Pacific Gas and Electric Company (PG&E) is working together with cities, counties and communities across our service area to review the area above and around the natural gas transmission pipelines for items that could pose a safety concern. We are providing the following information to address questions PG&E received from Lafayette community members regarding this gas safety work. For more information, please contact PG&E local outreach specialist Tom Nadolski at 1-925-348-1135 or by email at tom.nadolski@pge.com.

PG&E's Gas Safety Work in Lafayette

Nothing is more important to us than the safety of our customers and communities. PG&E has a comprehensive inspection and monitoring program to ensure the safety of its natural gas transmission pipeline system. PG&E regularly conducts patrols, leak surveys, and cathodic protection (corrosion protection) system inspections for its natural gas pipelines. If any issues are identified as a risk to public safety, we take steps right away to address them.

PG&E is also working with the Lafayette community to look at the area above and around the natural gas transmission pipeline for items like trees, brush and structures that could delay safety crews from accessing the pipeline in an emergency or for critical maintenance work. When located too close to the pipeline, tree roots can also cause damage to the protective coating of the pipe, exposing it to corrosion and leaks. By working together to make sure these items are located at a safe distance, we can help ensure the pipelines serving the Lafayette community continue to provide safe and reliable gas service for years to come.

Given the community's interest and at the request of the city, PG&E has prepared responses to community questions submitted to the City and published in the July 9 staff report.

Questions and Answers
<u>Exhibit A</u>

Q1.1: We need dialog focused on goals, alternatives, and informed compromise. To be fair distributing gas is difficult, dangerous, and expensive. Compromises must be made. So let's be clear about what we're trying to achieve, then compare and prioritize options. And let's be courageous enough to ask meaningful questions, including "What would it take to upgrade all old pipes to new, safer ones?" Maybe it would take 50 years and bankrupt us all, I don't know, but if that's the most effective solution, let's describe what it would take, so—if nothing else—we understand why compromises are required. I assume replacement is the benchmark, and would be done in stages. If that's the right thing to do, I would support the decision even through the inconvenience of construction.

The pipelines serving the Lafayette community have been extensively tested and evaluated as safe. We have taken a look at engineering and constructing a pipeline at another location along the Lafayette-Moraga Regional Trail and found that the impacts to the community and the environment are just too great, particularly when the pipelines are operating safely in its current location. Replacing a limited number of trees is the least invasive approach to prevent damage and ensure immediate access to the gas transmission line in an emergency or for important maintenance work. Building new pipelines at another location is likely to involve the removal of vegetation, along with a series of other potential environmental and community impacts, and would take many years to complete.

For example, the current pipeline replacement job along St. Mary's Road took several years to plan due to complex geotechnical risks that had to be evaluated against different pipeline routing options, and then detailed design could begin once a route was selected. The detailed design was also very complex due to the length of the replacement (just over one mile), the numerous existing underground utilities in the roadway, the narrow construction corridor, and traffic control considerations to limit impact to the schools and residents.

In the Lamorinda area, there are roughly 17 miles of gas transmission pipelines. We are unable to quantify the timeline for this amount of replacement without looking at each section of pipeline specifically and analyzing replacement alternatives, but it is safe to say it would take several years of work at a minimum and would limit the ability to perform other needed work on potentially higher risk pipelines throughout the PG&E gas transmission pipeline network.

Please note with regular maintenance and inspection, there is no set lifespan or limit to how long a pipeline may safely remain in operation. The U.S. Department of Transportation (DOT)'s pipeline safety division, for example, says that the life of a pipeline is virtually endless if is constructed and maintained correctly. That's why we are regularly inspecting and testing the pipes, and if any issues are identified through these efforts, we take immediate steps to address them.

Q1.2: WHAT are we trying to achieve (and avoid)?
Presumably the goals are to minimize risk, disruption, and cost, while maximizing service quality. From a risk-management perspective, what are the most important failure modes to avoid? What are the key performance measures to maximize?

