National Transportation Safety Board

Washington, D.C. 20594

Issued: 12 August 2011

OPERATIONS CHAIRMAN
FACTUAL REPORT ADDENDUM

A. Accident

Accident Number: DCA10MP008
Type of System: Natural Gas Transmission Pipeline
Accident Type: Pipeline Rupture
Location: San Bruno, California
Date: September 9, 2010
Time: about 6:11 pm
Owner/Operator: Pacific Gas and Electric Company
Material Released: Natural Gas
Pipeline Pressure: 386 - 396 psi at time of rupture
Component Affected: 30 inch diameter pipeline.

B. Group Chair and NTSB Staff

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C. Pre-Accident - Milpitas Terminal Electrical Work

The Pacific Gas and Electric Company (PG&E) work at Milpitas on the afternoon of September 9, 2010 was to transfer the 120Vac electrical loads from an existing electrical uninterruptible distribution panel (UDP[1]) onto an alternate power source[2]. The UDP electrical panel provided power to critical loads including the station chromatograph, programmable logic controllers (PLC's[3]), regulating valve controllers[4] and instrumentation[5] from the site uninterruptible power supply (UPS)[6]. According to PG&E, the programmable logic controllers and regulating valve controllers had been previously moved to an alternate power source in April of 2010[7]. The work on September 9, 2010 would transfer the remaining electrical circuits, including the chromatograph, PLC I/O blocks[8] power, two 24 Vdc power supplies that powered some station instrumentation, and communications equipment from their circuit at the UDP panel to small temporary UPS systems. When all of the critical loads had been moved from the existing distribution panel, it would be removed and replaced with a new panel and all of the loads returned. Prior to starting the work for the PLC I/O the Milpitas workers contacted the SCADA and controls supervisor to find out what the impacts would be at the site from removing power to the Genius I/O blocks at the PLC.

Following their conversation with the SCADA and controls supervisor, at 4:03 pm, the Milpitas workers called gas control and alerted them that the transfer of the flow computer and PLC I/O modules would begin shortly. After transferring the Genius I/O blocks at the PLC, the Milpitas workers transferred two power supplies PS-A and PS-B onto a mini-UPS[9]. Beginning at 4:18 pm, the SCADA trends show that gas control lost all SCADA pressures and valve positions for approximately 14 minutes, prompting a call from gas control to Milpitas asking what was going on. At the same time that the call was received, the Milpitas gas technician and contractor were re-energizing the circuits. At approximately 4:38 pm, after the alarms were cleared, the Milpitas workers called gas control and asked for confirmation that the SCADA readings were working normally. The gas control operator indicated that everything looked normal at Milpitas. After receiving this confirmation, the crew moved to the last breaker in the panel which was unidentified. In an interview with the technical crew leader, who was part of the Milpitas work, opening the last breaker at the electrical distribution panel resulted in an

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[1] UDP stands for Uninterruptible Distribution Panel and designates that this was an electrical panel connected to the site Uninterruptable Power Supply.
[2] The alternate power source for the remaining circuits was normal power with a mini-uninterruptable power supply connected in series.
[3] Programmable Logic Controller is a digital computer used for automation of electromechanical processes, such as the control of valve position to maintain a desired pressure output.
[4] Stand alone closed-loop controllers that operate the regulating valves
[5] Instrumentation – including valve position sensors and pressure transmitters serving the regulating valve controllers
[6] The Uninterruptible Power Supply was sized for the Milpitas with enough power to run critical equipment for a given duration after a power outage and until the generators can start up and provide power.
[7] No work clearance was provided to the NTSB for the mini-UPS installation of April 2010.
[8] I/O Module that communicates with the PLC and includes discrete and analog inputs and outputs also referred to as Genius I/O blocks.
[9] Based on interview statements by PG&E and electrical contractor

unexpected loss of power to the Mimic panel[10] located in an adjacent room. Rather than re-energize the breaker, the decision was made to restore power to the Mimic panel from an alternate power source. The Milpitas gas technician gathered up drawings at the station for the Mimic panel in an attempt to troubleshoot the loss of power. According to interview statements to the NTSB, amperage readings were taken from the various loads in the Mimic panel cabinet before installing an alternate electrical feed to power supply PS-C. During the time that technicians were restoring power to the Mimic panel from another source, the pressure displays on the front of the panel went blank. These displays were powered from 24Vdc power supplies PS-A and PS-B which had been moved to a mini-UPS earlier that day. Voltage readings at the power supplies indicated that the output was less than the nominal 24 volts with varying readings from 3 to 7 to 15 Vdc. The intermittent voltages resulted in a large portion of the SCADA data points for Milpitas being inaccurate and incapable of being monitored from gas control in San Francisco. According to the technician, the output voltages from the power supplies were low when load was applied but would return to normal when electrical load was removed.

At approximately 5:22 pm, according to the SCADA trends, pressures increased at the Milpitas headers and downstream in the Peninsula lines. The erratic voltages from the two power supplies had caused the pressure transmitters, which provided a signal to each of the regulating valve controllers, to read zero resulting in the regulating valve controllers to command the valves open. The PG&E SCADA and Controls supervisor stated that the valve controllers did not lose power; however, the pressure transmitter signals were affected by the erratic voltages from the power supplies. According to PG&E, the valve controllers had been relocated to an alternate 120Vac power source in April of 2010 preventing them from being impacted by the work on September 9, 2010.

The Milpitas gas technician was alerted to the problems at the terminal at 5:25 pm when a gas control operator called him to tell them about numerous high pressure alarms that he was seeing downstream on the peninsula lines. According to PG&E, the low dc power supply voltage from PS-A and PS-B had become erratic during the troubleshooting which affected the Milpitas pressure transmitters that served the regulating valve controllers. As the electrician and technical crew leader were troubleshooting power supplies PS-A and PS-B, the Milpitas gas technician noticed that the regulating valve controllers had unexpectedly "lost all data."

The loss of power from power supplies PS-A and PS-B affected SCADA pressure readings in one of two ways at Milpitas. Some values appeared to freeze, displaying their last known value while other transmitters displayed a zero or out of range reading. PG&E has explained that these differences were due to how the instrumentation was configured to communicate over SCADA. Because Milpitas uses a programmable logic controller and regulating valve controllers, sometimes redundant readings are brought

[10] The Mimic Panel was an old relay based local display of the Milpitas terminal that did not affect the gas operation. It is kept as a visual indicator of station operation and serves as a cabinet for terminal blocks and other site instrumentation wiring and power supplies.

into SCADA from the programmable logic controller.[11] PG&E maintains that instrumentation was affected differently by the power problems creating differences in the readings for redundant data. According to PG&E the frozen readings may have been in part due to SCADA 'ignoring' an out of range value from the transmitter. PG&E was unable to reproduce the entire pressure transmitter responses recorded on the day of the accident, when simulating the power supply failure modes at Milpitas after September 9, 2010.

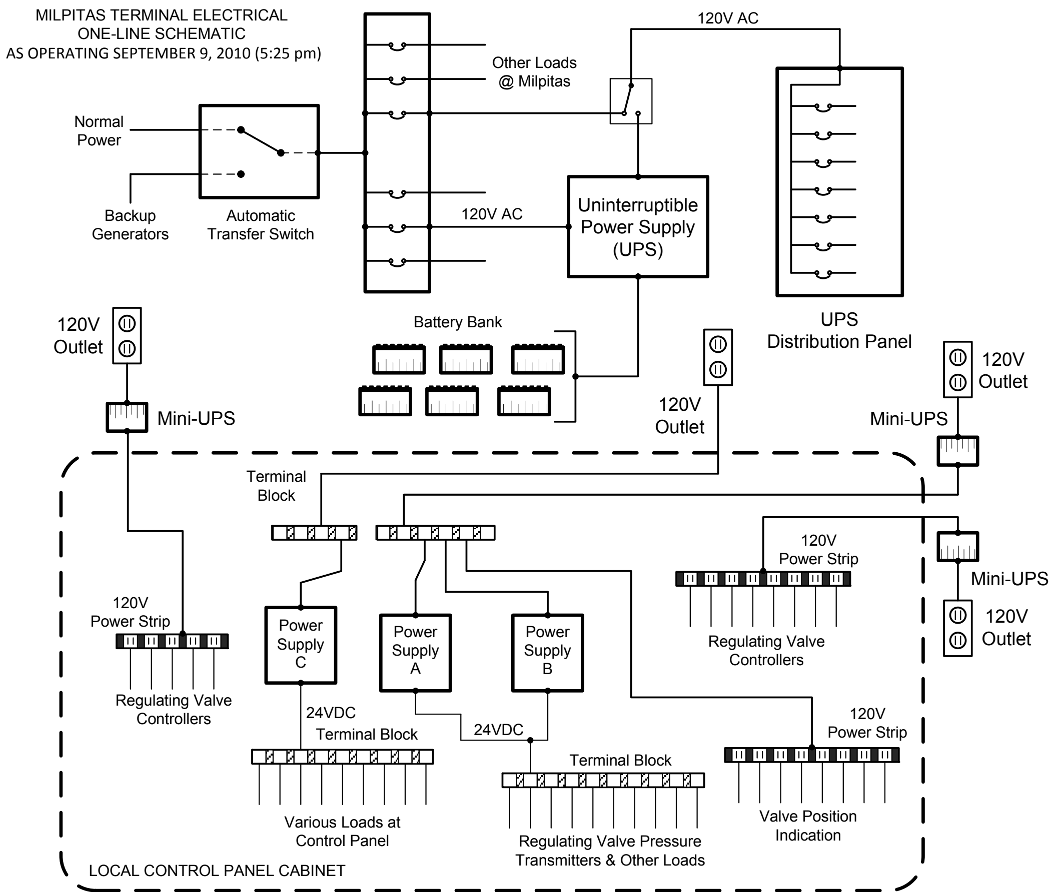

Figure 1: Electrical block diagram showing completed work at Milpitas on September 9, 2010

[Exhibit 2-BV Interview of Mitchell, PG&E 1-07-11]
[Exhibit 2-BO Interview of Groppetti, PG&E Contractor 1-5-11]
[Exhibit 2-CB Interview of Roccholz, PG&E 1-6-11]
[Interview of PG&E Gas Control Technician (Oscar Martinez)]
[Interview Transcript of PG&E Technical Crew Leader (Peter Beck)]
[Interview of Supervisor - SCADA and Control Group]

[11] Because the programmable logic controller sometimes receives inputs (pressure or valve position) from both the regulating valve controller and analog and digital inputs directly wired from the instrumentation, some points are redundant over SCADA.

D. Milpitas Work Impact on the Peninsula Line

SCADA Data provided to the NTSB included pressures, flows, and valve positions at Milpitas as well as pressure data from locations upstream and downstream (Appendix C, Attachment C through AD). The trends indicated that at 4:00 pm, prior to any work, Milpitas was delivering a total of 10-mmscfh[12] of natural gas to the Peninsula system through incoming Line 300B. The upstream pressure readings entering the station were approximately 575 psig on Line 131; 530 psig on Line 300A; 365 psig on Line 300B, and 315 psig on Line 107. Regulating valves on all incoming lines, with the exception of valves on Line 300B, were closed. All of the station monitor valves at the station were in the open position. Bypass regulating valves 29 and 62 were closed and flow from header-3 to header-2 was through valves 27, 27R, and 21R.[13] Manual valves R-23 and R-15 from Lines 300A and 107 were open to the mixer bypass and all of the downstream valves leaving Milpitas were open with pressures of approximately 355 psig. Refer to Appendix C, Attachment A for valve and piping configuration at Milpitas.

The Milpitas gas technician first notified the gas control center at 2:46 pm that work under clearance number Mil-10-09 would begin at the Milpitas. At 3:36 pm, the Milpitas gas technician called back to gas control and talked to a different gas control operator to ask if the block valves on incoming Lines 300A and 300B were fail close, spring return. The Milpitas gas technician briefly asked if the terminal can be run in bypass and the gas control operator said no. The Milpitas gas technician stated that he would lock the two block valves open (V-1 and V-2 shown in Attachment A of Appendix C). Based on interview statements from the Milpitas gas technician, before starting work on the power supplies serving Milpitas instrumentation or the PLC input/output modules (I/O modules), the Milpitas workers called and discussed the possible station impacts with the SCADA and controls supervisor. By 4:03 pm the Milpitas gas technician notified another gas control operator that they were going to lock out the regulating valve controllers at Milpitas before changing over the power serving the input/output (I/O) modules that communicate between the instrumentation (including pressure transmitters, flow meters and position sensors) and the programmable logic controller at Milpitas.

[12] Million cubic feet per hour converted to standard temperature and pressure
[13] Valve AR-21 is closed

The first disruption in the SCADA data appeared between 4:17 pm and 4:32 pm generated by the removal of power to the Genius I/O Block analog and digital modules at the programmable logic controller. Because some of the instrumentation was wired to the valve controller and other instrumentation was connected directly to the programmable logic controller modules, not every SCADA point was impacted by this work.[14] The first Milpitas alarms appeared at 4:17 pm indicating that the valve controllers were taken out of remote control[15]and placed in local manual control[16]. The Milpitas gas technician stated during an interview that when the valve controllers were placed in manual mode, they locked themselves in last position.[17] The valve position trends shown in Appendix C, Attachments C through L indicates that the regulating valves are either closed or fully open.

Controller error alarms showed up in the alarm logs at 4:20 pm indicating a loss of communication or an internal failure with the regulating valve controllers. PG&E has stated that these errors are consistent with a loss of power to the Genius I/O Block modules. Similar errors appeared when PG&E conducted tests at the Milpitas facility, following the accident, to re-create the alarms. At the same time that the valve controller errors appeared, there were multiple monitor valve alarms indicating that the valves were not open.[18] From 4:17 pm to about 4:32 pm, the SCADA trends at the Milpitas showed all of the monitor valves, bypass valves, and position controlled valves as not open. During this same time-span all of the Milpitas pressure readings dropped to zero. The pressure trends of pipelines upstream and downstream of the Milpitas showed no changes during this time. A gas control operator called the Milpitas gas technician at around 4:31 pm concerned about the loss of SCADA data from Milpitas. By 4:32 pm, the pressure and monitor valve SCADA readings were restored to normal operating conditions. According to PG&E the regulating valve controllers were placed back in auto control at this time. All of the alarms that had appeared during this time cleared by 4:38 pm[19]. The Milpitas gas technician called gas control shortly after this to confirm that the SCADA readings had returned to normal.

At 4:46 pm, the Milpitas gas technician called the gas control operator to alert him that technicians were going to remove power to the communications at Milpitas for the next phase of the work. At 5:01 pm, every regulating valve, except valve AR-7 on Line 300B, showed a controller error alarm which according to PG&E indicated a loss of communication or internal failure of controller. All of the controller error alarms cleared

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[14] PG&E has stated that the regulating valve position does not change state during this work as do the pressure readings.
[15] PG&E stated that remote control indicates that the valve is controlled from the console or gas control. The controller con/loc alarms indicate that valve is no longer controllable from the gas control.
[16] These appear as Automatic/Manual alarms in the alarm logs indicating that the valve controllers are no longer locally controlled from the pressure transmitter but manually controlled at the valve controller. In this mode the regulating valves would no longer respond to control center inputs or local pressure transmitter inputs. Valve position had to be adjusted locally at a manual knob on the front of the valve controller. This was discussed with the supervisor of SCADA and controls group before the work was performed.
[17] The gas technician states that the locked in value was 50%.
[18] These appear as Mon V# in the alarm logs, signifying that the monitor valves were not open.
[19] Cleared alarms indicate that the initiating event that caused the alarm has been corrected.

by 5:09 pm. There were no changes in valve position, flows, or pressures indicated in the SCADA data during the controller error alarms. The PG&E supervisor of SCADA and controls group stated during an NTSB interview that the controller error alarms are associated with work at Milpitas but was not certain which work generated the alarm entries. From 5:09 pm to 5:21 pm no further alarms appeared for the Milpitas.

At 5:21 pm, there were approximately 60 alarms on the gas control console that appeared in less than one second, including controller errors, backflow alarms[20], and monitor valve position alarms. The first of the alarms that displayed were valve controller alarms. Following the valve controller errors were two backflow alarms at the flow meters for incoming Line 107. By 5:22 pm, there were backflow alarms on Line 300B flow meters followed by differential pressure alarms[21] for the Line 131 flow meters. Within one-minute of the backflow and differential pressure alarms, a high and high-high pressure alarm appeared for the Los-Esteros flow meter located just downstream of the Milpitas on Line 101. At 5:24 pm, the gas control operator observed alarms at several downstream locations on Line 100[22] followed by Line 101[23] and Line 109 and Line 132 at Sierra Vista Avenue (refer to Appendix C, Attachment B for locations).

As earlier stated, the gas control operator called the Milpitas gas technician at 5:25 pm and informed him that they were receiving high-pressure alarms downstream of the Milpitas and that the "alarms look real." While on the phone with gas control, the Milpitas gas technician noticed that the regulating valve controller displays had lost all of the data. The gas technician asked the construction technician to put the electrical connection back the way it was before the problem with the valve controllers was noticed. The PG&E supervisor of SCADA and controls group stated that the changes occurring at Milpitas were consistent with the regulating valves going full open when power was disrupted to the pressure transmitters.

The SCADA trends at the station and from downstream locations indicated changes that occurred with the alarms at approximately 5:22 pm. The alarm entries coincided with pressure increases on both the incoming and downstream pressure transmitters. The incoming line pressures at Milpitas were initially operating at 572 psig on Line 131; 530 psig on Line 300A; 368 psig on Line 300B and 315 psig on Line 107. Between 5:22 pm and 5:54 pm, the incoming pressures on Lines 131 and 300A dropped to 530 psig and 507 psig, respectively, while pressure on Line 107 and 300B increased to approximately 370 psig and 473 psig, respectively. With the Milpitas regulating valves going full open, the higher pressure gas on Lines 131 and 300A flowed into header-3 and the bypass header backfeeding and pressurizing the low pressure feeds, Lines 107 and 300B. The incoming lines were designed to handle bidirectional flows and the monitor valves are set to the incoming line MOPs plus 10-psig; therefore, the pressures at the

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[20] Backflow alarms indicate a reversal to the normal flow of gas through a flow meter.
[21] Differential pressure alarms are generated in SCADA when the difference between the upstream and downstream pressures is outside the range of the flow meter.
[22] These appeared as alarms at Silver Creek, Aborrn, and White and Tully Roads
[23] This appeared as an alarm at N-Rengstrorff Avenue

bypass header, header-3, header-5, header-6 and header 7 rises above the MOP of the Peninsula lines which were protected by bypass line monitor valves and the second stage monitor valves on header-3 (MR26, 20 & 16). The unexpected back flow of gas from the higher pressure incoming lines to the lower pressure incoming lines was not the normal operation for September 9, 2010 and was a result of the regulating valves opening. Appendix C, Attachment S shows the incoming pressure changes beginning at 5:22 pm.

With the intermittent voltages from the 24Vdc power supplies, the affected Milpitas pressure readings were frozen or out of range to the gas control operators. PG&E has submitted pressure data information from Milpitas that was unaffected by the power supply failure on September 9, 2010. These pressure readings were taken from pressure transmitters at the flow meters and were not powered from the failed power supplies.[24] Appendix C, Attachment M (upper plot) shows how the downstream pressure measured on Line 132 at the Milpitas remained unchanged at 360 psig (Appendix C, Attachment P and Q) while the pressure reading, at the M-31 flow meter[25] (Appendix C, Attachment V), responded to the pressure increases at 5:22 pm. Attachment S of Appendix C shows the incoming pressures to the Milpitas as read from upstream station locations and as read at Milpitas on the same incoming lines (Lines 300A, 300B, L131 and L107). The upper plot shows pressure transmitters[26] unaffected[27] by the power supply failure and the lower plot are readings at Milpitas that froze in last state. The pressure trends shown in Appendix C, Attachment AA and AB were plotted from unaffected pressure transmitters between the stage-1 and stage-2 regulators at Milpitas (refer to Appendix C, Attachment A). These trends confirmed the backflow of gas at the header with pressure rising from 360 psig to 495 psig between 5:22 pm and 5:56 pm.

The outgoing pressure trends (Appendix C, Attachment V) from the station and locations downstream (Appendix C, Attachments M and N) followed a similar upward trend to that of the header pressures. Downstream pressures measured at Milpitas reached approximately 396 psig[28] at 5:25 pm (Appendix C, Attachment V) before dropping to 375 psig at 5:44 pm and then rising back to 393 psig by 5:55 pm. SCADA pressure readings downstream from Half Moon Bay (10 miles south of the rupture) and Martin (7.0 miles north of the rupture location) showed rising pressures from 5:22 pm to 6:11 pm with peak pressures of 386.4 psig and 386 psig respectively.

[24] These pressure readings were at the flow meters and were collected over SCADA but were not displayed to the gas control operator. Refer to the Attachments for trends.
[25] This pressure reading was unaffected by the power drop at Milpitas.
[26] These readings, were taken from stations upstream of Milpitas and were unaffected by the work. PG&E has indicated that the upstream readings were indicative of the readings at Milpitas. This can be seen in Attachment S prior to 4:00 pm where the upper and lower plots show similar values.
[27] PG&E has determined that some pressure transmitters were impacted during the loss of power at 5:22 pm and other pressure transmitters were not. Readings from both transmitters have been examined.
[28] Manual readings taken at Milpitas by the gas technician on the output pressure of Line 132 were 396 psig. This was recorded in the control center logs. The M32 flow meter pressure readings also confirm a maximum pressure of 396 psig.

At 5:42 pm, the Milpitas gas technician told the gas control operator that he will make a set point change to the monitor valves (M5 and M6) on line 300B and lower the set point to 370 psig. With the header pressures close to 475 psig, the monitor valves would start to close, isolating Line 300B. At 5:52 pm, the alarm logs showed that gas control made a pressure set point change to the stations upstream of the Milpitas. Pressure Limiting Station 7A & 7B[29] and Sheridan Road (V1) were given set points of 370 psig while Sheridan Road (V2)[30] was set to 350 psig. Pressure trends in Appendix C, Attachment S (upper plot), Appendix C, Attachment AA, Attachment AB, and Appendix C, Attachment V indicate a reduction in the pressures at the Milpitas at approximately 5:54 pm. At 5:55 pm, the Milpitas gas technician called into gas control to report that monitor valves five and six were not open on Line 300B. Line 300B pressures leveled out at approximately 475 psig at 5:55 pm as shown by Appendix C, Attachment S (upper plot).

Instantaneous increases and decreases in pressure and valve position were observed in the trends beginning at 6:04 pm and extending through 8:40 pm. Most notable were the downstream pressure readings at the Milpitas terminal shown in Appendix C, Attachments P and Q. Appendix C, Attachment Q shows the downstream Milpitas pressure for Line 132 with a step change pressure decrease from 360 psig to 267 psig at 6:03 pm, followed by another 40 psig pressure drop at 6:04 pm and a pressure rise to 623 psig just after 6:05 pm. During interviews with NTSB, PG&E had stated that these were erroneous pressure readings attributed to the troubleshooting of the power supplies A&B at Milpitas between 5:25 pm and 8:40 pm.[31]

Pipeline pressures into the Milpitas shown in Appendix C, Attachment S (upper plot) shows a maximum pressure of 475 psig just after 6:00 pm well below the 623 psig reading. At around the same time, the header pressures at Milpitas shown in Appendix C, Attachments AA and AB show a maximum pressure of approximately 440 psig on the headers downstream of the stage-1 regulation at the station. Downstream pressures on Lines 101, 109 and 132 increased during this time period but did not reflect any deviations to their trends at 6:04 pm. Pressure readings on the chart recorders located downstream of the Milpitas (see Appendix C, Attachment B for locations) were consistent with the values in the SCADA data.

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[29] PLS 7A and 7B are pressure limiting station on Line 300A and 300B.

[30] Sheridan Road is a regulating station on Line 303

[31] PG&E has indicated that the valve position readings being erroneous is further supported by the load valves showing position changes when it should not have been commanded to move at all. Load valves are only commanded open when the trim valve position is commanded outside its 20-80 percent range.

Table 1: Chart Recorder Pressure Readings (NTSB IR-011_007)

Location	Highest Pressure Recorded (psig)[32]	Line Number
Summit & Skyline (Hillsborough)	384	L132
Pacific & Poinsettia (San Mateo)	380	L101
Charter & Bayshore (Redwood City)	380	L101
Alpine & Junipero Serra (Menlo Park)	385	L109
Alpine & Piers (Portola Valley)	385	L132

[Appendix C, SCADA Attachments A-AD]
[Exhibit 2Y - San Francisco Control Room Logs 09-09-10]
[NTSB_058-002 Pressure Trends and Why Valves Were Commanded Open.pdf]
[Exhibit 2I - NTSB 014-008 SCADA ALARMS]
[Exhibit 2V - January Interview of SCADA Controls Group Supervising Engineer]
[Exhibit 2M - NTSB 036-004 SCADA Pressure Transducer Locations.pdf]
[NTSB_036-008 Milpitas UPS Upgrade Project As-Builts]
[Exhibit 2-BV Interview of Mitchell, PG&E 1-07-11]
[Exhibit 2-BO Interview of Groppetti, PG&E Contractor 1-5-11]
[Exhibit 2-CB Interview of Roccholz, PG&E 1-6-11]
[Interview of PG&E Gas Control Technician (Oscar Martinez)]
[Interview Transcript of PG&E Technical Crew Leader (Peter Beck)]

E. Pacific Gas and Electric Company Emergency Response

The pressure trends examined from a location seven miles downstream from the rupture site show that Line 132 began to lose pressure at approximately 6:11 pm. Gas control was alerted to the pressure drop approximately five minutes later as Martin station (Martin) was generating low-low alarms having dropped in pressure from 386 psig to 144 psig. The low and low-low alarms at Martin were acknowledged by two transmission coordinators. The PG&E dispatch center located in Concord, California (dispatch center) was first notified of an explosion in the San Bruno area at 6:18 pm by an off duty PG&E employee. A gas control operator in San Francisco was alerted to the low pressures at Martin during a discussion with an operator at alternate gas control at 6:19[33] pm.

[32] Approximate readings as best discerned from the printouts provided
[33] The Martin low and low-low pressure alarms were acknowledged by two different gas transmission coordinators

A PG&E senior distribution specialist who was an off-duty on-call supervisor saw the fire from the freeway on his way home. The supervisor called the Concord dispatch center at 6:23 pm and told them he was going to the scene. At the same time the dispatch center called out a PG&E gas service representative working in Daly City, about seven miles away, to respond to the scene of the fire.

By 6:30 pm, the PG&E gas control operators and supervisors had been notified by dispatch regarding the outside calls reporting a fire in the San Bruno area. During a conversation between the gas control senior transmission coordinator and a gas transmission coordinator the incident is referred to as "a line break of San Bruno with flames." Gas control was aware of the earlier high pressures on Line 132, the pressure drop and alarms on Line 132 at Martin and reports of a fire in the San Bruno area. Earlier notifications to gas control from the dispatch center and PG&E employees included reports of a gas station explosion or airplane crash accompanied by persistent roaring sounds similar to a jet engine. At 6:35 pm, an off-duty mechanic qualified to operate mainline valves notified Concord dispatch center about the fire and proceeded to the PG&E Colma yard (about five miles away) to obtain the tools to shut off mainline valves. This mechanic was also called by his supervisor to respond to the accident while en-route to obtain valve shutoff tools. By 6:38 pm, a discussion between a gas control operator and Milpitas supervisor mentioned that this "could be a line break." The supervisor then suggested that the Milpitas gas technician be relieved and sent to Martin and that another gas control technician go to Milpitas.

At about 6:40 pm, the Peninsula Division on-call supervisor requested that a second mechanic should also respond to the PG&E Colma yard to assist the first mechanic. In addition, a second off-duty on-call supervisor, and a gas maintenance and construction superintendent, who lives about four miles from the rupture site learnt of the incident through media reports and notified gas control in San Francisco that he was also responding to the scene. According to dispatch center, the gas service representative and the senior distribution specialist were the first confirmed PG&E employees to arrive on-scene at about 6:41 pm. The gas maintenance and construction superintendent arrived shortly thereafter. However, none of these three PG&E first responders were qualified to operate mainline valves. The gas maintenance and construction superintendent became the deputy incident commander and worked with the senior distribution specialist. The overall incident commander was the San Bruno Fire Department battalion chief.

By 6:46 pm calls from Milpitas to the gas control operator indicated that a technician was on his way to Martin and that the gas control operator had identified the low pressure was upstream[34] of Martin. At 6:50 pm, the dispatch center and the gas control focused on maintaining pressure on Line 132 at 353 psig downstream of the Milpitas. The dispatcher told the gas control operator "Well I would just continue to feed, hold it steady…I don't want to lose San Francisco."

[34] In Line 132 gas flows from south to north. The rupture location is at mile point 39.28 (relative to Milpitas, Mile point 0). Upstream denotes events south of the reference and downstream denotes events to the north of the reference point.

The two mechanics left the PG&E Colma yard at 7:06 pm and arrived at the upstream mainline valve at 7:20 pm. A San Francisco transmission and regulation supervisor authorized the shutdown of the mainline valves and at 7:29 pm called gas control to have them remotely closed downstream valves V-10 and V-13 at Martin thereby shutting off the flow of gas at approximately seven miles downstream of the rupture. By shutting the Martin valves, gas control effectively cut off the pressurized gas entering Line 132 from north of Martin leaving only the residual gas in the pipe to fuel the north end of the ignition. The mainline valve upstream of the rupture location (valve at Mile Point 38.49) was manually closed by both mechanics at 7:30 pm, which isolated the upstream side of the Line 132 rupture.

At approximately 7:42 pm there was a call from the deputy incident commander at the site of the accident to gas control where the incident commander asked, "hey, can you check your SCADA, because all of a sudden this pressure's diminishing and I haven't had any word that we have any valve crews out there….So I guess some of the firemen are getting a little closer…" The gas control operator informed the deputy incident commander that all they had done is to shut remote control valves at Martin which was approximately seven miles downstream from the accident scene.

The senior distribution specialist contacted the PG&E gas control at about 7:45 pm and reported the fire was caused by a rupture of PG&E's transmission pipeline. The senior distribution specialist supervised PG&E field response activities to the incident while he was based at the incident command center. At the same time, the two mechanics also manually closed the two valves downstream of the rupture (MP valves 40.05 and 40.05-2) to shorten the isolated section at Healy station (Healy). At about 7:52 pm, the mechanics manually closed the valve at District Regulator Station 190 at the intersection of Glenview Avenue and San Bruno Avenue to stop gas flow on a local distribution line.

By 6:58 pm, the gas maintenance and construction superintendent contacted the Peninsula division gas maintenance and construction superintendent who in turn activated PG&E's Peninsula Operations Emergency Center (OEC) in San Carlos.[35] The unit set up initially by PG&E directed field resources in the San Bruno area. Due to the scale of the incident, an EOC (Emergency Operations Center) in San Francisco headquarters was also activated at approximately 7:16 pm. The EOC is a central location from which the emergency response activities of the local operating department are prioritized and coordinated.

[Exhibit 2B PG&E Event Timeline]
[Exhibit 2DX Timeline of Events for September 9, 2010 Prepared by NTSB]
[Exhibit 2Y - San Francisco Control Room Logs 09-09-10]
[Exhibit 2BG Interview of Breiz, PG&E 1-3-11]
[Exhibit 2CA Interview of Robertson, PG&E 1-6-11]

[35] PG&E has a number of OECs which are emergency command posts that are permanently equipped with computers, desks, and communication equipment and are only used during emergency situations. They can be local or regional depending on the size of the emergency. EOC Personnel responsibilities are laid out in the PG&E emergency plans and everyone has an assigned task or tasks to complete during the emergency.

[Exhibit 2DF Interview of John Corona, PGE September 16, 2010]
[Exhibit 2CD Sickinger, PG&E 1-5-11]
[Exhibit 2CG Interview of Wagner, PG&E 1-4-11]
[NTSB_054-010 Number of gas employees qualified to operate valves]

F. Peninsula Transmission Line Configuration and Release – Sept 9, 2010

The PG&E Peninsula system is comprised of three transmission lines, Lines: 101, 109, and 132 that transport gas from south to north. The three lines originate at Milpitas (mile point zero) and extend into San Francisco approximately 51 miles downstream. In between Milpitas and San Francisco are junctions and cross connects where the lines crisscross or join at a smaller valve station. Lines 109 and Line 132 run in tandem up to Healy, where they are joined, at about 40.05 miles north, before Line 132 diverges and continues northeast to join with Line 101 near Martin located 46.59 miles north of the Milpitas. Martin is the last pressure reducing station for Line 132 and Line 101 before gas is delivered into San Francisco. Line 109 continues north from Healy through Sullivan station (Sullivan) before connecting with the other lines in San Francisco. Six crossties are located between the Milpitas and Martin tying the three Peninsula lines together at key locations. These six cross-ties allow gas to be moved between the three transmission lines to meet seasonal operating conditions or shifting demands and equalize pressures. The valves at the cross-tie locations were manually opened or closed based on summer or winter operating conditions. The locations of all of the cross-ties are identified in Appendix C, Attachment B and summarized in Table 1 along with the valve status reported by PG&E on September 9, 2010.

Pressure readings on the Peninsula lines are recorded either with pressure transmitters that communicate to the SCADA center in San Francisco or with local chart recorders installed at various mile points along the transmission lines. The locations of pressure transmitters and chart recorders are identified in Appendix C, Attachment B. Pressure data was obtained for each of the chart recorders as well as SCADA monitoring points along the three Peninsula lines. SCADA data has been plotted in the attachments of Appendix C.

The rupture in Line 132, segment 180 occurred at mile point 39.28 resulting in a double ended break with gas released from both the north and south end of the ruptured segment. Cross-ties between Line 132 and the other Peninsula lines are located north and south of the rupture location. To the north of the rupture are Healy and Martin; the nearest being Healy at ¾ of a mile, followed by Martin 7.3 miles downstream. Lines 101 and 132 are cross-tied at Martin and Line 109 and Line 132 are cross-tied at Healy. According to PG&E, no backflow (gas flow from north to south) occurred from either Lines 101 or 109 from the cross-ties at Healy and Martin. PG&E has submitted documentation that indicates the cross-tie valve between Lines 132 and 109 was closed at Healy[36] and the cross-tie valve between Line 132 and 101 was closed at Martin on September 9, 2010. This did not prevent the backflow of gas from locations north of Martin back through Line 132. Appendix C, Attachment N shows the pressures at points

[36] No pressure transmitters are installed at Healy station nearest to the point of rupture.

along Line 132 (upper plot) as well as at Martin and Sullivan Avenue[37] (refer to Appendix C, Attachment B) for Line 109 (lower plot). Line 109 at Sullivan Avenue shows a drop in pressure from 382 to 182 psig following the rupture. Martin shows a drop from 386 to 50 psig on the lower plot of Appendix C, Attachment N, triggering the first low-low alarm at gas control on September 9, 2010[38].

Upstream (south) of the accident site, the cross-ties valves were opened at Sierra Vista Avenue and at Edgewood Road located 13.7 and 36 miles upstream of the rupture, respectively (refer to Appendix C, attachment B). The nearest SCADA pressure monitoring point upstream of the rupture is at Half Moon Bay[39], just over ten miles away. According to PG&E the SCADA pressure readings at Half Moon Bay are only valid for Line 132 prior to the rupture.[40] The Edgewood road cross-tie valve was opened and maintained line pressure downstream towards the rupture location.

PG&E used all recorded pressure drops and flows on Line 132 and adjacent lines to calculate the flows and volume of natural gas released from the time of the rupture to the time the fractured segment was isolated. Pressure from Martin, downstream, and at meter site one, upstream, were used to model a release from the rupture. The largest volume of gas released was from the south end where cross-ties into Line 132 from Lines 101 and 109 maintained higher line pressures towards the break. The total combined released volume estimated by PG&E is 47.6 mmscf[41] with a +/- 10% error.

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[37] Sullivan Avenue is located approximately 4 miles north of the rupture site on Line 109.

[38] The first low-low alarm appeared 5-minutes after the rupture at approximately 6:16 pm as a Martin Station upstream pressure alarm.

[39] Half Moon Bay is a 12 inch transmission line that connects to Lines 109 and 132. It is protected by a pneumatic automatic shutdown valve.

[40] According to PG&E the values from this pressure transducer, post rupture, are not valid indicators of the Line 132 pressures. The Half Moon Bay transducer was located on a distribution line that was isolated by a line break automatic valve. Therefore, the pressures recorded after 6:11 pm are not representative of L132 transmission line pressures.

[41] Million standard cubic feet is the volumetric measure of gas in cubic feet adjusted to standard temperature and pressure (70 deg F and 14.7 psia).

Table 2: Cross-tie valves on the peninsula system and position on September 9, 2010

Refer to Appendix C, attachment B for transmission line routing & locations				
Cross-tie	Manual / Remote Control	Lines	Mile Point	Open or Closed
Sierra Vista Ave (132A)	Manual	L109, L101, L132	10.32	*Open*
Edgewood Rd (147 Cross tie)	Manual	L109, L101, L132	25.6	*Open*
Ralston Ave	Manual	L109, L132	29.06	Closed
Crystal Springs	Manual	L109, L132	31.93	Closed
Healy Station[42]	---	---	40.05	---
• **V-1 & V-2**	Manual	L109, L132	---	*Open*
• **V-3 & V-4**	Manual	L109, L132	---	Closed
Martin Station(132B)	---	---	46.59	---
• **V-19**	Manual	L101, L132	---	Closed
Martin Regulation Valves				
• **V-1 & V-2**	Manual	L132	46.59	*Open*
• **V-10 & V-13**	Remote	L132	---	*Open*

[NTSB_Request 009-001A What is volume of gas lost on L132]
[NTSB_056-001 Volume Released Calculations or Models Used]
[NTSB_069-001 confirmation that Sullivan was not back feeding]
[Exhibit 2W - NTSB (035-12) Line 132 Cross Tie Schematic]
[Exhibit 2M - NTSB 036-004 SCADA Pressure Transducer Locations]
[NTSB_036-04S1 – Mile Points of Pressure Readings]
[NTSB_Data Request #011-007A_All Pressure Charts from Facilities]
[NTSB_058-007 Chart Recorders and which line they serve]

[42] At least one of each set of valves must be open to flow from Line 109 to 132.

G. Milpitas Terminal:

Milpitas is the final pressure (upstream) reducing terminal of the Peninsula system providing gas control the ability to move gas between various incoming transmission pipelines and to maintain downstream pressure for Line 100, San Jose DFM[43], Line 101, Line 109, and Line 132. The Milpitas is normally an un-manned terminal; however, on September 9, 2010 the terminal was occupied by a contractor and three PG&E employees performing electrical work. The control room and original control panel, referred to as the Mimic panel[44], remained at the facility but the controls have been upgraded to include a programmable logic controller (PLC) integrated with a SCADA network to allow for the remote operation from the gas control. The Mimic panel is a large panel board showing the station piping with pressures and valve states indicated by lights or digital displays. Electronic controllers that operate regulating valves are mounted in the Mimic panel in the Milpitas but communicate to the PLC.

The Milpitas piping configuration is a carryover from the 1980s when it was used to blend a variety of gas streams of differing heating values from several sources through a mixer within the terminal. The mixer has since been removed, but the line configuration and valves remain the same. Four incoming gas lines with operating pressures, as shown in Table 3, enter the station where they split and pass through two stages of pressure regulation consisting of a monitor valve and two regulating valves, before recombining downstream at header-2. Each stage of regulation at Milpitas is controlled independently but is configured identically. The incoming lines are all bi-directional and the first stage of regulation and monitor valves are outfitted to control pressures of the incoming lines in either direction. The second stage of regulators and monitor valves are set to operate to the pressures of the downstream lines. Leaving header-2, downstream of the second stage of regulators, the gas passes through a separator and is delivered into the five outgoing transmission lines. Refer to Appendix A.

The Milpitas regulating valves operate up to the Maximum Operating Pressure (MOP) of the line they serve, while the monitor valves were set to operate above MOP but below the Maximum Allowable Operating Pressure (MAOP) of the transmission line, they serve. In some cases the transmission line MOP and MAOP are identical values as noted in Table 2. According to PG&E, the monitor valve set points at Milpitas are about 10 psig above the maximum operating pressure of the line they are installed to protect.[45] In addition to the incoming lines, there are two bypass lines at Milpitas, a mixer bypass and station bypass line. Each of these bypass lines includes a regulating valve and corresponding monitor valve, located upstream of the regulating valve, to ensure over-pressure control of the outgoing transmission lines. Additional information on the equipment at the Milpitas can be found in Appendix A.

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[43] San Jose Distribution Feeder Main

[44] The mimic panel is a relay based control panel with lights indicating valve position, pressure displays and hand switches for valves. It was used for station control before the installation of the Programmable Logic Controller (PLC).

[45] 49CFR§192.201(2) (i) allows for a pressure up to 10% above MAOP for line protection devices in case of abnormal conditions.

Table 3: Incoming and outgoing lines at the Milpitas Terminal at MP 0.00

Refer to Appendix C, attachment A for the Milpitas Terminal Operating Diagram

Incoming lines at Milpitas				*Outgoing* lines from Milpitas			
Line	Diameter	MAOP	MOP	**Line**	Diameter	MAOP	MOP
---	*Inches*	*psig*	*psig*	---	*inches*	*psig*	*psig*
L107	36	720	477	**L100**	20	400	375
L131	30	595	590	**SJDFM**	24	200	200
L300A	34	558	558	**L101**	36	400	375
L300B	34	600	600	**L109**	24	375	375
---	---	---	---	**L132**	24	400	375

[Exhibit 2G - NTSB 004-001 Milpitas One Line Diagram]
[Exhibit 2V - January Interview of SCADA Controls Group Supervising Engineer]
[NTSB_033-007 Provide documentation Regulating Equip Set points]
[Photograph of the (MIMIC) Control Panel from the Milipitas Terminal]
[NTSB_073-001 Monitor Valve Set points]
[NTSB_053-012 Operational Diagram Key]
[NTSB_033-006 PG&E's procedures related to control set-points]

H. Dispatch Emergency Procedure

PG&E defines the process of responding to a gas emergency through the Company Gas Emergency Program. A gas emergency is defined as an actual or potential hazardous escape of gas including an over pressure or under pressure situation. The Company Gas Emergency Plan or (CGEP) encompasses the responsibilities of the dispatch operators, first responders and supervisors. The severity of an event is broken down into levels one through three with three being the most severe and impacting the largest numbers of customers. The CGEP flow chart of the program dictates that the initial response comprises level one involving the dispatch center a service technician to assess the situation. As more information is obtained and further support deemed necessary, the response may be escalated to a level two or level three. The company Operation Emergency Center (OEC) and Gas Restoration Center (GRC) are opened when the event reaches a level two status. Gas control does not appear in this workflow diagram. However, PG&E summarized the dispatch center and control center interaction as:

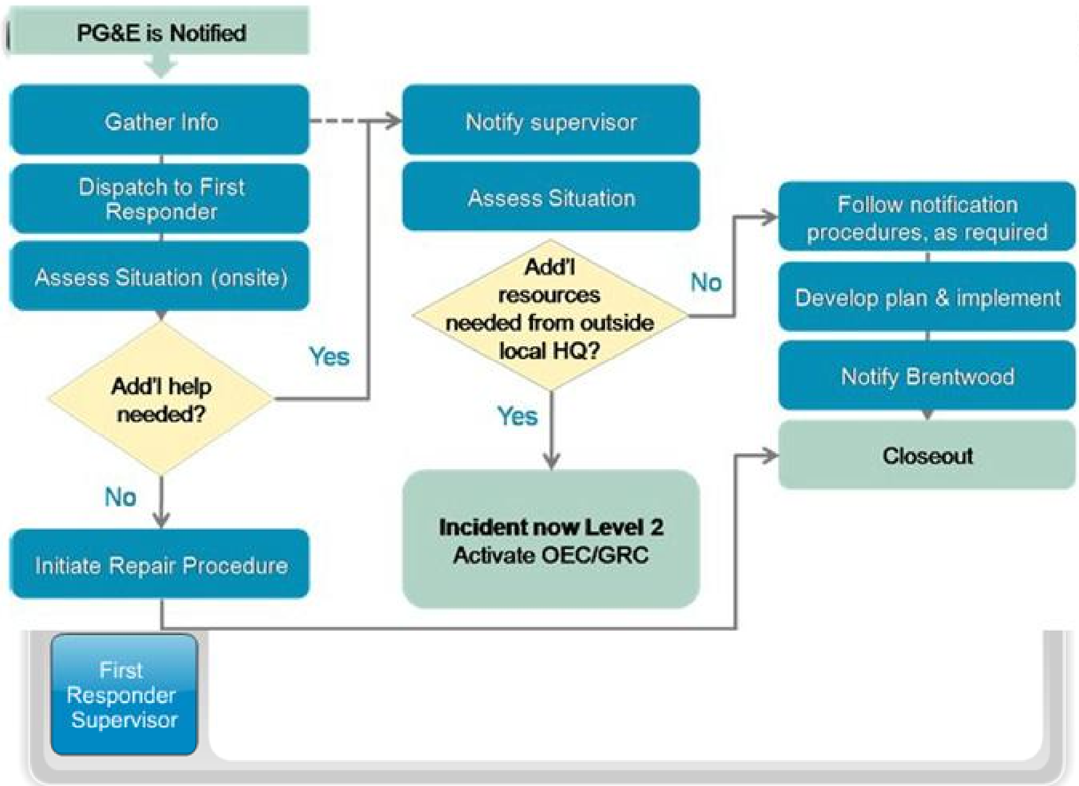

Figure 2: Flow chart of PG&E's Company Gas Emergency Plan

"Dispatch will notify Gas Control of a gas event as noticed in the Utility Standard TD-4413S (Gas Event Reporting Requirements). Dispatch will send a field employee to the location of the gas incident per Utility Procedure TD-6436P-12 (Handling Emergency conditions Reported by Outside Agencies and Company personnel). Depending on the actual field condition observed, Gas Control and Dispatch may have further interaction to dispatch additional field personnel or exchange information regarding the event."[46]

The actions of dispatch personnel are defined under PG&E's TD-6436P-12 procedure. The PG&E dispatch procedure of handling emergency conditions reported by outside agencies and company personnel on high or low gas pressure events[47] requires that the dispatch center dispatch a field employee to the gas incident location. This same procedure requires that the field personnel evaluate the danger to life and property, assess damage(s) and make or ensure that conditions are safe. The procedure requires field personnel to notify a field service supervisor, dispatcher, gas maintenance and construction supervisor, and/or on-call gas supervisor (if outside of normal business hours). The procedure discussed guidance for incoming 911 calls to the dispatch center, but made no mention of whether the field personnel, dispatch center, or the gas control are to directly initiate contact with emergency services through 911 or other means.

