Niska
Gas Storage

February 6, 2015

Mr. Kenneth Bruno
Gas Safety and Reliability Branch
Safety and Enforcement Division
505 Van Ness Avenue
San Francisco, CA 94102-3298

Dear Mr. Bruno:

Your letter dated January 5, 2015 transmitted the findings from the inspection of our Integrity Management (IM) Plan conducted at our Wild Goose Storage (WGS) Facility between July 28, 2013 and August 2, 2013. Our response to each of the findings is provided below.

1. WGS Integrity Management Plan (IMP) did not include the basic baseline information (PIR calculation Station: 987+46 to 997+60) identified during the 2004 baseline assessment for the 30-inch line (East: Butler road, West: Irrigation land). WGS needs to incorporate all pertinent baseline data from previous versions of the IMP to the current revision.

   Response: Niska agrees that there is benefit in consolidating information from previous issues of the WGS IMP into the current version and to that end have revised the current version of the plan to incorporate pertinent baseline information. However, Niska does not agree that the omission constitutes a violation. All previous versions of the plan are retained and kept with the current version and can be referenced.

   Status: Completed. Information is included in the revision to the IMP.

2. WGS needs to calculate the PIR for the 24-inch line and incorporated the information into the WGS IMP.

   Response: The PIR calculation for the 24-inch pipeline has been calculated and included with the calculations for the 18-inch and 30-inch pipelines in the current version of the plan.

   Status: Completed. Calculation is included in the revision to the IMP. See table below.

Table 5
Baseline Information

Pipeline Diameter	Pipeline MAOP	PIR	Class Loc.	Identified Sites	No. HCAs
18"	2111 psig	571 ft	1	No	0
24"	2100 psig	759 ft	1	No	0
30"	1458 psig	791 ft	3*	--	1

*Station: 987+46 to 997+60 (MP 18.7 to MP 18.9); East: Butler Road, West: Irrigation land

3. The WGS IMP did not include an explanation to validate the selected method used to address the identified threats to the covered segment.

Response: According to our notes from the closing meeting, this finding related to the assessment method selected for the baseline assessment conducted in 2007 of the covered segment on the 30-inch pipeline. Niska does not agree that this is a violation. The rationale for the selected method was described in the 2004 version of the IMP. As stated in the response to Finding #1, relevant baseline information from the prior versions of the IMP has been consolidated into the current version.

Status: Completed. The rationale has been added to Section 5 of the IMP. See text below.

5.12 The baseline assessment for the one covered pipeline segment identified on the 30" pipeline was completed in September 2007. The integrity assessment method selected for the assessment was pipeline in-line inspection using metal loss and geometry tools. The selection was based on a threat and risk analysis which identified outside force as the highest ranked threat.

Since the 30" pipeline transports dry sales gas to/from the Wild Goose Plant to/from a sales transmission pipeline, it is normally at minimal risk to internal corrosion. Only during plant upset conditions would internal corrosion be a threat to the pipeline's integrity. Although the pipeline was pressure tested prior to commissioning of the pipeline, it was decided to conduct a metal loss pipeline in-line inspection in order to locate and size pipe wall imperfections.[1]

Based on the threat and risk analysis performed at the time and recent construction of the pipeline (2003), the reassessment of the pipeline was set at the maximum allowable interval of 7 years.

4. WGS's risk assessment failed to account for factors that could affect the likelihood of a natural gas release and for factors that could affect the consequences of potential natural gas releases. The assessment must combine these factors in an appropriate manner to produce a risk value for each pipeline segment. WGS's risk assessment matrix did not capture the calculation for consequences. Calculation for consequences must be justified based on the risk matrix provided. The consequences should consider worst case scenarios unless logical justification can be provided. The previous calculation indicated that the consequences depend on the likelihood, but they must be considered independent of each other. The consequences should consider the worst case scenarios. Furthermore, WGS IMP, Section 4.4.6 Risk Result Validation, states that WGS will conduct a risk result validation at least once each calendar year but WGS was not able to provide the necessary records to validate the results of the risk assessments.

Response: The 2011, 2012, and 2013 risk assessments utilized a different consequence severity and likelihood criteria than the criteria contained in the current version of the IMP. The decision was made in 2013 to adopt

[1] *Page 2, Section 3.2.2, Wild Goose Storage, Inc. Integrity Management Plan, Wild Goose Pipeline System, Final, Revision 0, dated 12/08/2004.*

the Niska Gas Storage risk matrix, but change was made after the 2013 risk assessment was completed.

