[9] A ***State Waiver inspection area*** outside of a ***State Waiver segment*** is not required to be included as a "covered segment" in accordance with 49 CFR 192.903.

ii) The ***State Waiver inspection area*** and ***State Waiver segment*** must have integrity threats identified, assessed, and remediated in accordance with these State Waiver conditions, 49 CFR 192.917, and 49 CFR Part 192, Subpart O.

iii) Any high consequence area (HCA) in either a ***State Waiver segment*** or a ***State Waiver inspection area*** must be assessed and remediated for threats in accordance with these State Waiver conditions and 49 CFR Part 192, Subpart O.

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[7] For all in-service and pressure test failures, PG&E must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. PG&E must provide the written results of this root cause analysis to CPUC within 90 days of the failure.

[8] The grant of this State Waiver, as used throughout, is the signed issuance date of the State Waiver.

[9] PG&E must follow the reporting requirements in **Condition 15 – Annual Report** as well as those noted throughout the conditions contained herein.

iv) All waiver conditions that are applicable to a ***State Waiver segment*** or to a ***State Waiver inspection area*** are applicable to HCAs where the HCA overlaps a ***State Waiver segment*** or a ***State Waiver inspection area***.

v) All State Waiver conditions that are applicable to a ***State Waiver inspection area*** are also applicable to the ***State Waiver segment***. A ***State Waiver segment*** must meet the requirements of 49 CFR 192, Subpart O, if Subpart O is more stringent than the State Waiver conditions.

vi) The ***State Waiver inspection area*** must be able to be assessed using inline inspection (ILI) tools, including tethered or remotely controlled tools, in accordance with 49 CFR 192.150 and 192.493.

c) **Damage Prevention Program**: PG&E must incorporate within a ***State Waiver inspection area*** the applicable best practices of the Common Ground Alliance (CGA)[10] in its damage prevention (DP) program.

3) **Condition 3 – Corrosion Control**

PG&E must promptly address any corrosion control deficiencies in a ***State Waiver segment*** that are indicated by the inspection and testing programs required under 49 CFR 192.463 and 192.465.

a) **Cathodic Protection Test Station Spacing**: At least one (1) cathodic protection (CP) pipe-to-soil test station must be located within each ***State Waiver segment***, with a spacing not to exceed ½ mile between CP pipe-to-soil test stations. In cases where obstructions or restricted areas prevent such test station placement, the test station must be placed in the closest practical location, not to exceed a 3,000-foot spacing. CP pipe-to-soil test stations must be installed within 12 months of the grant of this State Waiver.

b) **Annual Monitoring of Test Station Potential Measurements**: At least once every calendar year, not to exceed 15 months, PG&E must monitor CP pipe-to-soil test stations to meet 49 CFR 192.463 and 192.465 for the ***State Waiver segment*** and must include "on and off" potential measurements. Test station readings (pipe-to-soil potential measurements) must comply with Appendix D – Section I.A. (1) of 49 CFR Part 192 or remediation detailed in paragraph (c) of this condition is required. For hard spots identified with a Brinell Hardness

[10] Common Ground Alliance. (March 2020). Best Practices Guide. Retrieved from: https://commongroundalliance.com/BPguide.

(HB) of 300 HB or greater, CP voltage levels must be maintained more electro-positive than minus 1.2 volts direct current (DC).

c) **<u>Inadequate Cathodic Protection Level Determination</u>**:

i) In instances where inadequate potentials are a result of an electrical short to an adjacent foreign structure, a rectifier malfunction, an interruption of power source, or an interruption of CP current due to other non-systemic or location-specific causes, PG&E must document and repair these instances. A close interval survey (CIS) will not be required.

ii) All other instances must be assessed as detailed in **Condition 4 – Close Interval Surveys**.

d) **<u>Remedial Action Plans</u>**:

i) Within six (6) months of identifying a deficiency, PG&E must develop a remedial action plan to restore CP to meet 49 CFR 192.463. Within two (2) months of the finding, PG&E must apply for any necessary environmental permits (Federal or state).

ii) PG&E must complete the remediation and confirm restoration of adequate CP over the entire area where inadequate CP levels were detected within 12 months of the deficiency finding or as soon as practicable after obtaining the necessary permits.

4) **<u>Condition 4 – Close Interval Surveys</u>**

a) **<u>Survey Methodology and Boundaries</u>**:

i) PG&E must perform an "on and off" current CIS at a maximum 5-foot spacing along the entire length of each ***State Waiver segment***.[11]

ii) PG&E must evaluate each ***State Waiver segment*** in accordance with 49 CFR 192.463.

iii) For inadequate CP level determination described in **Condition 3(c)(ii)**, PG&E must conduct a CIS in both directions from the test station with an inadequate CP reading with the CIS ending at the adjacent test stations.

b) **<u>Survey Intervals</u>**: PG&E must perform the CIS within the following timeframes:

[11] Each condition in this State Waiver that requires PG&E to perform an action with respect to the ***State Waiver inspection area*** also requires PG&E to perform that action on each ***State Waiver segment*** within the area.

i) Initial assessment must be completed for each newly incorporated and extended ***State Waiver segment*** within 12 months after the grant of the State Waiver. For a ***State Waiver segment*** renewal, the CIS may be conducted at the next reassessment interval.[12]

ii) Reassessments must be conducted every five (5) years not to exceed 66 months. CIS assessments within the reassessment interval are not required to be performed in the same year as ILI reassessments.

c) **Survey Remediation and Remedial Action Plans**:

i) If a ***State Waiver segment*** requires the use of 100 millivolt shift criteria[13] or the installation of linear anodes along the ***State Waiver segment*** to meet the CP requirements of 49 CFR 192.463, it is not eligible to operate with a Class 1 pipe in a Class 3 location. PG&E must either: (1) replace the pipe in the ***State Waiver segment*** with Class 3 location standard (design factor) pipe (see 49 CFR 192.111(a)); (2) recoat the pipe with non-shielding external coating within 12 months of the finding; or (3) lower the MAOP to meet 49 CFR 192.611.

ii) Within four (4) months of identifying a deficiency, PG&E must develop a remedial action plan to restore CP to meet 49 CFR 192.463. Within two (2) months of the remedial action plan being developed, PG&E must apply for any necessary environmental permits (Federal or state).

iii) PG&E must complete remediation of each ***State Waiver segment*** and confirm restoration of adequate CP over the entire area where inadequate CP levels were detected within 12 months of the survey or as soon as practicable after obtaining the necessary permits.[14]

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[12] A CIS survey conducted in 2020 for a ***State Waiver segment*** that is permit condition compliant would not need to be resurveyed in 2021 but could wait until the next CIS survey reassessment time.

[13] A.W. Peabody, "Peabody's Control of Pipeline Corrosion," second edition, "Criteria for Cathodic Protection." "The 100mV polarization criterion should not be used in areas subject to stray current because 100 mV of polarization may not be sufficient to mitigate corrosion in these areas. This criterion also should not be used in areas where the intergranular form of external SCC, also referred to as high-pH or classical SCC, is suspected. The potential range for cracking lies between the native potential and -850 mV (CSE) such that application of the 100mV polarization criterion may place the potential of the structure in the range for cracking."

[14] If remediation based upon the findings of the CIS is not practicable within 12 months of the CIS survey, PG&E must submit a schedule and justify the delay 60 days prior to the 12-month completion requirement CPUC. PG&E must receive a "no objection" letter from CPUC prior to a pipe coating remediation schedule extension.

5) **<u>Condition 5 – Inline Inspection</u>**

a) **<u>Threat Identification</u>**: PG&E must implement data integration and identify integrity threats in the ***State Waiver inspection area*** at least once each calendar year, with intervals not to exceed 15 months, in accordance with 49 CFR 192.917 and **Condition 13(c) – Data Integration**. The stress corrosion cracking (SCC) threat assessment for the ***extended State Waiver segment***,[15] must be conducted using the current incorporated by reference (IBR) edition of the American Society of Mechanical Engineers (ASME) Standard B31.8S, "Managing System Integrity of Gas Pipelines" (ASME B31.8S) Appendix A3 and National Association of Corrosion Engineers (NACE) Standard Practice (SP) 0204-2008, "Stress Corrosion Cracking Direct Assessment Methodology," Sections 1.2.1.1 and 1.2.2.

b) **<u>Inline Inspection Methodology</u>**: PG&E must conduct instrumented ILI integrity assessments in accordance with 49 CFR 192.493, for each ***State Waiver inspection area*** for all threats identified in accordance with 49 CFR 192.919 and 192.921.

i) At a minimum, PG&E must conduct ILI assessments for corrosion and denting with high-resolution (HR) magnetic flux leakage (HR-MFL) and HR deformation tools with deformation-extended sensor arms not limited by pig cups.

ii) For near-neutral or high-pH SCC (cracking threat), PG&E must use an ILI tool[16] that will identify tight cracks.[17]

iii) A ***State Waiver segment*** with electric flash welded (EFW) pipe must have an ILI tool assessment run for hard spots and cracking from hard spots.

iv) In a ***State Waiver inspection area*** that has experienced pipe or girth weld leaks or ruptures due to soil movement, or the threat has been identified, PG&E must run inertial measurement unit (IMU) and HR-deformation ILI tools for detection and remediation of strains and denting of the pipe body and girth welds from soil or pipe movements that impair pipeline integrity. Remediation must be conducted as determined by **Condition 13(j) – Pipe and Soil Movement**.

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[15] The ***extended State Waiver segment*** is defined as the ***State Waiver segment*** and the five (5) contiguous miles past each endpoint.

[16] The crack ILI tool must be comparable to an electro-magnetic acoustic transducer (EMAT) ILI tool.

[17] PG&E may propose an alternative assessment method for SCC (such as spike hydrostatic testing in accordance with 49 CFR 192.506) to CPUC. PG&E must receive a “no objection” letter from CPUC prior to implementing any alternative assessment methods for SCC.

c) **<u>Inline Inspection Assessment Intervals</u>**: PG&E must conduct initial assessments and reassessments for the ***State Waiver inspection area*** in accordance with the following:

i) Initial ILI assessments must be conducted as follows:

(1) If the ***State Waiver segment*** has EFW pipe, it must be assessed for hard spots within 18 months of the State Waiver grant date.

(2) If cracking has been identified as a threat for the ***extended State Waiver segment****,* it must be assessed within 18 months of the State Waiver grant date.

(3) All other identified threats must be assessed within two (2) years of the State Waiver grant date.

(4) For newly identified threats, assessments must be completed within two (2) years of identification.

(5) Previous ILI assessments may be applied if **Condition 8 – Anomaly Evaluation and Remediation** is completed, and the **Condition 5(c)(ii)** reassessment interval is maintained.

ii) Reassessments must be completed in accordance with the shortest interval of the following:

(1) 49 CFR 192.939(a);

(2) Intervals of five (5) calendar years not to exceed 66 months, if the ***State Waiver segment*** contains any of the following:

(a) low-frequency electric resistance welded (LF-ERW) or EFW pipe,

(b) hard spots,

(c) shorted carrier pipe to the casing,

(d) susceptible to SCC, or

(e) pipe or soil movement; or

(3) The engineering critical assessment (ECA) determined interval, if applicable.

iii) After conducting two (2) assessments of a threat, one (1) of which must be after the grant of this State Waiver, PG&E may request reassessment intervals up to seven (7) years for that threat assessment. PG&E must submit for and receive a “no objection” letter from CPUC prior to implementing this change.

iv) If factors beyond PG&E’s control prevent the completion of an assessment within the required timeframe or reassessment interval, PG&E must perform the assessment as soon as practicable, and PG&E must submit a letter justifying the delay and provide the anticipated date of completion to CPUC no later than two (2) months prior to the end the timeframe or interval. PG&E must receive a "no objection" letter from CPUC for the delay or must lower the MAOP of the ***State Waiver segment*** in accordance with 49 CFR 192.611.

d) **<u>Remediation</u>**: Anomaly assessments must be evaluated and remediated in accordance with **Condition 8 – Anomaly Evaluation and Remediation**.