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[46] Excerpt from the TD-6436P-12 Procedure and PG&E Response NTSB 053-002

[47] Per PG&E's procedure: High or low gas pressure events include "Breaks in gas transmission lines operating at 60 psig or greater."

PG&E has stated that the gas control and dispatch center personnel do not make calls to emergency responders or 911 call centers in the case of a suspected pipeline rupture. The PG&E procedure does discuss cases where the dispatch center is to notify 911, such as in the case of an accident resulting in an injured employee. The procedure does not address timeliness of response or the involvement of city or emergency officials. Notifications outlined in the procedure are limited to company personnel and supervisor level PG&E employees. The procedure does not distinguish between a transmission pipeline rupture or distribution pipeline leak when defining roles and responsibilities pertinent to emergency response.

[NTSB_053-001 Control Room Procedures]
[NTSB_053-003 Gas Control and Dispatch Coordination]
[NTSB_053-002 Dispatch Center Procedures]
[NTSB_016-012 Web Based Training on Emergency Response]

I. Control Center Alarm Procedures

The gas control's alarm response procedure is contained in a PG&E control room document titled Alarm Limits Policy and Procedure dated April 28, 2008. This document is written to include both transmission and distribution pipeline systems. In this document, transmission lines are defined as pipelines operating at 60 psig or more. The policy requires that all transmission pipelines have established high-high and low-low pressure alarms. Flow alarms are used on select transmission lines. The high-high and low-low alarm settings are determined by a gas quality response team lead. Digital points[48] in the SCADA system are required to have alarm limits, which are outlined in an attachment to the policy and procedure document.

High-high pressure alarms are established under the policy as the lower of MAOP plus 3 psi or MOP plus 3 psi. The low-low alarm limits are not to be set below the minimum required pressure minus 3-psig. The high-high and low-low pressure alarms cannot be altered by the gas control operator. The high and low pressure alarms are set to monitor the normal operating range for the system; these may be adjusted by the gas control operator. High pressure alarms are required to be set at or below the MOP while the low pressure alarms are set above the minimum required pressure.

According to PG&E, under the alarm review section of the policy document all high-high and low-low alarm limits are to be reviewed during October of each year and any changes are implemented by mid November. The review of alarm limits is requested by gas control from the responsible transmission system planning engineers and maintenance and construction personnel. Changes to the alarm limits policy are implemented through gas control.

[48] A digital point in the SCADA system is defined as a discrete value consisting of only two states such as on/off.

Under the alarm response policy all alarms must be acknowledged. High and low alarms require only that the gas control operator review the alarm for an explanation that is consistent with system or loading conditions. No notification of the maintenance and construction field personnel is required if the gas control operator's analysis of the alarm indicates that the alarm is due to normal system conditions; if not then the procedure for a high-high or low-low alarm is followed.

The document states that the transmission coordinators and gas control system operators will acknowledge, analyze and respond to all high-high and low-low alarms within the first ten minutes. The procedure requires:

- *Brentwood*[49] gas control will establish communication with system gas control regarding the active alarm.
- *Brentwood* gas control and system gas control will analyze the upstream and downstream points to help determine the system condition and the cause of the active alarm.
- Upon completion of the analysis, a corrective action will be taken which may include a remote operation, contacting the responsible field Maintenance & Construction personnel and continued monitoring.

If the alarm continues into a second 10-minute interval:

- The Transmission Coordinator and Gas System Operator will communicate and coordinate the next steps with responsible field Maintenance & Construction personnel and/or Gas Transmission and Distribution (GT&D) engineering personnel.
- If the Transmission Coordinator, Gas System Operator, and field Maintenance & Construction personnel and/or GT&D engineering personnel cannot agree on a course of action, the Operations on-call representative is called. The Gas System Operator on-call Supervisor will discuss and agree on a course of action that will be communicated to the Transmission Coordinator or Gas System Operator on shift.

Under the digital alarm[50] policy the response to each active digital alarm is defined by the responsible maintenance supervisor. Gas system control maintains a database of each digital alarm and its associated response. Alarms at the gas control are acknowledged, analyzed, and responded to by the responsible maintenance group. Digital alarm responses are categorized as immediate notification, next day notification, next working day notification, or immediate response. The remainder of the Alarm policy and procedure summarizes the alarm settings in a matrix, outlines the change process, and defines how to establish alarm limits on new gas SCADA points.

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[49] The Brentwood facility is defined by the document as being the remote operations center while system gas control is the primary control center located in San Francisco. The procedure reads "Brentwood", however, PG&E has indicated the policy is referring to the primary gas control center located in San Francisco even though it reads "Brentwood gas control".

[50] Digital alarms are binary two state alarms that are either on or off.

[NTSB_014-006 SCADA Alarm Policy]
[NTSB_033-006 PG&E's procedures related to control set-points]
[NTSB_053-001 Control Room Procedures]
[NTSB_053-003 Gas Control and Dispatch Coordination]
[NTSB_053-002 Dispatch Center Procedures]

J. Work Clearances

PG&E Utility work procedure WP4100-10 describes the types of clearances required when performing work that will potentially affect gas pressure, gas flow, gas quality, or the ability for the gas control to monitor the SCADA points[51]. Under this procedure, a clearance supervisor or qualified designee fills out the standard form that identifies the work to be performed, drawings that will be relevant to the work discussed on the clearance, start time and duration of the work, impacts to SCADA points, special instructions and sequence of operations. The clearance coordinator at gas control validates and verifies the clearance before approval by gas control. The clearance supervisor oversees the clearance during the work and acts as the point of contact with gas control. Additional information on the Milpitas work clearance on September 9, 2010 is included in Appendix B.

[NTSB_044-001 Clearance Training]
[Exhibit 2AM: Milpitas Work Clearances, August thru September 2010 (NTSB_011-008)]
[NTSB_003-001 S2 WP4100-10 Clearance Procedures]

K. Line 132 Historic Operating Pressures

PG&E has indicated that they increased pressure on Line 132 to its Maximum Allowable Operating Pressure of 400 psig on two occasions in accordance with their integrity management program in order to maintain a five-year maximum operating pressure. According to PG&E records, these pressure increases were performed on December 11, 2003 and again on December 9, 2008 during months when the gas flows (demands) were the greatest on the system. Appendix C, Attachments Y and Z include the SCADA pressures recorded along Line 132 between the Milpitas and Martin during the 2003 and 2008 pressure increase for comparison to those pressures recorded during the September 9, 2010 event on Line 132. SCADA pressures provided from 2003 were only available in hourly averages. SCADA pressures from 2008 and 2010 were submitted in 20-second intervals. Appendix C, Attachment Y[52] contains the information from the 2003 pressure increase showing a maximum pressure generated at Milpitas of 402.73 psig. This pressure was maintained at just over 400 psig, at Milpitas, for about one-hour before being reduced. Meanwhile, the pressure readings at Half Moon Bay, located approximately 10 miles upstream of the rupture location, showed a pressure of

[51] SCADA points are all of the system data and alarms generated from the Supervisory Control and Data Acquisition (SCADA) system such as pressure data or pressure alarms.
[52] The 2003 pressure data was supplied to the NTSB as one-hour averages.

383 psig while Martin, approximately seven miles downstream from the rupture location, also showed a peak maximum pressure of 383 psig.

On December 9, 2008, Line 132 was again pressurized to approximately 400 psig at the Milpitas terminal from 12:45 pm to 2:10 pm; refer to Appendix C, Attachment Z and Z.1. The pressures at Milpitas reached a maximum of 402 psig during this time with maximum pressures recorded at Half Moon Bay and Martin of 382 psig. The maximum pressure recorded just prior to the September 9, 2010 rupture was 386 psig at Martin, greater than either previous recorded maximum pressure. No recorded pressures are available at Martin from October of 1968 when the maximum allowable pressure was established for Line 132 based on a 400 psig log entry at Milpitas.

Flow rates and pressures provided by PG&E from September 9, 2010 and prior to the time of rupture showed a pressure of 386.4 psig at Half Moon Bay and a reading of 386 psig at Martin station with a stated flow of 1.9 mmscfh.[53] The difference in Line 132 pressure readings between Half Moon Bay and Martin showed a 0.4 psig over an approximate 17.5 mile span of pipe bracketing the rupture location.

SCADA pressure data for line 132 was provided for the years 2002 through 2010 in hourly readings for examination. The 2002 through 2010 pressure cycle data may be found graphically for Martin station in the attachments of Appendix C, Attachment AG through AK. These trends show the maximum pressure differential within approximately seven miles of the rupture location. PG&E noted that some of the data provided included inconsistent readings affected by calibrations, instrumentation problems or SCADA system issues.

[Appendix C, SCADA Attachments A-AK]

L. Integrity Management Program

1) <u>Integrity Management Regulations</u>

The Natural Gas Transmission Pipeline Integrity Management rule (DOT 192 Subpart O) enacted by PHMSA on February 14, 2004 had four goals:

- Accelerating the integrity assessment of pipelines in High Consequence Areas,
- Improving integrity management systems within companies,
- Improving the government's role in reviewing the adequacy of integrity programs and plans, and
- Providing increased public assurance in pipeline safety.

The Gas Integrity Management Program rule required that natural gas transmission line operators to develop a written Integrity Management Plan. The plan must address the following 16 elements:

- Identification of all high consequence areas
- Baseline Assessment Plan
- Identification of threats to each covered segment, including by the use of data integration and risk assessment
- A direct assessment plan, if applicable
- Provisions for remediating conditions found during integrity assessments
- A process for continual evaluation and assessment
- A confirmatory direct assessment plan, if applicable
- A process to identify and implement additional preventive and mitigative measures
- A performance plan including the use of specific performance measures
- Recordkeeping provisions
- Management of Change process
- Quality Assurance process
- Communication Plan
- Procedures for providing to regulatory agencies copies of the risk analysis or integrity management program
- Procedures to ensure that integrity assessments are conducted to minimize environmental and safety risks
- A process to identify and assess newly identified high consequence areas

The operator may choose either a prescriptive or performance based program as outlined in ASME B31.8S 2004, *Supplement to B31.8 on Managing System Integrity of Gas Pipelines*

2) <u>PG&E Integrity Management Program Overview</u>

PG&E's Integrity Management Program (IMP) is implemented through PG&E's Risk Management Program (RMP) and includes the following procedures:

- RMP-01, Risk Management, Issued 11/13/01

  This procedure documents a process for maintaining PG&E's Risk Management Program and performing risk calculations required by PG&E's Integrity Management Program. The procedure defines total risk as the Likelihood of Failure (LOF) multiplied by the Consequences of Failure (COF). LOF is defined as a weighted sum of four threats, External Corrosion 25%, Third Party Damage 45%, Ground Movement 20%, and Design/Materials 10%. COF for non high consequence areas is defined as a weighted sum of three consequences, Impact on Population 50%, Impact on Environment 10%, and Impact on Reliability 40%. COF for high consequence areas is a function of the potential impact radius (PIR). All of the factors used in PG&E risk algorithms were established by a committee of PG&E employees and have not been revised since RMP-01 was originally issued on November 13, 2001.

PG&E calculates total risk for all transmission pipeline segments within the system. PG&E reviews the results of the risk calculation and selects a target threshold. Segments above the target threshold are reviewed for significant risk drivers. From these, segments are selected for investigation and mitigation efforts. These efforts may include in-line inspections, corrosion surveys, leak surveys, pressure tests, pipe replacement, line marking, and landowner notification.

- RMP-02, External Corrosion Threat Algorithm, Issued 11/26/01

  RMP-02 contains an algorithm to calculate the risk to the PG&E system of external corrosion. It details possible threats to the pipeline caused by items such as soil resistivity, coating age, coating design, and dc/ac interference. To develop a ranking for coated piping, the algorithm considers the results of pressure tests, visual inspections of the coating, casing surveys, corrosion leak rate, and external corrosion direct assessment (ECDA)[54] data.

- RMP-03, Third party Threat Algorithm, Issued 11/13/01

  RMP-03 considers the likelihood of excavation frequency, class location, ground cover protection, third party damage prevention, pipe diameter, and wall thickness, among other factors, to rank the vulnerability of pipelines to third party threats.

- RMP-04, Ground Movement and Natural Forces Threat Algorithm, Issued 11/26/01

  RMP-04 considers threats to the pipeline caused by water and seismic fault crossings, unstable soil conditions, seismic areas, and erosion areas. The algorithm also considers ground movement mitigative measures and the girth weld condition.

- RMP-05, Design / Materials Threat Algorithm, Issued 11/18/01

  RMP-05 considers design and material factors including, pipe seam design, girth weld design, material flaws or unique joints, pipe age,

[54] ECDA is a method where a pipeline is surveyed with two complementary tools and likely areas of potential corrosion are selected. These areas are then excavated and physically examined for corrosion damage.

maximum operating pressures as a percentage of pipe strength, leak history, and pressure testing.

- RMP-06, Gas Transmission Integrity Management Program, Issued 12/09/04

  PG&E developed RMP-06 the Gas Transmission Integrity Management Program to meet the requirements of 49 CFR §192 Subpart O. Subpart O describes all of the elements needed in an integrity management plan for a transmission pipeline and lists numerous threats to the integrity of the pipeline system the plan must cover. PG&E designed RMP-06 "to provide the best methods and implementation to ensure the safety of gas transmission pipelines located where a leak or rupture could do the most harm, defined as High Consequence Areas (HCA's)." This procedure is the controlling document for the Gas Transmission Integrity Management Program and is modeled after the ASME B31.8S 2004, *Supplement to B31.8 on Managing System Integrity of Gas Pipelines, and requirements for prescriptive programs.*

  RMP-06 contains requirements for threat identification and data integration, including sources of data to be used to create record of pipeline design. This pipeline design information is maintained in PG&Es Geographic Information System. The procedure also considers threats to pipeline integrity such as external corrosion, internal corrosion, stress corrosion cracking, pipe manufacturing and pipeline construction defects, equipment failure, third party damage, incorrect operations, and external forces.

  The procedure requires development of a baseline assessment plan[55] for the integrity assessment of all high consequence areas using in-line inspection, pressure testing, or direct assessment. Fifty percent of assessments must have been completed by December 17, 2007, and remaining initial assessments must be completed by December 17, 2012.

  The Integrity Management Program in RMP-06 also includes requirements for measuring performance, record keeping, change management, quality assurance, communication, and notification.

- RMP-08, Identification, Location, and Documentation of High Consequence Areas (HCAs), Issued 05/19/04

  RMP-08 uses Method 2, the Potential Impact Circle method, described in 49 Code of Federal Regulation (CFR) §192.903 to determine HCAs.

[55] The base line assessment plan is a list of all PG&E pipeline segments that require an integrity assessment.

- RMP-09, External Corrosion Direct Assessment (ECDA) Procedure, Issued 08/22/2002

  RMP-09 includes requirements for performing an ECDA pre-assessment including data collection, indirect inspections, prioritizing excavation locations and examinations, and post-assessment including data analysis. The procedure is based on NACE RP 0502-2002.

- RMP-10, Dry Gas Internal Corrosion Direct Assessment (ICDA), Issued 04/05/10

  RMP-10 includes requirements for performing an ICDA pre-assessment including data collection, identifying sites, prioritizing excavation locations and examinations, and post-assessment including data analysis. The procedure is based on ASME B31.8S-2004. Internal Corrosion is not included in PG&E's equation used to calculate the likelihood of failure in RMP-01 Risk Management. Because of this, RMP-01 states that the limited number of; pipelines with the threat of internal corrosion are classified as high risk.

- RMP-11, In-Line Inspections, Rev. 2 Issued 06/10/08

  RMP-11 includes a procedure for performing a pre-assessment including data and work necessary to make the line piggable,[56] in-line inspection including internal cleaning and inspection tool running, direct examination of identified anomalies, and post-assessment including data analysis and mitigation planning. The procedure is based on ASME B31.8S-2004.

- RMP-13, Stress Corrosion Cracking Direct Assessment (SCCDA), Issued 1/2/07

  RMP-13 includes requirements for performing an SCCDA pre-assessment including data collection, indirect inspections, prioritizing excavation locations and examinations, and post-assessment including data analysis. The procedure is based on ASME B31.8S-2004 and NACE RP 0204-2004. Stress corrosion cracking is not included in PG&E's equation used to calculate the likelihood of failure in RMP-01, which states that the limited numbers of pipelines with the threat of stress corrosion cracking are classified as high risk.

[56] Piggable refers to a line that can accommodate the passage of an in-line cleaning, batch, and inspection tools

In accordance with RMP-01 PG&E checks for stress corrosion cracking with all integrity management direct examinations PG&E performs.

[Exhibit 2-AV: Excerpts from PG&E Risk Management Plan]
[Exhibit 2-AU: Excerpts from PG&E Integrity Management Plan]
[Exhibit 2-U: Supervising Engineer for the ILI and DA Programs Supervising Engineer for the ILI and DA Programs]

3) <u>PG&E Baseline Assessment Plan</u>

PG&E's baseline assessment plan states PG&E will conduct an inventory of all the pipeline design attributes, operating conditions, environment (e.g. structure, faults, etc) threats to the structural integrity, leak experience, and inspection findings. PG&E uses a GIS mapping database as the system of record for class locations and identification of HCAs.

According to the 2009 Baseline Assessment Plan, PG&E's system includes 1021 miles of High Consequence Areas and about 500 miles of non-HCA pipeline. Of the 1021 miles to be assessed by December 17, 2012:

- Eight hundred thirteen HCA miles will be assessed using direct assessment methodologies (External Corrosion Direct Assessment, Internal Corrosion Direct Assessment, and Stress Corrosion Cracking Direct Assessment).

- Two hundred eight miles of HCA miles will be assessed using In-Line Inspection tools.

- Five hundred miles of non-HCA will be assessed using In-Line Inspection tools.

- Zero miles will be assessed using pressure testing.

[Exhibit 2AW: Line 132 Baseline Integrity Management Assessment]

4) PG&E Performance Measures

PG&E collects and reports to PHMSA performance measures for the Integrity Management Program (IMP) in accordance with RMP-06 Section 10 and Title 49 CFR § 192.945. Semi-annual reports must include:

- Number of total pipeline system miles
- Number of total miles of pipelines inspected
- Number of high consequence area miles in the integrity management program
- Number of high consequence area miles inspected in accordance with the integrity management program
- Number of immediate repairs completed in high consequence areas
- Number of scheduled repairs completed in high consequence areas
- Number of leaks in high consequence areas classified by cause
- Number of failures in high consequence areas classified by cause
- Number of incidents in high consequence areas classified by cause

Leaks, failures, and incidents are mutually exclusive events and defined by the regulation as follows:

- **Leak** - An unintentional release of gas from the pipeline that is not an "Incident." This includes any unintentional release of gas from a pipeline that does not result in an injury, death, or $50,000 or more in property damage.

- **Failure** - Failure is a general term used to imply that a part in service has become completely inoperable; or is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use. A Failure does not involve a release of gas.

- **Incident** - An Incident involves a release of gas from a pipeline and a death, or personal injury necessitating in-patient hospitalization; or estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more; or an event that is significant, in the judgment of the operator, even though it did not meet the criteria above.[57]

[57] In accordance with California General Order 112E, an incident in California also includes "Incidents which have either attracted public attention or have been given significant news media coverage, that are

Tables 4, 5, and 6 are the leaks, failures, and incidents classified by cause that PG&E reported[58] through June 30, 2010.

Table 1: Leaks

	2004	2005	2006	2007	2008	2009	2010
External Corrosion		1	1	2	2	3	1
Internal Corrosion							
SCC							
Manufacturing			1		1		
Construction	1			1	1	3	3
Equipment		7	1	1	1	2	
Third Party		1		1		1	
Incorrect Operations							
Weather Outside Force							
Totals	1	9	3	5	5	9	4

Table 2: Failures

	2004	2005	2006	2007	2008	2009	2010
External Corrosion		9		1	3		
Internal Corrosion							
SCC							
Manufacturing							
Construction							
Equipment						2	3
Third Party		3		1		1	1
Incorrect Operations						3	1
Weather Outside Force							
Totals	0	12	0	2	3	6	5

suspected to involve natural gas, which occur in the vicinity of the operator's facilities; regardless of whether or not the operator's facilities are involved."

[58] PG&E reported integrity management program measures under two Operator IDs, 15007 Pacific Gas & Electric Co., and 18608 Standard Pacific Gas Line Inc.

Table 3: Incidents

	2004	2005	2006	2007	2008	2009	2010
External Corrosion							
Internal Corrosion							
SCC							
Manufacturing							
Construction							
Equipment							
Third Party				1			
Incorrect Operations		1					
Weather Outside Force							
Totals	0	1	0	1	0	0	0

[Pacific Gas & Electric Co. Gas Integrity Management Plan Reports]
[Standard Pacific Gas Line Inc. Integrity Management Plan Reports]

5) PG&E Integrity Management Program as Applied to Line 132

PG&E also followed the requirements stated in 49 CFR §192.5 to determine class location, which are based on the number of dwellings in the class area. PG&E has identified Line 132 from mile point 8.39 to mile point 40.08, including the rupture location, as a Class 3[59] location and a high consequence area.

The PG&E corrosion control program with respect to Line 132, pipe-to-soil measurements are conducted every other month and rectifier reading are obtained annually for external corrosion control monitoring. There was no visible evidence of external or internal corrosion or stress corrosion cracking on the Line 132 sections examined by the NTSB Materials Laboratory.[60] The available tools under the 49 CFR §192 code for inspection of Line 132 were ECDA, Inline Inspection (ILI) or pressure testing. PG&E selected ECDA to assess the corrosion and coating of a section of Line 132 in 2005 and 2009. According to PG&E, bends in the pipeline, non-piggable valves, and changes in pipe diameter made in-line inspection impracticable for Line 132.[61]

[59] Class location is defined in 49 CFR §192.5 and it refers to the number of buildings in an area that is 220 yards on either side of the centerline of a continuous one mile length of pipeline. Class 1 has 10 or fewer buildings, Class 2 has 10 to 46 buildings, Class 3 has 46 or more buildings, and Class 4 has buildings 4 or more stories that are prevalent.
[60] For further details see the Metallurgical Group Chairman's factual report.
[61] In PG&E's 2011-2013 gas rate case filed in 2009, PG&E requested permission to upgrade sections of Lines 101, 109 and 132 to accept in-line inspection tools.

PG&E was aware that there are some manufacturing and construction threats on Line 132, which include age of the pipeline, susceptibility to ground movement, and potential seam threats such as low-frequency electric resistance welded (ERW) pipe.[62] Title 49 CFR §192.917(e)(3) allows a segment identified as having a potential manufacturing or construction threat to be considered stable if the operating pressure experienced on the segment has not increased over the maximum operating pressure experienced in the five years preceding the designation of the high consequence area. If the MAOP increases, the stresses leading to cyclic fatigue increase or if the operating pressure exceeds the maximum operating pressure during the 5 year period, the manufacturing or construction threat may become unstable and under the regulation must be prioritized as a high risk segment for baseline assessment or subsequent reassessment. Since 2003, PG&E has twice raised the pressure to about 400 psi to maintain the maximum operating pressure of the pipeline.[63] This practice has been suspended pending the outcome of the San Bruno investigation.

NTSB reviewed the geographical information system (GIS) data on the pipeline survey sheets provided by PG&E for Line 132 and found:

- The pipe wall thickness recorded in the GIS system and on the pipeline alignment sheets for Line 132 is an assumed value for 21.5 of the 51.5 miles (41.75%) of Line 132.

- The manufacturer of the pipe recorded in the GIS system and on the pipeline alignment sheets for Line 132 is NA (unknown)[64] for 40.6 of the 51.5 miles (78.81%) of Line 132.

- The depth of cover for the pipe recorded in the GIS system and on the pipeline alignment sheets for Line 132 is NA (unknown) for 42.7 of the 51.5 miles (82.79%) of Line 132.

- Three different values are used for the specified minimum yield strength (SMYS) of grade B pipe: 35,000; 40,000; and 45,000 psi. American Standard Association code B31.1.8 1955[65] as well as the current ASME codes B31.8 specify 35,000 psi for grade B pipe SMYS.

[62] See 49 CFR §192.917(e)(4).
[63] The California Public Utility Commission (CPUC) also made it clear that they do not share PG&E's interpretation of 49 CFR 192.917 as requiring a pressure increase to MAOP every 5 years and stated that "artificially raising the pressure in a pipe that has identified integrity seam issues seems to be a wrongheaded approach to safety."
[64] PG&E stated that NA is considered to mean null, blank, unknown, or not available.
[65] Prepared and published by ASME.

- Segments 106.5 and 188.1 use assumed values for SMYS of 33,000 psi and 52,000 psi respectively. 49 CFR Section 192.107 requires operators to use a value of 24,000 psi when the SMYS is unknown.

- A number of segments specify 30 inch diameter seamless pipe when there was no API qualified domestic manufacturer of such pipe when the line was constructed.

- Six consecutive segments totaling 3649 feet of pipe specify a minimum depth of cover of 40 feet.

[Exhibit 2-R: 49 CFR §192.903]
[Exhibit 2-S: PG&E PIR & HCA Drawings]
[Exhibit 2-T: Standard Cathodic Maintenance Report]
[Exhibit 2-U: Supervising Engineer for the ILI and DA Programs
Supervising Engineer for the ILI and DA Programs]
[NTSB Data Request #055-003, Pipe Manufacturing Threats]
[NTSB Data Request #057-005, Question on Raising Pipeline Pressures]
[Exhibit 2P: PG&E Line 132Survey Sheets]

M. Use of Automatic Shut-Off Valves and Remote Control Valves

US Department of Transportation regulations (49 CFR §192.935) require that "An operator must take additional measures beyond those already required by [49 CFR] part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area…. Such additional measures include, but are not limited to, installing Automatic Shut-Off Valves (ASV) or Remote Control Valves (RSV)…If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV."

PG&E's Integrity Management Program procedure RMP-06 issued December 9, 2004[66] required the following with respect to automatic shut-off valves and remote control valves:

> *In addition to normal valve replacement, Company shall consider the addition of automatic shut-off valves (ASV) or remote control valves (RSV) if they would be an efficient means of adding protection to an HCA. The specific guidelines for utilizing automatic shut-off valves are being developed and the Lead Risk Mgmt Engineer is responsible for ensuring these guideless are implemented prior to 12/31/05.*

[66] The original issue and revision to RMP-06 are approved by the Vice President – Gas Transmission and Distribution, President/CEO Standard Pacific Pipelines, Inc.

In a 2005 audit of PG&E's Integrity Management (IM) Program (section N), the California Public Utilities Commission identified as a "Most Significant Integrity Management Program Concerns/Issue" the following:

> *PG&E had no process in place to evaluate automatic shut off valves or remote control valves. Furthermore, PG&E proposed in their IM plan to wait until December of 2006 to develop this process.*

Following the audit, PG&E added the following to RMP-06:

> *Per letter to [Risk Management] file 8.10 dated 6/14/06 by [a senior consulting gas engineer], the company has concluded that, in most cases, the uses of ASVs or RCVs as a preventative and mitigation measure in a HCA has little or no effect in increasing human safety or protecting pipelines. ASV or RCV may, however, help reduce shutdown time and gas releases during repair which would reduce repair cost and improve system recovery….We do not recommend using ASV or RCV as a general mitigation measure…*

The senior consulting gas engineer's letter to file does not document any advantages of using ASVs or RCVs as either a prevention or mitigation measure.

Use of automatic shutoff valves or remote control valves as a preventative and mitigation measure is not included in PG&E's algorithm used to calculate the consequences of failure in procedure RMP-01 of the integrity management plan, nor are they considered in the RMP-04 ground movement threat algorithm.

PG&E in written comments submitted to US Department of Transportation, Research, and Special Programs Administration (now Pipeline and Hazardous Material Administration (PHMSA)) for a 1997 public meeting on automatic shutoff valves and remote control valves include the following statements:

- [PG&E] *Have no objection to installing RCVs, have found them reliable, install them when upgrading existing major control stations or installing new stations.*
- *Safety would be enhanced by reducing the volume of flammable gas released.*
- *Major technical advantage by isolating section quickly without dispatching personnel and knowledge of valve status using SCADA.*
- *Major economic advantages are minimizing company liability, and potential for minimizing gas customer outage by quickly isolating section and providing alternate gas supply.*
- *Main disadvantages are high cost and potential for inadvertent shutdown.*

[Exhibit 2-Q: Senior Consulting Engineer RMP-06 Memo to File and Supporting Documents]

N. California Public Utility Commission

The California Public Utility Commission (CPUC) currently regulates natural gas distribution and intrastate transmission pipelines within California. The CPUC began regulating natural gas pipeline safety in California on July 1, 1961 under General Order 112. General Order 112 was based on American standard Association (ASA) Standard B31.1.8-1958 *Gas Transmission and Distribution Piping Systems*, sponsored and published by the American society of Mechanical engineers (ASME).

General Order 112 mandated requirements for the design, construction, inspection, testing, operation, and maintenance of natural gas piping systems. Furthermore, General Order 112 mandated that each gas utility maintain records of compliance and that the records be available for CPUC inspection at all times. General Order 112 also required 30 day notice for all proposed installations, reconstructions, and changes to MAOP. General Order 112 requirements for design, construction, inspection, and testing were not applied retroactively to existing installations including PG&E's Line 132.

The present General Order 112E incorporates all requirements of 49 CFR 192 and some requirements that are more stringent than the federal code.

The Federal government certified CPUC to inspect and enforce pipeline safety regulations in California. As part of certification California has adopted rules which incorporate Minimum Federal Safety Standards for Transportation of Natural and Other Gas By Pipeline. CPUC has direct oversight of PG&E.

1) CPUC Organization, Structure, Funding and Training

The CPUC has about 1000 employees but only 19 inspectors, and 6 supervisors are on the pipeline safety staff for a total of about 12 person-years. The CPUC has a group that adjudicates rate cases and develops gas revenue requirements that is separate from the pipeline safety division.

Training for the CPUC inspector includes an engineering degree, as well as six core PHMSA courses that include the Gas Integrity Management Course plus other web-based training.

The CPUC receives federal grants which supplement funding of the gas safety program. The CPUC is annually evaluated by PHMSA as part of the grant process. Three of the last five years, CPUC has received a 100% rating from PHMSA.

CPUC typically audits distribution and transmission facilities every two or three years. The CPUC concentrates their resources at facilities they identify as needing additional inspection and will conduct an audit once a year if necessary.

2) CPUC Integrity Management Audits of PG&E

CPUC audited the PG&E Integrity Management Plan in 2005 and 2010. A PHMSA inspector assisted four CPUC inspectors with the 2005 audit. This audit was performed in accordance with PHMSA protocols; however, a formal report was not issued to PG&E. The CPUC did identify four shortcomings in the procedural areas of the 2005 audit.

- A finding that PG&E integrity management processes and overall documentation needed to be more robust.
- The repair criteria called "scheduled other" where an 80% wall loss was detected through inline inspection and PG&E did not classify it as requiring immediate action. However, once the audit was completed, PG&E revised their procedures to consider any such wall loss as requiring immediate action.
- That periodic program evaluation was not sufficiently thorough and complete for identification of new threats, preventative, and mitigative actions.
- That the quality assurance program did not specify criteria for acceptability.

The 2010 audit was based on the PHMSA Integrity Management Inspection Protocol. This protocol covers the entire integrity management process. CPUC uses checklists and reviews related procedures, records, and project files pertaining to the PG&E program. This audit was performed by a team of four CPUC engineers. The CPUC audit team identified several findings that required remediation by PG&E.[67]

The audit identified that consultants hired by PG&E to review aspects of PG&E's Integrity Management Program found areas of concern that PG&E was slow to address. There were external reviews performed by consultants in 2007 and 2009. The 2007 consultant review was not addressed by PG&E until December 2009. The 2009 consultant review had not been addressed by PG&E by CPUC's May 2010 (IM) audit.

[67] This audit is still open and has not yet been closed out by CPUC.

The CPUC identified an excessive use of the exception process to avoid excavating or examining certain indications found through integrity management inspections. In one case the delay in excavating a known indication was over 90 days. PG&E is required to excavate all discovered anomalies within 365 days and instead took 27 months to complete the examinations.

CPUC also evaluated PG&E's self assessment of their Integrity Management plan by reviewing PG&E's continual evaluation of the program and the self assessment portion of the IM program to determine if the regulations are being followed and PG&E is doing an effective job with continuous improvement and effective self assessment.

PG&E has taken action to address findings of both the 2005 and 2010 CPUC Integrity Management audits.

[Exhibit 2-AY: CPUC 2005 and 2010 IMI Audit Items (NTSB 008-001)]
[Exhibit 2-DH: PG&E Response to CPUC 2010 IM Inspection]
[Exhibit 2-DK: PG&E Response of 12-16-10 to CPUC May 2010 IM Audit.pdf]
[California PUC General Order 112 Effective as of July 1, 1961]
[Exhibit 2DG: CPUC General Order 112E]

O. Pipeline and Hazardous Material Safety Administration, Office of Pipeline Safety Oversight

The statutes under which PHMSA, Office of Pipeline Safety (OPS) operates provide for state assumption of all or part of the intrastate regulatory and enforcement responsibility through annual certifications and agreements. Federal grant funds are used as an incentive to improve state program performance and to encourage states to take on more responsibility for pipeline safety. OPS, is authorized to reimburse a state agency up to 80 percent of the actual cost of carrying out the state's pipeline safety program, including the cost of personnel and equipment. Federal funding is determined through an allocation formula based on factors such as the extent to which the state asserts safety jurisdiction, whether the state has adopted all federal requirements, and the number and qualifications of the inspectors.

1) PHMSA Integrity Management Audit Format and Reviews of State Integrity Management Audits

PHMSA provides the state regulators a 120 page integrity management protocol checklist covering the 16 elements of the integrity management plan as described by 49 CFR 192 Subpart O. The typical integrity management plan audit covers the following: identifying high consequence areas, baseline assessment plans, identifying threats, data integration and risk assessment, direct assessment plan, remediation, continual evaluation and assessment, confirmatory direct assessment, preventative and mitigative measures, performance measures, record keeping, management of change, quality assurance, communication plans and submittal of program documents.

PHMSA performs high level reviews of state auditors to determine whether improvements are needed. PHMSA is planning a state partner workshop in the summer of 2011 to address needed changes and improvements.

2) PHMSA Evaluation of CPUC

PHMSA evaluates each state's pipeline safety plan and assigns the state plan a score upon which funding of the state program by the PHMSA is determined. The California PUC auditing program score was 99.5 in 2009, 99 in 2008, and 100 in the years before. The CPUCs overall score is about 90 and this is due to their jurisdictional status and the lack of legislation giving them full authority over all gas pipelines.

3) PHMSA Natural Gas Transmission Pipeline Regulations History

On August 19, 1970 OPS/PHMSA issued regulations for the Transportation of Natural and Other Gas by Pipeline; Minimum Federal Safety Standards, 49 CFR Part 192 as authorized by the Natural Gas Pipeline Safety Act enacted on August 12, 1968. The regulations required operators to pressure test their newly installed pipelines to a pressure greater than[68] the proposed Maximum Allowable Operating Pressure (MAOP) for 8 hours. It also codified the definition of MAOP. However pipelines installed before the rulemaking were neither required to be pressure tested nor have their MAOPs reduced. The reasoning for excluding existing pipelines was based on the industry use of a national consensus standard for gas pipelines[69] prior to the new regulations. This standard required testing of pipelines consistent with the requirements of the new regulation since 1952. Between 1935 and 1951, the standard required a pipeline to be tested to a pressure 50 psi in excess of the proposed maximum operating pressure.

[68] The actual test pressure is based on Class Location and varies from 1.1 times MAOP for Class 1 to 1.5 times MAOP for Class 3 and 4.

[69] Use of these national consensus standards was voluntary.

P. PG&E Camera Inspection of Line 132

PG&E conducted an internal camera inspection of Line 132 from mile points 38.49 to 40.05 between September 29, 2010 and October 8, 2010. The camera used was a Versatrax 300 VLR which has 6500 feet of tether enabling the inspection of more than one mile of pipe in a single run. Nine inspections runs were recorded on DVD discs.

Inspection 1- this was from San Andreas Station to the north towards the Glenview Avenue and Earl Avenue accident site. A total of 2854 feet of pipeline were inspected.

Inspection 2 – began from Healy to the south towards the Glenview Avenue and Earl Avenue accident site. Only 110 feet were able to be inspected due to a steep grade and a slick oil-like coating inside the pipeline.

Inspection 3 – was from the Glenview Avenue and Earl Avenue site to the south towards San Andreas Station. The inspection covered 1441 feet and because of the moderate grade and numerous sharp angles of the piping at certain joints, PG&E was unable to inspect about 139 feet of piping.

Inspection 4 - beginning at the Glenview Avenue and Earl Avenue accident site for a run north towards Healy. The inspection was only able to cover 997 feet due to a moderate grade and numerous angle points. The camera was able to enter the 24 inch outside diameter pipe installed in 1994.

Inspection 5 - beginning at the basketball court on Catalpa Way for a run south towards the Glenview Avenue and Earl Avenue site. The inspection was only able to cover 487 feet but the camera was able to enter limited footage of the 24 inch pipe installed in 1994. PG&E was unable to inspect about 584 feet of piping in this section.

Inspection 6 - beginning at Catalpa Way and ran north towards the Healy. The inspection was able to cover 1599 feet due to a steep downward grade and numerous angles of the inspected piping causing sticking of the camera probe.

Inspection 7 – occurred from Rollingwood Drive towards Catalpa Way. The progress of the inspection was halted at 72 feet due to oil in the line causing the camera probe to slip but it was able to overlap the previous pipe inspection from Catalpa, north.

Inspection 8 – began from Rollingwood Drive in the northerly direction towards Healy. The inspection covered 554 feet.

Inspection 9 - from Rollingwood Drive south towards Catalpa which was a repeat of inspection seven after the pipeline liquids were vacuumed from the pipeline. The inspection covered 84.5 feet.

[Exhibit 2CL Excerpts from PG&E Camera Inspection of Line 132, Segment 180]

Q. PG&E Pipeline 2020

Following the accident, PG&E announced, on October 12, 2010, Pipeline 2020, a program with five areas of focus to strengthen the utility's natural gas transmission system through a combination of targeted investments, research and development, improved processes and procedures, and tighter coordination with public agencies. The five areas include:

1) Modernize Critical Pipeline Infrastructure to upgrade key gas transmission pipeline segments located in heavily populated and other critical areas.
2) Expand the Use of Automatic or Remotely Operated Shut-Off Valves on segments of its gas transmission pipelines located in heavily populated areas.
3) Spur Development of Next-Generation Inspection Technologies by establishing an independent, nonprofit entity dedicated to researching and developing next-generation pipeline inspection and diagnostic tools.
4) Develop Industry-Leading Best Practices related to pipeline integrity, safety, and training.
5) Enhance Public Safety Partnerships with local communities, public officials, and first responders.

[Exhibit 2-CM PG&E PIPELINE 2020 PROGRAM]

R. PG&E Line 132 Construction - 1948

According to PG&E, the original installation of Line 132 consisted of multiple phases that covered a four year span from 1944 to 1948. The survey sheets for Line 132 shows that over 50 percent of the line between Milpitas and Martin date back to 1948 or earlier. The project scope document for the 1948 work calls for 18 miles of 30 inch main and 5 miles of 24 inch main to complete Line 132 between Crystal Springs Lake and the Potrero gas plant in order to meet peak demands and supply a new steam electric plant. As part of the project, to avoid over pressuring the lines in San Francisco a pressure limiting station, remotely operated was called for at Martin station. The project also created a 20 inch cross tie between Lines 101 and 132 at Martin station. As stated in the scope document "To assist in meeting the peak hour demands in the San Francisco Peninsula area, it is planned as a daily operation to pack Main Line 132 between Milpitas and San Francisco to 350 psig and draft it down to normal operating pressures." In a letter dated November 5, 1951 for the completion of GM98015, it states that GM98015 was physically started on June 14, 1948 and the 24 inch and 30 inch gas mains were completely installed and the line was in place and operational by December 6, 1948.

The 24 inch pipe installation was awarded to M&K Corporation with supervision by the PG&E general construction department. The project called for the installation of 26,124 feet of 24 inch outside diameter (OD) double wrapped transmission main with necessary valves and fittings to tie into 30 inch extension of main Line 132 at Martin and extending into Potrero gas plant. The 24 inch project documentation indicates 9,806 feet of 24 inch line were stocked at Martin substation along with 6,516 feet of 24 inch plain end pipe hauled from Martin and 9,331 feet of 24inch OD plain end pipe hauled from Western Pipe and Steel by the contractor. As part of the 24 inch installation, 325 feet of 30inch casing was installed across Bayshore Blvd and to the west property line of San Bruno Avenue. The progress report indicates the 24 inch line was pressurized with gas and leak tested using soap and water.

The 30 inch pipe and 20 inch cross-tie were awarded to the Pacific Pipeline and Engineers Limited and Stolte Incorporated and were supervised by PG&E general construction. In the Authorization for the 30 inch pipeline installation the contract document states that all materials, except those for concrete work and tile drain replacements, were furnished by PG&E and delivered by truck to the job site. The 30-inch installation was started on August 23, 1948 with the first pipe received on September 3, 1948.

According to an entry in the construction journal for the 30 inch installation, each welder was assigned a stencil so that each x-rayed weld could be identified by the welder. Each welder making the stringer bead would place their mark on the north or San Francisco side within 2 inches of the welded seam and the welder making the succeeding passes would place his mark on the south side. Progress reports for the 30-inch line construction states that an average of 10 percent of the total girth welds were to be radiographed. Radiography and inspections were conducted to a predetermined set of standards prepared and agreed to by the contractor's welding engineer, the company's engineer of gas construction, and representatives of the company making the radiographic tests. The project journal shows 209 recorded radiographs in the logs with 15 rejects.[70] Of the 15 rejects, five were longitudinal welds and ten were in circumferential welds. In addition, there were 14 circumferential welds labeled "Borderline." The progress reports on the 30-inch installation indicate that the pipe wrapping was stopped on September 15, 1948 when x-rays showed cracks on welded seams. The progress report indicates that a meeting with the city representatives, the vice president of Consolidated Western Steel (Los Angeles) and PG&E representatives took place regarding the issue; however, no resolution is noted. Journal entries indicated that the five seam welds showed lack of penetration or cracks. The same sheet shows that at least some of the welds were repaired and x-rayed again.

[70] Four of the rejects were re-examined and determined to be acceptable from an original 19 rejects.

Also included in the log entries are welder certifications indicating that sample girth or circumferential welds were prepared and tested to qualify the welders. In an October 1948, letter from the bureau of tests and inspections to the gas construction department, the bureau reported on a 13 feet section of 30inch pipe with a single girth weld which revealed several defects during an x-ray examination. The pipe was sent to the lab for mechanical testing and further inspection of the weld. In their report, the bureau noted that there were at seven points along the weld where the gamma ray prints indicated particularly bad faults. The x-ray inspection stated porosity, lack of penetration, burn through and undercut as some of the reasons for the poor weld. The faults were cut out and tested for ultimate strength against the PG&E specifications. Two of the seven test specimens met the strength requirements[71].

The 1948 construction journals also showed that on September 20, 1948, different welding rods were being used on the girth welds for the 30 inch pipe. The journal entry states that, "…the same day Westinghouse Electric welding rod type AP-MO Class E7010 was used by approx. eight of Pacific Pipe line and Engineering welders…the surface pin holes were so bad that some of the welders wouldn't even try to complete the weld with this rod; however, we did get 4 welds completed with this wire. Each succeeding pass had fewer surface holes." The entry finishes for that day with, "These welds were made right in the line and the wrapping crew was so close that we could not have x-rays made of them. I am sure they would stand up to any type of bend or pull test and perhaps show up good in an x-ray but due to circumstances we didn't do any of these things to the weld."

The construction progress reports states that the x-ray company left the job on October 28, 1948 after completing 209 tests. The progress reports and journal entries indicated that Line 132 was welded up at the Mills Estate creek crossing on November 20, 1948 and that the final tie-in between the 30 inch and 24 inch lines are made just 10 days later. Surplus pipe from the job included 30inch OD pipe with 0.375inch wall, electric welded, steel double wrapped and bare as well as 30-inch OD pipe with 0.3125 wall electric welded steel, bare.

The 1948 construction specifications issued for the installation of the 30inch, 24inch and 20inch gas transmission mains under GM98015 were issued in July 13, 1948. The construction specifications indicate that PG&E would furnish all materials that are required to be incorporated in or to become a permanent part of the gas pipeline, including the welding rod. Under the 1948 specifications only the 20inch and 24inch pipe are specified as being seamless pipe conforming to the API standards 5-L for grade B pipe. The 30inch pipe material was specified as 30 inch OD with 0.375 inch wall thickness, electric welded, longitudinal seam type and with the following physical and chemical properties:

[71] The specification at the time required that the weld metal exhibit 72,000 psi strength or that the test coupon breaks in the parent metal before breaking at the weld.