The risk assessments completed in 2011, 2012, and 2013 did take into account factors that would affect the likelihood of a natural gas release and those that would affect the consequences of potential natural gas releases. What is at issue is the way in which the consequence severity and likelihood were scored. In the 2011, 2012, and 2013 assessments, both the consequence severity and likelihood were scored assuming controls already in place. It was further assumed that the existing controls mitigated both consequence severity and likelihood. This resulted in risk priority scores of 10 that indicated little or no risk for all threats except Weather Related/Outside Force which had a risk priority score of 3 based on a worst case scenario of an earthquake.

Based on feedback from SED staff during the audit and exposure to other risk assessment approaches through limited benchmarking, modifications were made for the 2014 risk assessment conducted in June 2014. For the 2014 risk assessment, the most credible worst case scenario determined for each threat. The consequence severity was scored based on the expected consequences if the event occurred and likelihood was scored based on an assessment of current controls. The Niska Risk Matrix has more granularity than the previous criteria and allows for scoring of individual consequence categories. Scores from the 2014 risk assessment will be validated during the 2015 annual program review which is scheduled for June 2015.

Niska believes the modifications made in 2014 address this finding. Going forward the risk assessment methodology will continue to be refined as more experience is gained with performing risk assessments. An example of possible future refinement would be to develop an algorithm that weights the various consequence categories.

Status: Completed. Section 4.4.3 of the IMP has been revised to incorporate the modifications described above. See text below.

4.4.3 Risk Analysis Method

The risk analysis method will address all of the threat categories listed in Section 4.1.1, Table 2 and the interactive threats described in Section 4.1.2. For a covered segment of pipeline, the risk score associated with each threat will be defined as follows:

Risk Score = I x P

Where: I = Impact or consequence severity

P = Probability or likelihood of the worst case consequence scenario occurring

The impact severity for each impact category will be scored based on the consequences expected if the worst case scenario developed as described in Section 4.4.1 occurs, and the probability will be scored

based on an assessment of the effectiveness of current controls in place to address the threat.

Since the impact categories are equally weighted, the risk score for a given threat is calculated by multiplying the highest scored impact category by the probability score. The resultant score is plotted on the risk matrix in Appendix A to determine if additional mitigation is warranted. Instructions for assigning impact and probability ratings along with the rating definitions are provided in Appendix A.

5. The WGS IMP did not account for the evaluation and remediation of other condition(s) that did not meet the criteria in ASME Section 7, Figure 4.

Response: Niska does not agree this is a violation. According to our notes from the closing meeting, this finding relates to PHMSA protocol E01c and E02d. The version of the IMP reviewed by SED included the provision for other conditions not meeting the criteria for conditions with special requirements for scheduling remediation in Section 5.5.4 which is reproduced below.

5.5.4 Other Conditions
Threat conditions that do not meet the criteria in 5.5.1 through 5.5.3 above will be scheduled and remediated according to the provision of ASME/ANSI B31.8S, Section 7, and Figure 4.

Status: Completed. To make this provision more prominent, Section 5.5 of the IMP which was previously titled "Anomalous Conditions" has been retitled in the revision to the IMP to "Remediation Schedule". Section 5.5.1 covers other conditions and reads as follows:

5.5.1 Except for those conditions meeting the criteria described in Sections 5.5.2 through 5.5.4 below which have special requirements for scheduling remediation, all conditions must be scheduled and remediated according to the provision of ASME B31.8S, Section 7, Figure 4.

6. The WGS IMP, Section 5.3.2 did not address the justification for using a 7-year window for the reevaluation interval.

Response: According to our notes from the closing meeting, this finding related to the justification for selecting the maximum 7-year interval for reassessment following the baseline assessment of the covered segment. The 2004 version of the IMP states only that the reassessment would be scheduled using in-line inspection tools at the maximum interval of 7 years. It is likely that the maximum interval was selected largely due to the recent construction and commissioning of the pipeline (2003). To address this finding going forward, the IMP revision adds a new process step in Sections 5.3 and 8.5 to document the justification and include a review of the interval justification as part of the annual program review.

Status: Completed. The revision to the IMP includes this new process step in Section 5.3.2 and new Section 8.5.3. See text below.

5.3.2 The reassessment interval for a covered segment will be determined based on the results of the periodic evaluations described in Section 5.3.1, with the maximum interval being no more than seven (7) years after the date of the baseline assessment (for newly identified covered segments) or the date of the last completed integrity assessment of that covered segment. The justification for the reassessment interval will be documented and reviewed as part of the annual IMP program review (See Section 8.5).