6) **<u>Condition 6 - Girth Welds</u>**

a) **<u>Construction Girth Weld Non-Destructive Test Records</u>**: PG&E must provide records to CPUC that demonstrate the girth welds in the ***State Waiver inspection area*** were either:

i) Non-destructively tested (NDT) at the time of construction in accordance with the Federal pipeline safety regulations at the time the pipelines were constructed, or

ii) At least 1% of the girth welds and a minimum of two (2) girth welds in each ***State Waiver segment*** were NDT after initial construction and prior to the State Waiver application. PG&E must demonstrate these welds were excavated, NDT, and repaired, if the welds do not meet Federal pipeline safety regulations at the time the pipelines were constructed.

b) **<u>Missing Records</u>**: If PG&E cannot provide girth weld records to CPUC to demonstrate compliance with **Condition 6(a)**, PG&E must complete either **Condition 6(b)(i)** or both **Conditions 6(b)(ii)** and **(iii)** within 12 months of the grant of this State Waiver as follows:

i) Certify to CPUC, in writing, that there have been no in-service leaks or breaks in the girth welds in the ***State Waiver inspection area*** for the life of the pipeline; or

ii) Evaluate the terrain along each ***State Waiver segment*** for threats to girth weld integrity from soil or settlement stresses, perform NDT, and remediate all such integrity threats;[18] and

iii) Excavate,[19] visually inspect, and perform NDT on at least two (2) girth welds on each ***State Waiver segment*** in accordance with the applicable American Petroleum Institute Standard 1104, "*Welding of Pipelines and Related Facilities*" (API 1104) as follows:

(1) Using the edition of API 1104 current at the time the pipeline was constructed;

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[18] If a ***State Waiver segment*** has not had girth weld NDT to meet **Condition 6** – **Girth Welds** and has experienced pipe or girth weld leaks or ruptures due to soil movement or the threat has been identified, then **Condition 5(b)(iv)** must be conducted within 12 months of the finding.

[19] PG&E must evaluate the pipe for SCC any time the ***State Waiver inspection area*** is uncovered or excavated in accordance with **Condition 8(b) or (c)** of this State Waiver. Pipe with fusion bonded epoxy coating does not require SCC evaluation when excavated unless SCC has been identified as a threat in the ***State Waiver inspection area***.

(2) Using the edition of API 1104 IBR in the Federal pipeline safety regulations at the time the pipeline was constructed; or

(3) Using the edition of API 1104 currently IBR in 49 CFR 192.7.

c) **<u>Defective Girth Welds</u>**: If any girth weld in a ***State Waiver segment*** is found unacceptable in accordance with the API 1104 IBR Edition at the time of pipeline construction, PG&E must repair the girth weld immediately and then prepare an inspection and remediation plan for all remaining girth welds in the ***State Waiver segment*** based upon the repair findings and the threat to the ***State Waiver segment***. PG&E must submit the inspection and remediation plan for girth welds to CPUC and must receive a "no objection" letter for the girth weld remediation plan prior to its implementation.[20] PG&E must remediate girth welds in the ***State Waiver segment*** in accordance with the inspection and remediation plan within 90 days of the "no objection" letter receipt.[21]

7) **<u>Condition 7 - Stress Corrosion Cracking Threat</u>**

PG&E must evaluate the entire length of each ***State Waiver inspection area***[22] for SCC as follows:

a) **<u>Threat Assessments</u>**: PG&E must complete the SCC threat assessment as detailed in **Condition 5(a) – Threat Assessment**.

b) **<u>SCC Integrity Assessment</u>**: If the threat assessment required under **Condition 7(a)** indicates the ***extended State Waiver segment***[23] is susceptible to either near-neutral or high-pH SCC, PG&E must perform an SCC assessment on the ***extended State Waiver segment*** in accordance with **Condition 5 – Inline Inspection**. SCC integrity assessment using spike pressure testing is not approved for this State Waiver.[24]

c) **<u>Examination of Pipe</u>**: If the threat of SCC exists in the ***extended State Waiver segment*** as determined in **Condition 7(a)**, PG&E must directly examine the pipe for SCC when the

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20 CPUC must respond to PG&E's submittal letter within 90 days of receipt with a decision letter, or either give PG&E a request for additional information or a need of additional time for CPUC to review the request.

21 PG&E must include any plan requirements or comments received from CPUC into the remediation plan.

22 PG&E has documented 0 occurrences of SCC or cracking in the ***State Waiver segment/State Waiver inspection area***.

23 The ***extended State Waiver segment*** is defined as the ***State Waiver segment*** and the five (5) contiguous miles past each endpoint.

24 PG&E may propose an alternative assessment method for SCC (such as spike hydrostatic testing in accordance with 49 CFR 192.506) to CPUC. PG&E must receive a "no objection" letter from CPUC prior to implementing any alternative assessment methods for SCC.

coating has been identified as poor during the pipeline examination. The examination must be conducted using an accepted crack detection practice in accordance with 49 CFR 192.710(c)(4), (d), and **Condition 7(d)** when the ***extended State Waiver segment*** is uncovered for any reason to comply with the State Waiver and integrity management activities, not including One Call activities (49 CFR 192.614).

d) **Inspection of Pipe at Excavations**: Except for pipe coated with non-shielding coatings (fusion-bonded or liquid-applied epoxy coatings) and excavations performed in accordance with 49 CFR 192.614(c), PG&E must directly examine the pipe for SCC using non-destructive examination methods appropriate for the type of pipe and integrity threat conditions in the ditch. PG&E must use appropriate methods for crack detection, such as phased array ultrasonic testing (PAUT), inverse wavefield extrapolation (IWEX), or magnetic particle inspection (MPI),[25] when an ***extended State Waiver segment*** is uncovered, and the coating has been identified as poor during the pipeline examination. Visual inspection is not sufficient to determine "poor coating." PG&E must "jeep" the excavated segment to determine the coating condition. Examples of "poor coating" include, but are not limited to, a coating that has become damaged and is losing adhesion to the pipe which is shown by falling off the pipe and/or shields the CP. PG&E must keep coating records[26] at all excavation locations in the ***State Waiver inspection area*** to demonstrate the coating condition.

e) **Discovery of SCC**: If PG&E discovers SCC[27] activity by any means within the ***extended State Waiver segment*** in similar pipe vintage (manufacturer, manufacturing time or age, diameter, wall thickness, grade, and seam type) and pipe coating vintage (in accordance with 49 CFR 192.917(e)), or the ***extended State Waiver segment*** has had an in-service or hydrostatic test SCC failure or leak,[28] the ***State Waiver segment*** must be further assessed and mitigated, within

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25 When MPI finds cracking, another method must be used to size the crack unless the crack can be completely ground out and still meet the pipeline MAOP.

26 The records must include, at a minimum, a description of PG&E's detection procedures, records of finding, and mitigation procedures implemented for the excavation.

27 "SCC" activity shall be defined as greater than 20 percent wall thickness depth and 2-inches in length.

28 For all in-service and pressure test failures, PG&E must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. PG&E must provide the written results of this root cause analysis to CPUC within 90 days of the failure.

18 months of finding SCC and reassessed every five (5) calendar years or less[29] based upon the evaluated growth of the SCC, using one (1) of the following methods:

i) **Spike Hydrostatic Test Program**:[30]

(1) PG&E must perform its SCC spike hydrostatic test program in an ***extended State Waiver segment*** in accordance with 49 CFR 192.506 and include an ECA of the results that includes a determination of the reassessment interval, and

(2) If a joint of pipe in an ***extended State Waiver segment*** leaks or ruptures during a hydrostatic test due to SCC, PG&E must replace the pipe joint that does not meet 49 CFR 192.611 in the ***extended State Waiver segment*** with new pipe. PG&E must complete a successful SCC hydrostatic test prior to returning the ***extended State Waiver segment*** to operational service;

ii) **Crack Detection Tool Assessment**: PG&E must run an electro-magnetic acoustic transducer (EMAT) ILI tool or other equivalent crack detection ILI tool in the ***extended State Waiver segment***;

iii) **MAOP Lowered**: PG&E must lower the MAOP of the ***State Waiver segment*** to 60% specified minimum yield strength (SMYS);

iv) **Pipe Replacement**: PG&E must replace all pipe and comply with 49 CFR 192.611 and 192.619 in the ***State Waiver segment***; or

v) **Operating Pressure Lowered**: PG&E must lower the operating pressure of the ***State Waiver segment*** to 20% below the maximum pressure during the preceding 90-day operating interval until PG&E conducts an ECA and remediates the ***State Waiver segment***.

f) **SCC Remediation Plan**: If PG&E discovers any SCC activity in the ***extended State Waiver segment***, PG&E must submit an SCC remediation plan to CPUC no later than 90 days after the finding of SCC.[31] The plan must:

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29 PG&E has the option to submit a written request to CPUC for extension of the crack assessment interval to seven (7) years, as defined in 49 CFR 192.939(a), if the ECA shows that five (5) calendar year assessments are not required. PG&E must receive a "no objection" letter from CPUC prior to extending the assessment interval to seven (7) calendar years.

30 PG&E may propose an alternative assessment method for SCC (such as spike hydrostatic testing in accordance with 49 CFR 192.506) to CPUC. PG&E must receive a "no objection" letter from CPUC prior to implementing any alternative assessment methods for SCC.

31 For PG&E to go forward with the technical justification for addressing the SCC threat, PG&E must receive a "no objection" letter from CPUC.

i) Meet **Condition 7(e)** and include an SCC remediation/repair plan with SCC characterization and timing; or

ii) Include a technical justification that shows that PG&E is addressing the threat for SCC in the ***State Waiver segment***.

8) **Condition 8 - Anomaly Evaluation and Remediation**

a) **General**: PG&E must use the procedures specified in the State Waiver conditions, 49 CFR 192.712, and **Attachment A** when evaluating anomalies. PG&E must account for ILI tool tolerance and corrosion growth rates in determining scheduled response times and repairs and must document and justify the values used.

i) **ILI Tool Accuracy**: PG&E must demonstrate ILI tool tolerance accuracy for each ILI tool run by using calibration excavations and unity plots that demonstrate ILI tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +10% accuracy for 80% of the time). PG&E must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool and includes that tolerance in determining the size of each anomaly feature reported to PG&E. PG&E must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently overcalling or under-calling, the remaining ILI features must be re-graded accordingly. ILI tools used must be calibrated as follows:

(1) **General ILI Tool Calibration**: ILI tool calibrations must use ILI tool run results and anomaly calibrations from either the ***State Waiver inspection area*** or from the complete ILI tool run segment if the continuous ILI segment is longer than the ***State Waiver inspection area***. ILI calibration excavations may include previously excavated anomalies or recent anomaly excavations with known dimensions that were field measured for length, depth, and width, externally re-coated, CP maintained, and

documented for ILI calibrations prior to the ILI tool run. A minimum of four (4) calibration excavations must be used for unity plots.[32]

(2) **EMAT ILI Tool Calibration**:

(a) ILI calibration for EMAT ILI Tools must be based upon excavation results of a minimum of the two (2) most severe anomalies from a combined review of crack depth and length. If the EMAT tool identifies only one (1) anomaly, the anomaly must be excavated and assessed. PG&E can propose alternative EMAT ILI Tool evaluation procedures to CPUC but must receive a "no objection" letter prior to usage of these procedures.

(b) If the EMAT ILI tool does not identify any cracking anomalies above the minimum length and depth criteria for 90% probability of detection, PG&E must provide the following to CPUC:

(1) EMAT ILI service provider report with any PG&E provided reporting thresholds for cracking;

(2) Calibration data showing the ILI tool meets API Standard 1163 IBR - *Sections 6 - Qualification of Performance Specifications*, *Section 7 - System Operational Verification*, and *Section 8 - System Results Validation*, as applicable; and

(3) Previous in-ditch non-destructive examination records showing no SCC findings.