Table 4: PG&E 1948 30" Pipe Specification

Property	PG&E	API 5LX[72]	Units
Maximum Transverse Yield	52,000	52,000[73]	Psi
Maximum Ultimate Strength	72,000	66,000[74]	psi
Elongation in 2"	22	20	Percent
Carbon	0.30	0.28	Percent
Manganese	1.15	1.25	Percent
Phosphorous	0.045	0.04	Percent
Sulphur	0.05	0.05	Percent

Of the 95,000 feet of 30-inch pipe to be installed, 6,600 feet were to be supplied to the contractor as bare pipe. The pipe was to be supplied in stockpiles at the pipe wrapping plant in the Bechtel Corp. yard in Watson, California. Welding rods were specified as 5/32-inch Fleetweld No. 5 for stringer beads inside welds and tacking, 3/16-inch Shield arc No. 85 for succeeding passes on the 30 inch mains. The specifications required a minimum trench depth for 30inch pipe to be 60 inches. Minimum depth of cover in beds of creeks or drainage ditches and canals is specified as 30 inches.

Pipes with electric welded longitudinal seams were required to be lined up so that the longitudinal welds on the abutting lengths were staggered. "The welds shall be so placed as to be in the top quadrant of the installed sections and not less than 6 inches of the arc apart." When making angles in the pipe that are less than 20 degrees the contractor was to use mitered angle welds. A single ended miter was allowed up to 5 degrees. All mitered angles were required to be welded inside and out. All welded field joints were to be arc welded and all welders were to be thoroughly experienced pipeline welders. The specifications for welding required was that the faces of all welds be convex with a reinforcing such that the overall weld thickness is at least greater than the plate thickness. No undercutting of the welds was acceptable. Each welder was to be assigned a number that was to be punched on each weld by the welder for future identification. The marks were to be located in the top quadrant of the pipe and within 2-inches of the longitudinal seam.

Under "weld testing" the specifications required that the girth welds develop the full tensile strength of the pipe material. Tensile testing of a weld coupon was to result in a break in the parent material or at a value of 72,000 psi. The specification called for approximately 10% of the welds to be radiographed and held to a predetermined set of standards prepared and agreed to by the Contractors welding engineer, the company's engineer of gas construction and representatives of the company making the radiographic tests.

[72] Fourth Edition "Specification for High Test Line Pipe" Properties of X52 pipe; Issued February 1954
[73] This appears as a Minimum and not a Maximum in the API standard. The PG&E specification calls for a Maximum value.
[74] This appears as a Minimum and not a Maximum in the API standard. The PG&E specification calls for a Maximum value.

1956 Project and Materials Records

The 1956 relocation work on segment 180 was performed by the PG&E construction group and the documentation provided to the NTSB, from PG&E, includes approximately 300 pages of journal vouchers, material transfers, paving receipts and various other cost accounting sheets. The 1956 documentation does not include PG&E's specifications, purchase orders for new pipe, inspection records, foreman's log books, as-built drawings, or radiography reports. No records for post installation pipeline testing were provided other than an invoice and accounting entry that showed the purchase of two-cases of bar-soap[75] "for testing." PG&E stated that in-house welders using test procedures from a 1956 PG&E book of standards completed the girth welds. PG&E was unable to locate a copy of the 1956 standards but stated that 1961 and later editions are available.

Based on the information provided by PG&E for the 1956 relocation of segment 180, the work occurred from June through September of 1956 under job GM136471 and work order 4017-G. In a letter attached to the project documentation the work was to "relocate a section (30inch pipe) of gas transmission main Line 132 in Crestmoor Park Subdivision, unit #7 (previously, Mills Estate Property) which conflicts with the proposed street grading and was subject to lower street crossing at the company expense by right of way agreement[76]."

The PG&E document titled "Estimate for Appropriation Work order," for project GM136471 dated June 21, 1956 showed that 1,900 feet of pipe were to be installed, 1,400 feet of 1948, 30 inch pipe was to be removed and salvaged,[77] and 450 feet of 1948, 30inch transmission pipeline was to be abandoned in place. An additional copy of this work order included corrected handwritten pipe lengths in the margin. According to PG&E the handwritten values are as-built information for the actual lengths of pipe installed. The actual lengths that appear on the work order are 1,851 feet installed, 687 feet abandoned, and 1,248 feet removed and salvaged[78]. The total abandoned plus salvaged pipe total 1,930 feet. The only project drawing[79] provided from PG&E, dated 1956, shows the relocated section would tie-in to the existing Line 132, 120 feet north of Claremont Drive and 14 feet south of San Bruno Avenue. The construction print identifies 1,900 feet of 30 inch pipe to be installed and shows two areas for abandoning pipe and two areas for salvaging pipe along the original 30inch length. The new Line 132 routing is shown 10feet off of the east side of Glenview drive following the offset in the street at Earl Avenue. Depth of cover appears as a general note on the drawing to be maintained at 24 inches except at San Bruno Avenue.

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[75] Bar Soap was shipped on July 9, 1956 according to the invoice (page 167 of IR 010-005). The reference to Bar Soap is mentioned as "for testing" appears on page 168 of NTSB IR 010-005. This would have been used to test the girth or circumferential welds made in the field.
[76] Contained on page 23 of NTSB IR 010-005
[77] Contained on page 21 of "GM No 136471_Brisbane 60 PO for Line 132" NTSB IR 010_005. The document reads 1,400 feet under the Estimate of Cost Items but reads 1,450 feet under the section to be abandoned or replaced.
[78] Contained on page 4 of "GM No 136471_Brisbane 60 PO for Line 132" NTSB IR 010_005.
[79] Exhibit 2AQ: 1956 Drawings of Relocation of Line 132 GM136471

Material Procurement

No new material purchase orders appeared for pipe used in the 1956 relocation work. The PG&E project GM136471 Line 132 1956 relocation project documentation includes two PG&E material procurement orders:

- Material procurement order (#26166) dated June 12, 1956 for 1,186 feet of material code 01-1373 pipe with the description "…30-inch O.D., D.W. 375 wall" and 23 feet – 4 inches of material code 01-1485 pipe with a description of "…30-inch O.D., Bare 375 wall".

- Material procurement order (#21315) dated June 12, 1956 requests 73 feet of "Pipe steel 30-inch bare" with a material code of 01-1485.

Credit Requisitions for Salvaged Pipe

Included in the 1956 project are seven PG&E credit requisitions, for materials returned to the warehouse, marked as "salvaged."

- Number 2840100 - July 16, 1956 reads 1,080 lbs with a material code entry of "52-1003" and description of "[illegible][80] scrap from 9-ft 30-inch bare pipe."

- Number 2840142 - July 23, 1956 reads 315 feet of material code entry "01-1373" and a description of "Pipe, DW 30-inch gas transmission."

- Number 2737360 – September 5, 1956 reads 272 feet with a material code of "01-1664" and a description of "Pipe steel B.E. 30-inch x .375-inch wall double wrapped (bad wrap) (9pcs)." Written on the requisition is "clean and recondition."

- Number 2858276 – September 7, 1956 reads 45 feet with a material code of "01-1373" and a description of "Pipe steel D.W. 30-inch."

- Number 2862165 – September 24, 1956 reads 1,510 lbs with a material code of "52-1003" and description "[illegible][81] from 13-feet of 30-inch pipe."
- Number 2858307 – October 3, 1956 reads 64-feet of material code "01-1373" and description of "Pipe, steel, Bare 30-inch."

[80] The illegible portion appears to read as W.I. Other documentation with this same material code appeared in the 1961 construction documents with a written description of Wrought Iron. According to PG&E this designates the material is scrap.
[81] The illegible portion appears to read as W.I. Other documentation with this same material code appeared in the 1961 construction documents with a written description of Wrought Iron. According to PG&E this designates the material is scrap.

- Number 3116195 – March 25-1957 reads 415 feet[82] with a description of "30-inch Trans. Main installed GM 98015." The worksheet also contains the word "Abandoned" in brackets.

Salvaging Operations

Based on documentation from project GM136471, the existing pipeline salvaging operations occurred during August and September 1956. A PG&E form dated September 15, 1956[83] indicates that a crane was rented for pipe salvage between August 28 and September 4, 1956. A transportation invoice[84] that was included in the 1956 relocation project documentation shows that nine-pieces of 30 inch pipe were transported on August 31, 1956 by PG&E from San Bruno to PG&E's Decoto yard facility.[85] A freight bill is also shown for nine-pieces of 30 inch pipe in 31-foot lengths with a destination of Richmond, California[86] on September 4, 1956.[87]

Material Transfers

Four documents entitled "PG&E Combined Shipping Notice and Transfer" from the 1956 Line 132 relocation indicates the movement of material from one project to another:

- Number 04864 – October 11, 1956 shows a material transfer from the 1956 relocation project (GM136471) to project 130004. The description is "Pipe, steel, gas line, DW, 30" O.D. x .375 wall." Noted on this document is "Originally installed on GM98015 (1949). Salvaged on GM136471. Reused on GM130004. Salvaged pipe was hauled to Richmond for wrapping by Warren Transportation. After wrapping, it was hauled to project site near Morgan Hill…" The quantity is 487feet and 9inches with a material code of 01-9991.

- Number 04865 – October 11, 1956 shows a material transfer from the 1956 relocation project (GM136471) to project GM134616. The description is "Pipe, steel, gas line, DW, 30-inch O.D. x .375 wall." The quantity is 61ft and 8 inches with a material code of 01-9991.

- Number 08620 – October 17, 1956 shows a material transfer from the relocation project (GM136471) to project GM136774. The quantity is 158 feet with a material code of 01-9991.

[82] This credit requisition has a quantity of 687 feet marked out with 415 feet handwritten below it
[83] Page 192 of "GM No 136471_Brisbane 60 PO for Line 132" NTSB IR 010_005.
[84] Page 65 of "GM No 136471_Brisbane 60 PO for Line 132" NTSB IR 010_005; Invoice number 6-3673 from Warren Transportation
[85] PG&E had a materials warehouse located in Decoto Yard in Union city
[86] PG&E has indicated that Bituminous Products was located in Richmond California and was a coating facility
[87] Page 146 of "GM No 136471_Brisbane 60 PO for Line 132" NTSB IR 010_005

- Number 09680 – March 19, 1957 shows a material transfer from the relocation project (GM136471) back to itself. The quantity is 90 feet with a material code of 01-9991.

Documentation provided by PG&E on a separate Line 132 capital project, project GM130004, occurring in the same time frame as the relocation project, shows that material was transferred from project GM130004 to the Line 132 relocation project GM136471. The following statement was noted in a project memo on GM130004 dated June 26, 1956[88], referencing project GM130004:

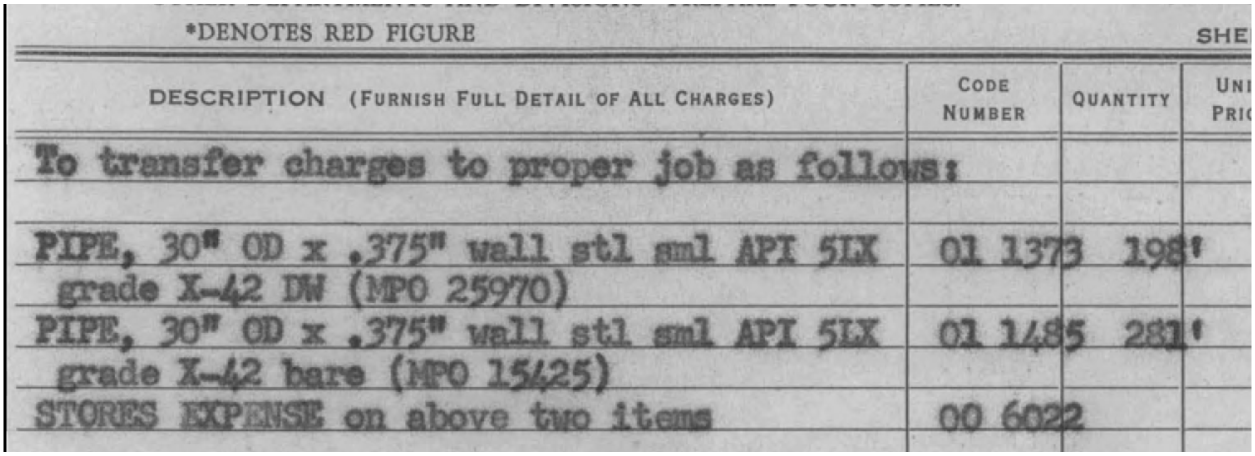
"281 feet of pipe ordered on MP 15425 and 198 feet of pipe ordered on B/O MPO 25970 was used on WO 4017G, Location 132, Account 1124 on July 20 1956. It will be in order for you to make the necessary transfer of costs of pipe and other related costs. It will also be necessary to recorder 30-inch pipe for GM130004…"

PG&E has stated that permitting delays on project GM130004 delayed its completion date to October of 1956. Material transfer number 04864 shows a total of 479 feet of pipe transferred from the relocation project to project GM130004 on October 11, 1956. The transfer of material is captured on journal voucher number 174143 from the 1956 relocation project dated September of 1956.[89] The voucher documents the assignment of the material and reconditioning costs to project GM130004. PG&E has identified[90] this journal voucher as the source of the information that was erroneously used to populate the material of Line 132, segment 180 on the first survey sheets. In the absence of pre-existing survey sheets, job packages with original design drawings and as-built drawings are also used as source documents to when survey sheets are not available.[91]

Material Codes

Journal voucher 174143 referenced material codes 01-1373 and 01-1485 for the transfer of material between GM136471 and GM130004 (Figure 2). According to PG&E, the material codes that appeared on the journal voucher were not consistent with the text that appears in description column. This inconsistency was based on the material code entries of a 1967 materials code listing for the 01-1373 and 01-1485 numbers that appeared on the journal voucher. The description line includes the words "sml" and "X-42" which PG&E has indicated is incorrect when compared to the material codes. According to PG&E, the "sml" was the source of the seamless material designation appearing in the Line 132 survey sheets. When examining the material purchase orders[92] 25970 and 15425, referenced by the journal voucher, they each include similar descriptions that read "Pipe, 30-inch, O.D. steel *seamless*, API 5LX grade *X-42* 0.375…"

[88] NTSB_035-009 – Project 130004 Excerpts.
[89] Page58 of "GM No 136471_Brisbane 60 PO for Line 132" NTSB IR 010_005
[90] NTSB IR 035_018 How was pipe reconditioned
[91] NTSB IR 010-002; What is source of GIS information
[92] NTSB_035-009 – Project 130004 Excerpts.



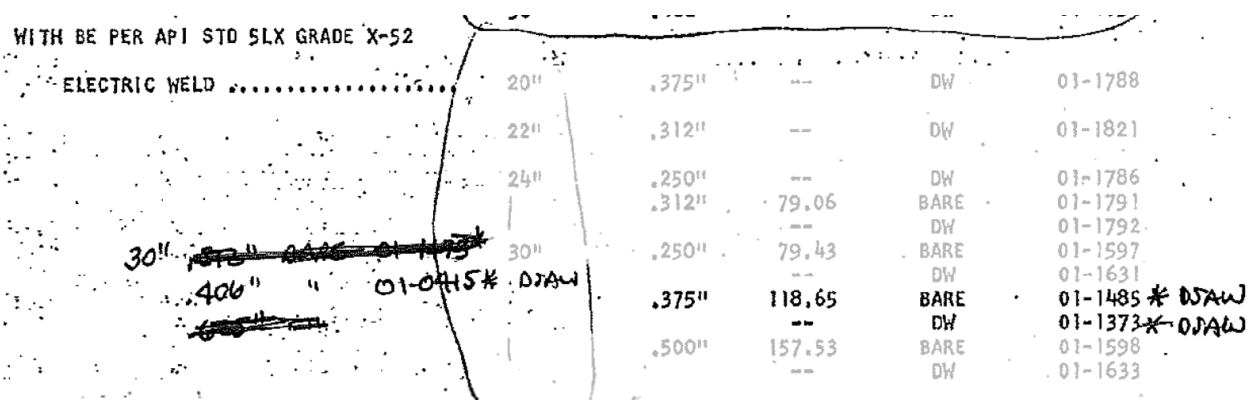
*DENOTES RED FIGURE SHE

DESCRIPTION (FURNISH FULL DETAIL OF ALL CHARGES)	CODE NUMBER	QUANTITY	UNI PRI
To transfer charges to proper job as follows:			
PIPE, 30" OD x .375" wall stl sml API 5LX grade X-42 DW (MPO 25970)	01 1373	198'	
PIPE, 30" OD x .375" wall stl sml API 5LX grade X-42 bare (MPO 15425)	01 1485	281'	
STORES EXPENSE on above two items	00 6022		

Figure 3: Journal Voucher from the 1956 Line 132 Relocation (GM136471)

PG&E was not able to locate a materials code sheet from 1948 or 1956 but has provided material code listings from 1967 and 1986. According to PG&E the material numbers are generally not re-used because of the potential for confusion. As an example, the materials codes 01-1485 and 01-1373[93] are the same on both the 1967 and 1986 material code worksheets.

In the 1967 materials code worksheet described code 01-1485 as electrically welded per API Std. 5LX Grade X-52 bare pipe, 30inch with 0.375 inch wall thickness with beveled ends (BE). The 01-1373 material code description identifies electrically welded per 30inch API Std. 5LX Grade X-52, 30inch with 0.375 inch wall thickness, double wrapped (DW) and beveled ends. Both of these material codes includes asterisks with the handwritten word "DSAW" to indicate that the weld is a double submerged arc per the 1986 material code designation (Figure 4).



WITH BE PER API STD 5LX GRADE X-52

ELECTRIC WELD

30" ~~.375" BARE 01-1485~~ *

.406" " 01-0415* DSAW

20"	.375"	--	DW	01-1788
22"	.312"	--	DW	01-1821
24"	.250"	--	DW	01-1786
	.312"	79.06	BARE	01-1791
		--	DW	01-1792
30"	.250"	79.43	BARE	01-1597
		--	DW	01-1631
	.375"	118.65	BARE	01-1485 * DSAW
		--	DW	01-1373 * DSAW
	.500"	157.53	BARE	01-1598
		--	DW	01-1633

Figure 4: Excerpt from the PG&E 1967 Materials Code Listing

[93] PG&E noted that this material code has been retired since the company no longer orders double wrapped pipe.

The options for seamless pipe in the 1967 material codes list appeared in Grade B, X-42 and X-52 and multiple diameters that were up to a maximum of 16 inches. Seamless and API STD 5LX Grade X-52 material codes were available as "New bare and double wrapped" only. For API Grade X-42 material, the 1967 material code sheet included options for either "new bare and double wrapped" or "reconditioned bare and double wrapped." PG&E has not identified specifications for reconditioning pipe for the applicable period (1948-1956) [94].

PG&E Statement on Source of 1956 Relocation Pipe

PG&E asserts that based on counts of pipe lengths or tallies from the period; there was sufficient pipe on hand in 1956 to construct the Line 132 relocation. Based on the pipe tallies, 320,065 feet of 30 inch pipe was procured from Consolidated Western, 1,699 feet from Basalt-Kaiser, and 320 feet from Pacific Pipe between 1947 and 1957. When PG&E compared the 322,084 feet of total available pipe to project requirements over the same period there was sufficient pipe to cover those project needs.[95] PG&E stated that the 1956 project would have been completed from pipe in supply at the yard from previous purchases and that no new pipe would have been purchased. PG&E has also stated that casing was stored at the same yard as pipe and that it is conceivable to say that casing may have been used.

Although PG&E has not provided solid documentation to support the origins of the 1956 pipe and short spool pieces found in segment 180, they stated that it is their belief that the pipe used on the 1956 relocation of Line 132 was most likely manufactured by Consolidated Western in years 1948, 1949 or 1953. PG&E cites characteristics of the pipe that appear in the NTSB Materials lab factual report,[96] figures 19a and figure 45 as well as the painted numbers on the inside surfaces of the pipe that appear in figure 22 as indicators of the pipe's origin. PG&E stated that the stamping located on pup number 4, north of the initiating fracture, and identified in figure 19a of the NTSB material lab report is consistent with the process described in the ASME Research Report CRTD-Vol.43[97] "History of Line Pipe Manufacturing in North America" under the section of Seam Weld and Other Features. Based on the description of the stamping process described in the passage in this document, PG&E states that the brand stamp in figure 19a of the NTSB Materials lab report, while not at 180 degrees from the seam, is consistent with the brand stamping used by Consolidated Western when manufacturing pipe.

[94] NTSB IR 038-001 How was pipe reconditioned.
[95] Refer to pipe tallies of NTSB IR 035-016 Amended.
[96] Exhibit 3A in the NTSB docket
[97] ASME Research Report CRTD-Vol 43 "History of Line Pipe manufacturing in North America",Pgs8-2 & 8-3 of Seam Welds and Other OD Physical Features

The passage that appears in the ASME document reads, "In addition, when most CW[98] pipe skelp was rolled on skelp mills it was common to use an engraved roll in the last stand of the mill, resulting in a brand located 180 degrees from the weld. In both the lap weld and CW cases, the name or brand recurred at an interval reflecting the diameter of the engraved roll." The NTSB has not identified any definitive source of the stamp and the Consolidated Western invoices indicate that at least some of the pipe supplied in 1948 was made from plate not skelp. The stamp identified in the NTSB materials lab report is located 90 degrees from the longitudinal seam and not 180 degrees.

PG&E also references Figure 45 of the NTSB materials lab report, stating, "Only the outside seam weld (OD bead) is seen to exist. There is no evidence of an internal seam weld (ID[99] bead). Assuming that the manufacturing process called for DSAW line pipe, this suggests a manufacturing sequence where the outside seam weld was intended to be welded first, followed by the inside seam weld." Using the assumption that the incomplete weld of the materials report represents a DSAW process, PG&E asserts that, based on a historical review of the manufacturing process of DSAW pipe, only two pipe manufacturers were known to have welded the outside diameter bead first on a double submerged arc welded pipe. PG&E further identified through purchasing records that Consolidated Western was the only one out of these two manufacturers supplying pipe to the company at the time. The basis for the assumption of a double submerged arc welding process and the historical review performed by PG&E, that showed which mills welded the outside seam first, were not supplied to the NTSB.

In working to identify the source of the 1956 pipe, PG&E has performed some limited internal camera inspections of Line 132 to determine joint length and painted joint or serial numbers on the internal surfaces of the pipe wall. PG&E used the internal camera inspection results and the photograph from the NTSB Materials lab report (figure 22a &b) and compared them against other sources of documentation to identify the source of the material. Based on this work, PG&E identified Line 153, Line 131 and the original Line 132 projects as being possible sources of the 1956 relocation pipe. PG&E stated that pipe on these three projects was manufactured at the Consolidated Western Pipe Maywood California plant until May 1949, and afterwards at its South San Francisco plant.

As a result of an interview conducted by the NTSB, a former mechanical engineer working at the South San Francisco Consolidated Western plant described the process used for manufacturing pipe through 1950 when he left the company. His description of the process was consistent with single submerged arc welding. The mechanical engineer stated: "all of the pipe that we manufactured was only welded on the outside with complete penetration." The engineer further described that all pipe from the South San Francisco plant was rolled from plate through rollers and then hydraulically expanded to its final diameter. The welds were not x-rayed but samples were cut from various pipe segments and sent out for tensile and bend testing. He stated that not every pipe was given a hydrostatic test but the pipe that failed was never reused, and failed pipe was cut

[98] CW in this passage is referring to a Continuously Welded process
[99] Inside Diameter

up and sold as scrap. The engineer further stated that joining of multiple pipe segments was not allowed by the company. He described how the ends each pipe were manually welded by certified welders and the crown was ground down flush to the pipe wall not more than approximately 6inches from the end of the pipe. He said the facility would never grind the entire length of the seam weld.

According to PG&E statements, the company researched into the source of the Line 132 relocation pipe and identified the following three projects:

- Line 153 constructed in 1949 on project GM 100099: A PG&E 1949 Moody engineering inspection report[100] describes a serial number format used by Consolidated Western's manufacturing process for pipe purchased on PO 7R66858 for the Line 153 project. PG&E has stated that the format described in the report is consistent with the painted number "1299?-12?" documented in the NTSB Materials lab report (figure 22). PG&E has indicated that their post-accident camera inspection revealed more examples of painted numbers on Line 132 that matched the format in the Moody report.

- Line 131 constructed in 1954 on project GM 123902: PG&E has identified joint numbers on Line 132 from the post-accident camera inspections that match pipe tally sheets from a second Consolidated Western purchase in 1953. According to PG&E documentation for the construction of Line 131 shows pipe being transported from a coating contractor in Richmond, California to a warehouse in Emeryville, California. PG&E states that the pipe tally sheets for joint number and the length of the joints exactly match the joint numbers and footages documented in the camera inspection.

- Line 132 from 1948 on project GM 98015: According to PG&E the original Line 132 installation resulted in excess pipe that was moved to various projects and placed into the materials warehousing system. PG&E states that at least one of the joint numbers found during a camera inspection of pipe segments near the rupture location (segments 181, 182.6, 182.9) matches pipe tally sheets with joint numbers and footages of all joints installed on the original project. PG&E believes that this finding supports the statement that at least some of the pipe installed on the 1956 Line 132 relocation project was originally purchased in 1948 under project GM 98015.

[100] Materials Lab - Attachment 3 - Moody Engineering Co. "Inspection Order 7R-81743, Purchase Order 7R-66858 consolidated Western Steel corp., 30" O.D. x 3/8" (NTSB 035-002).

[NTSB Exhibit 2AQ: 1956 Drawings of Relocation of Line 132 GM136471]
[Exhibit 2-DV 1956 Relocation Source of Pipe Material][101]
[NTSB Request 010-002-What is Source of GIS Information]
[NTSB_038-001 How was pipe reconditioned]
[Exhibit 2AZ: NTSB_011-010 PG&E 1956 Journal Voucher, Material Codes and Pipeline Survey Sheet]
[PG&E Construction Specs for 1948 (GM98015) Project - Crystal Springs to Martin Stn 30_24 20]
[Exhibit 2P – PG&E Line 132 Survey Sheets]
[Exhibit 3A - NTSB Materials lab report]
[Exhibit 3B - NTSB Materials lab report]
[NTSB_035-009 – Project 130004 Excerpts]
[Exhibit 2DV – 1956 Relocation Source of Pipe Material]
[Materials Lab - Attachment 3 - Moody Engineering Co. "Inspection Order 7R-81743, Purchase Order 7R-66858, Consolidated Western Steel Corp., 30" O.D. x 3/8" Wall Line Pipe."][102]
[Exhibit 2AF: NTSB 035-016 – Who Manufactured the Pipe at the Accident Site and the Manufacturing Process]
[NTSB_010-005 - As-Built information from 1956 / relocation GM No 136471_Brisbane 60 PO for Line 132]
[Exhibit 2BB: Excerpts from NTSB_018-002 1948 Construction of Line 132]
[Interview Transcript of Pipe Manufacturer Employee (Massaglia)]
NTSB 018-002, GMG98015 - Estimate - Progress Reports - Job Stories

S. PG&E Lines 101 and 109 History

PG&E Line 101 was originally installed by contractors in 1929 and portions have been replaced over the years by both contractors and PG&E crews. The majority of Line 101 has been replaced.

Line 101 begins at mile point 0 and ends at mile point 51.50. The pipe diameter varies from 20 inch to 36 inch and wall thickness and pipe grade range from 0.576 wall X-60 to 0.281 wall Grade B. The pipeline has been replaced in sections over a number of years. Examples include:

- 3000 feet of 20 inch 0.312 wall Grade B replaced in 1952 beginning at mile point 27.79 to mile point 27.91
- 15427 feet of 24 inch 0.375 wall X-60 replaced in 1986 beginning at mile point 28.83 to 31.16.

[101] NTSB_035-009 – Project 130004 Excerpts
[102] Materials Lab - Attachment 3 - Moody Engineering Co. "Inspection Order 7R-81743, Purchase Order 7R-66858 consolidated Western Steel corp., 30" O.D. x 3/8" (NTSB IR_035-002).

- 12952 feet of 36 inch 0.350 wall X-52 replaced in 1965 at mile point 5.03 to 7.22.
- 2229 feet of 20 inch 0.312 wall X-42 replaced in 1955 at mile point 14.52 to 14.78
- 3661 feet of 34 inch 0.344 wall X-52 replaced in 1973 at mile point 10.53 to 11.25
- 600 feet of 30 inch 0.312 wall X-42 replaced in 1959 at mile point 10.40 to 10.52

Line 109 was originally installed by contractors in 1936 and portions of it have been replaced by PG&E crews and contractors as well. Line 109 pipe diameter ranges from 22 inch to 30 inch and 0.312 to 0.375 inch wall and grade B to X-60 and unknown. Line 109 runs from mile point 0 to mile point 52.71. This pipeline like Line 101 has also been replaced in sections over the years. Examples include:

- 2131 feet of 30 inch 0.375 wall X-52 replaced in 1964 at mile point 30.11
- 3 feet of 22 inch 0.312 wall X-52 replaced in 1967 at mile point 32.3673
- 199 feet of 22 inch 0.312 wall unknown grade replaced in 1964 at mile point 29.56
- 925 feet of 30 inch 0.3125 wall X-52 replaced in 1967 at mile point 33.08

Both lines are under cathodic protection using a rectifier system that is read annually and PG&E takes pipe-to-soil potential readings every other month.

[NTSB Data Response 055-001, Answer to what lines were installed by PG&E?]

T. Outside Force (Natural and Man-made)

1) Seismic/Soil Movement

i) PG&E Study

As a part of 1985 gas pipeline replacement program, PG&E planned to replace portions of Lines 109 and 132 in the San Francisco Peninsula. PG&E conducted a seismic study along the existing and preferred new routes for Lines 109 and Line 132, and a report was issued on November 1, 1992. PG&E stated that the 1992 study included "travel along the existing and preferred new routes using aerial reconnaissance from helicopters, visual inspections from motor vehicles, and site visits on foot." PG&E also reviewed written eyewitness accounts of the 1906 earthquake effects to assess the characteristics of surface faulting and ground deformation, reviewed pertinent published and unpublished maps, studied relevant literature, and conducted geologic mapping of key sites along Lines 109 and 132. Locations where Lines 109 and 132 crossed the San Andreas Fault were considered most vulnerable and these crossings were eliminated by the rerouting.

The PG&E study determined that liquefaction and ground settlement were not a hazard to Lines 109 and 132 through San Bruno. San Andreas Fault was identified as the greatest seismic hazard to PG&E pipelines in San Francisco Peninsula. The sections replaced in1993-1994 included Line 109 running through; Daly City, South San Francisco, and San Bruno along Skyline Boulevard and in the San Francisco watershed area. The section of Line 132 replaced was located near Claremont Drive and along Skyline Drive and Skyline Boulevard in the City of San Bruno and in the San Francisco watershed area. A small section of Line 132 was replaced at the intersection of Glenview Drive and Plymouth Way. These replaced sections of Lines 109 and 132 each had crossed the San Andreas Fault in 2 locations along Skyline Boulevard. The replacement lines were re-routed to run parallel to and further from the San Andreas Fault to the next ridgeline to minimize possible earthquake damage. The November 1992 study determined the Segment 180 was located in "an area of low to moderate hazard near Glenview Drive south of its intersection with Earl Avenue." Consequently no replacement was proposed for this line.

RMP-04 developed in 2001, covers assessment of risks due to seismic activity and damage to the PG&E pipeline system due to the ground movement threats. The factors used in the relative ranking include: shaking intensity, fault crossing hazards, liquefaction potential, seismic triggered landslide potential, girth weld age, and mitigation status. Furthermore, segment 180 of Line 132 does not cross the San Andreas Fault and the soil around the Line 132, Segment 180 was not considered to be unstable or normally subject to liquefaction by PG&E. The ground movement threat ranking of segment 180 of Line 132 under RMP-04 was 0 in 2009 and 0 in 2010.

On February 2, 2011 Tele-Rilevamento Europa (TRE) Canada submitted to PG&E its final report detailing the SqueeSAR[103] analysis of ground displacement over time from May of 1992 to August of 2010 for the Earl Avenue and Glenview Drive area of San Bruno, California. SqueeSAR plots data points using radar and multiple satellite data onto a selected area and through historical data and photography can track any significant movement of an area of ground. The system focuses on 4 points north, south, east and west of the target and follows their reference points over time to determine any movement. It can also be used to track seasonal variations. TRE data indicated the fill beneath the Earl

[103] SqueeSAR is a company owned by TRE Canada that develops reference points on an area to be examined for earth movement and by use of historical photographs from multiple satellites follows these point over a period of time and can track movements, seismic or otherwise, to within 1 mm/year with an accuracy of plus or minus 5 mm.

Avenue and Glenview Drive area of San Bruno did not experience any significant vertical movement during this period.

[Geologic Hazards Report for Lines 109 and 132 in San Bruno]
[PG&E Presentation to San Bruno Planning Commission]
[Environmental Analysis – Natural Gas transmission Lines 109 and 132]
[NTSB_008-007 Provide Seismic Map overlay from GIS]
[NTSB Data Request #035-004, Earthquake Engineering Evaluation Question]
[NTSB Data Request #068-001, Line 132 Risk calculation Figures for 2009 & 2010]
[NTSB Data Request #035-005, How do Seismic Events Relate to Integrity Management]
[NTSB Data Request 054-008 Attachment - TRE Report]

ii) City Of San Bruno:

The City of San Bruno's map detailing all water leaks in the San Bruno area from 2000 to 2007 indicated no water leaks within a block of Glenview Drive and Earl Avenue.

The City of San Bruno commissioned a Geologic and Geotechnical consultant to conduct an investigation for the Crestmoor Canyon area for rain induced water damage and the report was delivered on March 2008. The report found nine priority sites where water discharges had caused soil erosion and damage to the slope. However, none of these areas were in the vicinity of Glenview Drive and Earl Avenue.

The major problem identified to be soil erosion and instability caused by seasons of unusually heavy rainfall in areas where runoff was concentrated upon canyon slopes. The report suggests the city to improve its monitoring of these areas.

The report mapped 3 earthquake faults adjacent to or extending through the canyon limits. The Sierra fault is potentially active but is located at the far eastern end of the canyon study area while the accident area is on the western side. Two other fault traces have been mapped along the western portion of the canyon and are likely associated with past movement along the San Andreas Fault zone, with the master trace located immediately east and about parallel to Skyline Boulevard.

The City of San Bruno also produced a log of the repairs necessitated by the Loma Prieta earthquake. There was one leak on a 4 inch water main; another leak required hauling away of mud surrounding a water main, and one gas regulator leak. These leaks were on the east edge of the city at least 5 miles from the accident pipeline.

[San Bruno Water Leak Location Map from 2000-2007]
[Crestmoor Canyon Geotechnical Investigation Report]
[Water Utilities Division Work Order of 1989 for Sixth Street]

iii) American Lifelines Alliance

The American Lifelines Alliance published "Guidelines for the Design of Buried Steel Pipe" in July 2001. The document provides formulas for calculating seismic stresses and has several case studies where the results were calculated and a discussion of how these theoretical calculated stresses can be addressed through sound engineering principle to mitigate the threats. It also provides evidence that for steel pipe with modern post 1945 welding, assuming the welding is in accordance with ASME B-31.8 and the pipeline are not perpendicular to the fault line the performance of the pipe in earthquake systems is good. This same document includes equations for calculating the live loads on pipe that result from concentrated forces acting through soil. The live load pressures are translated into a deformation and through wall bending stress for a given pipe diameter and soil modulus.

[Guidelines for the Design of Buried Steel Pipe]

iv) US Geologic Survey:

After the 1989 Loma Prieta earthquake, PG&E had three gas line failures, all in the San Francisco Marina District, according to a study conducted by Donald Ballentine of MMI engineering for the US Geological Survey.[104]

[The Shake-Out Scenario - Supplemental Study for the US Geological Survey]
[Shaking Intensity of San Bruno Area Map by the US Geological Survey]

2) Pipe Bursting 2008- Sewer Replacement

Drawings provided by the City of San Bruno shows that the original installation of the sanitary sewer line in the Crestmoor subdivision was 1958. These drawings clearly noted the location and profile of the PG&E's 30 inch natural gas transmission line running along Glenview Drive intersected by a 6inch diameter sewer line that travels east along the center of Earl Avenue. An elevation or section view on the 1958 drawing shows a bend in the 30 inch transmission line at Earl Avenue[105]. The original 6inch vitreous clay sewer line remained in service until it was replaced in June of 2008 with a 10 inch diameter line.

[104] "The Shake Out Scenario Supplemental Study Oil and Gas Pipelines" by Donald Ballentine of MMI Engineering May 2008, prepared for US Geological Survey and California Geological Survey
[105] Refer to the Crestmoor Park No 7 improvement Plans for more detail.

The work to upsize the sewer line was issued to the contractor as a change order specifying approximately 300 feet of sewer pipe be upsized from 6 inch vitreous clay pipe using only a trenchless pipe bursting method. The 10 inch line was installed in the same location as the original line.

Pneumatic pipe bursting is a trenchless method of pipe replacement that uses a compressor, bursting head, cable and winch assembly. In order to install the new line two pits are required; an insertion pit[106] and an exit pit[107]. The contractor introduced the bursting head into the existing clay pipe through an insertion pit located 300 feet upstream on Earl Avenue and west of exit pit. The bursting head was guided and pulled to the east through the existing clay pipe by a cable and pulley assembly located at an exit pit on Glenview Drive. The process was repeated for another portion of the project using the same insertion pit and another exit pit located further west on Earl Avenue. The pulling of the bursting head and new pipe was accomplished using a winch located above the exit pit at street level. While the bursting head was pulled through the existing clay pipe, compressed air was used to power the hammer on the burst head, breaking the clay pipe and propelling the head forward.[108] The new 10-inch replacement pipe was connected to the back end of the bursting head pulled through the void created by the displaced clay pipe. According to the wastewater services manager of the wastewater division of the city of San Bruno the upsizing of the sewer line was required due to insufficient capacity on the sanitary sewer system. This capacity issue was an infiltration and inflow problem from ground water or rainwater entering the sanitary sewer lines from manholes or joints between sections of the pipe. The city identified no other project or maintenance work on the sewer lines where Earl Avenue and Glenview drive meet.

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[106] Normally a long slender trench or pit to allow the pipe to bend as it is introduced into the ground.

[107] Typically a square pit enlarged around an existing manhole location to allow for the cable, pulley block and bursting head removal.

[108] The bursting head is tapered with an outer diameter greater than the inner diameter of the clay pipe

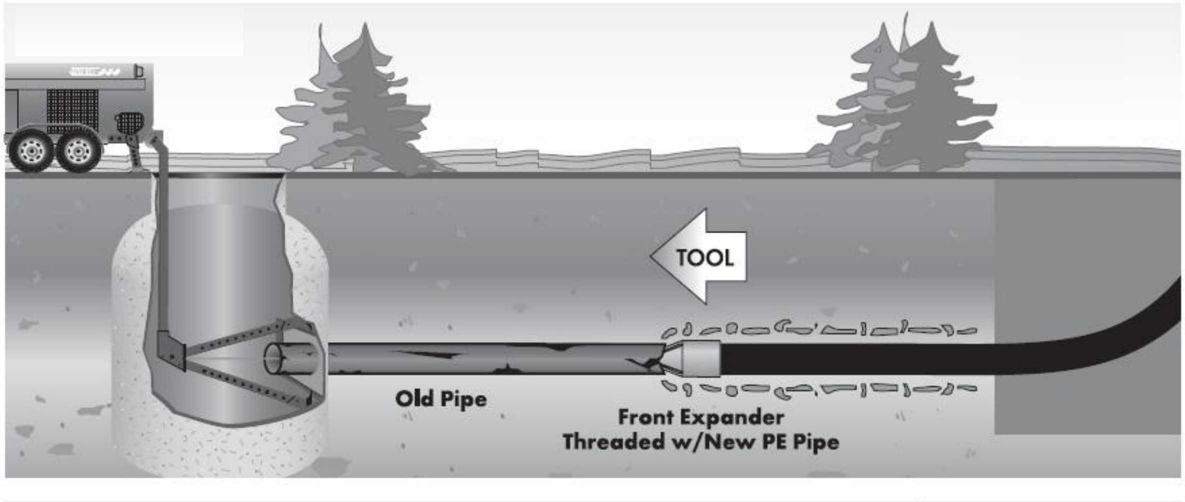


Figure 5: Typical Pipe Bursting with Winch and Exit Pit[109]

2008 Sanitary Sewer Line Installation

Cell phone records showed the contractor notifying the Underground Service Alert[110] (USA) of the location of the planned sewer work on May 30, 2008. During NTSB interviews, the contractor's superintendent[111] stated that he received a call back from PG&E notifying him of the presence of a high pressure transmission line in the vicinity of the work and that PG&E would have a representative on site when working close to the main. The superintendent received instruction to call the PG&E inspector within 48 hours of when the digging near the transmission main would occur. Call records from the superintendent's cell phone showed a call placed to the PG&E inspector on June 3, 2008. PG&E indicated, during interviews of the inspector, that they have a company policy that states all transmission mains will have a PG&E inspector watching when contractors are using heavy equipment within 5 feet of a transmission lines. This policy offers additional protection to the transmission mains but does not apply to distribution lines. The PG&E inspector is not the same person that marks and locates the gas line buts acts only as an observer. According to statements from PG&E, the inspector was not an engineer or trained to make technical evaluations of work performed near the transmission pipe.

[109] TT-Technologies "A Guide to Pneumatic Pipe Bursting"
[110] Underground service alert is a call-before-dig program that contacts local utilities to conduct line locating and prevent potential damage to utility services
[111] The job superintendent was also the vice president and half owner of the contracting company.

The foreman stated that the PG&E inspector first showed up at the construction site on Friday, June 6, 2008. The contractor's foreman was a full time employee of the company with over 20 years experience. According to interview statements to the NTSB, from the contractor's foreman, the crew was digging the insertion pit and removing the manhole for the exit pit as well as fusing the polyethylene pipe on Friday, June 6, 2008; preparing for the pipe bursting on Monday.

The PG&E inspector was a gas mechanic who stated in the NTSB interviews that he had performed numerous inspections for stand-by calls. According to statements from the foreman, the PG&E inspector stopped by the job site on Friday, June 6, 2008 to find out when the construction crew would be crossing the transmission main. The foreman said that he asked the PG&E inspector to return on Monday for the excavation of the gas line. The PG&E inspector testified that when he arrived on Monday, the contractor had removed the top layer of asphalt and had employees hand digging around the pipe to locate the transmission main. The contractor's superintendent stated that the PG&E inspector was onsite during backhoe operations around the transmission line and that no contact was made to the pipe. Hand digging was performed around the pipe after the asphalt was removed. The PG&E inspector stated that he watched the contractor dig on the west side of the line down to approximately midway on the pipe. The PG&E inspector said that he was made aware that the contractor was installing a sewer line and was told that the sewer was being installed using a pipe-bursting tool. The contractor's foreman stated that the PG&E inspector asked why the transmission main needed to be potholed and that the foreman let him know what the risk was with pipe bursting. Both the superintendent and foreman stated that the PG&E inspector had no questions regarding the method used to replace the sewer line and the PG&E inspector stated that he has seen pipe bursting before. The PG&E inspector stated that he told the foreman that he needs to see both sides of the pipe and at least 18 inches below the gas main. The inspector said he left instructions with the foreman to call him when they approached the gas main then left the site with the understanding that the contractor would have the line exposed that Wednesday[112].

The foreman cell phone records showed that a call was made on Tuesday, June 10, 2008 at approximately 2:00 pm to the PG&E inspector's cell phone. According to the interview statements from the foreman, he was calling to alert the inspector that the trench would be backfilled that day. The PG&E inspector stated that he had intended to check on the progress of the work on Tuesday but did not make it to the site until approximately 7:00 pm after being notified by his supervisor that he needed to return to the construction site. The PG&E inspector stated that by the time he arrived to the project site, the pipe bursting was already completed and the sewer line was connected. The inspector stated that he had used a tape measure to measure the top of pipe on the gas main and sewer main. The PG&E inspector's worksheet reads "clearance 6-inches" and just beneath that

[112] This is noted in handwriting on the standby request

there was a notation that read “30-inch main = 31-inches to top, 8-inch sewer 70-inch to top.” The difference in readings, minus the diameter of the 30-inch main gives a clearance of 9 inches. The inspector stated to the foreman that the requirement was for 12 inches clearance but that what he had measured was probably enough.

According to interview statements from the contractor’s foreman, the PG&E inspector made a phone call after measuring the clearance and came back 10 minutes later requesting that the contractor place wood between the pipes. According to the foreman, they placed one or two 2x6’s in the clearance between the pipes.[113] The PG&E inspector stated during the interviews that he only saw the west side of the transmission line exposed[114] and that after getting readings between the pipes the contractors broke up for the evening. The inspector mentioned that he did not recall making any phone call that evening but if he had, it would have probably been to talk to the load center alerting them that work was taking place on the line. The foreman stated that the PG&E inspector did not say anything regarding damage to the pipe. The PG&E inspector said that he had not noted coating damage or backhoe marks on the exterior of pipe.

The PG&E inspector stated that he did not witness the backfill and was never told what material would be used as backfill but that 6-inch of clean sand was required as per PG&E policy. The foreman indicated that he did not remember getting instructions from the PG&E employee regarding backfill but that they would normally use a class-2 base rock. PG&E had supplied the Standby Request worksheet used by the inspector when reviewing the contractors work. The request includes handwritten notes stating the clearance of the pipe was 9 inches and that the inspector was on-site on June 9 and June 10, 2008. The foreman’s logs indicate that the burst tool was set on Friday and that they fused the polyethylene pipe sections for the pull. On Monday, the work log showed that they started to pull pipe 300 feet of pipe at 1:00 pm and that the pipe came out 7 hours later. The logs showed that on Tuesday, 10laterals from residences were tied into the new sewer main and those connections backfilled. Wednesday and Thursday were spent backfilling and Friday, June 13, 2008 they were paving.

The job superintendent stated that prior to the work a visual inspection of the site soil conditions was performed prior to initiating the work and that the depth and diameter of the gas line were investigated; however, no engineering study was made to document soil conditions or water table. The superintendent estimated that the original pipe to pipe clearance between the gas line and sewer line was 12-inches. The superintendent stated that the equipment used for the pneumatic pipe bursting was a Hercules bursting head operating at 300 cfm[115] and 100-120 psig. Documentation provided by the contractor shows the equipment as

[113] These were laid on their sides making up a 3 inch stacked arrangement

[114] The PG&E inspector stated that he believed the line was excavated on both sides of the pipe but that there were steel plates installed over the trench preventing him from seeing the pipe on both sides.

