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February 8, 2019

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Attn: Filing Center

Re: **LC 71: NW Natural's 2018 Integrated Resource Plan Final Comments**

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), files herewith its Final Comments on NW Natural's 2018 Integrated Resource Plan.

Please address correspondence on this matter to me with copies to the following:

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Sincerely,

NW NATURAL

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON LC 71
IN THE MATTER OF
NW NATURAL'S 2018 INTEGRATED RESOURCE PLAN

NW NATURAL'S FINAL COMMENTS

1. INTRODUCTION

Northwest Natural Gas Company (NW Natural or the Company) files these Final Comments in response to the Final Comments submitted in this docket by the Public Utility Commission of Oregon (OPUC), Staff.

NW Natural's Final Comments are organized generally along the same lines as Staff's Comments.

2. LOAD FORECAST

In its Final Comments, Staff provided its recommendations on several topics regarding load forecasting. Below is NW Natural's response.

Expert Forecasts

Staff Recommendations:

- In addition to the statistical analysis, Staff requests that the Company's next IRP contain a narrative to explain the near term factors that the subject matter expert (SME) panel forecast is capturing that led the Company to favor the choice of blending and transitioning years from the SME panel forecast to the econometric forecast.
- Staff recommends the establishment of a consistent standard relating to the year in which the Company blends and fully transitions from the SME panel to the econometric forecast. The standard should stay the same from one IRP to the next unless the Company has reason to believe it has found a substantial improvement over the current method.

NW Natural strives to be as detailed as possible in the narrative information provided in its IRP, while attempting to preserve its accessibility and readability. This is one of the reasons that the build up of the customer forecast is discussed in detail at our technical working groups. Per Staff's suggestion, for the 2020 IRP the Company looks forward to working with Staff to continue to improve on this balance and determining the right balance of narrative explanation related to SME panel forecasts in future IRPs.

The Company would like to address the potential implication of Staff's recommendation regarding the Company's forecast blending process that such process is something other than a "consistent standard" from IRP to IRP. Staff states that the blending year "should stay the same from one IRP to the next unless the Company has reason to believe it has found a substantial improvement over the current method." As presented in statistical detail in Chapter 3 of the IRP (please see section *2.3 Subject Matter Expert Panel Forecast* and subsection *Timing of Transition Between Types of Customer Forecasts*) this is precisely the case in the 2018 IRP. The Company did indeed find substantial forecast improvement in adjusting the blending year between its SME panel and econometric forecasts, and chose to do so. The adjustment, based on evaluation of forecast accuracy, is consistent with the Company's approach to all of its IRP analyses, which is to always work to determine the methods that result in the most accurate forecasts possible. The Company believes this approach is an appropriate, consistent standard that is compatible with Staff's recommendation.

Commercial Load Growth Forecast

Staff Recommendation:

- Focusing on the [changes in proportions of commercial market segments being added to NW Natural's system], a common tool used within load forecasting to track the usage of market segments is tracking customers with the NAICS or SICS database. Staff recommends that NW Natural pursue the creation of such a tool for the 2020 IRP.

As described in response to information requests related to projected commercial customer usage, the Company has not yet definitively established the drivers of higher usage for new and conversion customers. Information related to industry and commercial activity is captured for new customers, and we will investigate the viability of tracking usage by market segments by NAICS industry for future IRPs.

Interaction Effects Utilized in the Daily System Load Model

Staff Recommendation:

- For the 2020 IRP, Staff recommends the Company use an automated stepwise regression process for variable selection to compare against a model similar to the 2018 IRP in the use of interaction variables. Cross validation, or more specifically k-fold validation[ ], would then help assess how the results of each predictive model will generalize to an independent data set.

NW Natural thanks Staff for their feedback regarding the Daily System Load Model. The Company will work with Staff and stakeholders through technical working groups to address Staff's concerns regarding model evaluation and specification testing for the 2020 IRP.

Capacity Planning Standard

Staff Recommendation:

- Prior to the 2020 IRP, Staff recommends NW Natural coordinate a series of workshops to address concerns regarding the Company's method of implementing probabilistic methodology.

NW Natural thanks Staff for their involvement in reviewing the changes to the capacity planning standard. Staff recommends a series of workshops regarding implementation of probabilistic methodology. NW Natural believes the Technical Working Group (TWG) meetings, which are held over a period of several months before filing an IRP, is the proper place for stakeholders to review and provide input to all methodologies to be used in the IRP before they are implemented into the analysis. NW Natural presents methodological information early in the TWG process so that we may incorporate any stakeholders' feedback into our methodologies and spend additional time at TWG meetings to discuss questions or concerns from stakeholders.

NW Natural appreciates Staff's reference to guidelines for Monte Carlo analyses from a US EPA technical panel. The items mentioned in the guidelines were discussed at the TWG when the methodology was presented. NW Natural looks forward to engaging with Staff at technical working groups for the 2020 IRP.

Econometric Modeling Approach to Customer Count Forecasts, and Allocation of Annual Customer Forecasts to Monthly Values to Facilitate Peak Load Forecasting

NW Natural thanks Staff for its in-depth review of the Company's econometric customer forecast methodologies. We will continue to provide full detailed documentation of our approach in future IRP processes.

3. AVOIDED COSTS AND DEMAND SIDE RESOURCES

End Use Load Profiles

Staff Recommendation:

- NWN work with staff to review proposed end use load profiles as part of UM 1893. Review may potentially involve a third party evaluator and additional supporting research

NW Natural looks forward to continued work with Energy Trust, Staff, and other stakeholders through the UM 1893 process. NW Natural developed end use load profiles in its 2016 IRP to recognize the different impacts on peak load across different energy efficiency measures. NW Natural's 2018 IRP further refined these end use load profiles. These end use load profiles were developled using data specific to NW Natural customers. NW Natural believes that the utilities are in the best position to collect the data and estimate end use load profiles for their customers.

4. DEMAND SIDE RESOURCES

Action Item 9 – Acquiring therm savings

Staff Recommendation:

- Acknowledgement of NWN's Action Item number 9: Working through Energy Trust, NW Natural will acquire therms savings of 5.2 million therms in 2019 and 5.4 million thems in 2020, or the amount identified and approved by the Energy Trust board.

NW Natural thanks Staff for recommending acknowledgement of Action Item 9 and will continue to partner with Energy Trust to seek the acquisition of all cost effective energy efficiency.

Targeted DSM

Staff Recommendation:

- NWN launch the targeted DSM pilot in 2019. This is an Action Item from the 2016 IRP. The pilot study is behind schedule and the results could have informed many aspects of NWN's 2018 IRP. Staff does not believe NWN has sufficiently evaluated targeted DSM as alternatives to proposals in this 2018 IRP to pursue pipeline reinforcements and RNG.

For context, NW Natural is the first natural gas utility in North America to propose a targeted energy efficiency pilot for use in distribution system planning. Additionally, there are aspects of the proposed pilot that are novel even given recent electric utility targeted load management projects in the Pacific Northwest. We are excited about the prospect of being a leader in this area and proud that we will be able to provide learnings about non-pipe options to address weaknesses on a natural gas distribution system that can be used around the region and beyond. With this background, NW Natural is concerned by Staff's assertion that it "does not believe that NWN has sufficiently explored geographically targeted energy efficiency and demand response options as alternatives to … reinforcement projects…." Again, given that NW Natural has chosen to be proactive and a leader in this area as the first natural gas only utility on the continent to consider this concept in more detail (and in many regards the first natural gas utility to develop how to think about reducing peak hour load through energy efficiency), we feel Staff is setting a standard that is nearly impossible to meet by suggesting the Company is somehow lagging in its efforts.

NW Natural plans to begin the Geographically-Targeted Energy Efficiency (GeoTEE) Pilot with the Energy Trust in the summer of 2019. While the pilot *filing* is running behind the original schedule, actual pilot activities have not been delayed and are expected to begin in the summer of 2019. Staff is mistaken that any results would – or could – have been available to inform the 2018 IRP. To be able to achieve the pilot's goal of making GeoTEE an option for least cost and least risk consideration in distribution system planning going forward, the pilot program will take place over several years, with the majority of the impact evaluation of the pilot being done in latter years.

For history, the 2016 IRP Action Item to proceed with planning the GeoTEE pilot was acknowledged in February 2017. After acknowledgment of the action item, NW Natural and Energy Trust began the process of determining the best path forward for the pilot project in Summer 2017. An important step in this process was working with Energy Trust to settle on a pilot location. Based on a number of principles, which can be seen in the draft pilot filing, NW Natural presented a list of potential pilot locations to Energy Trust. Based upon the goals of the pilot, Energy Trust completed an evaluation and recommeneded a single pilot location – the town of Silverton – for the pilot. NW Natural supported Energy Trust's recommendation.

Given that the single feed pipeline into Silverton did not have a suitable meter, the Company made plans to install a meter once the pilot location was determined so that the load specific to Silverton could be monitored. Due to the location of the meter and flooding issues at the site from heavy rain in Fall 2017, the meter was installed in January 2018. Given that at least two years of data are needed to make a multi-year forecast of peak load in Silverton – a forecast that is critical given that it makes the baseline against which the impact of pilot activities will be measured – it is required the meter be in place for the rest of the 2017-2018 heating season as well as the 2018-2019 heating season before beginning pilot activities. Consequently, actual pilot activities beyond preparation work could not start until Summer 2019, even if the pilot plan had been filed earlier.

Demand Response

Staff Recommendation:

- NWN hire a third party to perform a Demand Response Potential Study in its service territory. Staff does not believe NWN has sufficiently evaluated demand response programs as alternatives to proposals in this 2018 IRP to pursue pipeline reinforcements and RNG. This analysis should include their interruptible rates as a DR option.

It is important to note, when discussing NW Natural's demand response measures in the context of resource planning, that the Company has long employed a successful (but often overlooked) form of demand response program in its interruptible rate schedules. Large customers, distributed throughout the Company's territory, utilize these schedules. In addition, the Company analyzed the viability of targeted interruptiblity agreements as site-specific alternatives to traditional infrastructure investment for each of the projects in the 2018 IRP, as described in Chapter 8 and documented via responses to several OPUC data requests. It is unclear why Staff would state that the Company did not "sufficiently evaluate" these options – Staff provides no details regarding unanalyzed options currently available to us with regards to projects under consideration.

As was discussed with Staff at several workshops, NW Natural plans to study additional demand response options in the near future, though it is unclear that a third party investigation is a necessary or preferred option. Unlike geographically targeted energy efficiency, there is more information from existing programs elsewhere that NW Natural has found can be used to develop potential demand response programs – specifically those that address geographically specific needs of distribution system planning. The design and results of these studies will be shared with stakeholders.

5. SUPPLY SIDE RESOURCES

Staff Recommendation:

- NW Natural develop more detailed discussion around potential future supply-side resource investments in future IRPs in order to provide sufficient information and more transparent analysis for resource planning purposes. The Company should include Action Items for any significant investments, including those associated with anticipated studies expected within the first four years of the IRP.

Investments Mentioned in the IRP but not included in the Action Plan

Staff states that:

> *Staff found near-term investments that potentially warranted inclusion in the Action Plan. In initial comments, Staff requested that if NW Natural anticipates incurring significant expenses at the Portland Gasco LNG Plant in the next four years, the Company should file an updated Action Plan detailing the expenses that NW Natural sees as likely or as likely contingent on the results of third-party analysis. Staff also requested that NW Natural re-file its Action Plan with the Miller Station study included as an action item.*

As it did in the 2014 and 2016 IRPs and in the interest of transparency, NW Natural included information on its asset management program for its storage plants. Similar to the 2016 IRP and as Staff's investigation found, NW Natural openly shared potential investments in the Portland LNG Plant and the Miller Station compression study in an Appendix in the interest of communication with OPUC. As noted in NW Natural's Reply Comments, any work towards compressor replacement would be contingent on the outcome of the study or new information. While the Company believes such informational studies completed in the ordinary course of business do not require Action Plan inclusion and Commission acknowledgement, the Company noted in its Reply Comments that it is not opposed to including the study as an Action Plan item.

NW Natural believes that its criteria for including a resource acquisition as an Action Plan item are consistent with the purpose of the IRP process[1] and past guidance from OPUC Staff and Commission. They are that the resource action:

1. Is outside business as usual and is considered a significant project;[2]
2. Is specific on timing and cost; and
3. Is a project that the Company has not already determined it will proceed with.[3]

For the Portland LNG Plant, we are currently in the process of evaluating the current state of the facility, examining expected future conditions, and performing a rigorous alternatives analysis. NW Natural performs this type of evaluation and alternatives analysis in the normal course of business to help inform future resource decisions. While this planning process is taking place, it is not possible for the Company to provide specific information about the timing or cost of future activities at the facility, and the Company does not find it particularly helpful to speculate on the results of any ongoing analyses. Additionally there are no actions at this time that the Company has identified to take at the facility over the next two to four years. These actions will be the result of the ongoing evaluation. Therefore, the Company does not believe there is any meaningful action item related to the Portland LNG facility that could or should be included in the 2018 IRP Action Plan.

[1] "The purpose of the IRP process is to provide the utility with the information and opinion of stakeholders and the Commission based on information presented by the utility." Order No. 16-071 in Docket LC 62.

[2] In Staff Report in Docket LC 62 Page 6, Staff states it "does not believe it [i.e., an Action Item] requires Commission acknowledgement as it reflects normal good business practice and is not a major resource acquisition."

[3] In Staff Initial Comments in Docket LC 60, Staff states that "projects…that may have already commenced…would exclude them from the Action Plan."

Similarly, the Miller Station compression study will occur in the normal course of business. Further, Staff has previously asked the Company not to include items where a decision has been made to proceed as acknowledgement would have the appearance of preapproval. The decision to proceed with the study has been made and unless Staff has reason to believe that the study would not be acknowledged, there is a concern about the appearance of preapproval.

Renewable Natural Gas – Pilot Project

See discussion below related to RNG Resource Evaluation Methodology.

6. PORTFOLIO SELECTION

Carbon Price Path Near or Equal to Zero

Staff Recommendation:

- For any state that contintues not to have a carbon policy by the next IRP, [1] include an additional carbon price path in the stochastic anaylsis that is near or equal to zero, and [2] allow a carbon price to begin as late as 2030 *(Numbering added)*.

Staff recommended two changes to the stochastic modeling of carbon policy, which are included in the Company's risk analysis.

Per Staff's first recommendation, NW Natural agrees to include a zero carbon price path as a 5th potential price path in the risk analysis until either Washington or Oregon pass carbon compliance obligations. If one state passes carbon compliance cost legislation, this lowest bound price path will be adjusted based on a volume weighted calculation (currently about 90% OR and 10% WA).

NW Natural disagrees with Staff's second recommendation about extending the potential start date from 2026 back to 2030. The Company believes that carbon compliance costs are likely to occur in the near future and delaying the potential start date back to 2030 is a less reasonable assumption than 2026 given the strong push for the Cap and Invest bill currently being crafted during Oregon's 2019 legislative session.

While feedback on carbon pricing was not provided during the technical working groups, NW Natural is glad to incorporate Staff's first recommendation of a zero carbon compliance path into the stochastic analysis. The Company does not plan on incorporating Staff's second recommendation of a later potential start date unless directed otherwise by the Commission. Incorporating Staff's recommendation would not impact any of the current action items, but the Company will include this recommendation in the risk analysis for future resource decisions. These stochastic assumptions are applied consistently across all resources, which includes potential RNG projects and the evaluation presented in Appendix H.

Forecasting future policy is difficult and cannot be informed through past data or trend analysis. Therefore, the assumptions regarding future carbon policy can always be debated. As such, it is most helpful to have these discussions during the formative time period of the technical working groups. Regardless, it is NW Natural's intention to update these assumptions as necessary, usually following the legislative sessions of both states. These assumptions will be based on the Company's best knowledge at the time.

7. DISTRIBUTION SYSTEM PLANNING

Staff Recommendations:

- Based on available evidence, acknowledge the following distribution projects:
    - The Hood River project;
    - The South Oregon City project.
- Collect more data, as recommended by Staff in Final Comments, and resubmit acknowledgement requests in an IRP update or in the next IRP for the following distribution projects:
    - Happy Valley project;
    - Kuebler reinforcement project;
    - Sandy Feeder reinforcement project;
    - North Eugene reinforcement project.

Overview

The Company thanks Staff for its earnest efforts to improve its understanding of the analytical process behind the reinforcement projects in the 2018 IRP, and its recommendation of acknowledgement for two projects for areas where customer outages have already occured.

Additionally, the Company would like to provide a correction. In post-filing workshops, NW Natural indicated that system modeling used to support the need for both the Happy Valley and North Eugene projects was based on actual conditions experienced during a January 2017 cold event.[4] This is inaccurate. While the system models initially provided to Staff for these areas were properly calibrated to calculate accurate pressures, they were set to simulate pressures under peak conditions rather than actual historical conditions. The Company sincerely regrets this error and confusion that it caused. We have subsequently completed modeling for the two areas simulating January 2017 conditions[5], which is discussed below. Future IRP submissions will include sytem models showing both actual historical conditions and simulated peak conditions to prevent future errors.

General

For several years, NW Natural has consistently strengthened its distribution system planning process by rigorously monitoring system conditions, increasing focus on forward-looking

[4] Additionally, in the IRP both Happy Valley and North Eugene refer to "Observed pressures" being well below NW Natural's 10 psig distribution system standard. For Happy Valley, this should be revised to read "an observed pressure was found to be in violation of NW Natural's 10 psig distribution system standard." For North Eugene, there were no observed pressures found to be in violation of NW Natural's 10 psig distribution system standard.

[5] This information has been provided in supplemental response to LC 71 DR 52 (included as Attachment 2 in this filing).

analysis, and integrating demand-side options in resource decisions. The Company believes it is a leader among other gas LDCs in terms of its incorporation of distribution system planning within its broader IRP process.

Distribution system planning is a crucial component of NW Natural's overall integrated resource planning. Failures in the distribution system present hazardous situations[6] that are not directly comparable to temporary outages on an electrical system. NW Natural, like all gas utilities, monitors its distribution system through a combination of cold weather surveys, direct data readings from measuring equipment placed throughout its territory as required by 49 CFR part 192.741 and carefully calibrated system models that calculate conditions in specific local areas based on proven formulas and methods from collected data[7]. The Company uses well-established system standards for the performance and safety of distribution infrastructure[8], and when it detects violation of those standards, it must move to address the situation in a timely fashion in order to safely and reliably serve customers.

The timeline required to design, permit, procure, construct, and complete the system reinforcement projects that are included in the 2018 IRP can range from a year up to possibly two years, depending on the scope of the project. In delaying the construction timeline by potentially several years, NW Natural's customers will be at risk of experiencing gas outages during future cold weather events.

The software platform used to model gas systems – Synergi – is industry standard (used by 96% of large LDCs in the United States) and is extensively utilized by NW Natural and other natural gas utilities. Synergi is an advanced hydraulic modeling software that allows operators to model large, complex integrated multi-pressure pipeline systems. Synergi software has been used by the industry for over 40 years to help operators make design, planning, and operating decisions based on its calulations. As established during the 2018 IRP discovery process and routinely in past IRPs and rate cases, the Synergi model is validated and quality-checked; its output recreates conditions throughout the system with a very high degree of accuracy, even in areas distant from physical measurement equipment. The Synergi models of NW Natural's distribution system are built using pipe size, customer load information, and SCADA inputs (flow, metering, pressures) located throughout NW Natural's system. With these known inputs, Synergi accurately calculates the system pressures. This methodology is used every day by NW Natural to evaluate new customer loads and their impact on the system, temporary pipeline shutdown and tie-in procedures to support construction activites, and daily BTU modeling of the system that is crucial for accurate customer billing.

The Synergi methodology was presented in the 2014, 2016, and 2018 IRPs and several additional workshops. Since filing the IRP, the Company has worked with Staff to improve the

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[6] E.g., customer equipment failures, appliance pilot light outages, unheated homes during extreme cold.
[7] NW Natural meets the requirements of 49 CFR 192.741 with hundreds of installed SCADA pressure recording points and pressure chart recorders. These pressure recording points, coupled with modeling, adequately monitor the distribution system for unsatisfactory operating conditions. 49 CFR 192.741 does not require that operators "give consideration to installing temporary recording gauges at locations in the distribution system at suspected or anticipated low-pressure points." 49 CFR 192.741(c) requires operators to inspect the regulator and the auxiliary equipment and correct any unsatisfactory conditions when there are indications of low or high pressure.
[8] See supplemental response to LC 71 DR 95 (included as Attachment 1 in this filing).

shared knowledge of our processes and modeling methodology and looks forward to continuing this process in future IRPs.

NW Natural is open to adding incremental data collection equipment to its system to further validate its analyses of future distribution system projects. Through the post-filing collaboration with Staff, NW Natural has had the opportunity to provide important additional data. NW Natural has provided[9]:

- Direct pressure reads from SCADA equipment and field personnel
- Customer outage reports where available
- Synergi modeling output and model calibration checks
- Updated Cold Weather Survey pressure reads

In general, it is important to note that field observations validate Synergi modeling, but they cannot replace its use. Even with additional data collection points installed on the system, in the absence of very cold weather, the data would not be sufficient to identify areas at risk of outage as the system adds customers. Note that additional customers to the system do not need to be located in areas at risk in order to increase the chance of outages. Customer demands are regularly updated in Synergi models and the impacts of these demands on system performance can be identified when the model is balanced. The Company will still rely on Synergi to monitor specific locations. The proposed projects do indeed have directly collected supporting data, but many distribution projects will be identified through forecasted load and/or system modeling.

Staff only recommends acknowledgment of the Hood River and Oregon City reinforcement projects, the two areas where system deficiencies under less than peak conditions have already led to customer outages. The Company is concerned that this may set a precedent of using service outages as a standard for acknowledgement. Three out of the four remaining distribution projects address documented actual violations of the Company's distribution system planning standards using pressure readings, which are designed with the goal of providing safe operations and averting customer outages. The fourth project (North Eugene) violated the Company's distribution system planning standards using Synergi modeling of peak day conditions, but for reasons described below, we are removing of this project from the Action Plan. These projects are addressed individually below.

As mentioned above, and discussed more fully below for those projects which Staff has not recommended acknowledgenent, the area to be reinforced by each proposed distribution system project has experienced and the Company has documented pipeline conditions which exceed the thresholds set for reinforcement. Table 1 summarizes the relevant criteria and the data collected for each project.

[9] See supplemental responses to LC 71 DRs 52 and 95 (included as Attachments 2 and 1 in this filing) for full technical detail.

Table 1: Reinforcement Criteria Met for Distribution System Projects (with actual pressure readings)

Project	Reinforcement Criteria Met	Supporting Data
Hood River Reinforcement	Experience distribution system pressure <10 psi	Customer outages in January 2017
South Oregon City Reinforcement	Experience distribution system pressure <10 psi	Customer outages in January 2017
Kuebler Road Reinforcement	Experience >40% pressure drop along transmission system	Measured pressure drop of 63.6% from Turner Gate Station to district regulator on January 6, 2017
Sandy Feeder Reinforcement	Experience >40% pressure drop along transmission system	Measured pressure drop of 81.5% from Sandy Gate Station to district regulator on January 6, 2017
Happy Valley Reinforcement	Experience distribution system pressure <10 psi	Cold weather survey measured 9 psi on Jan 4, 2017 in Happy Valley

Sandy Feeder Reinforcement

The Sandy Feeder Reinforcement is a high pressure feeder pipeline that supplies natural gas to the community of Sandy, Oregon. This project is discussed at length in Staff Final Comments, Attachment 1, pages 8-12. Staff states that additional field data indicating system weakness are required before acknowledgement of the Sandy Feeder Project. Staff may have misunderstood that the existing Sandy Feeder has a recorded pressure drop of 81.5%, which exceeds NW Natural's reinforcement criteria. Additionally, Staff may have misunderstood the impact of low inlet pressure on regulator performance and appears to introduce an alternative reinforcement standard based on a lack of downstream pressure issues.

The Company has provided supporting data collected on site to support its proposed action. The recorded low regulator inlet pressure[10] under less than peak weather conditions is a serious issue. These data points were recorded by field personnel dispatched to this location during a cold weather event. This pressure reading indicates the Sandy Feeder has greatly exceeded NW Natural's reinforcement standard and is very near failure. Further, system modeling accurately calculates the condition of the Sandy Feeder under less-than-peak demand, illustrating that high pressure system reinforcement standards for pressure drop (40%) on a pipeline[11] are cleary exceeded under less than peak demand. The measured pressure drop on the Sandy Feeder on January 6, 2017 was 318 psig (390 - 72) or 81.5%, which results in approximately 96% of the maximum flow rate capacity for the pipeline (see Table 2 below). This greatly exceeds the 40% pressure drop criteria for high pressure pipelines and indicates that this pipeline requires reinforcement.

[10] See supplemental response to LC 71 DR 95 (included as Attachment 1 in this filing).
[11] This is an AGA-wide standard. Please see response to LC 71 DR 95 (included as Attachment 3 in this filing) for full details on reinforcement standards.

Table 2 – Sandy Gate Station with Gas Flow Calculations

Sandy Gate Station Pressure (psig) - Measured	District Regulator Pressure (psig) – Measured	Resulting Pressure Drop
390	72	318 psi (81.5%)

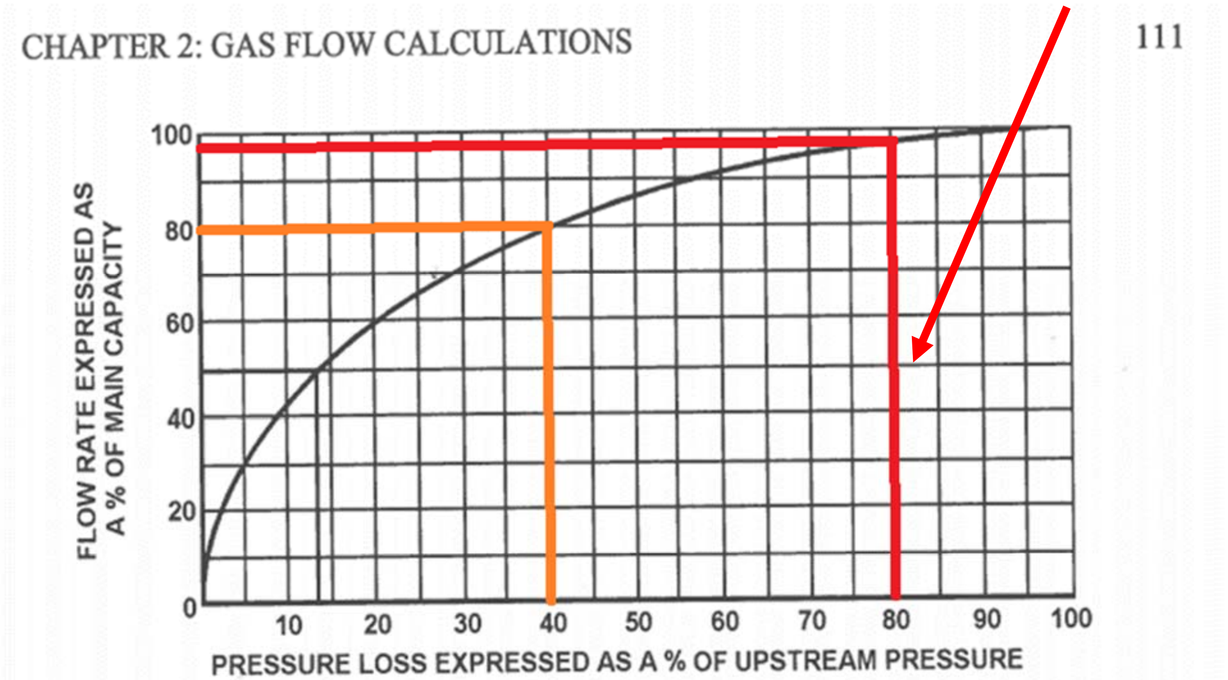

Figure 38. **Relation between flow rate and pressure loss for a main operated at high pressure.**[19]

In Staff's final comments, Staff mentions that regulator inlet pressures must be at least 20 psi above the outlet pressure. To clarify, this 20 psi should not be used as a design standard. It was referenced by NW Natural in DR 52 (included as Attachment 4 for this filing) as the typical pressure restriction that a district regulator has on gas flows. NW Natural has a variety of pressure regulators in its systems, and the manufacturer requirements for minimum inlet pressure for proper regulator function vary. These pressure regulators are mechanically driven and use the pressure in the pipeline to properly function. As inlet pressure decreases, the capacity, or amount of gas that can be served by the regulator, drops dramatically. The inlet pressure of a district regulator must be high enough to serve the load downstream, hence the use of the 40% pressure drop as a design standard.

The 72 psig inlet on the Sandy feeder results in an 84.1% reduction in the flow capacity of the installed regulator compared with design conditions. Any increase in demand will trigger severe downstream pressure issues and expose many customers to service disruptions as this regulator is the primary source of gas to the Sandy distribution system. Staff overlooks NW Natural's high pressure reinforcement standard and appears to suggest a standard that states reinforcement projects can only be acknowledged once outages or unacceptably low pressures are actually recorded during a cold weather event. By dismissing the Company's high pressure pipeline standard and recorded data showing violation of reinforcement standards, Staff is recommending against the Company addressing a known system constraint on its high pressure system. Once a high pressure pipeline exceeds capacity, a large number of customers become at risk for service outages. Additionally, the time to design, gain acknowledgement, and construct these longer high pressure pipelines leave customers at risk for longer periods of time.

Kuebler Road Reinforcement

The Kuebler Road Reinforcement project is designed to reinforce the high pressure feeder system in Salem, Oregon. This system supplies natural gas to approximately 50% of the customers in the Salem area. The project is discussed at length in Staff Final Comments, Attachment 1, pages 30-35. Staff states that additional field data indicating system weakness are required before granting acknowledgement of the Kuebler Road Reinforcement. Staff also states, incorrectly, that actual pressure measurements indicating weakness do not exist.

NW Natural has provided data and information that supports the need for the project. Field pressure readings indicating weakness were taken on site and documented on January 6, 2017[12] and document that high pressure system reinforcement standards for pressure drop (40%) on a pipeline were cleary exceeded under less than peak demand conditions. The measured pressure drop on the South Salem system from Turner gate to the Kuebler Regulator on January 6, 2017 was 140 psig (220 - 80) or 63.8%, which results in approximately 93% of the maximum flow rate capacity for the pipeline (see Table 3 below). This exceeds our 40% system reinforcement pressure drop criteria for high pressure pipelines and indicates that this pipeline requires reinforcement.

[12] See Staff Final Comments, Attachment 1, page 32 and the response to LC 71 DR 52 (included as Attachment 4 in this filing).

Table 3 – Turner Gate Station Pressures and Gas Flow Calculation Chart

Turner Gate Station Pressure (psig) - Measured	District Regulator Pressure (psig) – Measured	Resulting Pressure Drop
220	80	140 psi (63.6%)

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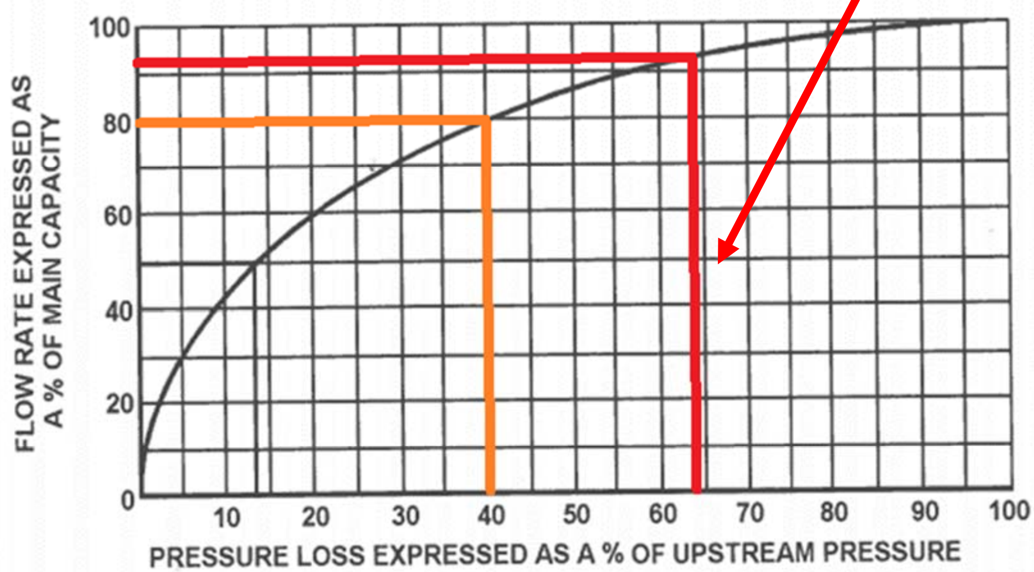


Figure 38. **Relation between flow rate and pressure loss for a main operated at high pressure.**[19]

If a peak event were to occur with the existing feeder configuration, system modeling indicates that hundreds of customers would experience pressures below our 10 psig Distribution System standard and many customer outages would be expected to occur. It would be a violation of service standards to our customers to delay this project until peak or extremely cold weather occurs so that even more supporting data can be gathered.

Happy Valley and North Eugene Reinforcements

As mentioned above, NW Natural has provided new information to Staff that corrects an inaccuracy in the information initially presented regarding the Happy Valley and North Eugene projects. This includes updated system modeling that correctly calculates pressures under actual (January 2017) conditions, and additional pressure reads completed during cold weather surveys near both project areas[13].

[13] See supplemental response to LC 71 DR 52 (included as Attachment 2 in this filing).

Happy Valley

In the case of the Happy Valley, updated modeling confirmed violations of our distribution system standards indeed occurred under experienced conditions. Further, as was mentioned above, in revisiting pressure read records, we were able to locate actual pressure data from within the project area confirming that system standards were violated (see Table 4 below).