PG&E is working every day to improve the safety and reliability of its natural gas system. This includes looking at every part of its pipelines from valves to distribution lines to identify and address any potential safety concerns. Over the last seven years, PG&E has implemented important changes in its gas safety operations, including enhancing the testing and inspecting of its gas transmission pipeline system and ensuring multiple layers of protection are in place to keep customers safe. This includes:

- Leak Surveys
- Integrity Assessments and Strength Testing
- Pipeline Patrols
- Corrosion Protection and Mitigation
- Valve Automation and Replacement

Another key component of PG&E's gas safety efforts is the Community Pipeline Safety Initiative. This program reviews the area above and around the gas transmission pipeline to help ensure access for safety crews in an emergency or for important maintenance work. This will also help prevent damage to the pipe from tree roots and create a line-of-sight for the area above the pipeline to reduce third-party dig-ins.

Q1.3: WHAT are we trying to achieve (and avoid)?
The answer should be a list of attributes, quantified or at least weighted, and applied consistently. This forms the basis for a standardized scorecard to evaluate options. Group items to simplify however is helpful, e.g.:

a) Risk of sudden failures due to...
- Earthquake
- Digging
- Fire vehicle access...

b) Risk of gradual failures due to...
- Tree roots?
- Corrosion and/or component failure (Note: this can happen to any component of any system. In fairness, discussing this should not automatically imply corporate guilt any more than discussing auto accidents implies driver guilt).

c) Service quality
- Capacity for growth
- Service interruptions

If the St. Mary's area is sufficiently different from other areas, then segment and address them separately. Presumably PG&E already plans this way.

PG&E is required to confirm the integrity of its transmission pipelines pursuant to federal code. To prioritize pipeline projects, we conduct a risk assessment annually that takes into consideration historic and potential threats that could impact the safe operation of the pipeline. These can include corrosion, construction or manufacturing-related defects, third-party damage, incorrect operations and weather-related and outside forces, as well as potential impacts to nearby populations, the environment and reliability.

Risk is evaluated by a dynamic segment or section of pipeline, instead of by city or location. All factors mentioned above have the potential to impact overall pipeline safety on each pipeline section and are equally important to consider when evaluating risk on the system. Each section of pipeline in Lafayette has unique characteristics and geographic makeup and, therefore, there is no one single risk factor that stands apart from the others that can be applied holistically to all pipelines in the City of Lafayette.

The key performance metrics are determined and documented annually and include the following:

- Number of miles of pipeline inspected versus program requirements (which should be represented in the program schedule).
- Number of immediate repairs completed as a result of the integrity management inspection program.
- Number of scheduled repairs completed as a result of the integrity management inspection program.
- Number of leaks, failures, and incidents, classified by cause.

PG&E continues to conduct regular patrols, leak surveys, and cathodic protection (corrosion protection) system inspections. Any issue identified as a threat to public safety is always addressed immediately. PG&E does not delay or defer work that is necessary for public safety.

Q1.4: HOW: Describe the options (i.e. solutions). How can they be combined?
Any realistic plan would include multiple actions, drawn from a menu of identified options. Especially, can we have a candid discussion about automated shut-off technologies? If we can't discuss shut-off details publicly because of security concerns, could we at least designate a committee to evaluate it? Could it buy us time while a new line is installed?

Mike, I see you've done recent fieldwork on this: thanks for that info and generally helping keep us informed. And kudos to PG&E for the progress already made on this initiative locally and state-wide. More to come, I'm sure.

Please see response above for information on how PG&E manages risk. As noted above, PG&E continually evaluates new data to make informed changes in risk assessment.

In regards to your question on automated shutoff valves, multiple layers of protection are essential to keeping the gas transmission pipelines and the people who live near them safe. That is why we are inspecting and testing our pipes, conducting leak surveys and upgrading pipes. Shut-off valves are another important component of our emergency response.

There are two types of automated shut-off valves recognized within the natural gas industry: Remote Control Valves (RCVs), which can be operated remotely from PG&E's 24/7 Gas Control Center, and Automatic Shutoff Valves (ASVs), which will close automatically as a result of rapidly falling pipeline pressures and/or increased flow at the valve location and can also be operated remotely from PG&E's Gas Control Center.

PG&E uses a decision tree approved by the California Public Utilities Commission (CPUC) to identify appropriate locations for valve automation throughout its gas system. Please refer to Figure 4-3, “Decision Tree – Population Density” on Page 4-11 of the attached document “*Valve Automation Program*” for additional information on PG&E’s Valve Automation Program. It was initially proposed to and approved by the CPUC in PG&E’s Pipeline Safety Enhancement Plan (PSEP) and re-approved in PG&E’s 2015 Gas Transmission and Storage rate case. The decision tree takes into consideration the proximity of populations and potential seismic events, among other factors.