(4) PG&E must receive a "no objection" letter from CPUC that no excavation is required for the EMAT ILI tool calibration.

ii) **Unity Plots**: The unity plots must show actual anomaly depth versus predicted depth.

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32 Other known and documented pipeline features that are appropriate for the type of ILI tool used may be used as calibration excavations for ILI tool calibration with technical documentation of their validity. To use other known and documented pipeline features as calibration excavations for ILI tool calibration, PG&E must complete the following: (1) submit a plan for using known and documented pipeline features such as calibration excavation data, to CPUC. The plan must include at least the following information: a) reason that known and documented pipeline features will be used in place of anomalies on the pipelines; b) the pipeline features that will be used for the ILI tool calibration; and c) the technical justification for using the pipeline features for ILI tool calibration; (2) receive a "no objection" letter from CPUC prior to performing the ILI tool calibration using pipeline features; (3) submit a report to CPUC, and with the results of the use of pipeline features for the ILI tool calibration that includes technical documentation establishing the validity of using the pipeline features for the ILI tool calibration.

iii) **<u>ILI Tool Evaluations</u>**: ILI tool evaluations for metal loss must use "6t x 6t"[33] interaction criteria for determining anomaly failure pressures and response timing.

iv) **<u>Discovery Date</u>**: The discovery date[34] must be within 180 days of any ILI tool run for each type of ILI tool (e.g., HR-geometry, HR-deformation, HR-MFL, EMAT, IMU, or other equivalent ILI tools).

b) **<u>Remediation schedule for "State Waiver inspection area"</u>**: PG&E must remediate the ***State Waiver inspection area***[35] as follows:

i) **<u>Immediate repair conditions for a "*State Waiver inspection area*"</u>**: PG&E must repair the following conditions immediately upon discovery in a ***State Waiver inspection area***:

(1) Metal loss anomaly where the calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with 49 CFR 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.

(2) Metal loss greater than 80% of nominal wall, regardless of dimensions.

(3) Metal loss preferentially affecting a detected pipe weld seam, and the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is less than 1.25 times the MAOP or the metal loss is greater than 50% of pipe wall thickness.[36]

(4) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(5) A crack or crack-like anomaly meeting any of the following criteria:

(a) Crack depth plus any metal loss is greater than 50% of pipe wall thickness;

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[33] "6t" means pipe wall thickness times six (6).

[34] Discovery date is the day, month, and year that PG&E receives the ILI tool run results from the ILI tool service provider.

[35] Throughout this State Waiver, the ***State Waiver inspection area*** includes the ***State Waiver segment***, so any anomalies found in a ***State Waiver segment*** must be remediated to meet the requirements for a ***State Waiver inspection area*** in addition to the requirements of this condition for a ***State Waiver segment***. The ***State Waiver segment*** has additional remediation criteria in later sections of this State Waiver condition.

[36] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

(b) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(c) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with 49 CFR 192.712(d), that is less than 1.25 times the MAOP.

(6) An indication or anomaly that, in the judgment of PG&E, requires immediate action.

ii) **<u>One-year conditions – Hard Spots for a "State Waiver inspection area"</u>**: PG&E must repair by installation of a Type B sleeve or cut-out and recoat within 12 months of discovery, any hard spots found in the pipe body of EFW pipe discovered after the grant of the State Waiver with a hardness on the HB scale of either (1) 300 HB or greater and 2-inches in length or width; (2) 300 HB or greater with any cracking or metal loss over 10% of wall thickness; or (3) a single reading of 320 HB or greater at any location.

iii) **<u>One-year conditions – dents, metal loss, and cracks for a "State Waiver inspection area"</u>**: PG&E must repair the following conditions within 12 months of discovery in a ***State Waiver inspection area***:

(1) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than nominal pipe size (NPS) 12), unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(2) A dent with a depth greater than 2% of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(3) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(4) Metal loss anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with 49 CFR 192.712(b), at the location of the anomaly less than or equal to 1.39 times the MAOP for Class 2

locations, and 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations outside of the ***State Waiver segment*** with a predicted failure pressure greater than 1.1 times the MAOP, PG&E must follow the remediation schedule specified in ASME/ANSI B31.8S, Section 7, Figure 4.

(5) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, with a predicted failure pressure determined in accordance with 49 CFR 192.712 less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.

(6) Metal loss preferentially affecting a detected pipe weld seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0 (49 CFR 192.113), and where the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[37]

(7) A crack or crack-like anomaly that has a predicted failure pressure determined in accordance with 49 CFR 192.712(d) that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, and 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.

iv) **Two-year condition for crack repairs for a "State Waiver inspection area"**: PG&E must remediate any crack or crack-like anomaly that has a crack depth greater than 40% of the pipe wall thickness within two (2) years of discovery that are in the ***State Waiver inspection area*** and area outside of the ***State Waiver segment***.

(v) **Monitored conditions for a "State Waiver inspection area"**: PG&E does not have to schedule the following conditions for remediation but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change

[37] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

that may require remediation. Monitored conditions are the least severe and will not require examination and evaluation until the next scheduled integrity assessment.

(1) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe), and engineering analyses of the dent conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(2) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and engineering analyses of the dent conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(3) A dent with a depth greater than 2% of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and engineering analyses conducted in accordance with 49 CFR 192.712 and **Attachment A** to demonstrate the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(4) A dent that has metal loss, cracking, or a stress riser, and an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** to demonstrate the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(5) Metal loss preferentially affecting a detected pipe weld seam and where the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[38]

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[38] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

(6) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with 49 CFR 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[39] The crack depth is less than 40% of the pipe wall thickness.

c) **Remediation schedule for a "State Waiver segment"**: In addition to the requirements in paragraphs (a) and (b) of **Condition 8** for a ***State Waiver inspection area***, PG&E must remediate conditions in a ***State Waiver segment*** as follows:[40]

i) **One-year conditions for a "State Waiver segment"**: PG&E must repair the following conditions within one (1) year of discovery in a ***State Waiver segment***:

(1) **Pipe Wall**: Pipe wall thickness metal loss greater than 40%.

(2) **Weld Metal**: Girth weld metal loss greater than 30% of pipe wall thickness or pipe weld seam metal loss greater than 15% of pipe wall thickness.[41]

(3) **Class 1 pipe**: Any anomaly with a predicted failure pressure less than 1.39 times the MAOP.

(4) **Class 2 pipe**: Any anomaly with a predicted failure pressure less than 1.67 times the MAOP.

(5) **Class 3 pipe**: Any anomaly with a predicted failure pressure less than 2.0 times the MAOP.

ii) **One-year crack repair conditions for a "State Waiver segment"**: PG&E must repair all anomalies with a predicted failure pressure determined in accordance with 49 CFR

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[39] Failure stress pressure and crack growth analysis of cracks and crack-like defects must be determined using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other). Examples of technically proven models include but are not limited to: for the brittle failure mode, the Raju/Newman Model; for the ductile failure mode, Modified LnSec, API RP 579-1/ASME FFS-1, June 15, 2007, (API 579-1, Second Edition) – Level II or Level III, Colas™, PAFFC, and Pipiest. All crack fracture mechanic evaluation models must be used within the assessment limits of the model.

[40] The ***State Waiver inspection area*** includes the ***State Waiver segment***, so any anomalies found in a ***State Waiver segment*** must be remediated to meet the requirements for a ***State Waiver inspection area*** in addition to the requirements in this condition. The ***State Waiver segment*** must also be remediated to meet all additional remediation requirements specifically for the ***State Waiver segment*** as required in the State Waiver conditions.

[41] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

192.712(d) that is less than 1.39 times the MAOP, or a crack depth that is greater than 40% of the pipe wall thickness.

iii) **Un-cleared shorted casing for a "State Waiver segment"**: PG&E must repair within 12 months of discovery any identified corrosion, cracking or other anomaly that is shorted to a casing that is greater than 30% of the pipe wall thickness.

iv) **Monitored conditions for a "State Waiver segment"**: PG&E does not have to schedule the following conditions for remediation but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation in a ***State Waiver segment***. Monitored conditions are the least severe and will not require examination and evaluation until the next scheduled integrity assessment.

(1) **Class 1 pipe**: Any anomaly with a predicted failure pressure greater than or equal to 1.39 times the MAOP and an anomaly depth less than or equal to 40% wall thickness loss.

(2) **Class 2 pipe**: Any anomaly with a predicted failure pressure greater than or equal to 1.67 times the MAOP and an anomaly depth less than or equal to 40% wall thickness loss.

(3) **Class 3 pipe**: Any anomaly with a predicted failure pressure greater than or equal to 2.0 times the MAOP and an anomaly depth less than or equal to 40% of pipe wall thickness.

9) **Condition 9 - Pipe Casings**

PG&E must identify all shorted casings within a ***State Waiver segment*** no later than six (6) months after the grant of this State Waiver and classify any shorted casings as either having a "metallic short" (the carrier pipe and the casing are in metallic contact) or an "electrolytic short" (the casing is filled with an electrolyte) using a commonly accepted method such as the Panhandle Eastern, Pearson, Direct Current Voltage Gradient (DCVG), Alternating Current Voltage Gradient (ACVG), or AC Attenuation.

a) **Clear Shorted Casings**: Where practical, PG&E must clear shorted casings identified within a ***State Waiver segment*** no later than 12 months after the grant of this State Waiver as follows:

i) **Metallic Shorts**: PG&E must clear any metallic short on a casing in a ***State Waiver segment*** no later than 12 months after the short is identified.

ii) **Electrolytic Shorts**: PG&E must remove the electrolyte from the casing/pipe annular space on any casing in a ***State Waiver segment*** that has an electrolytic short within 12 months of identifying the short. If PG&E identifies any shorts after uprating, they must be cleared no later than 12 months after identification.

iii) **All Shorted Casings**: PG&E must install external corrosion control test leads on both the carrier pipe and the casing in accordance with 49 CFR 192.471 to facilitate the future monitoring for shorted conditions. PG&E may then choose to fill the casing/pipe annular space with a high dielectric casing filler or other material that provides a corrosion-inhibiting environment provided PG&E completed an assessment and all necessary repairs.

b) **Remediation of Un-cleared Casing Shorts**: If it is impractical for PG&E to clear a shorted casing within a ***State Waiver segment***, PG&E must document the actions taken to remediate the shorted casing and must receive a "no objection" letter from CPUC to use ILI assessments instead of clearing the short.[42] In addition to the notification, PG&E must conduct the following:

i) A ***State Waiver segment*** with shorted casings must be assessed with the appropriate ILI tools (a minimum of HR-MFL and HR-Deformation ILI and with EMAT ILI when a ***State Waiver segment*** is susceptible to SCC) on a five (5) calendar year assessment schedule, not to exceed 66 months.

ii) PG&E must remediate any identified corrosion, cracking, or other anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**.

10) **Condition 10 - Pipe - Seam Evaluations**

PG&E must conduct engineering integrity assessments to identify any pipe in the ***extended State Waiver segment*** that may be susceptible to pipe seam leak, rupture, or other failure issues because of the vintage of the pipe, the manufacturer of the pipe, other physical or operational characteristics, or unknown pipe characteristics as follows:

a) **Identify and Test Pipe Seam Issues**:

i) Within 12 months of the State Waiver grant, PG&E must perform an engineering integrity analysis to determine if the pipe seam is susceptible to seam threats located in the ***extended***

[42] CPUC must respond to PG&E's submittal letter within 90 days. CPUC may provide a decision, request for additional information, or notify PG&E of CPUC's need for additional time to provide a decision.