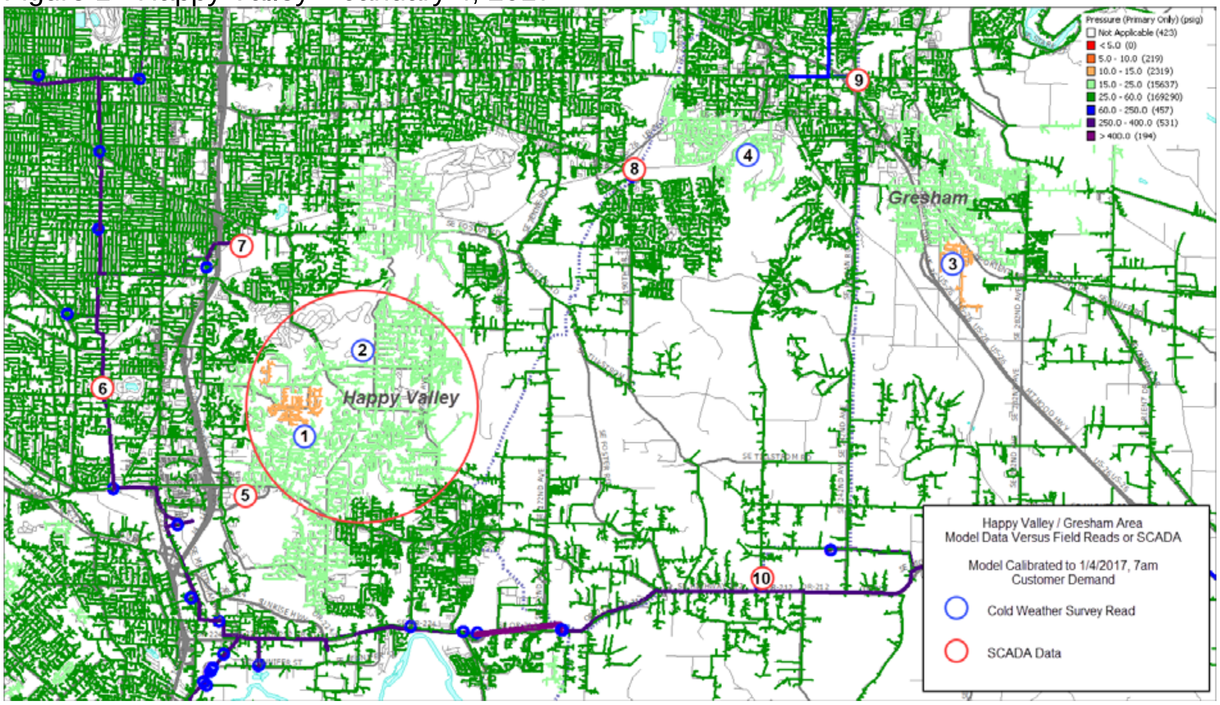
Table 4
Happy Valley Area Modeling Data versus Field Collected Data or SCADA Data

Location On Map	Plat	Cold Weather Survey Site Address/Location	City	Date	Time	Field PSIG	Model PSIG
1	1-041-042	11150 SE Valley View Terrace	Happy Valley	01/04/17	7:15 AM	22	18.7
2	1-039-043	12601 SE Callahan Rd	Happy Valley	01/04/17	7:00 AM	9	11
3	1-036-056	2927 SE Kane Ave	Gresham	01/04/17	6:57 AM	17	14.5
4	1-034-052	830 SW Florence Place	Gresham	01/04/17	6:45 AM	18	18.3

Location On Map	Plat	SCADA Site Address/Location	City	Date	Time	SCADA PSIG	Model PSIG
5	1-043-040	Kaiser Sunnyside Hospital	Portland	01/04/17	7:00 AM	23.5	24.1
6	1-040-037	SE Bell Rd & SE Sandview St	Portland	01/04/17	7:00 AM	49.8	50
7	1-037-040	SE 100th Ave & SE Glenwood St	Portland	01/04/17	7:00 AM	47.1	50
8	1-035-049	Johnson Creek Gate Station	Portland	01/04/17	7:00 AM	42	48.3
9	1-032-054	Gresham Gate Station	Gresham	01/04/17	7:00 AM	45	48.6
10	1-044-054	Sandy Gate Station	Boring	01/04/17	7:00 AM	47.8	50

The following map shows the location of the pressure comparison data points and the general project area for Happy Valley. Note that the Figure 1 below shows system conditions based on January 4th, 2017 at 7am.

Figure 1 - Happy Valley – January 4, 2017



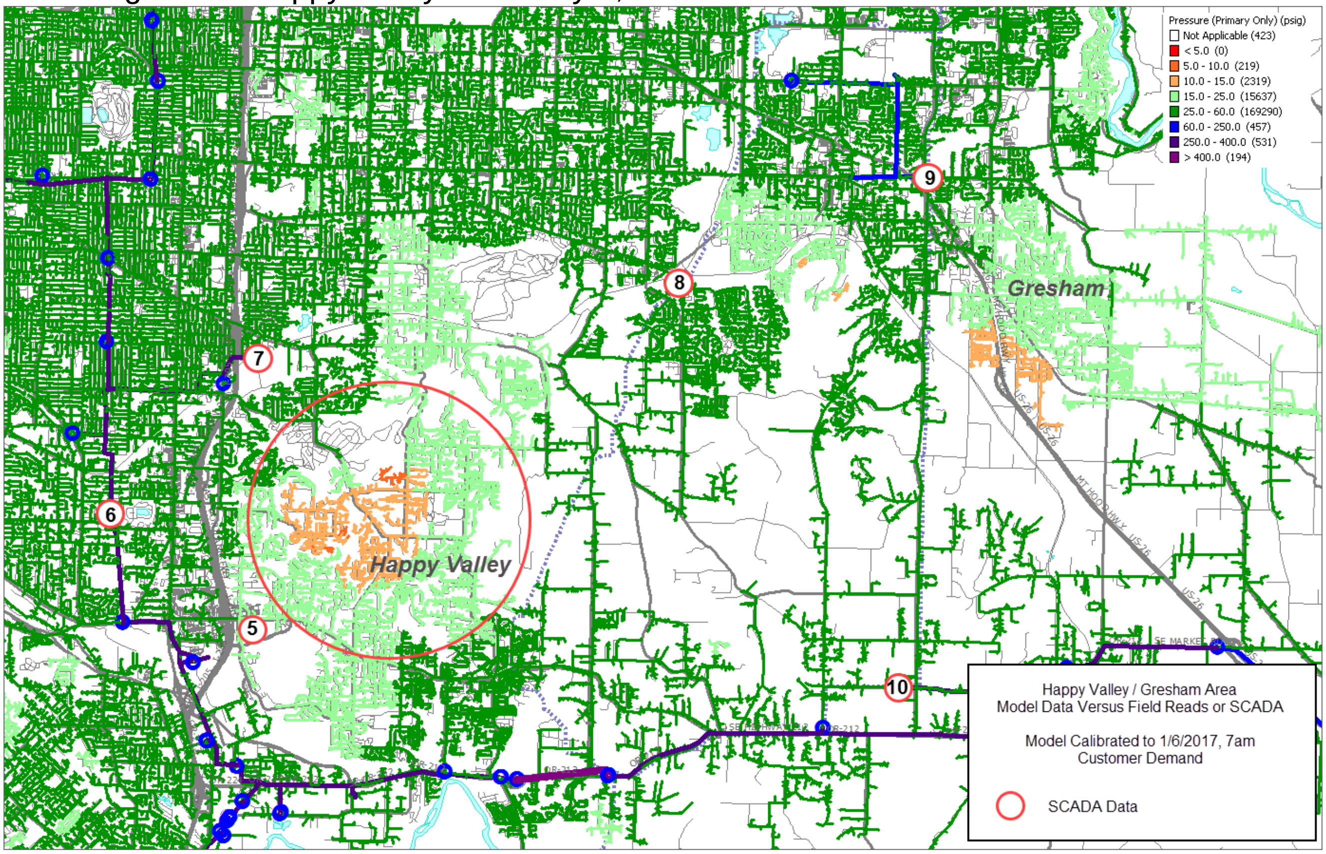
The Happy Valley area is an especially illustrative example of how Synergi is used to calculate system conditions in a distribution system. NW Natural has shown through data requests and meetings with Staff that its model calculations of Happy Valley conditions closely match collected data from the area.

Table 5 and Figure 2 below show modeled system conditions based on January 6th, 2017, 7am customer demand when temperatures were, on average, four degrees colder. Note the significant change in pressures within the Happy Valley area between the two cold mornings.

Table 5 Happy Valley – January 6, 2017

Location On Map	Plat	SCADA Site Address/Location	City	Date	Time	SCADA PSIG	Model PSIG
5	1-043-040	Kaiser Sunnyside Hospital	Portland	01/06/17	7:00 AM	19.6	21.4
6	1-040-037	SE Bell Rd & SE Sandview St	Portland	01/06/17	7:00 AM	49.8	50
7	1-037-040	SE 100th Ave & SE Glenwood St	Portland	01/06/17	7:00 AM	47.1	50
8	1-035-049	Johnson Creek Gate Station	Portland	01/06/17	7:00 AM	39.6	47.3
9	1-032-054	Gresham Gate Station	Gresham	01/06/17	7:00 AM	43.9	48
10	1-044-054	Sandy Gate Station	Boring	01/06/17	7:00 AM	47.5	50

Figure 2 – Happy Valley – January 6, 2019



NW Natural believes that these modeled results, with the additional recorded data requested by Staff, support a clear justification for this project that is consistent with the Company's established distribution planning process and previous IRP projects.

North Eugene

As mentioned above, the system modeling initially provided with regards to the North Eugene project simulated peak, rather than actual experienced conditions. Updated system modeling that correctly calculates pressures under actual (January 2017) conditions has been provided. Further, as was mentioned above, in revisting pressure read records, we were able to locate actual pressure data from within the project area, which has also been provided via supplemental response to LC 71 DR 52 (included as Attachment 2 for this filing).

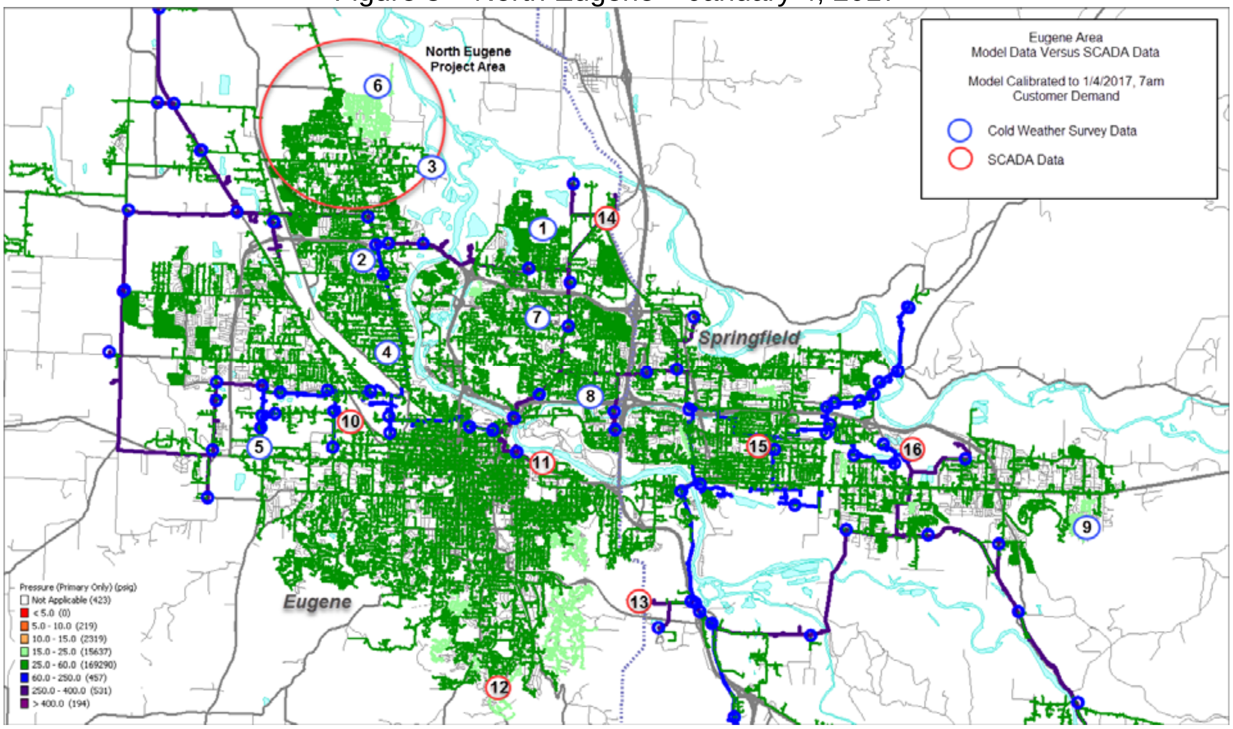
Table 6
Eugene Area Modeling Data versus Field Collected or SCADA Data

Location On Map	Plat	Cold Weather Survey Site Address/Location	City	Date	Time	Field PSIG	Model PSIG
1	2-226-010	3402 Honeywood St	Eugene	01/04/17	8:24 AM	35	38.1
2	2-227-016	200 Silver Ln	Eugene	01/04/17	7:30 AM	34	35.3
3	2-224-014	205 Chapman Rd	Eugene	01/04/17	7:45 AM	30	27.8
4	2-229-016	1224 Elkay Rd	Eugene	01/04/17	7:18 AM	33	33.3
5	2-233-019	4201 Commerce St	Eugene	01/04/17	7:00 AM	31	34.7
6	2-222-016	909 Beacon (Nursery)	Eugene	01/04/17	7:54 AM	26.5	22.0
7	2-229-010	2225 Jeppesen Acres Rd	Eugene	01/04/17	7:30 AM	34	34.5
8	2-231-009	3395 Oxbow Way	Eugene	01/04/17	7:15 AM	28	28.5
9	1-235-007	1220 S 69th Pl	Springfield	01/04/17	7:15 AM	22	24.2

Location On Map	Plat	SCADA Site Address/Location	City	Date	Time	SCADA PSIG	Model PSIG
10	2-232-016	Emerald Forest Products	Eugene	01/04/17	7:00 AM	121.2	125.9
11	2-233-010	University of Oregon	Eugene	01/04/17	7:00 AM	352.9	352.6
12	2-240-011	Eugene City Pressure	Eugene	01/04/17	7:00 AM	25.5	25.0
13	2-238-007	South Eugene Gate	Eugene	01/04/17	7:00 AM	379.7	383.7
14	2-226-008	North Eugene Gate	Eugene	01/04/17	7:00 AM	369.9	367.9
15	2-233-003	Springfield City Pressure	Springfield	01/04/17	7:00 AM	26.3	27.9
16	1-232-001	International Paper Reg	Springfield	01/04/17	7:00 AM	135.29	135.0

The following map shows the location of the pressure comparison data points and the general project area for North Eugene. Note that figure below shows system conditions based on January 4, 2017 at 7:00 am.

Figure 3 – North Eugene – January 4, 2017



While the Company remains concerned with system conditions in North Eugene, we agree with Staff's suggestion that additional information is necessary to show a violation of distribution system planning standards. The Company proposes to collect more data in Eugene via updated system modeling and/or additional direct data collection and resubmit the project for acknowledgement in an IRP update or in the next IRP.

Summary

NW Natural again thanks Staff for its thorough review of the reinforcement projects in the 2018 IRP, and its recommendation of acknowledgement for two projects referenced above. However, with the exception of the North Eugene project, NW Natural wishes to emphasize that the provided data supports the need for the remaining projects. This data includes information that was directly recorded in each of the project areas as well as the results of a system modeling approach that is consistent with previous IRP projects, several other Company processes, and the practices of our peers. We have high confidence in the accuracy of this approach. NW Natural cautions against the potentially retroactive precedent implied by Staff's recommendation to postpone reinforcement of system areas known to be at risk, and respectfully recommends acknowledgement of the well supported Hood River, Oregon City, Happy Valley, Sandy Feeder, and Kuebler Rd. projects.

8. RENEWABLE NATURAL GAS EVALUATION METHODOLOGY

The Proposed RNG Evaluation Methodology and Coordination with Other Policies

Staff Recommendations:

- Staff recommends that NW Natural Re-file Appendix H to address the concerns identified by Staff in Final Comments.
- Staff recommends that NW Natural file a revised RNG Action Item. Staff proposes an RNG Action Item for assessing and procuring up to a limited amount of cost-effective RNG over the next two years using the methodology in Appendix H, and participating with stakeholders in an investigation into the use of NW Natural's proposed avoided cost methodology to evaluate RNG.

NW Natural Will File a Revised Appendix H

Staff has requested that NW Natural file a revised Appendix H with some recommended changes. NW Natural agrees to file a revised Appendix H and will incorporate most of Staff's recommendations. Staff's recommendations are the following:

> ***Staff's request 1a:*** *Use the most up to date estimate of GHG policy expectations. The current forecast from the 2018 IRP is already out of date, as it expects a carbon price in Washington to already have begun.*

The assumptions used for the example in the current Appendix H are consistent with the rest of the assumptions used in the 2018 IRP. Every IRP will be somewhat out of date by the time it is filed, as the assumptions that direct the analysis are established and presented in technical working groups (TWGs) well in advance of the final filing of the IRP. The lengthy process of conducting and developing a least cost, least risk, integrated resource plan makes the inclusion of somewhat stale assumptions inevitable. However, the Company will update its assumptions regarding GHG policy expectations if expectations considerably change and have a material impact on resource decisions. Given that Washington did not pass any GHG policy this past year, NW Natural will update its baseline GHG policy expectations to reflect this change in expectations before any resource decision.

> ***Staff's request 1b:*** *Include a zero- or low-price carbon price path in the stochastic analysis as well as allowing the carbon price paths to begin in any year from 2019 to 2030 instead of using a price that must begin by 2026.[ ] This will account for the risk to customers of procuring a long-term contract for RNG in a world where a carbon price turns out to be lower or later than expected. Because a carbon price is the most difficult variable to predict in the stochastic analysis, including a wider range of potential policies reasonable acknowledges this uncertainty and the risk it may pose to customers.*

The combination of the different price paths and different potential start dates provides a robust set of potential compliance cost paths to be used in the Company's risk analysis. NW Natural presented the details of the carbon compliance cost paths to be used for the risk analysis during its TWGs. The Company made clear that a zero carbon price path would not be included as a potential option per feedback from stakeholders about the 2016 IRP and asked for feedback on this assumption. We did not receive any feedback from stakeholders regarding the absence of a zero carbon price path at the time, nor at any time before the IRP was filed, inclusive of comments on the draft IRP. NW Natural appreciates Staff's feedback and, in future IRPs, would like the opportunity to incorporate Staff's recommendations through engagement in the TWG and draft IRP. NW Natural agrees to incorporate Staff's first recommendation of a zero carbon compliance path into the stochastic analysis for future resource decisions. This will be reflected in the revised Appendix H. However, the Company believes that delaying the potential start date of carbon policy from 2026 to 2030 is a less likely assumption, and it will not incorporate this change unless directed otherwise by the Commission.

> ***Staff's request 2:*** *NW Natural should update inputs, assumptions, or forecasts to the RNG Evaluation Methodology at the time that the Company is evaluating a potential RNG project.*

NW Natural agrees to use the best knowledge it has at the time of evaluating a potential RNG project. This means using the most updated forecasts, assumptions and cost inputs. This level of prudency is not specific to RNG or the RNG Evaluation Methodolgy, but is the same standard for all resource acquisitions. Table 7 lists the major inputs and forecasts used for resource decisions, and the frequency with which they are updated.

Table 7: Update frequency of Assumptions and Forecasts

Input/Assumption/Forecasts	Frequency of Update	Additional Explanation
Resource Under Evaluation	Most Current Estimate	For example, if an RNG project requires any capital costs, the most current estimate of those costs will be run through the cost-of-service model and used for the evaluation.
Gas Prices (Deterministic and Stochastic)	Twice a year	Our thrid party consultant provides long term gas price forecasts twice each year in August and February.
Peak Day Load Forecast	Once a year	These forecasts are updated spring/summer to include data from the most recent heating season.
Annual Load Forecast	Once a year	
GHG Compliance Cost Expectations (Determinisitic and Stochastic)	Once a year	The GHG compliance cost assumptions will be updated each year after the legislation sessions in each state.
Design, Normal, and Stochastic Weather	Each IRP	Changes in weather calculations are updated for each IRP.
Supply Resource Costs (Determinisitic and Stochastic)	Each IRP	For the 2018 IRP base case this included the cost of a pipeline uprate, a local pipeline expansion, and representative RNG resource #2 (on-system dairy).
Distribution Avoided Costs	Each IRP	NW Natural will calculate and present the avoided distribution avoided costs in each IRP.

Although we update some of the forecasts more frequently than the IRP, changes in methodology are vetted through the IRP process. This potentially means using assumptions from the most recent, but perhaps not-yet-acknowledged, IRP analyses. NW Natural will include an additional column in Table H:1[14] to reflect the frequency the Company anticipates updating the input assumptions used in the RNG evaluation methodology in the revised Appendix H. Note that the Company would update input assumptions anytime necessary if unforeseen changes occur that would have a material impact on these inputs. Language in the revised Appendix H will reflect that inputs will be from the "most recent update" instead of "most recently acknowledged IRP".

> ***Staff's request 3:*** *The Company should update Appendix H with a description of the modeling process in SENDOUT*.

NW Natural agrees to include a more detailed description of the SENDOUT modeling process in the revised Appendix H that focuses on how RNG is being modeled in SENDOUT. Note that SENDOUT modeling is not unique to Appendix H, but uses the same assumptions, inputs, and the application used for the representative RNG resources evaluated throughout the 2018 IRP (see Chapters 6 and 7) and presented in TWGs #3 through #6. Appendix H is applying the

[14] See page H.4 of the 2018 IRP.

same resource modeling process used for the aggregated representative RNG resources presented in the IRP to specific RNG projects.

NW Natural did not include a detailed description of modeling RNG in SENDOUT in the 2018 IRP as we try to balance being concise with including all the necessary information. The Company will include a section describing the SENDOUT application for the first time in the revised Appendix H.

Limited RNG Acquisition Over the Next Two Years

Staff Recommendation:

- Staff proposes that NW Natural file a revised RNG action item to acquire up to a limited number of cost-effective therms of RNG over the next two years using the avoided cost RNG Evaluation Methodology in the revised Appendix H. Staff suggests three and a half million therms as a reasonable limit that is approximately one third the amount of energy efficiency the Company plans to acquire over the next two years.

For context, the evaluation methodology proposed in Appendix H was developed to value RNG consistently with conventional gas supply resources by accounting for the avoided costs provided by RNG resources. Therefore, purchasing RNG resources found to be cost effective using this methodology does not come at an extra cost, but would be beneficial to customers. NW Natural recognizes that the application of avoided costs to RNG resources is novel and requires time for stakeholders to weigh in and establish an accepted evaluation methodology. NW Natural is not opposed to limiting the amount of RNG that could be procured using this methodology while Staff conducts an investigation. However, limiting RNG, as suggested by Staff, does present complications due to the dynamics of the RNG market.

Per discussions at TWGs, workshops and as discussed in Appendix H, the role NW Natural is most likely to play within the RNG market is as a fixed-priced buyer, allowing RNG developers and producers to lock in a portion of their sales via long term contracts at known prices. Due to the current premium, yet volatile and uncertain, price of RNG being sold into the CNG market under shorter term contracts, delivery of RNG to NW Natural (bundled with environmental attributes) is likely not to begin for several years, even if contracts were signed today. It is unclear that a two year cap would be workable for this type of RNG option given that the delivery of gas would be outside the two year window and the total aggregate amount of contracted RNG would likely exceed 3.5 million therms due to the length of the contract (e.g., ten years).

Instead, NW Natural proposes an alternative limit to use the methodology in the revised Appendix H to procure cost effective RNG up to 2% of NW Natural's forecasted annual sales load in any future year. Today that is roughly 15.5 million therms per year. For scale, the ODOE study on RNG found the average landfill in Oregon could produce about 4.1 million therms per year, with the largest potential landfill output being 17.4 million therms per year.[15] The range of output from landfills and other RNG resources, such as dairy farms and wastewater treatment plants, is similarly large; the Company feels that a 2% per year of annual sales is a reasonable limit that would allow for the purchase of RNG from roughly one large RNG resource or a few smaller RNG resources each year.

NW Natural understands Staff's recommendation of a limit as a good faith effort to accommodate the Company's acquisition of cost effective renewable resources while Staff completes its own investigation of the proposed methodology. NW Natural appreciates Staff's recommendation given the potential opportunity cost to customers of delayed progress on this issue. The Company suggests using the alternative cap (described above) to be in effect until Staff completes its investigation, and after which a process will be established to acquire *all* cost effective RNG resources.

RNG Evaluation Investigation

Staff Recommendations:

- Staff will conduct an investigation into the use of avoided costs by NW Natural to evaluate RNG acquisition.
- NW Natural will file the evaluation workpapers, modeling inputs and outputs, and results of the RNG Evaluation Methodology in the investigation docket at least 30 days prior to committing to any RNG resource.

NW Natural supports Staff's proposed investigation into the use of avoided costs to evaluate RNG resource acquisitions. The Company believes the methodology put forth in the 2018 IRP and Appendix H is the best way to evaluate RNG consistently against alternative resources, but understands the necessity for stakeholders to become familiar with RNG as a new resource. NW Natural has put forth this methodology in anticipation of being a leader among LDCs in acquiring cost effective RNG and reducing the carbon intensity of the product we deliver.

We would like to reiterate that the RNG available for customers may be limited as other companies, besides Oregon utilities, are bidding for these resources. A lengthy investigation could jeopardize RNG opportunities for Oregonians. Therefore, NW Natural suggests that Staff pursue an investigation with a definitive timeline, which NW Natural suggests takes place over the next six months.

Currently, NW Natural has not found any RNG projects that are shown to be cost effective using the methodology laid out in the 2018 IRP. To aid Staff's investigation, NW Natural proposes developing a maximum offer price for each considered project ($/Dth/year) for bundled RNG (i.e., inclusive of the environmental attributes) that would be considered a "ceiling" price and kept confidential with Staff and the Commission. NW Natural then would negotiate up to that price with a counter party. This offer would be included in the revised Appendix H to be filed at a

[15] *Biogas and Renewable Natural Gas Inventory SB334*, Oregon Department of Energy, pg 58: https://www.oregon.gov/energy/Data-and-Reports/Documents/2018-RNG-Inventory-Report.pdf.

later time. NW Natural would file any work papers, modeling inputs and outputs, and results detailing this offer for Staff to review 30 days prior to negotiation. There is no guarantee that a counter party would accept the offer reviewed by Staff. Regardless, Staff's review would be independent of whether or not the counterparty accepts or declines the price.

Beyond this maximum price offer, NW Natural will continue to research RNG opportunities. If opportunities arise and are found to be cost effective during the investigation, NW Natural will submit workpapers, modeling inputs and outputs, and results for Staff to review within 30 days prior to committing to an RNG resource. From Staff's recommendation, it is NW Natural's understanding that the 30 day review process would apply until end at the completion of the investigation, at which point Staff would have determined and established a methodology to evaluate the cost effectiveness of RNG for customers.

Prudence Review

Staff Recommendation:

- Any RNG contracts or projects will be subject to prudence review before cost recovery.

NW Natural recognizes that all resource decisions are subject to prudence review before cost recovery.

Establish an RNG Evaluation Methodology Review Process

Staff Recommendation:

- At the successful conclusion of the evaluation investigation, a process would be established for stakeholders to review the avoided costs and methodology annually or biennially.

NW Natural files an IRP every two years. TWGs are held to educate and inform stakeholders of the assumptions, inputs and methodology implemented to consistently evaluate resources, and to incorporate feedback received from those stakeholders. In addition, the avoided costs applied to energy efficiency are now going to be reviewed by the Commission through the UM 1893 process each year. The methodology of avoided costs for energy efficiency is the same being applied to RNG. Therefore, NW Natural believes it would be unnecessary and wasteful to establish yet another process for the separate evaluation of RNG. Such a process would be duplicative and redundant.

9. GENERAL COMMENTS

NW Natural thanks Staff for its comprehensive review of the 2018 IRP and Action Plan items. The Company requests that Staff resolve one process issue that was left absent in Staff's Final Comments. Action Plan #1 from the 2018 Joint Multiyear Action Plan states:

> *Recall 10,000 Dth/day of Mist storage capacity for the 2020-21 gas year. Recall 35,000 Dth/day of Mist storage capacity for the 2021-22 gas year.*

Staff makes no mention or recommendation regarding this item in its Final Comments. In subsequent conversations, the Company has come to understand that Staff has reviewed the item and recommends acknowledgement. The Company respectfully requests that Staff explicitly include this recommendation in the Staff Report.

10. CONCLUSION

NW Natural's 2018 IRP complies with the guidelines established for IRPs and the Company requests the Commission's acknowledgement of its Action Plan as filed with the following three exceptions described previously in these comments:.

1. Removal of the North Eugene reinforcement project.
2. The Company will re-file an updated Appendix H to the RNG evaluation methodology to include:
    - A zero carbon price path to be included in the stochastic analysis
    - A detailed description of evaluating RNG in SENDOUT
    - Language to indicate that NW Natural will use the most updated inputs for evaluation
    - A column in Table H:1 to indicate the frequency of updating the inputs
    - An actual bid for RNG, bundled with the environmental attributes, for a potential counterparty to be reviewed by Staff
3. The Company will aquire up to 2% of annual sales load of cost effective RNG using the evaluation methodology described in the revised Appendix H while Staff completes an investigation into the proposed RNG evaluation methodology.

LC 71 – NW Natural’s Final Comments

Attachment 1

Northwest Natural Gas Company

Supplemental Response to OPUC Staff DR 95

Filed on Huddle
February 8, 2019

Rates & Regulatory Affairs
LC 71
Integrated Resource Planning
Data Request Response

Request No.: LC 71 OPUC DR 95
95. See page 8.5-8.6 of the IRP. The Company describes a series of system reinforcement standards it uses for distribution system planning. Are these Company standards or federal and state safety standards? If these are Company standards, please provide a copy of Company codes that illustrate the standard. If these are federal or state standards, please provide a copy of the code or links to the section that illustrate the standard. If they are both, please provide copies of both standards and provide a description of the differences.

Request No.: LC 71 OPUC DR 95 – **Supplemental Request**
Please provide the citation and quote from the Gas Engineering and Operating Practices (GEOP),that specifically supports NW Natural's parameter (shown below) for high pressure distribution systems and specifically makes reference to the 40% pressure drop.

- Experiencing or modeling a 40% pressure drop that indicates reinforcing the facility is critical, as a 40% pressure drop equates to an 80% level of capacity utilization.

For clarification per Staff: The engineering language supporting the 40% distribution reinforcement standard, and an explanation of why the language supports a 40% reinforcement standard.

Response:

NW Natural has provided the same series of system reinforcement standards it has used for distribution system planning in the 2016, and 2018 IRP's and has been using for many years. Per 8.5-8.6 of the 2018 IRP:

> Transmission and high pressure distribution systems (systems operating at greater than 60 psig) have different characteristics than other components of NW Natural's distribution system, and design parameters associated with peak hour load requirements differ as well. System reinforcement parameters for these systems include:
>
> - Experiencing at least a 30% pressure drop over the facility that indicates an investigation will be initiated

- Experiencing or modeling a 40% pressure drop that indicates reinforcing the facility is critical, as a 40% pressure drop equates to an 80% level of capacity utilization

This standard is based on the Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, Chapter 2: Gas Flow Calculations, page 111.

- Consider minimum inlet pressure requirements for proper regulator function in addition to total pressure drop for pipelines that feed other high pressure systems

This standard is based on pressure regulator manufacturer requirements. NW Natural has a variety of pressure regulators in its systems, and the manufacturer requirements for minimum inlet pressure for proper regulator function are used on a case by case basis. Typical manufacturer and models of pressure regulators NW Natural uses are the Mooney Flowgrid, the Honeywell American Axial Flow, and the Fisher 627.

- Near-term growth indicated by one or more leading indicators (e.g., new road construction, subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance

- The ability to meet firm service customer delivery requirements (flow or pressure)

- Identified in the IRP associated with supply requirements or needs

The system reinforcement parameters associated with peak hour load requirements for distribution systems that are not high pressure (systems operating at 60 psig or less) are:

- Experiencing a minimum distribution pressure of 15 psig that indicates an investigation will be initiated

- Experiencing or modeling minimum distribution pressure of 10 psig that indicates reinforcement is critical

This standard is based on the minimum inlet pressure required for an Excess Flow Valve (EFV) to properly function, per 49 CFR §192.381 Service lines: Excess flow valve performance standards:

> (a) Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

(1) Function properly up to the maximum operating pressure at which the valve is rated;

(2) Function properly at all temperatures reasonably expected in the operating environment of the service line;

(3) At 10 p.s.i. (69 kPa) gage:

(i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

(ii) Upon closure, reduce gas flow—

(A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

(B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

(4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

- Near-term growth indicated by one or more leading indicators (e.g., new road construction, a new subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance

- Firm service customer delivery requirements (flow or pressure)

February 8, 2019 Supplemental Response:

NW Natural bases its high pressure pipeline design on the industry design standard documented in Gas Engineering and Operations Practice (GEOP) System Design book. The GEOP design book was created by the American Gas Association and industry members to provide an overview of design practices for gas distribution systems as noted in the Preface of the book (Figure 2 below). Part 1, Capacity Design, of the GEOP book introduces pipeline sizing and pressure drops stating “a properly sized pipe system will have the capacity to deliver gas a sufficient pressure to all customers at all times” (Figure 3 and 4 below). Chapter 2, Gas Flow Calculations, provides an overview of the background of compressed natural gas flow calculations (Figure 5 below).

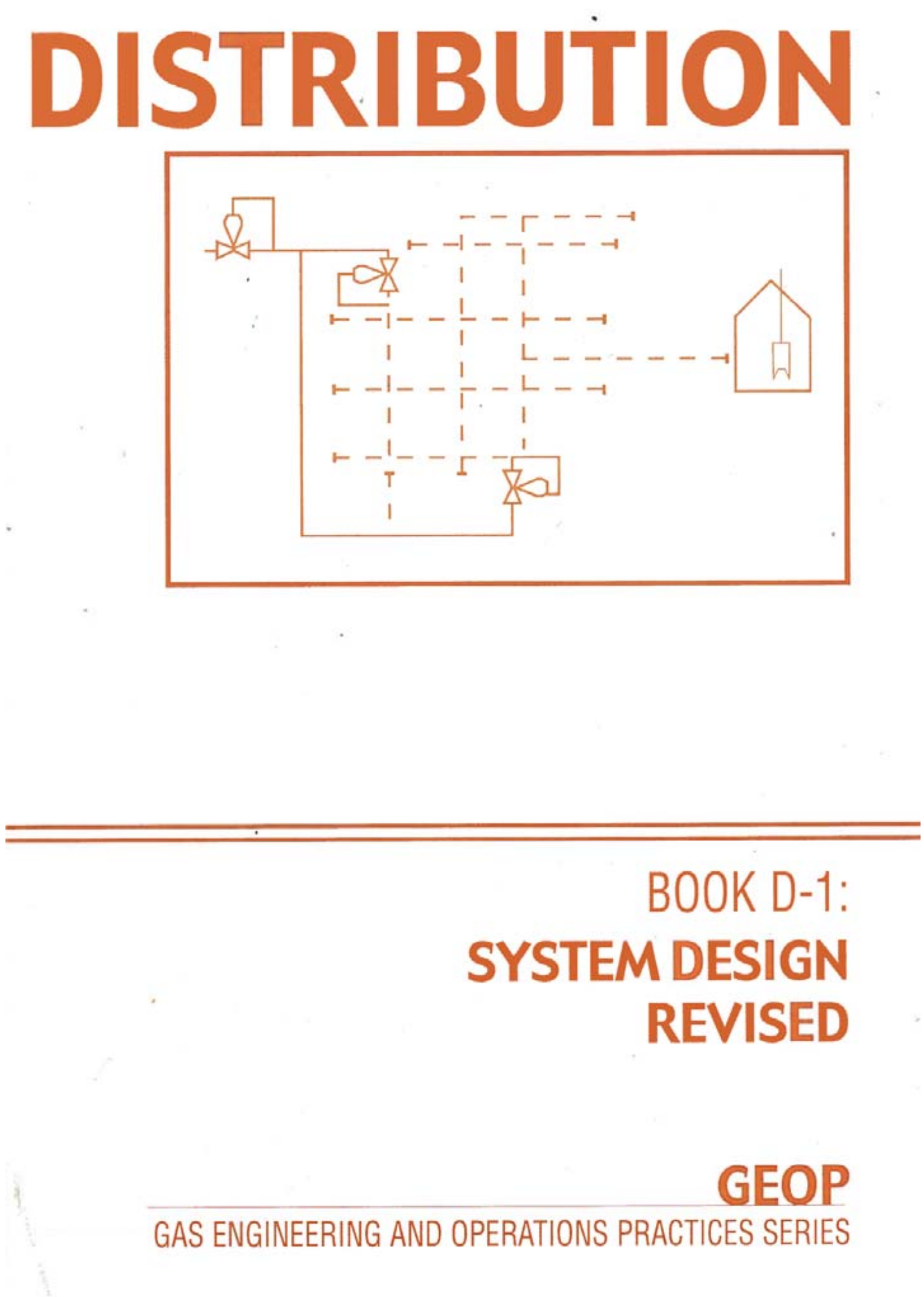


Figure 1 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Cover

PREFACE

Washington, DC
September, 2004

System Design was the sixth book published in 1990 as part of the original Gas Engineering and Operating Practices (GEOP) series. The series comprises six volumes, each consisting of from one to three books in the operational areas of Supply, Transmission, Distribution, Measurement, Utilization, and Technical Services.