In addition, PG&E’s Transmission Integrity Management Program procedures reference PG&E’s Valve Automation Program, which was incorporated into the Pipeline Safety Enhancement Program. These programs provide the decision-making process, including risk-based methodology, for placing ASVs and RCVs on transmission lines to comply with 49 Code of Federal Regulations (CFR) Part 192.935.
As indicated in the response above, the pipelines serving the Lafayette community have been extensively tested and evaluated as safe. We have taken a look at engineering and constructing a pipeline at another location along the Lafayette-Moraga Regional Trail and found that the impacts to the community and the environment are just too great, particularly when the pipelines are operating safely in their current location. Replacing a limited number of trees is the least invasive approach to prevent damage and ensure immediate access to the gas transmission line in an emergency or for important maintenance work. Building new pipelines at another location is likely to involve the removal of vegetation, along with a series of other potential environmental and community impacts, and would take many years to complete.

Please note with regular maintenance and inspection, there is no set lifespan or limit to how long a pipeline may safely remain in operation. The U.S. Department of Transportation’s pipeline safety division, for example, says that the life of a pipeline is virtually endless if is constructed and maintained correctly. That’s why we are regularly inspecting and testing the pipes, and if any issues are identified through these efforts, we take immediate steps to address them.

Q1.5: COMPARE options.
Propose and contrast recommended solutions. All assessments will be imperfect, but hey, that’s life. Describe benefits, costs, timelines, and other drawbacks of each proposal, to the degree those factors are known or can be estimated. Having a clear rationale makes it easier to accommodate input and create fast(er), (more) durable decisions, including budgets and implementation plans.

Although I enjoy our local landscape as much as the next person, I also appreciate not having a catastrophic event in my neighborhood. Let’s see to what degree we can achieve both. Again acknowledging I’m no expert, but it seems to me that cutting down any number of trees does not address all the safety issues. Maybe it’s prudent to be MORE aggressive than the current plan, possibly with regards to trees (but I admit hopefully not), probably with regards to other corrections.

Technical projects are hard. Public policy is harder. But transparency helps build and maintain support. Lafayette is probably better-suited to this approach than the average community, so let’s build a plan, with the opportunity for good faith to be shown as justified.

This approach works best if stakeholders are willing to wrap their heads around multiple imperfect options: I challenge us all to attempt that as best we can. Raise objections? Certainly, but I would not want to torpedo a well-thought-out (and well-communicated) plan—when we see one—on the basis of a single issue. Nor would I want to see us miss the big picture.

We understand how important trees are to the community. In Lafayette, our gas safety experts originally identified over 1,000 trees in close proximity to the gas pipeline. In order to be sure we are only removing those trees that pose a safety concern, a team of safety and pipeline integrity professionals, engineers, arborists, and environmental experts conducted an in-depth review of each tree near the pipeline. The review examined more than a dozen criteria related to the tree, the pipeline and the surrounding environment, such as: distance from tree to pipe, tree species and expected size at full maturity, depth of the pipeline, and ability to access the pipeline in an emergency.

What we found based on this review is that around 800 trees are far enough away from the pipeline that PG&E can manage the potential safety risk through ongoing monitoring, as part of our regular pipeline inspections and patrols. There are approximately 200 trees, however, that are located too close to the gas pipeline and pose a safety concern. These trees need to be removed and replaced away from the pipeline to help ensure the ongoing safety of the gas pipeline and the community.

We have looked at other alternatives, including consulting with certified arborists about the potential use of root barriers. Root barriers are guides surrounding tree roots to direct them downward, away from shallow infrastructure such as sidewalks. Please note roots directed downward become more likely to encounter and interact with gas transmission pipelines, causing damage to the pipe's external coating leading to corrosion and leaks.

In addition, while we understand some community members' interest in re-routing the pipelines, these lines are a critical component of the natural gas system serving nearly 11,000 customers in the local community, and thousands more in the Lamorinda area, including St. Mary's College and approximately 35 other schools, around 1,000 local businesses, and many more high-priority facilities like daycares and churches. The lines have been extensively tested and evaluated as operating safely in their current location. Building a new pipeline would involve the removal of vegetation, along with a series of other potential environmental and community impacts. Keeping these pipelines where they are and maintaining them going forward is the right thing to do and least impactful to the community and the environment.