[115] Cubic feet per minute

being a TT-Technologies Grundocrack tool[116] (340 strokes per minute). The contractor's foreman stated that the winch was a constant tension 10-ton unit located at the exit pit. The winch could be set for the desired tension and the foreman indicated that he recalled not exceeding 7-tons on the pull. Comments from a field representative for the manufacturer of the winch indicated that the constant tension winch load is typically applied in steps matching the resistance of the pull and is gradually increased to match the speed of the bursting head[117]. When the foreman was asked if he had performed this type of pipe bursting before under gas or water mains, he stated that "we cross a lot of water main and a lot of gas mains without any problems". The foreman indicated that he was certified 18 years ago on pipe-bursting through TT-Technologies.

Two pits were excavated for the pipe bursting approximately 300 feet apart with a sanitary sewer manhole removed to make the exit trench. The insertion trench was estimated by the contractor's superintendent and foreman as being anywhere from 22feet long by 2-feet wide to 24feet long and 2feet wide and by the foreman as 22feet long by 2feet. The foreman stated that he estimated the exit trench excavated for the pull-bar was 10feet by 8feet and the superintendent recalled the trench as being 8feet by 8feet. According to the foreman, the trench dug for the pull bar and pulley block was centered over the base of the manhole. The superintendent could not recall whether the exit pit was centered or offset from the manhole location.

The foreman stated that the exit trench included 1 inch by 12 inches wide aluminum sheet pile in the corners, driven two-ft into the earth. Two angled braces made contact with the shoring at the bottom of the trench. The foreman estimated that the distance between the manhole and gas main was approximately 12-feet.

Both the foreman and superintendent said that a trench had been hand-dug on both sides of; the natural gas main, exposing the main and sewer line. The foreman stated that this trench extended 7 feet to 8 feet on the east side of the gas main and 3 feet to 4 feet on the west side of the gas main and was 36 inches in width and 8 feet to 9 feet deep. Statements from the superintendent indicated that the trench over the gas main was 24 inches wide and 4 feet to 6 feet from the edge of the gas main in each direction. The contractor has submitted a response to the NTSB indicating that the backfill in the trenches was ¾ inch drain rock, per the job specifications, up to the sewer line pipe zone and then a class II rock above that. The backfill material was hand tamped[118] using a gas operated tamper in 8 inch intervals except over the gas main where compacting would have started at 2 feet above the pipe.

[116] The contractor supplied records showing that they had been certified in the use of this equipment by the manufacturer.
[117] As an example, the tension may be set at 1-ton initially then moved to 4 tons and finally 7-tons as the length of pipe pulled had increased.
[118] Documentation submitted to the NTSB indicated that the hand tamper was a Bomag BT 65/4 or equivalent

The superintendent and foreman both stated that the sewer pipe had been removed from the trench directly over the gas main by hand and that pneumatic bursting would have only been used up to the west side of the trench. Once the head of the bursting tool approached the west side of the excavation trench, the operation became a "static pull," where the bursting operation is stopped and the bursting head is pulled to the exit pit using only the winch. The superintendent stated that the pneumatic bursting is turned off 7 feet to 8 feet out from the gas main, allowing the winch to pull the old clay pipe forward into the open trench where the contractors removed the broken pieces. The superintendent stated that this is a normal procedure when crossing high pressure gas mains.

A home video of the 2008 pipe bursting was provided to the NTSB by a resident that had lived on Earl Avenue at the time of the work. The contractor verified that the video showed their equipment and appeared to be the work performed in 2008 in San Bruno. Still images from the video were provided to the city for confirmation of the location and orientation of the equipment. According to the city of San Bruno, the video shows that the winch was set up at the intersection of Glenview Drive and Early Avenue for one of the two pipe-pulls that appear on the DVD. The NTSB was able extract further information from the video images relevant to the analysis of the sewer work and potential impacts to the gas main.

Images from the video appear in Figures 6 and 7 showing the winch relative to the riser bar and pulley. The still images show that the winch was located on the west side of the exit pit with 3pieces of shoring used as bracing to resist the forces imposed at the pulley. A portion of the winch is set on a steel plate that is laid over the east side of the excavation above the gas main. The video includes shots of the 30 inch gas main as it crosses the potholing or excavation trench dug by the contractor.

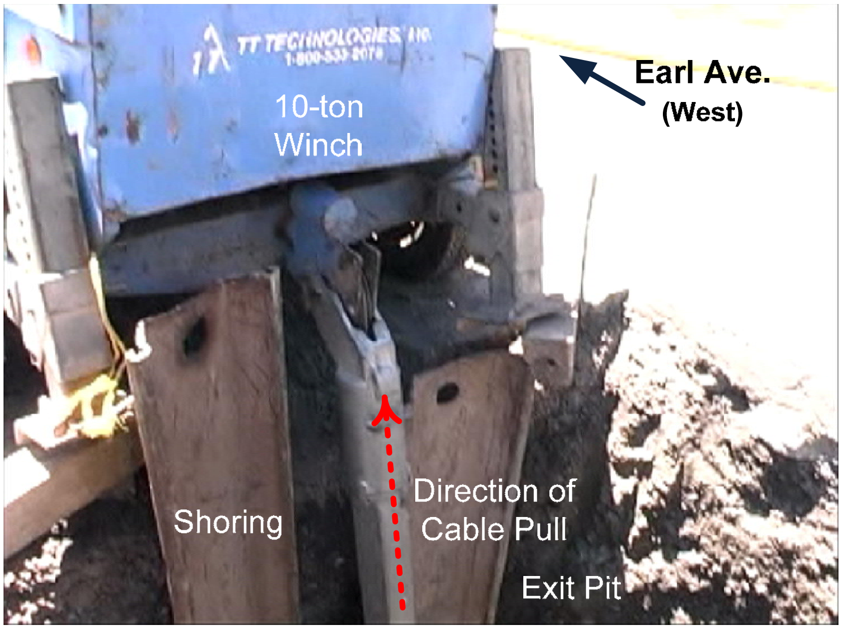


Figure 6: Still image from the 2008 Sewer Work Video showing the winch and riser bar in the exit pit

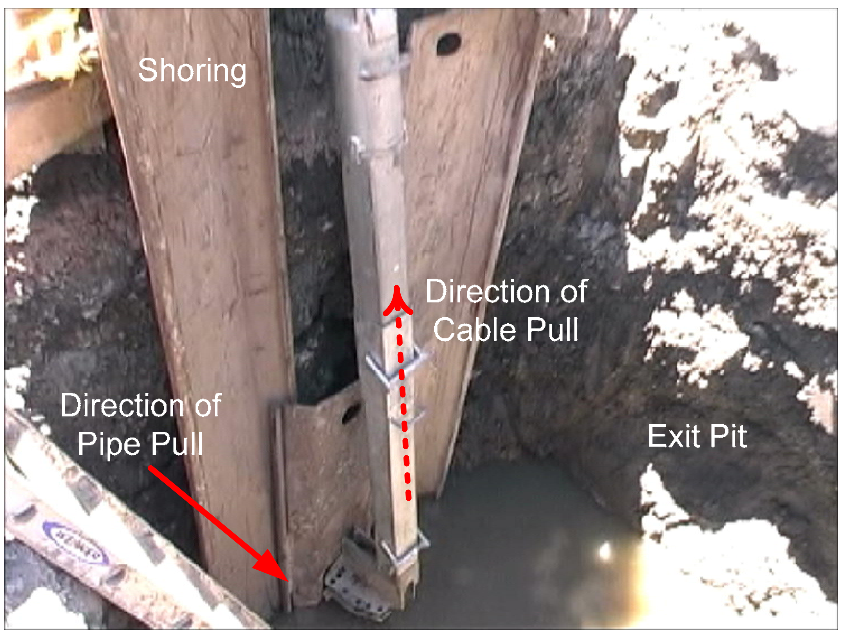


Figure 7: Still image from the 2008 video of the Sewer line replacement project showing the bracing assembly utilized by the contractor in the exit pit during pneumatic pipe bursting.

Surveys and Maps

The city of San Bruno surveyed the pipe, trench and all utilities running in the area. The information was presented as a CAD file plotted with grade profiles showing both plan views and elevation cross-sections of the pipes. This survey information was incorporated with the sewer line routing as it appeared in the

1958 construction prints and correlated against Google Earth maps from September of 2009. Refer to [Survey drawing from City of San Bruno]. The survey shows the centerline of the manhole cover approximately 21 feet north from the south cut end on the 30-inch pipe and approximately 12 feet – 9 inches east of the gas main centerline. Based on the NTSB material lab report measurements, the excavation over the natural gas main appeared centered, approximately 9 to 10 feet south of pup-1. The longitudinal seam on pup-1 is oriented approximately 71 degrees CW[119] from the 12:00 o'clock position and opposite of the direction of the bursting operation. The relative angle, on the survey drawing, between the sewer line centerline (north to south) with the sewer centerline (west to east) was approximately 61 degrees[120]. The cut ends of the gas main centerline were surveyed as being 4 feet below grade on the north end and 4.81 feet below grade at the south end. Because the sewer line crossed below the natural gas main, the exit pit bracing and pulley were located off-center from the gas main.

Google Earth shows the asphalt patches along Earl Avenue where tie-ins were made to the sewer line after the pipe bursting operation in June of 2008. The routing of the new line in 2008 followed the original routing and the Google map locations aligned well with the original construction prints. The Google maps image clearly shows the excavation over the natural gas main and the exit pit (located on Glenview drive). A measurement from Google maps shows the approximate dimension of the exit pit width of 8.95 feet.

[119] CW means clockwise when looking down the pipe in the direction of flow (south to north).
[120] This correlated well with Google Earth imagery and the original 1958 construction prints.

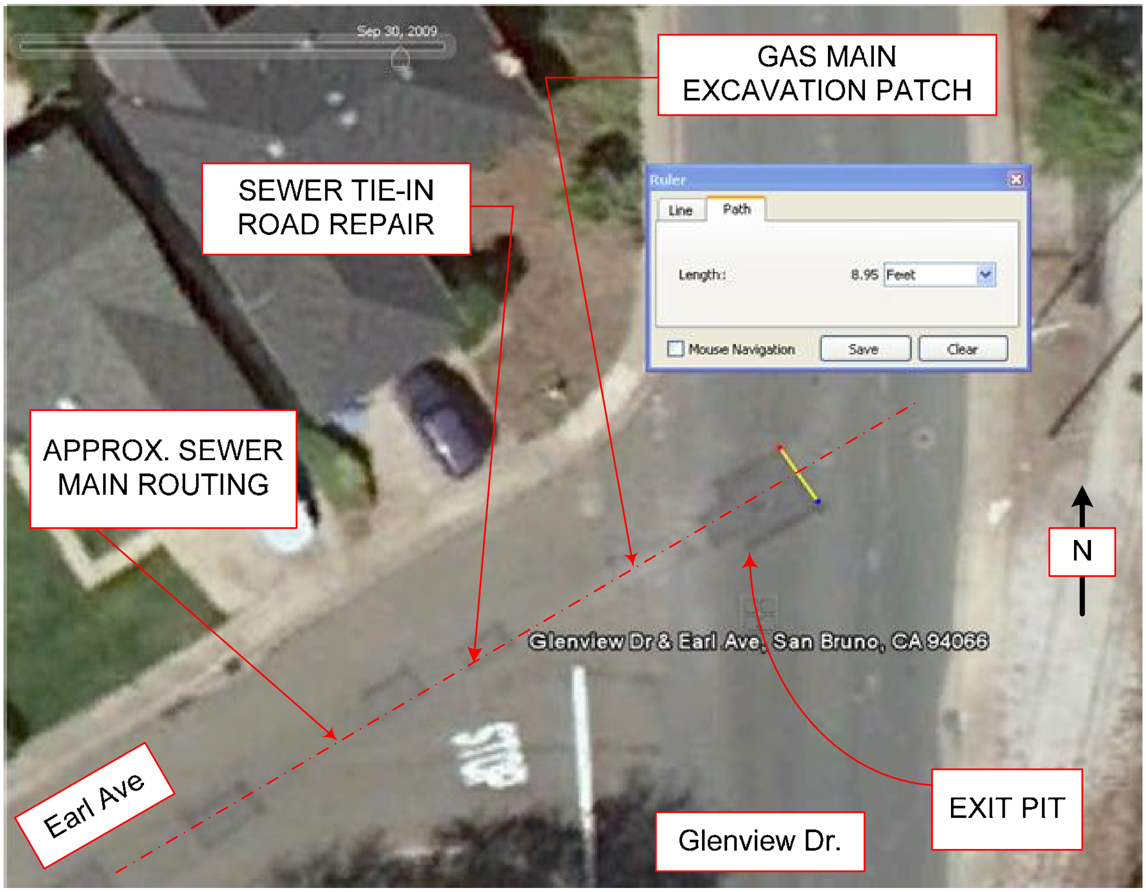


Figure 8: Google Maps and Paving Patches Post 2008 Sewer Repair

Literature Search

Several studies have been published that discuss the impacts of pneumatic bursting on sound pipe adjacent to the bursting head. A generally accepted safe maximum particle velocity of 5 inches per second has been established from the experiments conducted. One of the studies suggests that these velocities are unlikely to be reached at a distance greater than 2.5 feet from the bursting head. Another study concludes that a 95% probability of no impacts to adjacent services exists at a distance 7.5 feet from bursting head. Two reports indicate that a small excavation made around the nearby utility will help to shield the adjacent pipe from any harmful vibrations. None of the studies reviewed specifically addresses the impacts to nearby structures from the winch forces or offers guidance on how to construct an exit pit and bracing when nearby utilities are present.

[2008 Sewer Installation video by San Bruno resident]
[City of San Bruno Statement Regarding Pipe Bursting]
[San Bruno Blast Site Aerial View and Survey 6-20-2011]
[San Bruno Sewer Contractor Statement Regarding Pipe Bursting Video]
[Survey drawing from City of San Bruno]
[2008 Sewer installation construction documents]
[Interview of Jose Ornelas]
[Sketch of Jose Ornelas]
[Interview of John Harty]
[Sketch of John Harty]
[Interview of Steven Poulo]
[Interview of Mark Reinhardt]
[NTSB_036-009 PGE actions on USA tickets]
[Crestmoor Park No 7 Improvement Plans]
[Army Corp of Engineering “Guidelines for Pipe Bursting” TTC Technical Report #2001.02 by Jadranka Simicevic and Raymond L. Sterling; March 2001]
[“ASCE Manual of Practice for pipe bursting”, Trenchless Installation of Pipelines (TIPS) Committee; American Society of Civil Engineers]
[“Ground Vibration Associated with Pipe Bursting in Rocky Rock Conditions.” Trenchless Installation of Pipelines (TIPS) Committee, Dr. Alan Atalah P.E., American Society of Civil Engineers; March 22-24, 2004]

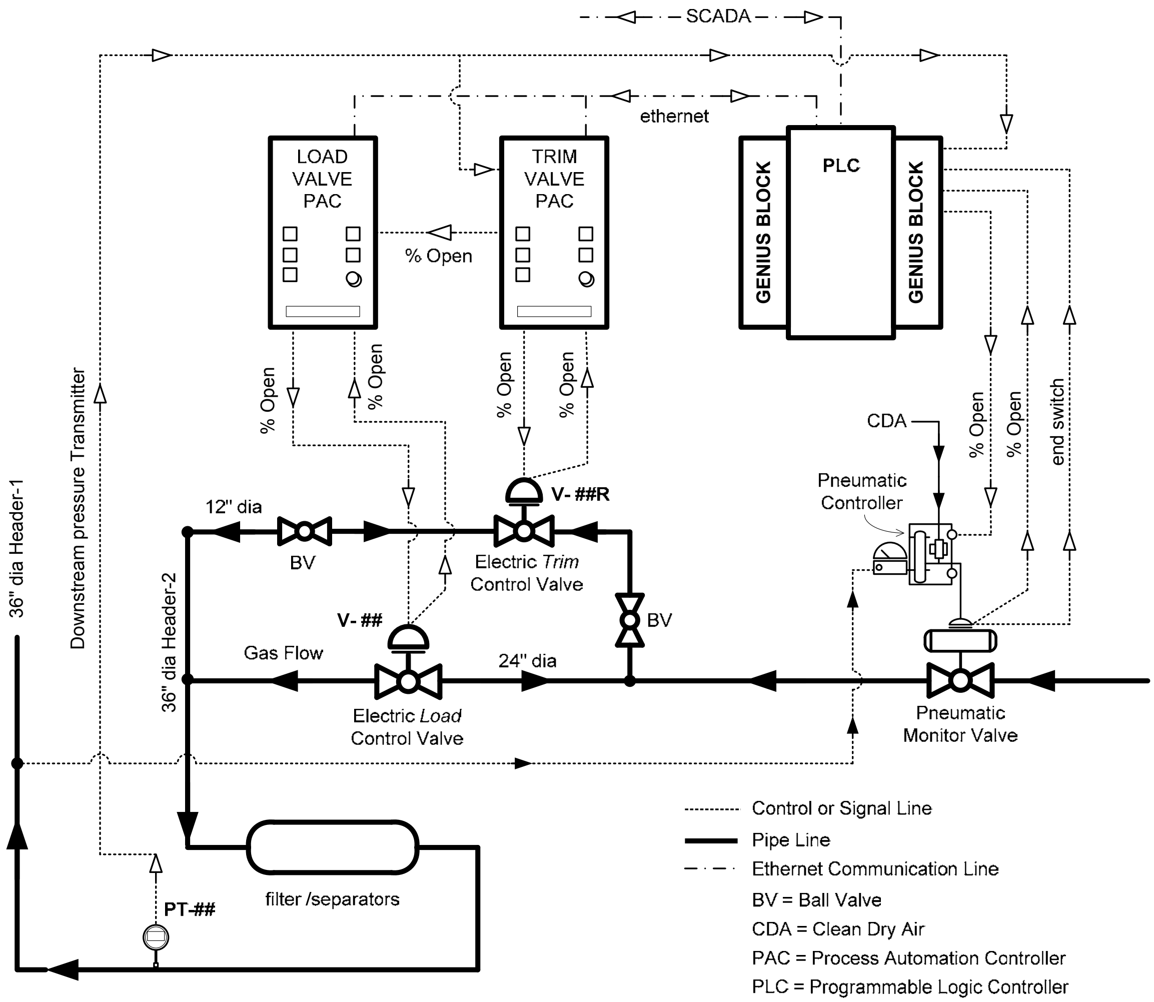
Appendix A - Milpitas Terminal Component Details

1) Regulating Valves

The pressure control on the incoming and outgoing lines at the Milpitas terminal relies upon 24 regulating valves. Each regulating valve consists of a ball valve with an electrically powered actuator that is position controlled from a 4-20mA signal from a dedicated Process Automation Controller (PAC). The PAC modules control the valve operation and communicate to the programmable logic controller through an Ethernet connection. The regulating valves may be given remote set points from a gas control operator over SCADA for pressure control, flow control or to hold a fixed percent open. The gas control commands are sent over the SCADA network to Milpitas. Any of the Milpitas SCADA data may be viewed from the gas control center in San Francisco or from a terminal located at the station.

At Milpitas, the relevant instrumentation displays, such as pressure and valve positions are mounted in an older relay control panel (Mimic panel[121]) within what was once the control room of the Milpitas. At the Mimic panel the PACs may be programmed, placed in local control, or switched from auto to manual operation. When placed in local control the PAC locks out gas control's ability to make changes remotely but does not stop the PAC from continuing to operate the valve position. When placed in manual control the control loop is disengaged and the valve position may be manually adjusted using a knob on the front of the controller. The valve position stays locked at the manual position setting until placed back in automatic or if the position is changed manually.

[121] Refer to reference: Photograph of the Mimic Panel at Milpitas



TYPICAL CONTROLS FOR STAGE 2 REGULATION PROCESS AND INSTRUMENTATION (only one line shown for clarity)

Figure 9: Stage 2 Controls Diagram for Controlling Milpitas Discharge Set points

Gas pressure is regulated across eight stage-1 regulator sets and three stage-2 regulator sets using two parallel regulating valves consisting of a trimmer valve and load valve. The trimmer valves are identified in Appendix C, Attachment A with an 'R' suffix and are installed in a line that is half the diameter of that of the load valves. The trimmer valve is the smaller[122] of the two regulating valves and acts as the primary pressure set point control for each line. The trimmer valve maintains the downstream pressure set point,[123] established by gas control, by modulating its position from 0 to 100% as commanded from its PAC. The larger of the two regulating valves is the load valve. The load valve is modulated through its PAC based on the percent open command[124] from the

[122] The pipe diameter for the trimmer valve is half of that for the load valve piping. This increases velocity through the line and gives the trimmer valve greater control of the line pressure and flow.
[123] Gas control may issue a set point value for flow or pressure at Milpitas. The valves operate to a control loop in the valve controller that constantly examines the error between the set point and process variable. The controller sends a signal to the valve actuator to adjust valve position according to this error.
[124] Note that the load valve does not respond to the actual position of the trimmer valve but the position that the trimmer valve is commanded to go by its controller.

trimmer valve PAC and does not begin to open or close until the command from the trimmer valve PAC is outside a 20 – 80% control band. Therefore, the load valve does not follow the actual position of the trimmer valve but responds to the position output from the trimmer valve controller, giving it faster response. The regulating valves are designed to fail in last position on loss of power and fail open on loss of control signal;[125] leaving only the monitor valve to maintain pressure control.

The regulating valve arrangement on the station and mixer bypass lines does not include a trimmer and load valve configuration. The bypass lines include a single full size regulating valve and a monitor valve (upstream of the regulating valve). Therefore, the controllers on the station and mixer bypass differ from those on the stage-1 and stage-2 regulators. The bypass controllers receive a pressure input and programmable logic controller command but do not include inputs associated with a trimmer valve. The bypass pressure set point is maintained through a single full sized regulating valve. The monitor valve and regulating valve of the bypass lines operate in a similar manner to the others at Milpitas with the same fail states.

2) Monitor Valves:

A monitor valve is located upstream of its corresponding regulating valve or regulating valve set for each stage of pressure reduction. The monitor valve is installed in order to protect the pipeline from exceeding its maximum allowable operating pressure in the event of a failed regulating valve. Eight of the monitor valves protect the bi-directional incoming lines to Milpitas and there is one monitor valve on each bypass line to protect the outgoing lines. There are three monitor valves installed between header-3 and header-2 to protect the downstream line pressure leaving Milpitas. Two additional monitor valves are installed on Line 109. Each of these monitor valves have local pressure set points below the established MAOP of the line they protect. The first stage regulations with eight monitor valves (upstream of flow meters M7-M14 of Appendix C, Attachment A) have pressure set points established to protect the incoming lines to Milpitas. The second stage regulation includes three monitor valves (MR-16, MR-20 & MR-26 of Appendix C, Attachment A) with pressure set points to protect the outgoing lines. The monitor valve is a normally open pneumatically operated and actuated full sized line valve that is designed to fail closed on a loss of control signal and fail last state on a loss of compressed air to the actuator. The pneumatics for the monitor valves are fed from a compressed air system located at the Milpitas and tied to the backup power system.

The Monitor valves have a pressure set point established locally at the valve controller enclosure located within the Milpitas valve yard. The monitor valves include position sensors and limit switches so that gas control can see the monitor valve position over SCADA and even have the ability to set the monitor valve position. Position control from the gas control center cannot over-ride the valve controller's local set point. The local set point takes precedence over any valve position commands from gas control to protect the line pressure from human error over SCADA. Both the analog and discrete

[125] The control signal to the valve is a 4-20mA value provided from the loop controller or PAC.

points for monitoring the valve position and alarm states are hardwired to the Genius I/O blocks at the Milpitas programmable logic controller. A monitor valve does not begin to operate and modulate the valve position until the valve controller has sensed a pipeline pressure that is above its set point.

3) Block Valves:

The Milpitas includes many locally controlled block valves whose position is set from the Mimic panel within the Milpitas control room or at hand switches in the yard. The block valves are used for on/off operation and do not modulate. These valves appear in Appendix C, Attachment A with an 'R' or 'V' prefix. Only lines 300A and 300B include block valves on the incoming side of the Milpitas where the gas enters a separator. These full size block valves, labeled V-1 and V-2, are pneumatically operated valves with spring-return, air to open actuators. A loss of air pressure or power to either of the V-1 or V-2 solenoid valves at the actuator would result in the valve failing closed. Depending on the valve's function, they have an end switch that indicates valve state open or closed to the gas control operator or they have both an indicator for the valve's position and an end switch. The valve states and positions are monitored over SCADA through inputs hardwired to the Genius I/O blocks at the Milpitas PLC.

4) Pressure Transmitters:

The Milpitas uses pressure transmitters to provide an input signal to the regulating valve controllers, monitoring line pressure, and calculating flow from the flow meters. The 40 devices are powered from various 24Vdc power supplies and are ranged from 0-800 psig. There is a single pressure transmitter per trimmer valve control loop (PAC) on the stage-2 regulating valves; however, the stage-1 regulating valves utilize two pressure transmitters; one upstream and one downstream for the regulating valve controllers. The dual pressure transmitters on the stage1 regulating valves allow the incoming lines to operate in a bi-directional mode. Pressure transmitters are installed on each of the 13 flow meters as well as the station and mixer bypass. The mixer bypass is controlled by two pressure inputs, one upstream, and other downstream. Lastly, there are pressures transmitters on each of the outgoing lines downstream of isolation block valves (shown as R on Appendix C, Attachment A). Not all of these transmitters are read at the gas control console; however, all of the data is stored on a PG&E server and was requested by the NTSB.

5) Flow Meters:

Milpitas includes 13 flow meters that measure the gas flow through each of the incoming and outgoing pipelines. The station bypass line includes an insertion meter. The flow meters are orifice plate style meters meaning that they operate by measuring pressure differential across the meter and the temperature of the gas. The pressure readings and temperatures are not displayed to the gas control operator over the SCADA console but are stored on the server for troubleshooting. The NTSB requested pressure data from these meters to validate the pressures that were appearing over SCADA at the Milpitas. PG&E asserts that the pressure data collected at the flow meters was not impacted by the intermittent power fluctuations that occurred at the station on September 9, 2010.

Appendix B – Milpitas Terminal Work Clearance

In support of a capital project to replace the uninterruptible power supply (UPS) serving the entire Milpitas, an electrical contractor and three PG&E technicians were transferring the individual loads from active circuits of the existing 120V single phase electrical panel to temporary mini-uninterruptible power supply units plugged into outlets. The load transfer included communications equipment, power supplies, and analog/digital modules that served the control devices and instrumentation within the station. Transferring the individual loads generated a momentary loss of power as each circuit breaker was opened at the panel and then re-energized on the mini-UPS. As required by PG&E procedures, there was a clearance form submitted to gas control for the September 9, 2010 work. The clearance process is used by PG&E to notify the gas control of planned work on a pipeline or at a station that will affect the flow of gas, SCADA monitoring, and/or gas quality. It is intended to inform all stakeholders of the work taking place on a system and the anticipated impacts to that system. Along with the form (emailed to the gas control) there is also a SharePoint site that is updated with the clearance information at key steps in the process.

A Clearance Form is a six page document that includes:
The date and time of the work being performed…
Whether interruptions to service are anticipated…
Identifies persons for authorization, notification and distribution…
Includes a calculated volumes released worksheet…
Identifies SCADA changes for pressure or alarm set point…
Special instructions sheet…
Sequence of operations sheet

PG&E Utility work procedure WP4100-10 identifies the types of clearances, when they are required, how they are to be filled out, the roles and responsibilities involved in execution and the quality assurance program that reviews the process. The clearance procedure is identified as a document that applies to all gas facilities and associated equipment operating over 60 psig and is primarily a safety document for working on pressurized or electrically energized systems. The procedure starts by defining whether the proposed work requires a system or non-system clearance. A system clearance is defined as a clearance that will have an effect on gas flow, gas quality, or the ability to monitor the flow of gas over SCADA. A system clearance requires authorization from gas system operations personnel. A non-system clearance will have no effects on gas quality, gas flow or the ability to monitor gas flow over SCADA. Non-system clearances may be approved at the supervisor level from the responsible maintenance group.

PG&E further defines three subtypes that fall under the two categories of clearance. These are new clearances, standard clearances or non-clearance routine work process (NCR) clearances. New clearances represent one-time work that is not typically repeated but may also be the first time execution of a future standard clearance. Standard clearances are routine or repetitive work such as annual maintenance to a regulator that must be isolated with block valves before it can be operated. Standard clearances may involve operating a MAOP separation valve. Lastly, there is a non-clearance routine work process; this is routine maintenance work that will not affect gas flow, gas quality or the ability to monitor flow. The non-clearance routine work process applies to work that fits the ten criteria outlined by the procedure, one of which is that the work must not exceed one-day duration. The gas operations group does not review non-clearance routine work processes. The PG&E procedure for the NCR's includes multiple requirements for approval, including a written procedure for approving and completing the work. The written procedure must clearly identify the description of the proposed work.

The clearance principles and procedures section of the PG&E clearance procedure requires that a qualified person complete the three steps: to obtain the clearance, to conduct a clearance tailboard meeting (pre-meeting) with all individuals performing work under the clearance, and to ensure that the equipment is properly cleared and safe to work on. The procedure requires locking out and tagging of all clearance points identified in the sequence of operations before work begins. The sequence of operation section of the procedure directs that all routing of gas flow be included in the sequence of operations portion of the clearance form and to review any changes to the sequence of operations for an already authorized clearance. The clearance procedure designates the clearance supervisor as the person who must remain responsible and available for the duration of the clearance although this responsibility may be handed off to another qualified clearance holder that is thoroughly knowledgeable of the clearance in process. This transfer must be communicated at a tailboard meeting and to gas control. In addition to reporting to gas control when the work has started and ended, the clearance supervisor must report key communication steps identified in the sequence of operations on the clearance form. For example, the procedure identifies a key communication step as the "operation of any piece of equipment that affects the flow and/or pressure of gas or the ability of gas control personnel to monitor the flow and/or pressure of gas on SCADA."

PG&E's clearance procedure states that a complete clearance package contains the following components –

- Application for gas clearance/face sheet
- Special instructions
- Sequence of operations, if necessary
- Up to date and correct operating maps and diagrams referenced on the clearance form
- Any other drawing used to prepare the clearance
- For piping changes that are part of the clearance, include a redlined operating diagram or map showing the before and after configuration.

The application for gas clearance approval requires that the clearance application completely describe the work to be performed and that all new clearances must have the start and end times, dates and the clearance supervisor's name. Gas system operations personnel authorize all system-clearances and the first line supervisor reviews and authorizes all non-system clearances. Gas service operations request any required changes via email to the originator and electronically authorize the application. The clearance originator is responsible for making any hard copies for distribution.

Section 13 of the PG&E clearance procedure discusses work at major stations, primarily outlining the greater level of management and documentation required for the job, especially when there are secondary clearance holders. Major stations are identified within the procedure and include the Milpitas. The requirements for work at major stations include the use of a clearance communication board which is a method of tracking the clearance work at key stages as well as which equipment has been locked out and/or tagged out.

Roles and responsibilities are covered under Attachment 1 of the PG&E clearance procedures as well as documentation requirements associated with gas clearance work. According to Attachment 1, the approval of a gas clearance resides with clearance coordinator. The clearance coordinator's responsibilities include review and approval of all system clearances and to make sure that each package is complete with all of the required forms completely filled out. The procedure requires that the clearance coordinator reviews the sequence of operations for the following impacts – scheduling or supply availability, flow direction, operation of identifiable valves, minimum pressure requirements, maximum allowable operating pressures, maximum operating pressure, available gas for purge and pack, minimum customer impacts, routing scenarios and isolation lines. The clearance coordinator's duties also include verifying that the sequence of operations is correct, confirming that all valve positions in the clearance are correct. The clearance coordinator is responsible for assembling the approved clearance package and uploading to the SharePoint site. The clearance coordinator may also assist in the writing of the clearance form.

The responsibilities of system gas control include managing the electronic master clearance SharePoint site for all clearances, reviewing all clearances within a 48 hour window, ensuring that the system conditions are met in accordance with each clearance, setting alarm limits as stated in the clearance document, recording the start and completion of the clearance on the cover sheet, granting preliminary and final approval upon request, and assuming the clearance coordinator's duties if that person is unavailable. The clearance supervisor notifies gas control when work is complete so that the time may be stamped and logged onto the SharePoint copy of the clearance.

Attachment 2 of the PG&E's clearance procedure is titled "gas clearance quality assurance process" and describes PG&E's policy of quarterly review of gas clearances. Each quarter selected clearances from the previous quarter are reviewed, including 100% of new system clearances, 10% or a minimum of three standard system clearances, six non-system clearances and 100% active clearances. For system clearances, the process review examines clearances to verify that the proper approval was obtained, the correct and current operating maps and diagrams are identified, the clearance supervisor has current training, to validate estimate blow down[126] calculations, to verify that required agency notifications are made and documented, to verify that the appropriate information was contained in the special instructions, and to verify that all steps identified as key communications steps have proper documentation of "completed" "date" and "time". The review also examines the field copy of the clearance to check whether the sequence of operations was altered and whether the operations were properly documented. The lead auditor summarizes the findings from the audit and presents this information to supervisors to discuss action items that may be needed to improve the overall process.

Approval for the September 9, 2010 work at the Milpitas had been identified under clearance number Mil-10-09, filed on August 19, 2010, and approved by gas control on August 27, 2010. Mil-10-09 was identified as a "system" clearance with a subtype as "new." On page two under the distribution list table, the Clearance Supervisor is listed as "TBD." The author of the clearance is not the same person acting as the clearance supervisor on the day of the work. On page four of the clearance "will normal function of the facility be maintained" is check marked "no;" however, where the form reads "If No, please explain," there is no explanation included. Part B on page four is checked "no" where it asked the requestor if gas control needs to change the SCADA alarms. There were no SCADA tags or alarm changes identified on page four. On page five of the form, the special instructions worksheet lists two items. The first special instruction directs the technician to contact gas control prior to work and at the completion of work and notes that the technician will be on site with the contractor and a measurement and control technician during the work. Moreover, the second special instruction gives the names and phone numbers of the two technicians working on the project. At the bottom of the special instructions page, as part of the form, is a note that reads, "All valve operations must be included in the sequence of operations sheet." The final page of the form, page six, is the sequence of operations sheet, which is blank for Mil-10-09. There is no indication that the regulating valves would be placed in manual or that there would be power interruptions to the instrumentation at Milpitas. There is no

[126] Blow-down represents the amount of gas vented to purge a pipe before performing work.

reference to another procedure specific to the gas control during loss of communication over SCADA.

The gas technician who participated in the September 9, 2010 work said that safety tailboards were held at 6:00am when he arrived at the Milpitas and again at 1:00pm and 1:30pm when the contractor arrived to discuss the work. The tailboard meetings were limited to the persons involved in the work at Milpitas.

[NTSB_044-001 Clearance Training]
[NTSB_011-008 Clearances issued for Milpitas]
[NTSB_003-001 S2 WP4100-10 Clearance Procedures]
[Interview of PG&E Gas Control Technician (Oscar Martinez)]
[Interview Transcript of PG&E Technical Crew Leader (Peter Beck)]

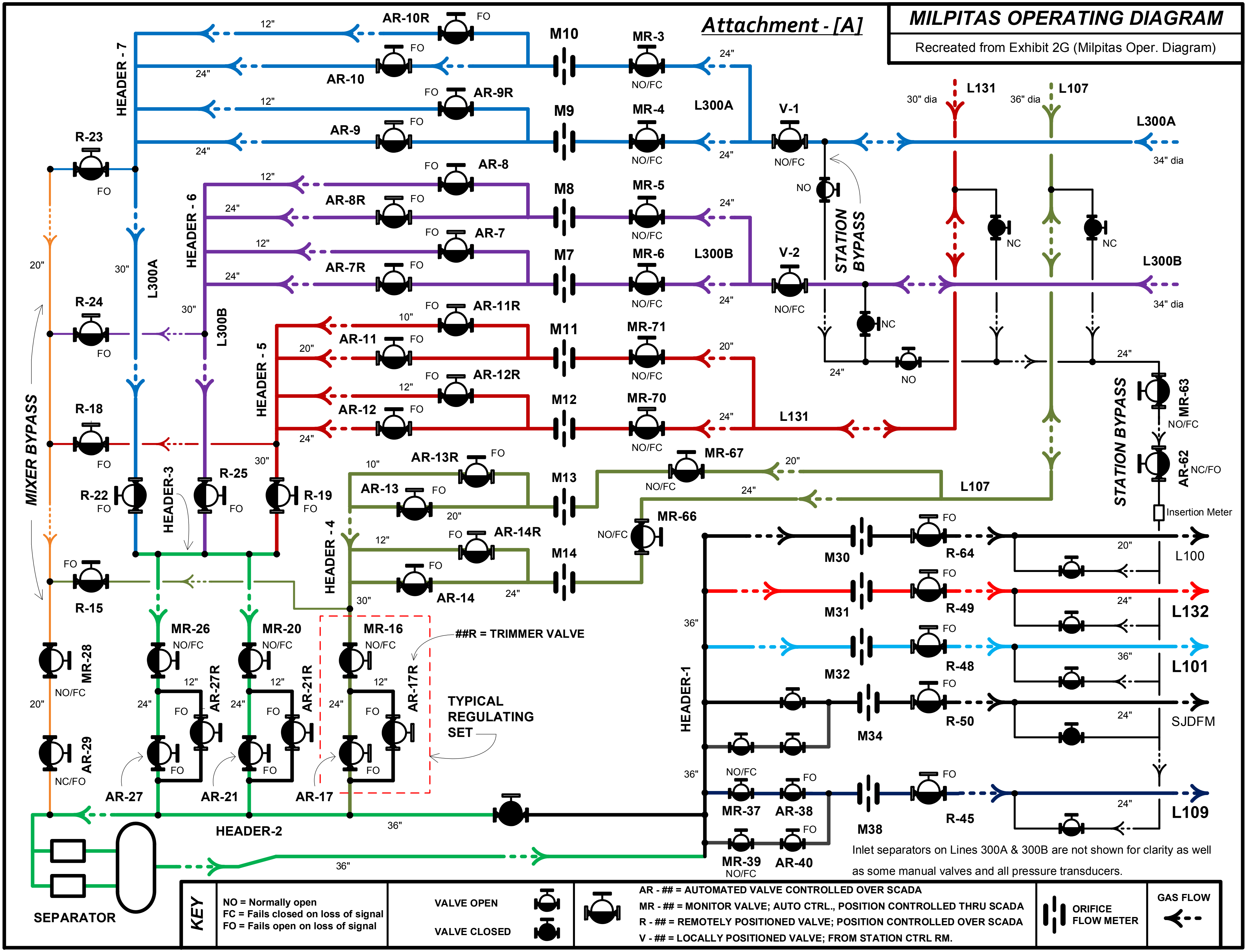
Appendix C: Attachments A through AK

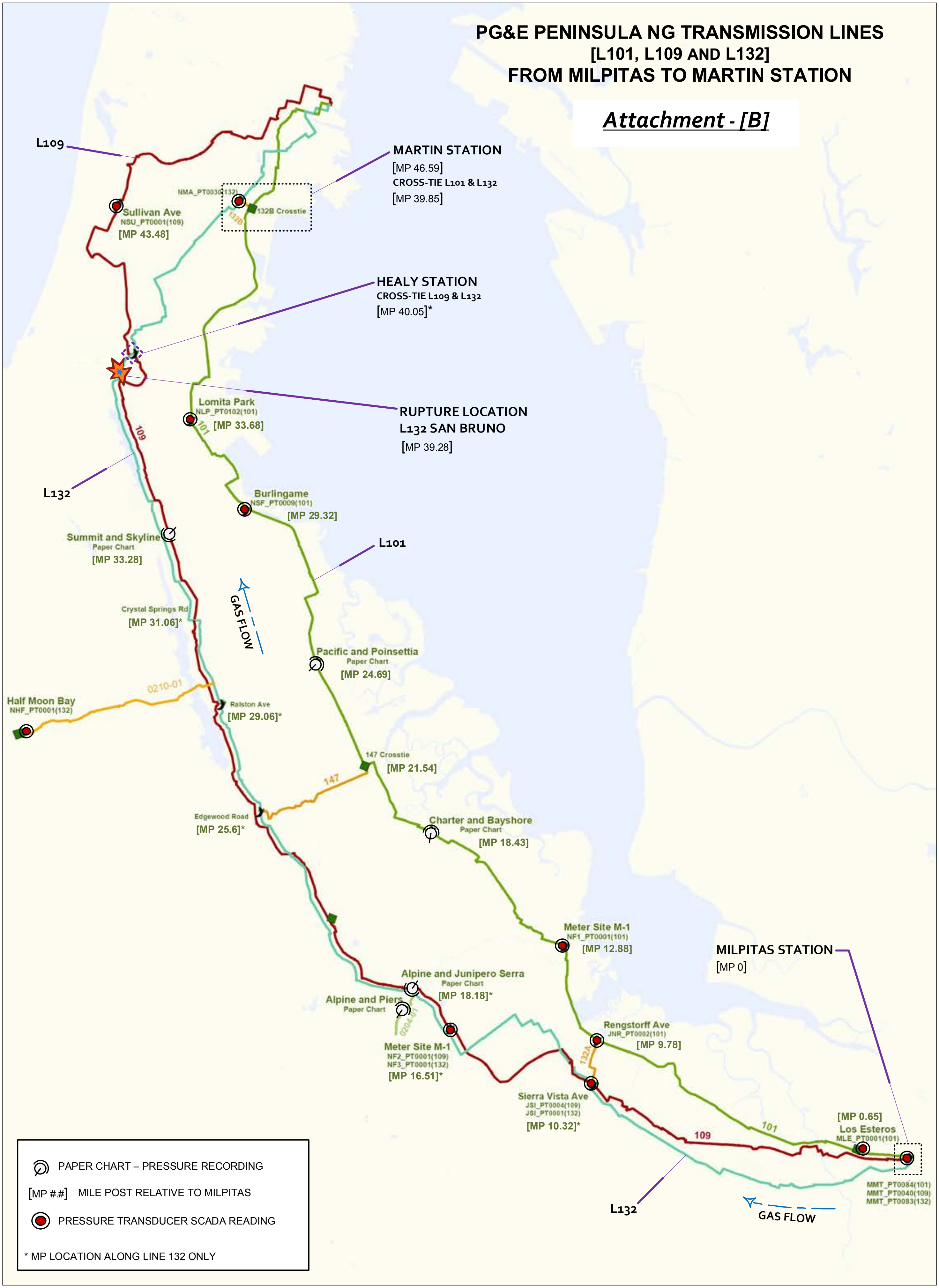
- **Milpitas Terminal Operating Diagram**
- **Peninsula Map with Cross-ties**
- **SCADA Trends**

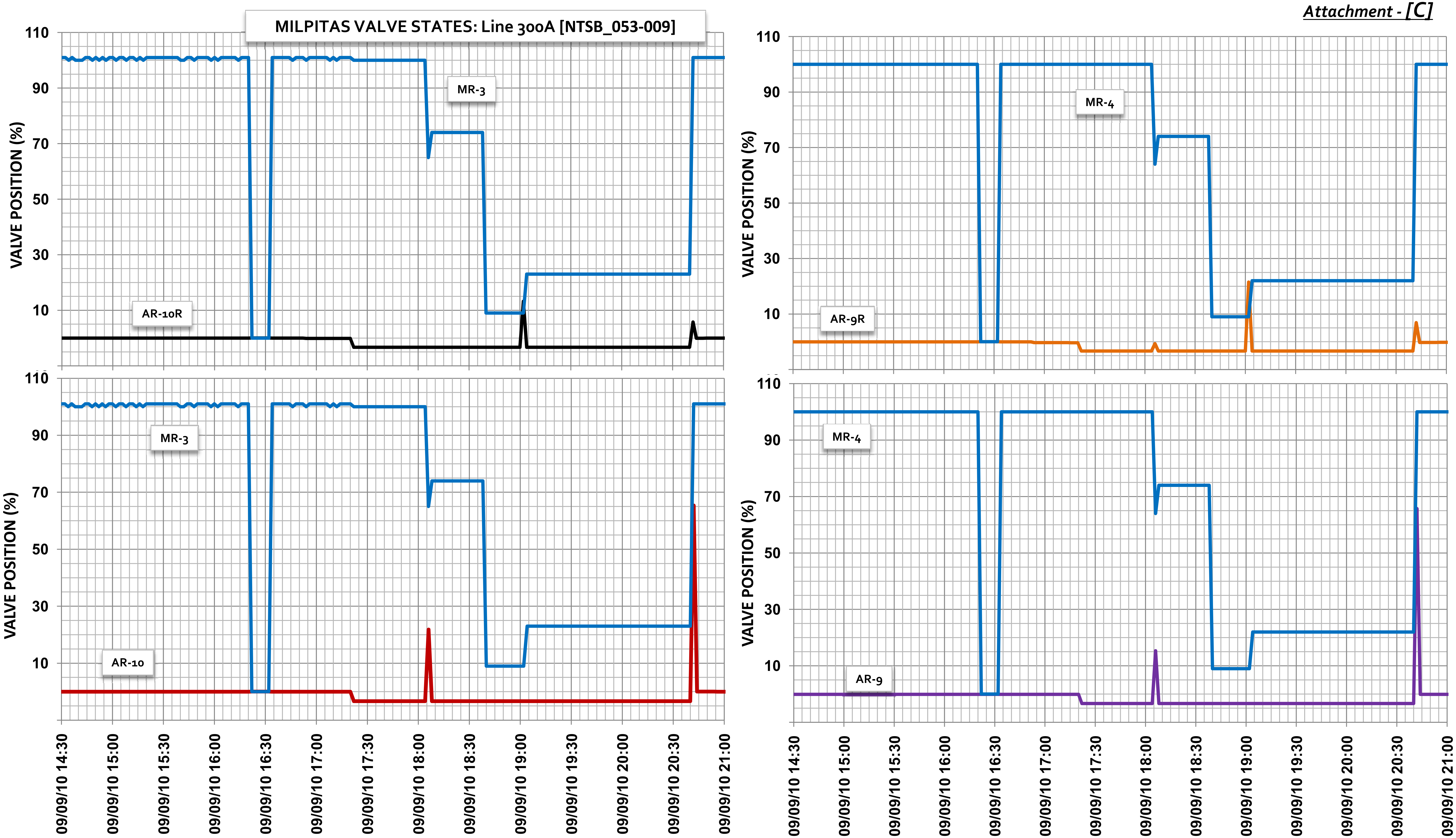
Data Referenced:

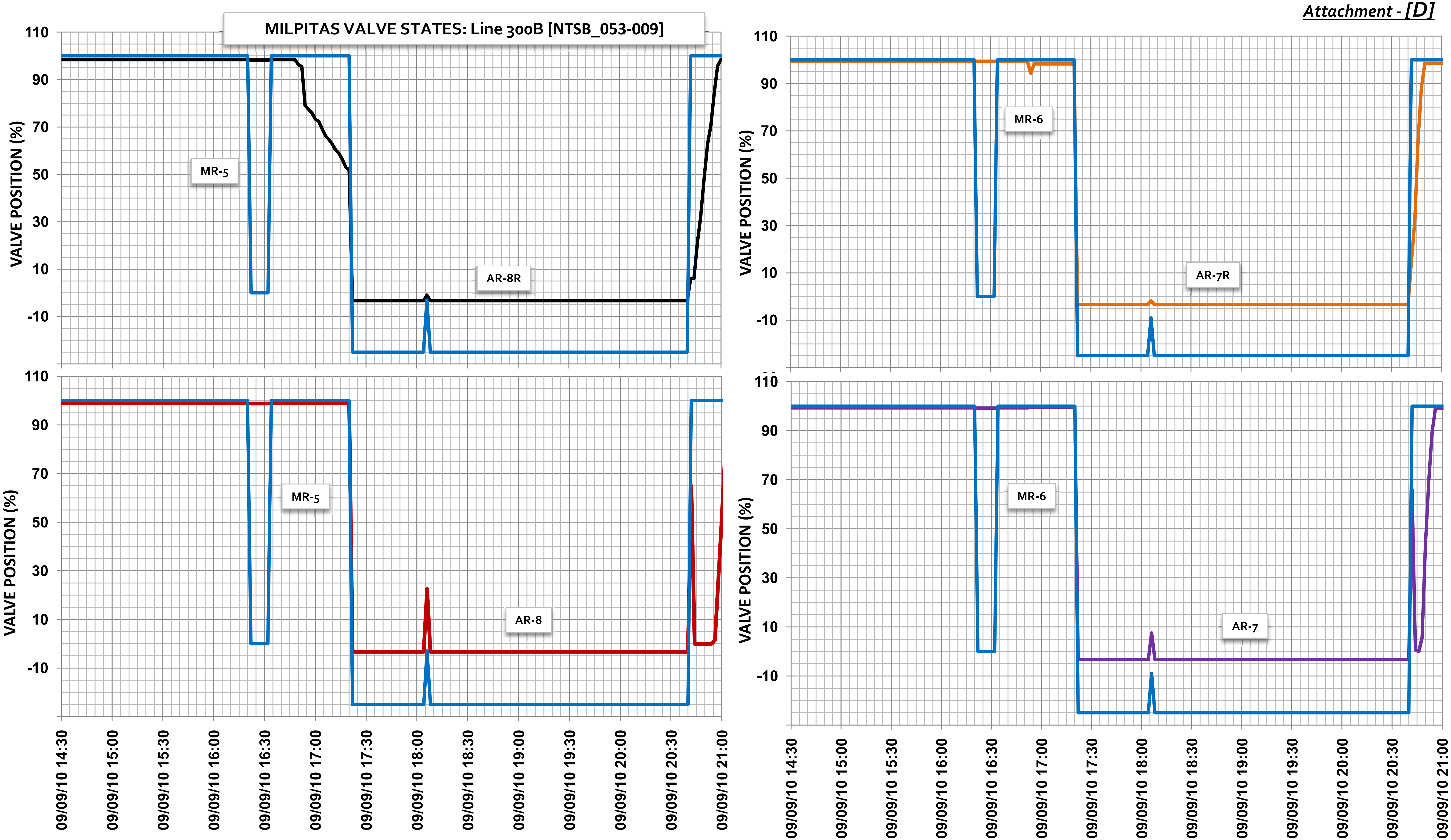
- [Exhibit 2G - NTSB 004-001 Milpitas One Line Diagram]
- [Exhibit 2M - NTSB 036-004 SCADA Pressure Transducer Locations]
- [NTSB_036-04S1 – Mile Points of Pressure Readings]
- [NTSB_053-009 - Valve States SCADA Data]
- [Exhibit 2K: SCADA Pressure Readings on 9-9-10 (16:12 Through 18:42)][127]
- [NTSB_014-008 Rev1 - SCADA DATA - Pressures]
- [NTSB_058-004 - PLS7A and PLS7B Pressure SCADA Data]
- [NTSB_064-006 - SCADA flows in 20-sec intervals]
- [NTSB_064-005 - SCADA Incoming pressures 20-sec intervals]
- [NTSB_053-008 - Upstream Station Pressures into Milpitas]
- [NTSB_053-007 - Pressures on all incoming lines]
- [NTSB_014-008 - SCADA DATA - Pressures]
- [NTSB_056-004 - Volume Released flow rate at time of rupture split by north and south]
- [NTSB_036-004 Rev2 – 2003 & 2008 Pressure readings]
- [NTSB_064-002 – 2008 Pressure readings in 20-sec intervals]
- [Historical Line 132 SCADA pressure readings from 2002 to Dec 31 2010]
- [Historical Flow data for Station Flow meters from 2008 to 2010]
- [SCADA Data from Martin Station from Sept. 9 to 10]

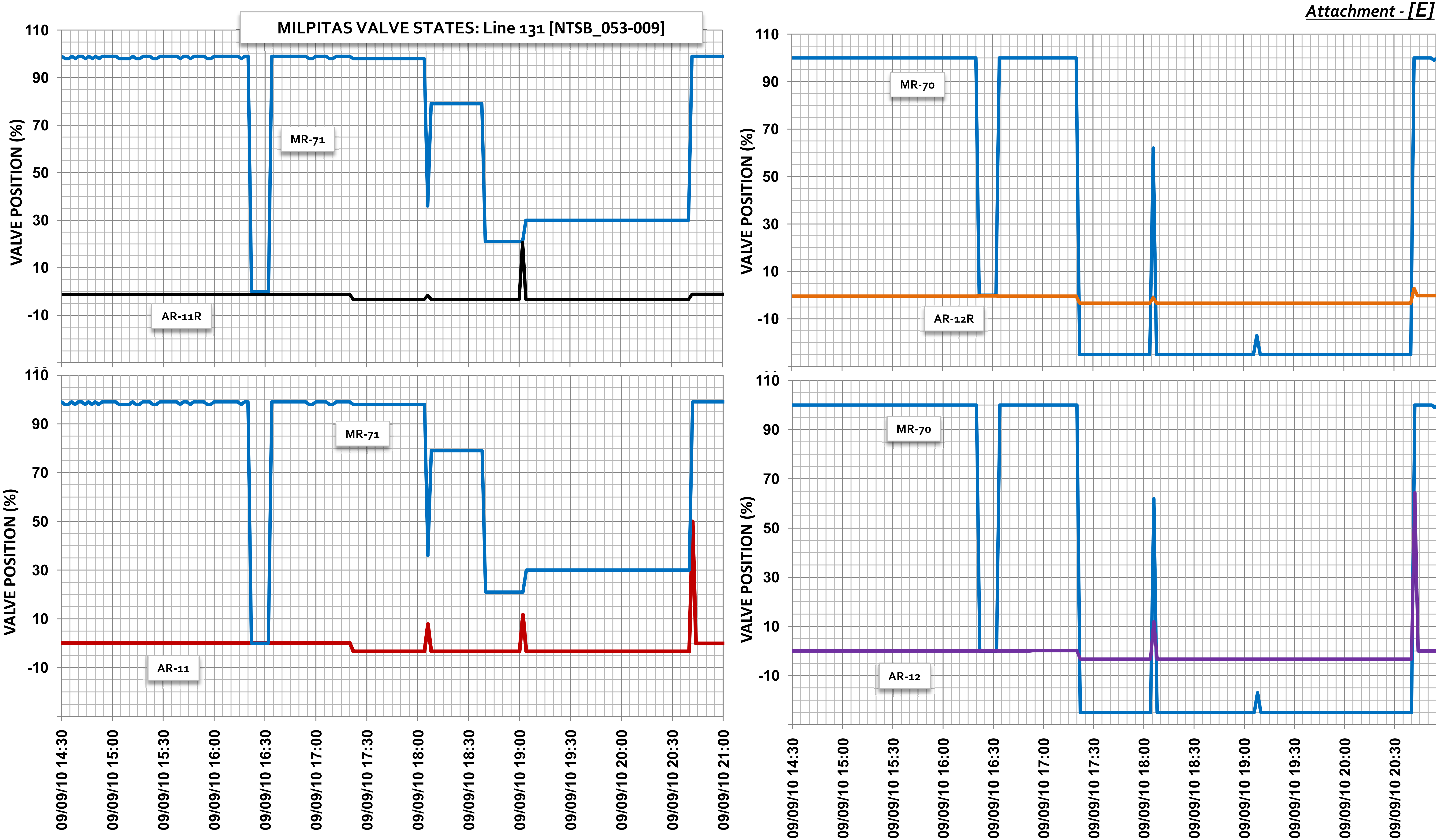
[127] NTSB_001-013-S1 - SCADA Pressures 4 before and after


Attachment - [A]
MILPITAS OPERATING DIAGRAM
Recreated from Exhibit 2G (Milpitas Oper. Diagram)
HEADER - 7
HEADER - 6
HEADER - 5
HEADER - 4
HEADER-3
HEADER-2
HEADER-1
AR-10R
AR-10
AR-9R
AR-9
AR-8
AR-8R
AR-7
AR-7R
AR-11R
AR-11
AR-12R
AR-12
AR-13R
AR-13
AR-14R
AR-14
M10
M9
M8
M7
M11
M12
M13
M14
MR-3
MR-4
MR-5
MR-6
MR-71
MR-70
MR-67
MR-66
L300A
L300B
L131
L107
V-1
V-2
STATION BYPASS
30" dia
36" dia
34" dia
NO
NC
NO/FC
NC/FO
FO
MR-63
AR-62
Insertion Meter
R-23
R-24
R-18
R-22
R-25
R-19
R-15
MIXER BYPASS
MR-28
AR-29
MR-26
MR-20
MR-16
AR-27R
AR-21R
AR-17R
AR-27
AR-21
AR-17
##R = TRIMMER VALVE
TYPICAL REGULATING SET
M30
M31
M32
M34
M38
R-64
R-49
R-48
R-50
R-45
L100
L132
L101
SJDFM
L109
MR-37
AR-38
MR-39
AR-40
SEPARATOR
Inlet separators on Lines 300A & 300B are not shown for clarity as well as some manual valves and all pressure transducers.
KEY
NO = Normally open
FC = Fails closed on loss of signal
FO = Fails open on loss of signal
VALVE OPEN
VALVE CLOSED
AR - ## = AUTOMATED VALVE CONTROLLED OVER SCADA
MR - ## = MONITOR VALVE; AUTO CTRL., POSITION CONTROLLED THRU SCADA
R - ## = REMOTELY POSITIONED VALVE; POSITION CONTROLLED OVER SCADA
V - ## = LOCALLY POSITIONED VALVE; FROM STATION CTRL RM.
ORIFICE FLOW METER
GAS FLOW

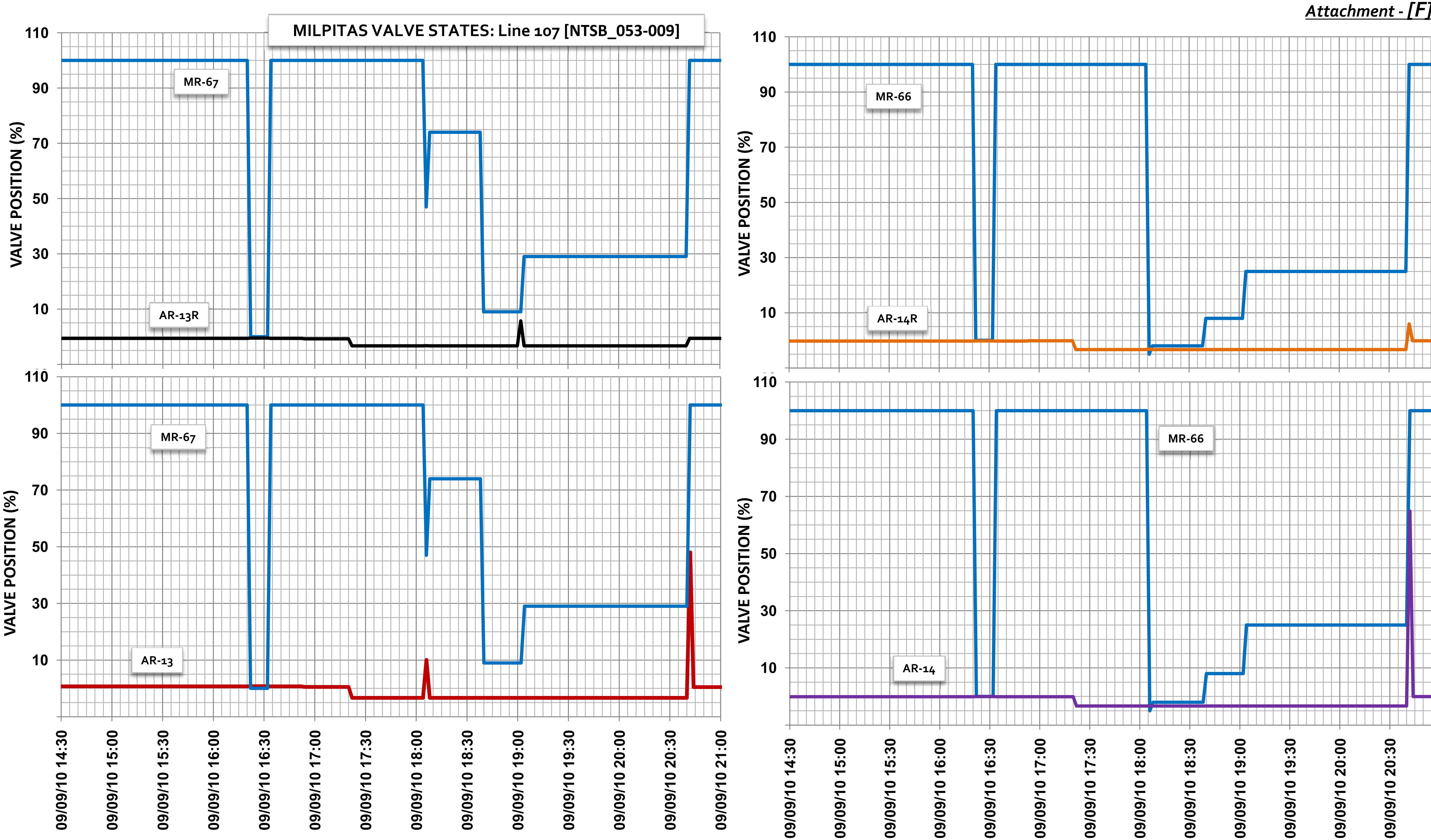

PG&E PENINSULA NG TRANSMISSION LINES
[L101, L109 AND L132]
FROM MILPITAS TO MARTIN STATION
Attachment - [B]
L109
MARTIN STATION
[MP 46.59]
CROSS-TIE L101 & L132
[MP 39.85]
NMA_PT0030(132)
132B Crosstie
132B
Sullivan Ave
NSU_PT0001(109)
[MP 43.48]
HEALY STATION
CROSS-TIE L109 & L132
[MP 40.05]*
RUPTURE LOCATION
L132 SAN BRUNO
[MP 39.28]
Lomita Park
NLP_PT0102(101)
[MP 33.68]
101
109
L132
Burlingame
NSF_PT0009(101)
[MP 29.32]
Summit and Skyline
Paper Chart
[MP 33.28]
L101
GAS FLOW
Crystal Springs Rd
[MP 31.06]*
Pacific and Poinsettia
Paper Chart
[MP 24.69]
Half Moon Bay
NHF_PT0001(132)
0210-01
Ralston Ave
[MP 29.06]*
147 Crosstie
[MP 21.54]
147
Edgewood Road
[MP 25.6]*
Charter and Bayshore
Paper Chart
[MP 18.43]
Meter Site M-1
NF1_PT0001(101)
[MP 12.88]
MILPITAS STATION
[MP 0]
Alpine and Junipero Serra
Paper Chart
[MP 18.18]*
Alpine and Piers
Paper Chart
Meter Site M-1
NF2_PT0001(109)
NF3_PT0001(132)
[MP 16.51]*
Rengstorff Ave
JNR_PT0002(101)
[MP 9.78]
132A
Sierra Vista Ave
JSI_PT0004(109)
JSI_PT0001(132)
[MP 10.32]*
109
101
[MP 0.65]
Los Esteros
MLE_PT0001(101)
MMT_PT0084(101)
MMT_PT0040(109)
MMT_PT0083(132)
L132
GAS FLOW
PAPER CHART – PRESSURE RECORDING
[MP #.#] MILE POST RELATIVE TO MILPITAS
PRESSURE TRANSDUCER SCADA READING
* MP LOCATION ALONG LINE 132 ONLY


MILPITAS VALVE STATES: Line 300A [NTSB_053-009]
VALVE POSITION (%)
110
90
70
50
30
10
MR-3
AR-10R
AR-10
MR-4
AR-9R
AR-9
09/09/10 14:30
09/09/10 15:00
09/09/10 15:30
09/09/10 16:00
09/09/10 16:30
09/09/10 17:00
09/09/10 17:30
09/09/10 18:00
09/09/10 18:30
09/09/10 19:00
09/09/10 19:30
09/09/10 20:00
09/09/10 20:30
09/09/10 21:00

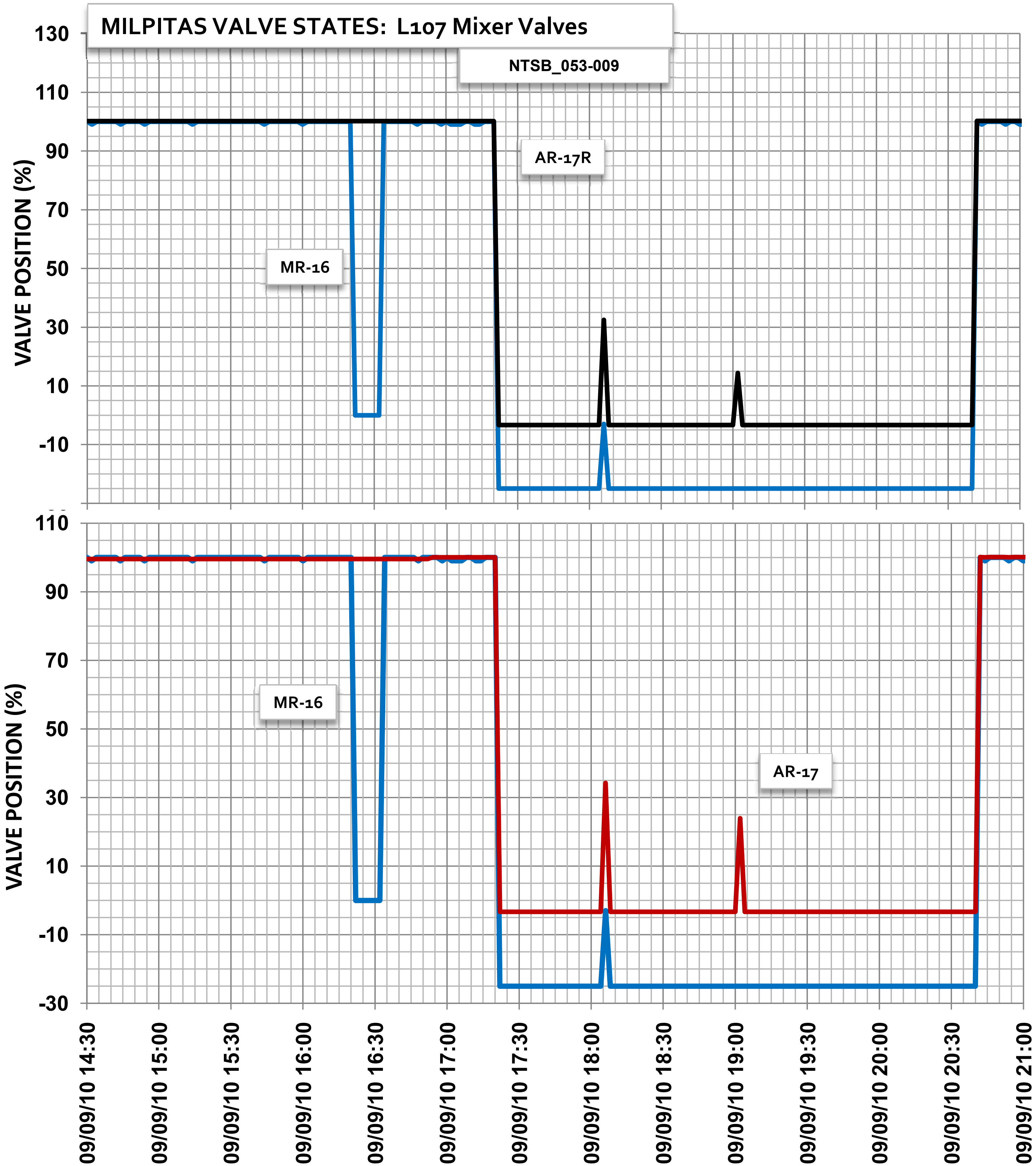

MILPITAS VALVE STATES: Line 300B [NTSB_053-009]
VALVE POSITION (%)
110
90
70
50
30
10
-10
MR-5
AR-8R
AR-8
MR-6
AR-7R
AR-7
09/09/10 14:30
09/09/10 15:00
09/09/10 15:30
09/09/10 16:00
09/09/10 16:30
09/09/10 17:00
09/09/10 17:30
09/09/10 18:00
09/09/10 18:30
09/09/10 19:00
09/09/10 19:30
09/09/10 20:00
09/09/10 20:30
09/09/10 21:00

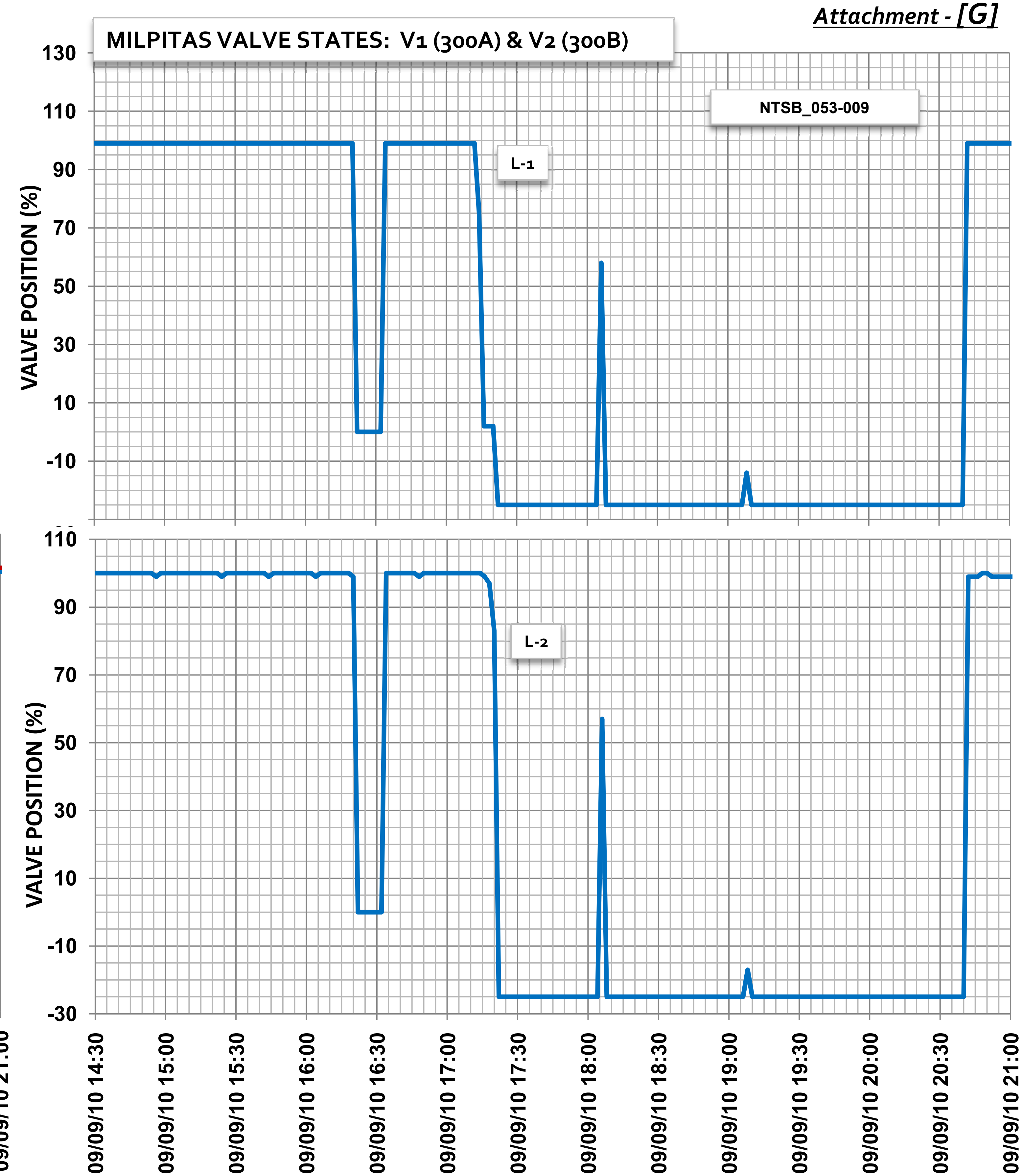

MILPITAS VALVE STATES: Line 131 [NTSB_053-009]
VALVE POSITION (%)
110
90
70
50
30
10
-10
MR-71
AR-11R
AR-11
MR-70
AR-12R
AR-12
09/09/10 14:30
09/09/10 15:00
09/09/10 15:30
09/09/10 16:00
09/09/10 16:30
09/09/10 17:00
09/09/10 17:30
09/09/10 18:00
09/09/10 18:30
09/09/10 19:00
09/09/10 19:30
09/09/10 20:00
09/09/10 20:30
09/09/10 21:00

Attachment - [F]

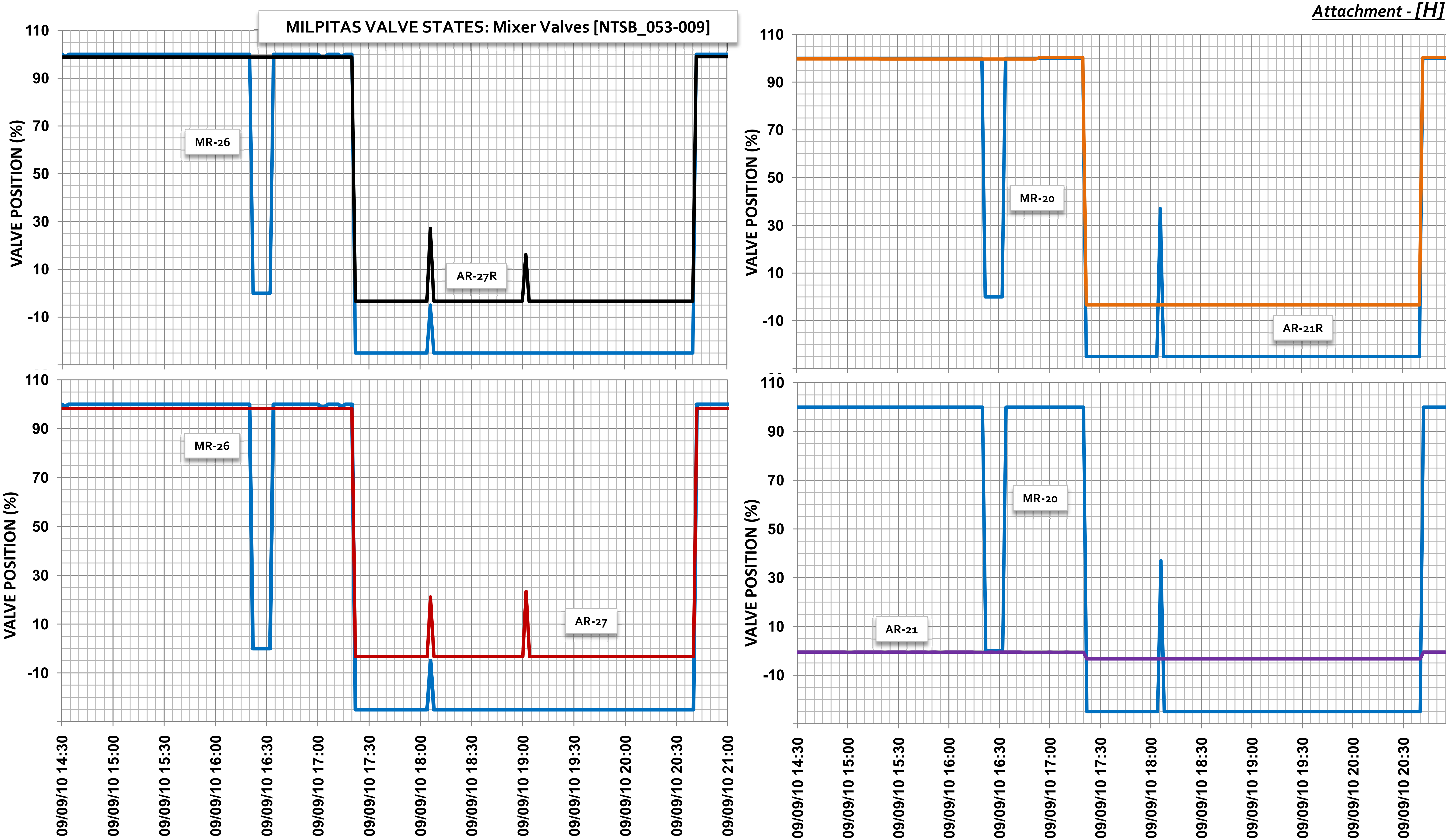


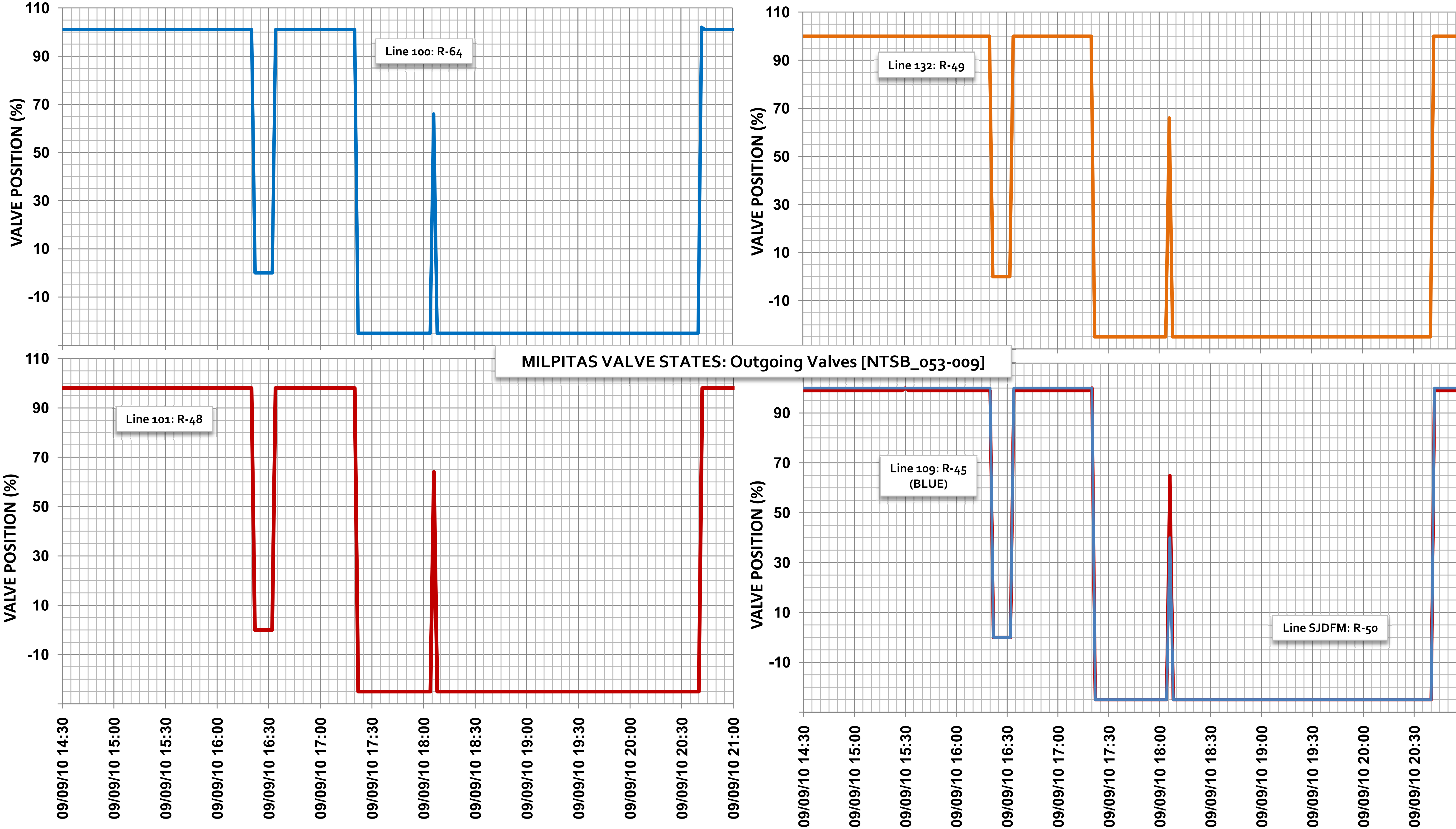
Attachment - [G]



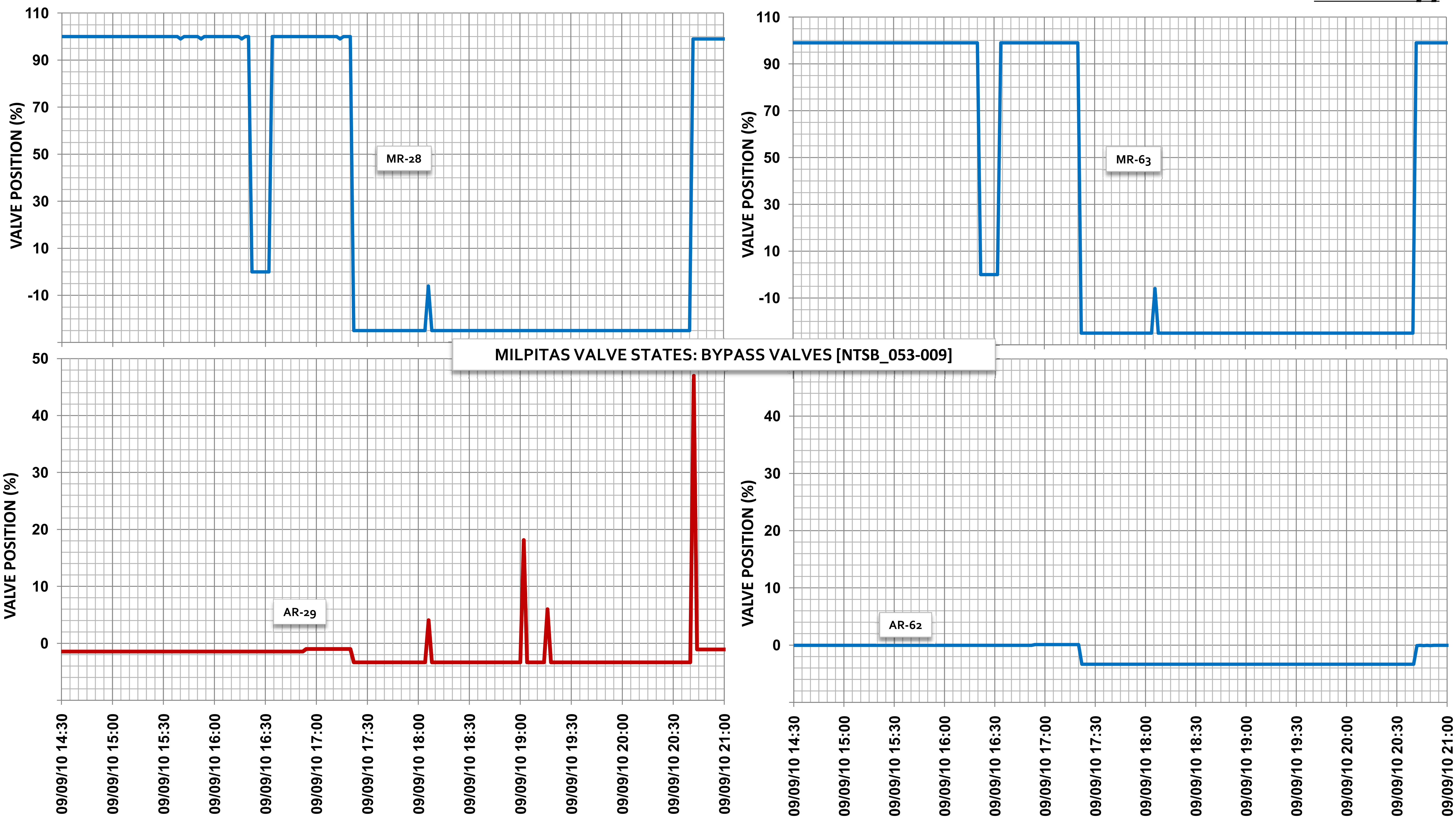


Attachment - [H]




MILPITAS VALVE STATES: Outgoing Valves [NTSB_053-009]
Line 100: R-64
Line 132: R-49
Line 101: R-48
Line 109: R-45 (BLUE)
Line SJDFM: R-50
VALVE POSITION (%)
110
90
70
50
30
10
-10
09/09/10 14:30
09/09/10 15:00
09/09/10 15:30
09/09/10 16:00
09/09/10 16:30
09/09/10 17:00
09/09/10 17:30
09/09/10 18:00
09/09/10 18:30
09/09/10 19:00
09/09/10 19:30
09/09/10 20:00
09/09/10 20:30
09/09/10 21:00

Attachment - [J]



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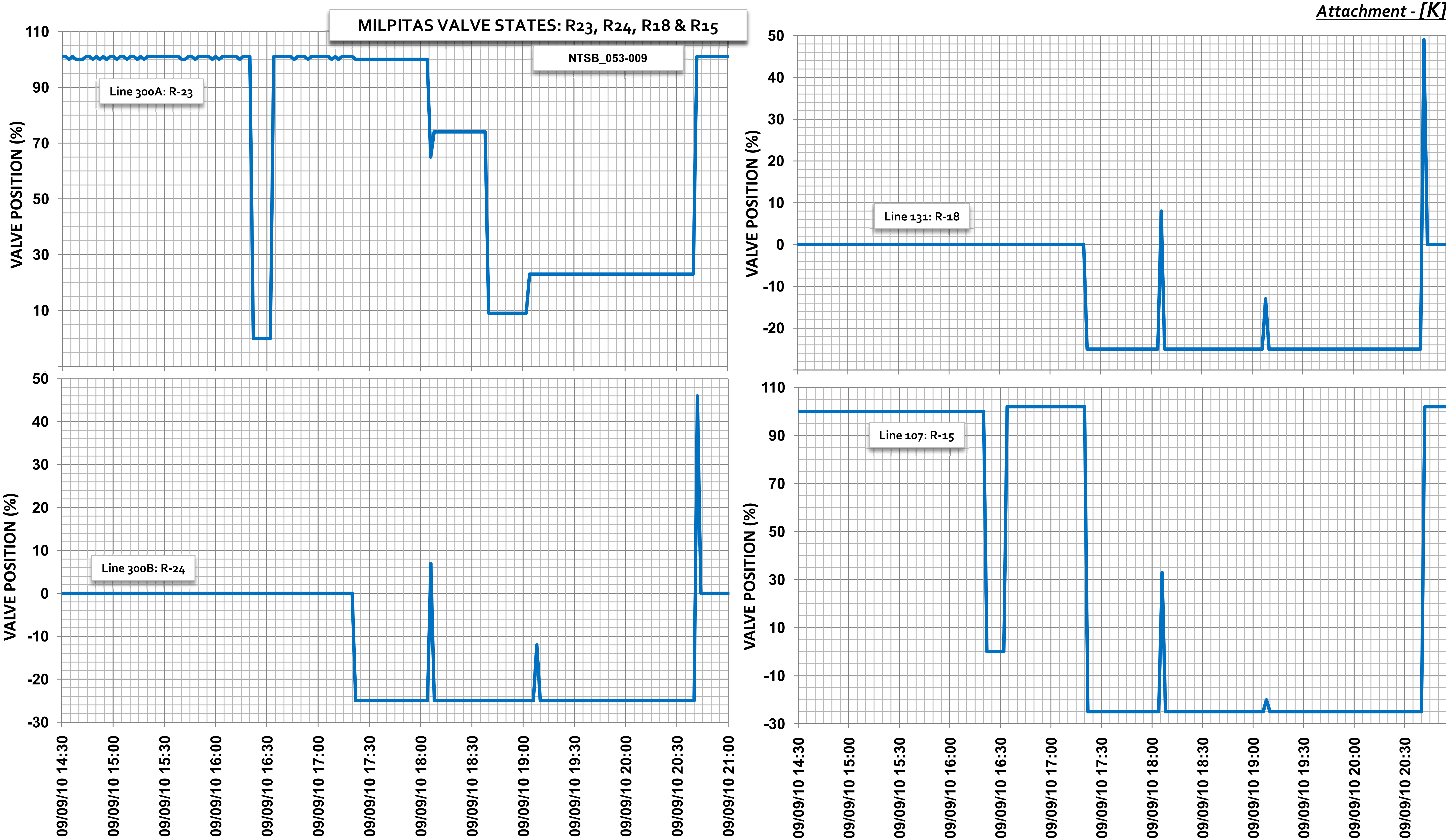
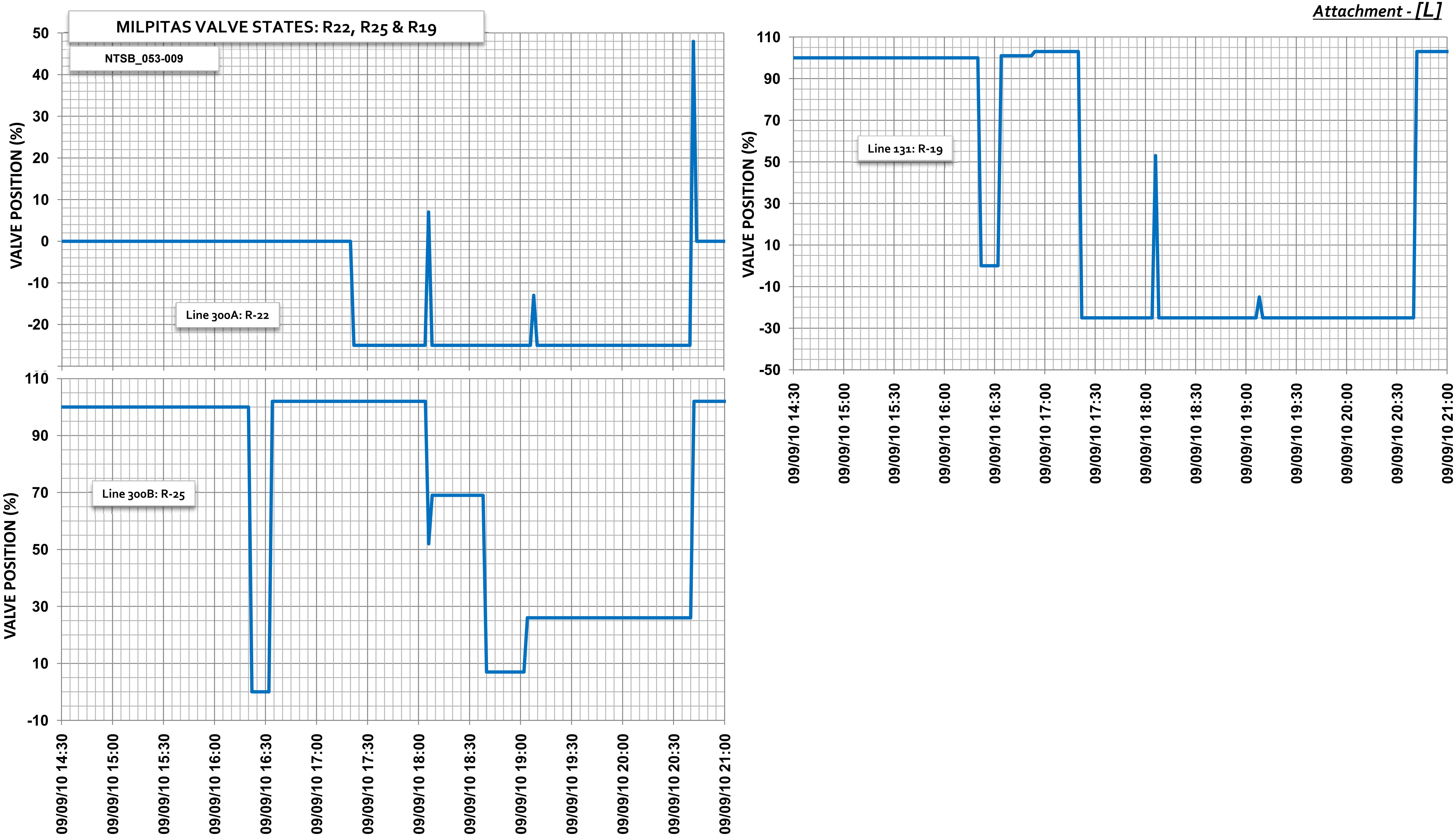