System Design, along with *Mains and Services - Operating Considerations,* make up the GEOP Distribution volume. Its purpose is to provide a current, concise-but complete-overview of the materials, equipment, and design practices for gas distribution systems. Whether a new hire or a CEO, you will be pleased with the way that GEOP authors and editors have simplified complicated subjects and gratified to find so much experience and knowledge at your fingertips.

As comprehensive as it is, *System Design* does not pretend to offer specific answers to every question that might arise in practice. The references it provides to other gas technology literature expands its usefulness beyond its contents. Readers owe a special debt of gratitude to Manuela Erickson of Safety and Compliance Evaluation, Inc. who indexed the book.

The contributions of the late Samuel I. Hyman touch many areas in the book. Not only did Sam, a prolific communicator with exceptional knowledge of a broad range of gas industry technology, write extensively for *System Design*, he was also reviewing manuscripts of other writers up to the very end of his life. The result owes much to his contributions, both direct and through his input to and stimulation of others.

Gerald G. Wilson
Chairman, GEOP Task Group, 1990

Robert L. Parker
Editor, 1990

Manuela Erickson, PE
Editor, 2004

Figure 2 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Preface

PART I
CAPACITY DESIGN

SCOPE

When gas is compressed, energy is stored in it; the pressure of the compressed gas is a measure of the amount of energy stored. As compressed natural gas flows through the distribution system's pipe from the source to the customer, its pressure gradually decreases because some of its stored energy is converted by friction to heat, which is lost to the earth in the vicinity of the pipe.

If the mains in a distribution system are too small, the pressure decrease (drop) will be excessive during periods of peak gas demand, resulting in pressures at remote locations in the system that are too low for proper operation of appliances. A properly sized pipe system will have the capacity to deliver gas at sufficient pressure to all customers at all times.

The optimum system will provide the proper capacity with the lowest possible investment. It will have been built with the pipe material most suited to the local circumstances and with proper regard for safety during construction and subsequent operations.

The technology and procedures for handling all of the common types of pipe sizing problems are covered in this Part of the book. The same kinds of information are required to define all pipe-sizing problems:

- Nature of the gas distributed
- Location of gas sources
- Operating restrictions, such as delivery pressures required by commercial or industrial customers
- Amount and distribution of the design load

After this information has been collected, the solution of a service or stub-main problem is straightforward. The smallest size pipe that will do the job should be used. The data used and the calculation procedures are presented in Chapter 2, and examples of their application are presented in Chapter 3.

The first step in the solution of a network problem is to assume a configuration of the pipe sections connecting the gas sources to all the customers. Guidelines for developing good layout patterns for new systems and alternatives for existing systems are presented in Chapter 4. The adequacy of the assumed configuration is checked by a calculation procedure called network analysis, which is described in Chapter 5. Usually, it is necessary to try several pipe configurations and compare their costs before the most economical layout is discerned. System cost comparisons should include the *timing* of the various investments as well as their amounts, because the interest on borrowed capital has a significant influence on the cost outcome, as discussed in

Figure 3 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Part 1, Capacity Design, page 5

Chapter 6.

Computer programs have been developed that use optimization logic to arrive at near-optimum reinforcements for existing systems or pipe layouts for new systems. These also are discussed in Chapter 6.

In summary, the material in Part I provides guidelines and describes many of the tools for capacity planning.

Gerald G. Wilson

Figure 4 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Part 1, Capacity Design, page 6

Chapter 2

GAS FLOW CALCULATIONS

Gerald G. Wilson

The pressure of the gas flowing through a pipe of uniform internal diameter gradually decreases in the direction of flow. The magnitude of the pressure decrease or drop depends on (1) the flow rate, (2) the dimensions and wall roughness of the pipe, and (3) the temperature, average pressure, and physical properties of the flowing gas. Calculations of the pressure drop are often used to determine whether a pipe configuration can deliver gas to the customers it serves at adequate pressure during design conditions.

Usually, the first step in the design of a gas piping system is to use one of the methods described in Chapter 1 to estimate the magnitude and distribution of the design loads that the system will be called upon to carry. Then, flow calculations are used to establish either the pipe sizes required to maintain adequate pressures throughout a new system under design conditions or the ability of an existing system to maintain adequate pressures. The specific procedures used for the common types of design situations are covered in later chapters; this chapter is concerned with the basic flow calculation procedures.

Flow calculations are based on the use of a flow equation, an algebraic relationship that relates the pressure drop to the other flow variables. Since the beginning of commercial transportation and distribution of gas, many different flow equations have been developed and used by the gas industry. The general form of most of them is derived from the Bernoulli energy balance. It includes a frictional energy loss term that must be evaluated empirically from the results of gas flow experiments. Since the experiments on which the various practical flow equations are based were conducted over different ranges of flow conditions, on pipes of different internal surface roughness, and to varying degrees of accuracy, these equations do not give the same results. Most are applicable over only a limited range of flow and pipe surface conditions.

Following a brief review of essential flow fundamentals, this chapter presents a general flow calculation procedure and outlines the ranges of applicability for the various practical flow equations. Examples of common types of flow calculations are given. Finally, some procedures that often can be used to simplify flow calculations are described.

FUNDAMENTALS OF FLUID FLOW

Any basic textbook on fluid mechanics published in the last three decades provides thorough coverage of gas flow behavior. Therefore, this section will be confined to a brief review of essential fundamentals.

Figure 5 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Chapter 2: Gas Flow Calculations, page 63

Figure 6 below is a copy of page 111 of the GEOP book. On that page is a graph (GEOP Figure 38) showing the relation between flow rate and pressure loss in a high pressure pipeline. The curve is non-linear and a 40% pressure drop represents 80% of the maximum possible flow through the pipeline segment (Figures 7 and 8 show the mathematical basis for pressure curve). GEOP states that “measures should be taken to increase capacity…” when a pipeline pressure drops “below 60% of the initial absolute pressure” (i.e. exceeds a 40% pressure drop). GEOP presents the 40% pressure drop as a rule of thumb and NW Natural considers the following additional factors when reviewing new high pressure system reinforcement projects:

- Consider minimum inlet pressure requirements for proper regulator function in addition to total pressure drop for pipelines that feed other high pressure systems

- Near-term growth indicated by one or more leading indicators (e.g., new road construction, subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance

- The ability to meet firm service customer delivery requirements (flow or pressure)

- Identified in the IRP associated with supply requirements or needs

NW Natural has a variety of pressure regulators in its systems, and the manufacturer requirements for minimum inlet pressure for proper regulator function are used on a case by case basis. These pressure regulators are mechanically driven and use the pressure in the pipeline to properly function. In Staff’s final comments, Staff mentions that regulator inlet pressures must be at least 20 psi above the outlet pressure. To clarify, this 20 psi should not be used as a design standard. It was referenced by NW Natural in DR 52 as the typical pressure restriction that a district regulator has on gas flows. As inlet pressure decreases, the capacity, or amount of gas that can be served by the regulator, drops dramatically. The inlet pressure of a district regulator must be high enough to serve the load downstream, hence the use of the 40% pressure drop as a design standard.

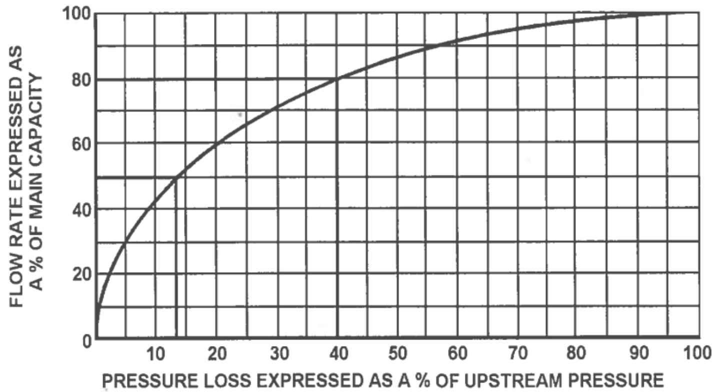


Figure 38. **Relation between flow rate and pressure loss for a main operated at high pressure.**[19]

RULE-OF-THUMB TEST OF ADEQUACY

A high degree of accuracy often is not required to obtain workable answers to pipe sizing and capacity problems. Some gas engineers have developed simple rule-of-thumb methods to solve many of the common problems that they encounter on a day-to-day basis.

For example, it has been found that a graph similar in form to the one shown in Figure 38 and derived in Appendix H is obtained for any pipe sections in a high pressure distribution system if percent main capacity is plotted against percent loss of upstream pressure.[19]

These plots are based on the use of a flow formula of the form:

$$\Delta P^2 = KQ_b^2$$

Examination of this curve shows that the gas flow rate is approximately 80% of the maximum possible flow rate when the absolute downstream pressure is dropped to 60% of the initial absolute upstream pressure. This observation has resulted in the rule-of-thumb that measures should be taken to increase the capacity or reduce the gas flow on a pipe section in a high pressure distribution system when its measured absolute downstream pressure approaches or begins to drop below 60% of the absolute upstream pressure.

Rule-of-thumb methods are not sufficiently accurate or general to serve as the basis for the overall design of a distribution system. Instead, they are best regarded as guides that can be used to obtain rapid, order-of-magnitude answers to some system capacity and pipe sizing questions.

Figure 6 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Chapter 2: Gas Flow Calculations, page 111

Appendix H

BASIS OF THE RULE-OF-THUMB TEST OF ADEQUACY

Gerald G. Wilson

If a square-law flow equation describes the flow behaviour of a section of pipe, then for any flow rate:

$$P_1^2 - P_2^2 = KQ^2 \qquad \text{(Eq. H-1)}$$

When the pipe operates at capacity:

$$P_1^2 - P_c^2 = KQ_c^2 \qquad \text{(Eq. H-2)}$$

where: P_c = pressure at downstream end of line when it is operating at capacity [psia]

Q_c = capacity of the section of pipe for an inlet pressure of P_1 [Mft^3/h]

Division of Equation H-1 by Equation H-2 yields:

$$\frac{P_1^2 - P_2^2}{P_1^2 - P_c^2} = \frac{KQ^2}{KQ_c^2} = \frac{Q^2}{Q_c^2}$$

When the numerator and denominator of the left member of this equation are divided by P_1^2, the equation becomes:

$$\frac{\dfrac{P_1^2}{P_1^2} - \dfrac{P_2^2}{P_1^2}}{\dfrac{P_1^2}{P_1^2} - \dfrac{P_c^2}{P_1^2}} = \frac{\left[1 - \left(\dfrac{P_2}{P_1}\right)^2\right]}{\left[1 - \left(\dfrac{P_c}{P_1}\right)^2\right]} = \frac{Q^2}{Q_c^2}$$

Taking the square-root of both sides of this equation:

$$\frac{Q}{Q_c} = \sqrt{\frac{1-(P_2/P_1)^2}{1-(P_c/P_1)^2}} \qquad \text{(Eq. H-3)}$$

To arrive at the equation plotted in Figure 14 in Chapter 2, it is necessary to assume that $(P_c/P_1)^2 \cong 0$. This assumption simplifies Equation H-3 to:

$$\frac{Q}{Q_c} = \sqrt{1-(P_2/P_1)^2} \qquad \text{(Eq. H-4)}$$

It can be shown easily that Equation H-4 yields the rule-of-thumb given in Chapter 2. When the downstream pressure is 60% of the upstream pressure:

Figure 7 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Appendix H, Basis of the Rule of Thumb Adequacy, page 517

$P_2 = 0.6P_1$

$P_2/P_1 = 0.6P_1/P_1 = 0.6$

Substitution of 0.6 for P_2/P_1 in Equation H-4 gives:

$$Q/Qc = \sqrt{1-(0.6)^2} = 0.8$$

$Q = 0.8Q_c$

The last equation shows that the flow rate is 80% of capacity when the downstream pressure is 60% of the upstream pressure.

This rule-of-thumb is a rough approximation because the assumption that $(P_c/P_1)^2 \cong 0$ is only roughly true. Table H-1 presents values of $(P_c/P_1)^2$ over the range of pressures encountered in high-pressure distribution systems. The value of 2 psig (14 kPa) used as the downstream pressure at capacity is a representative value of the minimum main pressure needed to assure proper operation of all appliances connected to a high-pressure distribution system. This rule is not applicable at inlet pressures below 13 psig (90 kPa) since the downstream pressure corresponding to 60% of the inlet pressure would be less than the 2 psig (14 kPa) pressure at capacity. The values of $(P_c/P_1)^2$ in Table H-1 show that it approximates zero at inlet pressures of 30 psig (207 kPa) and above but deviates quite significantly from zero at lower inlet pressures. Thus, the rule-of-thumb is most nearly correct at high inlet pressures; it tends to become increasingly conservative as the inlet pressure decreases.

That is, at moderate inlet pressures, the flow rate through a pipe section is greater than 80% of capacity when the downstream pressure has dropped to 60% of the inlet pressure. This can be deduced from Equation H-3 by use of the values in Table H-1.

TABLE H-1
Selected Values of $(P_c/P_1)^2$

P_1			
Gage [psig (kPa)]	**Absolute* [psia (kPa)]**	**(P_c/P_1)****	**$(P_c/P_1)^2$**
15 (103)	29.4 (203)	0.558	0.311
30 (207)	44.4 (306)	0.370	0.136
45 (310)	59.4 (410)	0.276	0.076
60 (414)	74.4 (513)	0.220	0.048

* For atmospheric pressure of 14.4 psia (99.3 kPa)
** For P_c= 16.4 psia (113 kPa)

Because of its conservative tendency, the rule-of-thumb is a useful test of adequacy throughout the range of pressures normally experienced in high-pressure systems.

Figure 8 - Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, The American Gas Association, Washington DC, Appendix H, Basis of the Rule of Thumb Adequacy, page 518

Sandy Feeder Project

The measured pressure drop on the Sandy Feeder on January 6. 2017 was 318 psig (390 - 72) or 81.5%, which results in approximately 96% of the maximum flow rate capacity for the pipeline. This greatly exceeds the 40% pressure drop criteria for high pressure pipelines and indicates that this pipeline requires reinforcement.

Sandy Gate Station Pressure (psig) - Measured	District Regulator Pressure (psig) – Measured	Resulting Pressure Drop
390	72	318 psi (81.5%)

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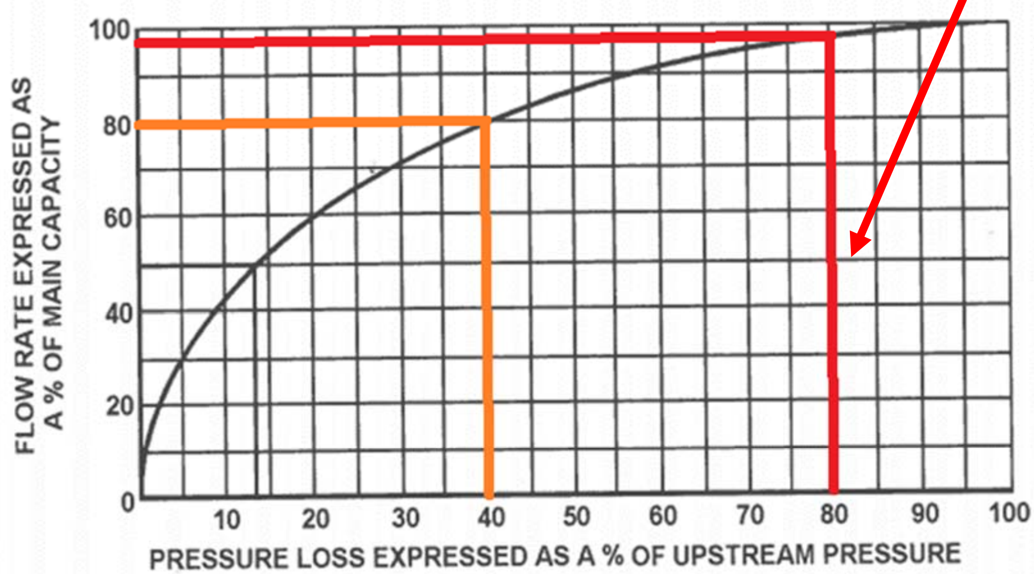

Figure 38. **Relation between flow rate and pressure loss for a main operated at high pressure.**[19]

Figure 9 – Measured pressure drop from Sandy Feeder from January 2017 showing 81.5% pressure drop representing 96% capacity in red. NW Natural design standard of 40% pressure drop shown in orange.

Normal winter operations activities were performed during this event. Field personnel validated that the regulators feeding the system were performing properly. The regulator at the end of the Sandy Feeder was bypassed during morning hours to maximize pressures. There are no interruptible customers in the Sandy system which could have been curtailed to remove demand from the feeder.

The performance of the lower pressure distribution system is wholly dependent upon the ability of the high pressure pipeline to deliver adequate gas pressure to the regulator inlet. The following district regulator is installed at the end of the Sandy Feeder:

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District Regulator 1-047-068-R-01: US Hwy 26 W. of Reuben Rd.

2" Mooney Flowgrid Regulator, 400 MAOP inlet, 57 MAOP outlet (outlet set-point 50 psig).

The Maximum Design Capacity is 604.5 MSCFH[1] at 400 psig inlet, 57 psig outlet, and the actual Capacity is 96.3 MSCFH[1] at 72 psig inlet, 50 psig outlet with the conditions experienced in January 2017. This corresponds to a regulator capacity reduction of 84.1%. As the downstream distribution system being fed by this district regulator continues the draw more flow, the pressure will be further reduced and at an increased rate. This would cause widespread customer outages in the Sandy distribution system.

To prevent outages, the regulator was bypassed, and manually operated by NW Natural crews to ensure adequate gas pressured during this cold weather event. This is an additional indication that the high pressure pipeline feeding Sandy is inadequate to serve existing customers further supporting the proposed pipeline reinforcement project.

Kuebler Road Project

The measured pressure drop on the South Salem system from Turner gate to the Kuebler Regulator on January 6. 2017 was 140 psig (220 - 80) or 63.8%, which results in approximately 93% of the maximum flow rate capacity for the pipeline. This exceeds our 40% system reinforcement pressure drop criteria for high pressure pipelines and indicates that this pipeline requires reinforcement.

Turner Gate Station Pressure (psig) - Measured	District Regulator Pressure (psig) – Measured	Resulting Pressure Drop
220	80	140 psi (63.6%)

[1] MSCFH means Thousands of Standard Cubic Feet per Hour

CHAPTER 2: GAS FLOW CALCULATIONS 111

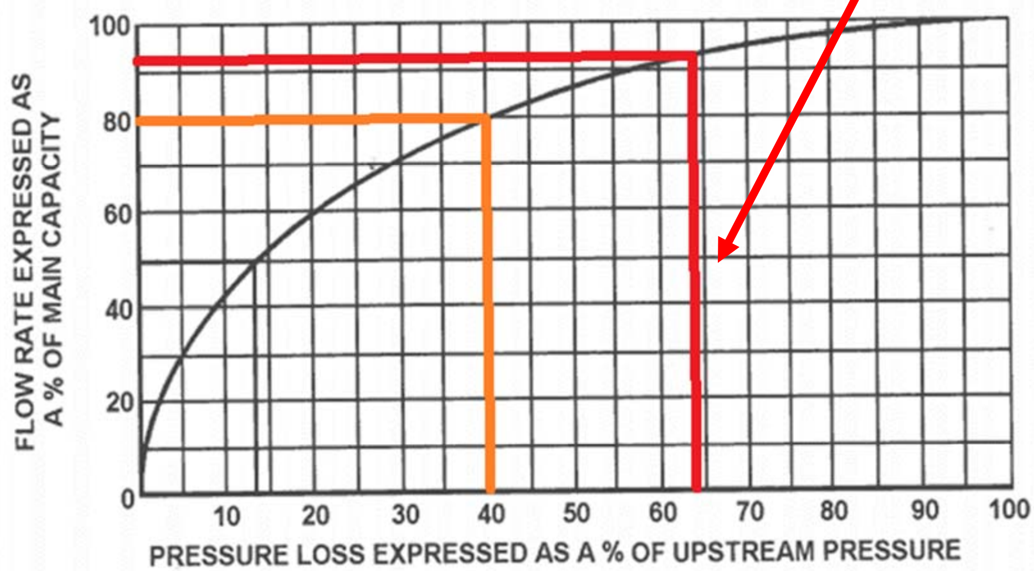


Figure 38. **Relation between flow rate and pressure loss for a main operated at high pressure.**[19]

Figure 10 – Measured pressure drop from Turner gate to Kuebler Rd from January 2017 showing 63.6% pressure drop representing 93% capacity in red. NW Natural design standard of 40% pressure drop shown in orange.

Normal winter operations activities were performed during this event. Field personnel validated that the regulators feeding the system were performing properly. The regulator at the southwest end of the Salem high pressure system (Kuebler Blvd. & Skyline Rd.) was bypassed during morning hours to maximize pressures. The regulator inlet pressure at this location reached a low pressure of 80 psig on the morning of January 6, 2017. There are no interruptible customers downstream of this regulator which could have removed demand from this regulator and its upstream system.

The performance of the lower pressure distribution system is wholly dependent upon the ability of the high pressure pipeline to deliver adequate gas pressure to the regulator inlet. The following district regulator is installed at Keubler Blvd and Skyline Rd

District Regulator 2-118-009-R01: Kuebler Blvd. & Skyline Rd.

2" American Axial Flow Regulator, 225 MAOP inlet, 45 MAOP outlet (outlet set-point 40 psig).

The Maximum Design Capacity is 606.1 MSCFH at 225 psig inlet, 45 psig outlet, and the actual Capacity is 234.2 MSCFH[1] at 80 psig inlet, 40 psig outlet with the conditions experienced in January 2017. This corresponds to a regulator capacity reduction of 61.4%. As the downstream distribution system being fed by this district regulator continues the draw more flow, the pressure will be further reduced and at an increased rate. This would cause widespread customer outages in the Salem distribution system.

To prevent outages, the regulator was bypassed, and manually operated by NW Natural crews to ensure adequate gas pressured during this cold weather event. This is an additional indication that the high pressure pipeline feeding Salem is inadequate to serve existing customers further supporting the proposed pipeline reinforcement project.

LC 71 – NW Natural’s Final Comments

Attachment 2

Northwest Natural Gas Company

Supplemental Response to OPUC Staff DR 52

Filed on Huddle
February 8, 2019

NW Natural®

Rates & Regulatory Affairs
LC 71
Integrated Resource Planning
Data Request Response

Request No.: LC 71 OPUC DR 52
52. Please provide further explanation of the January 2017 outages and/or pressure drops experienced in each of the locations for which NW Natural is seeking acknowledgement in the Action Plan for reinforcement projects. In your response, please include the following information:

a. Was this an isolated incident that occurred on one day or was this a prolonged event? Please provide dates and times for all related projects.

b. At what time and on which days in January 2017 were there observed pressure drops during non-peak conditions at the affected locations?

c. What percentage share of customers served in each of these locations separately was impacted by outage event(s)? How many customers were impacted by the January 2017 event?

d. Please provide all outage reports associated with the January 2017 event, with a narrative and references to the outage reports, illustrating why current operating conditions no longer meet demand or safety standards.

Request No.: LC 71 OPUC DR 52 – **Supplement Request**
52. Please provide at 10 different data points each for both the Happy Valley and North Eugene distribution system projects and using these additional data points, demonstrate how the modeling is accurate.

1. For the localized model verification, we request all SCADA data, field pressure readings, and charts from the relevant local area during the recent cold weather event. These should be displayed side-by-side with the Synergi modeling output for the same location under the same conditions.
2. We also request all nearby field pressure reading data for the relevant local area surrounding each project. The data should include the precise location of the pressure reading. Please include all data fields documented about these field readings, including any remedial action taken.

Response:

DR's 52, 55, 56, 57, and 58 are requests to gather information about the six 2018 IRP action item projects in an attempt to clarify why these projects need to be completed. NW Natural met with OPUC staff on Wednesday, October 10, 2018 to relay information about many of our processes and to clarify data requests. OPUC staff requested that NW Natural present the results for these data requests in project specific narrative format to ease individual project interpretation and evaluation.

LC 71 OPUC DR 52 Attachment A and Attachments 1-2 provide narratives and supporting data for each individual action item project that are presented in lieu of direct responses to DR's 52, 55, 56, 57, and 58.

LC 71 OPUC DR 52 Attachment A contains project narratives for each of the six action item projects.

LC 71 OPUC DR Attachment 1 contains a list of customer outages that occurred during the January 5-6, 2017 cold weather event from the Hood River and Oregon City project areas.

LC 71 OPUC DR Attachment 2 contains historical weather data (1985-Present) for each of the project areas. This data ranks cold weather events by severity and is presented to support that January 2017 weather was not anomalous, nor a peak weather event.

February 8, 2019 Supplemental Response:

As a supplement to DR 52, Staff is requesting additional information that validates the accuracy of the Synergi modeling process for each low pressure distribution system project during a cold weather event. The projects in Happy Valley and North Eugene were initiated by modeled results that show substandard pressures which will impact customers under peak demand conditions. Models cannot be validated at peak because peak pressure data is not available. Pressure data from January 2017 must be used to validate models. Data tables and maps are presented for the two low pressure distribution system projects below.

Happy Valley Reinforcement Project

The Happy Valley Project area is surrounded by SCADA sites but there is no SCADA data directly in the weakest zone. There are Cold Weather Pressure Survey sites within the weakest zone and a cold weather survey was performed in the Portland area on Jan 4, 2017. Note that the data from map locations #1 through #4 have not been provided to date. In revisiting pressure read records, we were able to locate actual pressure data from within the project area confirming that system standards were violated. The field pressure reading of 9 psig at location #2 indicates a violation of distribution system reinforcement standards. Colder weather actually occurred on Jan 5 & 6, 2017 but no cold weather pressure survey was performed. A model date of Jan 4, 2017 at 7am was selected to provide the greatest number of points for comparison.

Happy Valley Area Modeling Data versus Field Collected Data or SCADA Data

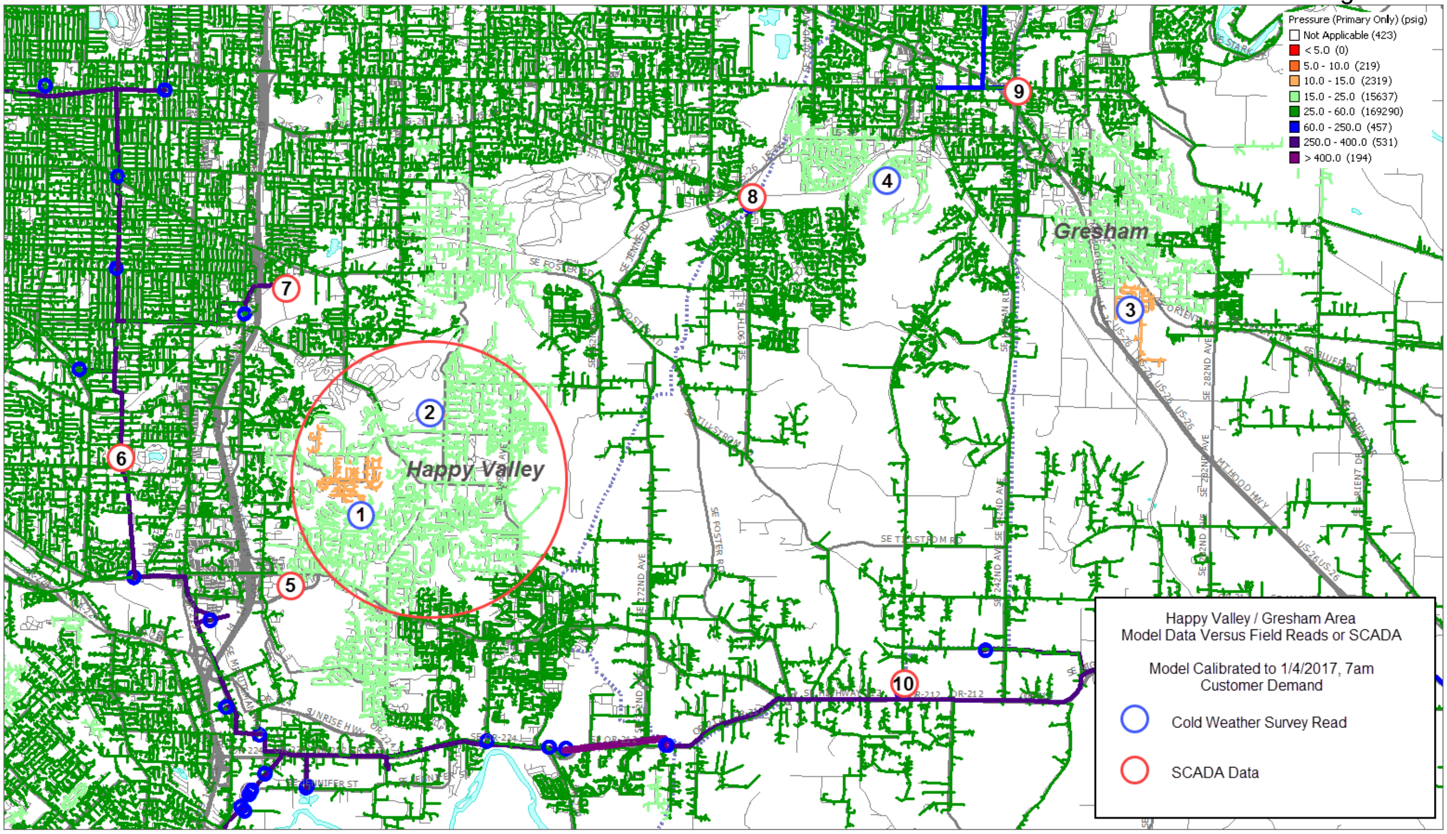
Location On Map	Plat	Cold Weather Survey Site Address/Location	City	Date	Time	Field PSIG	Model PSIG
1	1-041-042	11150 SE Valley View Terrace	Happy Valley	01/04/17	7:15 AM	22	18.7
2	1-039-043	12601 SE Callahan Rd	Happy Valley	01/04/17	7:00 AM	9	11
3	1-036-056	2927 SE Kane Ave	Gresham	01/04/17	6:57 AM	17	14.5
4	1-034-052	830 SW Florence Place	Gresham	01/04/17	6:45 AM	18	18.3

Location On Map	Plat	SCADA Site Address/Location	City	Date	Time	SCADA PSIG	Model PSIG
5	1-043-040	Kaiser Sunnyside Hospital	Portland	01/04/17	7:00 AM	23.5	24.1
6	1-040-037	SE Bell Rd & SE Sandview St	Portland	01/04/17	7:00 AM	49.8	50
7	1-037-040	SE 100th Ave & SE Glenwood St	Portland	01/04/17	7:00 AM	47.1	50
8	1-035-049	Johnson Creek Gate Station	Portland	01/04/17	7:00 AM	42	48.3
9	1-032-054	Gresham Gate Station	Gresham	01/04/17	7:00 AM	45	48.6
10	1-044-054	Sandy Gate Station	Boring	01/04/17	7:00 AM	47.8	50

The model used for this analysis was tuned for Jan 4, 2017, 7am, the time of the highest instantaneous demand for the day. This day was chosen because it corresponds with pressure data collected from a Cold Weather Pressure Survey.

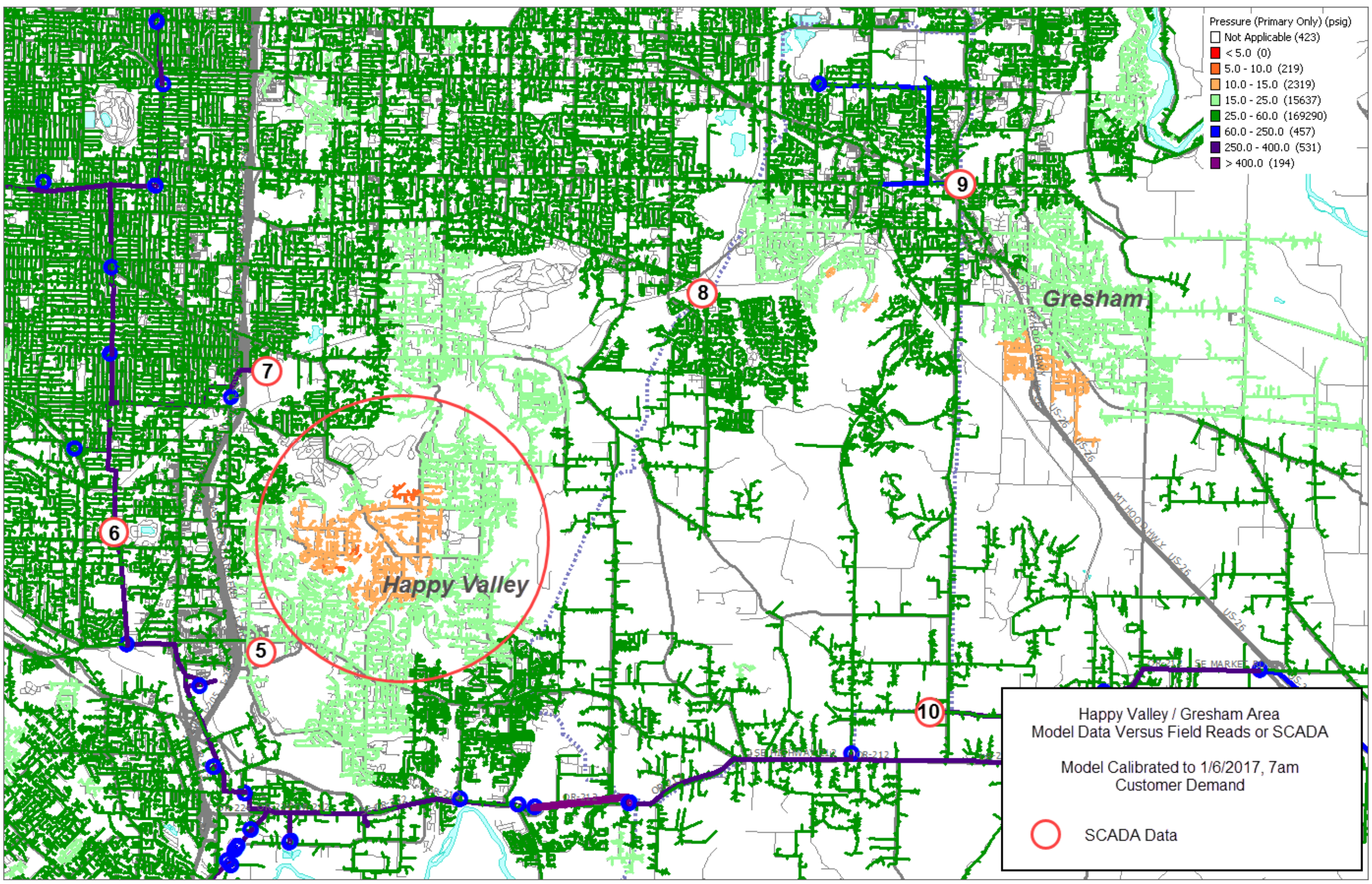
The following map shows the location of the pressure comparison data points and the general project area for Happy Valley. Note that the figure below shows system conditions based on January 4th, 2017 at 7am.