State Waiver segment.[43] This engineering integrity analysis must follow and document the processes listed herein along with other relevant materials:

(1) "M Charts" in "Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines," by Kiefner and Associates (updated April 26, 2007), under PHMSA Contract DTFAA-COSP02120; and

(2) Figure 4.2, "Framework for Evaluation with Path for the Segment Analyzed Highlighted" from TTO-5, "Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation," by Michael Baker Jr. and Kiefner and Associates, et. al. under PHMSA Contract DTRS56-02-D-70036.

ii) If the engineering integrity analysis identifies pipe seam issues in the ***extended State Waiver segment*** that are a threat to the integrity of the pipeline, PG&E must confirm there are no systemic issues with the weld seam or pipe. Within 12 months of analysis completion, PG&E must complete a hydrostatic test to a minimum of 1.39 times the MAOP for any identified ***State Waiver segment***.

b) **Seam Leak or Failure**:

i) If the pipeline experienced a seam leak or failure in the last five (5) years and PG&E did not perform a hydrostatic test meeting **Condition 1(b)** after the seam leak or failure in the ***State Waiver segment*** of the same weld seam and manufacturer, then PG&E must complete a hydrostatic test to a minimum of 1.39 times the MAOP within 18 months after the grant of this State Waiver in the ***State Waiver segment***.

ii) PG&E must determine from the hydrostatic test whether there are systemic issues with the weld seam or pipe. PG&E must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. PG&E must provide the written results of this root cause analysis to CPUC within 90 days of the failure.

c) **Pipe Replacement**: The ***State Waiver segment*** must be replaced if any of the following conditions exist or are discovered after the grant of this State Waiver:

[43] The ***extended State Waiver segment*** is defined as the ***State Waiver segment*** and the five (5) contiguous miles past each endpoint.

i) The ***State Waiver segment*** has any direct current-electric resistance welded (DC-ERW) seam or pipe with a longitudinal joint factor below 1.0 as defined in 49 CFR 192.113;

ii) The ***State Waiver segment*** pipe has any LF-ERW or EFW seam pipe joints that had pipe seam leaks or ruptures and the pipe has not been replaced with new pipe;[44]

iii) Pipe in the ***extended State Waiver segment*** was constructed or manufactured prior to 1954 and had pipe seam leaks or ruptures; [45]

iv) The ***State Waiver segment*** pipe has unknown manufacturing processes (i.e., unknown seam type, yield strength, or wall thickness); or

v) The ***State Waiver segment*** pipe has known manufacturing or construction issues that are unresolved, such as concentrated hard spots, hard heat-affected weld zones, selective seam corrosion, pipe movement that has led to buckling, past leak and rupture issues, or any other systemic issues.

d) **Girth Weld or Seam Weld Repairs**: Within a ***State Waiver segment***, PG&E must remove and replace, in accordance with 49 CFR Part 192 requirements, all weld seam or girth weld repairs that have been made by the usage of fittings such as weldolets, threadolets, repair clamps, and pipe sleeves (steel or composite). This remediation must be completed within six (6) months of the grant of this State Waiver or within six (6) months of the identification.

e) **Remediation Plan**: PG&E must remediate all weld seam leaks, failures, or ruptures[46] discovered in the ***State Waiver segment***. PG&E must submit a seam remediation plan for the ***State Waiver segment*** to CPUC no later than 30 days after finding a seam leak, seam failure, or seam rupture in the ***State Waiver segment*** containing one (1) of the following:

i) A longitudinal weld seam remediation/repair plan that meets **Condition 10** and includes replacement, hydrostatic testing, or ILI, with completion of the remediation/repair plan within six (6) months of discovery, or

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[44] As of the date of the grant of this State Waiver, PG&E reported no LF-ERW or EFW seam pipe in a ***State Waiver segment***.

[45] As of the date of the grant of this State Waiver, PG&E reported no pipe manufactured prior to 1954 with seam integrity issues in a ***State Waiver segment***.

[46] For all in-service and pressure test failures, PG&E must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. PG&E must provide the written results of this root cause analysis to CPUC within 90 days of the failure.

ii) A technical justification that shows that the ***State Waiver segment*** is not at risk for future longitudinal seam leaks or failures.

11) **<u>Condition 11 - Control of Interference Currents</u>**

PG&E must address induced alternating current (AC) from parallel electric transmission lines and other interference issues, such as direct current (DC), that may affect the pipeline in a ***State Waiver segment***. PG&E must have an induced AC or DC program and remediation plan to protect the pipeline from corrosion caused by stray currents within 12 months of the grant of this State Waiver.

a) **<u>Surveys</u>**: PG&E must perform periodic interference surveys to detect the presence and level of any electrical stray current, including when there are current flow increases over the ***State Waiver segment*** grounding design from any co-located pipelines, structures, or high voltage alternating current (HVAC) powerlines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures.

b) **<u>Analysis of Results</u>**: PG&E must analyze the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion (defined as 100 amps per meter squared for AC-induced corrosion), or if the interference impedes the safe operation of the pipeline, or that may cause a condition that would adversely impact the environment or the public.

c) **<u>Remediation</u>**: Remedial action is required when the interference in the ***State Waiver segment*** is at a level that could cause significant corrosion (defined as 100 amps per meter squared for AC-induced corrosion), or if it impedes the safe operation of a pipeline or may cause a condition that would adversely impact the environment or the public. Within six (6) months after completing the interference survey, PG&E must develop a remediation procedure and apply for any necessary permits to conduct remediation. PG&E must complete all remediation within six (6) months, or as soon as practicable, after obtaining the necessary permits for the remediation.

d) **<u>Completion Schedules</u>**: If environmental permitting or right-of-way factors beyond PG&E's control prevent the completion of any remediation within six (6) months of completing the interference engineering analysis of the survey results, PG&E must complete remediation as soon as practicable and submit a letter justifying the delay and providing the anticipated date of completion to CPUC no later than one (1) month prior to the end of the six (6) month completion date. Any extended evaluation and remediation schedules submitted to CPUC from PG&E must receive a "no objection" letter from CPUC.

12) **Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures**

PG&E must automate mainline valves[47] for closure or demonstrate capability to manually close mainline valves in accordance with the requirements of this **Condition 12**. A ***State Waiver segment*** must have upstream and downstream automatic shutoff valves (ASVs) or remote-controlled valves (RCVs) so that the distance between the valves is no greater than 20 miles.[48] PG&E must automate mainline valves to close in accordance with the requirements in **Condition 12** within 12 months of the grant of this State Waiver. The ***State Waiver segment*** must have procedures for rupture isolation as follows:

a) **Valve Locations**: ASVs or RCVs must be installed as shown in **Table 4 - Valves and Lateral Locations with Isolations Methods**. Each ***special permit segment*** must have telemetry connections to the PG&E supervisory control and data acquisition (SCADA) system installed.

b) **Automatic Shutoff Valve Requirements**:

i) If an ASV is used, PG&E must confirm the 30-minute ASV shut-in pressure for a ***State Waiver segment*** after "notification of potential rupture" by flow modeling of the ***State Waiver inspection area*** and any looped pipelines or gas receipt tie-ins between the ASVs or RCVs. Flow modeling must include anticipated maximum, normal, or any other flow volumes, pressures, or any other operating conditions that may be encountered during the calendar year. The flow model detection for a rupture must be based upon 0.500 times the pipe diameter area or smaller pipe area (partial pipe opening) for rupture sizing to account for pressure drop. If operating conditions change that could affect the ASV set pressures and the 30-minute isolation time after "notification of potential rupture," a new flow model must be conducted and ASV set pressures must be reset prior to the next review for ASV set pressures. If the ***State Waiver segment*** cannot be isolated within 30 minutes of a "notification of potential rupture" by usage of ASVs, then RCVs must be installed. **Table 4 - Valves and Lateral Locations with Isolations Methods** has the ASV shutoff pressures

[47] A mainline valve is a sectionalizing valve used to isolate or stop gas flow upstream or downstream along the pipeline.

[48] If the distance between mainline isolation valves exceed 20 miles, additional mainline valve(s) must be added.

and shutoff times for isolation of the ***special permit segment*** after "notification of potential rupture."

ii) ASVs must be equipped with rupture sensing equipment to detect the **State Waiver *segment*** "rate of pressure drop" with a set-point of 20-40 psig/minute or less unless PG&E submits a request for a "rate of pressure drop" set-point change and receives a "no objection" letter from CPUC for any revised shut-in pressures prior to their implementation.

iii) ASV shut-in pressures must be confirmed and reset on a calendar year basis not to exceed 15 months. PG&E must submit initial and annual ASV shut-in pressures to CPUC as detailed in **Condition 15 – Annual Report**, and receive a "no objection" letter from CPUC for any revised shut-in pressures prior to their implementation. CPUC must respond to PG&E's submittal letter within 90 days with a decision letter, or either give PG&E a request for additional information or additional time for CPUC to review the request.

iv) If the pipeline is impacted by extreme weather or other emergency conditions that reduce pipeline operating pressures in the ***State Waiver segment*** to operating pressures where the ASV shut-in pressures require emergency resetting, PG&E may reset ASV shut-in pressures below the operating pressure requirements for a maximum period of seven (7) days, but must notify CPUC within two (2) days of the pressure reset.

c) **Remote Monitoring and Control**: Each ***State Waiver segment*** must be controlled by a SCADA system and must be equipped for remote monitoring and control, or remote monitoring and automatic control, in accordance with 49 CFR 192.620(d)(3)(iii) and the below requirements in this **Condition 12**.

d) **Crossover or Lateral Pipe Connection Isolation**: If any crossover or lateral pipe[49] connects to the isolated segment between the upstream and downstream mainline valves, the nearest valve on the crossover connection(s) or lateral(s) must be isolated such that, when all valves are closed, there is no flow path for gas to flow to the leak or rupture site (except for residual gas already in the shut-off segment). If the nearest valve for a gas receipt or delivery line to the ***State Waiver inspection area*** is not isolated, isolation valves must be installed within 12

[49] **Table 4 - Valves and Lateral Locations with Isolations Methods** has a listing of all lateral valves. PG&E must update **Table 4** if a mainline, lateral, or crossover valve was mis-identified, added, or modified after the grant of the state waiver and submit this update in accordance with **Condition 15 – Annual Report**.

months of the grant of this State Waiver.[50] Valves that are in the PG&E O&M procedures as locked closed and that are only opened when manned by PG&E operating personnel do not require RCVs or ASVs for closure.

e) **<u>Remote-Control and Automatic-Shutoff Valve Status</u>**:

   i) RCVs must be constantly monitored for valve status (open, closed, or partial closed/open), upstream pressure, and downstream pressure.

   ii) A ***State Waiver segment*** with ASVs must have a minimum of one (1) pressure monitoring point within the segment when the mainline valve locations do not have pressure monitoring. If an ASV is used, PG&E must determine the set pressure used in **Condition 12(b)** on a calendar year basis not to exceed 15 months and must report the set pressure to CPUC each year in the **Condition 15 - Annual Report**. ASV pressure settings must be determined by flow modeling of the ***State Waiver segment***, ***State Waiver inspection area***, and all looped, delivery, or receipt pipelines tied into the ***State Waiver inspection area*** that could affect pressures in the ***State Waiver segment***. If the ASV pressure settings cannot be accurately determined, RCVs must be installed for the ***State Waiver segment***. The shutdown time for ASVs must be within 30 minutes of the "notification of potential rupture."

f) **<u>Mainline Valve Closure</u>**: Closure of the appropriate valves following a pipeline leak or rupture must occur "as soon as practicable" and must not exceed 30 minutes from the "notification of potential rupture" as defined below:[51]

   i) "Notification of Potential Rupture" means any of the following events that involve an unintentional or uncontrolled release of a large volume of gas from a transmission pipeline:

      (1) A release of gas observed by or reported to PG&E (e.g., by its controller(s) in a control room, field operations personnel, nearby pipeline or utility personnel, the public, local

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[50] Gas delivery or receipt pipelines must have a shutoff valve (gate or ball valve) either at the connection between the isolation valves for a ***State Waiver segment*** or at the delivery or receipt meter station. Any gas delivery or receipt station over 5-miles in length that is connected between the isolation valves for a ***State Waiver segment*** must have a RCV or ASV within 5-miles of the pipeline tie-in. For gas delivery or receipt pipelines manual shutoff valves can be used for isolation but must be closed within 30-minutes of the pipeline leak or rupture confirmation. Check valves cannot be used for pipelines over 8-inch diameter.