Attachment - [L]



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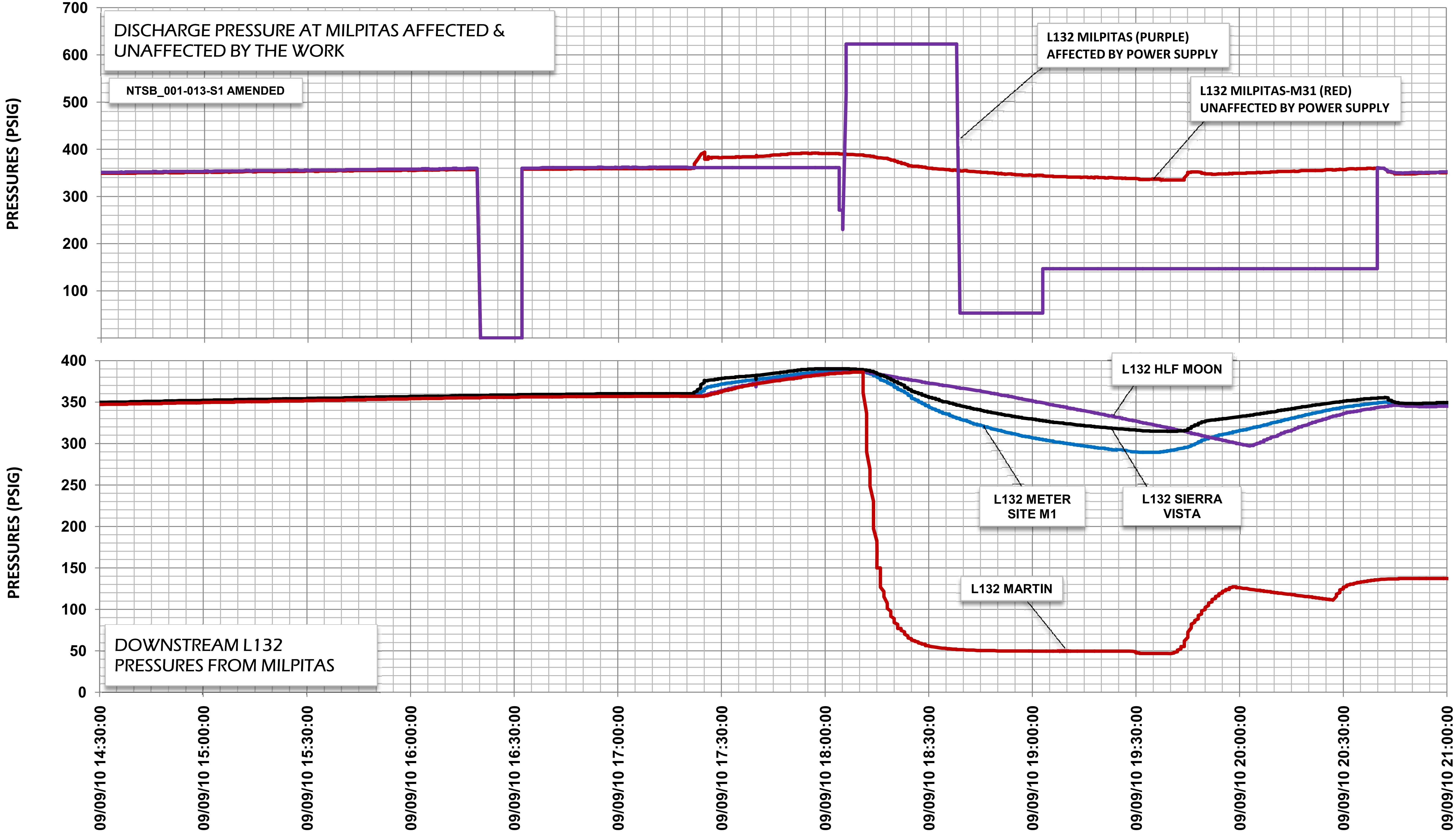
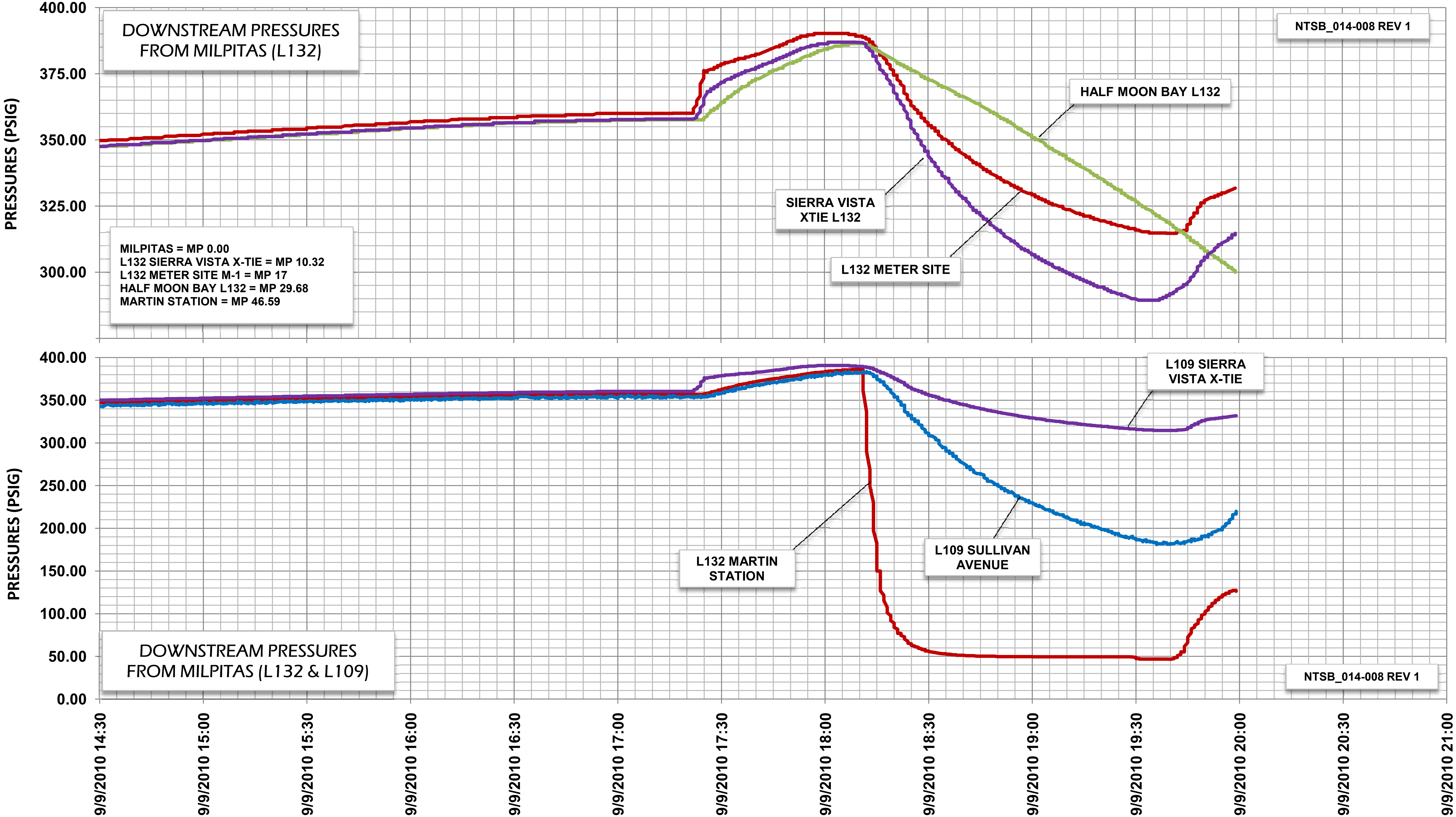
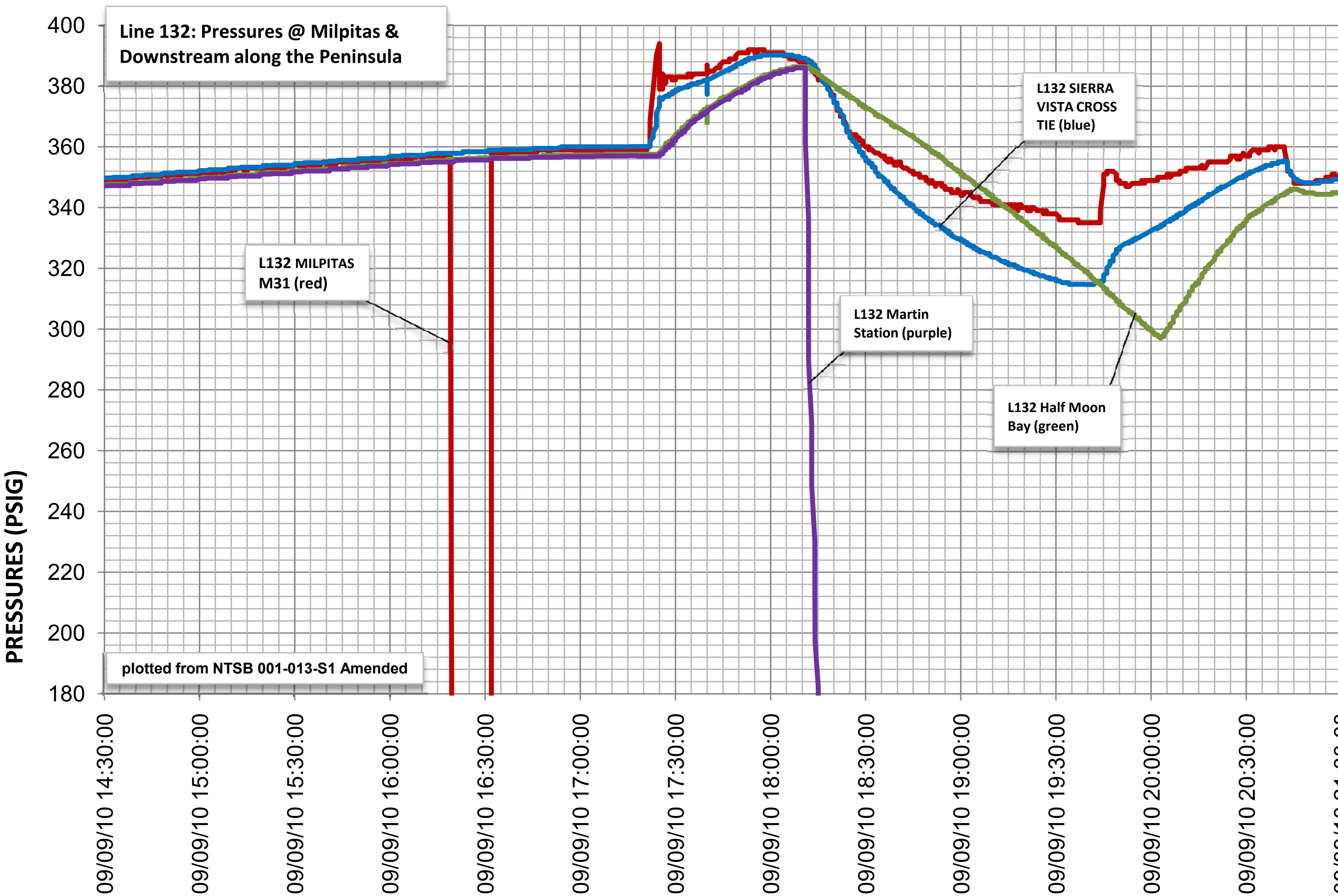


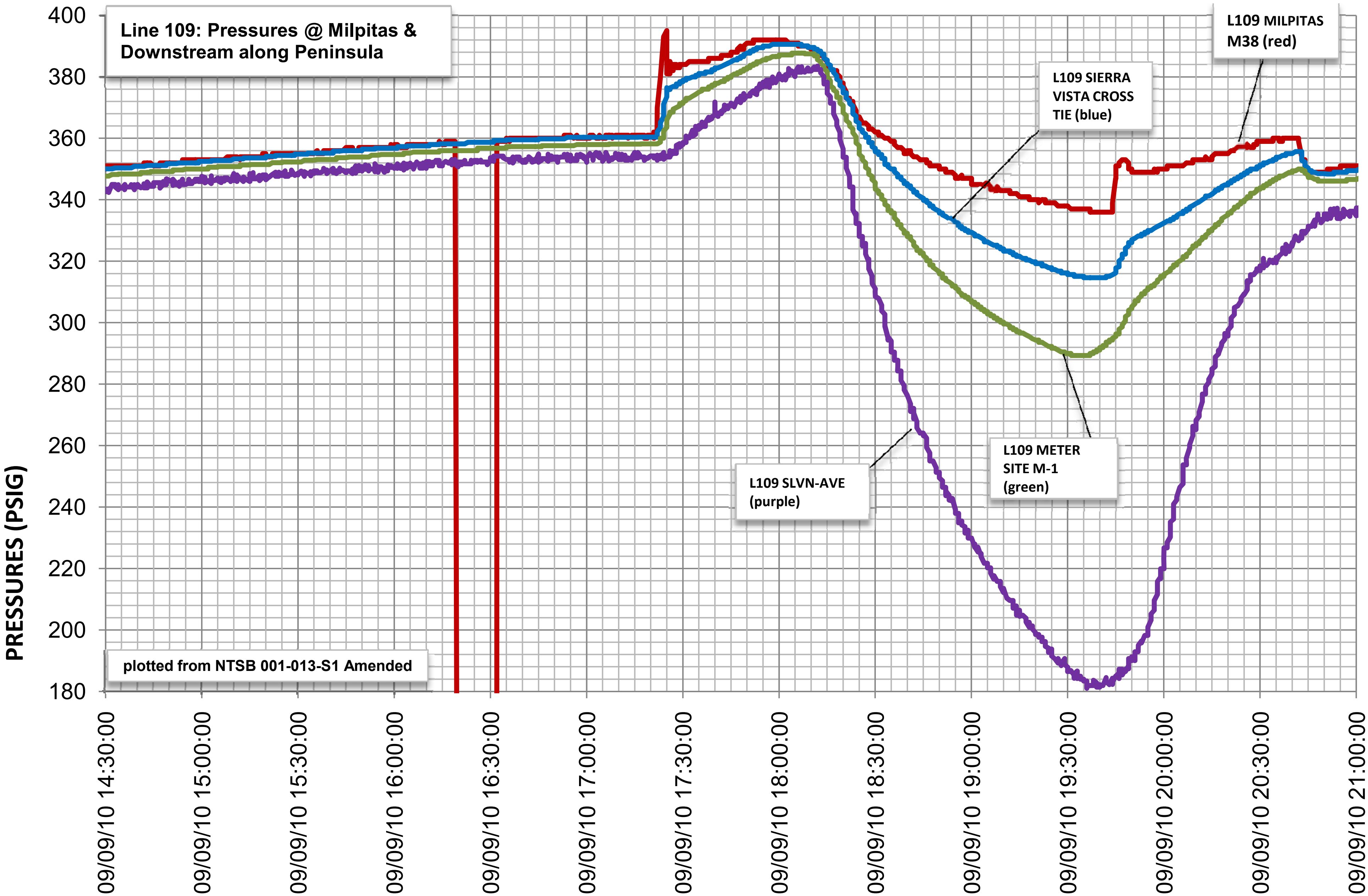


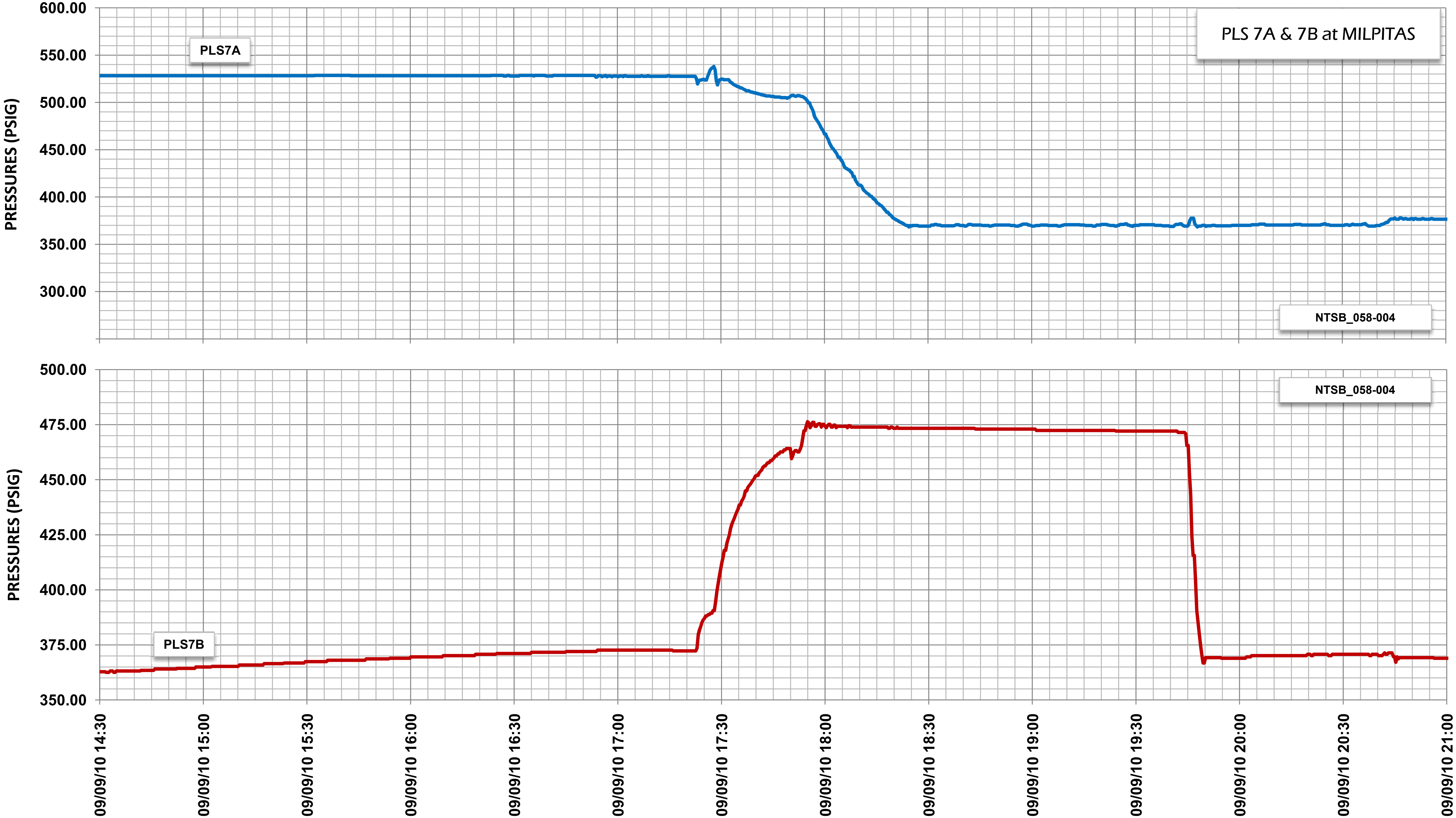
DOWNSTREAM PRESSURES FROM MILPITAS (L132)
NTSB_014-008 REV 1
PRESSURES (PSIG)
400.00
375.00
350.00
325.00
300.00
HALF MOON BAY L132
SIERRA VISTA XTIE L132
L132 METER SITE
MILPITAS = MP 0.00
L132 SIERRA VISTA X-TIE = MP 10.32
L132 METER SITE M-1 = MP 17
HALF MOON BAY L132 = MP 29.68
MARTIN STATION = MP 46.59
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
0.00
L109 SIERRA VISTA X-TIE
L132 MARTIN STATION
L109 SULLIVAN AVENUE
DOWNSTREAM PRESSURES FROM MILPITAS (L132 & L109)
NTSB_014-008 REV 1
9/9/2010 14:30
9/9/2010 15:00
9/9/2010 15:30
9/9/2010 16:00
9/9/2010 16:30
9/9/2010 17:00
9/9/2010 17:30
9/9/2010 18:00
9/9/2010 18:30
9/9/2010 19:00
9/9/2010 19:30
9/9/2010 20:00
9/9/2010 20:30
9/9/2010 21:00

Attachment - [N.1]

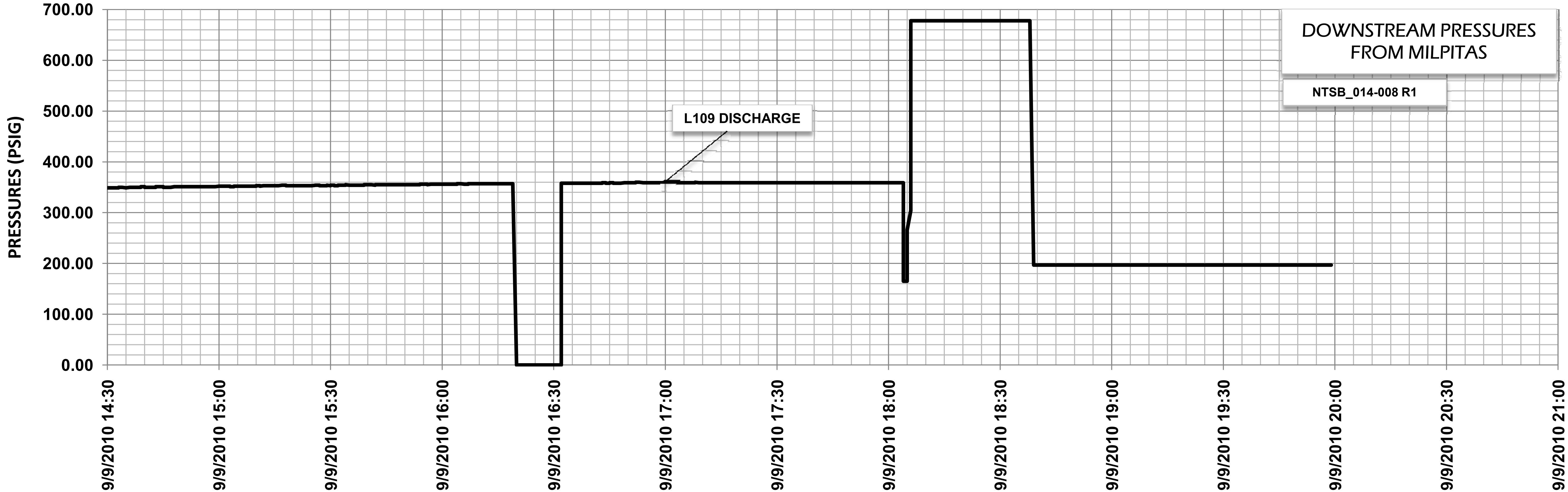


Attachment - [N.2]




PLS 7A & 7B at MILPITAS
PLS7A
NTSB_058-004
PRESSURES (PSIG)
600.00
550.00
500.00
450.00
400.00
350.00
300.00
NTSB_058-004
PLS7B
PRESSURES (PSIG)
500.00
475.00
450.00
425.00
400.00
375.00
350.00
09/09/10 14:30
09/09/10 15:00
09/09/10 15:30
09/09/10 16:00
09/09/10 16:30
09/09/10 17:00
09/09/10 17:30
09/09/10 18:00
09/09/10 18:30
09/09/10 19:00
09/09/10 19:30
09/09/10 20:00
09/09/10 20:30
09/09/10 21:00

DOWNSTREAM PRESSURES FROM MILPITAS
NTSB_014-008 R1
PRESSURES (PSIG)
700.00
600.00
500.00
400.00
300.00
200.00
100.00
L132 DISCHARGE
L101 DISCHARGE



DOWNSTREAM PRESSURES FROM MILPITAS
NTSB_014-008 R1
PRESSURES (PSIG)
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
L109 DISCHARGE
9/9/2010 14:30
9/9/2010 15:00
9/9/2010 15:30
9/9/2010 16:00
9/9/2010 16:30
9/9/2010 17:00
9/9/2010 17:30
9/9/2010 18:00
9/9/2010 18:30
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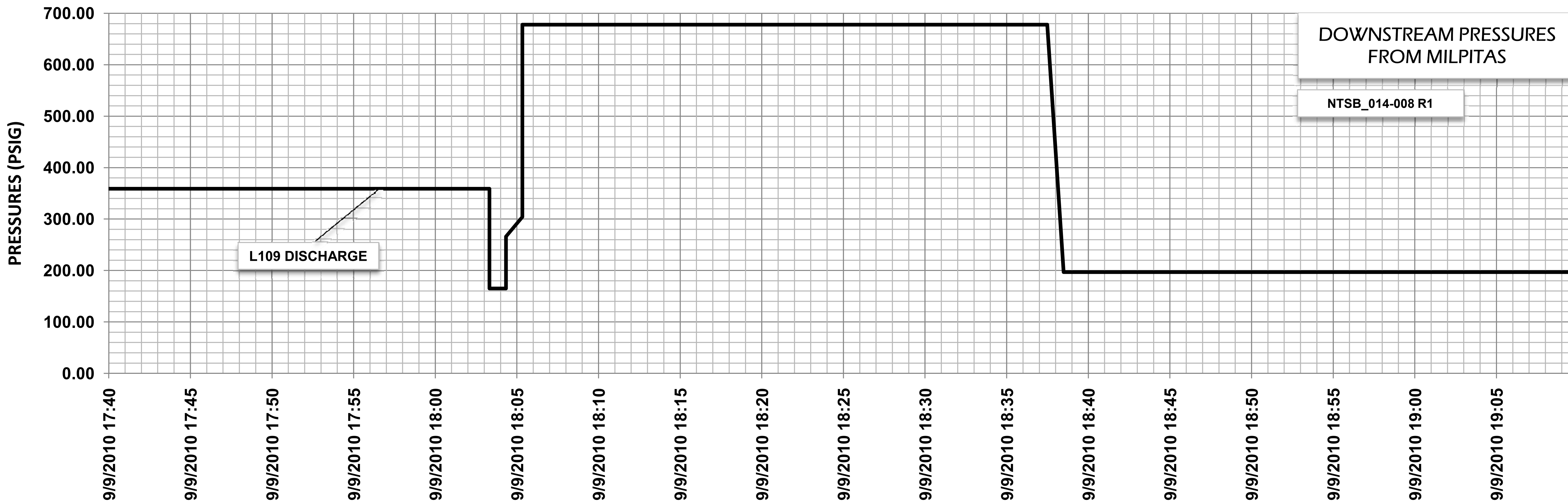
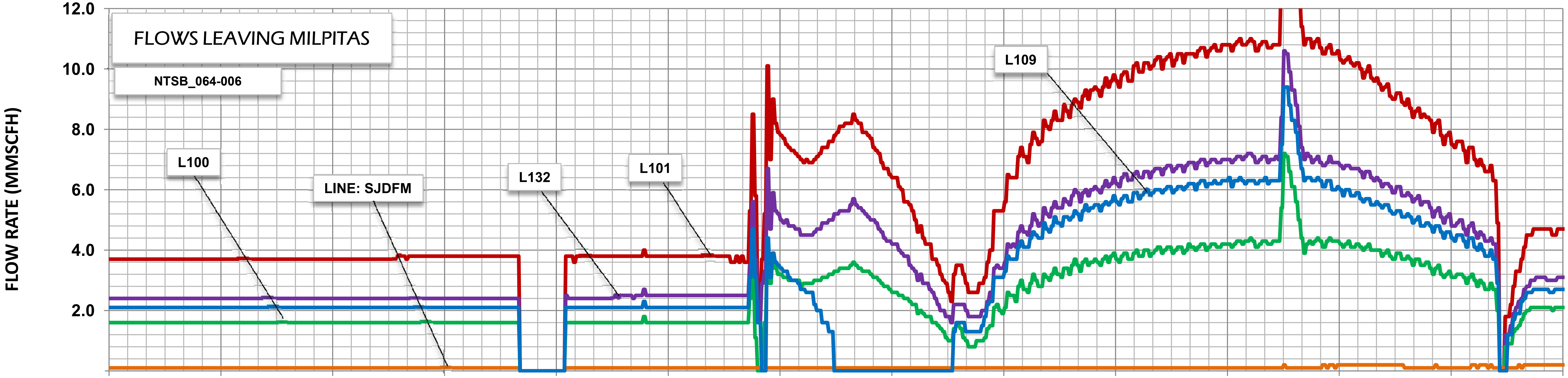
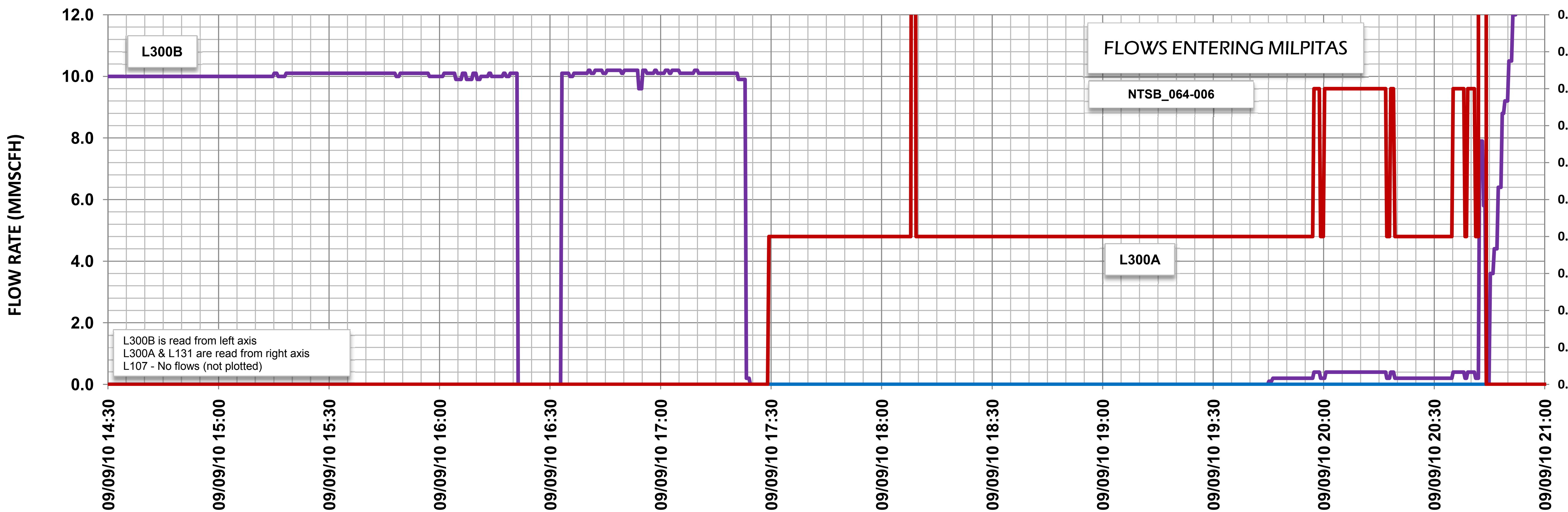
9/9/2010 20:30
9/9/2010 21:00

Attachment - [Q]

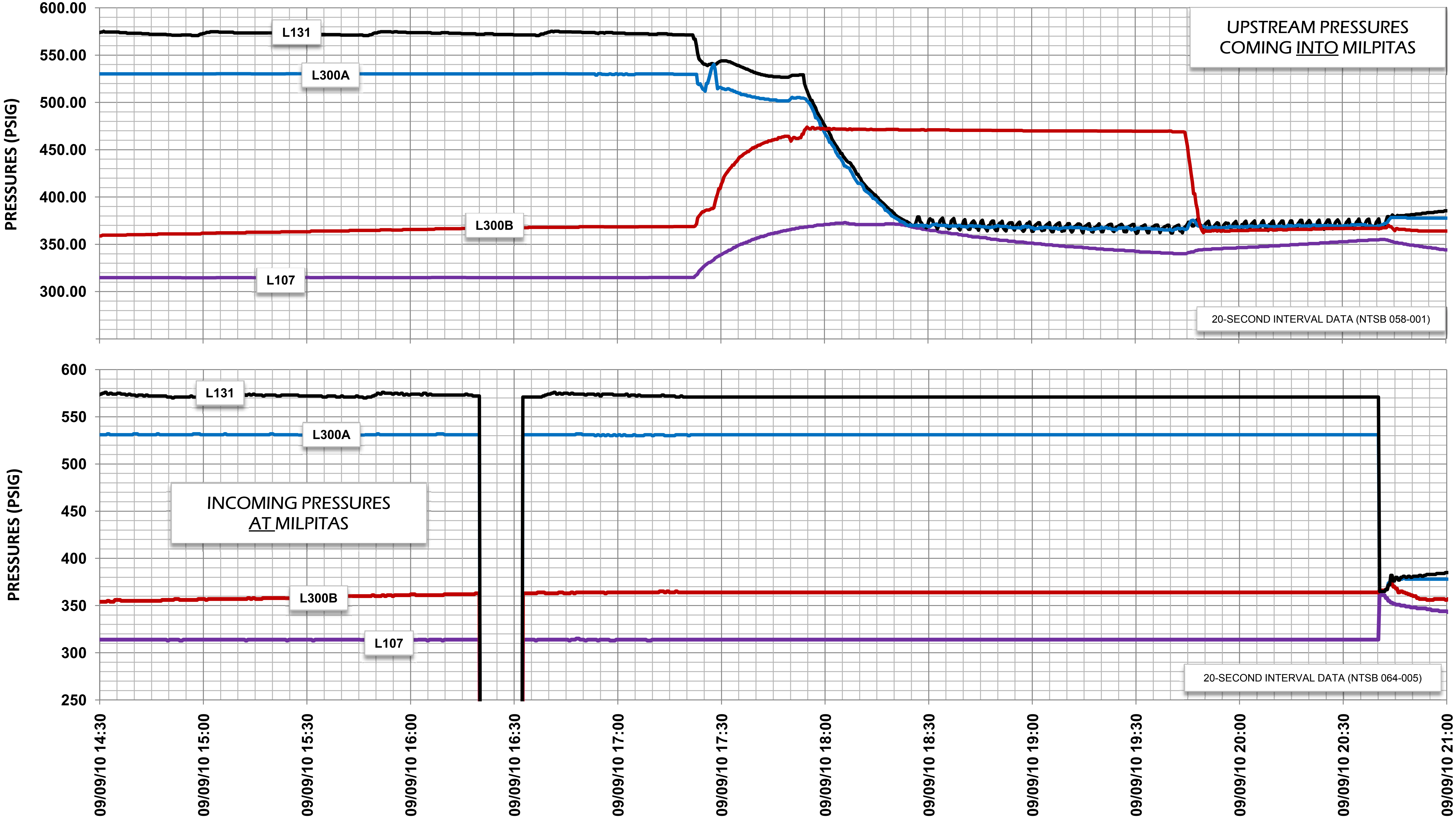


Attachment - [R]

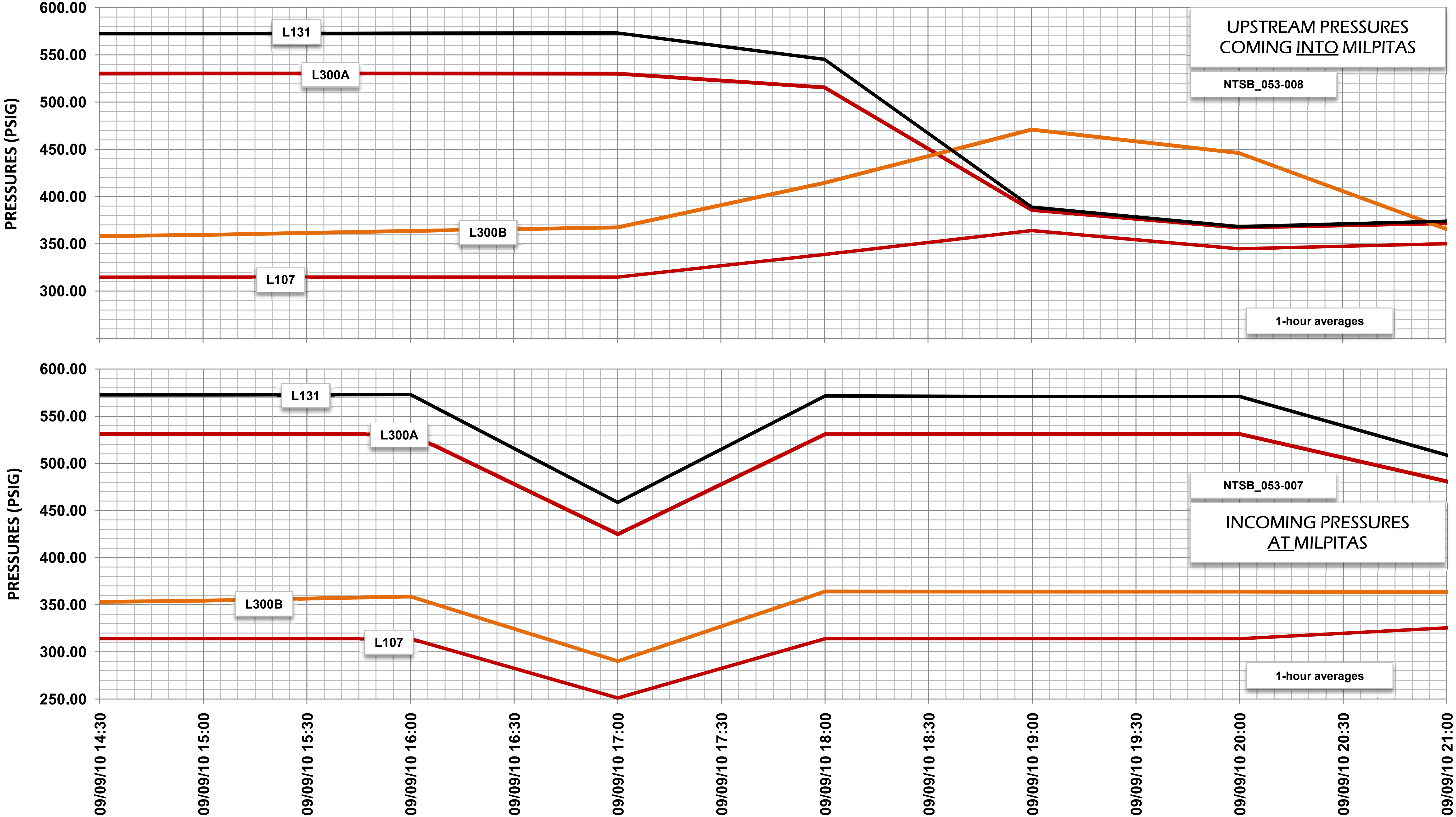




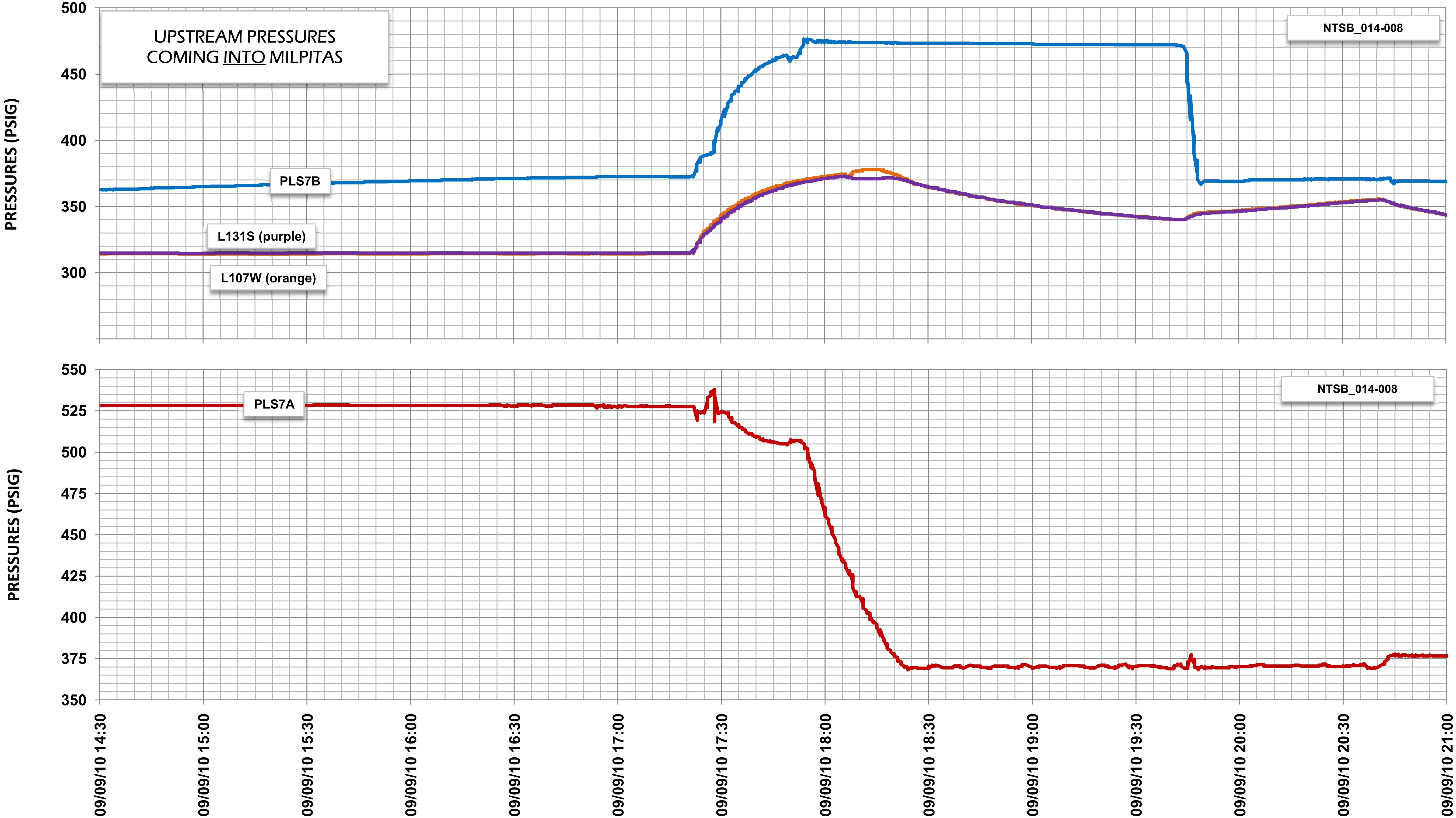
Attachment - [S]



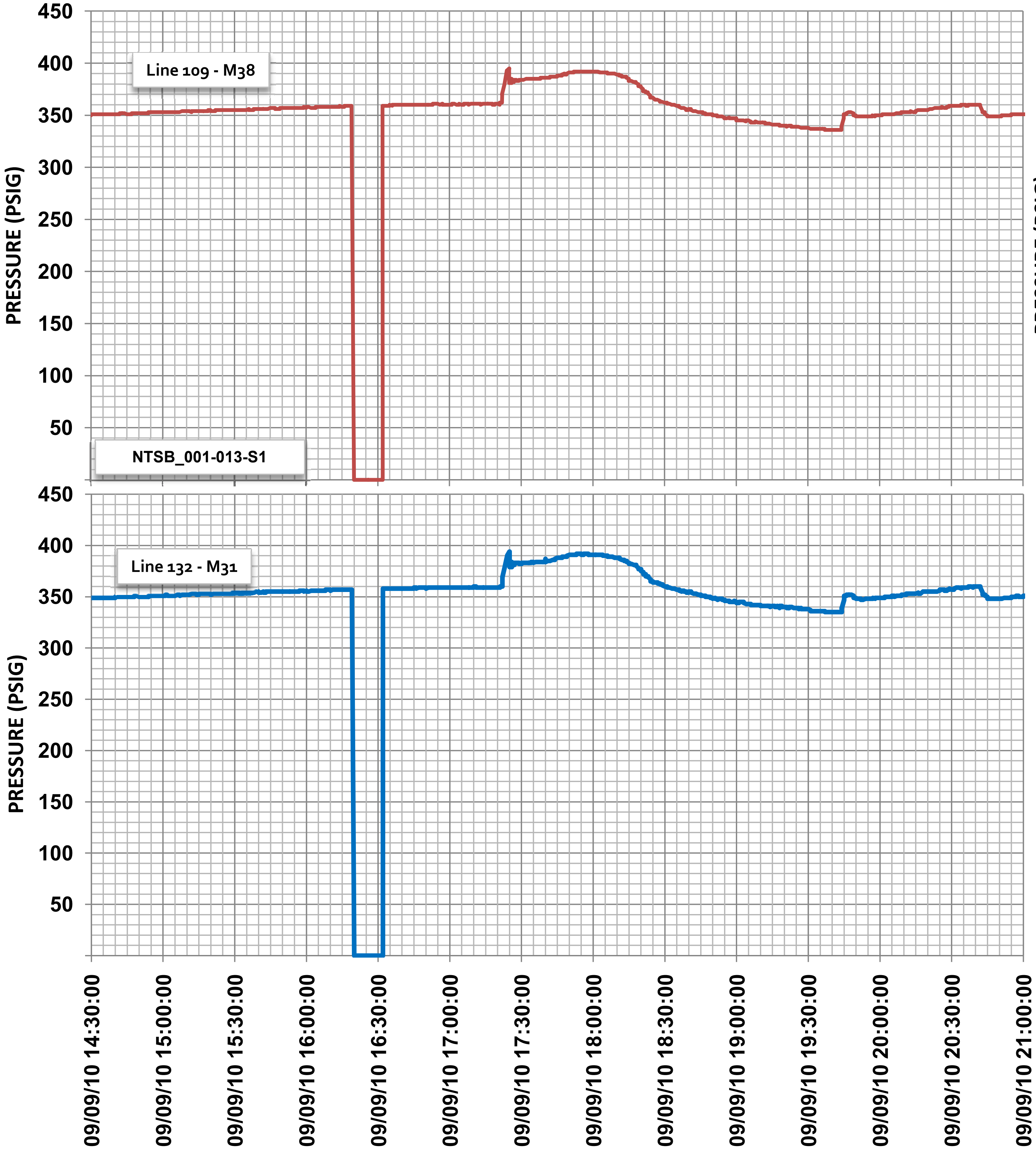
Attachment - [T]