Q2.1: I recently did a bike ride along the Lafayette- Moraga trail from the corner of South Lucille to the Moraga Commons. I was told by contractors (about 1-1/2 years ago) that they were installing automatic shut- off valves at the corner of South Lucille and St Mary's road. I noted that there are two vaults plus a solar panel. The id on the electrical panel says SCADA, which provides 24/7 data to your pipeline center in San Ramon. Can you please confirm that these are either automatic valves and/or remotely operated valves that can rapidly close in the event of a pressure drop due to leak or rupture.

In 2014, PG&E installed a supervisory control and data acquisition (SCADA) unit, which provides system visibility to PG&E's Gas Control center. Currently, there are no automatic or remotely controlled valves at South Lucille Lane and St. Mary's Road in Lafayette.

Q2.2 and 2.3: I also found two more locations with two relatively new underground vaults. One is located across St Mary road from the St Mary's college soccer/rugby field. The other one is located at 1413 Moraga Rd near condo units, reasonably close to the Moraga Commons Park, and near the southern terminus of the 12-inch gas line from Olympic Blvd. Can you also confirm if these are automatic/remotely activated gas valves? The St Mary's valves are about 1.4 miles from South Lucille and the Moraga Rd valves are about 0.7 miles from the St Mary's college valves. The gas line from South Lucille to St Mary's College travels through a much more rural and low populated area than Lafayette. The segment from the college to the Moraga commons has populations similar to or slightly less than Lafayette, in the area north of South Lucille to the terminus at Olympic Blvd.

I also rode north on the bike trail until the gas line changed direction near Las Huertas Rd, ultimately reaching Olympic Blvd and Reliez Station Road. It appears there are additional automatic valves at the South East Corner of the intersection. But I did not see any other vaults along the line north of South Lucille.

There are currently no automated valves within the City of Lafayette; however, PG&E has an automated valve project planned for 2021 on Line 191-1 near the intersection of Olympic Oaks Drive and Olympic Boulevard. In addition, the following are the locations of the mainline valves that can be used to isolate the pipeline in Lafayette:

- There are mainline valves along Line 191-1 located near the Olympic Boulevard and Boulevard Way intersection in Walnut Creek and also near Briones Park in Lafayette; in the event of an emergency, these valves can be used to isolate sections of Line 191-1 in Lafayette. Please note, shutting in the mainline valve on Line 191-1 near the intersection of Olympic Boulevard and Boulevard Way will also isolate sections of DFM 3001-01 and DFM 3002-01 in Lafayette.
- There are mainline valves along Line 191A located near Briones Park in Lafayette; in the event of an emergency, these valves can be used to isolate sections of Line 191A in Lafayette.
- There are mainline valves along Line 191B located near Briones Park in Lafayette; in the event of an emergency, these valves can be used to isolate sections of Line 191B in Lafayette.
- There is a mainline valve on DFM 3001-01 near the Olympic Oaks Drive and Olympic Boulevard intersection in Lafayette; in the event of an emergency, this valve can be used to isolate sections of DFM 3001-01 in Lafayette.
- There is a mainline valve on DFM 3002-01 near the Mount Diablo Boulevard and Oak Hill Road intersection in Lafayette; in the event of an emergency, this valve can be used to isolate sections of DFM 3002-01 in Lafayette.

Q2.4: Assuming these are automated valves, can PG&E define the criteria to install valves at these locations? And why (apparently) they did not install valves north of South Lucille, in the more populated areas of this pipeline?

PG&E uses a decision tree approved by the CPUC to identify appropriate locations for valve automation throughout its gas system. Please refer to Figure 4-3, “Decision Tree – Population Density” on Page 4-11 of the attachment document *“Valve Automation Program”* for additional information on PG&E’s Valve Automation Program. It was initially proposed to and approved by the CPUC in PG&E’s Pipeline Safety Enhancement Plan (PSEP) and re-approved in PG&E’s 2015 Gas Transmission and Storage rate case. The decision tree takes into consideration the proximity of populations and potential seismic events, among other factors.