LC 71 OPUC DR 52
NWN Response

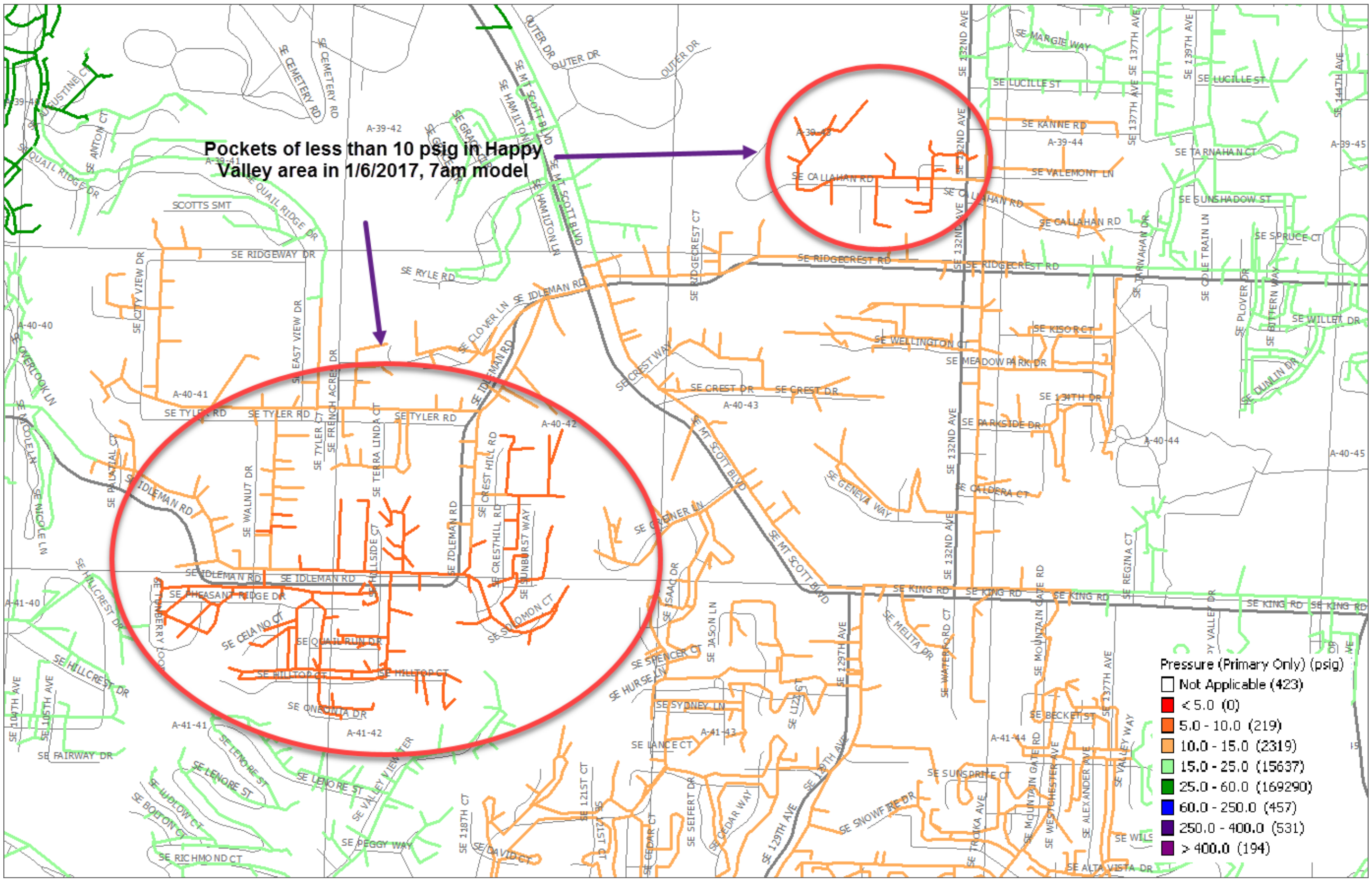


The table and map below show modeled system conditions based on January 6th, 2017, 7am customer demand when temperatures were on average, four degrees colder. Note the significant change in pressures within the Happy Valley area between the two cold mornings.

Location On Map	Plat	SCADA Site Address/Location	City	Date	Time	SCADA PSIG	Model PSIG
5	1-043-040	Kaiser Sunnyside Hospital	Portland	01/06/17	7:00 AM	19.6	21.4
6	1-040-037	SE Bell Rd & SE Sandview St	Portland	01/06/17	7:00 AM	49.8	50
7	1-037-040	SE 100th Ave & SE Glenwood St	Portland	01/06/17	7:00 AM	47.1	50
8	1-035-049	Johnson Creek Gate Station	Portland	01/06/17	7:00 AM	39.6	47.3
9	1-032-054	Gresham Gate Station	Gresham	01/06/17	7:00 AM	43.9	48
10	1-044-054	Sandy Gate Station	Boring	01/06/17	7:00 AM	47.5	50



The following map shows the areas of Happy Valley that the Jan 6, 2017 7am model calculates pressures to be less than 10 psig, violating our distribution system standards.



North Eugene Reinforcement Project

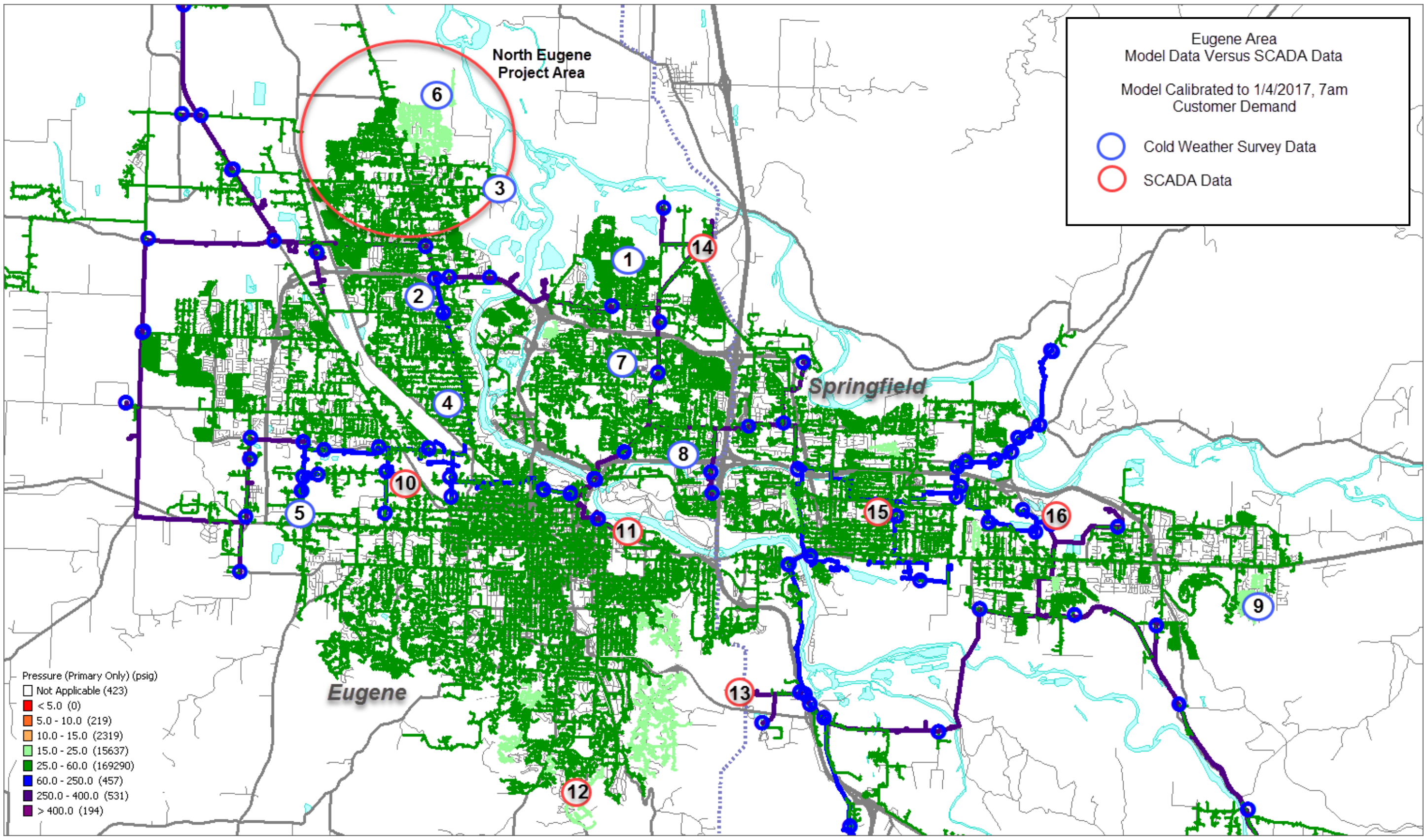
The North Eugene Project area has no SCADA sites within the project area or nearby. There are Cold Weather Pressure Survey sites within the weakest zone and a cold weather survey was performed in the Eugene area on Jan 4, 2017. Note that the data from map locations #1 through #9 have not been provided to date. Similar to Happy Valley, in revisiting pressure read records, we were able to locate actual pressure data from within the project area. A model date of Jan 4, 2017 was selected because it was the highest demand day in this area.

Eugene Area Modeling Data versus Field Collected or SCADA Data

Location On Map	Plat	Cold Weather Survey Site Address/Location	City	Date	Time	Field PSIG	Model PSIG
1	2-226-010	3402 Honeywood St	Eugene	01/04/17	8:24 AM	35	38.1
2	2-227-016	200 Silver Ln	Eugene	01/04/17	7:30 AM	34	35.3
3	2-224-014	205 Chapman Rd	Eugene	01/04/17	7:45 AM	30	27.8
4	2-229-016	1224 Elkay Rd	Eugene	01/04/17	7:18 AM	33	33.3
5	2-233-019	4201 Commerce St	Eugene	01/04/17	7:00 AM	31	34.7
6	2-222-016	909 Beacon (Nursery)	Eugene	01/04/17	7:54 AM	26.5	22.0
7	2-229-010	2225 Jeppesen Acres Rd	Eugene	01/04/17	7:30 AM	34	34.5
8	2-231-009	3395 Oxbow Way	Eugene	01/04/17	7:15 AM	28	28.5
9	1-235-007	1220 S 69th Pl	Springfield	01/04/17	7:15 AM	22	24.2

Location On Map	Plat	SCADA Site Address/Location	City	Date	Time	SCADA PSIG	Model PSIG
10	2-232-016	Emerald Forest Products	Eugene	01/04/17	7:00 AM	121.2	125.9
11	2-233-010	University of Oregon	Eugene	01/04/17	7:00 AM	352.9	352.6
12	2-240-011	Eugene City Pressure	Eugene	01/04/17	7:00 AM	25.5	25.0
13	2-238-007	South Eugene Gate	Eugene	01/04/17	7:00 AM	379.7	383.7
14	2-226-008	North Eugene Gate	Eugene	01/04/17	7:00 AM	369.9	367.9
15	2-233-003	Springfield City Pressure	Springfield	01/04/17	7:00 AM	26.3	27.9
16	1-232-001	International Paper Reg	Springfield	01/04/17	7:00 AM	135.29	135.0

The following map shows the location of the pressure comparison data points and the general project area for North Eugene. Note that the figure below shows system conditions based on January 4, 2017 at 7:00 am.



LC 71 – NW Natural’s Final Comments

Attachment 3

Northwest Natural Gas Company

Response to OPUC Staff DR 95

Filed on Huddle
December 7, 2018

NW Natural

Rates & Regulatory Affairs
LC 71
Integrated Resource Planning
<u>Data Request Response</u>

<u>Request No.</u>: LC 71 OPUC DR 95
95. See page 8.5-8.6 of the IRP. The Company describes a series of system reinforcement standards it uses for distribution system planning. Are these Company standards or federal and state safety standards? If these are Company standards, please provide a copy of Company codes that illustrate the standard. If these are federal or state standards, please provide a copy of the code or links to the section that illustrate the standard. If they are both, please provide copies of both standards and provide a description of the differences.

<u>Response:</u>

NW Natural has provided the same series of system reinforcement standards it has used for distribution system planning in the 2016, and 2018 IRP's and has been using for many years. Per 8.5-8.6 of the 2018 IRP:

> Transmission and high pressure distribution systems (systems operating at greater than 60 psig) have different characteristics than other components of NW Natural's distribution system, and design parameters associated with peak hour load requirements differ as well. System reinforcement parameters for these systems include:
>
> - Experiencing at least a 30% pressure drop over the facility that indicates an investigation will be initiated
> - Experiencing or modeling a 40% pressure drop that indicates reinforcing the facility is critical, as a 40% pressure drop equates to an 80% level of capacity utilization

This standard is based on the Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, Chapter 2: Gas Flow Calculations, page 111.

- Consider minimum inlet pressure requirements for proper regulator function in addition to total pressure drop for pipelines that feed other high pressure systems

This standard is based on pressure regulator manufacturer requirements. NW Natural has a variety of pressure regulators in its systems, and the manufacturer requirements for minimum inlet pressure for proper regulator function are used on a case by case basis. Typical manufacturer and models of pressure regulators NW Natural uses are the Mooney Flowgrid, the Honeywell American Axial Flow, and the Fisher 627.

- Near-term growth indicated by one or more leading indicators (e.g., new road construction, subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance

- The ability to meet firm service customer delivery requirements (flow or pressure)

- Identified in the IRP associated with supply requirements or needs

The system reinforcement parameters associated with peak hour load requirements for distribution systems that are not high pressure (systems operating at 60 psig or less) are:

- Experiencing a minimum distribution pressure of 15 psig that indicates an investigation will be initiated

- Experiencing or modeling minimum distribution pressure of 10 psig that indicates reinforcement is critical

This standard is based on the minimum inlet pressure required for an Excess Flow Valve (EFV) to properly function, per 49 CFR §192.381 Service lines: Excess flow valve performance standards:

> (a) Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:
>
> > (1) Function properly up to the maximum operating pressure at which the valve is rated;
> >
> > (2) Function properly at all temperatures reasonably expected in the operating environment of the service line;
> >
> > (3) At 10 p.s.i. (69 kPa) gage:
> >
> > > (i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and
> > >
> > > (ii) Upon closure, reduce gas flow—
> > >
> > > (A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's

specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

(B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

(4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

- Near-term growth indicated by one or more leading indicators (e.g., new road construction, a new subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance

- Firm service customer delivery requirements (flow or pressure)

LC 71 – NW Natural's Final Comments

Attachment 4

Northwest Natural Gas Company

Response to OPUC Staff DR 52

Filed on Huddle
October 23, 2018

NW Natural®

Rates & Regulatory Affairs
LC 71
Integrated Resource Planning
Data Request Response

Request No.: LC 71 OPUC DR 52

52. Please provide further explanation of the January 2017 outages and/or pressure drops experienced in each of the locations for which NW Natural is seeking acknowledgement in the Action Plan for reinforcement projects. In your response, please include the following information:

a. Was this an isolated incident that occurred on one day or was this a prolonged event? Please provide dates and times for all related projects.

b. At what time and on which days in January 2017 were there observed pressure drops during non-peak conditions at the affected locations?

c. What percentage share of customers served in each of these locations separately was impacted by outage event(s)? How many customers were impacted by the January 2017 event?

d. Please provide all outage reports associated with the January 2017 event, with a narrative and references to the outage reports, illustrating why current operating conditions no longer meet demand or safety standards.

Response:

DR's 52, 55, 56, 57, and 58 are requests to gather information about the six 2018 IRP action item projects in an attempt to clarify why these projects need to be completed. NW Natural met with OPUC staff on Wednesday, October 10, 2018 to relay information about many of our processes and to clarify data requests. OPUC staff requested that NW Natural present the results for these data requests in project specific narrative format to ease individual project interpretation and evaluation.

LC 71 OPUC DR 52 Attachment A and Attachments 1-2 provide narratives and supporting data for each individual action item project that are presented in lieu of direct responses to DR's 52, 55, 56, 57, and 58.

LC 71 OPUC DR 52 Attachment A contains project narratives for each of the six action item projects.

LC 71 OPUC DR Attachment 1 contains a list of customer outages that occurred during the January 5-6, 2017 cold weather event from the Hood River and Oregon City project areas.

LC 71 OPUC DR Attachment 2 contains historical weather data (1985-Present) for each of the project areas. This data ranks cold weather events by severity and is presented to support that January 2017 weather was not anomalous, nor a peak weather event.

Project Name: Hood River Reinforcement

System Background and Description: The Hood River Distribution System serves the town of Hood River, Oregon and its surrounding area. This system of approximately 2,500 customers is supplied solely by the NWPL Hood River Gate Station. The majority of customers in Hood River and the surrounding countryside are fed by one district regulator station. This configuration makes the system more vulnerable to choke points in the pipelines as customer demand increases.

Recent Events Supporting Reinforcement Project: Cold Weather, January 5-6, 2017

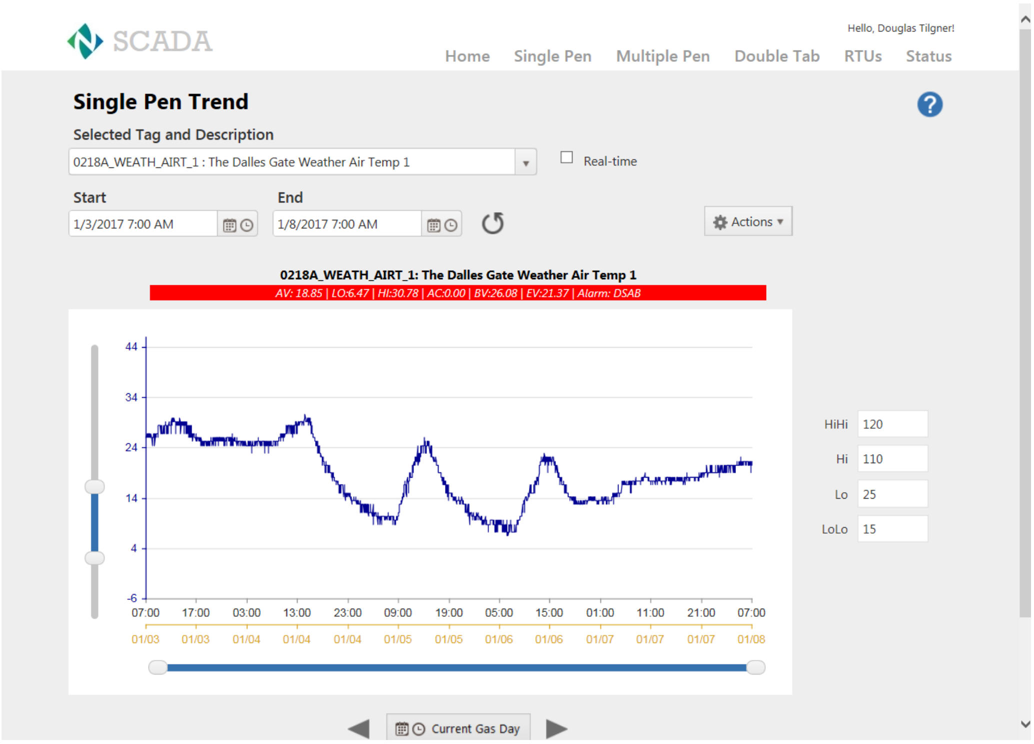
Summary:

- Non Peak cold weather events in January 2017 resulted in widespread low pressures resulting in reported outages of 62 customers in Hood River.[1] No system abnormalities were experienced to produce low pressure conditions[2]
- System reinforcement standards were violated by low system pressures less than 10 psig
- Weather events colder than January 2017 have occurred 8 times since the start of our hourly weather history in 1985[3]
- Modeling validates low pressures under experienced conditions
- The Hood River system remains a safety and reliability concern until reinforcement occurs

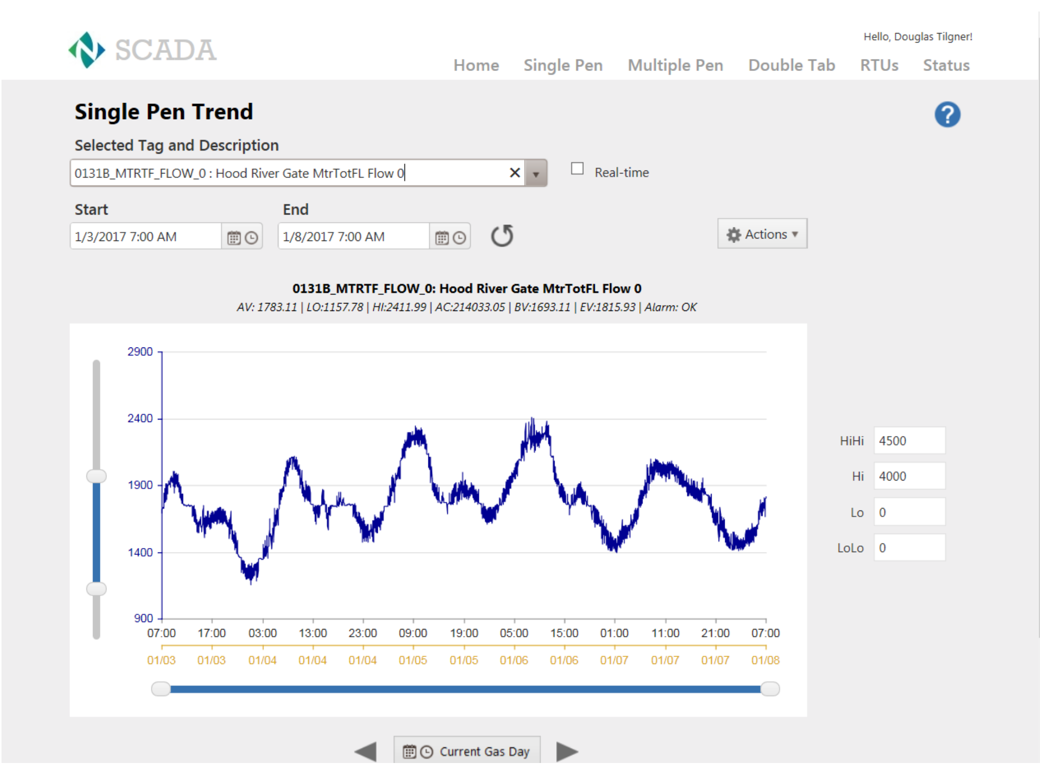
Weather: The following graphs were generated from data collected by the Gas Control SCADA system which monitors near real time data from the field. The period of all graphs is a five day period from 7 AM January 3, 2017 to 7AM January 7, 2017. This period was chosen to show the days before and after the cold event.

The first graph below shows air temperature in The Dalles, Oregon, about 40 miles east of Hood River. Hood River does not have an air temperature SCADA data tag. Spot checks of other air temperature sources indicate that Hood River experienced approximately the same weather as The Dalles during this event. The low temperature on the morning of January 5 was 8 DegF and the low on January 6 was 6 DegF. Colder temperatures were experienced at this location in 1990, 1996, 1989, 1985, 2013, 2004, and 1998 (see attached spreadsheet containing cold weather event data). January 2017 was not an anomalous weather event in Hood River, nor was it a design “Peak” day.

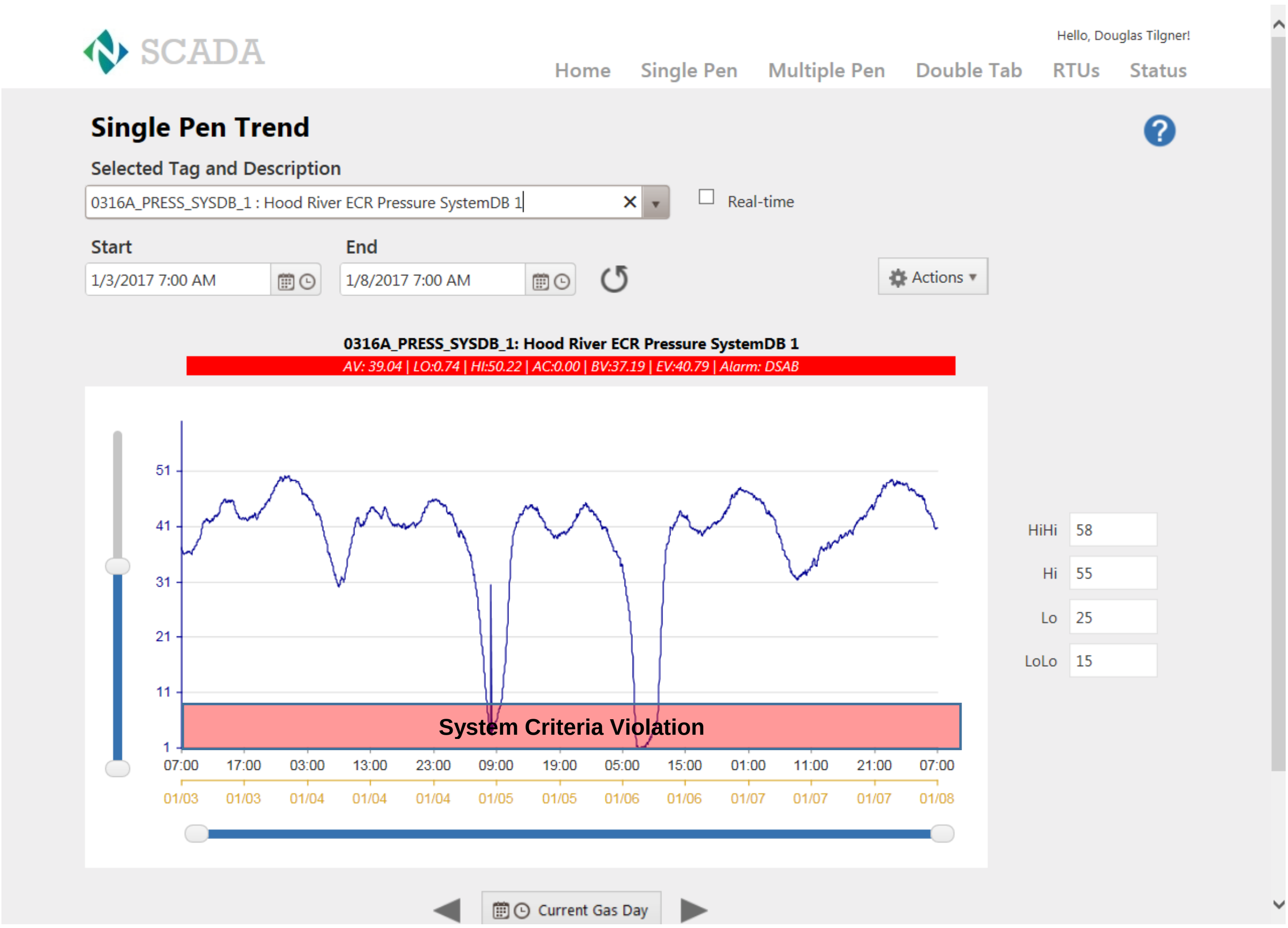
[1] See Attachment 1 to this response
[2] I.e., unexpected equipment malfunctions unrelated to cold weather
[3] See Attachment 2 to this response



System Conditions: The next graph shows the demand in therm/hr from Hood River Gate Station (NWPL). The Hood River system is fed by this single gate station so it accurately reflects the entire customer demand in Hood River. High flows of approximately 2,300 therm/hour were experienced on the two coldest mornings. The morning prior, January 4, saw a high flow rate of approximately 2,100 therm/hour. The colder mornings on January 5 & 6 resulted in approximately 10% (200 therm/hr) more demand than the previous day.



The following SCADA graph shows the system pressure near the Hood River Airport as indicated on system map below. This location is near the south end of the distribution system and should be representative of the lowest pressures in the system. January 5 saw pressures down to 3 psig at this location and it reached less than 1 psig on January 6. Pressures this low in a gas system will always result in at least a few outages, if not widespread outages. Notice that the morning of January 4 showed a downward spike in pressure but did not dip much below 30 psig. System pressures were more than adequate on the previous day. This is a very good example of how fast a heavily loaded gas system can fail under slight increases in customer demand.



The large system pressure drops experienced on the mornings of January 5 & 6 were created by just an additional 10% customer demand over the January 4 demand. On two consecutive mornings the system was unable to reliably deliver gas to customers. System pressures approached zero psig and 62 customers reported equipment issues (outages) due to low pressure. See attached spreadsheet containing customer pressure issues. A significant number of the approximately 2,500 customers in Hood River experienced pressures less than 10 psig. We would expect a design peak demand to exceed these experienced demand volumes and generate significantly more customer outages.

Normal winter operations activities were performed during this event. Field personnel validated that the regulator feeding the system was performing properly. This regulator was bypassed during morning hours to maximize pressures. There were no closed valves or damages in the system that would have contributed to low system pressures. Interruptible customers were curtailed as soon as the magnitude of the event was recognized. Significant low pressures and outages were still experienced after all winter troubleshooting was completed.

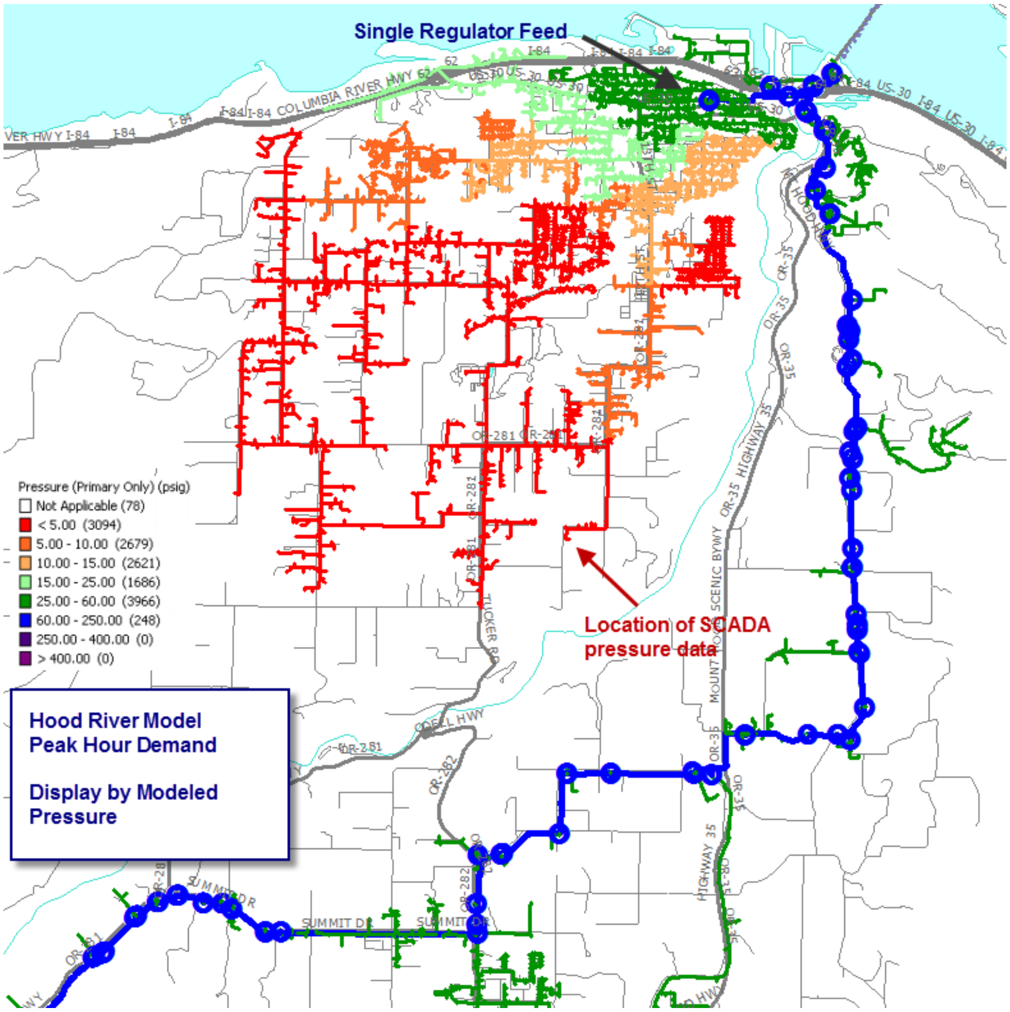
When low pressures are experienced during cold weather events, NW Natural investigates the District Regulator Station(s) that feed the distribution system to ensure they are functioning properly and that they are adequately sized. These stations are maintained in the field once per calendar year, and the regulator and relief sizing report is also verified annually. If a regulator station is not properly meeting demands then a relatively low cost/scope construction project can be planned to improve regulator performance.

If the District Regulator Station(s) are fully functional and adequately sized, then we would investigate the high pressure (greater than 60 MAOP) pipeline system that feeds these stations. These stations require a minimum inlet pressure (specific for each station) for the regulator to function properly. NW Natural system reinforcement criteria for lower pressure systems identifies 10 psig as our lowest operating pressure threshold due to the proper operation of Excess Flow Valves, a safety device. As large numbers of customers experienced less than 10 psig, the current capability of the Hood River system is a reliability issue and a safety concern.

During this cold weather event, neither the district regulator sizing nor the high pressure pipeline feed contributed to the low pressures experienced in the system, and the pressures experienced in the distribution system violated the reinforcement criteria.

Current System Analysis:

The Synergi model for the existing Hood River system (current piping configuration and customers) under peak hour customer demand is shown below. The model indicates that we would experience widespread low pressures (red areas = 5 psig or less) and resulting customer outages under peak hour conditions. The modeled results closely correlate with the system conditions experienced in January 2017. The experienced pressures significantly violates our system reinforcement criteria for lower pressure systems which specifies that 10 psig is the lowest acceptable pressure in a distribution system. System reinforcement actions must be taken to assure safe and reliable service to firm customers in Hood River.



System Reinforcement Selection:

The Hood River system was carefully examined to determine if there were choke points where pipelines could be replaced to ease cold weather impacts on system pressures. It was determined that significant portions of the system would have to be replaced for substantial gains in performance to be made. The less difficult system ties and replacements for size (choke points) had already been done in this system.