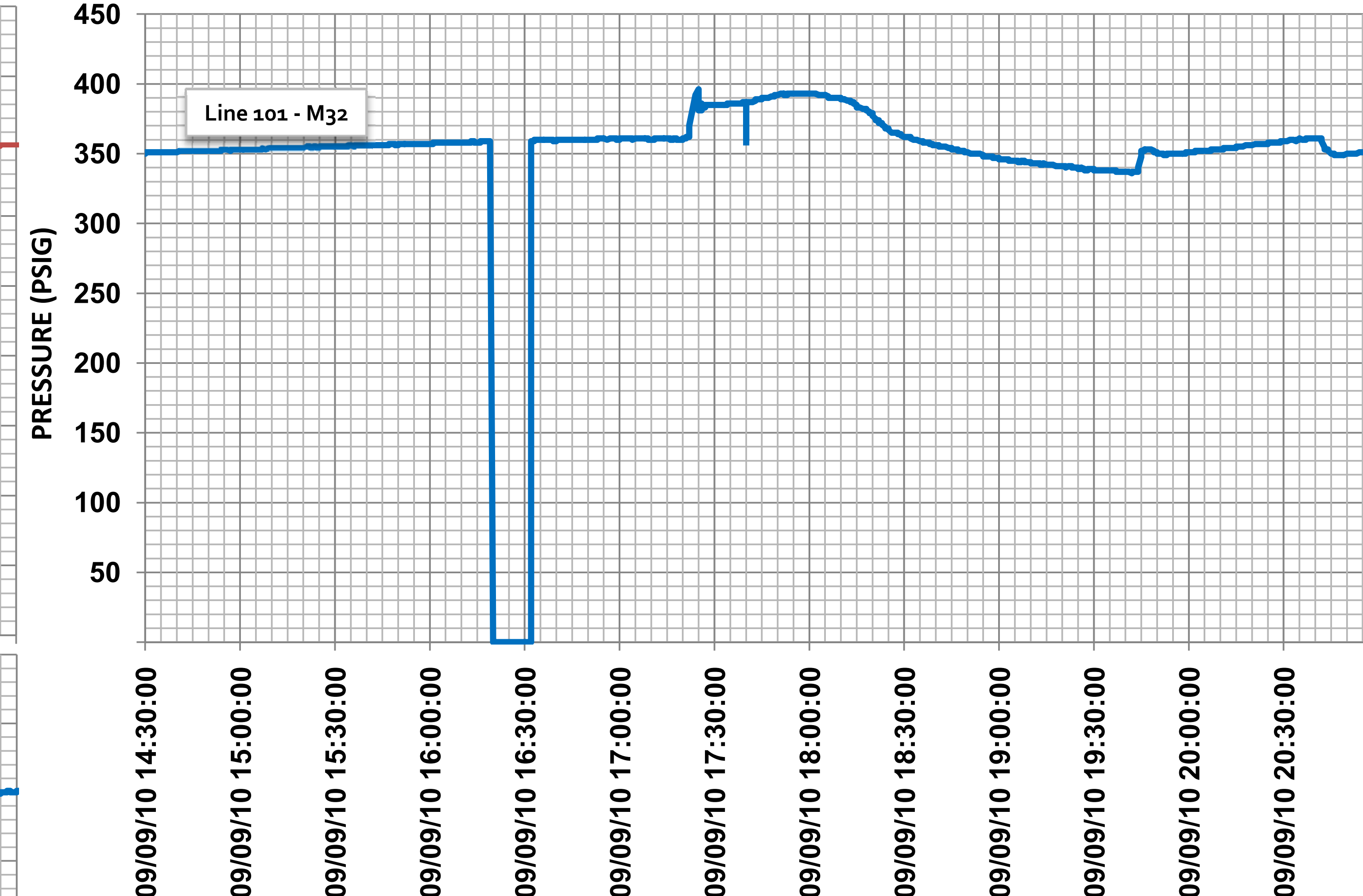


Attachment - [U]



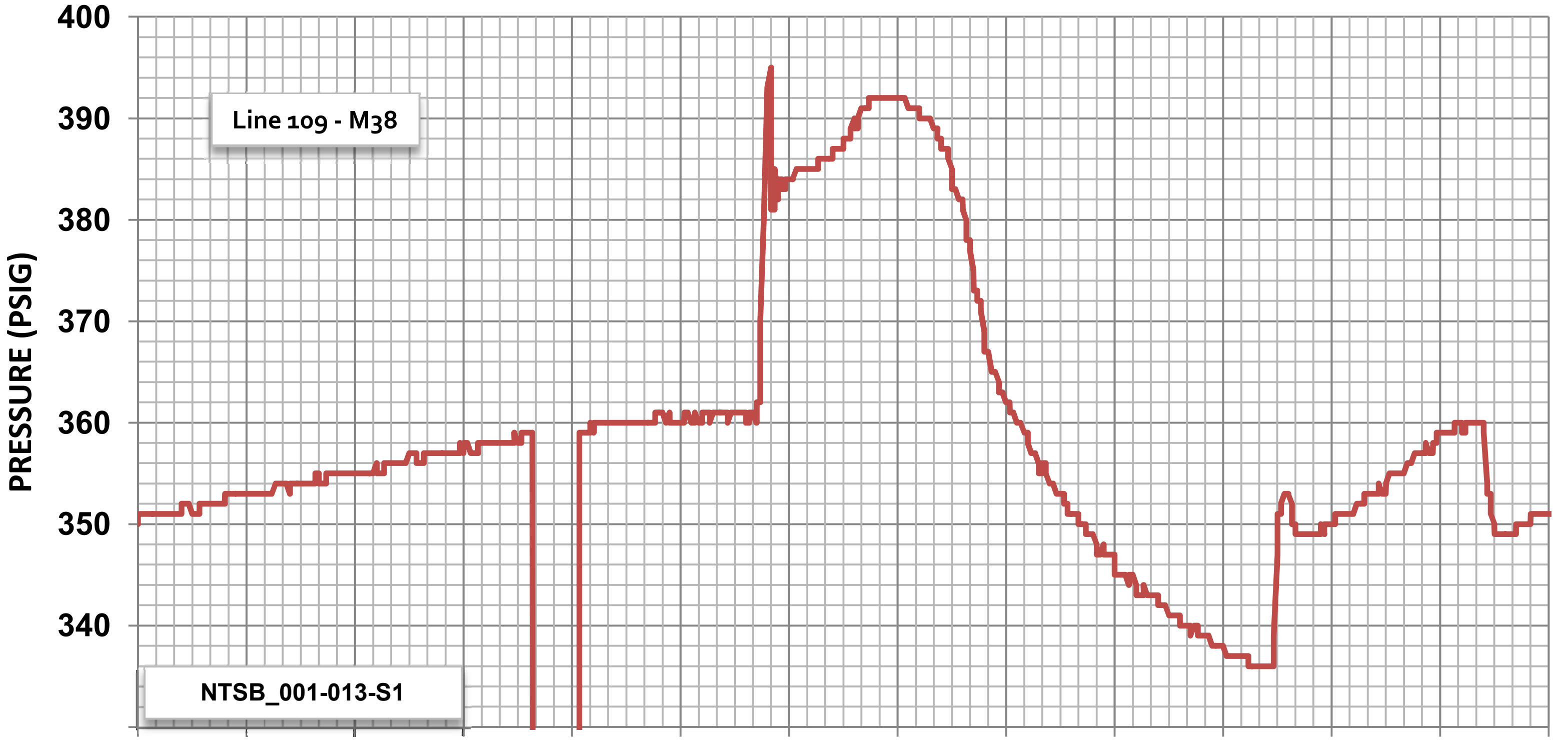
Attachment - [V]

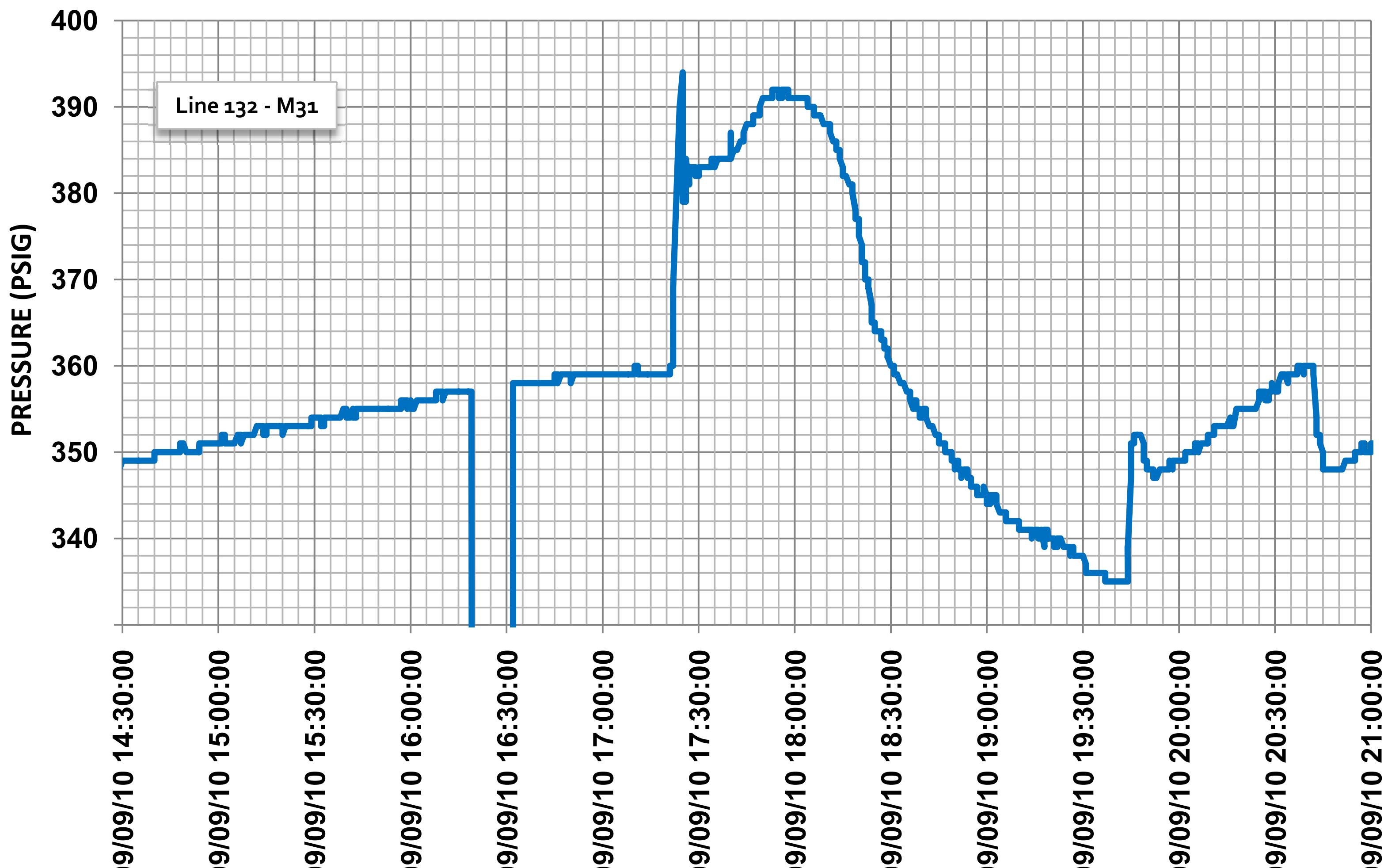


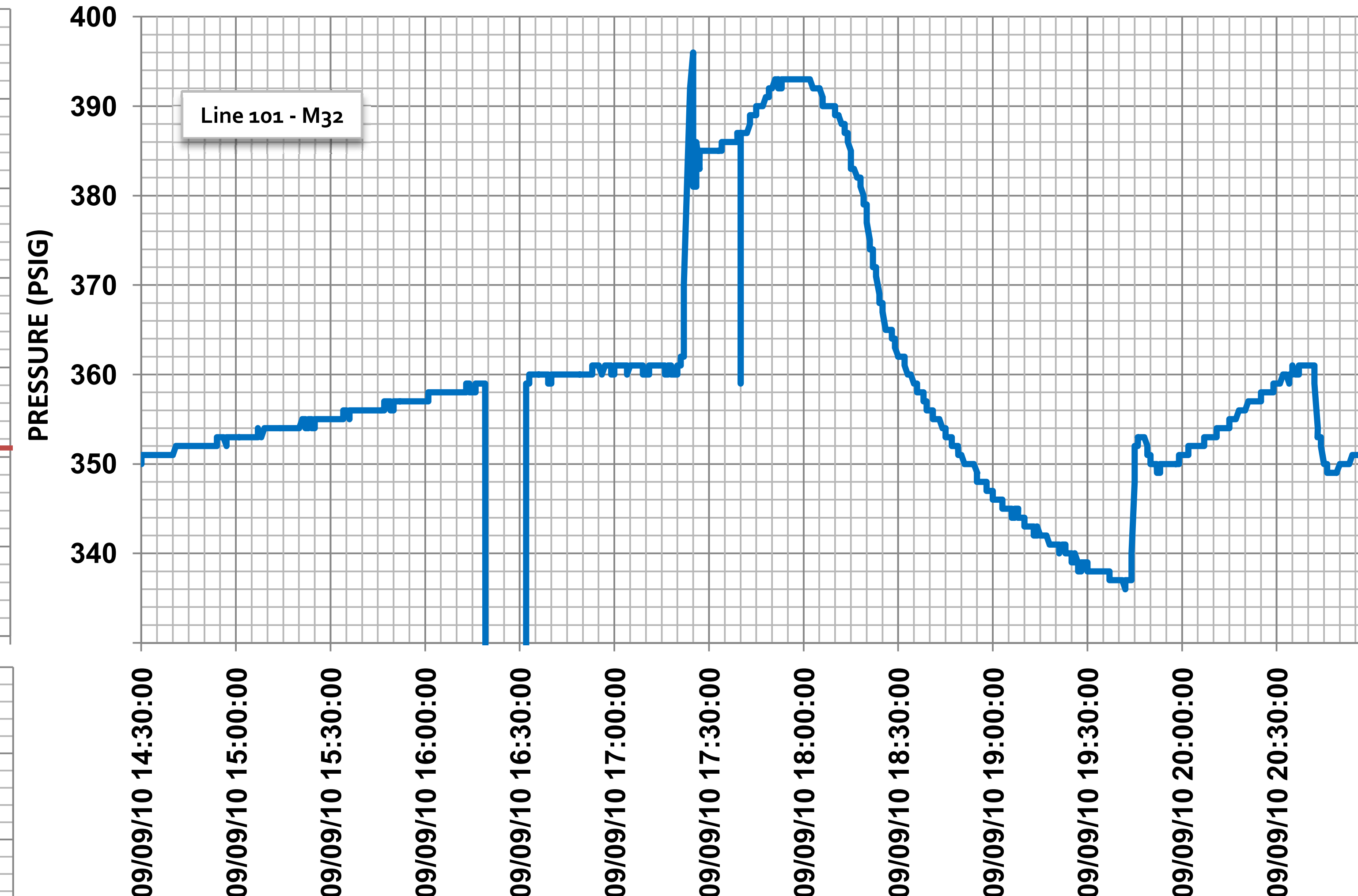


Pressure at Orifice Meters: M38, M31, M32

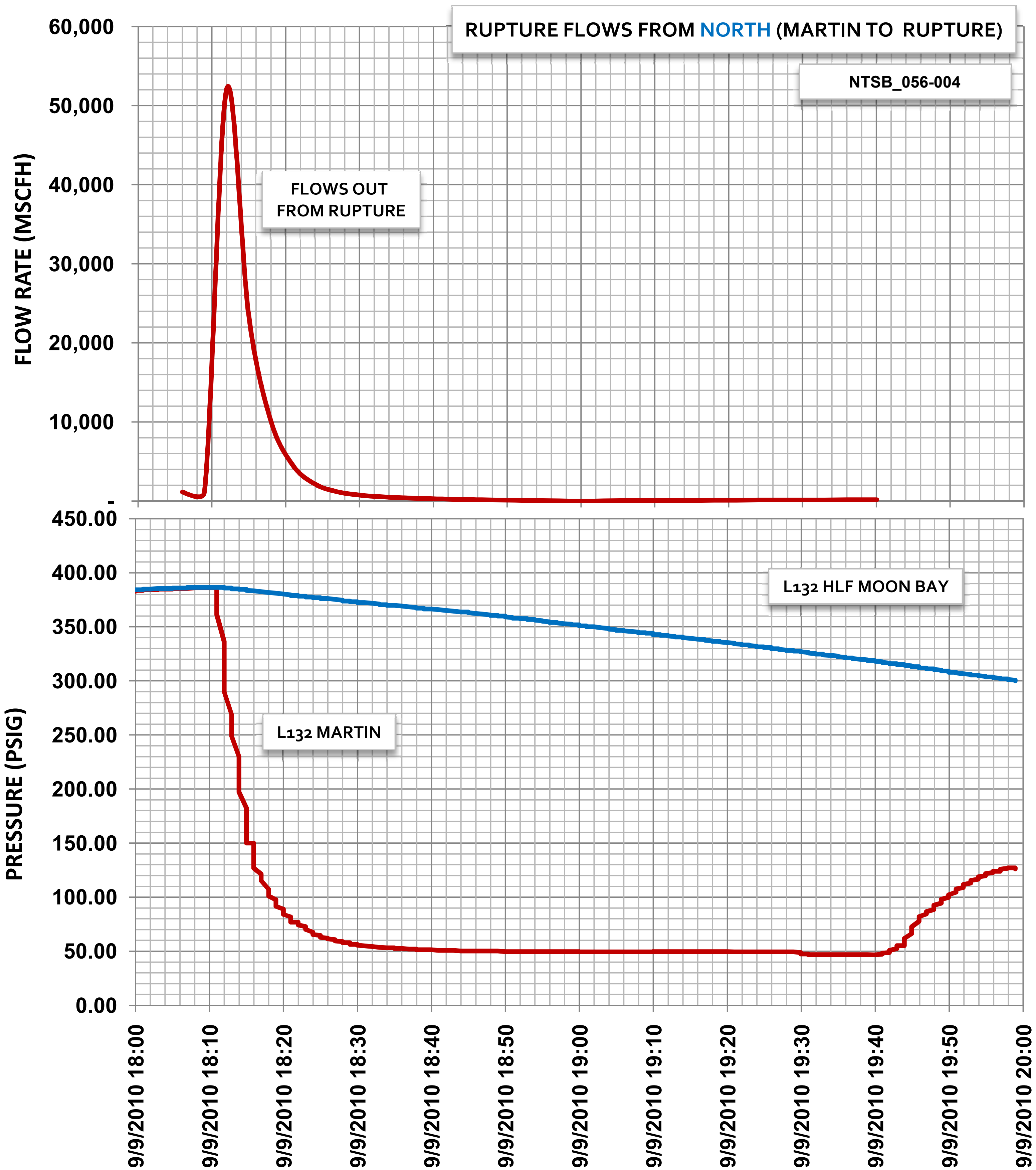
Attachment - [V.1]

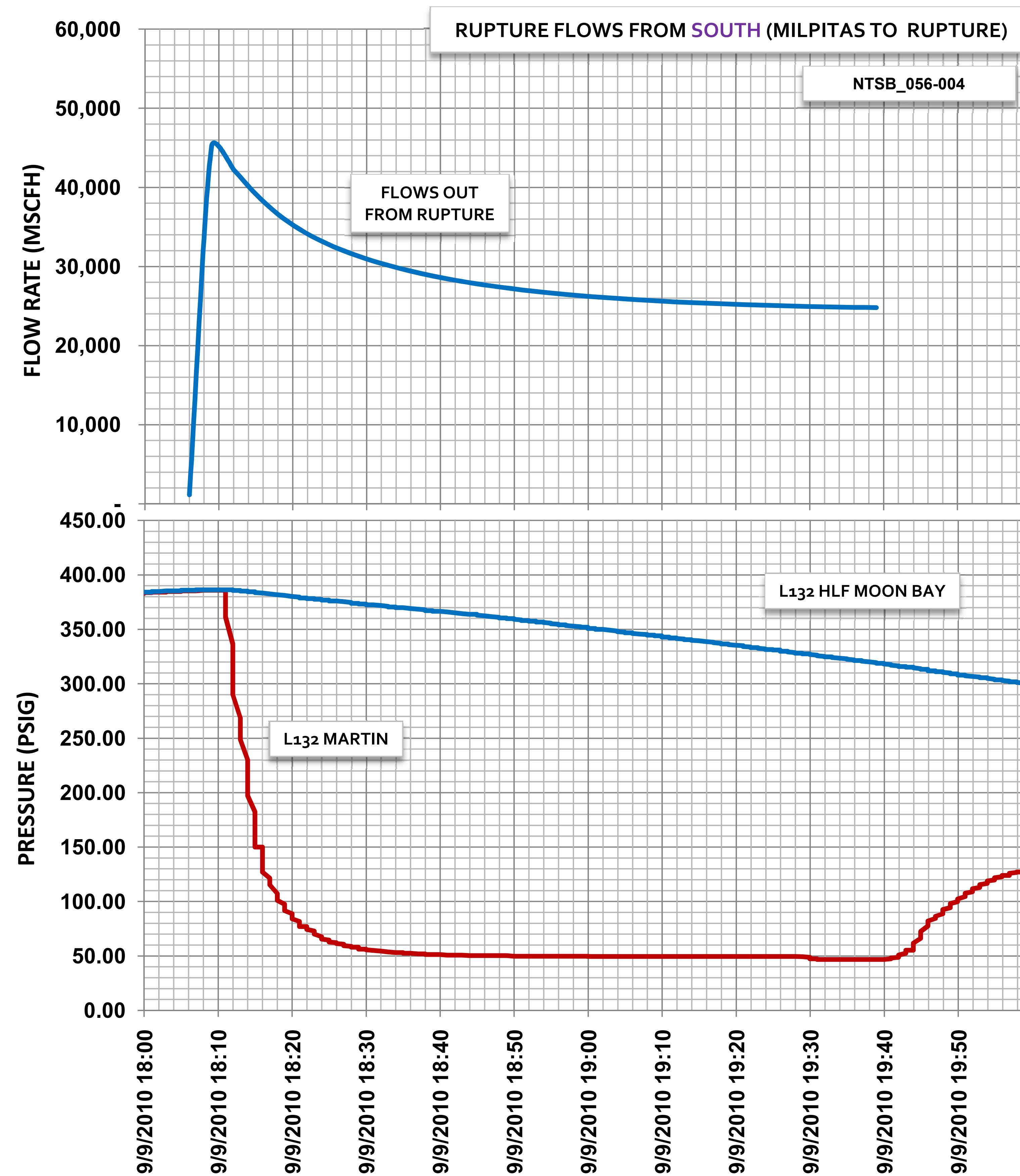




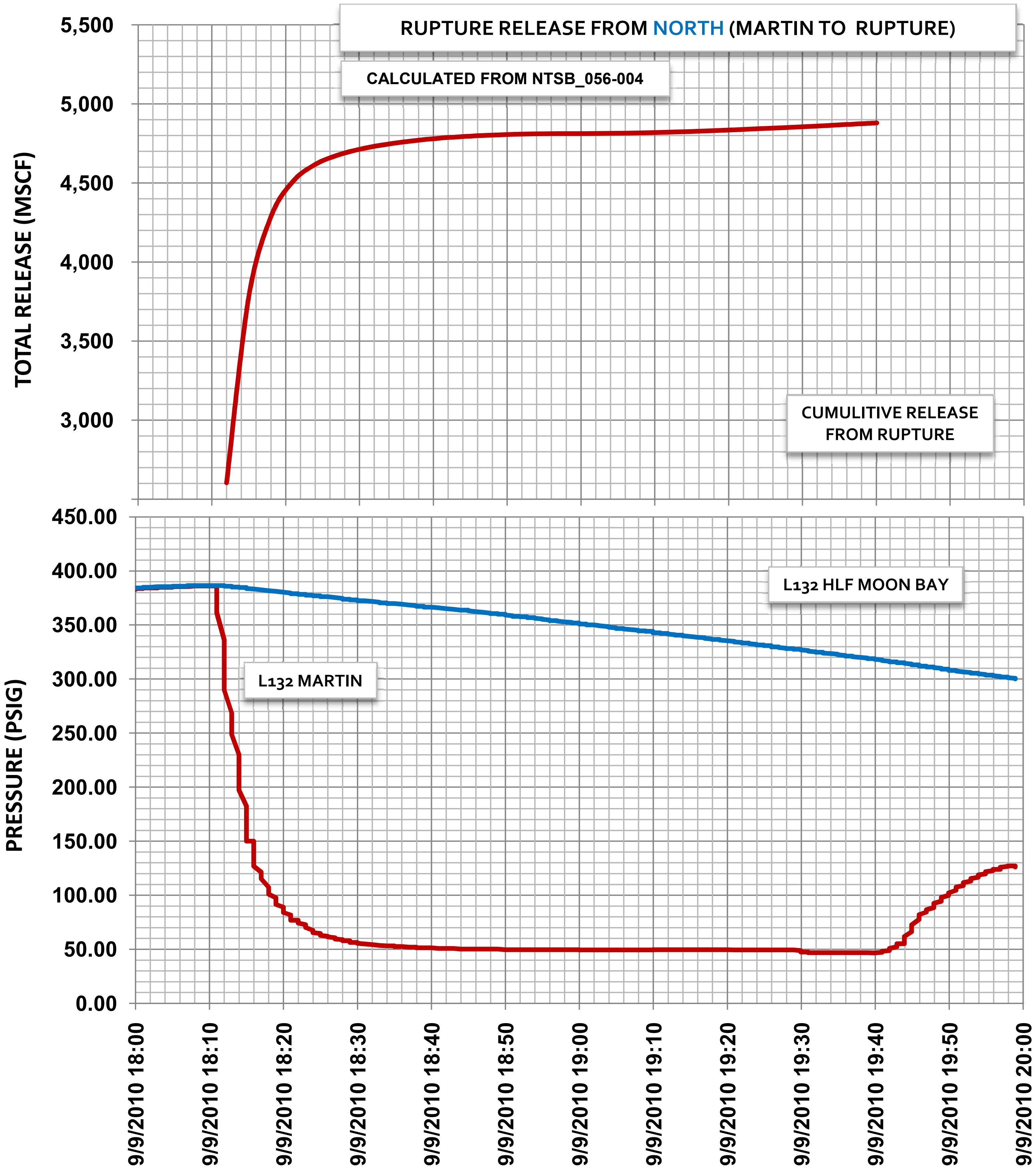


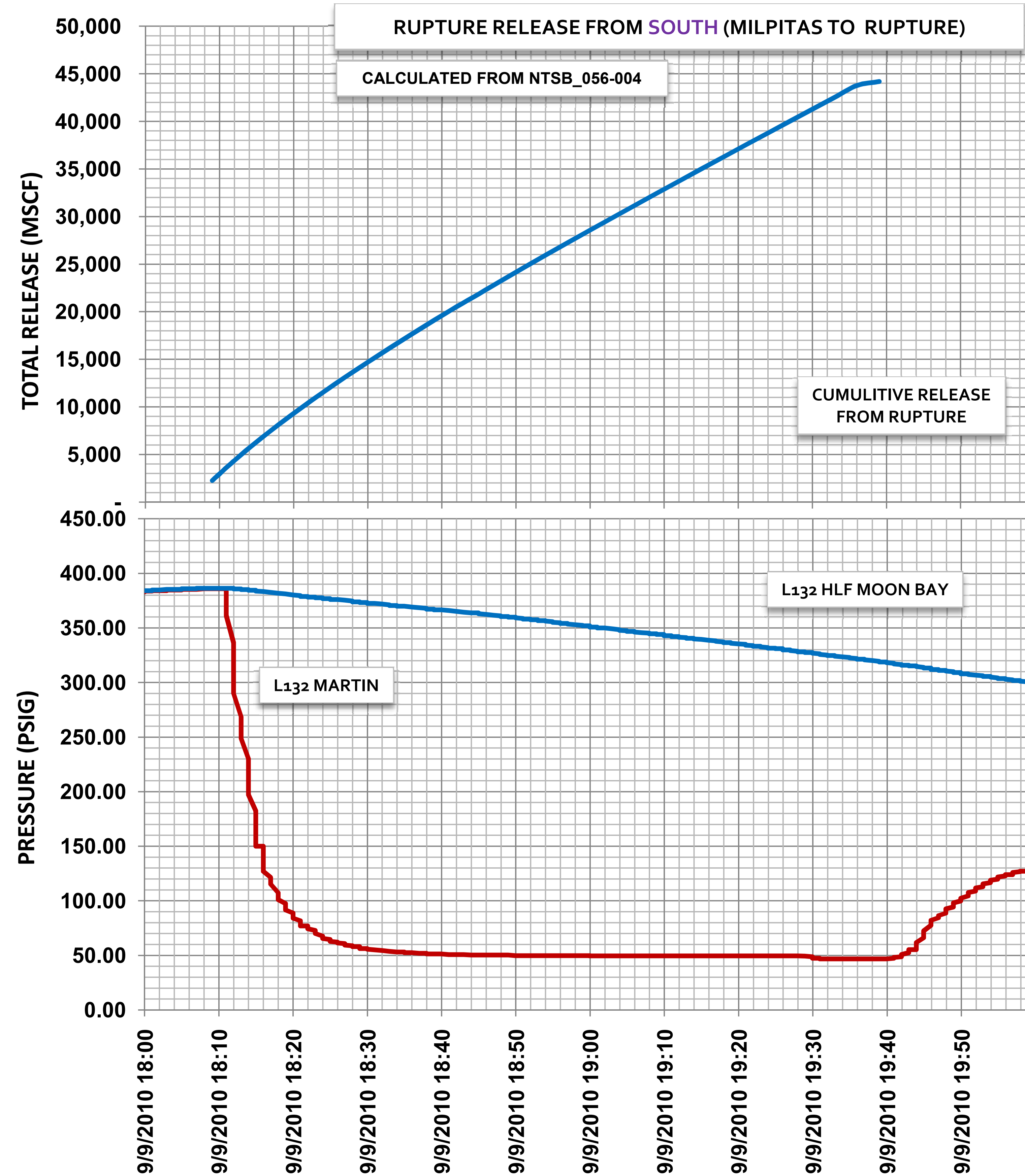
Pressure at Orifice Meters: M38, M31, M32


RUPTURE FLOWS FROM NORTH (MARTIN TO RUPTURE)
NTSB_056-004
FLOW RATE (MSCFH)
60,000
50,000
40,000
30,000
20,000
10,000
-
FLOWS OUT FROM RUPTURE
PRESSURE (PSIG)
450.00
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
0.00
L132 HLF MOON BAY
L132 MARTIN
9/9/2010 18:00
9/9/2010 18:10
9/9/2010 18:20
9/9/2010 18:30
9/9/2010 18:40
9/9/2010 18:50
9/9/2010 19:00
9/9/2010 19:10
9/9/2010 19:20
9/9/2010 19:30
9/9/2010 19:40
9/9/2010 19:50
9/9/2010 20:00

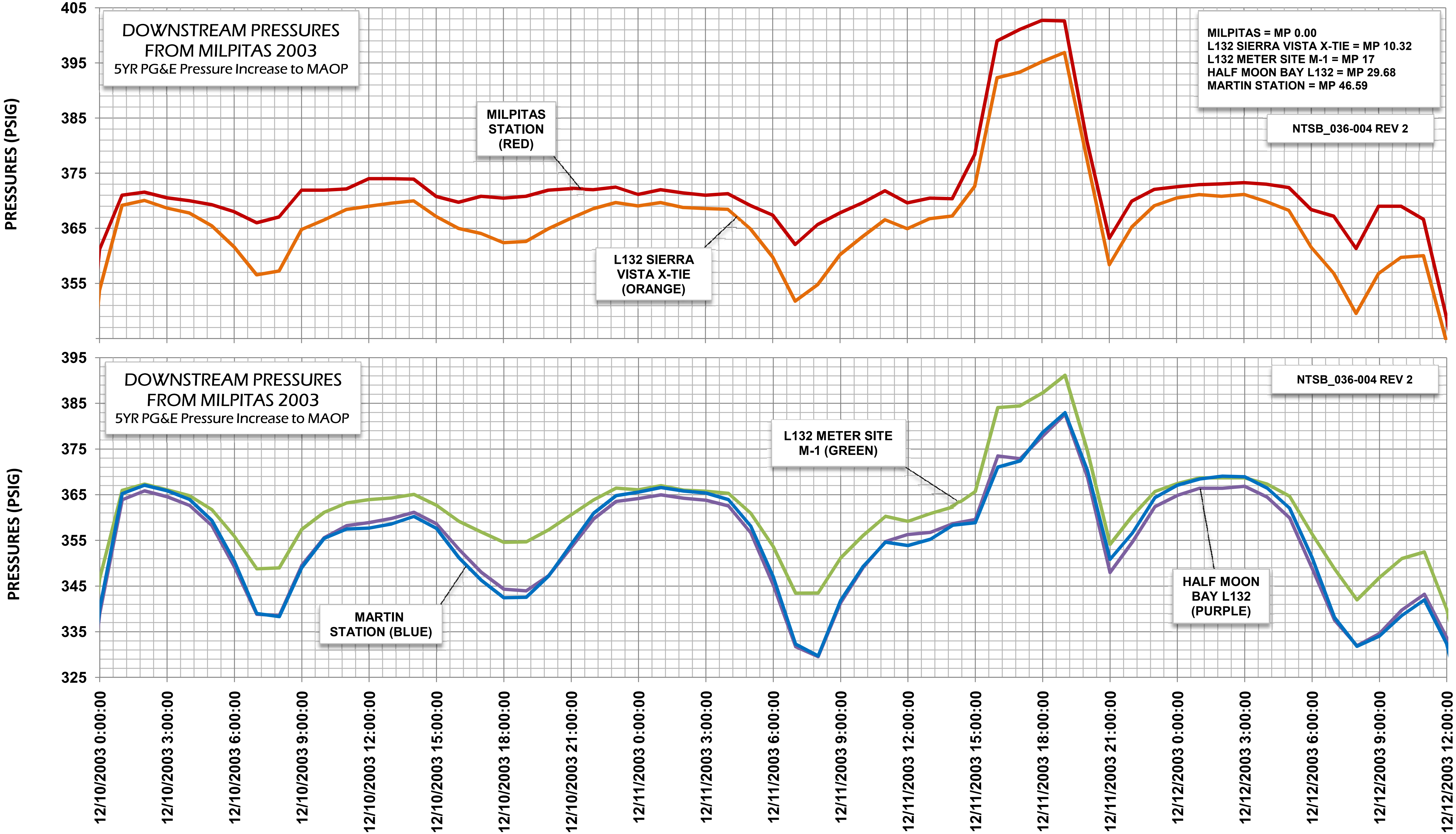

RUPTURE FLOWS FROM SOUTH (MILPITAS TO RUPTURE)
NTSB_056-004
FLOW RATE (MSCFH)
60,000
50,000
40,000
30,000
20,000
10,000
-
FLOWS OUT FROM RUPTURE
PRESSURE (PSIG)
450.00
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
0.00
L132 HLF MOON BAY
L132 MARTIN
9/9/2010 18:00
9/9/2010 18:10
9/9/2010 18:20
9/9/2010 18:30
9/9/2010 18:40
9/9/2010 18:50
9/9/2010 19:00
9/9/2010 19:10
9/9/2010 19:20
9/9/2010 19:30
9/9/2010 19:40
9/9/2010 19:50
9/9/2010 20:00

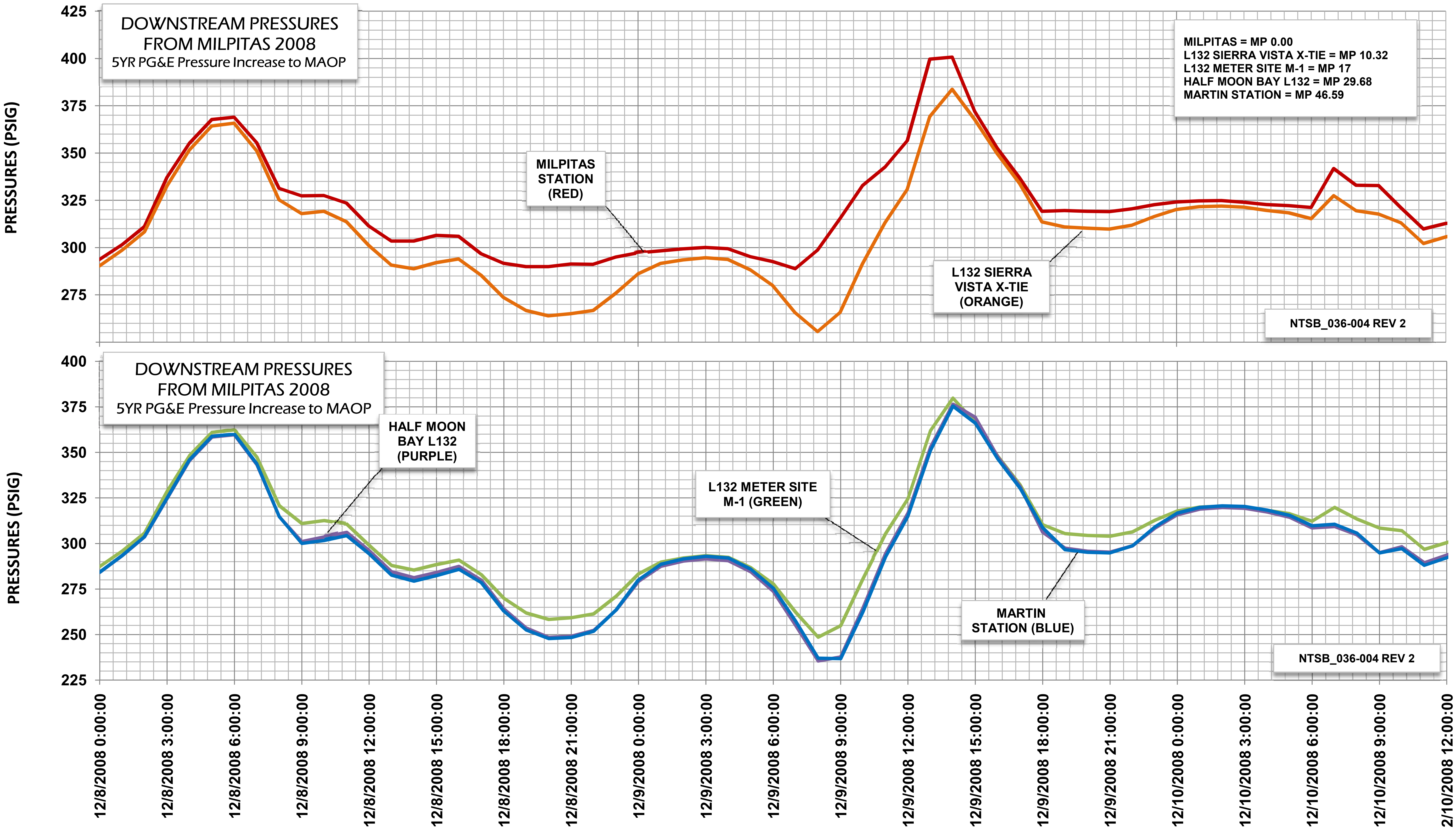
Attachment - [X]

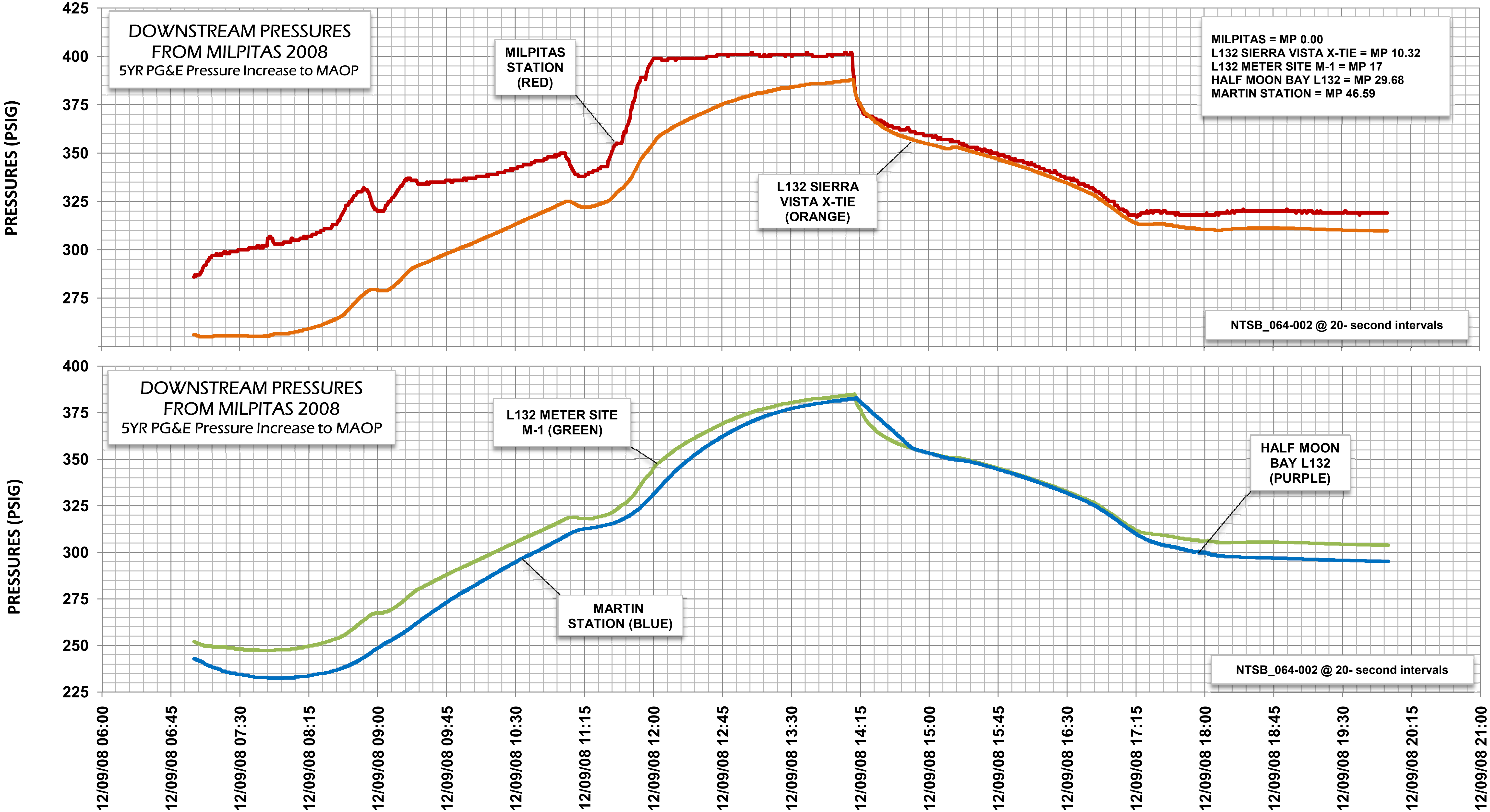




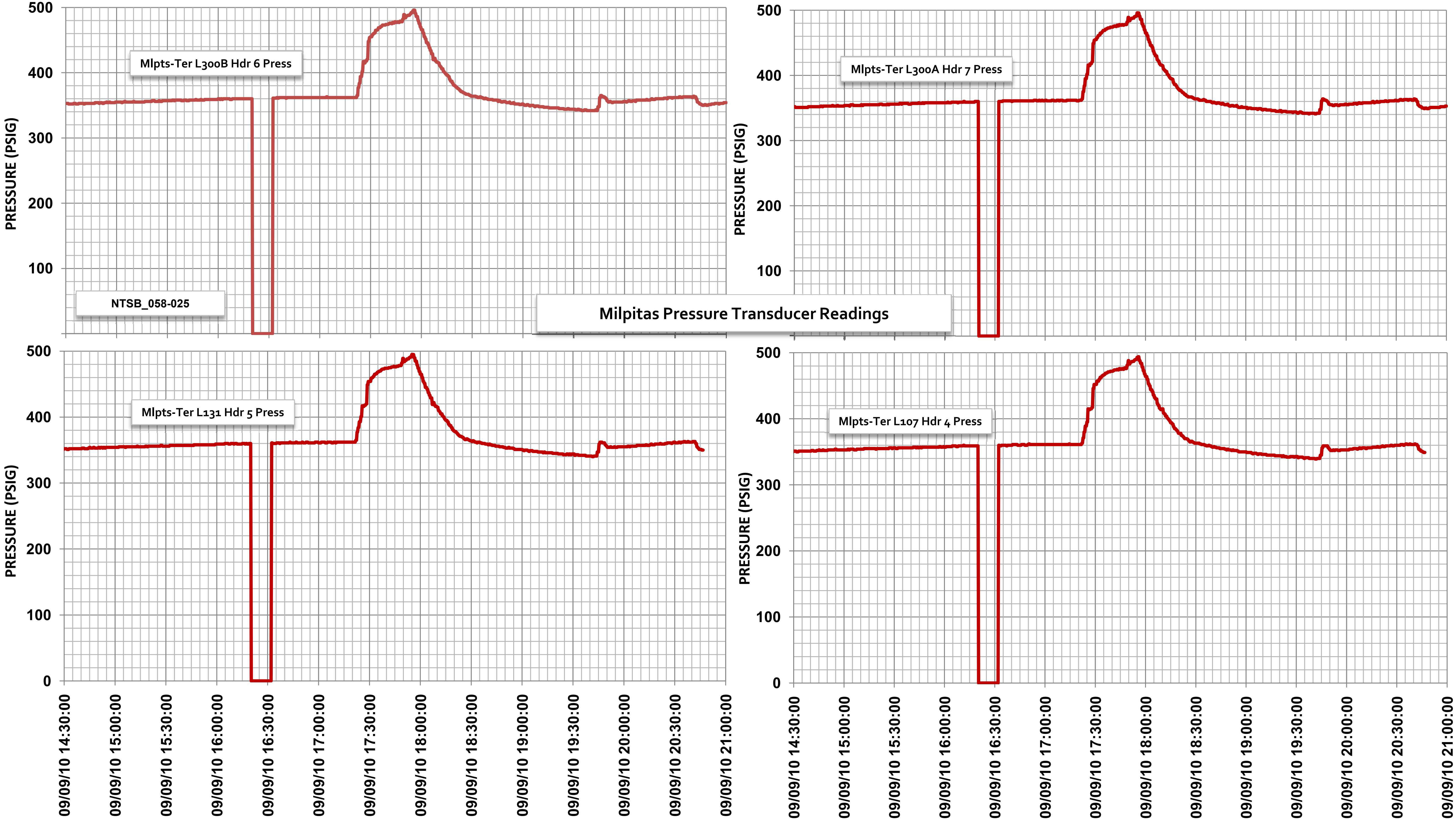
Attachment - [Y]