In addition, PG&E’s Transmission Integrity Management Program procedures reference PG&E’s Valve Automation Program, which was incorporated into the Pipeline Safety Enhancement Plan. These programs provide the decision-making process, including risk-based methodology, for placing ASVs and RCVs on transmission lines to comply with 49 CFR Part 192.935.
PG&E will install manual valves on the pipeline near South Lucille Lane in Lafayette, as this location does not meet the criteria for valve automation.

Q2.5: Can PG&E provide a complete list of automatic/remotely controlled valves as well as manually activated valves in Lafayette and the criteria used to locate the valves?

PG&E’s valve automation program and decision tree for where to install automated valves was developed with input from several industry and fire (first responder) experts, and has been approved by the CPUC. There are currently no automated valves within the City of Lafayette; however, PG&E has an automated valve project planned for 2021 on Line 191-1 near the intersection of Olympic Oaks Drive and Olympic Boulevard. In addition, the following are the locations of the mainline valves that can be used to isolate the pipeline in Lafayette:

- There are mainline valves along Line 191-1 located near the Olympic Boulevard and Boulevard Way intersection in Walnut Creek and also near Briones Park in Lafayette; in the event of an emergency, these valves can be used to isolate sections of Line 191-1 in Lafayette. Please note, shutting in the mainline valve on Line 191-1 near the intersection of Olympic Boulevard and Boulevard Way will also isolate sections of DFM 3001-01 and DFM 3002-01 in Lafayette.
- There are mainline valves along Line 191A located near Briones Park in Lafayette; in the event of an emergency, these valves can be used to isolate sections of Line 191A in Lafayette.
- There are mainline valves along Line 191B located near Briones Park in Lafayette; in the event of an emergency, these valves can be used to isolate sections of Line 191B in Lafayette.

- There is a mainline valve on DFM 3001-01 near the Olympic Oaks Drive and Olympic Boulevard intersection in Lafayette; in the event of an emergency, this valve can be used to isolate sections of DFM 3001-01 in Lafayette.
- There is a mainline valve on DFM 3002-01 near the Mount Diablo Boulevard and Oak Hill Road intersection in Lafayette; in the event of an emergency, this valve can be used to isolate sections of DFM 3002-01 in Lafayette.

Q2.6: PG&E states that the selected trees must be cut to provide rapid access to a gas line leak/rupture, resulting in increased risk to the public if the trees are not cut. However, first responders have stated that they will not enter an active gas rupture zone until the gas leak has been stopped, presumably by use of manual and/or automatic shut-off valves. So it is not logical to argue that cutting trees along the pipeline prior to a leak will increase the safety to the public. Working manual valves or automatic valves need to be activated first, before any efforts by PG&E crews and first responders can enter the rupture area. What am I missing in your argument for cutting the trees for access?

As a utility provider, it is our responsibility to address any potential risk we identify to keep our customers and communities safe. Multiple layers of protection are essential to keeping the gas transmission pipelines and the people who live near them safe. That's why we are inspecting and testing our pipes, conducting leak surveys and upgrading pipes. Shut-off valves are another important component of our emergency response efforts, but they are a reactive response. When it comes to safety, we also need to be proactive. Every emergency situation is different, and working together with local first responders, PG&E crews must assess each individual situation and make specific decisions about how best to make the situation safe and protect our customers. We cannot foresee what first responders – whether our safety crews, fire, police, or ambulance – will need in the event of an emergency, which is why it is critical that the area above the pipeline is clear for access.

Q2.7: PG&E has also suggested that tree roots can induce pipeline corrosion, potentially leading to a material rupture/break in the line. Doe PG&E have any real evidence (not just expert opinion) that this has occurred in their entire system in the past? Corrosion is a serious issue from both internal and external sources. PG&E has committed to the highest pipeline safety standards in the US, and as such must have a very thorough corrosion mitigation (cathodic protection), monitoring and line replacement. If induced corrosion is a real (as opposed to a theoretical risk), I would think that PG&E's corrosion control programs would identify the tree root issue along with all potential sources of corrosion.

PG&E has not experienced a transmission pipeline incident directly caused by tree and root interaction; however, the studies PG&E commissioned found that at approximately 75% of the 53 sites examined, and at 90% of sites with trees within five feet of the pipeline, tree roots were found to have caused damage to the pipe's external coating. When the external coating is damaged, it can lead to corrosion and leaks. The studies also found that tree roots can wrap around a pipe and cause stress to it, especially during the windstorms that uproot trees and potentially pipes.