[51] The pipeline valve section location to be closed and isolated (if there should be a rupture) must be confirmed by PG&E through Gas Control or other field operations personnel monitoring of the appropriate pipeline pressures, pressure changes, or flow rate changes through a compressor discharge section or by location confirmation from responsible persons.

responders, or public authorities) that may be representative of an unintentional or uncontrolled release event meeting **paragraphs (2)** or **(3)** of this definition;

(2) PG&E observes an unanticipated or unplanned pressure loss outside of the pipeline's normal operating pressures, as defined in PG&E's written procedures. If PG&E establishes an unanticipated or unplanned pressure loss threshold that is greater than a 10% pressure loss, occurring within a time interval of 15 minutes or less, PG&E must document in its written procedures the need for a greater pressure-change threshold due to pipeline flow dynamics (including the pipeline operating pressure, gas flow rate or volume), that are caused by fluctuations in gas demand, gas receipts, or gas deliveries; or

(3) PG&E observes an unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication that may be representative of an event meeting **paragraph (2)** of this definition.

<u>Note:</u> Notification of potential rupture occurs when an event, as defined in this **section/paragraphs (2)** or **(3)** above, is first observed by or reported to PG&E.

ii) PG&E must evaluate and identify a rupture,[52] as defined above, as being either an actual leak event, rupture event, or non-rupture event in accordance with operating procedures and 49 CFR 192.615.

g) **<u>Gas Control Center Monitoring</u>**: The PG&E Gas Control Center must monitor the ***State Waiver inspection area*** 24 hours a day, seven (7) days a week, and must confirm the existence of a leak or rupture as soon as practicable in accordance with PG&E pipeline operating procedures.

h) **<u>Remote Monitoring</u>**: PG&E must maintain remote monitoring and automatic control equipment, mainline valves, mainline valve operators, and pressure sensors in accordance with 49 CFR 192.631 and 192.745. All remote monitoring and automatic control equipment, including pressure sensors, must have backup power to maintain communications and control to the PG&E Gas Control Center during power outages.

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[52] For all in-service and pressure test failures, PG&E must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. PG&E must provide the written results of this root cause analysis to CPUC within 90 days of the failure.

i) **Point-to-Point Verification**: PG&E must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with 49 CFR 192.631(c) and (e).

j) **Valve Maintenance**: PG&E must maintain all valves used to isolate a leak or rupture in accordance with this State Waiver and 49 CFR 192.745.

k) **Inoperable Valves**: PG&E must take remedial measures to correct any valve used to isolate a leak or rupture that is found to be inoperable or unable to maintain shutoff, as follows:

   i) Repair or replace the valve as soon as practicable but no later than six (6) months after the finding;

   ii) Designate an alternative valve within 14 calendar days of the finding while repairs are being made. Repairs must be completed within six (6) months; and

   iii) If valve repair or replacement cannot be met due to circumstances beyond PG&E's control, PG&E must notify, in writing, CPUC of the reasons the schedule cannot be met and obtain a letter of "no objection" from CPUC prior to implementing the schedule change.

l) **Emergency Communications**:

   i) PG&E must establish and maintain adequate means of communication with the appropriate public safety access point (9-1-1 emergency call center) or emergency management coordinating agency and must notify them, as well other emergency responders, if there is a leak or rupture, as required in 49 CFR 192.615;

   ii) PG&E must immediately and directly notify the appropriate public safety access point (9-1-1 emergency call center) or other emergency management coordinating agency for the communities and jurisdictions in which the pipeline is located when a release is indicated;[53] and

   iii) In accordance with these State Waiver conditions and as required in 49 CFR 192.615 and 192.631, PG&E must establish actions required to be taken by a pipeline controller or the appropriate emergency response coordinator when an emergency occurs in the ***State Waiver inspection area***.

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[53] PG&E must designate the pipeline controller or the appropriate operator emergency response coordinator in its operating procedures and train the designated individual for coordinating with emergency responders.

13) **Condition 13 - State Waiver Specific Conditions**

PG&E must comply with the following requirements:

a) **Line-of-Sight Markers**: PG&E must install and maintain line-of-sight markings on the pipeline in each ***State Waiver segment***, except in agricultural areas or large water crossings, such as lakes, where line-of-sight signage is not practical. Line-of-sight markers must be installed within six (6) months of the grant of this State Waiver and replaced as necessary by PG&E within 30 days after identification of line-of-sight marker removal.

b) **Depth of Cover Survey**:

i) PG&E must complete, within six (6) months of the grant of this State Waiver, a depth of cover survey for each ***State Waiver segment***.

ii) PG&E must implement additional safety measures for any pipe in a ***State Waiver segment*** that does not meet 49 CFR 192.327(a) for a Class 1 location where there is a reduced depth of cover. A ***State Waiver segment*** with depth of cover less than 24-inches must be either lowered, have additional soil cover added, or have a concrete pad installed unless it is in consolidated rock.

iii) For PG&E to use other remedial measures for depth of cover requirements that are based upon the threat, such as increased pipeline patrols or additional line markers, PG&E must submit these procedures to CPUC for a "no objection" letter prior to usage. CPUC must respond to PG&E's submittal letter within 90 days. CPUC may provide a decision, request for additional information, or notify PG&E of CPUC's need for additional time to provide a decision.

c) **Data Integration**: PG&E must develop and maintain data integration[54] in accordance with 49 CFR 192.917, of all State Waiver condition findings and remediation in a ***State Waiver segment*** and ***State Waiver inspection area***. Data integration must be completed at least once each calendar year, with intervals not to exceed 15 months.

i) Data integration must include the following information: (1) Pipe diameter, wall thickness, grade, and seam type; (2) pipe coating; (3) MAOP; (4) class location, including boundaries on aerial photography; (5) HCAs, including boundaries on aerial photography; (6)

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[54] Data integration is defined as the gathering of relevant pipeline attributes, operational, maintenance, environmental, and integrity information and integrating this information together to assess threats to the pipeline and to use this information to conduct assessments and remediation for those threats.

hydrostatic test pressure, including any known test failures; (7) casings; (8) any in-service ruptures or leaks; (9) ILI survey results, including HR-MFL, HR-geometry/caliper, or deformation tools; (10) the most recent CIS results; (11) depth-of-cover surveys; (12) rectifier readings for the past five (5) years; (13) CP test point survey readings for the past five (5) years; (14) AC/DC interference surveys; (15) pipe coating surveys; (16) pipe coating and anomaly evaluations from pipe excavations; (17) SCC excavations and findings; and (18) pipe exposures from encroachments.[55] Structures must be validated each calendar year by obtaining new aerial imagery or by ground patrol in accordance with **Condition 13(h)**.

ii) If requested by CPUC, PG&E must complete and submit data integration documentation and drawings, with four (4) years of prior data, beginning with the 2nd annual report of this modified State Waiver.

iii) PG&E must maintain data integration as a composite of all applicable data elements in a comparable data viewer.

d) **Pipe Properties Testing**: If the pipe does not meet **Condition 16(b)**, PG&E must test the pipe in a ***State Waiver segment*** as follows: [56]

i) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for any ***State Waiver segment***, without TVC[57, 58] pipe material properties records, in accordance with this condition and either 49 CFR 192.607 or 192.105 for determining MAOP. Non-destructive or destructive tests, examinations, and assessments must be completed within 18 months of the grant of this State Waiver.

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55 Hydrostatic test failures, in-service ruptures, rectifier readings, CP test point survey readings, AC/DC interference surveys, pipe coating surveys, pipe coating and anomaly evaluations from pipe excavations, SCC excavations and findings, and pipe exposures from encroachments must be maintained for data integration into a comparable data viewer. These data elements may not be on a drawing.

56 If CPUC determines that the material records do not meet the requirements of TVC, then the completion of **Condition 13(d)** will be required for each ***State Waiver segment***.

57 TVC procedures and records must follow the following: 1) "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements and Other Related Amendments"; 84 FR 52218 to 52219; October 1, 2019; and 2) PHMSA Advisory Bulletin: Pipeline Safety: Verification of Records; 77 FR 26822; May 7, 2012; https://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf.

58 Material records must cover the entire length of the ***State Waiver segment***, regardless of when the pipeline, single or multiple pipe joints, or other pipeline components were installed. Affidavits for a material record are not acceptable TVC material records.

ii) PG&E must test pipe in each ***State Waiver segment*** without TVC material properties and of different vintages as defined in **Condition 13(d)(iv)**. Material tests must be conducted at two (2) excavation sites per mile with excavations spaced between 1,320 to 3,960 feet in each mile segment. If the ***State Waiver segment*** is less than ½ mile, only one (1) excavation site is required.

iii) PG&E must perform a minimum of two (2) destructive or NDT methods at an excavation site. PG&E must conduct NDT assessments using test procedures, calibration pipe of similar confirmed properties for equipment testing, and ball indention methodology, or an equivalent method.[59] If NDT of pipe material properties show that the pipe wall thickness is not within API 5L specification tolerances, and the pipe grade is under the strength requirements of API 5L by 1,000 pounds per square inch (psi) or more, then PG&E will confirm the yield strength of that individual pipe using destructive test methods or remove the ***State Waiver segment*** pipe. If ILI tools are used to verify the pipeline materials, PG&E must submit an assessment procedure to CPUC for a "no objection" letter prior to its usage. CPUC must respond to PG&E's submittal letter within 90 days. CPUC may provide a decision, request for additional information, or notify PG&E of CPUC's need for additional time to provide a decision.

iv) PG&E must assess pipe in a ***State Waiver segment*** with missing mill test reports (MTRs) or missing mill inspection reports (i.e., Moody Engineering Reports) for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a 2-year interval), and construction dates (within a 2-year interval).

v) PG&E cannot use the material properties determined from either destructive or NDT required by this condition to raise the original grade or specification of the pipeline material. PG&E must use the applicable standard referenced in 49 CFR 192.7.

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[59] PG&E must submit the non-destructive assessment method and procedures to CPUC. CPUC must respond to PG&E's submittal letter within 90 days. CPUC may provide a decision, request for additional information, or notify PG&E of CPUC's need for additional time to provide a decision.

vi) For a future ***State Waiver segment*** with missing mill inspection reports for mechanical and chemical properties, PG&E must use the above methodology, or PG&E may elect to remove pipe joints for destructive testing.[60]

e) **Pipeline System Flow Reversals**: For pipeline system flow reversals lasting longer than 90 days and where the MAOP for class location changes are exceeded under either 49 CFR 192.619(a)(1) or 192.611[61] in a ***State Waiver segment***, PG&E must prepare a written plan that corresponds to the applicable criteria identified in the PHMSA Advisory Bulletin, ADB-2014-04, "Guidance for Pipeline Flow Reversals, Product Changes and Conversion of Service" (79 FR 56121; Sept. 18, 2014). PG&E must submit the written flow reversal procedure to CPUC. PG&E must receive a "no objection" letter from CPUC prior to implementing the pipeline system flow reversal through a ***State Waiver segment***.

f) **Environmental Assessments and Permits**: PG&E must evaluate the potential environmental consequences and affected resources of any land disturbances and water body crossings, and pipeline natural gas emissions from implementation of the State Waiver conditions for a ***State Waiver segment*** or ***State Waiver inspection area*** prior to the disturbance or activity. If a land disturbance, water body crossing, or pipeline natural gas emission is required, PG&E must obtain and adhere to all applicable Federal, state, and local environmental permit requirements when conducting the State Waiver conditions activity.

g) **Gas Quality**: PG&E must transport gas through the ***State Waiver segment*** whose composition quality is suitable for sale to gas distribution customers, including no free-flow water or hydrocarbons, no water vapor content that exceeds acceptable limits for gas distribution customer delivery, hydrogen sulfide (H_2S) not to exceed one (1) grain per 100 cubic feet, or carbon dioxide (CO_2) not to exceed three (3) percent by volume.

h) **Annual Class Location Study**: PG&E must conduct a class location study on the ***State Waiver inspection area*** at least once each calendar year, with intervals not to exceed 15 months, in accordance with 49 CFR 192.609.