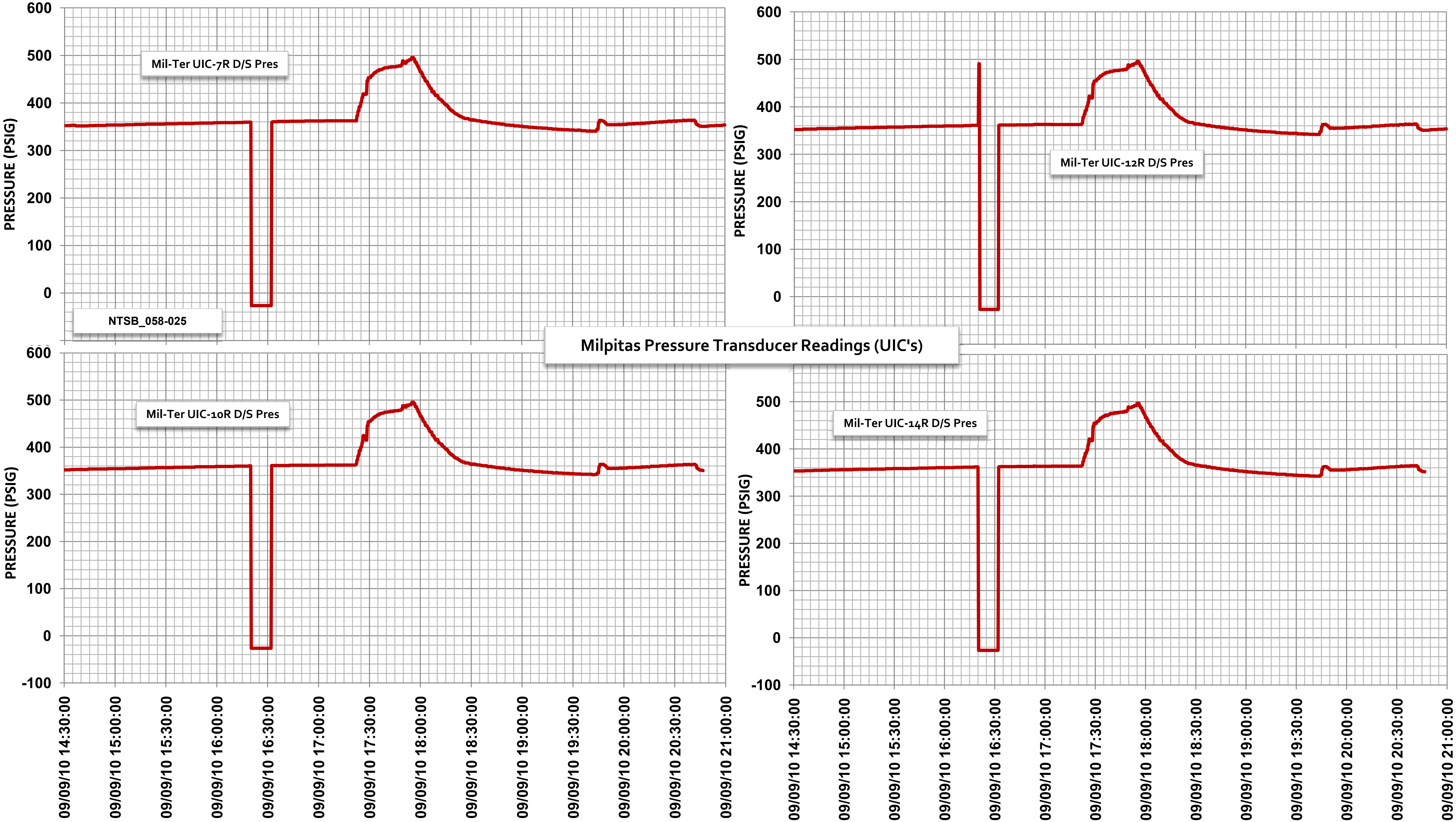

DOWNSTREAM PRESSURES FROM MILPITAS 2008
5YR PG&E Pressure Increase to MAOP
PRESSURES (PSIG)
425
400
375
350
325
300
275
MILPITAS STATION (RED)
L132 SIERRA VISTA X-TIE (ORANGE)
MILPITAS = MP 0.00
L132 SIERRA VISTA X-TIE = MP 10.32
L132 METER SITE M-1 = MP 17
HALF MOON BAY L132 = MP 29.68
MARTIN STATION = MP 46.59
NTSB_036-004 REV 2
DOWNSTREAM PRESSURES FROM MILPITAS 2008
5YR PG&E Pressure Increase to MAOP
PRESSURES (PSIG)
400
375
350
325
300
275
250
225
HALF MOON BAY L132 (PURPLE)
L132 METER SITE M-1 (GREEN)
MARTIN STATION (BLUE)
NTSB_036-004 REV 2
12/8/2008 0:00:00
12/8/2008 3:00:00
12/8/2008 6:00:00
12/8/2008 9:00:00
12/8/2008 12:00:00
12/8/2008 15:00:00
12/8/2008 18:00:00
12/8/2008 21:00:00
12/9/2008 0:00:00
12/9/2008 3:00:00
12/9/2008 6:00:00
12/9/2008 9:00:00
12/9/2008 12:00:00
12/9/2008 15:00:00
12/9/2008 18:00:00
12/9/2008 21:00:00
12/10/2008 0:00:00
12/10/2008 3:00:00
12/10/2008 6:00:00
12/10/2008 9:00:00
12/10/2008 12:00:00


DOWNSTREAM PRESSURES
FROM MILPITAS 2008
5YR PG&E Pressure Increase to MAOP
MILPITAS STATION (RED)
L132 SIERRA VISTA X-TIE (ORANGE)
MILPITAS = MP 0.00
L132 SIERRA VISTA X-TIE = MP 10.32
L132 METER SITE M-1 = MP 17
HALF MOON BAY L132 = MP 29.68
MARTIN STATION = MP 46.59
NTSB_064-002 @ 20- second intervals
PRESSURES (PSIG)
425
400
375
350
325
300
275
DOWNSTREAM PRESSURES
FROM MILPITAS 2008
5YR PG&E Pressure Increase to MAOP
L132 METER SITE M-1 (GREEN)
HALF MOON BAY L132 (PURPLE)
MARTIN STATION (BLUE)
NTSB_064-002 @ 20- second intervals
PRESSURES (PSIG)
400
375
350
325
300
275
250
225
12/09/08 06:00
12/09/08 06:45
12/09/08 07:30
12/09/08 08:15
12/09/08 09:00
12/09/08 09:45
12/09/08 10:30
12/09/08 11:15
12/09/08 12:00
12/09/08 12:45
12/09/08 13:30
12/09/08 14:15
12/09/08 15:00
12/09/08 15:45
12/09/08 16:30
12/09/08 17:15
12/09/08 18:00
12/09/08 18:45
12/09/08 19:30
12/09/08 20:15
12/09/08 21:00

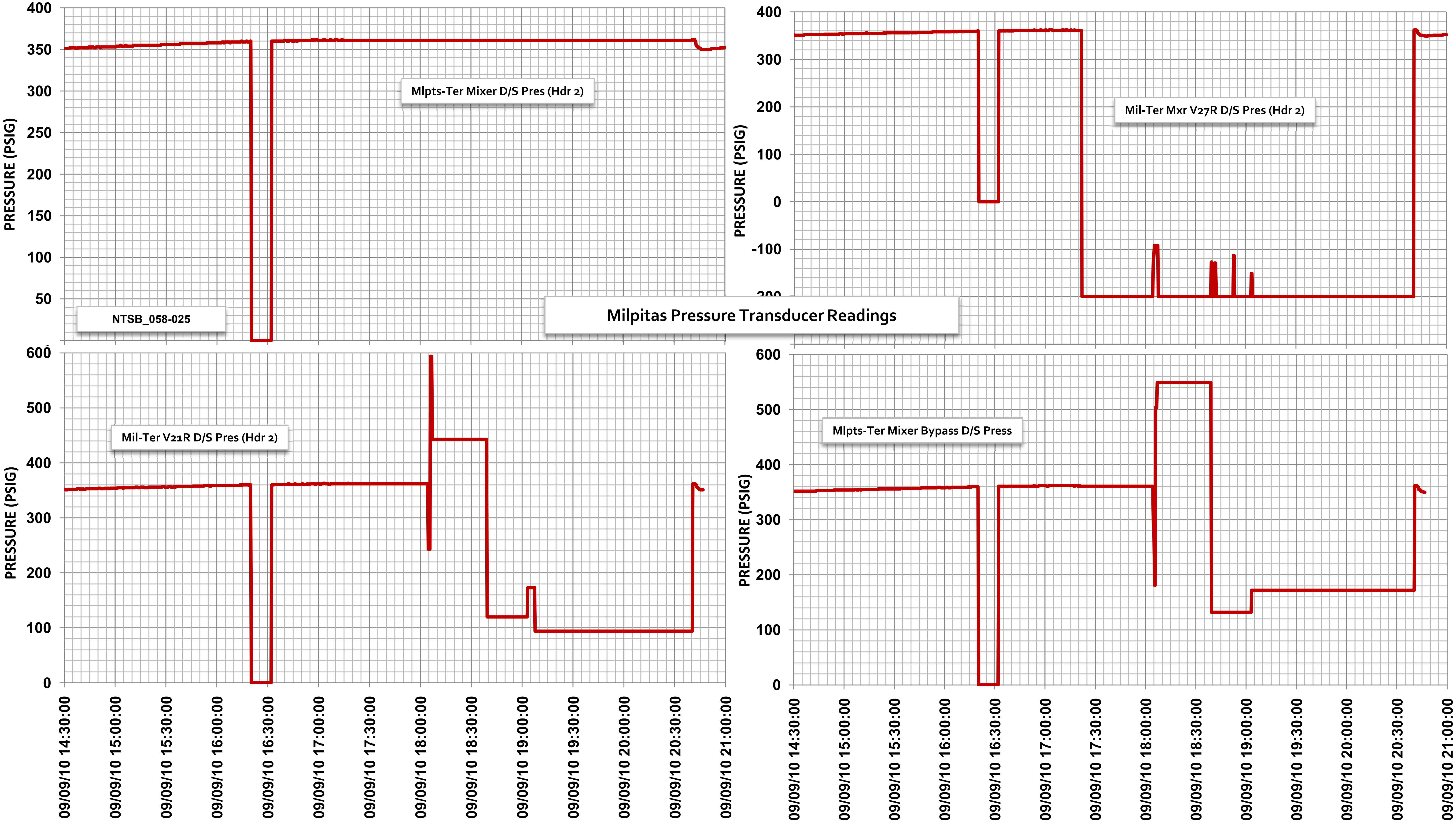
Attachment - [AA]

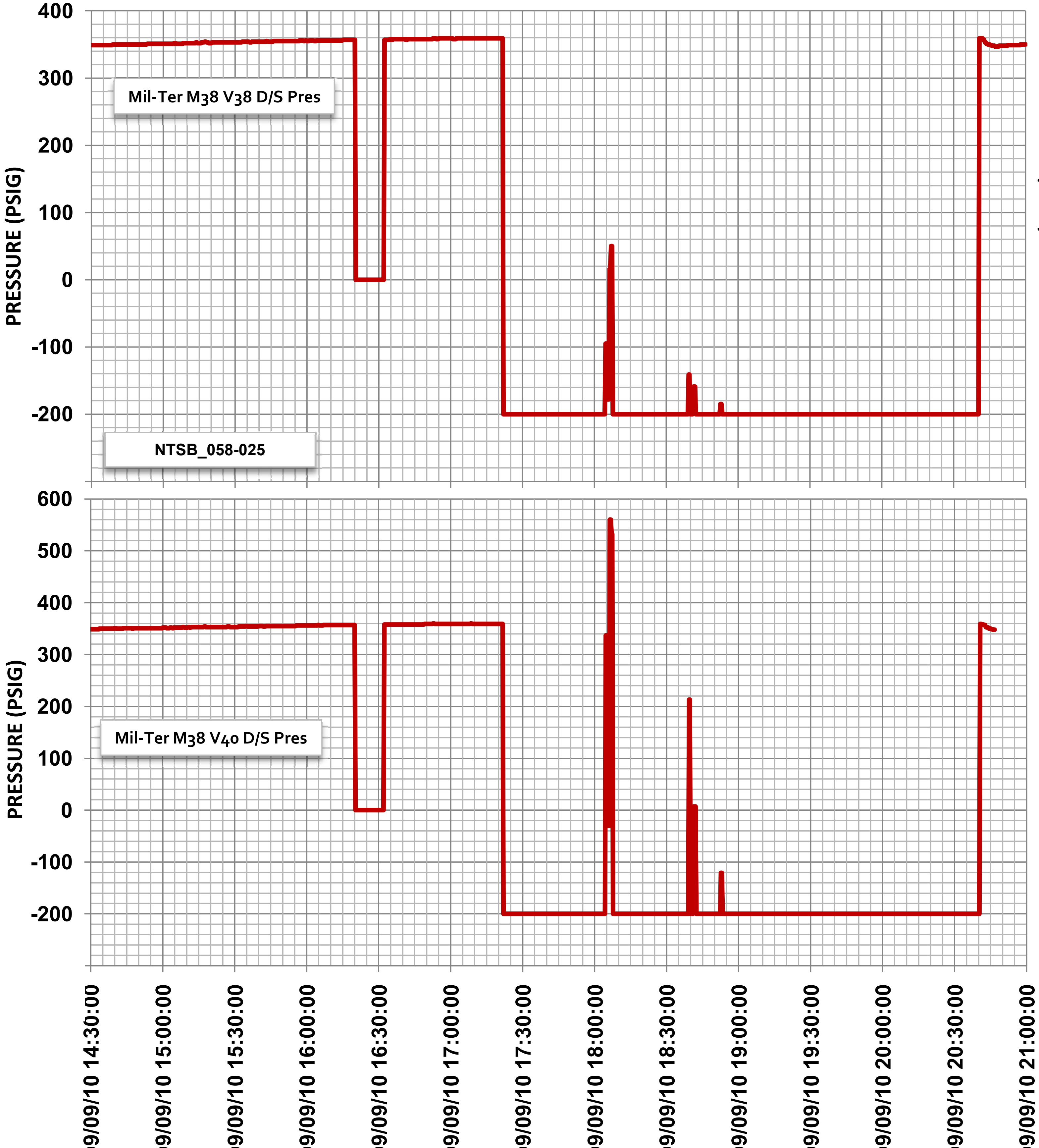


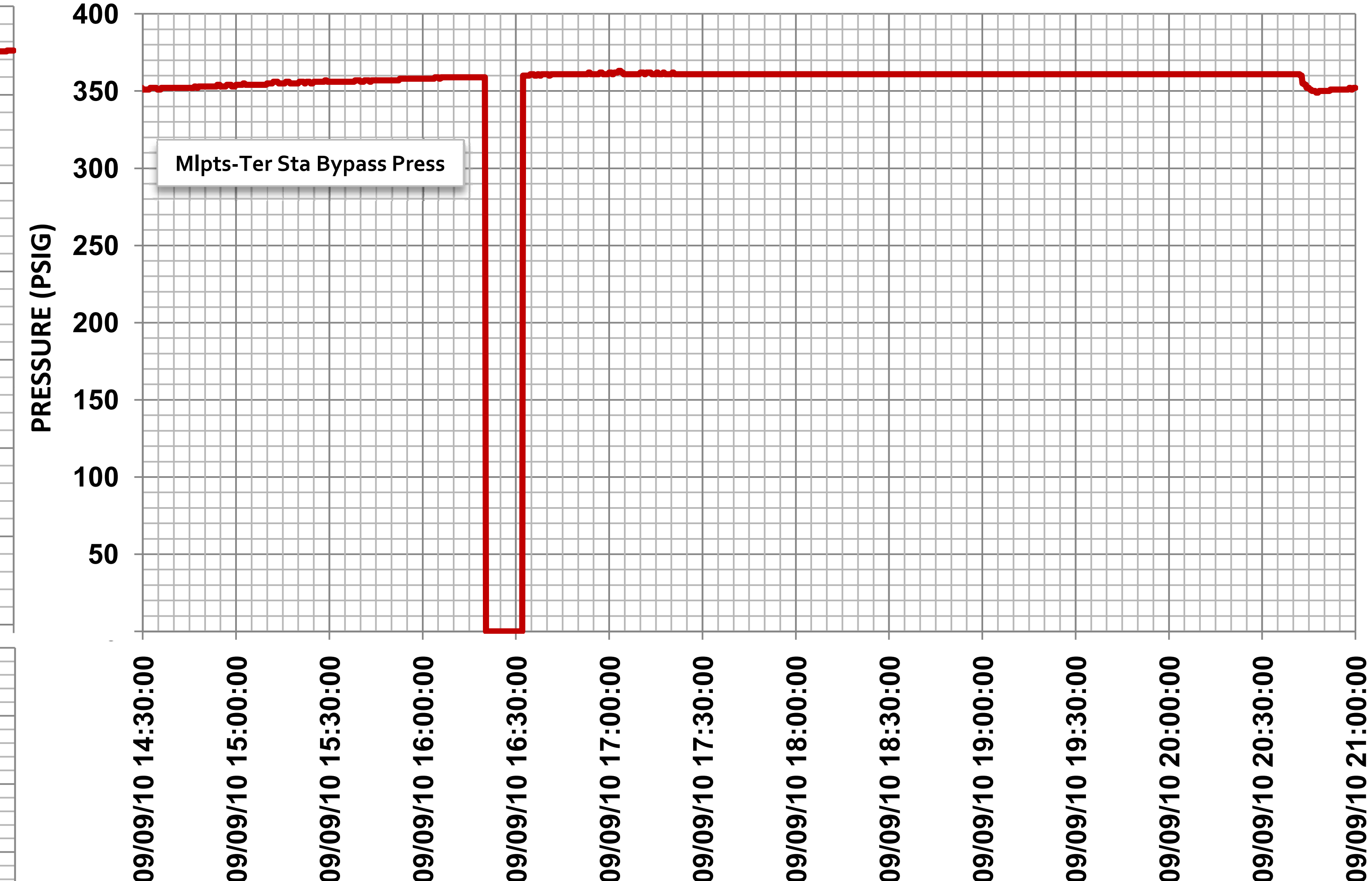
Attachment - [AB]



Attachment - [AC]

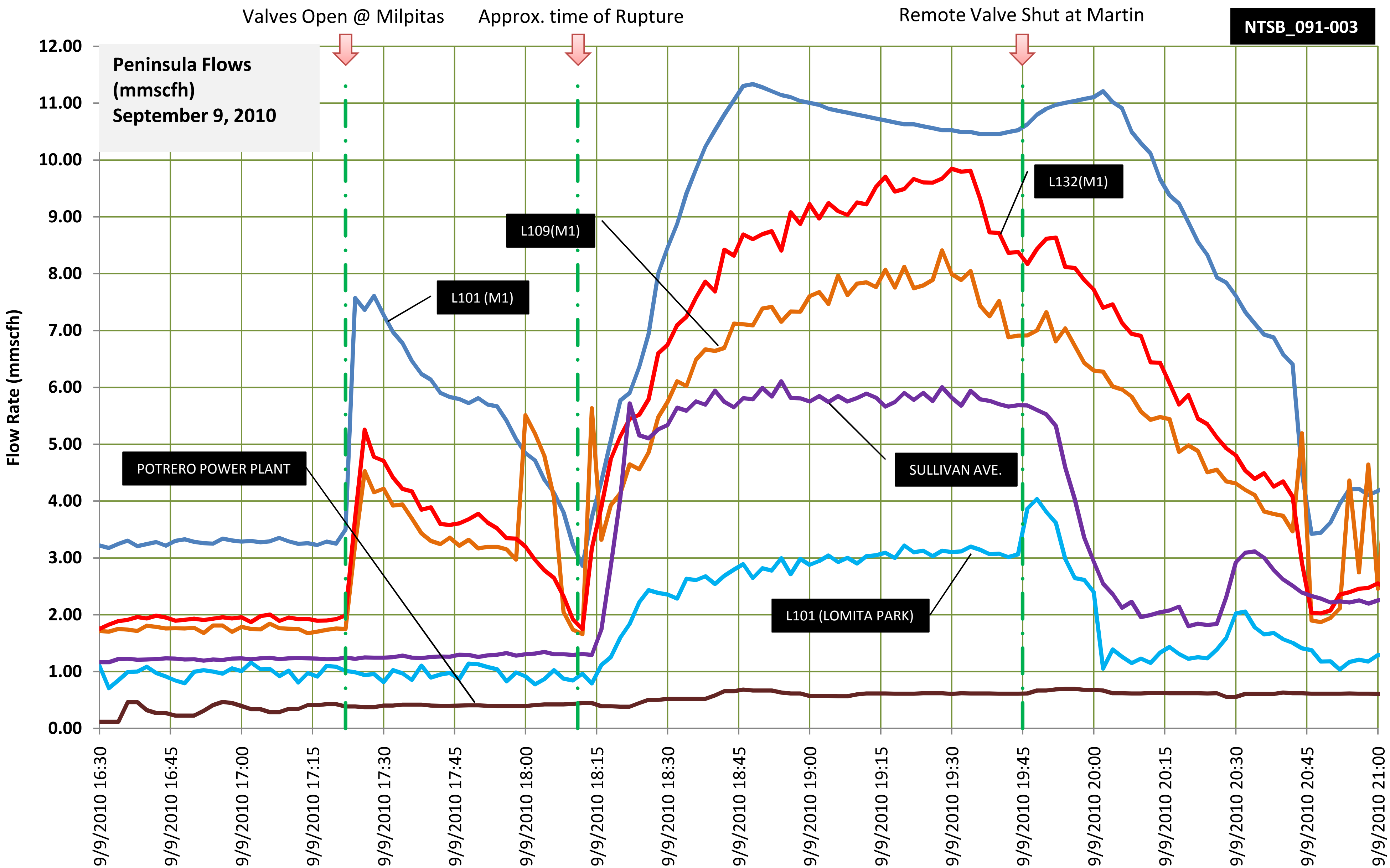


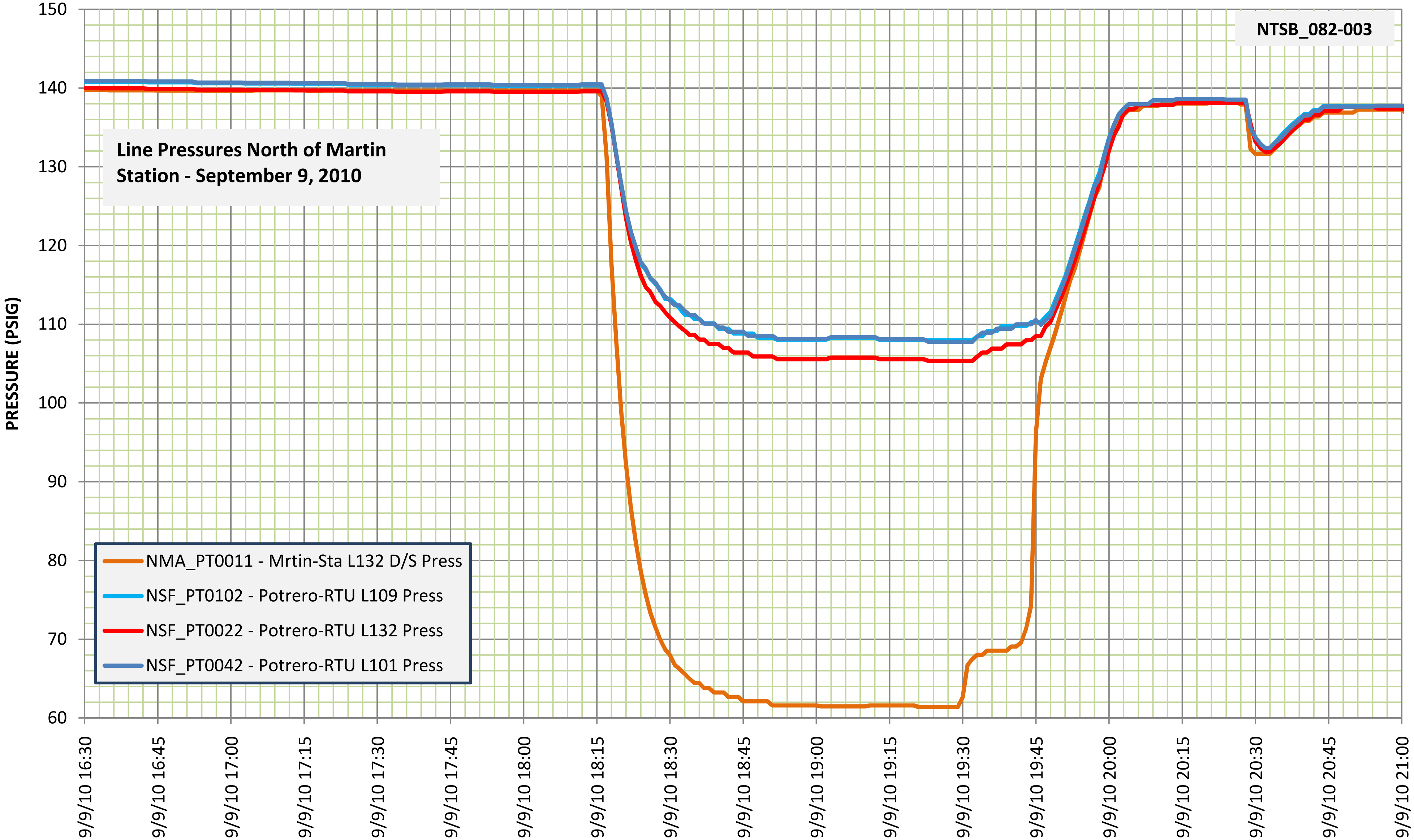




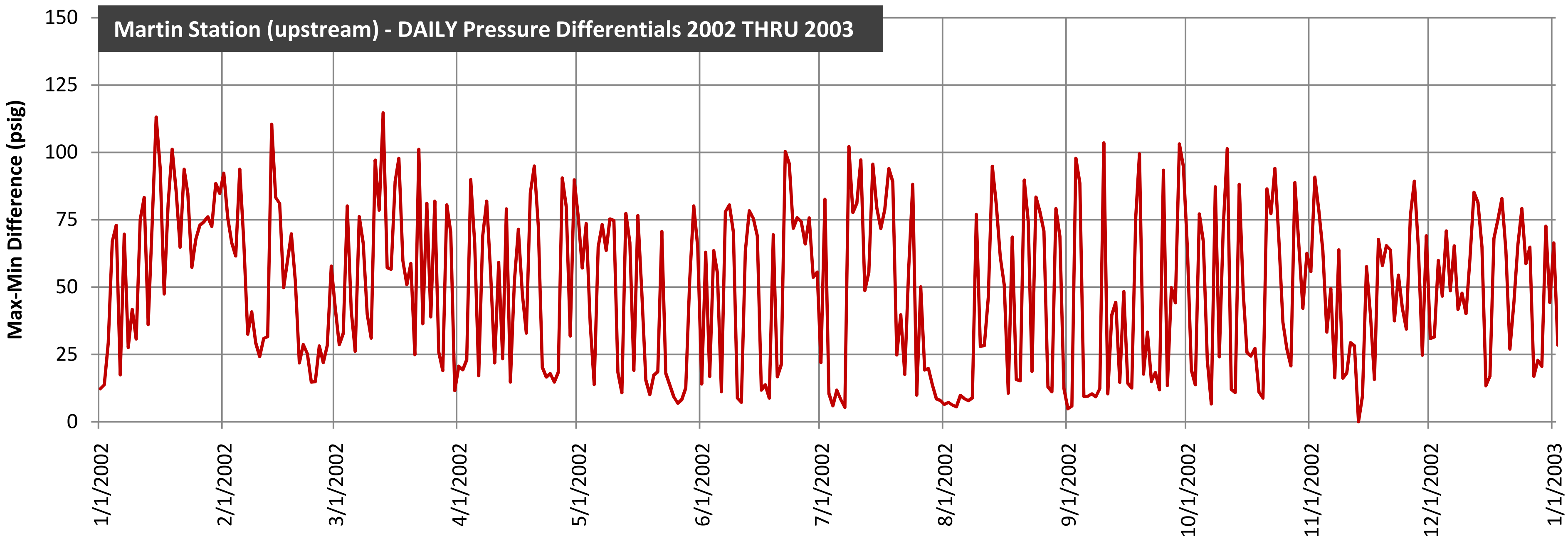
Milpitas Pressure Transducer Readings

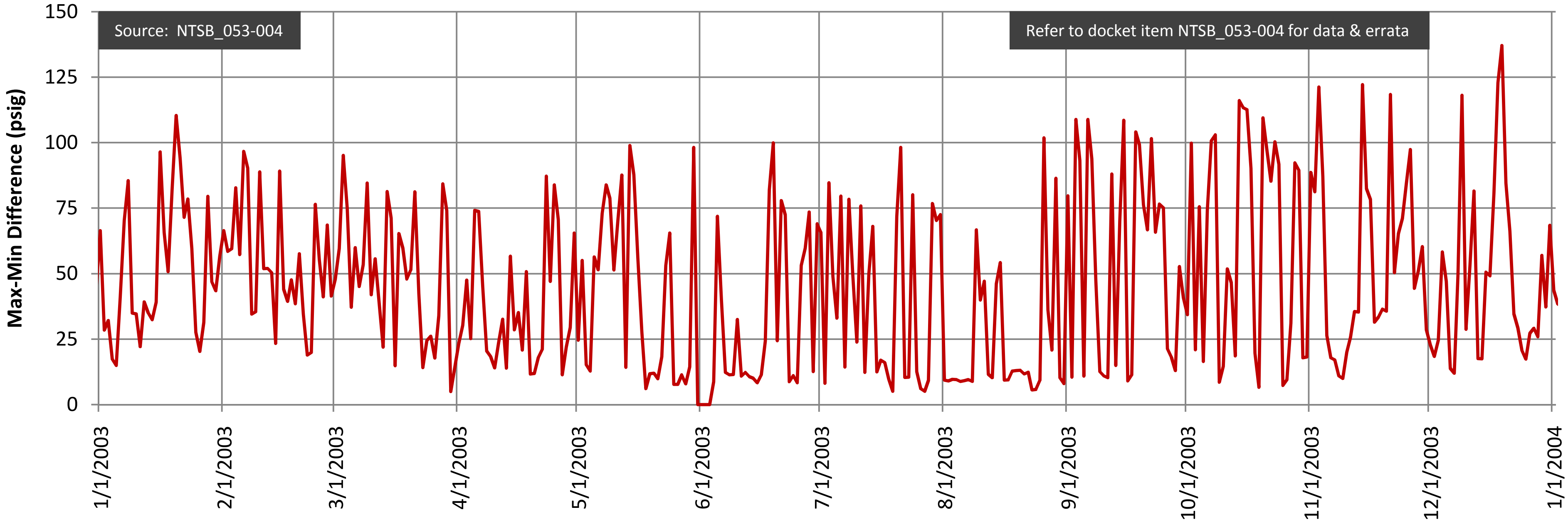
Attachment - [AE]



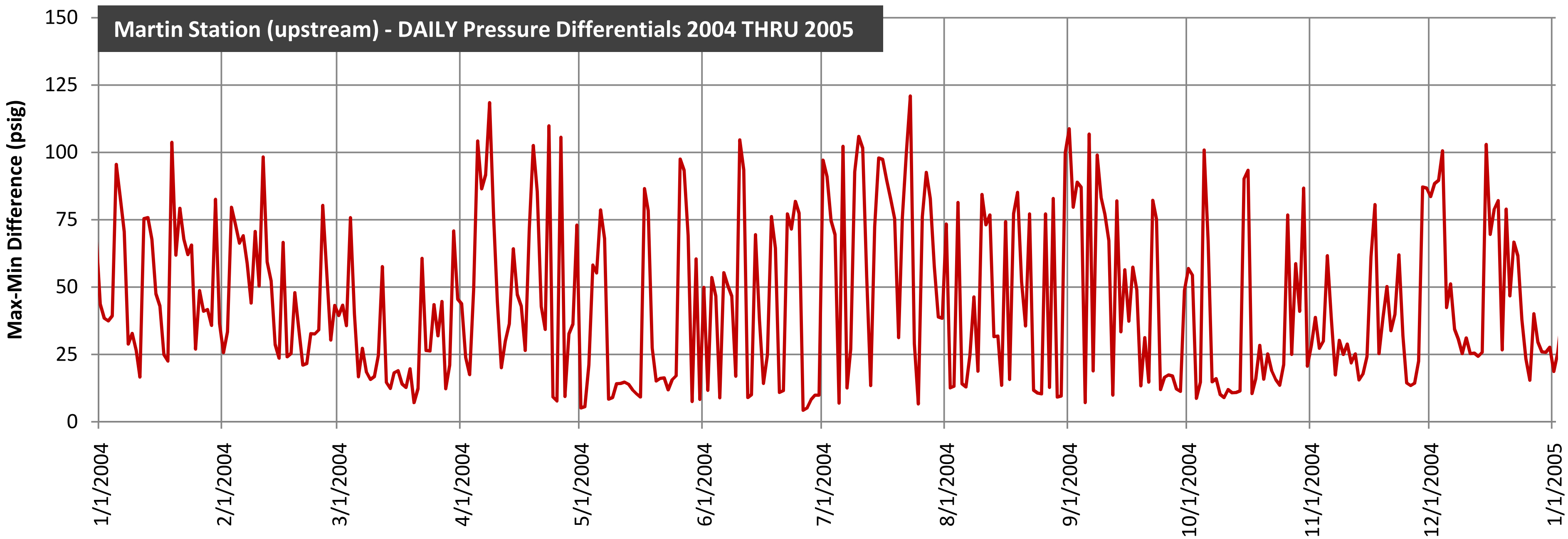

NTSB_082-003
Line Pressures North of Martin Station - September 9, 2010
PRESSURE (PSIG)
150
140
130
120
110
100
90
80
70
60
NMA_PT0011 - Mrtin-Sta L132 D/S Press
NSF_PT0102 - Potrero-RTU L109 Press
NSF_PT0022 - Potrero-RTU L132 Press
NSF_PT0042 - Potrero-RTU L101 Press
9/9/10 16:30
9/9/10 16:45
9/9/10 17:00
9/9/10 17:15
9/9/10 17:30
9/9/10 17:45
9/9/10 18:00
9/9/10 18:15
9/9/10 18:30
9/9/10 18:45
9/9/10 19:00
9/9/10 19:15
9/9/10 19:30
9/9/10 19:45
9/9/10 20:00
9/9/10 20:15
9/9/10 20:30
9/9/10 20:45
9/9/10 21:00

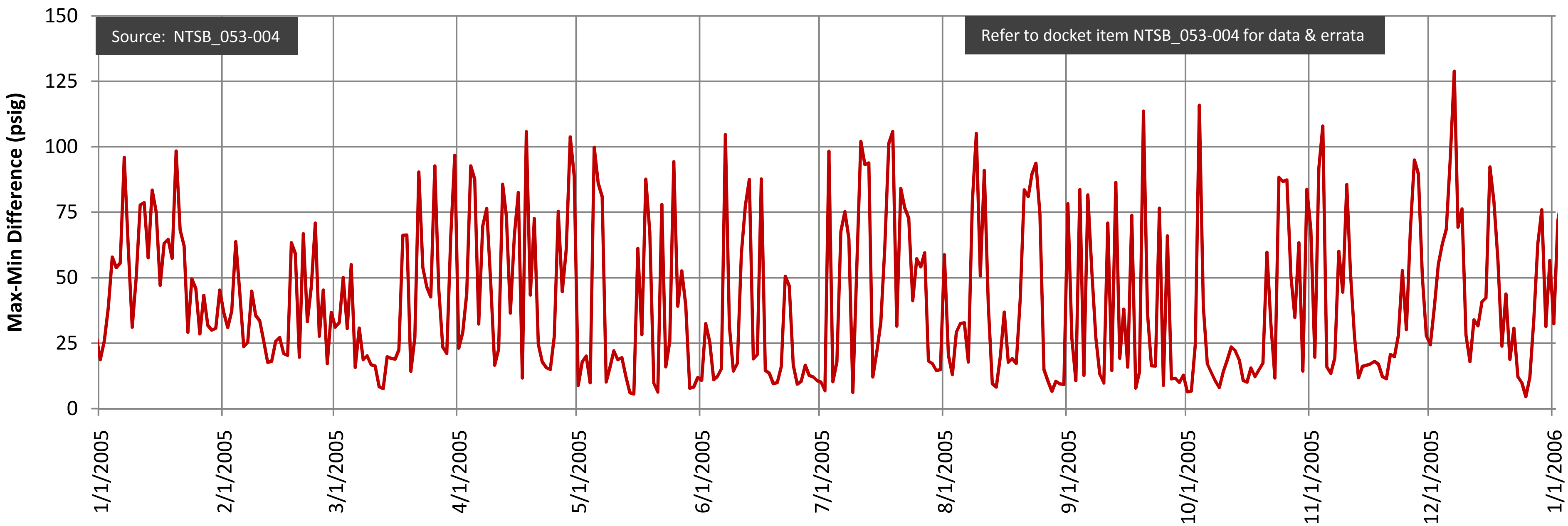
Attachment - [AG]



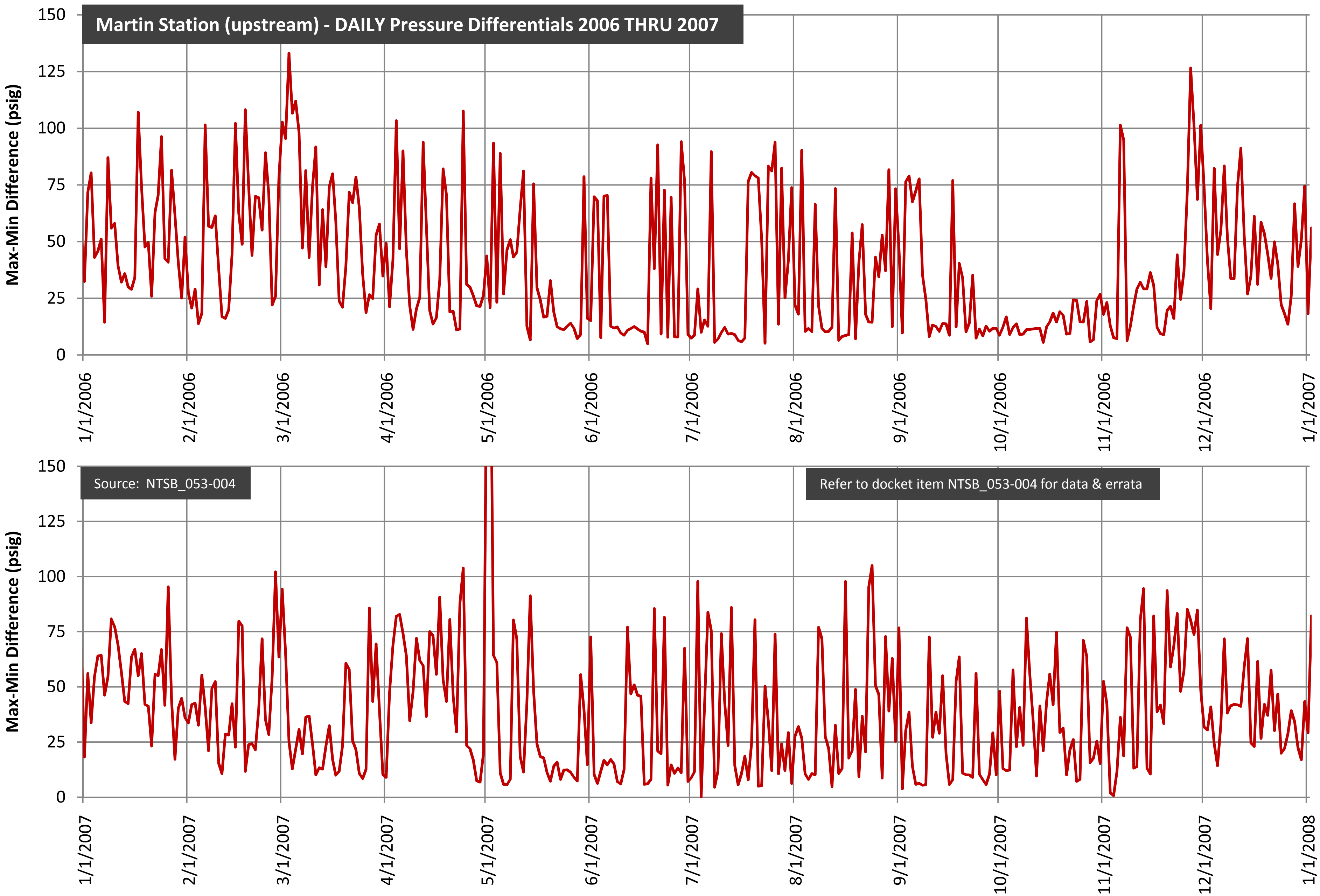


Attachment - [AH]

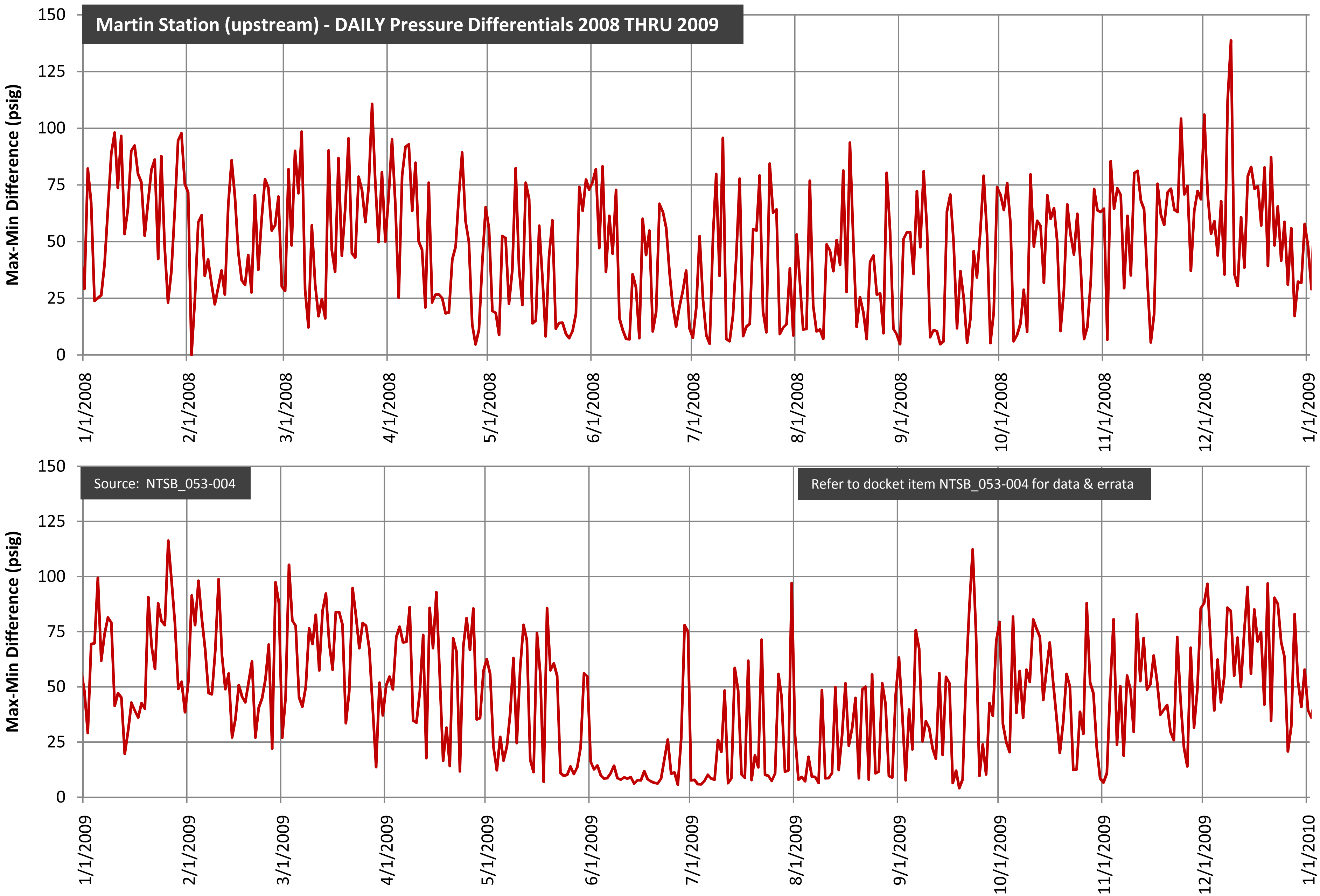




Attachment - [AI]



__Attachment - [AJ]__



Attachment - [AK]