In addition, below are instances where PG&E has documented tree roots causing damage to its gas transmission pipelines:

Pipeline	Location	Date	Description of Damage
L-137A	Eureka	September 2005	Leak
L-142S	Kern	2013	Coating Damage
DFM 1816-01	Santa Cruz	2013	Coating Damage
DFM 1816-01	Aptos	Spring 2014	Pipe Damage (Dent)
L-021E	Healdsburg	October 2014	Coating Damage
DFM 1042-01	Fall River Mills	February 2015	Coating Damage

L-196A	Rio Vista	September 2015	Coating Damage
L-177A	North Valley	October 2015	Coating Damage
L-021D	Sonoma	March 2016	Pipe Damage (Dent)
L-177B	Chico	May 2016	Coating Damage
L-021E	Humboldt	May 2016	Coating Damage

Please note that while PG&E records indicate that these 11 instances of damage have occurred on PG&E's gas transmission pipelines due to vegetation, the list of instances was not exhaustive and would require extensive additional review to complete.

Sample photos of tree roots interacting with pipes can be found in the publicly available report from the United States Department of Transportation's Pipelines and Informed Planning Alliance: http://www.ingaa.org/file.aspx?id=11683. Please see Appendix C of the report for photos of tree roots damaging the external coating of gas pipelines in locations where trees were in the area above the pipe.

In order to help ensure the gas transmission pipelines continue to operate safely, the Community Pipeline Safety Initiative was launched to address trees and structures located too close to the pipeline. When items are located too close, they can delay access for safety crews in an emergency or for important maintenance work.

Q2.8: If such tree roots are a bona-fide risk to the line, has PG&E performed any quantitative risk studies which show the increase in risk of rupture or ignition per/year/mile of lines with tree roots versus lines with no tree roots? And has PG&E conducted a quantitative risk study on the current pipeline system in Lafayette? What is the annual probability of a major ignition in the city? And what are the major contributors to this risk?

In summary, PG&E has done a dis-service to the residents of Lafayette by offering only one proposed solution to risk reduction-the cutting of trees along the pipeline route. PG&E needs to offer alternate solutions which would accomplish the objective we all strive for and that is minimizing the risk of another San Bruno situation. I would like to see your proposal for installing automatic/remotely activated valves vs cutting trees. Or rerouting sections of the gas line in certain high-risk areas. Or some other imaginative solution.

PG&E has not performed any specific quantitative risk studies that show the increase in risk of ruptured lines with tree roots versus lines with no tree roots; however, it does calculate quantitative risk for all its transmission pipelines. Tree root interaction is one component in the model, which contains hundreds of data elements.

PG&E calculates the potential for ruptures per mile per year for every transmission pipeline section in its service area, including those in Lafayette. PG&E manages the integrity of its transmission pipelines pursuant to federal code. This includes conducting a risk assessment annually that takes into consideration historic and potential threats that could impact the safe operation of the pipeline. These can include corrosion, construction or manufacturing-related defects, third-party damage, incorrect operations and weather-related and outside forces, as well as potential impacts to nearby populations, the environment and reliability. PG&E considers tree roots a risk of weather related and outside forces, as well as a contributor for corrosion susceptibility risk.

Risk is evaluated by a dynamic segment or section of pipeline, instead of by city or location. All factors mentioned above have the potential to impact overall pipeline safety on each pipeline section and are equally important to consider when evaluating risk on the system. Each section of pipeline in Lafayette has unique characteristics and geographic makeup and, therefore, there is no one single risk factor that stands apart from the others that can be applied holistically to all pipelines in the City of Lafayette.