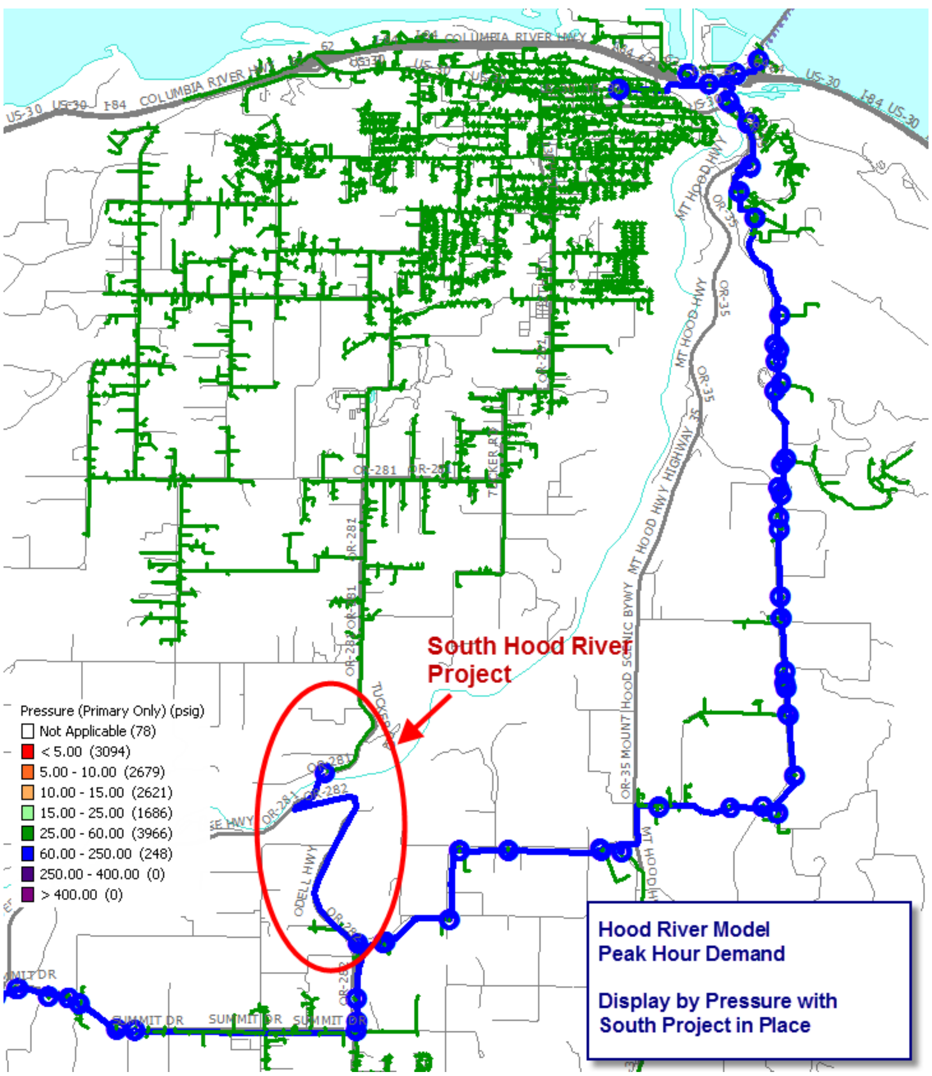
Pressure uprates of gas systems are always considered viable alternatives as they are usually much less expensive than pipeline construction. The Hood River system is already operating at 60 MAOP and cannot be uprated to increase system capacity.

Analysis shifted to new pipeline design. As stated above, the Hood River system is fed by a single district regulator. A very desirable attribute in a new pipeline would be a second feed into the system, both to alleviate cold weather pressures and to work as a redundant supply in the system. The high pressure system in Hood river runs from north to south along the east side of town and then across the south end. Any project to bolster this system has to involve high pressure gas. The east side high pressure is isolated from the core of Hood River by a large canyon containing a river and a tall rock plateau. These are significant obstacles and focus was turned to the high pressure systems in the north and south.

Pipeline design processes iteratively weigh cost versus performance by many variables including pipe size, pipe length, pipe route, operating pressure, customer demand, soil conditions, restoration costs, terrain, and many more. It should also be noted that pipeline attributes can change between preliminary design and final design, ready for construction. Field validation is an important part of final design.

A southern pipeline design was determined to offer the best solution for addressing the pressure issues in Hood River because:

- Pressure issues are remediated
- Expected costs are lowest
- Traffic, public, and customer impacts are minimal.



The southern project was selected as the preliminary pipeline design for the Hood River Reinforcement Project.

Additional Alternative Analysis:

The benefit volume from this pipeline project (modeled therms delivered to customers on peak from this project) is compared to other alternatives. A high level design for a satellite LNG facility for peak shaving is created which is sized to match the pipeline project benefit. The resulting satellite LNG facility design had a higher estimated cost than the proposed pipeline project.

The alternative analysis also examines the possibility of acquiring interruptible customer contracts that will match or exceed the project benefit therms and defer pipeline construction. An analysis of existing firm customers within the Hood River system was performed to identify if sufficient volumes could be recovered from firm customers by contracting with them to become interruptible. There was not sufficient firm demand available on peak to replace the pipeline project benefit volume.

The pipeline project was selected as the initial design for the Hood River Reinforcement Project and was determined to be our best alternative for 2018 IRP action item submittal.

Project Name: Sandy Feeder Reinforcement

System Background and Description: The Sandy Feeder pipeline serves the town of Sandy, Oregon and its surrounding area. This system of approximately 2,000 customers is supplied by the NWPL Sandy Gate Station. The Sandy Feeder pipeline is a 3 ½" wrapped steel pipeline that was installed in 1965 and operates at 400 MAOP.

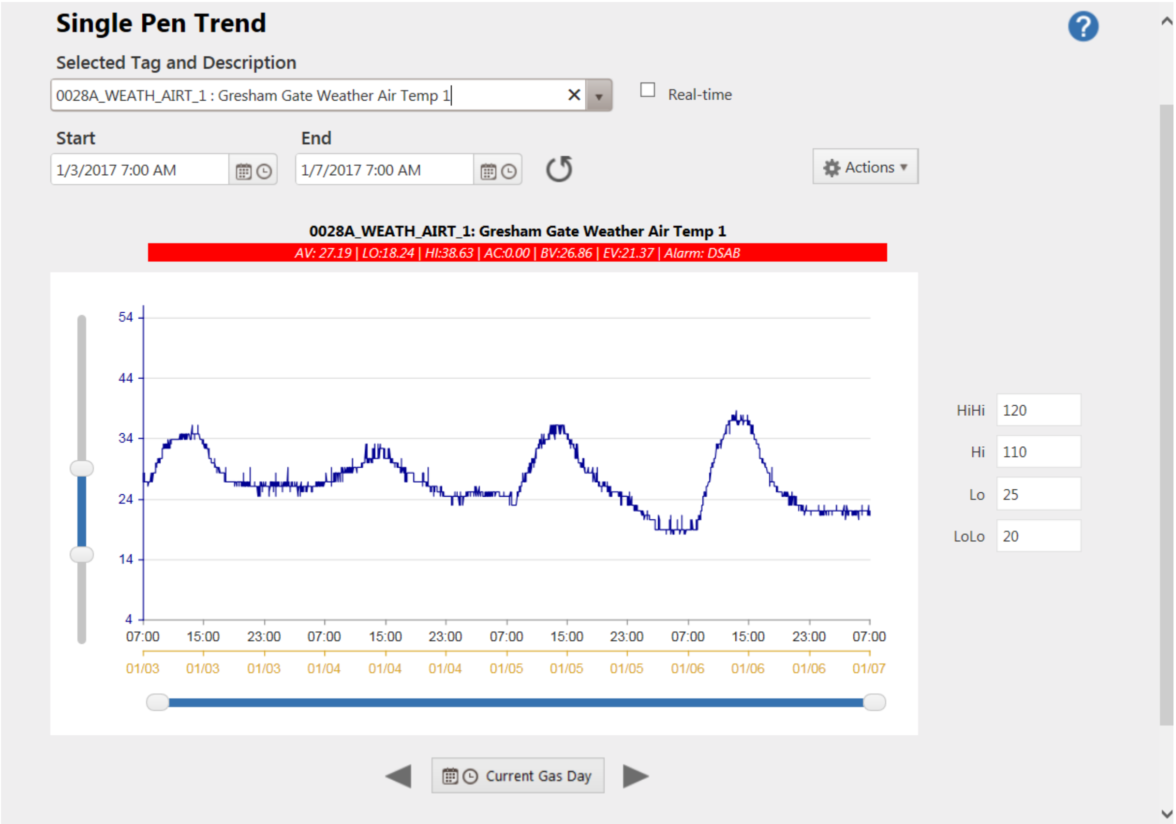
Recent Events Supporting Reinforcement Project: Cold Weather, January 5-6, 2017

Summary:

- Non Peak cold weather events in January 2017 resulted in very significant pressure drops on the Sandy Feeder pipeline. No system abnormalities were experienced to produce these pressure drops[1]
- No customers outages were reported
- Modeling validates the experienced pressure drop conditions
- System reinforcement standards were violated by pressure drops exceeding 40% on this high pressure pipeline
- Marginally higher demands than were experienced in January 2017 would result in downstream regulator malfunction and subsequent low pressures and customer outages
- The Sandy system remains a safety and reliability concern until reinforcement occurs

Weather: Sandy also experienced the cold weather and increased customer demand that other areas faced in January 5-6, 2017. The following graph was generated from data collected by the Gas Control SCADA system which monitors near real time data from the field. The period of the graph is a five day period from 7 AM January 3, 2017 to 7AM January 7, 2017. This period was chosen to show the days before and after the cold event. There is no SCADA temperature location in Sandy but we do have a SCADA air temperature at our Gresham Gate Station, about 12 miles northwest. This SCADA site indicates a low air temp of about 18 DegF on the morning of January 6, 2017.

[1] I.e., unexpected equipment malfunctions unrelated to cold weather



Historical air temperature data (see attached coldest events by location spreadsheet) shows that we have experienced numerous colder days in recent history including 1989, 1996, 1990, 2004, 2008, 1998, and 2014. The January 2017 event was not an anomalous weather event in Sandy nor was it a design "Peak" day.

System Conditions: Normal winter operations activities were performed during this event. Field personnel validated that the regulators feeding the system were performing properly. The regulator at the end of the Sandy Feeder was bypassed during morning hours to maximize pressures. There were no closed valves or damages to the upstream feeder or in the system. There are no interruptible customers in the Sandy system which could have been curtailed to remove demand from the feeder.

The lower pressure system (less than 60 psig) in the town of Sandy is currently configured well and no customer outages or significantly low pressures were experienced by Sandy customers.

The performance of the lower pressure system is wholly dependent upon the ability of the high pressure pipeline to deliver adequate gas pressure to the regulator inlet. The high pressure pipeline that feeds Sandy is the current bottleneck in this system. Regulator inlet pressure is the telling statistic that identifies the capacity issues of the Sandy Feeder Pipeline. The pressure being delivered to the Gate Station end of the Sandy Feeder is approximately 390 psig.

The following regulator inlet and outlet pressures were measured by field personnel at the end of the Sandy Feeder at Rueben Rd. and Hwy 26:

January 6, 2017, approximately 5am to 10am

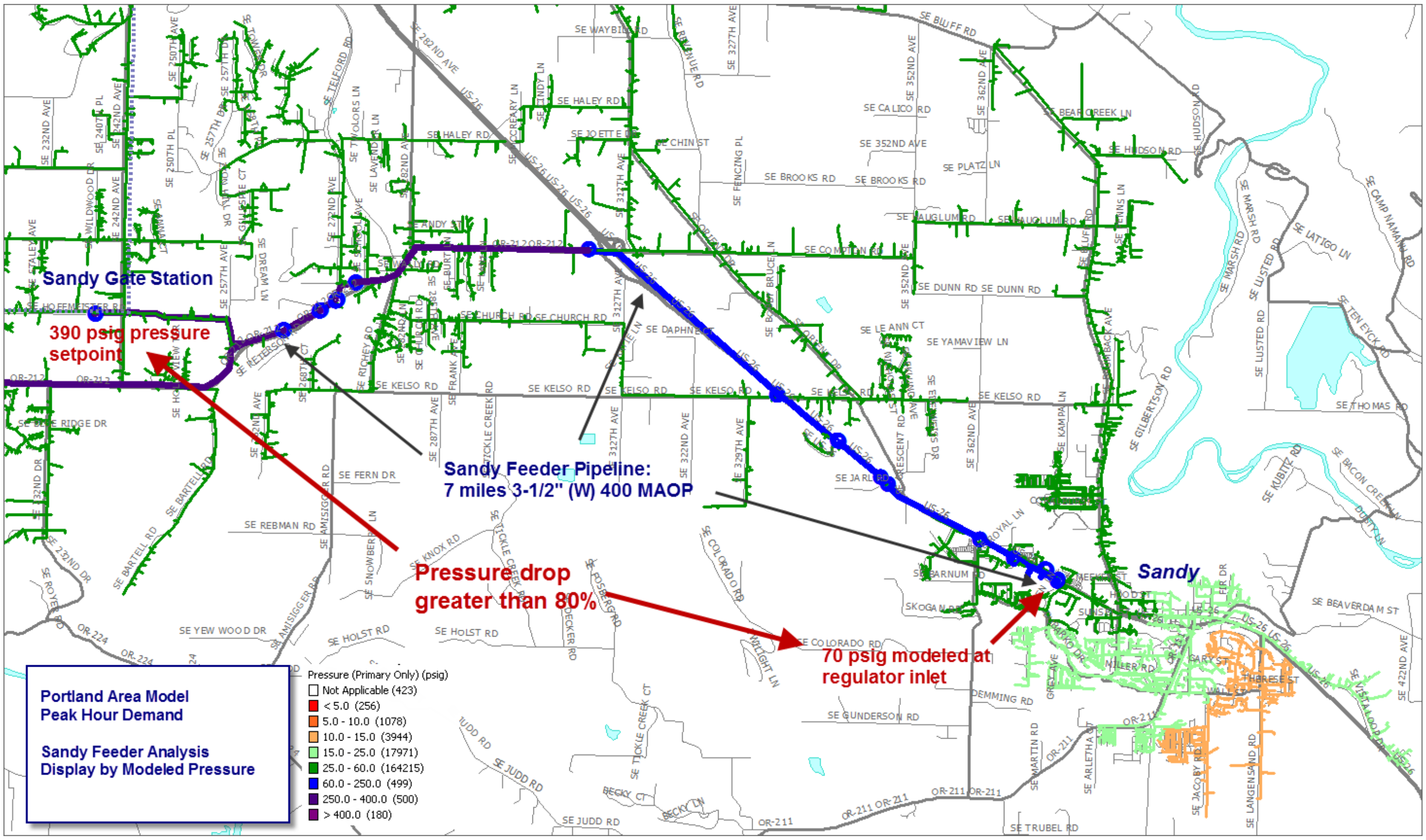
Inlet Press	Outlet Press	Air Temp	
175	50		
140	52	18	
120	52	17	
87	52	17	
72	**52**	**17**	**inlet pressure at 20 psig above outlet pressure**
72	**52**	**18.5**	**inlet pressure at 20 psig above outlet pressure**
97	52	25	
130	52	28	

District Regulators require that the inlet pressure be at least 20 psig higher than the outlet pressure for proper operation. The regulators feeding the town of Sandy were very close to being starved by low inlet pressure. This was not an isolated incident, very low inlet pressures were also reported (but not documented) on days prior to and after January 6, 2017.

The measured pressure drop on the Sandy Feeder on January 6. 2017 was 313 psig (390 - 72) or just over 80%. This closely correlates to the peak hour Synergi model which predicts 70 psig on peak. This result greatly exceeds our 40% pressure drop criteria for high pressure pipelines and indicates that this pipeline requires reinforcement.

Current System Analysis:

The Synergi model for the existing Sandy system (current piping configuration and customers) under peak hour customer demand is shown below. The model indicates that the distribution system within the town of Sandy is adequate but weak (orange) in the east under peak hour conditions. The primary concern for this system is the capacity of the Sandy Feeder pipeline. Modeling indicates very large pressure drops (greater than 80%) on this high pressure pipeline that greatly exceed system reinforcement standards (40%) on a peak hour. The existing pipeline configuration significantly violates our system reinforcement criteria for high pressure systems which specifies that 40% is the largest acceptable pressure drop. System reinforcement actions must be taken to assure reliable service to firm customers.

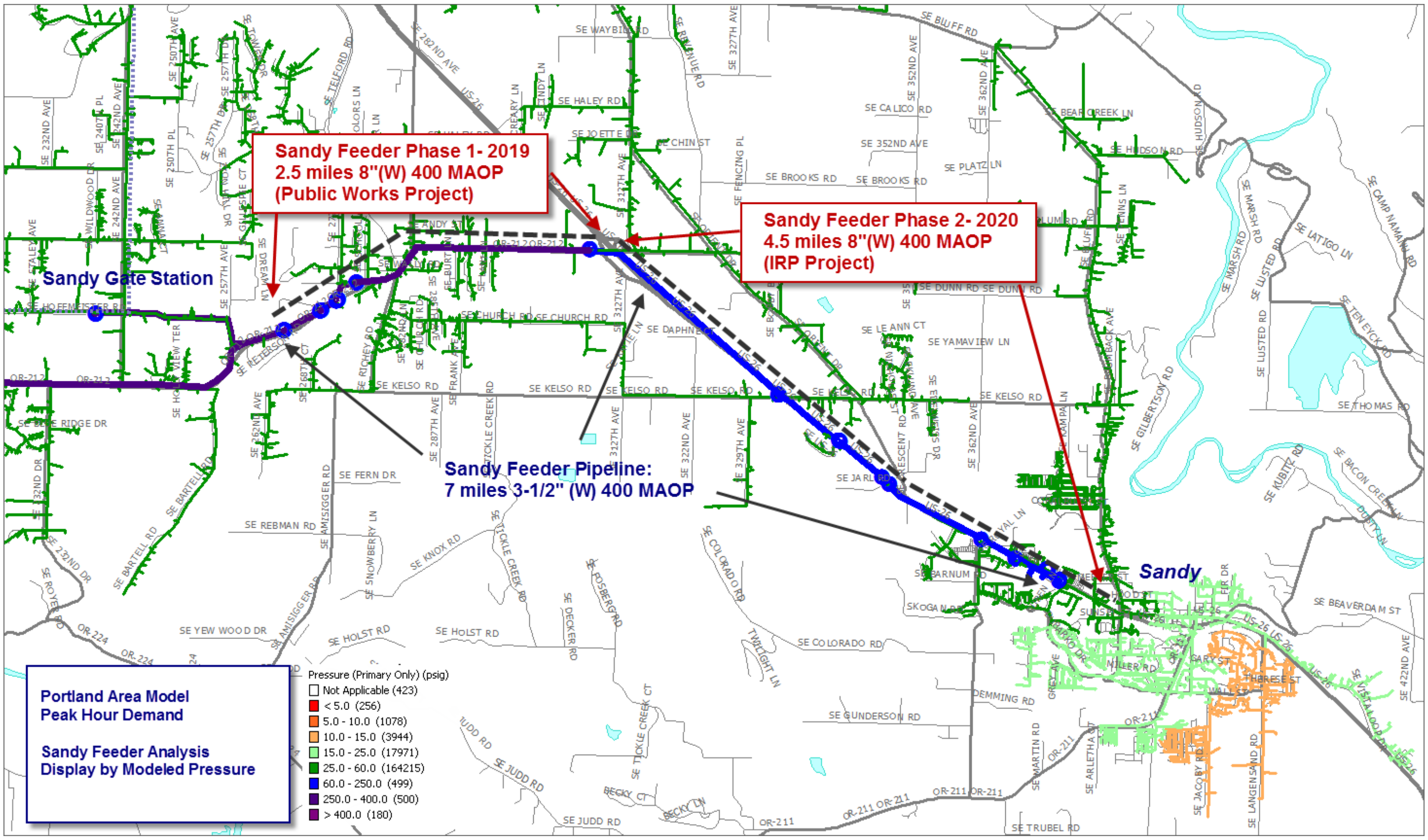


System Reinforcement Selection:

The Sandy Feeder pipeline was installed in 1965 and was sized to support the town of Sandy with some margin for growth. Today, this pipeline's capacity is being stressed by over 50 years of additional demand from customer growth in the town and surrounding area. This pipeline has no choke points which could be replaced to increase capacity. The appropriate choice for pipeline design in this case is replacement for the Sandy Feeder.

Pressure uprates of gas pipelines are always considered viable alternatives as they can be relatively inexpensive procedures. The Sandy Feeder pipeline is already operating at 400 MAOP and cannot be uprated to increase pipeline capacity.

The preliminary design for this pipeline consisted of approximately 7 miles of 8" wrapped steel operating at 400 MAOP. This was a direct replacement of the 3 ½" pipeline with an 8" pipeline. About 2.5 miles of this pipe runs along Hwy 212. ODOT is working on a project to widen and regrade Hwy 212 which requires us to move our existing pipeline. Public works activities such as this impact NW Natural regularly. The overall project design changed to split this replacement project into two phases. Phase 1 in 2019 is a replacement of the first 2.5 miles of the existing feeder and will be a Public Works activity. The remaining 4.5 miles of replacement was submitted in the 2018 IRP as Phase 2 to be installed in 2020. The drawing below shows the preliminary project layout:



Additional Alternative Analysis:

Once a pipeline project is selected, the benefit volume from this pipeline project is compared to other alternatives. For this project the benefit volume is calculated as the net therms required to restore pressure drop on the existing pipeline to 30% pressure drop. A high level design for a satellite LNG facility for peak shaving is created which is sized to match the pipeline project benefit. The resulting satellite LNG facility design for Sandy had a higher estimated cost than the proposed pipeline project.

The final alternative analysis is to examine the possibility of acquiring interruptible customer contracts that will match or exceed the project benefit therms and defer pipeline construction. An analysis of existing firm customers within the Sandy system was performed to identify if sufficient volumes could be recovered from firm customers by contracting with them to become interruptible. There was not sufficient firm demand available on peak to replace the pipeline project benefit volume.

The Sandy Feeder Reinforcement Project as defined above was selected as the best alternative for 2018 IRP action item submittal.

Project Name: South Oregon City Reinforcement

System Background and Description: The Oregon City Distribution System serves the town of Oregon City, Oregon and its surrounding area. This system of approximately 4,000 customers is supplied mainly by the NWPL Oregon City Gate Station. A district regulator under the old Oregon City Bridge also brings gas into Oregon City from the Portland high pressure system (400 MAOP). Generally speaking, the customers in downtown Oregon City are fed by this regulator and its gas from Portland. The customers on top of the hill and to the west, east and south are served from Oregon City Gate Station.

Recent Events Supporting Analysis: Cold Weather, January 5-6, 2017

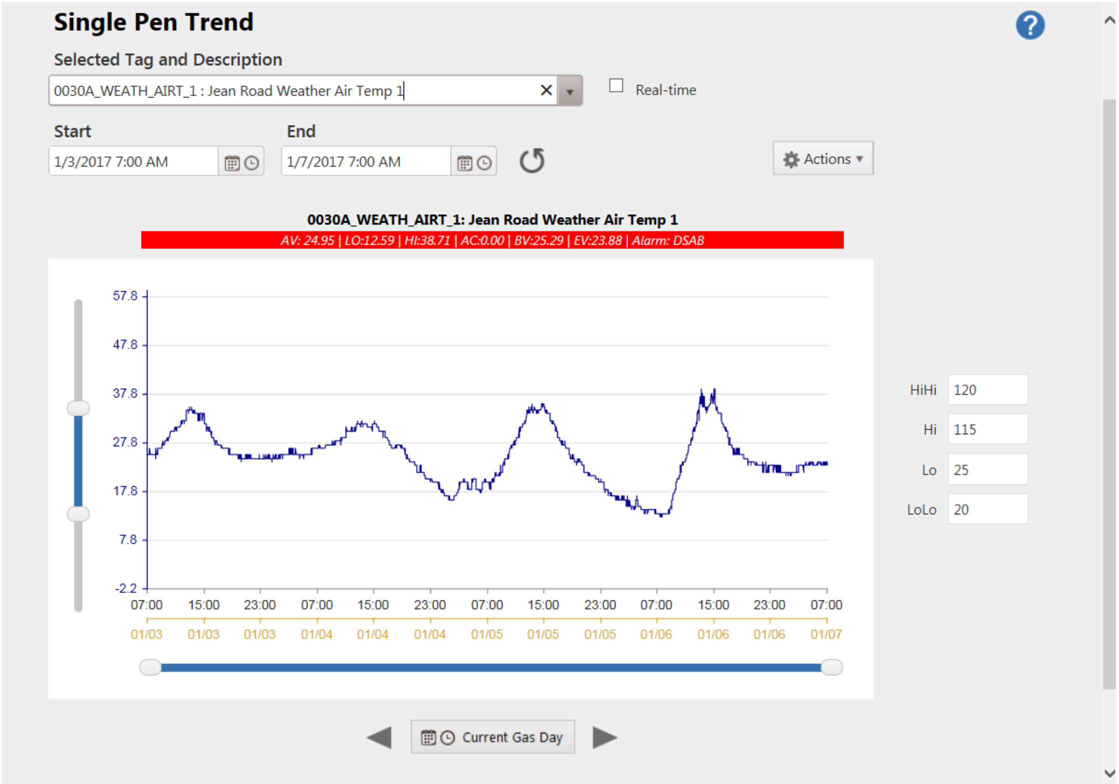
Summary:

- Non Peak cold weather events in January 2017 resulted in widespread low pressures and reported outages of 87 customers in South Oregon City[1]
- No system abnormalities were experienced to produce low pressure conditions[2]
- Modeling validates low pressures under experienced conditions
- System reinforcement standards were violated by low system pressures less than 10 psig
- The South Oregon City system remains a safety and reliability concern until reinforcement occurs

Weather: The following graph was generated from data collected by the Gas Control SCADA system which monitors near real time data from the field. The period of the graphs is a five day period from 7 AM January 3, 2017 to 7AM January 7, 2017. This period was chosen to show the days before and after the cold event for reference.

The graph shows air temperature at Jean Rd. Station in Tualatin, Oregon, about 7 miles west of Oregon City. Oregon City does not have an air temperature SCADA data tag. The low temperature on the morning of January 5 was 15 DegF and the low on January 6 was 13 DegF. Colder temperatures were experienced in this area in 1989, 1990, 1985, 2014, 2013, and 2009 amongst others (see attached spreadsheet containing cold weather event data by area). January 2017 was not an anomalous weather event in Oregon City nor was it a design “Peak” day.

[1] See Attachment 1 to this response
[2] I.e., unexpected equipment malfunctions unrelated to cold weather



System Conditions: NW Natural began receiving no heat calls from customers in the Oregon City area on the morning of January 5, 2017. The outage of 71 customers located in a clustered area in southwest Oregon City indicates a system problem versus individual customer issues. Crews were dispatched and cold weather troubleshooting occurred. Normal winter operations activities were performed during this event. Field personnel validated that the regulators feeding the system were performing properly. One regulator was bypassed during morning hours to maximize system pressures. There were no closed valves or damages in the system. No interruptible customers were curtailed as there were no large interruptibles in this area. All customers were relit the same day. Customer outage spreadsheet is attached.

The following morning, January 6, 2017 was slightly colder. Field personnel were on site to bypass regulators to begin the day. This maximizes system pressures during the peak demand hours. Low pressures persisted in some locations and 16 customers called in to report outages. All customers were relit the same day. Customer outage spreadsheet is attached.

When low pressures are experienced during cold weather events, NW Natural investigates the District Regulator Station(s) that feed the distribution system to ensure they are functioning properly and that they are adequately sized. These stations are maintained in the field once per calendar year, and the regulator and relief sizing report is also verified annually. If a regulator station is not properly meeting demands then a relatively low cost/scope construction project can be planned to improve regulator performance.

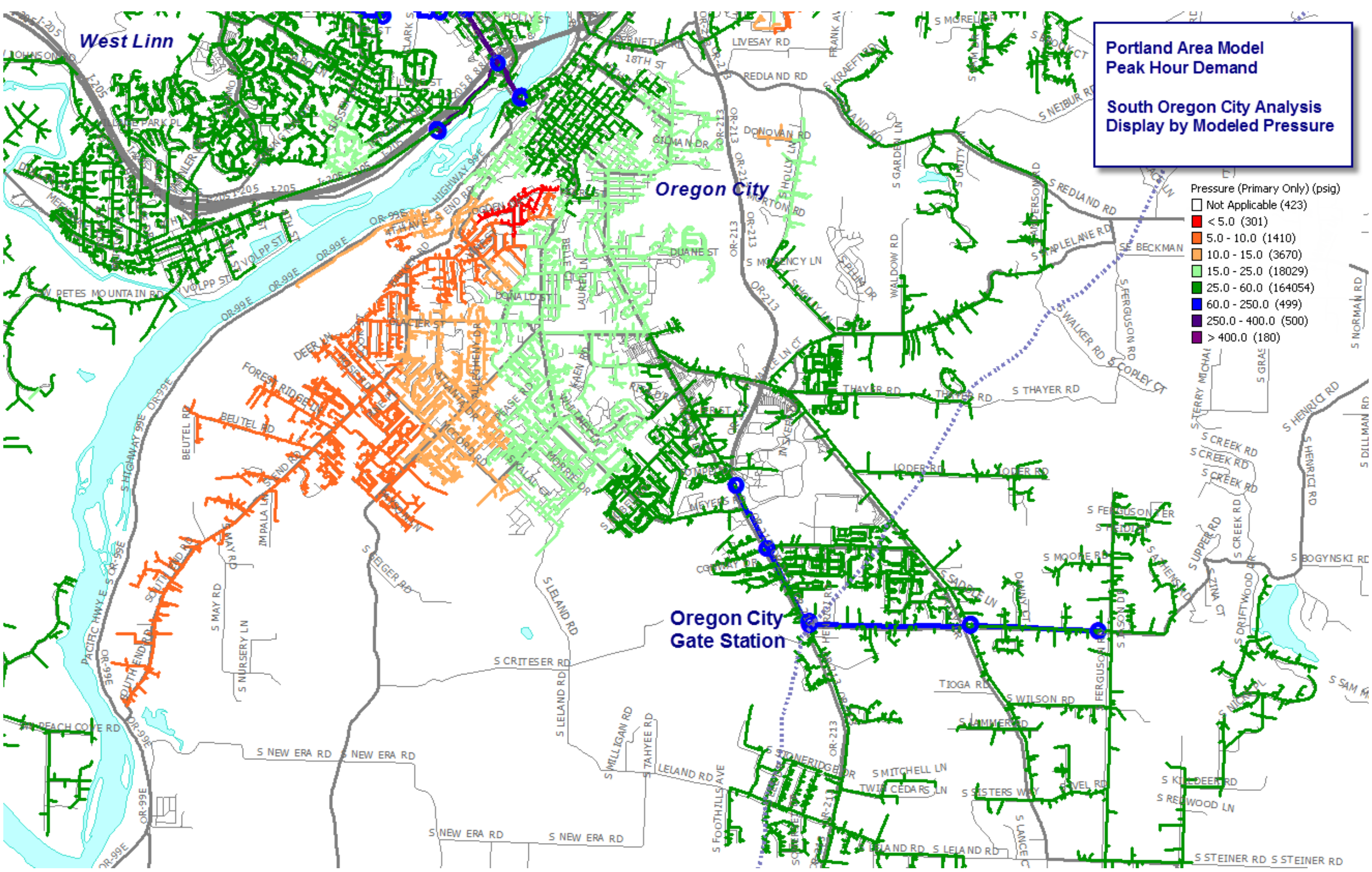
If the District Regulator Station(s) are fully functional and adequately sized, then we would investigate the high pressure (greater than 60 MAOP) pipeline system that feeds these stations. These stations require a minimum inlet pressure (specific for each station) for the regulator to function properly.

Customer outages confirm that we experienced widespread low pressure issues well below our 10 psig system reinforcement standard. Our system reinforcement standard for lower pressure systems identifies 10 psig as our lowest operating pressure threshold due to the proper operation of Excess Flow Valves, a safety device.

During this cold weather event, neither the district regulator sizing nor the high pressure pipeline feed contributed to the low pressures experienced in the system.

Current System Analysis:

The Synergi model for the existing Oregon City system (current piping configuration and customers) under peak hour customer demand is shown below. The model indicates that we would experience widespread low pressures (orange = 5-10 psig, red = 5 psig or less) and resulting customer outages under peak hour conditions. This significantly violates our system reinforcement criteria for lower pressure systems which specifies that 10 psig is the lowest acceptable pressure in a distribution system. The 10 psig threshold is driven by Excess Flow Valves which according to manufacturer specifications, are not designed to operate properly below that pressure. System reinforcement actions must be taken to assure safe and reliable service to firm customers in South Oregon City.



System Reinforcement Selection:

The Oregon City system was carefully examined to determine if there were choke points where pipelines could be replaced to ease cold weather impacts on system pressures. It was determined that significant portions of the system would have to be replaced for substantial gains in performance to be made. The less difficult system ties and replacements for size (choke points) had already been done in this system. Significant feeder pipelines must be built to improve cold weather system performance.

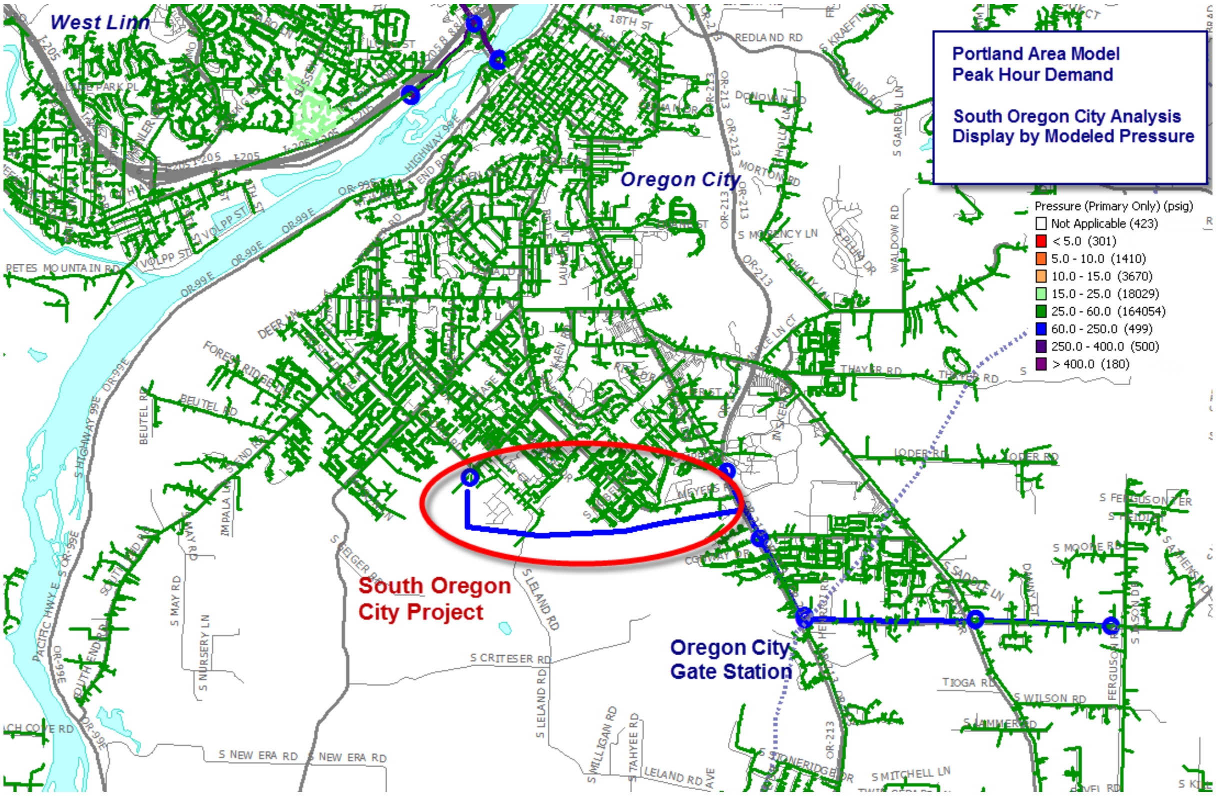
Pressure uprates of gas systems are always considered viable alternatives as they are usually much less expensive than pipeline construction. The Oregon City system is already operating at 60 MAOP and cannot be uprated to increase system capacity.