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60 PG&E must prepare a procedure in accordance with **Condition 13(d) – Pipe Properties Testing** for material documentation and submit to CPUC and receive a "no objection" letter prior to usage of the procedure. CPUC must respond to PG&E's submittal letter within 90 days. CPUC may provide a decision, request for additional information, or notify PG&E of CPUC's need for additional time to provide a decision.

61 An example of exceedance of 49 CFR 192.619(a)(1) is a Grandfathered MAOP which has a design factor above 0.72. An example of exceedance of 49 CFR 192.611 is a Class 1 to 3 location change.

i) **<u>Notifications</u>**: For any State Waiver condition that requires PG&E to provide a notice for a "no objection" response from CPUC, other notice, annual report, or documentation to CPUC, PG&E must also send a copy to the Director, PHMSA State Programs.

j) **<u>Pipe and Soil Movement</u>**: Girth weld strain from soil movement exerted onto the pipeline in the ***State Waiver segment*** must not exceed 0.5 percent and must account for girth weld misalignment. PG&E must develop procedures on how to evaluate and remediate soil stresses and strains on the pipeline including IMU intervals. PG&E must submit soil stress and strain evaluation and remediation procedures to CPUC, within three (3) months of identification and must receive a "no objection" letter prior to implementation.

k) **<u>Gas Leakage Surveys and Remediation</u>**:

i) PG&E must conduct gas leakage surveys using instrumented gas leakage detection equipment along each ***State Waiver segment*** and at all valves, flanges, pipeline tie-ins, ILI launcher and ILI receiver facilities in each ***State Waiver inspection area*** at least twice each calendar year, not to exceed 7½ months. PG&E must document the type of equipment used, survey findings, and remediation of all instrumented gas leakage surveys.

ii) A gas transmission pipeline leak is a gas leak that can be seen, heard, felt, or detected by instrumented gas leakage detection equipment, or is an existing, probable, or future hazard to the public, operating personnel, property, or the environment. PG&E must grade and remediate all gas transmission pipeline leaks in the ***State Waiver segment*** and at all valves, flanges, pipeline tie-ins, ILI launcher, and ILI receiver facilities in each ***State Waiver inspection area***, as follows:

(1) A Grade 1 leak requires immediate and/or continuous remediation efforts to stop the leak. A Grade 1 leak is defined as any of the following:

(a) Any leak which, in the judgment of the operating personnel at the scene, is regarded as an immediate hazard;

(b) Escaping gas that has ignited;

(c) Any indication of gas which has migrated into or under a building, or into a tunnel.

(d) Any reading at the outside wall of a building, or any reading where gas would likely migrate to an outside wall of a building;

(e) Any reading of 80% lower explosive limit (LEL), or greater, in a confined space;

(f) Any reading of 80% LEL, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building; or

(g) Any leak that can be seen, heard, or felt, and which is in a location that may endanger the public, property, or environment.

(2) A Grade 2 leak requires remediation activity to be completed within 30 days or must have continuous remediation efforts to stop the leak. A Grade 2 leak is defined as any of the following:

(a) Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building;

(b) Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak;

(c) Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 leak;

(d) Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard;

(e) Any reading between 20% LEL and 80% LEL in a confined space;

(f) Any reading on a pipeline operating at 30% SMYS or greater, in a Class 3 or 4 location, which does not qualify as a Grade 1 leak;

(g) Any reading of 80% LEL, or greater, in gas associated substructures; or

(h) Any leak which, in the judgement of operating personnel at the scene, is of sufficient magnitude to justify schedule repair.

(3) A Grade 3 leak must be reevaluated at the next scheduled survey, or within 7½ months of the date discovered, whichever occurs first, until the leak is cleared, re-graded, or remediated. Remediation of Grade 3 leaks must be completed within 24 months of discovery of the leak. A Grade 3 leak is defined as any of the following:

(a) Any reading of less than 80% LEL in small gas associated structures;

(b) Any reading in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building; or

(c) Any reading of less than 20% LEL in a confined space.

iii) When a pressure limiting device or relief valve allows a gas release to the atmosphere that is located along the ***State Waiver inspection area***, PG&E must conduct an O&M procedure assessment of the pilot, springs, pressure gauges, and other pressure limiting equipment to ensure these items are properly functioning, sensing, and retaining set pressures. If a pressure limiting device or relief valve deficiency cannot be remediated, the pressure limiting device or relief valve must be replaced or continuously monitored until remediated. PG&E cannot extend or change any remediation timing or continuous monitoring requirements in this paragraph without a "no objection" letter received by PG&E from CPUC.

iv) PG&E may request an extension of the remediation time interval requirements by sending a request to CPUC but must receive a "no objection" letter from CPUC prior to extending the leak remediation timing or continuous monitoring requirements in **Condition 13(k)**.[62]

l) **Right-of-Way Patrols**: In addition to the requirements of 49 CFR 192.705, PG&E must perform right-of-way patrols as follows:

i) Aerial flyover patrols or ground patrols by walking or driving of a ***State Waiver segment*** right-of-way once each month, not to exceed 45 days, contingent on weather conditions. Should mechanical availability of the patrol aircraft or weather conditions become an extended issue, the ***State Waiver segment pipeline*** aerial flyover patrol must be completed within 60 days of the last patrol by other methods such as walking or driving the pipeline route, as feasible.

ii) If the schedule for either ground patrols or aerial flyover patrols cannot be met due to circumstances beyond PG&E's control, PG&E must notify CPUC in writing of the reasons the schedule cannot be met and obtain a letter of "no objection" within three (3) business days of the exceedance.

m) **Minimization of Gas Released to the Environment**:

i) PG&E must reduce the release of gas to the environment when replacing any pipe between the mainline isolating valves for a ***State Waiver segment***. PG&E must use one (1) or more of following methods that will reduce the environmental effects of methane (gas) being

[62] Any PG&E request for a time interval extension for a 24-month remediation interval must be 90 days prior to the end of the 24-month remediation interval.

released. PG&E must calculate the volume of natural gas that will be released by each method or combination of methods and select an option(s) that minimizes the release of gas to the environment and is consistent with pipeline safety.[63]

1) Isolate a smaller pipeline segment length by use of valves and/or the installation of control fittings near the pipe being replaced;
2) Flaring the gas released from the pipeline from the nearest isolation valves or control fittings from the pipe being replaced;
3) Pressure reduction in the pipeline segment by use of inline compression;
4) Pressure reduction by use of mobile compression from the nearest isolation valves from the pipe being replaced;
5) Transfer the gas to a lower pressure pipeline system or segment from the nearest isolation valves nearest to the pipe being replaced such as through a lateral delivering gas to another pipeline facility; or
6) An alternative method demonstrated to minimize the release of gas to the environment similar to the other methods listed in the methods (1) through (5) above.

ii) PG&E must document the determination and justification for the reduction method(s) implemented and how the method(s) used minimized the release of natural gas to the environment and was consistent with pipeline safety. PG&E must also document and justify, any substantial difference (over 10 percent additional release) between the actual amount of natural gas released and the estimated volume calculated before the replacement.

iii) PG&E must report all mainline blowdowns between the mainline isolating valves for a ***State Waiver segment*** due to pipe replacement as detailed in the **Condition 15(i) - Annual Report**.

14) **<u>Condition 14 - Field Activity Notices to CPUC</u>**

PG&E must give a minimum 14-day notice to CPUC to enable CPUC to observe the excavations relating to **Condition 8 – Anomaly Evaluation and Remediation** and **Condition 13(d) – Pipe Properties Testing** of field activities in the ***State Waiver inspection area***. Immediate response

[63] **Condition 13(m)** would not be required for a blowdown due to an immediate repair, as detailed in **Condition 8 - Anomaly Evaluation and Remediation**, or where immediate action is required to ensure public safety.

conditions do not require 14-day notice, but PG&E should notify CPUC no later than two (2) business days after the immediate condition is discovered CPUC may elect not to require a notification for some activities.

15) **Condition 15 - Annual Report**

Annually[64] after the grant of this State Waiver, PG&E must report the following to CPUC:

a) The number of new residences, other structures intended for human occupancy, and public gathering areas built within each ***State Waiver segment*** during the previous year. PG&E must include a summary of the results of the study conducted to meet **Condition 13(h) - Annual Class Location Study** in the annual report.

b) Any new integrity threats identified during the previous year and the results of any ILI or direct assessments performed (including any un-remediated anomalies over 30% wall loss; cracking found in the pipe body, weld seam, or girth welds; and dents with metal loss, cracking, or stress riser) and any soil movement (lateral or subsidence) that affects pipeline integrity[65] during the previous year in the ***State Waiver inspection area***, including their survey station, predicted failure pressure, anomaly depth and length, class location, and whether these threats are in an HCA.

c) In the 1st, 2nd, and 3rd annual reports PG&E must report each ***State Waiver segment*** that does not have the following complaint TVC records:

    i) A pressure test that meets **Condition 1(b)**. PG&E must report the planned or actual completion dates for the ***State Waiver segment*** pressure test including test pressure.

    ii) Material pipe properties tests that meet **Condition 13(d) – Pipe Properties Testing**. PG&E must report the planned or actual completion dates for the ***State Waiver segment*** material pipe property tests.

d) Any reportable incident, any leak normally indicated on the DOT Annual Report, and all repairs on the pipeline that occurred during the previous year in a ***State Waiver inspection area***. PG&E must include the location by mile post, county/parish, and state, the date of

[64] CPUC must receive the annual report by the last day of the month in which the State Waiver is dated. For example, the annual report for a State Waiver dated February 21, 2024, must be received by CPUC no later than February 31, each year beginning in 2025.

[65] PG&E must develop and implement an O&M procedure to review soil movements that could damage the ***State Waiver segment*** on a periodic interval so the lateral stresses will not exceed 100% of SMYS (0.5% strain) on girth welds.

discovery, date of repair, and estimated gas loss (cubic feet) per day and in total for any Grade 1, 2, or 3 gas leak as described in **Condition 13(k) - Gas Leakage Surveys and Remediation**.

e) Any ongoing DP initiatives affecting a ***State Waiver inspection area*** and a discussion of the success of the initiatives, including findings and remediation actions.

f) PG&E must submit annual data integration information, as required in **Condition 13(c) - Data Integration,** beginning with the 2nd annual report, which must include an annual overview of any new threats. If requested by CPUC, PG&E must submit a full information package of the requested pipeline attribute and integrity items outlined in the condition.

g) If PG&E uses ASVs for **Condition 12 – Mainline Valve**, PG&E must report the set pressure and how it was determined for each year to meet "as soon as practicable but 30 minutes or less."

h) Any emergency events that cause closure of mainline valves, including the location (County, State and MP) of valves and closure times.

i) PG&E must report the diameter and location of the lateral, if any lateral or crossover piping is not included in **Table 4 – Valves and Lateral Locations with Isolation Methods** or installed between isolation valves for a ***State Waiver segment***.

j) PG&E must report all mainline blowdowns between the mainline isolating valves for a ***State Waiver segment*** due to pipe replacement which includes the date of blowdown, location (milepost/stationing), and the amount of gas released to comply with **Condition 13(m) – Minimization of Gas Released to the Environment**.

k) Any mergers, acquisitions, transfer of assets, or other events affecting the regulatory responsibility of the company operating the pipeline.

l) A senior executive officer, vice president, or higher executive of PG&E must review for correctness, date, and sign the annual report prior to submitting it to CPUC.

m) PG&E must schedule a review meeting regarding **Condition 15 - Annual Report** with the CPUC prior to or within one (1) month of the filing of each year.[66] During the annual review meeting, PG&E must review the status of implementing the State Waiver conditions with CPUC.