8.5.3 Other items to be reviewed concurrently during the program and process reviews include:

i. Reassessment intervals of all covered segments and the interval(s) confirmed or adjusted as required

ii. Training status of IM team members

7. The WGS IMP, Section 5.2.2 Table 4 identified that records can be used as the primary assessment method which is not in compliance with ASME/ANSI B31.8S, Section 6. WGS's primary assessment method must follow the selection criteria of ASME/ANSI B31.8S, Section 6.

Response: Niska acknowledges there are errors in Table 4 (see highlighted items below). However, Niska disagrees with the general finding that the information in the table is not in compliance with Section 6. Excepting the errors, the table shows records as the primary assessment method for those threats that according to Section 6 cannot be appropriately addressed by in-line inspection and/or pressure testing (Welding/Fabrication-Related Defects, Equipment Failures, Incorrect Operations, and Weather Related/Outside Force threats). Further, Section 6 points to Section 7 for addressing Random Threats.

To ensure closer alignment with the requirements of ASME B31.8S Section 6, Table 4 has been revised to correct errors and to also include the Prevention/Detection Methods described in Section 7.

Table 4
Threats and Integrity Assessment Methods

Threat	Primary Assessment Method	Supplemental Method
Time Dependent Threats		
External corrosion	Pressure Test	ILI or DA
Internal corrosion	Pressure Test	ILI or DA
Stress corrosion cracking	Bell hole exam and evaluation or—*should be "and"* Hydrotest	ILI or DA
Static (stable) or Resident Threats		
Construction and manufacturing-related defects, including the use of low frequency electric resistance welded (ERW) pipe, lap welded pipe, flash welded pipe, or other pipe potentially susceptible to manufacturing defects.	Analyze manufacturer's records. Conduct Pressure Test only if MAOP upgrade is planned—*should be primary for pipe seam aspect*	
Welding or fabrication related defects ▪ Defective pipe girth weld ▪ Defective fabrication weld ▪ Stripped threads, broken pipe, coupling failure	Analyze QC/Integrity records and evaluate potential for ground movement.	Pressure Test or ILI

Threat	Primary Assessment Method	Supplemental Method
Equipment failures ▪ Gasket O-ring failure ▪ Control/Relief equipment malfunction ▪ Seal/pump packing failure	Analyze records from inspections conducted per O&M procedures.	
Time-Independent Threats (Random)		
Third party/mechanical damage	Analyze records from patrols and leak surveys per O&M procedures,	ILI-*should be primary for dents/metal loss*
Incorrect operations (including human error)	Conduct audits/reviews of operating procedures and operator performance.	Maintain OQ Program
Weather related and outside force damage ▪ Cold weather ▪ Lightning, heavy rains or floods ▪ Earth movement	Analyze records from patrols and other inspections. If on-going subsidence, monitor progress of movement.	

Status: Completed. Table 4 (renumbered Table 6) has been revised as shown below and is included in the revision of the IMP.

Table 6
Threats and Integrity Assessment Methods

Threat	Integrity Assessment Method(s)	Notes
Time Dependent Threats		
External Corrosion (EC)	Pipeline In-Line Inspection	Metal Loss Tools
	Pressure Test	
	ECDA	Not used by WGS
Internal Corrosion (IC)	Pipeline In-Line Inspection	Metal Loss Tools
	Pressure Test	
	ICDA	Not used by WGS
Stress Corrosion Cracking (SCC)	Pipeline In-line Inspection	Crack Detection Tool
	Pressure Test	
	SCCDA	Not used by WGS
Static (stable) or Resident Threats		
Manufacturing-related defects	Pressure Test	Pipe seam defects only
Welding or fabrication related defects	Physical examination and evaluation of weld or component	Supplement with Prevention Methods. See Table 4, ASME B31.8S for applicable methods
Equipment failures	Physical examination and evaluation of the specific piece of equipment	Supplement with Prevention Methods. See Table 4, ASME B31.8S for applicable methods
Time-Independent Threats (Random)		
Third party/mechanical damage	Pipeline In-Line Inspection	Metal Loss, Caliper Tools
Incorrect operations (including human error)	Prevention Methods	• Compliance audits • O&M procedures • Operator Training
Weather related and outside force damage	Prevention Methods	Method depends on specific threat (e.g., land movement, flooding). See Table 4, ASME B31.8S for applicable prevention/detection methods

8a. The WGS IMP, Section 6 did not address all the plausible additional measures beyond those already required by Part 192 to protect the high consequence area and enhance public safety. WGS did not have a systematic, documented decision-making process in place to decide which measures are to be implemented, involving inputs from relevant parties of the WGS.