Analysis shifted to new pipeline design and how to get more gas into the weak areas. Any project to bolster this system has to involve high pressure gas. The only two sources of high pressure gas in the Oregon City area are from the Gate Station and from the regulator in downtown Oregon City. The downtown regulator is isolated from the weak systems to the south. Oregon City is very much a town divided by topography due to the 100 foot tall basalt cliffs that surround the downtown area. The least cost solution is a pipeline from the Oregon City gate station in the south to the area of low pressure.

Pipeline design processes iteratively weigh cost versus performance by many variables including pipe size, pipe length, pipe route, operating pressure, customer demand, soil conditions, restoration costs, terrain, and many more. It should also be noted that pipeline design can change between preliminary design and final design, ready for construction. Field validation is an important part of final design.

A 1.5 mile high pressure pipeline design in south Oregon City was determined to offer the best solution for addressing the pressure issues because:

- Pressure issues are remediated
- Expected costs are lowest
- Follows BPA right of way so that traffic, public, and customer impacts are minimal
- Future extension of the pipeline is possible



This route was selected as the preliminary pipeline design for the South Oregon City Reinforcement Project.

Additional Alternative Analysis:

Once a pipeline project is selected, the benefit volume from this pipeline project (modeled therms delivered to customers on peak from this project) is compared to other alternatives. A high level design for a satellite LNG facility for peak shaving is created which is sized to match the pipeline project benefit. The resulting satellite LNG facility design had a higher estimated cost than the proposed pipeline project.

The final alternative analysis is to examine the possibility of acquiring interruptible customer contracts that will match or exceed the project benefit therms and defer pipeline construction. An analysis of existing firm customers within the Oregon City system was performed to identify if sufficient volumes could be recovered from firm customers by contracting with them to become interruptible. There was not sufficient firm demand available on peak to replace the pipeline project benefit volume.

The pipeline project was selected as the initial design for the South Oregon City Reinforcement Project and was determined to be our best alternative for 2018 IRP action item submittal.

Project Name: Happy Valley Reinforcement

System Background and Description: The distribution system in the area of Happy Valley, OR is an interconnected part of the much larger East Portland system. The Happy Valley system serves approximately 2,500 customers is supplied mainly by gas from the NWPL Southeast and Johnson Creek Gate Stations. The Happy Valley/Sunnyside area has experienced significant growth for many years. Many main extensions and small system reinforcement projects have occurred over time to meet the growing customer demand. This area has been a cold weather concern for many years.

Recent Events Supporting Analysis: Cold Weather, January 5-6, 2017

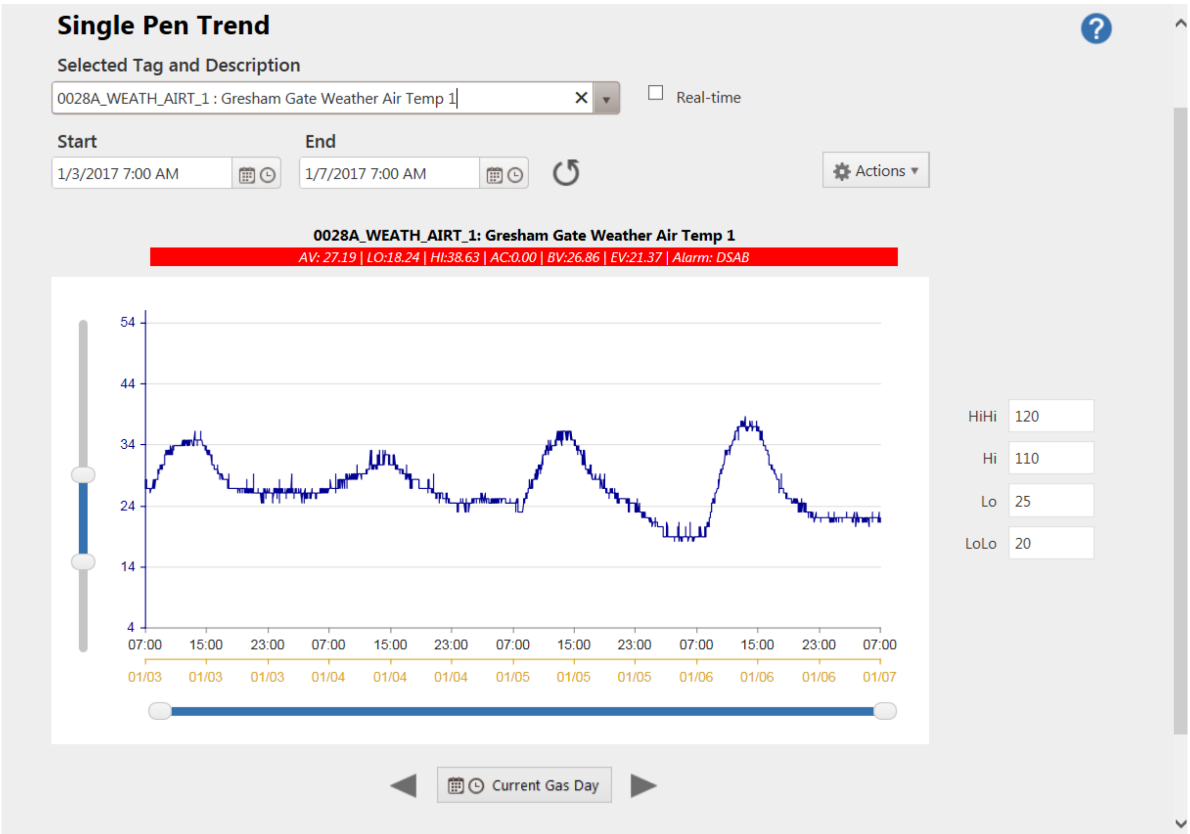
Summary:

- A SCADA pressure location near the area of weakness validates model results which predict widespread low pressures below 10 psig. No system abnormalities were experienced to produce low pressure conditions[1]
- Modelling confirmed that system reinforcement standards were violated by low system pressures less than 10 psig
- The Happy Valley system remains a safety and reliability concern until reinforcement occurs

Weather: The following graphs was generated from data collected by the Gas Control SCADA system which monitors near real time data from the field. The period of the graphs is a five day period from 7 AM January 3, 2017 to 7AM January 7, 2017. This period was chosen to show the days before and after the cold event for reference.

The graph shows air temperature at Gresham Gate Station in Gresham, Oregon, about 5 miles northeast of Happy Valley. Happy Valley does not have an air temperature SCADA location. This SCADA site indicates a low air temp of about 18 DegF on the morning of January 6, 2017. Colder temperatures were experienced in this area in 1989, 1990, 1985, 2014, 2013, and 2009 amongst others (see attached spreadsheet containing cold weather event data by area). January 2017 was not an anomalous weather event in Happy Valley nor was it a design “Peak” day.

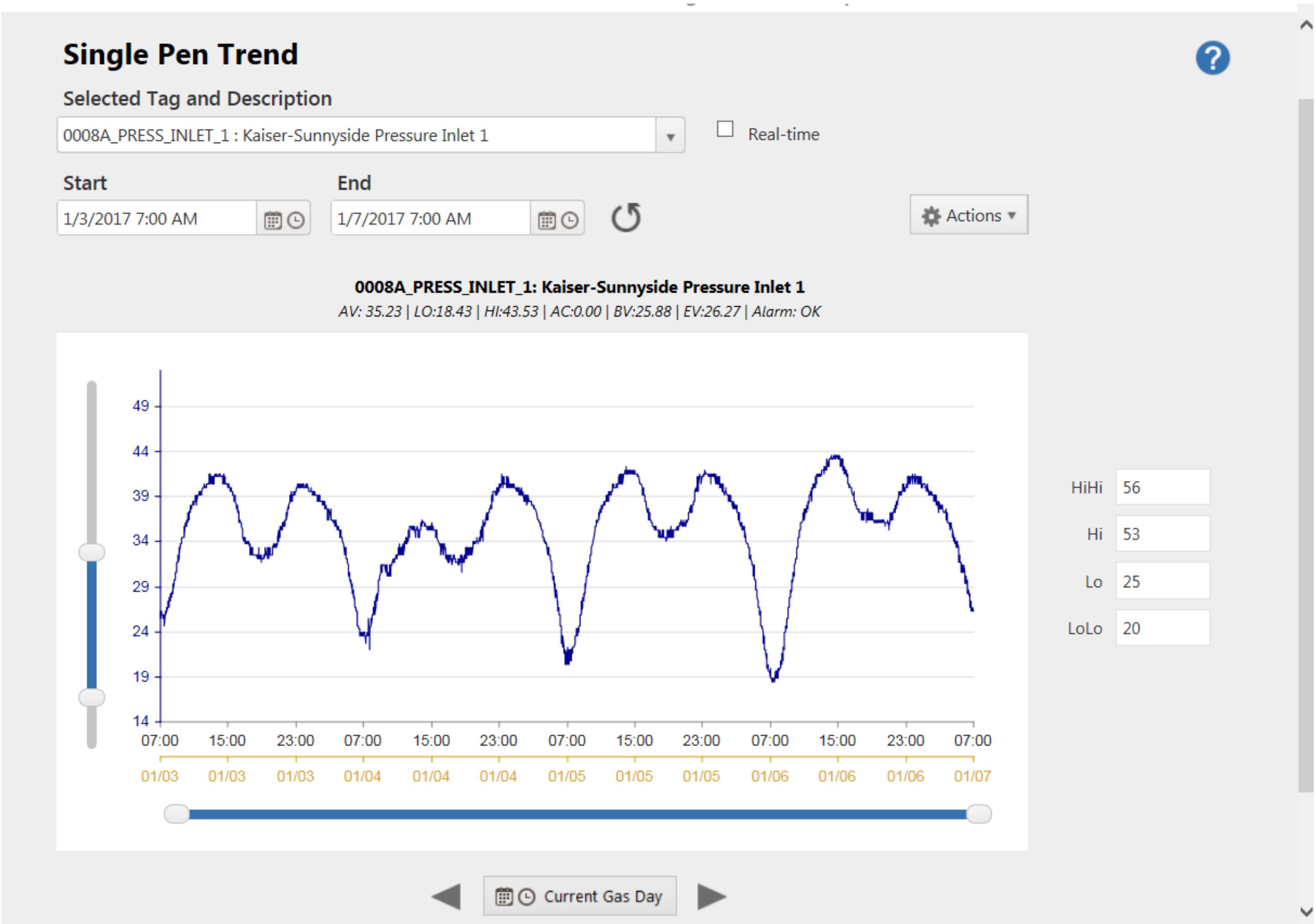
[1] I.e., unexpected equipment malfunctions unrelated to cold weather



System Conditions: NW Natural did not experience customer outages in Happy Valley during the January 2017 cold weather event. Normal winter operations activities were performed during this event. Field personnel validated that the regulators feeding the system were performing properly. There were no abnormalities experienced in this system. No interruptible customers were curtailed as there were no large interruptibles in this area.

There is no current SCADA data feed that indicates system pressures in the weakest areas of Happy Valley. A SCADA pressure location does exist at the Kaiser-Sunnyside Medical Center immediately to the southwest of Happy Valley along Sunnyside Rd. The 6” 57 MAOP pipeline that parallels Sunnyside Rd from west of Interstate 205 to SE 172nd is a critical backbone in this area. The pressures seen on this pipeline are directly related to lower pressures that would be witnessed on top of the hill in Happy Valley. The pressure at Kaiser-Sunnyside is a key indicator of the health of this feeder and validates model results that show very low pressures in Happy Valley.

The following SCADA graph from the Kaiser-Sunnyside location indicates that system pressures on the 6” Sunnyside Rd pipeline sagged heavily on the mornings of January 5-6, 2017. The nearby regulators feeding this pipeline were set to feed at 50 psig. These regulators all functioned properly. Heavy demand on this pipeline under cold conditions causes significant pressure drops as customer demand ramps up in cold mornings.

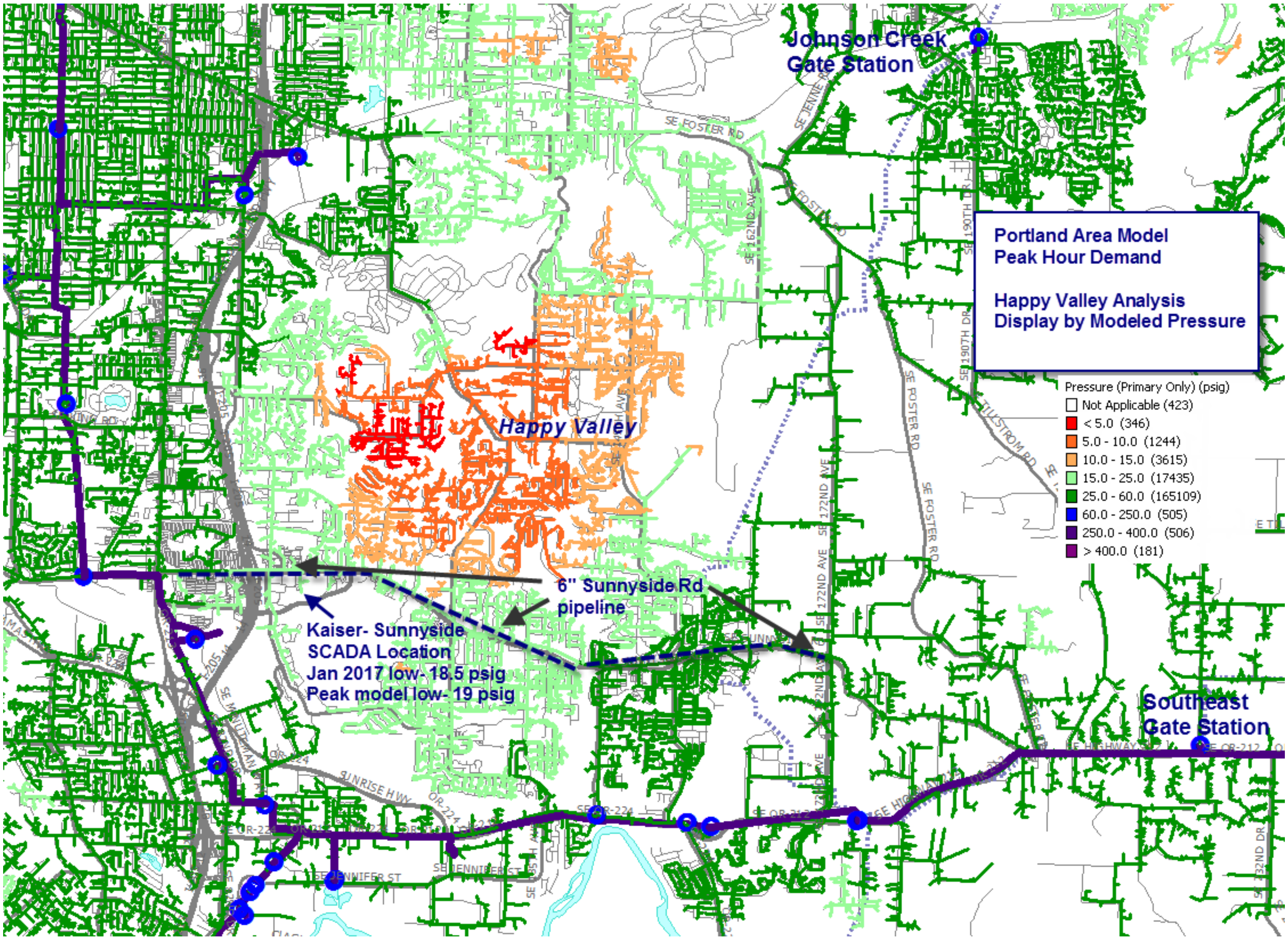


The mornings of January 5 & 6, 2017 saw low pressures of 20 psig and 18.5 psig respectively at the Kaiser location. These pressure reads by themselves do not violate any standards but indicate a very weak pipeline backbone that cannot properly support customer demands under peak conditions.

Current System Analysis:

The Synergi model for the existing Happy Valley area (current piping configuration and customers) under peak hour customer demand is shown below. The model indicates that we would experience widespread low pressures (orange = 5-10 psig, red = 5 psig or less) and resulting customer outages under peak hour conditions.

The modeled pressure at Kaiser-Sunnyside under peak demand closely correlates with the SCADA pressures experienced in January 2017. Although no outages were experienced, a significant number of customer pressures in the Happy Valley system violated the 10 psig minimum standard under less than peak demand.



Modeled low pressures violates our system reinforcement criteria for lower pressure systems which specifies that 10 psig is the lowest acceptable pressure experienced or modeled in a distribution system. The10 psig threshold is driven by Excess Flow Valves which according to manufacturer specifications, are not designed to operate properly below that pressure. System reinforcement actions must be taken to assure safe and reliable service to firm customers in Happy Valley.

System Reinforcement Selection:

The Happy Valley system was carefully examined to determine if there were choke points where pipelines could be replaced to ease cold weather impacts on system pressures. It was determined that significant portions of the system would have to be replaced for substantial gains in performance to be made. The less difficult system ties and replacements for size (choke points) had already been done in this system. Significant feeder pipelines must be built to improve cold weather system performance.

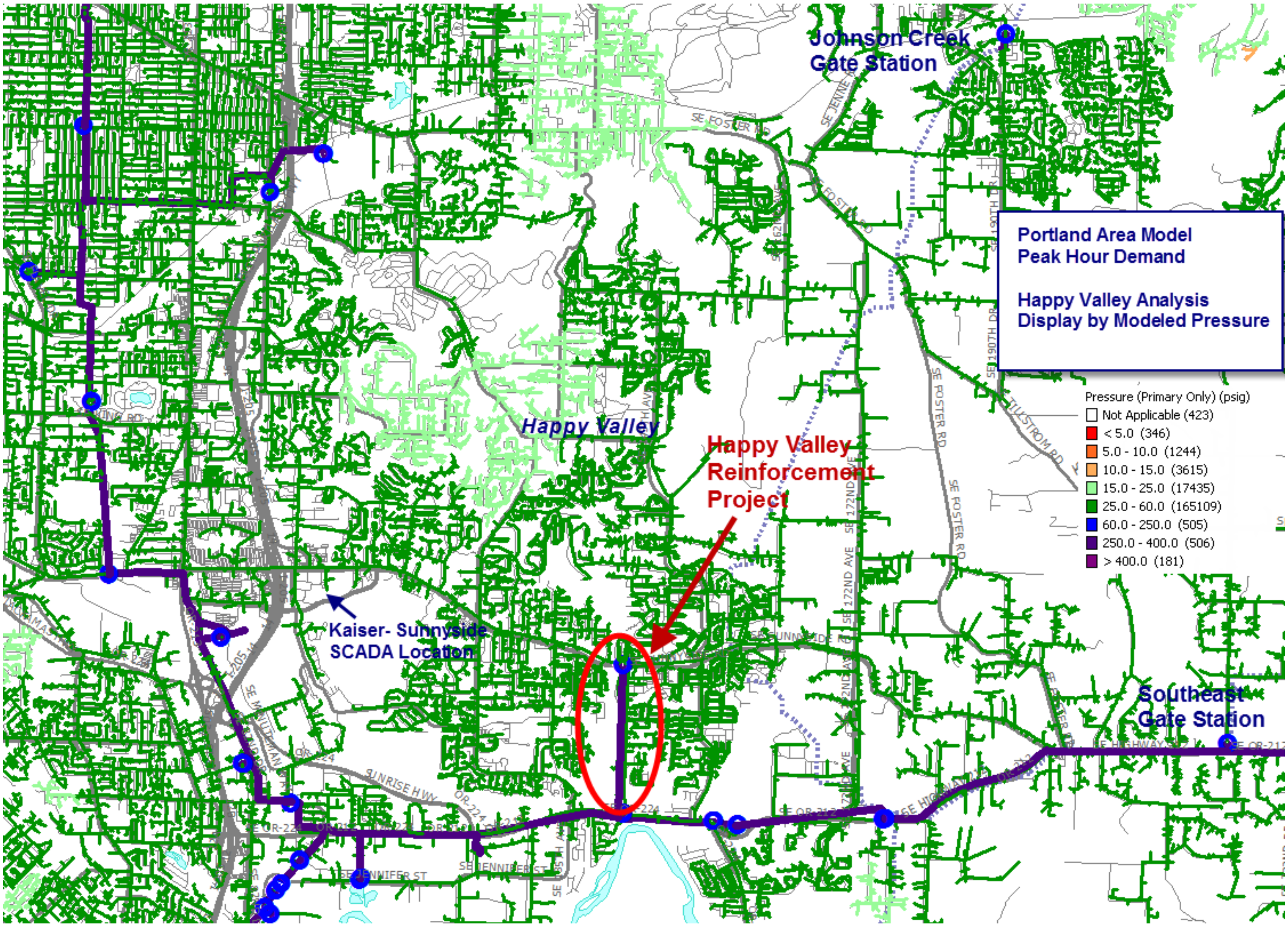
Pressure uprates of gas systems are always considered viable alternatives as they are usually much less expensive than pipeline construction. The Happy Valley system is already operating at 57 MAOP and cannot be uprated to increase system capacity.

Analysis shifted to new pipeline design and how to get more gas into the weak areas. A backbone pipeline like the 6” on Sunnyside Rd. should not be experiencing such large pressure drops. This is an indication that the 6” is undersized for the customer demand it is experiencing. This pipeline needs an additional source of support, likely from a high pressure source.

Pipeline design processes iteratively weigh cost versus performance by many variables including pipe size, pipe length, pipe route, operating pressure, customer demand, soil conditions, restoration costs, terrain, and many more. It should also be noted that pipeline design can change between preliminary design and final design, ready for construction. Field validation is an important part of final design.

A 1.2 mile high pressure pipeline design in Happy Valley was determined to offer the best solution for addressing the pressure issues because:

- Pressure issues are remediated
- Expected costs are lowest
- Least impacts on public, traffic, and customers
- Future extension of the pipeline is possible



This route was selected as the preliminary pipeline design for the Happy Valley Reinforcement Project.

Additional Alternative Analysis:

Once a pipeline project is selected, the benefit volume from this pipeline project (modeled therms delivered to customers on peak from this project) is compared to other alternatives. A high level design for a satellite LNG facility for peak shaving is created which is sized to match the pipeline project benefit. The resulting satellite LNG facility design had a higher estimated cost than the proposed pipeline project.

The final alternative analysis is to examine the possibility of acquiring interruptible customer contracts that will match or exceed the project benefit therms and defer pipeline construction. An analysis of existing firm customers within the Happy Valley system was performed to identify if sufficient volumes could be recovered from firm customers by contracting with them to become interruptible. There was not sufficient firm demand available on peak to replace the pipeline project benefit volume.

The pipeline project was selected as the preliminary design for the Happy Valley Reinforcement Project and was determined to be our best alternative for 2018 IRP action item submittal.

Project Name: North Eugene Reinforcement

System Background and Description: The distribution system in North Eugene in the area of River Rd. has experienced significant residential growth for a number of years. Subdivisions continue to be developed and new homes are being built. Like many gas systems it continues to grow organically, one main extension at a time to serve new customers.

This system consists of a 4" backbone pipeline on River Rd. with 2" and 1" mains extending into neighborhoods. There are approximately 1,500 customers in this localized area. Gas supplies come from high pressure pipelines to the south and west. Many main extensions and small system reinforcement projects have occurred over time to meet the growing customer demand.

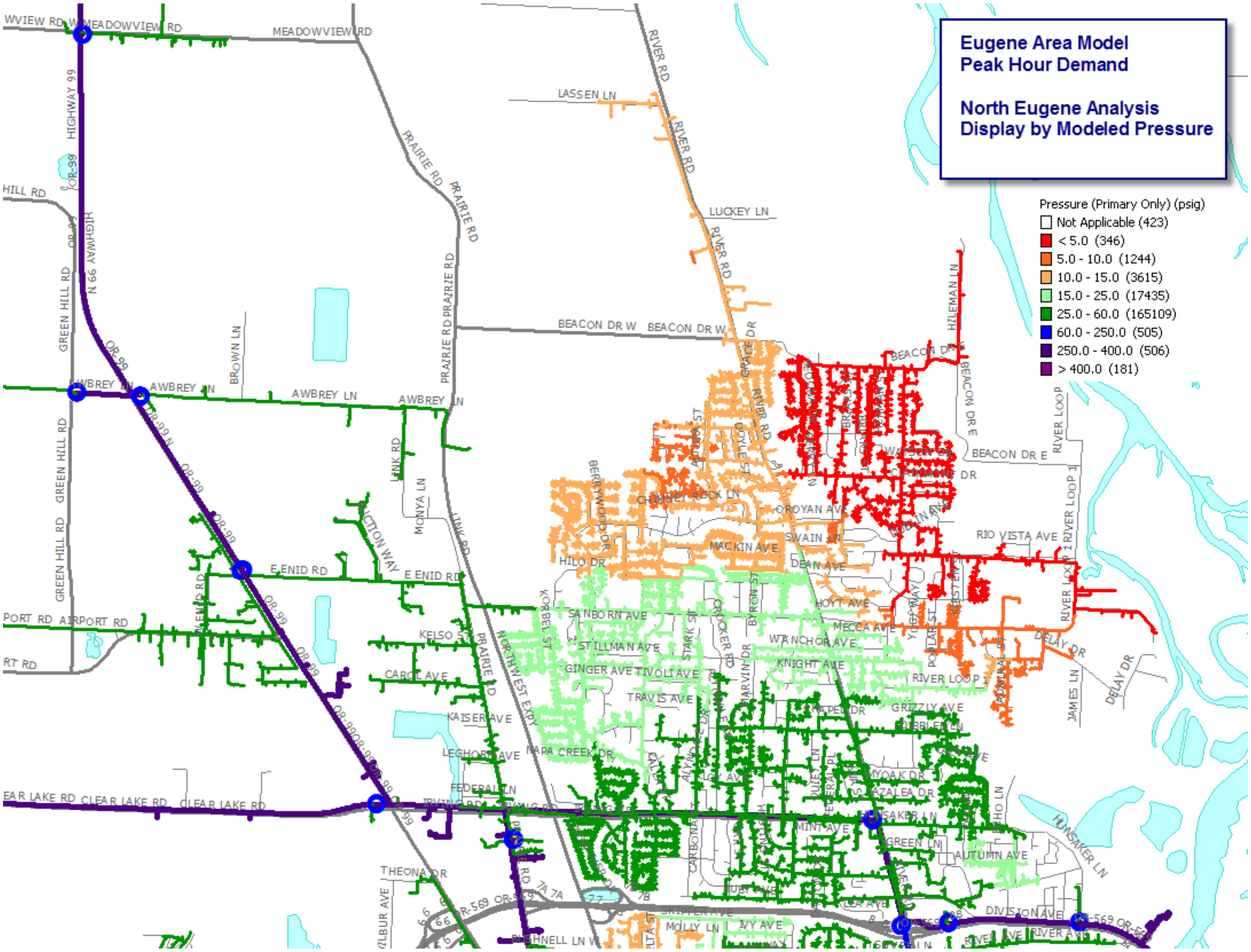
Summary:

- System reinforcement standards are violated by modeled low system pressures less than 10 psig
- No system abnormalities were experienced to produce low pressure conditions[1]
- The North Eugene system remains a safety and reliability concern until reinforcement occurs

Current System Analysis:

The Synergi model for the existing North Eugene area (current piping configuration and customers) under peak hour customer demand is shown below. The model indicates that we would experience widespread low pressures (orange = 5-10 psig, red = 5 psig or less) and resulting customer outages under peak hour conditions.

[1] I.e., unexpected equipment malfunctions unrelated to cold weather



Modeled low pressures violate our system reinforcement criteria for lower pressure systems which specifies that 10 psig is the lowest acceptable pressure experienced or modeled in a distribution system. The10 psig threshold is determined by Excess Flow Valves which according to manufacturer specifications, are not designed to operate properly below that pressure. System reinforcement actions must be taken to assure safe and reliable service to firm customers in North Eugene.

System Reinforcement Selection:

The North Eugene system was carefully examined to determine if there were choke points where pipelines could be replaced to ease cold weather impacts on system pressures. It was determined that significant portions of the system would have to be replaced for substantial gains in performance to be made. The less difficult system ties and replacements for size (choke points) had already been done in this system. Significant feeder pipelines must be built to improve cold weather system performance.

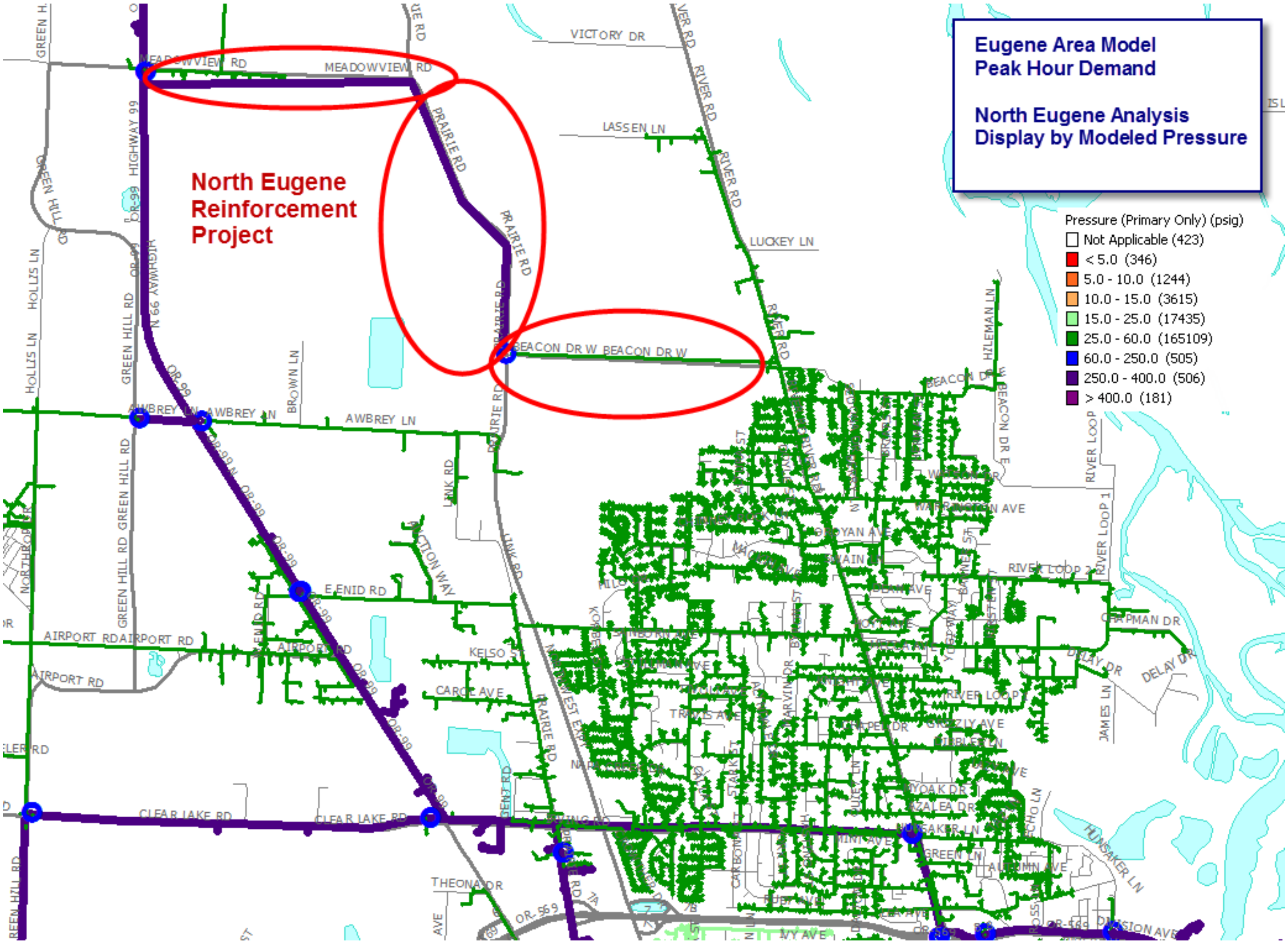
Pressure uprates of gas systems are always considered viable alternatives as they are usually much less expensive than pipeline construction. The North Eugene system is operating at 45 MAOP. An uprate of this system is technically possible, but pressures below 10 psig (violating system reinforcement criteria) would remain in this area even after an uprate.

Analysis shifted to new pipeline design and how to get more gas into the weak areas. A high pressure pipeline parallel to OR Hwy 99 is approximately 2.5 miles west of this area. A high pressure spur to the east towards River Rd, would provide an optimal mix of meeting today's demand and providing capacity to address growth.

Pipeline design processes iteratively weigh cost versus performance by many variables including pipe size, pipe length, pipe route, operating pressure, customer demand, soil conditions, restoration costs, terrain, and many more. It should also be noted that pipeline design can change between preliminary design and final design, ready for construction. Field validation is an important part of final design.

A pipeline design of 2 miles of high pressure and one mile of lower pressure pipeline in North Eugene was determined to offer the best solution for addressing the pressure issues because:

- Pressure issues are remediated
- Expected costs are lowest
- Least impacts on public, traffic, and customers
- Future extension of the pipeline is possible



This route was selected as the preliminary pipeline design for the North Eugene Reinforcement Project.

Additional Alternative Analysis:

Once a pipeline project is selected, the benefit volume from this pipeline project (modeled therms delivered to customers on peak from this project) is compared to other alternatives. A high level design for a satellite LNG facility for peak shaving is created which is sized to match the pipeline project benefit. The resulting satellite LNG facility design had a higher estimated cost than the proposed pipeline project.