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[66] CPUC has the authority to waive this meeting.

16) **<u>Condition 16 – Documentation</u>**

PG&E must maintain the following records for a ***State Waiver segment*** as follows:

a) PG&E must keep documentation of compliance with all conditions of this State Waiver for the life of the pipe.

b) Documentation of the mechanical and chemical properties (e.g., mill test reports) that show the pipe in a ***State Waiver segment*** meets the wall thickness, yield strength, tensile strength, and chemical composition requirements of API Standard 5L, 5LX or 5LS, "Specification for Line Pipe" (API 5L) incorporated by reference into the 49 CFR Part 192 code at the time of manufacturing, or, if the pipe was manufactured and placed in-service prior to the inception of 49 CFR Part 192, the API 5L standard in use at that time. Any pipe in a ***State Waiver segment*** that does not have TVC mill test reports or does not meet **Condition 13(d) – Pipe Properties Testing** and 49 CFR 192.607 cannot be authorized per this State Waiver.

17) **<u>Condition 17 - Extension of the State Waiver Segment</u>**

CPUC may extend a ***State Waiver segment*** to include contiguous segments up to the limits of the ***State Waiver inspection area*** pursuant to PG&E implementing the following conditions:

a) Within six (6) months after the Class 1 to Class 3 location change, PG&E must provide notice to CPUC of the request for a ***State Waiver segment <u>extension</u>***.

   i) The notice must include the ***State Waiver segment extension*** survey stations, mile posts, additional pipeline footage, pipe attributes (wall thickness, grade, seam type, external coating, and latest pressure test), predicted failure pressure of any anomalies over 30% wall loss, schedule of inspections, and of any anticipated remedial actions.

   ii) PG&E must update the Final Environmental Assessment (FEA) to reflect the ***State Waiver segment*** extension and the FEA section titled, "Affected Resources and Environmental Consequences" as necessary. PG&E must submit the updated FEA with its request for an extension to CPUC for review and consideration.

   iii) Any request for a ***State Waiver segment*** extension does not become effective until PG&E receives a "no objection" response from CPUC.

b) Any proposed ***State Waiver segment extension*** must meet the following requirements prior to the class location change or within 12 months of the class location change:

   i) PG&E must remediate all anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**;

ii) PG&E must have hydrostatically tested[67] a ***State Waiver segment*** and ***extension*** in accordance with **Condition 1 – Maximum Allowable Operating Pressure**, as applicable; and

iii) PG&E must complete all required State Waiver conditions, except **Condition 17(b)** above, for each ***State Waiver segment extension*** within two (2) years of the Class 1 to Class 3 location change, unless specified otherwise.

c) PG&E must apply all the State Waiver conditions and limitations included herein to all future ***State Waiver segment extensions***.

18) **Condition 18 – Certification**

PG&E must meet the following conditions for certification:

a) A senior executive officer, vice president, or higher executive of PG&E must certify in writing the following:

i) Each ***State Waiver inspection area*** and ***State Waiver segment*** meet the conditions described in this State Waiver;

ii) PG&E has updated its O&M, IMP, and DP procedures required by **Condition 2 – Procedure Updates** to require the implementation of the State Waiver conditions for each ***State Waiver segment*** and ***State Waiver inspection area***;

iii) PG&E has prepared an uprating plan in accordance with **Condition 1(c)**, if applicable; and

iv) PG&E has implemented all conditions as required by this State Waiver.

b) PG&E must send the certifications required in **Condition 18(a)**, with State Waiver condition status, completion date, compliance documentation summary, and the required senior executive signature and date of signature to CPUC within one (1) year of the issuance date of this State Waiver.

Limitations

This State Waiver is subject to the limitations set forth in 49 CFR 190.341, as well as the following limitations:

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[67] For all in-service and pressure test failures, PG&E must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. PG&E must provide the written results of this root cause analysis to CPUC within 90 days of the failure.

1) CPUC has the sole authority to make all determinations on whether PG&E has complied with the specified conditions of this State Waiver. Failure to comply with any condition of this State Waiver may result in revocation of the waiver.
2) Any work plans and associated schedules for a ***State Waiver segment*** and ***State Waiver inspection area*** are automatically incorporated into this State Waiver and are enforceable in the same manner.
3) Failure by PG&E to submit the certifications required by **Condition 18 - Certification** within the time frames specified may result in revocation of this State Waiver.
4) As provided in 49 CFR 190.341, CPUC may issue an enforcement action for failure to comply with this State Waiver. The terms and conditions of any corrective action order, compliance order, or other order applicable to a pipeline facility covered by this State Waiver will take precedence over the terms of this State Waiver.
5) If PG&E sells, merges, transfers, or otherwise disposes of all or part of the assets known as a ***State Waiver segment*** or ***State Waiver inspection area***, PG&E must provide CPUC with written notice of the change within 30 days of the consummation date. In the event of such transfer, CPUC reserves the right to revoke, suspend, or modify the State Waiver if the transfer constitutes a material change in conditions or circumstances underlying the waiver.
6) CPUC grants this State Waiver limited to a term of no more than 10 years from the date of issuance. If PG&E elects to seek renewal of this State Waiver, PG&E must submit its renewal request at least 180 days prior to expiration of the 10-year period to CPUC. All requests for a renewal must include a summary report in accordance with the requirements in **Condition 15 - Annual Report** above and must demonstrate that the State Waiver is still consistent with pipeline safety. CPUC may seek additional information from PG&E prior to granting any request for State Waiver renewal.

Attachment A - Dent Anomalies – Engineering Critical Assessment

To evaluate dents and other mechanical damage anomalies that conform to the conditions described in **Table 3 – Dent Criteria** below, PG&E must perform an engineering critical assessment (ECA) as follows:

1) Identify and assess all threats for the pipe segment such as ground movement, other external loading, cracking, and corrosion that may be impacting the dent and mechanical damage.
2) Review all available high-resolution magnetic flux leakage (HR-MFL), high-resolution deformation, inertial mapping tool, and crack detection ILI data for damage in the dent area and any associated weld region.
3) If multiple ILI runs over time are available, the dent profile between the most recent and previous inline inspections should be compared to identify changes or significant changes in dent depth and shape and its possible impact to the integrity of the pipeline.
4) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.
5) Identify and quantify all significant loads acting on the dent.
6) PG&E must use finite element analysis to quantify the dent strain, and then estimate the damage using either Strain Limit Damage (SLD) or Ductile Failure Damage Indicator (DFDI) at the dent. Finite element analysis modeling of the dent must include all associated anomalies, defects, and welds. Other methodologies and approaches that are supported by peer reviewed publications will also be considered as part of the ECA but will require a "no objection" letter from CPUC.
7) The analyses performed must account for material property uncertainties and model inaccuracies and ILI tool sizing tolerances.
8) Using operational pressure data, appropriate fatigue models, and assuming the appropriate safety factor, PG&E must estimate the fatigue life of the dent in accordance with API 1156 (1997 Edition), API RP 1183 (1st Edition, 2020, or IBR Edition) or other published literature that is technically appropriate for dent assessment. Multiple dent or other fatigue models must be evaluated as part of the ECA.
9) If the dent is suspected to have cracks, then a crack growth rate assessment is required (or the dent needs to be remediated) to ensure adequate life for the dent with crack(s) and the crack(s) in the dent must be evaluated and remediated in accordance with the criteria in **Condition 8 – Anomaly Evaluation and Remediation**.

10) If PG&E uses other technologies or techniques to comply with failure pressure determinations, PG&E must submit advance notification to CPUC, and must receive a “no objection” letter from CPUC prior to usage.

11) The ECA process must be repeated following each assessment to ensure conformance to the original ECA conclusions.

12) To use ECA for dents with a depth greater than 6% up to 10% of the outside diameter (OD) requires a “no objection” letter from CPUC.

13) PG&E must remediate dents and mechanical damage that do not pass the criteria defined in **Table 3 – Dent Criteria**, or PG&E must conduct an acceptable ECA as described in this **Attachment A, Items 1 through 12**.

14) PG&E must submit the dent ECA procedure to CPUC for a “no objection” letter prior to conducting the anomaly evaluation. CPUC must respond to PG&E ’s submittal letter within 90 days. CPUC may provide a decision, request for additional information, or notify PG&E of CPUC’s need for additional time to provide a decision.

Table 3 – Dent Criteria		
Dent type	**Critical Dents that Require Action**	**ECA an Option**
Plain Dent	Dent of depth > 6% Outside Diameter (OD) or dent strain level exceeding: i. Dent with strain > 6% limit (ASME B31.8, 2018 Edition) **or** ii. Strain Limit Damage (SLD) or Ductile Failure Damage Indicator (DFDI) > 0.6 (per API RP 1183, IBR Edition or 1st Edition, 2020, if not IBR)	YES
Dent Associated with Corrosion**	i. Dent depth of > 6% OD with corrosion of any depth **or** ii. Dent of depth ≤ 6% OD with corrosion depth that is more than 15% of the pipe wall thickness	YES
Dent Associated with Metal Loss other than Corrosion**	Dent associated with metal loss other than corrosion: Gouge, axial or circumferential groove, SCC, fatigue cracks, and/or other cracks	YES
Dent Affecting Weld (Girth Weld, Longitudinal Seam Weld or Spiral Seam Weld)	Dent of any depth affecting pipe with: Low Frequency Electric Resistance Welded (LF-ERW), Electric Flash Welded (EFW), Lap Welded, or Longitudinal Joint Factor < 1.0*	YES*
	Dent of depth > 2% OD affecting other types of weld seams, see above, or girth welds with strain level exceeding 4% (ASME B31.8, 2018 Edition)	YES
Skewed and/or Multiple Dent Peaks	Any complex dent geometry identified by PG&E or ILI vendor such as skewed dent, two or multi-peak deformations	YES

* Lack of ductility must be integrated into the ECA.

** Corrosion failure pressure with safety factor must meet the MAOP requirements in **Condition 8 - Anomaly Evaluation and Remediation**.

Note: PG&E may use 49 CFR Part 192 compliant dent remediation procedures for the evaluation and remediation of a dent ≤ 6% OD, with a corrosion depth < 15% of the pipe wall, and corrosion failure pressure with safety factor that meets the MAOP requirements in **Condition 8 - Anomaly Evaluation and Remediation**.