Response: Niska does not believe that it is necessary or practical to address "all plausible" additional measures in the IMP. Niska believes that the various alternatives for additional measures that could be taken to mitigate a risk are more appropriately discussed and evaluated as part of the risk assessment process.

Niska further believes that the current IMP contains the necessary process elements for identifying the need for and making informed decisions on additional measures. The need to implement additional measures beyond current controls is determined as part of the risk assessment process as described in Section 6.1, reproduced below. If the assessment results indicate that additional measures are needed, appropriate internal (WGS and Niska) personnel along with any external subject matter experts would be brought in to discuss approaches and alternatives for additional measures or actions, including enhancing current controls which would mitigate the consequence and/or the probability of the worst case scenario occurring. The proposed change(s) would be routed through the Management of Change process (Section 7.3) to ensure proper review and approval by relevant parties within WGS and Niska.

6.1 Identification of Additional Measures

Risk assessments performed on covered segments (see Section 4.4) will be used to identify the need for additional preventive and mitigative measures to protect high consequence areas and to enhance public safety. Additional measures could include, installing automatic shut-off or remotely operated valves, installing computerized monitoring and leak detection systems, replacing pipe segments with heavier wall pipe, providing additional training on emergency or abnormal operations response procedures, conducting drills with local emergency responders, and implementing additional inspection or maintenance programs.

Status: Closed. No additional action planned.

8b. WGS did not provide a risk analysis methodology that ASVs or RCVs will add protection to a high consequence area in an event of gas release.

Response: As a gas storage operator Niska routinely incorporates ASVs and RCVs in its plant and pipeline system designs and understands their value in ensuring employee and public safety and protecting assets. The 30" pipeline already includes three automatic emergency shutdown valves along its 25.1-mile length. One is located at the WGS Compressor Station, one at the PG&E Delevan Meter Station delivery point and one at the middle of the pipeline (Mid Valve Station), approximately 11.5 miles to the west of the WGS Compressor Station. The valves have local high and low set points which automatically trigger valve closure and are remotely

monitored through SCADA. The HCA is situated within a 1,014 foot section of the 30" pipeline, starting approximately 6.3 miles west of the WGS Compressor Station.

To address this finding going forward, an additional appendix will be developed to provide criteria and direction for determining if installation of an ASV or RCV will provide additional protection for any new HCAs that may be identified on its pipeline system.

Status: Open. Expected completion is June 2015.

9. WGS did not have the relevant records to demonstrate personnel performing the IM assessment have the knowledge and the expertise in making a sound decision. A resume without supporting documentation is not considered a valid document supporting their training and experience for their assigned responsibilities.

10. WGS did not have the proper documentation to validate the training and qualification of the contractors used to carry out assessments and evaluation of assessment results.

Response: With regard to Findings #9 and #10, Niska agrees that this is an area of the IMP that requires strengthening. To address both findings we plan to create a list of specific IM training and experience requirements and map the training to each IM team role. The training/experience requirements would be included in the IMP as Appendix B and would apply to WGS personnel and contractors performing IM roles. Conceptually, contractors would be required to either have completed the same training as WGS team members (for a given role) or demonstrate that the training they have completed is equivalent. The status of completed training would be documented in a training log and kept with other IM records. Additionally, to address this finding going forward, the revision of the IMP adds a new process step in Sections 8.4 and 8.5 to document the justification and include a review of the interval justification as part of the annual program review.

Status: Open. The proposed revisions have been incorporated into the revision of the IMP (see text below). Expected completion of Appendix B and communication to internal and external IMP members is June 2015.

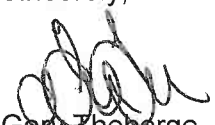
8.4.1 WGS Integrity Management Program team members, including any internal and external SMEs must have the appropriate training or experience for their assigned responsibilities. All team members must meet the minimum training and experience specified in Appendix B (under development) for their particular role(s). Completed training will be documented and tracked and reviewed as part of the annual program review.

8.5.3 Other items to be reviewed concurrently during the program and process reviews include:

i. Reassessment intervals of all covered segments and the interval(s) confirmed or adjusted as required
ii. Training status of IM team members

Niska is committed to continuously improving the WGS IM Program and are applying the comments and feedback provided during the audit. Niska will report back to SED when the remaining open items are completed. If you have questions about this response, please contact me at 403-513-8631 or by e-mail at gary.theberge@niskapartners.com .

Sincerely,



Gary Theberge
Manager, Engineering & Operations

Cc: Pat Baynard, Wild Goose Production Coordinator
Mark Casaday, Niska Gas Storage Chief Operating Officer