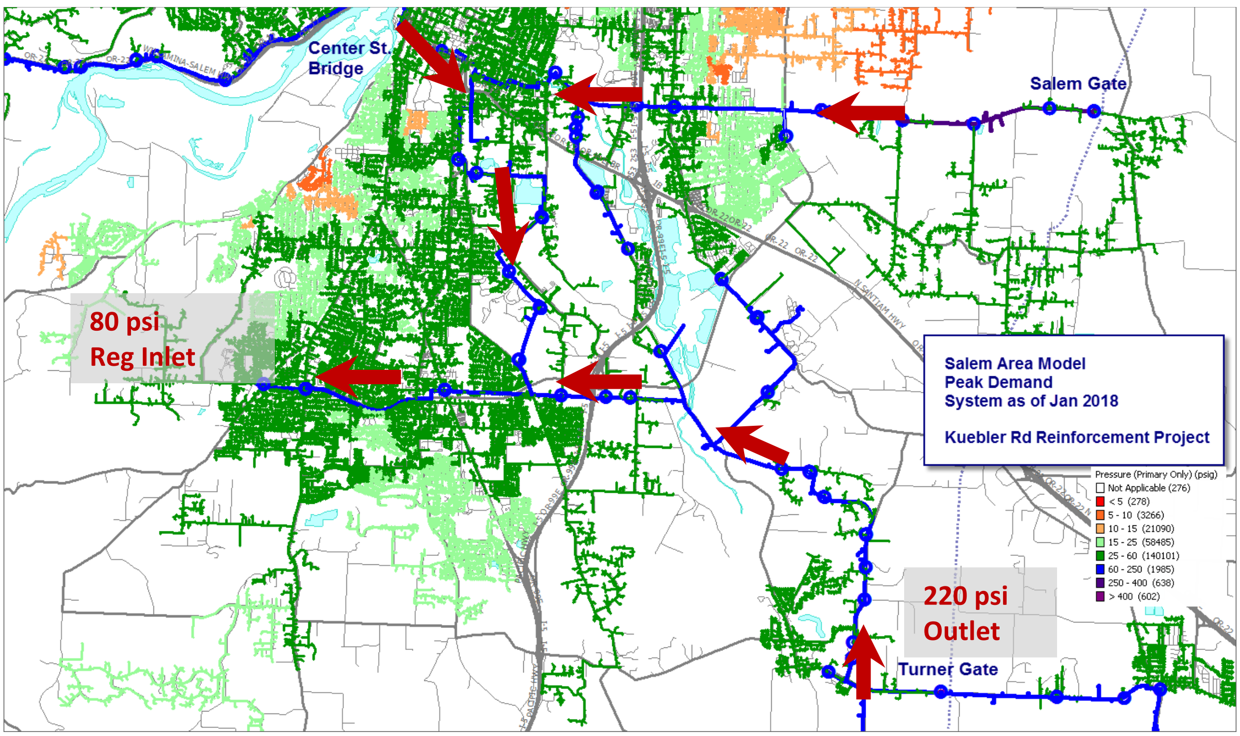
The final alternative analysis is to examine the possibility of acquiring interruptible customer contracts that will match or exceed the project benefit therms and defer pipeline construction. An analysis of existing firm customers within the North Eugene system was performed to identify if sufficient volumes could be recovered from firm customers by contracting with them to become interruptible. There was not sufficient firm demand available on peak to replace the pipeline project benefit volume.

The pipeline project was selected as the preliminary design for the North Eugene Reinforcement Project and was determined to be our best alternative for 2018 IRP action item submittal.

Project Name: Kuebler Road Reinforcement

System Background and Description:

The 225 MAOP high pressure system in Salem is fed by three different sources: Turner Gate in the south and Salem Gate and Center Street Bridge regulators in the north. The north and south portions of this system are connected by a single 6-inch pipe which does not have adequate capacity under cold weather conditions. Growth to the south and west has increased demand on the Turner Gate and the high pressure distribution system to the point where pressure drop criteria are exceeded and regulator inlet pressures are in jeopardy.



Recent Events Supporting Reinforcement Project: Cold Weather, January 5-6, 2017

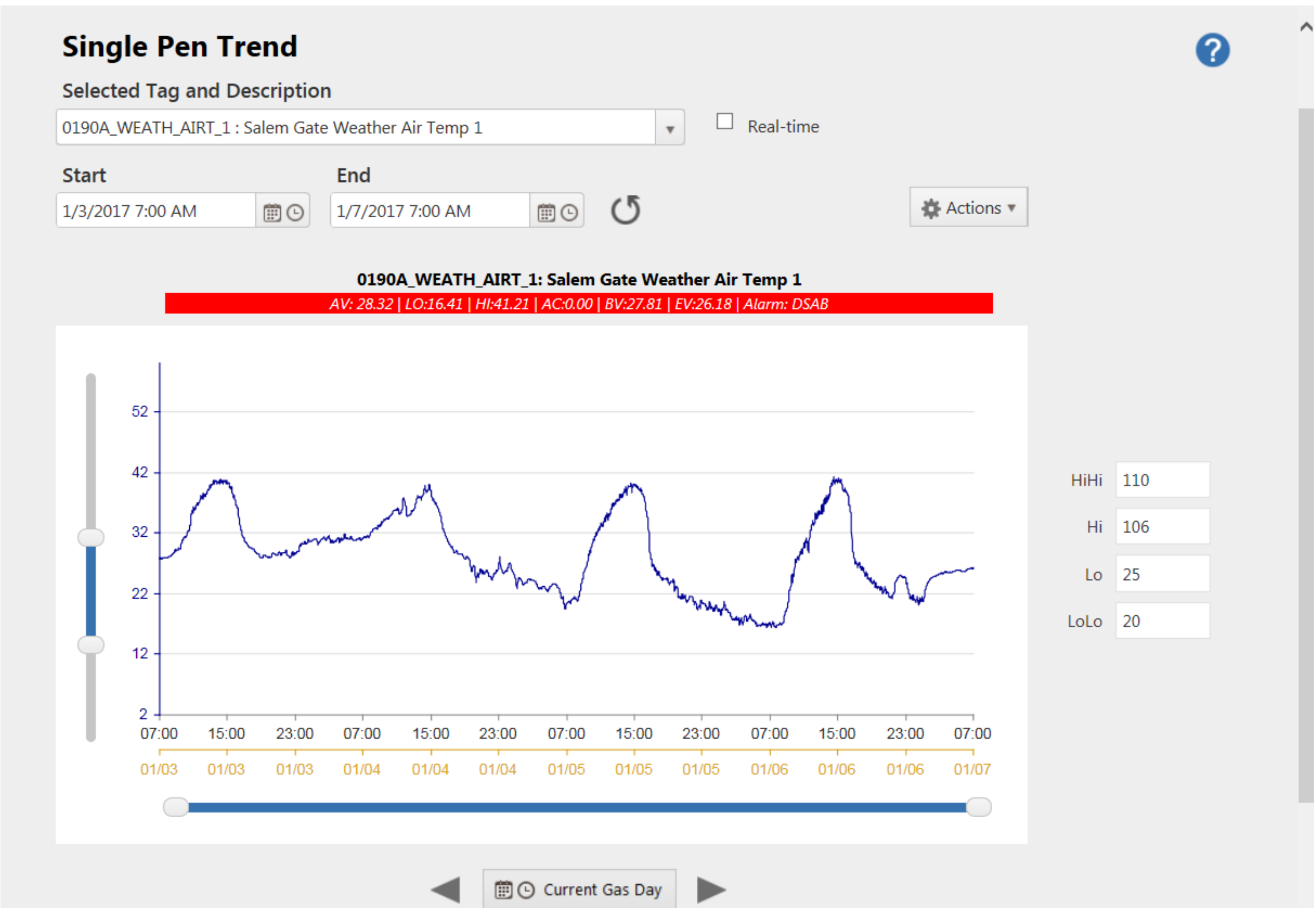
Summary:

- Non Peak cold weather events in January 2017 resulted in significant pressure drops on the Salem high pressure system (225 MAOP). No system abnormalities were experienced to produce pressure drops[1]
- No customers outages were reported
- Modeling validates the experienced pressure drop conditions
- System reinforcement standards were violated by pressure drops exceeding 40% on this high pressure pipeline

[1] I.e., unexpected equipment malfunctions unrelated to cold weather

- Marginally higher demands than were experienced in January 2017 would result in downstream regulator malfunction and subsequent low pressures and customer outages
- The South Salem system remains a safety and reliability concern until reinforcement occurs

Weather: Salem experienced the cold weather and increased customer demand that other areas faced in January 5-6, 2017. The following graph was generated from data collected by the Gas Control SCADA system which monitors near real time data from the field. The period of the graph is a five day period from 7 AM January 3, 2017 to 7AM January 7, 2017. This period was chosen to show the days before and after the cold event. The graph below depicts the air temperature at the Salem Gate Station. This SCADA site indicates a low air temp of about 16 DegF on the morning of January 6, 2017.



Historical air temperature data (see attached coldest events by location spreadsheet) shows that Salem has experienced numerous colder days in recent history including 1989, 1990, 2013, 1985, 2009, and 2004 amongst others. The January 2017 event was not an anomalous weather event in Salem nor was it a design “Peak” day.

System Conditions: Normal winter operations activities were performed during this event. Field personnel validated that the regulators feeding the system were performing properly. The regulator at the southwest end of the Salem high pressure system (Kuebler Blvd & Skyline Rd) was bypassed during morning hours to maximize pressures. The regulator inlet pressure at this location reached a low pressure of 80 psig on the morning of January 6, 2017. There were no closed valves or damages to the upstream feeder or in the system. There are no interruptible customers downstream of this regulator which could have removed demand from this regulator and its upstream system.

The performance of the lower pressure system is wholly dependent upon the ability of the high pressure pipeline to deliver adequate gas pressure to the regulator inlets. The high pressure system in Salem is the current bottleneck in this system and is in danger of starving district regulators.

District Regulators require that the inlet pressure be at least 20 psig higher than the outlet pressure for proper operation. The regulators feeding Southwest Salem which are set to feed at 40 psig (45 MAOP system) were very close to being starved by low inlet pressure. This was not an isolated incident, low inlet pressures at the Southwest Salem regulator have also reported (but not documented) on days prior to and after January 6, 2017 and during previous events.

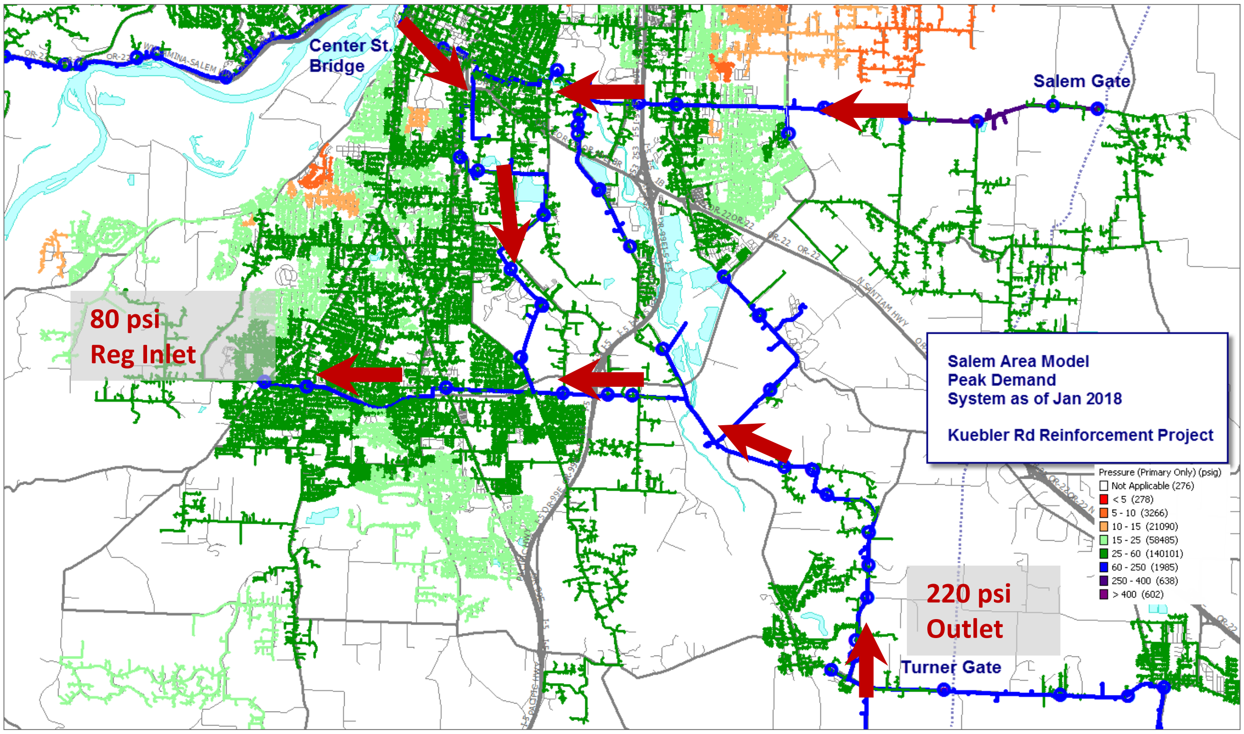
The measured pressure drop on the South Salem system from Turner gate to the Kuebler Regulator on January 6. 2017 was 140 psig (220 - 80) or just over 60%. This result exceeds our 40% system reinforcement pressure drop criteria for high pressure pipelines and indicates that this pipeline requires reinforcement.

Current System Analysis:

The Synergi model for the existing South Salem system (current piping configuration and customers) under peak hour customer demand is shown below. Arrows are added to this model to indicated flow directions on the high pressure system to better understand how the three gas sources support each other.

The model indicates that the distribution system within the town of Salem is adequate but weak (orange) in some under peak hour conditions. These weaknesses are being addressed over time with small system ties.

The primary concern for this system is the capacity of the high pressure system (225 MAOP) west of Turner Gate. Modeling indicates very large pressure drops (greater than 60%) on this high pressure pipeline that greatly exceed system reinforcement standards (40%) on a peak hour. The existing pipeline configuration significantly violates our system reinforcement criteria for high pressure systems which specifies that 40% is the largest acceptable pressure drop. System reinforcement actions must be taken to assure reliable service to firm customers.



System Reinforcement Selection:

The Kuebler Road Reinforcement project is needed to support high pressure distribution system pressures for firm service customers in the South Salem area.

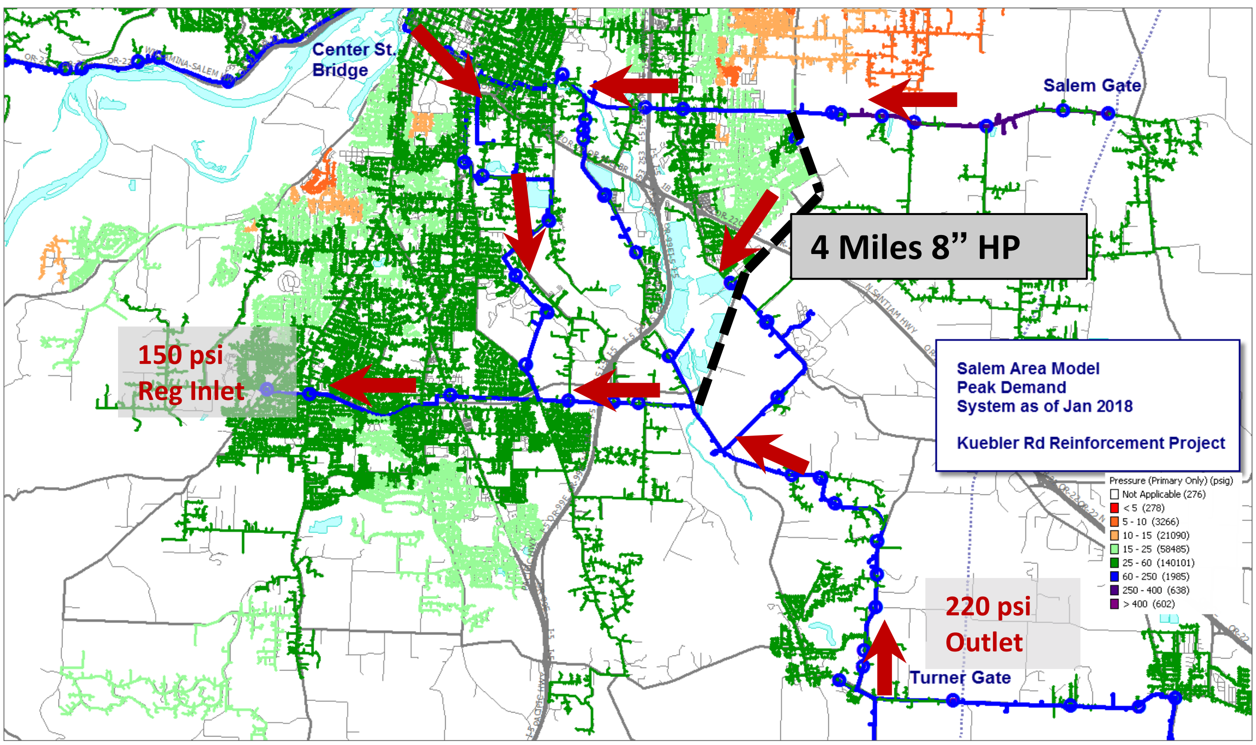
Pressure uprates of gas pipelines are always considered viable alternatives as they can be relatively inexpensive procedures. The Salem high pressure system operates at 225 MAOP. Pipeline records indicate that there are many sections of the Salem high pressure system that were installed in the late 1950's and early 1960's that were not designed or pressure tested to allow for service above 225 psig. It is not a NW Natural practice to retest and recertify pipes from this vintage.

Pipeline design processes iteratively weigh cost versus performance by many variables including pipe size, pipe length, pipe route, operating pressure, customer demand, soil conditions, restoration costs, terrain, and many more. It should also be noted that pipeline design can change between preliminary design and final design, ready for construction. Field validation is an important part of final design.

The Kuebler Road Project installs approximately four miles of high pressure pipeline to create a high pressure loop in the Salem 225 MAOP system. This pipeline allows Salem Gate and the Center Street Bridge regulators to contribute significantly more supply to the southern end of the system and reduce demand from Turner Gate. The project restores pressures at the southwest end of the Salem high pressure system to reasonable conditions on Peak. This project also has the benefit of eliminating required capacity improvements at Turner Gate, which were estimated to cost $2 million.

A 4 mile high pressure pipeline design along Kuebler Road in South Salem was determined to offer the best solution for addressing the pressure issues because:

- High Pressure system issues are remediated
- Provides a high pressure loop in the Salem System which enhances performance and reliability
- Expected costs are lowest
- Eliminates required improvement costs at Turner Gate, $2 million
- Pipeline route through relatively undeveloped area reduces road traffic, public and customer impacts



The Kuebler Road pipeline route was chosen as the preliminary pipeline design for the Kuebler Road Reinforcement Project.

Additional Alternative Analysis:

Once a pipeline project is selected, the benefit volume from this pipeline project is compared to other alternatives. For this project the benefit volume is calculated as the net therms required to restore pressure drop on the existing pipeline to 30% pressure drop. A high level design for a satellite LNG facility for peak shaving is created which is sized to match the pipeline project benefit. The resulting satellite LNG facility design for Southwest Salem had a higher estimated cost than the proposed pipeline project.

The final alternative analysis is to examine the possibility of acquiring interruptible customer contracts that will match or exceed the project benefit therms and defer pipeline construction. An analysis of existing firm customers within the Southwest Salem system was performed to identify if sufficient volumes could be recovered from firm customers by contracting with them to become interruptible. There was not sufficient firm demand available on peak to replace the pipeline project benefit volume.

The Kuebler Road Reinforcement Project as defined above was selected as the best alternative for 2018 IRP action item submittal.

Order Type	Account	Premise #	Date	Status	Premise Address	City	Plat	Complete Date	Completed Time	AM/PM
6000	2413345	13803582000	20170105	U	1165 Tucker Rd	Hood River	1008140	20170105	11600	PM
6000	2596682	15802631000	20170105	U	1705 Montello Ave	Hood River	1005140	20170105	15600	PM
6000	3153828	13803638000	20170105	U	831 Sieverkropp Dr	Hood River	1006141	20170105	112700	AM
6000	2527209	26541618000	20170105	U	1621 3rd St	Hood River	1006141	20170105	120900	PM
6000	2947063	26551277000	20170105	U	1630 3rd St	Hood River	1006141	20170105	121200	PM
6000	1980714	26516512000	20170105	U	212 Betty Lou St	Hood River	1006141	20170105	123200	PM
6100	1143867	26467626000	20170105	U	514 Betty Lou St	Hood River	1006141	20170106	10900	PM
6500	3430864	26490248000	20170105	U	1621 4th St	Hood River	1006141	20170106	113800	AM
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6000	3001408	26533387000	20170106	U	208 Betty Lou St	Hood River	1006141	20170106	20000	PM
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6000	1936379	26543734000	20170105	U	18672 Sunblaze Dr	Oregon City	1056033	20170105	25600	PM
6000	772369	26544022000	20170105	U	18680 Sunblaze Dr	Oregon City	1056033	20170105	30000	PM
6000	1834496	25112803000	20170105	U	11857 White Ln	Oregon City	1058034	20170105	30200	PM
6100	316532	25104685000	20170105	U	11345 Pennys Way	Oregon City	1058033	20170105	30700	PM
6000	2664853	25114826000	20170105	U	11863 White Ln	Oregon City	1058034	20170105	30800	PM
6000	151680	25043783000	20170105	U	11243 Brandow St	Oregon City	1057033	20170105	31800	PM
6000	3185677	26240274000	20170105	U	14588 Henrici Rd	Oregon City	1060040	20170105	32000	PM
6000	2874682	26546522000	20170105	U	18792 Sunblaze Dr	Oregon City	1056034	20170105	32100	PM
6000	1435831	12263561000	20170105	U	11075 Navajo Way	Oregon City	1058033	20170105	32800	PM
6000	1882136	25029276000	20170105	U	11517 Shelby Rose Dr	Oregon City	1057033	20170105	33000	PM
6100	479020	25098127000	20170105	U	19224 Pine Pl	Oregon City	1057034	20170105	34000	PM
6000	1204208	25096465000	20170105	U	11812 Payson Ln	Oregon City	1058034	20170105	34100	PM
6000	2775912	25088928000	20170105	U	11805 Payson Ln	Oregon City	1058034	20170105	34600	PM
6000	1970983	25058619000	20170105	U	11327 Brandow St	Oregon City	1057033	20170105	34700	PM
6000	2782899	25048699000	20170105	U	11257 Maywood Ct	Oregon City	1057033	20170105	35200	PM
6000	146343	25101277000	20170105	U	11835 Payson Ln	Oregon City	1058034	20170105	35500	PM
6000	701442	25007430000	20170105	U	21048 S South End Rd	Oregon City	1061031	20170105	35500	PM
6000	1059440	25065859000	20170105	U	11269 Maywood Ct	Oregon City	1057033	20170105	35900	PM
6000	291729	25057317000	20170105	U	11409 Shelby Rose Dr	Oregon City	1057033	20170105	40200	PM
6000	315920	25102721000	20170105	U	19545 Jennifer Lynn Ct	Oregon City	1058033	20170105	40300	PM
6000	316213	12262077000	20170105	U	21111 S South End Rd	Oregon City	1061031	20170105	40800	PM
6000	3099455	25064664000	20170105	U	11373 Shelby Rose Dr	Oregon City	1057033	20170105	41000	PM
6000	897053	25034365000	20170105	U	19080 S Maywood St	Oregon City	1057033	20170105	41600	PM
6000	3403807	26574067000	20170105	U	12084 Hazelnut Ave	Oregon City	1058034	20170105	41800	PM
6000	1268721	25129424000	20170105	U	11840 Partlow Rd	Oregon City	1057034	20170105	41900	PM
6100	305986	25036371000	20170105	U	19067 S Maywood St	Oregon City	1057033	20170105	42400	PM
6000	450706	26574310000	20170105	U	12072 Hazelnut Ave	Oregon City	1058034	20170105	42600	PM
6000	1212709	25110710000	20170105	U	19546 Jennifer Lynn Ct	Oregon City	1058033	20170105	42700	PM
6000	1148272	25096096000	20170105	U	19586 Kari Ann Ct	Oregon City	1058033	20170105	42900	PM
6000	2195124	25108826000	20170105	U	11664 Finnegans Way	Oregon City	1058033	20170105	44200	PM
6000	1882136	25029276000	20170105	U	11517 Shelby Rose Dr	Oregon City	1057033	20170105	45200	PM
6000	1535318	25103397000	20170105	U	11550 Pennys Way	Oregon City	1058033	20170105	45200	PM
6100	316043	12261713000	20170105	U	19407 S South End Rd	Oregon City	1057033	20170105	50000	PM

6000	1642560	26531580000	20170105	U	18744 Sunblaze Dr	Oregon City	1056033	20170105	50200	PM
6000	1246124	25043787000	20170105	U	11423 Brandow St	Oregon City	1057033	20170105	51100	PM
6000	3324470	12263875000	20170105	U	19348 S South End Rd	Oregon City	1057033	20170105	51400	PM
6000	2309177	25059794000	20170105	U	11339 Brandow St	Oregon City	1057033	20170105	52000	PM
6000	317052	12264057000	20170105	U	11008 Beutel Rd	Oregon City	1057032	20170105	82500	AM
6000	3253300	26223739000	20170105	U	11060 Beutel Rd	Oregon City	1057032	20170105	84700	AM
6000	419256	25128246000	20170105	U	19265 Cantata Dr	Oregon City	1057033	20170105	110600	AM
6000	3318006	25130912000	20170105	U	11334 Legato Dr	Oregon City	1058033	20170105	111400	AM
6000	99661	25128245000	20170105	U	11344 Legato Dr	Oregon City	1058033	20170105	112500	AM
6000	994288	12261725000	20170105	U	915 Clearbrook Dr	Oregon City	1055035	20170105	114900	PM
6600	2797293	16102225000	20170105	U	20001 S Leland Rd	Oregon City	1058036	20170106	21700	PM
6100	1305276	12263868000	20170105	U	808 Promontory Ave	Oregon City	1054036	20170106	30100	PM
6100	3242789	25087672000	20170105	U	19215 Merchant Pl	Oregon City	1057033	20170106	114700	AM
6500	929396	25042654000	20170105	U	19423 Hazelgrove Dr	Oregon City	1058034	20170106	121900	PM
6000	3011118	12240905000	20170106	U	1314 Madison St	Oregon City	1053037	20170106	21700	PM
6000	3185677	26240274000	20170106	U	14588 Henrici Rd	Oregon City	1060040	20170106	32300	PM
6600	3360827	25048013000	20170106	U	15088 Persimmon Way	Oregon City	1059041	20170106	41900	PM
6100	921659	16011181000	20170106	U	18841 Cook St	Oregon City	1056034	20170106	42400	PM
6600	3131452	13284840000	20170106	U	19129 S Beavercreek Rd	Oregon City	1057039	20170106	43300	PM
6800	418294	16102115000	20170106	U	904 Molalla Ave	Oregon City	1055037	20170106	45300	PM
6000	1842542	26065165000	20170106	U	1125 Leonard St	Oregon City	1055036	20170106	82900	AM
6000	2874682	26546522000	20170106	U	18792 Sunblaze Dr	Oregon City	1056034	20170106	94900	AM
6500	2133770	26531581000	20170106	U	18752 Sunblaze Dr	Oregon City	1056033	20170106	100000	AM
6800	418294	16102115000	20170106	U	904 Molalla Ave	Oregon City	1055037	20170106	103600	AM
6000	317000	12263991000	20170106	U	10953 Forest Ridge Ln	Oregon City	1057032	20170106	104000	AM
6000	2670079	25104189000	20170106	U	11687 Finnegans Way	Oregon City	1058033	20170106	110000	AM
6000	857265	11244183000	20170106	U	19417 Vincent Dr	Oregon City	1057034	20170106	112900	AM
6500	418853	26530624000	20170106	U	18895 S Rose Rd	Oregon City	1056033	20170106	114600	AM
6000	1835631	25107529000	20170106	U	11755 White Ln	Oregon City	1058034	20170106	121500	PM
6000	292755	11251416000	20170107	U	420 Latourette St	Oregon City	1054036	20170107	104100	AM
6000	1083476	25084768000	20170107	U	19147 Merchant Pl	Oregon City	1057033	20170107	110500	AM

SiteId	Year	Month	DayRank	EventRank	Gas_Day	TempGHA	MinEventTemp	MinTempDiff
KDLS	1990	12	48	1	12/19/1990	14.6375	2.779167	0
KDLS	1990	12	10	1	12/20/1990	5.841667	2.779167	0
KDLS	1990	12	1	1	12/21/1990	2.779167	2.779167	0
KDLS	1990	12	5	1	12/22/1990	4.475	2.779167	0
KDLS	1990	12	8	1	12/23/1990	5.558333	2.779167	0
KDLS	1990	12	29	1	12/24/1990	12.53333	2.779167	0
KDLS	1990	12	58	1	12/28/1990	16.02083	2.779167	0
KDLS	1990	12	12	1	12/29/1990	6.366667	2.779167	0
KDLS	1990	12	51	1	12/30/1990	15.32917	2.779167	0
KDLS	1996	1	46	2	1/29/1996	14.59583	3.445833	0.6666667
KDLS	1996	1	4	2	1/30/1996	3.908333	3.445833	0.6666667
KDLS	1996	1	2	2	1/31/1996	3.445833	3.445833	0.6666667
KDLS	1996	2	3	2	2/1/1996	3.5	3.445833	0.6666667
KDLS	1996	2	11	2	2/2/1996	6.0125	3.445833	0.6666667
KDLS	1996	2	18	2	2/3/1996	9.304167	3.445833	0.6666667
KDLS	1996	2	90	2	2/4/1996	19.42083	3.445833	0.6666667
KDLS	1989	2	61	3	2/1/1989	16.3875	4.9125	2.133333
KDLS	1989	2	7	3	2/2/1989	5.383333	4.9125	2.133333
KDLS	1989	2	6	3	2/3/1989	4.9125	4.9125	2.133333
KDLS	1989	2	14	3	2/4/1989	7.829167	4.9125	2.133333
KDLS	1989	2	36	3	2/5/1989	13.45	4.9125	2.133333
KDLS	1989	2	64	3	2/6/1989	16.87083	4.9125	2.133333
KDLS	1989	2	68	3	2/7/1989	17.62083	4.9125	2.133333
KDLS	1989	2	86	3	2/8/1989	19.10833	4.9125	2.133333
KDLS	1985	11	35	4	11/22/1985	13.30417	5.629167	2.85
KDLS	1985	11	9	4	11/23/1985	5.629167	5.629167	2.85
KDLS	1985	11	23	4	11/24/1985	10.60833	5.629167	2.85
KDLS	1985	11	69	4	11/25/1985	17.65	5.629167	2.85
KDLS	1985	11	49	4	11/27/1985	14.8625	5.629167	2.85
KDLS	1985	11	21	4	11/28/1985	10.53333	5.629167	2.85
KDLS	1985	11	30	4	11/29/1985	12.8875	5.629167	2.85
KDLS	1985	11	41	4	11/30/1985	14.01667	5.629167	2.85
KDLS	1985	12	15	4	12/1/1985	8.929167	5.629167	2.85
KDLS	1985	12	75	4	12/2/1985	18.03333	5.629167	2.85
KDLS	2013	12	17	5	12/7/2013	9.2	7.4	4.620833
KDLS	2013	12	13	5	12/8/2013	7.4	7.4	4.620833
KDLS	2004	1	26	6	1/4/2004	12.05	9.05	6.270833
KDLS	2004	1	16	6	1/5/2004	9.05	9.05	6.270833
KDLS	1998	12	79	7	12/19/1998	18.62083	9.383333	6.604167
KDLS	1998	12	19	7	12/20/1998	9.383333	9.383333	6.604167
KDLS	1998	12	20	7	12/21/1998	10.08333	9.383333	6.604167
KDLS	1998	12	22	7	12/22/1998	10.54583	9.383333	6.604167
KDLS	1998	12	44	7	12/23/1998	14.45417	9.383333	6.604167
KDLS	1998	1	24	8	1/11/1998	10.70417	10.70417	7.925
KDLS	1998	1	65	8	1/12/1998	17.14167	10.70417	7.925
KDLS	2017	1	72	9	1/4/2017	17.95833	11.72917	8.950001
KDLS	2017	1	25	9	1/5/2017	11.72917	11.72917	8.950001
KDLS	2017	1	34	9	1/6/2017	13.11667	11.72917	8.950001
KDLS	2017	1	74	9	1/7/2017	18.00417	11.72917	8.950001
KDLS	2008	12	91	10	12/14/2008	19.475	12.5	9.720833
KDLS	2008	12	70	10	12/15/2008	17.825	12.5	9.720833
KDLS	2008	12	43	10	12/16/2008	14.225	12.5	9.720833
KDLS	2008	12	27	10	12/20/2008	12.5	12.5	9.720833

KDLS	2008	12	28	10	12/21/2008	12.5	12.5	9.720833
KDLS	2008	12	62	10	12/22/2008	16.4	12.5	9.720833
KDLS	2008	12	96	10	12/23/2008	19.7	12.5	9.720833
KDLS	2008	12	100	10	12/24/2008	20.075	12.5	9.720833
KDLS	2009	12	54	11	12/7/2009	15.725	13.025	10.24583
KDLS	2009	12	37	11	12/8/2009	13.475	13.025	10.24583
KDLS	2009	12	31	11	12/9/2009	13.025	13.025	10.24583
KDLS	2009	12	45	11	12/10/2009	14.5625	13.025	10.24583
KDLS	2009	12	97	11	12/11/2009	19.7	13.025	10.24583
KDLS	1993	11	73	12	11/23/1993	17.96667	13.06667	10.2875
KDLS	1993	11	32	12	11/24/1993	13.06667	13.06667	10.2875
KDLS	1993	11	38	12	11/25/1993	13.59167	13.06667	10.2875
KDLS	1993	11	71	12	11/26/1993	17.9125	13.06667	10.2875
KDLS	1993	1	59	13	1/6/1993	16.0875	13.11667	10.3375
KDLS	1993	1	55	13	1/7/1993	15.75833	13.11667	10.3375
KDLS	1993	1	52	13	1/8/1993	15.39167	13.11667	10.3375
KDLS	1993	1	33	13	1/9/1993	13.11667	13.11667	10.3375
KDLS	1993	1	53	13	1/10/1993	15.55833	13.11667	10.3375
KDLS	1993	1	80	13	1/11/1993	18.6625	13.11667	10.3375
KDLS	1993	1	67	13	1/12/1993	17.5875	13.11667	10.3375
KDLS	1993	1	76	13	1/13/1993	18.06667	13.11667	10.3375
KDLS	1993	1	87	13	1/14/1993	19.25	13.11667	10.3375
KDLS	1993	1	84	13	1/15/1993	19.025	13.11667	10.3375
KDLS	2017	1	57	14	1/12/2017	15.80417	13.6375	10.85833
KDLS	2017	1	42	14	1/13/2017	14.0375	13.6375	10.85833
KDLS	2017	1	39	14	1/14/2017	13.6375	13.6375	10.85833
KDLS	2017	1	40	14	1/15/2017	13.7875	13.6375	10.85833
KDLS	2017	1	50	14	1/16/2017	14.86667	13.6375	10.85833
KDLS	1985	2	47	15	2/3/1985	14.61667	14.61667	11.8375
KDLS	1985	2	88	15	2/4/1985	19.30833	14.61667	11.8375
KDLS	2014	2	56	16	2/6/2014	15.8	15.8	13.02083
KDLS	2014	2	66	16	2/7/2014	17.15	15.8	13.02083
KDLS	1997	1	89	17	1/13/1997	19.30833	16.36667	13.5875
KDLS	1997	1	60	17	1/15/1997	16.36667	16.36667	13.5875
KDLS	2014	11	63	18	11/15/2014	16.4	16.4	13.62083
KDLS	2014	11	78	18	11/16/2014	18.2	16.4	13.62083
KDLS	1985	12	77	19	12/11/1985	18.11667	18.11667	15.3375
KDLS	1985	12	85	19	12/12/1985	19.0375	18.11667	15.3375
KDLS	2009	1	81	20	1/26/2009	18.725	18.725	15.94583
KDLS	2016	12	82	21	12/17/2016	18.8125	18.8125	16.03333
KDLS	2016	12	83	21	12/18/2016	18.89167	18.8125	16.03333
KDLS	1993	2	92	22	2/26/1993	19.59167	19.59167	16.8125
KDLS	1993	2	99	22	2/27/1993	19.89167	19.59167	16.8125
KDLS	2010	11	93	23	11/23/2010	19.625	19.625	16.84583
KDLS	2010	11	98	23	11/24/2010	19.8125	19.625	16.84583
KDLS	1997	1	94	24	1/26/1997	19.68333	19.68333	16.90417
KDLS	2007	1	95	25	1/14/2007	19.7	19.7	16.92083