Attachment B - State Waiver Segments and Inspection Area Route Maps

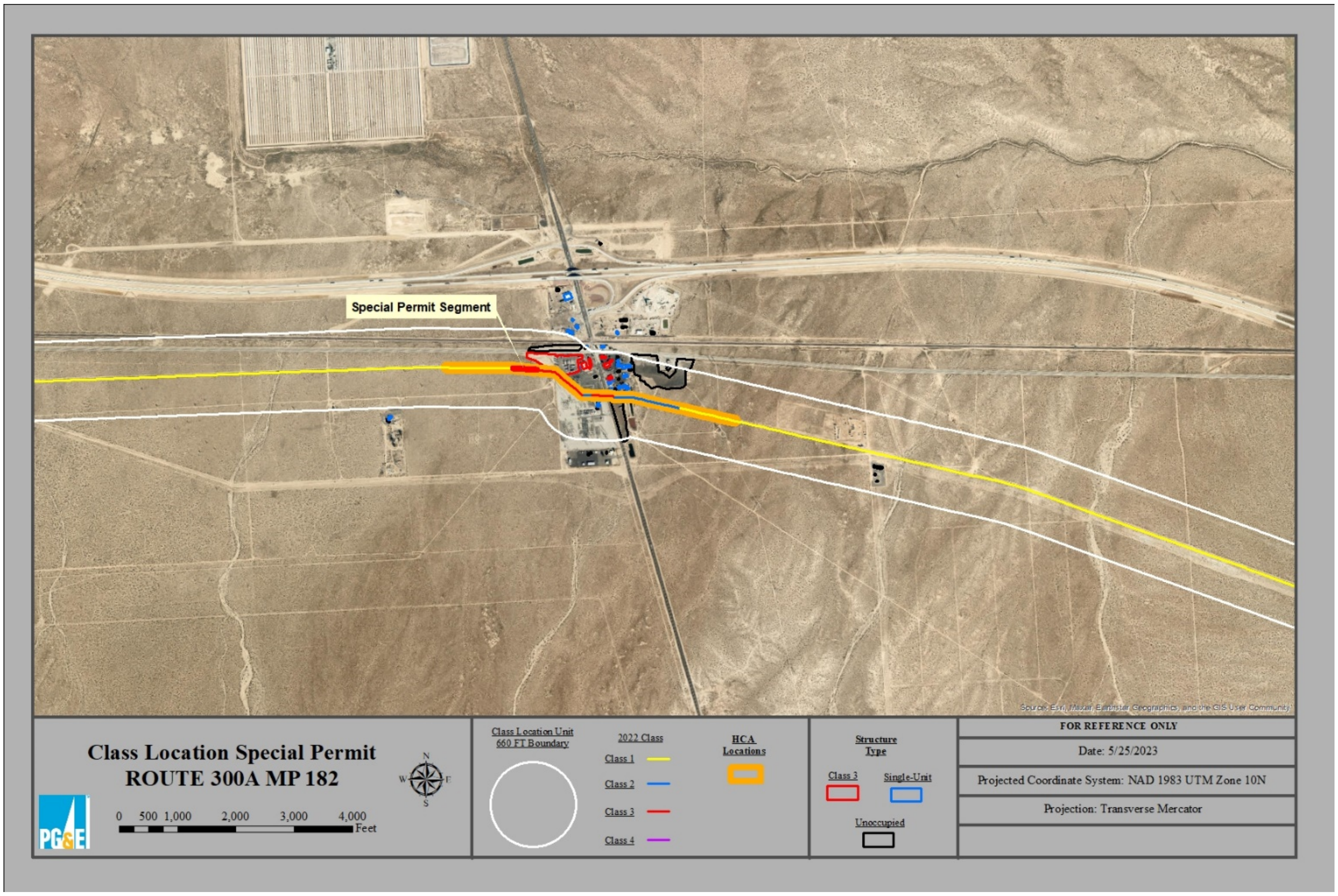

Figure 1. State Waiver (Special Permit) segment on PG&E's line 300A pipeline

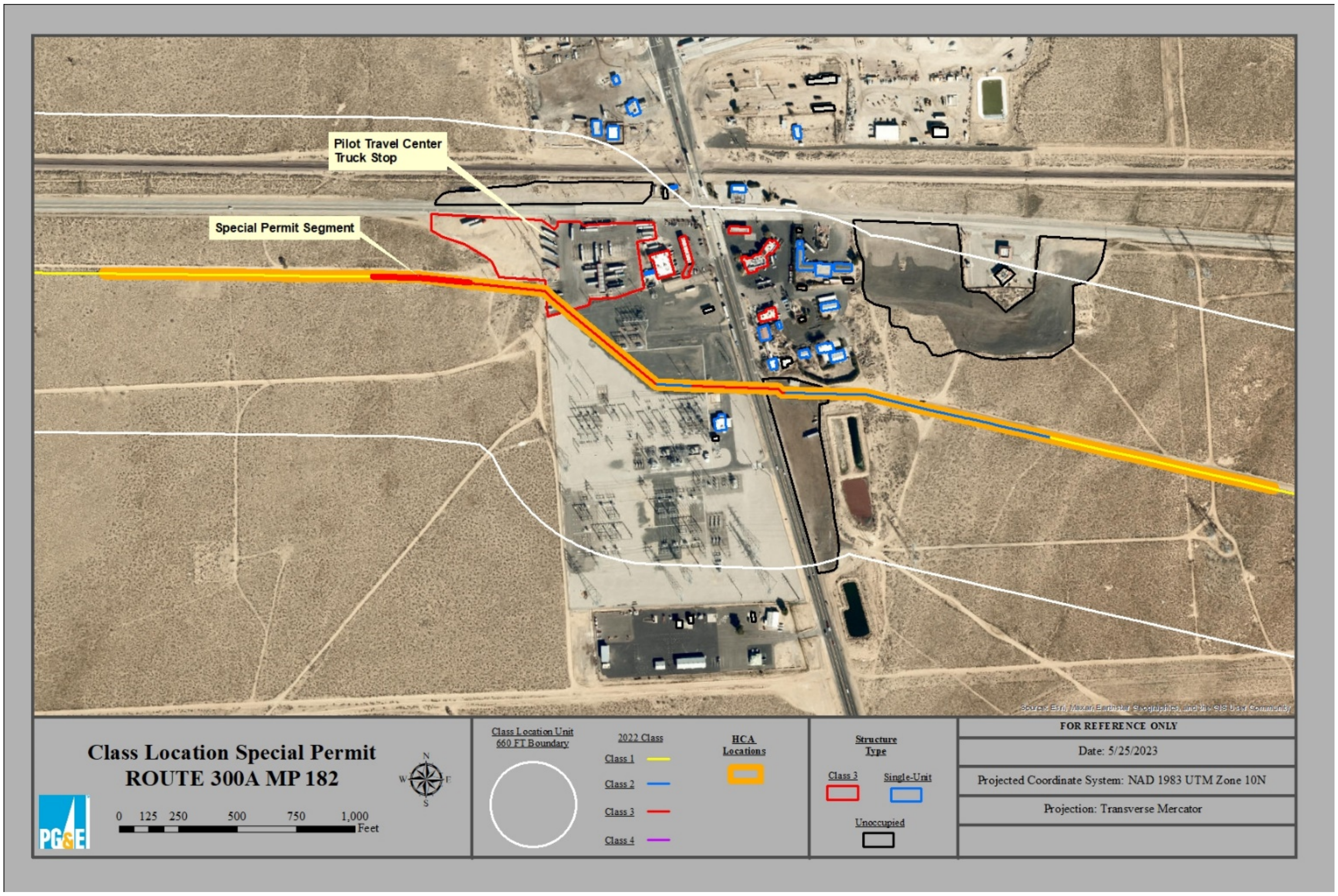

Figure 2. Detail Map of the State Waiver (Special Permit) segment on PG&E's line 300A pipeline

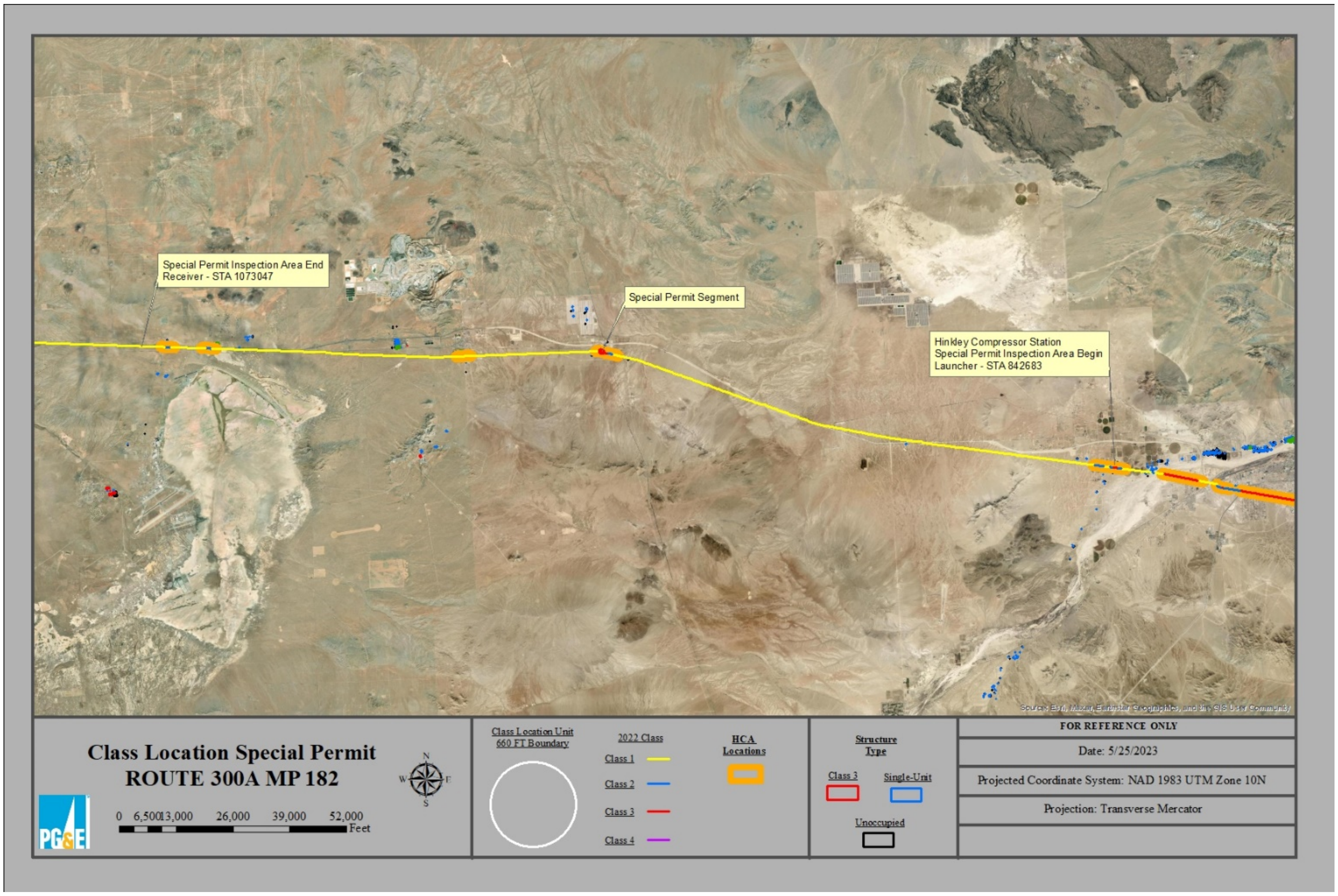

Figure 3. State Waiver (Special Permit) Inspection Area on PG&E's line 300A pipeline

Table 4 – Valves and Lateral Locations with Isolations Methods						
State Waiver Segment Nos.	Mile Post /Stationing	Type	Valve / Lateral Name (if Applicable)	Nominal Diameter (inches)	Valve Automation Methodology	Required Valve Automation Methodology for State Waiver[68]
1	159.17; STA:841695.57	RCV	V-159.17	34	Remote	Requirement satisfied for state waiver segment
	170.62; STA:902285.00	RCV	V-170.62A	34	Remote	Requirement satisfied for state waiver segment
	180.64; STA:954858.15	RCV	V-180.64A	34	Remote	Requirement satisfied for state waiver segment
	192.36; STA:1016740.75	RCV	V-192.36A	34	Remote	Requirement satisfied for state waiver segment
	203.00; STA:1073105.85	Manual	V-203.00A	34	Manual	Requirement satisfied for state waiver segment
	203.01; STA:1073163.08	Manual	V-203.01A	34	Manual	Requirement satisfied for state waiver segment
	203.02; STA:1073211.85	RCV	V-203.02A	34	Remote	Requirement satisfied for state waiver segment

Note: Condition 12 is applicable to all crossover valves, valve spacing, and lateral tie-ins. If PG&E has a ***state waiver segment*** or ***state waiver inspection area*** mainline valve spacing that is over 20 miles, a mainline valve must be installed to keep the isolation valve spacing below a 20-mile spacing. The isolation mainline valve must be installed within 18 months of the grant of this state waiver.

[68] Any isolation valve that is not an RCV, ASV, or check valve must be blinded or closed. Isolation valve(s) shown as CLOSED, when opened, must be manned by PG&E personnel. **Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures** is applicable to all crossover valves, valve spacing, and lateral tie-ins.