SiteId	Year	Month	DayRank	EventRank	Gas_Day	TempGHA	MinEventTemp	MinTempDiff
KPDX	1989	2	52	1	2/1/1989	25.6625	12.7875	0
KPDX	1989	2	2	1	2/2/1989	12.84583	12.7875	0
KPDX	1989	2	1	1	2/3/1989	12.7875	12.7875	0
KPDX	1989	2	13	1	2/4/1989	20.275	12.7875	0
KPDX	1989	2	59	1	2/5/1989	26.16667	12.7875	0
KPDX	1989	2	100	1	2/6/1989	29.59167	12.7875	0
KPDX	1990	12	23	2	12/19/1990	21.5	15.1625	2.375
KPDX	1990	12	3	2	12/20/1990	15.1625	15.1625	2.375
KPDX	1990	12	4	2	12/21/1990	16.25417	15.1625	2.375
KPDX	1990	12	6	2	12/22/1990	18.13333	15.1625	2.375
KPDX	1990	12	7	2	12/23/1990	19.35833	15.1625	2.375
KPDX	1990	12	29	2	12/24/1990	22.50833	15.1625	2.375
KPDX	1990	12	40	2	12/28/1990	24.00417	15.1625	2.375
KPDX	1990	12	5	2	12/29/1990	16.575	15.1625	2.375
KPDX	1990	12	43	2	12/30/1990	24.30833	15.1625	2.375
KPDX	1996	1	53	3	1/29/1996	25.76667	19.775	6.987499
KPDX	1996	1	8	3	1/30/1996	19.775	19.775	6.987499
KPDX	1996	1	14	3	1/31/1996	20.59583	19.775	6.987499
KPDX	1996	2	9	3	2/1/1996	19.97917	19.775	6.987499
KPDX	1996	2	17	3	2/2/1996	20.84167	19.775	6.987499
KPDX	1996	2	24	3	2/3/1996	21.59583	19.775	6.987499
KPDX	1996	2	90	3	2/4/1996	29	19.775	6.987499
KPDX	1998	12	70	4	12/19/1998	27.57083	20.07917	7.291666
KPDX	1998	12	10	4	12/20/1998	20.07917	20.07917	7.291666
KPDX	1998	12	20	4	12/21/1998	21.225	20.07917	7.291666
KPDX	1998	12	25	4	12/22/1998	21.80417	20.07917	7.291666
KPDX	1998	12	42	4	12/23/1998	24.2375	20.07917	7.291666
KPDX	1985	11	44	5	11/22/1985	24.32917	20.175	7.387499
KPDX	1985	11	11	5	11/23/1985	20.175	20.175	7.387499
KPDX	1985	11	15	5	11/24/1985	20.69167	20.175	7.387499
KPDX	1985	11	64	5	11/25/1985	26.8875	20.175	7.387499
KPDX	1985	11	32	5	11/28/1985	22.9	20.175	7.387499
KPDX	1985	11	33	5	11/29/1985	22.96667	20.175	7.387499
KPDX	1985	11	38	5	11/30/1985	23.92083	20.175	7.387499
KPDX	1985	12	31	5	12/1/1985	22.7875	20.175	7.387499
KPDX	2014	2	36	6	2/5/2014	23.45	20.225	7.4375
KPDX	2014	2	12	6	2/6/2014	20.225	20.225	7.4375
KPDX	2014	2	48	6	2/7/2014	25.4	20.225	7.4375
KPDX	2014	2	81	6	2/8/2014	28.475	20.225	7.4375
KPDX	2013	12	85	7	12/4/2013	28.85	20.825	8.0375
KPDX	2013	12	75	7	12/5/2013	28.025	20.825	8.0375
KPDX	2013	12	58	7	12/6/2013	26.075	20.825	8.0375
KPDX	2013	12	22	7	12/7/2013	21.35	20.825	8.0375
KPDX	2013	12	16	7	12/8/2013	20.825	20.825	8.0375
KPDX	2013	12	61	7	12/9/2013	26.525	20.825	8.0375
KPDX	2009	12	51	8	12/7/2009	25.625	20.9	8.112499
KPDX	2009	12	35	8	12/8/2009	23.45	20.9	8.112499
KPDX	2009	12	18	8	12/9/2009	20.9	20.9	8.112499
KPDX	2009	12	30	8	12/10/2009	22.7	20.9	8.112499
KPDX	2004	1	60	9	1/4/2004	26.3	21.05	8.262499
KPDX	2004	1	19	9	1/5/2004	21.05	21.05	8.262499

KPDX	2004	1	21	9	1/6/2004	21.35	21.05	8.262499
KPDX	2004	1	67	9	1/7/2004	27.275	21.05	8.262499
KPDX	2008	12	56	10	12/14/2008	25.925	22.3625	9.574999
KPDX	2008	12	46	10	12/15/2008	25.025	22.3625	9.574999
KPDX	2008	12	49	10	12/16/2008	25.55	22.3625	9.574999
KPDX	2008	12	27	10	12/20/2008	22.4	22.3625	9.574999
KPDX	2008	12	26	10	12/21/2008	22.3625	22.3625	9.574999
KPDX	2008	12	47	10	12/22/2008	25.4	22.3625	9.574999
KPDX	2008	12	78	10	12/23/2008	28.25	22.3625	9.574999
KPDX	2017	1	93	11	1/3/2017	29.2	22.49583	9.708332
KPDX	2017	1	88	11	1/4/2017	28.88333	22.49583	9.708332
KPDX	2017	1	45	11	1/5/2017	24.86667	22.49583	9.708332
KPDX	2017	1	57	11	1/6/2017	26.05833	22.49583	9.708332
KPDX	2017	1	76	11	1/7/2017	28.07917	22.49583	9.708332
KPDX	2017	1	79	11	1/11/2017	28.275	22.49583	9.708332
KPDX	2017	1	37	11	1/12/2017	23.73333	22.49583	9.708332
KPDX	2017	1	28	11	1/13/2017	22.49583	22.49583	9.708332
KPDX	2017	1	39	11	1/14/2017	23.9875	22.49583	9.708332
KPDX	2017	1	41	11	1/15/2017	24.07083	22.49583	9.708332
KPDX	2017	1	50	11	1/16/2017	25.60833	22.49583	9.708332
KPDX	2010	11	34	12	11/23/2010	23.3	23.3	10.5125
KPDX	2010	11	89	12	11/24/2010	28.9625	23.3	10.5125
KPDX	1995	2	77	13	2/12/1995	28.175	25.86667	13.07917
KPDX	1995	2	54	13	2/13/1995	25.86667	25.86667	13.07917
KPDX	1998	1	55	14	1/11/1998	25.8875	25.8875	13.1
KPDX	1998	1	69	14	1/12/1998	27.42917	25.8875	13.1
KPDX	1993	1	72	15	1/7/1993	27.68333	26.8625	14.075
KPDX	1993	1	62	15	1/10/1993	26.8625	26.8625	14.075
KPDX	1993	1	97	15	1/11/1993	29.26667	26.8625	14.075
KPDX	2007	1	68	16	1/12/2007	27.425	26.8625	14.075
KPDX	2007	1	63	16	1/13/2007	26.8625	26.8625	14.075
KPDX	2007	1	74	16	1/14/2007	27.875	26.8625	14.075
KPDX	2007	1	99	16	1/15/2007	29.45	26.8625	14.075
KPDX	2007	1	84	16	1/16/2007	28.55	26.8625	14.075
KPDX	2011	2	65	17	2/25/2011	27.125	27.125	14.3375
KPDX	1985	2	66	18	2/3/1985	27.21667	27.21667	14.42917
KPDX	1985	2	87	18	2/4/1985	28.8625	27.21667	14.42917
KPDX	1984	12	71	19	12/31/1984	27.57143	27.57143	14.78393
KPDX	2006	2	73	20	2/17/2006	27.8	27.8	15.0125
KPDX	1993	11	80	21	11/23/1993	28.425	28.425	15.6375
KPDX	1985	12	82	22	12/18/1985	28.49583	28.49583	15.70833
KPDX	1985	12	95	23	12/26/1985	29.22917	28.53333	15.74583
KPDX	1985	12	83	23	12/27/1985	28.53333	28.53333	15.74583
KPDX	1985	12	91	23	12/28/1985	29.07083	28.53333	15.74583
KPDX	2014	12	86	24	12/30/2014	28.85	28.85	16.0625
KPDX	2005	1	92	25	1/15/2005	29.15	29.15	16.3625
KPDX	1990	2	94	26	2/13/1990	29.2125	29.2125	16.425
KPDX	1989	3	96	27	3/2/1989	29.24583	29.24583	16.45833
KPDX	2010	12	98	28	12/30/2010	29.3	29.3	16.5125

SiteId	Year	Month	DayRank	EventRank	Gas_Day	TempGHA	MinEventTemp	MinTempDiff
KTTD	1989	2	51	1	2/1/1989	24.39583	10.04583	0
KTTD	1989	2	2	1	2/2/1989	11.13333	10.04583	0
KTTD	1989	2	1	1	2/3/1989	10.04583	10.04583	0
KTTD	1989	2	19	1	2/4/1989	19.14583	10.04583	0
KTTD	1989	2	41	1	2/5/1989	23.69583	10.04583	0
KTTD	1989	2	73	1	2/6/1989	26.375	10.04583	0
KTTD	1989	2	76	1	2/7/1989	26.61667	10.04583	0
KTTD	1996	1	26	2	1/29/1996	20.8375	13.84167	3.795833
KTTD	1996	1	7	2	1/30/1996	15.18333	13.84167	3.795833
KTTD	1996	1	5	2	1/31/1996	14.6375	13.84167	3.795833
KTTD	1996	2	3	2	2/1/1996	13.84167	13.84167	3.795833
KTTD	1996	2	10	2	2/2/1996	16.35	13.84167	3.795833
KTTD	1996	2	21	2	2/3/1996	19.275	13.84167	3.795833
KTTD	1996	2	81	2	2/4/1996	26.8875	13.84167	3.795833
KTTD	1990	12	30	3	12/19/1990	21.82083	14.3875	4.341666
KTTD	1990	12	4	3	12/20/1990	14.3875	14.3875	4.341666
KTTD	1990	12	6	3	12/21/1990	14.99167	14.3875	4.341666
KTTD	1990	12	9	3	12/22/1990	16.24583	14.3875	4.341666
KTTD	1990	12	15	3	12/23/1990	18.29583	14.3875	4.341666
KTTD	1990	12	31	3	12/24/1990	22.00417	14.3875	4.341666
KTTD	1990	12	45	3	12/28/1990	23.9375	14.3875	4.341666
KTTD	1990	12	8	3	12/29/1990	15.70833	14.3875	4.341666
KTTD	1990	12	48	3	12/30/1990	24.225	14.3875	4.341666
KTTD	1985	11	29	4	11/22/1985	21.55	16.45833	6.4125
KTTD	1985	11	11	4	11/23/1985	16.45833	16.45833	6.4125
KTTD	1985	11	12	4	11/24/1985	17.12917	16.45833	6.4125
KTTD	1985	11	71	4	11/25/1985	26.175	16.45833	6.4125
KTTD	1985	11	98	4	11/27/1985	28	16.45833	6.4125
KTTD	1985	11	13	4	11/28/1985	17.775	16.45833	6.4125
KTTD	1985	11	16	4	11/29/1985	18.72083	16.45833	6.4125
KTTD	1985	11	25	4	11/30/1985	20.82917	16.45833	6.4125
KTTD	1985	12	18	4	12/1/1985	18.92083	16.45833	6.4125
KTTD	2004	1	32	5	1/4/2004	22.4	17.825	7.779167
KTTD	2004	1	17	5	1/5/2004	18.8	17.825	7.779167
KTTD	2004	1	14	5	1/6/2004	17.825	17.825	7.779167
KTTD	2004	1	39	5	1/7/2004	23.6	17.825	7.779167
KTTD	2008	12	54	6	12/14/2008	24.425	19.25	9.204166
KTTD	2008	12	47	6	12/15/2008	23.975	19.25	9.204166
KTTD	2008	12	50	6	12/16/2008	24.35	19.25	9.204166
KTTD	2008	12	20	6	12/20/2008	19.25	19.25	9.204166
KTTD	2008	12	22	6	12/21/2008	20	19.25	9.204166
KTTD	2008	12	40	6	12/22/2008	23.675	19.25	9.204166
KTTD	2008	12	79	6	12/23/2008	26.825	19.25	9.204166
KTTD	1998	12	84	7	12/19/1998	26.94583	20.1625	10.11667
KTTD	1998	12	23	7	12/20/1998	20.1625	20.1625	10.11667
KTTD	1998	12	28	7	12/21/1998	21.48333	20.1625	10.11667
KTTD	1998	12	36	7	12/22/1998	22.95417	20.1625	10.11667
KTTD	1998	12	55	7	12/23/1998	24.45	20.1625	10.11667
KTTD	2014	2	43	8	2/5/2014	23.75	20.525	10.47917
KTTD	2014	2	24	8	2/6/2014	20.525	20.525	10.47917
KTTD	2014	2	57	8	2/7/2014	24.575	20.525	10.47917

KTTD	2014	2	97	8	2/8/2014	27.875	20.525	10.47917
KTTD	2013	12	74	9	12/6/2013	26.525	21.275	11.22917
KTTD	2013	12	34	9	12/7/2013	22.4	21.275	11.22917
KTTD	2013	12	27	9	12/8/2013	21.275	21.275	11.22917
KTTD	2013	12	95	9	12/9/2013	27.65	21.275	11.22917
KTTD	2010	11	33	10	11/23/2010	22.4	22.4	12.35417
KTTD	2017	1	77	11	1/12/2017	26.70417	22.80833	12.7625
KTTD	2017	1	37	11	1/13/2017	23.12083	22.80833	12.7625
KTTD	2017	1	35	11	1/14/2017	22.80833	22.80833	12.7625
KTTD	2017	1	46	11	1/15/2017	23.9625	22.80833	12.7625
KTTD	2017	1	58	11	1/16/2017	24.57917	22.80833	12.7625
KTTD	1998	1	38	12	1/11/1998	23.2125	23.2125	13.16667
KTTD	2009	12	44	13	12/7/2009	23.9	23.75	13.70417
KTTD	2009	12	42	13	12/8/2009	23.75	23.75	13.70417
KTTD	2009	12	61	13	12/9/2009	24.875	23.75	13.70417
KTTD	2009	12	93	13	12/10/2009	27.5	23.75	13.70417
KTTD	1993	1	52	14	1/6/1993	24.4	24.30833	14.2625
KTTD	1993	1	63	14	1/7/1993	25.225	24.30833	14.2625
KTTD	1993	1	78	14	1/8/1993	26.75833	24.30833	14.2625
KTTD	1993	1	90	14	1/9/1993	27.35833	24.30833	14.2625
KTTD	1993	1	49	14	1/10/1993	24.30833	24.30833	14.2625
KTTD	1993	1	64	14	1/11/1993	25.37917	24.30833	14.2625
KTTD	1993	1	65	14	1/12/1993	25.58333	24.30833	14.2625
KTTD	1993	1	72	14	1/13/1993	26.23333	24.30833	14.2625
KTTD	1985	2	91	15	2/2/1985	27.48333	24.40833	14.3625
KTTD	1985	2	53	15	2/3/1985	24.40833	24.40833	14.3625
KTTD	1985	2	86	15	2/4/1985	26.99167	24.40833	14.3625
KTTD	1993	11	67	16	11/23/1993	25.85417	24.47083	14.425
KTTD	1993	11	56	16	11/24/1993	24.47083	24.47083	14.425
KTTD	1993	11	70	16	11/25/1993	26.00417	24.47083	14.425
KTTD	1995	2	59	17	2/12/1995	24.79583	24.79583	14.75
KTTD	1995	2	60	17	2/13/1995	24.8125	24.79583	14.75
KTTD	2017	1	69	18	1/5/2017	25.87917	25.08333	15.0375
KTTD	2017	1	62	18	1/6/2017	25.08333	25.08333	15.0375
KTTD	2017	1	66	18	1/7/2017	25.81667	25.08333	15.0375
KTTD	1997	1	68	19	1/15/1997	25.8625	25.8625	15.81667
KTTD	2005	1	75	20	1/15/2005	26.6	26.6	16.55417
KTTD	2011	2	80	21	2/25/2011	26.825	26.825	16.77917
KTTD	2006	2	82	22	2/17/2006	26.9	26.9	16.85417
KTTD	2007	1	87	23	1/12/2007	27.125	26.9	16.85417
KTTD	2007	1	83	23	1/13/2007	26.9	26.9	16.85417
KTTD	2007	1	85	23	1/14/2007	26.975	26.9	16.85417
KTTD	2007	1	92	23	1/15/2007	27.5	26.9	16.85417
KTTD	2007	1	89	23	1/16/2007	27.275	26.9	16.85417
KTTD	1990	2	88	24	2/13/1990	27.175	27.175	17.12917
KTTD	1985	12	94	25	12/26/1985	27.6125	27.6125	17.56667
KTTD	1993	2	96	26	2/16/1993	27.8125	27.8125	17.76667
KTTD	2005	12	99	27	12/15/2005	28.0625	28.0625	18.01667
KTTD	1989	3	100	28	3/2/1989	28.18333	28.18333	18.1375

SiteId	Year	Month	DayRank	EventRank	Gas_Day	TempGHA	MinEventTemp	MinTempDiff
KEUG	2013	12	50	1	12/4/2013	25.25	6.125	0
KEUG	2013	12	49	1	12/5/2013	25.025	6.125	0
KEUG	2013	12	36	1	12/6/2013	22.55	6.125	0
KEUG	2013	12	2	1	12/7/2013	7.625	6.125	0
KEUG	2013	12	1	1	12/8/2013	6.125	6.125	0
KEUG	2013	12	6	1	12/9/2013	13.55	6.125	0
KEUG	2013	12	14	1	12/10/2013	18.275	6.125	0
KEUG	2013	12	21	1	12/11/2013	19.025	6.125	0
KEUG	1990	12	28	2	12/19/1990	20.96667	11.175	5.05
KEUG	1990	12	4	2	12/20/1990	11.69583	11.175	5.05
KEUG	1990	12	3	2	12/21/1990	11.175	11.175	5.05
KEUG	1990	12	12	2	12/22/1990	17.43333	11.175	5.05
KEUG	1990	12	8	2	12/23/1990	13.97083	11.175	5.05
KEUG	1990	12	25	2	12/24/1990	20.3375	11.175	5.05
KEUG	1990	12	100	2	12/28/1990	28.37917	11.175	5.05
KEUG	1990	12	16	2	12/29/1990	18.46667	11.175	5.05
KEUG	1990	12	54	2	12/30/1990	25.80833	11.175	5.05
KEUG	1989	2	13	3	2/2/1989	17.875	12.09167	5.966666
KEUG	1989	2	5	3	2/3/1989	12.09167	12.09167	5.966666
KEUG	1989	2	7	3	2/4/1989	13.75417	12.09167	5.966666
KEUG	1989	2	15	3	2/5/1989	18.35833	12.09167	5.966666
KEUG	1989	2	24	3	2/6/1989	19.62083	12.09167	5.966666
KEUG	1989	2	19	3	2/7/1989	18.84583	12.09167	5.966666
KEUG	1989	2	46	3	2/8/1989	24.575	12.09167	5.966666
KEUG	2008	12	27	4	12/15/2008	20.75	17	10.875
KEUG	2008	12	9	4	12/16/2008	17	17	10.875
KEUG	2009	12	29	5	12/7/2009	21.2375	17.075	10.95
KEUG	2009	12	11	5	12/8/2009	17.3	17.075	10.95
KEUG	2009	12	10	5	12/9/2009	17.075	17.075	10.95
KEUG	2009	12	20	5	12/10/2009	18.95	17.075	10.95
KEUG	2009	12	84	5	12/11/2009	27.725	17.075	10.95
KEUG	1998	12	22	6	12/20/1998	19.05417	18.475	12.35
KEUG	1998	12	17	6	12/21/1998	18.475	18.475	12.35
KEUG	1998	12	18	6	12/22/1998	18.68333	18.475	12.35
KEUG	1998	12	43	6	12/23/1998	24.40417	18.475	12.35
KEUG	1993	1	26	7	1/9/1993	20.45	19.42083	13.29583
KEUG	1993	1	23	7	1/10/1993	19.42083	19.42083	13.29583
KEUG	1993	1	58	7	1/11/1993	26.21667	19.42083	13.29583
KEUG	1993	1	40	7	1/12/1993	24.19583	19.42083	13.29583
KEUG	1985	11	93	8	11/22/1985	28.05417	21.50417	15.37917
KEUG	1985	11	30	8	11/23/1985	21.50417	21.50417	15.37917
KEUG	1985	11	38	8	11/24/1985	23.65833	21.50417	15.37917
KEUG	1985	11	59	8	11/28/1985	26.29167	21.50417	15.37917
KEUG	1985	11	31	8	11/29/1985	21.77083	21.50417	15.37917
KEUG	1985	11	45	8	11/30/1985	24.5125	21.50417	15.37917
KEUG	1985	12	34	8	12/1/1985	22.35417	21.50417	15.37917
KEUG	2017	1	53	9	1/4/2017	25.62917	22.03333	15.90833
KEUG	2017	1	32	9	1/5/2017	22.03333	22.03333	15.90833
KEUG	2017	1	85	9	1/6/2017	27.72917	22.03333	15.90833
KEUG	2017	1	89	9	1/7/2017	27.89583	22.03333	15.90833
KEUG	2014	2	98	10	2/5/2014	28.25	22.1	15.975

KEUG	2014	2	33	10	2/6/2014	22.1	22.1	15.975
KEUG	2014	2	56	10	2/7/2014	25.85	22.1	15.975
KEUG	2004	1	35	11	1/5/2004	22.4	22.4	16.275
KEUG	2004	1	97	11	1/6/2004	28.175	22.4	16.275
KEUG	1993	11	57	12	11/23/1993	26.12917	23.325	17.2
KEUG	1993	11	37	12	11/24/1993	23.325	23.325	17.2
KEUG	1993	11	47	12	11/25/1993	24.71667	23.325	17.2
KEUG	2007	1	39	13	1/12/2007	23.675	23.675	17.55
KEUG	2007	1	63	13	1/13/2007	26.525	23.675	17.55
KEUG	2007	1	55	13	1/14/2007	25.85	23.675	17.55
KEUG	2007	1	67	13	1/15/2007	26.75	23.675	17.55
KEUG	1996	1	44	14	1/30/1996	24.46667	24.23333	18.10833
KEUG	1996	1	48	14	1/31/1996	24.85	24.23333	18.10833
KEUG	1996	2	42	14	2/1/1996	24.32917	24.23333	18.10833
KEUG	1996	2	41	14	2/2/1996	24.23333	24.23333	18.10833
KEUG	1996	2	77	14	2/3/1996	27.21667	24.23333	18.10833
KEUG	2005	12	60	15	12/15/2005	26.3	25.4	19.275
KEUG	2005	12	51	15	12/16/2005	25.4	25.4	19.275
KEUG	2016	12	52	16	12/16/2016	25.475	25.475	19.35
KEUG	2017	1	70	17	1/13/2017	26.88333	26.40417	20.27917
KEUG	2017	1	61	17	1/14/2017	26.40417	26.40417	20.27917
KEUG	1985	12	95	18	12/25/1985	28.0875	26.49583	20.37083
KEUG	1985	12	62	18	12/26/1985	26.49583	26.49583	20.37083
KEUG	1985	12	65	18	12/27/1985	26.66667	26.49583	20.37083
KEUG	2008	1	74	19	1/23/2008	26.975	26.6	20.475
KEUG	2008	1	64	19	1/24/2008	26.6	26.6	20.475
KEUG	1985	12	66	20	12/18/1985	26.70833	26.70833	20.58333
KEUG	1985	12	78	20	12/19/1985	27.275	26.70833	20.58333
KEUG	1985	12	69	20	12/20/1985	26.80417	26.70833	20.58333
KEUG	1987	1	68	21	1/8/1987	26.78333	26.78333	20.65833
KEUG	1993	1	71	22	1/17/1993	26.8875	26.8875	20.7625
KEUG	1985	2	72	23	2/3/1985	26.89167	26.89167	20.76667
KEUG	1985	2	88	23	2/4/1985	27.81667	26.89167	20.76667
KEUG	2014	12	80	24	12/30/2014	27.35	26.9	20.775
KEUG	2014	12	73	24	12/31/2014	26.9	26.9	20.775
KEUG	1991	1	75	25	1/4/1991	27.11667	27.11667	20.99167
KEUG	1991	1	76	25	1/5/1991	27.12917	27.11667	20.99167
KEUG	2011	2	79	26	2/25/2011	27.275	27.275	21.15
KEUG	1995	2	81	27	2/13/1995	27.45833	27.45833	21.33333
KEUG	1997	1	82	28	1/14/1997	27.48333	27.48333	21.35833
KEUG	2017	12	99	29	12/9/2017	28.29583	27.52917	21.40417
KEUG	2017	12	83	29	12/11/2017	27.52917	27.52917	21.40417
KEUG	2017	12	94	29	12/12/2017	28.0625	27.52917	21.40417
KEUG	1990	2	86	30	2/13/1990	27.8	27.8	21.675
KEUG	2013	1	87	31	1/2/2013	27.8	27.8	21.675
KEUG	2000	11	90	32	11/18/2000	28	28	21.875
KEUG	2015	11	91	33	11/29/2015	28.02917	28.02917	21.90417
KEUG	2016	1	92	34	1/2/2016	28.03333	28.03333	21.90833
KEUG	1987	1	96	35	1/16/1987	28.175	28.175	22.05

SiteId	Year	Month	DayRank	EventRank	Gas_Day	TempGHA	MinEventTemp	MinTempDiff
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KSLE	1989	2	5	1	2/2/1989	14.175	10.55	0
KSLE	1989	2	1	1	2/3/1989	10.55	10.55	0
KSLE	1989	2	3	1	2/4/1989	13.12083	10.55	0
KSLE	1989	2	17	1	2/5/1989	20.37083	10.55	0
KSLE	1989	2	36	1	2/6/1989	24	10.55	0
KSLE	1989	2	41	1	2/7/1989	25.00417	10.55	0
KSLE	1990	12	12	2	12/19/1990	19.52917	12.4	1.849999
KSLE	1990	12	2	2	12/20/1990	12.4	12.4	1.849999
KSLE	1990	12	4	2	12/21/1990	14.0625	12.4	1.849999
KSLE	1990	12	7	2	12/22/1990	16.9875	12.4	1.849999
KSLE	1990	12	6	2	12/23/1990	16.22917	12.4	1.849999
KSLE	1990	12	30	2	12/24/1990	23.12083	12.4	1.849999
KSLE	1990	12	48	2	12/28/1990	25.80417	12.4	1.849999
KSLE	1990	12	8	2	12/29/1990	16.99167	12.4	1.849999
KSLE	1990	12	89	2	12/30/1990	27.94167	12.4	1.849999
KSLE	2013	12	73	3	12/4/2013	27.4625	18.5	7.95
KSLE	2013	12	60	3	12/5/2013	26.375	18.5	7.95
KSLE	2013	12	58	3	12/6/2013	26.225	18.5	7.95
KSLE	2013	12	15	3	12/7/2013	19.925	18.5	7.95
KSLE	2013	12	9	3	12/8/2013	18.5	18.5	7.95
KSLE	2013	12	54	3	12/9/2013	26.075	18.5	7.95
KSLE	2013	12	61	3	12/10/2013	26.525	18.5	7.95
KSLE	2013	12	59	3	12/11/2013	26.225	18.5	7.95
KSLE	1998	12	83	4	12/19/1998	27.80833	18.8375	8.287499
KSLE	1998	12	10	4	12/20/1998	18.8375	18.8375	8.287499
KSLE	1998	12	14	4	12/21/1998	19.72917	18.8375	8.287499
KSLE	1998	12	21	4	12/22/1998	21.52917	18.8375	8.287499
KSLE	1998	12	38	4	12/23/1998	24.14583	18.8375	8.287499
KSLE	1985	11	39	5	11/22/1985	24.35833	19.15833	8.608333
KSLE	1985	11	11	5	11/23/1985	19.15833	19.15833	8.608333
KSLE	1985	11	13	5	11/24/1985	19.66667	19.15833	8.608333
KSLE	1985	11	33	5	11/28/1985	23.61667	19.15833	8.608333
KSLE	1985	11	23	5	11/29/1985	22.14583	19.15833	8.608333
KSLE	1985	11	32	5	11/30/1985	23.43333	19.15833	8.608333
KSLE	1985	12	26	5	12/1/1985	22.56667	19.15833	8.608333
KSLE	2009	12	31	6	12/7/2009	23.3	20	9.45
KSLE	2009	12	20	6	12/8/2009	21.275	20	9.45
KSLE	2009	12	16	6	12/9/2009	20	20	9.45
KSLE	2009	12	19	6	12/10/2009	20.975	20	9.45
KSLE	2004	1	18	7	1/5/2004	20.7875	20.7875	10.2375
KSLE	2004	1	46	7	1/6/2004	25.7	20.7875	10.2375
KSLE	1993	1	51	8	1/9/1993	25.89583	21.54583	10.99583
KSLE	1993	1	22	8	1/10/1993	21.54583	21.54583	10.99583
KSLE	1993	1	74	8	1/11/1993	27.48333	21.54583	10.99583
KSLE	2008	12	25	9	12/15/2008	22.475	22.175	11.625
KSLE	2008	12	24	9	12/16/2008	22.175	22.175	11.625
KSLE	2014	2	71	10	2/5/2014	27.425	22.7	12.15
KSLE	2014	2	27	10	2/6/2014	22.7	22.7	12.15
KSLE	2014	2	47	10	2/7/2014	25.7375	22.7	12.15
KSLE	2016	12	81	11	12/15/2016	27.7875	23.0375	12.4875

KSLE	2016	12	28	11	12/16/2016	23.0375	23.0375	12.4875
KSLE	1996	1	29	12	1/30/1996	23.05	23.05	12.5
KSLE	1996	1	37	12	1/31/1996	24.025	23.05	12.5
KSLE	1996	2	35	12	2/1/1996	23.7125	23.05	12.5
KSLE	1996	2	34	12	2/2/1996	23.6625	23.05	12.5
KSLE	1996	2	57	12	2/3/1996	26.20833	23.05	12.5
KSLE	2017	1	40	13	1/5/2017	24.92917	24.92917	14.37917
KSLE	2017	1	65	13	1/6/2017	26.90833	24.92917	14.37917
KSLE	2017	1	82	13	1/7/2017	27.7875	24.92917	14.37917
KSLE	2007	1	42	14	1/12/2007	25.325	25.325	14.775
KSLE	2007	1	67	14	1/13/2007	27.05	25.325	14.775
KSLE	2007	1	68	14	1/14/2007	27.05	25.325	14.775
KSLE	2007	1	96	14	1/15/2007	28.175	25.325	14.775
KSLE	2017	1	75	15	1/12/2017	27.55833	25.58333	15.03333
KSLE	2017	1	43	15	1/13/2017	25.58333	25.58333	15.03333
KSLE	2017	1	55	15	1/14/2017	26.1	25.58333	15.03333
KSLE	2017	1	79	15	1/15/2017	27.70833	25.58333	15.03333
KSLE	1985	2	44	16	2/3/1985	25.60417	25.60417	15.05417
KSLE	1985	2	84	16	2/4/1985	27.8125	25.60417	15.05417
KSLE	1985	12	76	17	12/25/1985	27.61667	25.64167	15.09167
KSLE	1985	12	49	17	12/26/1985	25.8125	25.64167	15.09167
KSLE	1985	12	45	17	12/27/1985	25.64167	25.64167	15.09167
KSLE	1985	12	78	17	12/29/1985	27.69583	25.64167	15.09167
KSLE	2010	11	50	18	11/23/2010	25.85	25.85	15.3
KSLE	1995	2	52	19	2/13/1995	25.89583	25.89583	15.34583
KSLE	2005	12	62	20	12/15/2005	26.75	25.925	15.375
KSLE	2005	12	53	20	12/16/2005	25.925	25.925	15.375
KSLE	2008	12	56	21	12/22/2008	26.15	26.15	15.6
KSLE	1985	12	87	22	12/19/1985	27.85417	26.85417	16.30416
KSLE	1985	12	63	22	12/20/1985	26.85417	26.85417	16.30416
KSLE	1984	12	64	23	12/31/1984	26.87143	26.87143	16.32143
KSLE	1991	1	69	24	1/4/1991	27.1875	27.1875	16.6375
KSLE	1987	1	70	25	1/8/1987	27.31667	27.31667	16.76667
KSLE	2013	1	93	26	1/11/2013	28.025	27.45833	16.90833
KSLE	2013	1	90	26	1/12/2013	27.95	27.45833	16.90833
KSLE	2013	1	72	26	1/13/2013	27.45833	27.45833	16.90833
KSLE	2011	2	77	27	2/25/2011	27.65	27.65	17.1
KSLE	1987	1	80	28	1/16/1987	27.77917	27.77917	17.22917
KSLE	1985	12	85	29	12/11/1985	27.8375	27.8375	17.2875
KSLE	1985	12	92	29	12/12/1985	27.96667	27.8375	17.2875
KSLE	1985	12	88	29	12/13/1985	27.86667	27.8375	17.2875
KSLE	1997	1	86	30	1/14/1997	27.84583	27.84583	17.29583
KSLE	1993	11	91	31	11/23/1993	27.95833	27.95833	17.40833
KSLE	1993	11	95	31	11/24/1993	28.15	27.95833	17.40833
KSLE	2006	2	94	32	2/17/2006	28.1	28.1	17.55
KSLE	1990	2	97	33	2/13/1990	28.2125	28.2125	17.6625
KSLE	2006	12	98	34	12/17/2006	28.475	28.475	17.925
KSLE	2008	1	99	35	1/23/2008	28.55	28.55	18
KSLE	1987	12	100	36	12/25/1987	28.55833	28.55833	18.00833