Q3: PG&E has been in the business of transmitting and distributing essential gas and electricity services to our homes and businesses for over a hundred years. They are the experts in this field. They are not without fault and they have accepted accountability for their mistakes and have worked in earnest to address and resolve these faults. PG&E is not a corporate monopoly, rather it is a coalition of expertly trained and dedicated employees - people like you and me who live in our Lafayette neighborhoods. What PG&E seeks to do is for our own safety. They are condemned for their failure to have adequately trimmed tree branches that fell in high winds and sparked the Butte fires a few years ago and were rightfully condemned for their failure to replace ancient gas supply lines whose failure resulted in the unforgivable tragedy of San Bruno. But they stepped up and took responsibility for those epic failures and every single employee of PG&E dedicated themselves to PG&E's mission to never allow a repeat of these failures. This mission requires the trimming and/or removal of drought-stricken trees and trees that encroach upon and compromise transmission and distribution lines so we don't have a repeat of Butte or San Bruno. Upgrading the line along St. Mary's road may be an inconvenience but it is necessary to insure our safety and to protect against another San Bruno-like tragedy. So you can't have it both ways - you can't condemn PG&E for their failures to keep us safe and also condemn them for cutting the trees and replacing their infrastructure in order to keep us safe.

I am not an employee of PG&E nor do I have any relatives employed by PG&E. I am simply a resident of Lafayette without a selfishly myopic view of PG&E's activity in Lafayette. We are all part of a much greater community that should remember and honor the victims of the San Bruno tragedy by supporting PG&E's safety improvement efforts spawned by this tragedy to insure a similar tragedy never occurs in Lafayette or anywhere else.

Q4: I noticed along Hidden Valley Road, Davey Tree Service, PG&E contractor, trimmed the trees above the power lines and did not remove the large pieces of wood. This has created a very large fire danger since this dead wood is along Highway 24.

The vegetation work on Hidden Valley Road in Lafayette is associated with an Enhanced Electric Vegetation Management (EEVM) project. The Enhanced Electric Vegetation Management (EEVM) Program, formerly known as Public Safety and Regulatory (PS&R), is a proactive strategy to reduce customer outages, ensure public safety, reduce the possibility of fire ignition when trees (whole or partial) fall into power lines, and improve customer satisfaction and reliability. Under EEVM, PG&E develops a plan to address high risk locations where vegetation-related power outages have occurred in the past. This work, among other things, is designed to reduce the likelihood of wildfires.

PG&E’s normal practice for an EEVM projects is to remove debris upon completion. PG&E’s contractor is still working in the area and the project has not been completed .PG&E’s contractor expects to remove the wood at this location in early August.

Q5: My name is Damon Pellegrini I live at 3233 sweet dr. I am a fire captain with San Ramon Valley Fire. The tree removal of our oldest residents is an attempt by PG&E to say they “did something” to prevent a natural gas disaster. My protocol as a firefighter is to isolate, deny entry and evacuation of residents. They want to remove our oldest residents to make it easier for them to inspect from the air. There is NO reason for this, simply the pipe needs to be replaced it was installed in the 50s-70s with steel. The new standard is plastic the moves with the shifting of the earth. That pipe needs to be moved to the center of the bike trail and away from the back fences of the affected neighborhoods. If the city council and PG&E really wanted to protect its citizens this is exactly what would happen. If I respond to this pipe being compromised my protocol from DOT requires me to create a safe zone 300 yards-1/2 mile, these are PG&E and federal guidelines. They simply don’t want to pay for what would keep us safe and the city received a fat payday for selling out to them. I am disappointed the city did not due it’s due diligence to study this problem. Damon Pellegrini

With regular maintenance and inspection, there is no set lifespan or limit to how long a pipeline may safely remain in operation. The U.S. Department of Transportation's pipeline safety division, for example, says that the life of a pipeline is virtually endless if is constructed and maintained correctly. That's why we are regularly inspecting and testing the pipes, and if any issues are identified through these efforts, we take immediate steps to address them.

PG&E's gas transmission pipelines, which are made of steel, are generally resistant to earthquake damage and are designed to be fully operational following earthquakes. In locations where there is believed to be a greater risk of pipeline failure from an earthquake, PG&E works to manage the risk of damage to the pipeline or replace the section of line with a design that is expected to perform well during an earthquake. PG&E performs engineering assessments to determine what, if any, additional mitigations may be required to help prevent the effects of a seismic event on pipelines where potential hazards exist. For instance, at certain locations, PG&E may install a pipe with an increased wall thickness or at a more favorable fault crossing angle. Please note Lafayette does not have active fault traces that require these measures to be implemented.

In regards to your questions related to pipeline relocation, we have taken a look at engineering and constructing a pipeline at another location along the Lafayette-Moraga Regional Trail and found that the impacts to the community and the environment are just too great, particularly when the pipeline is operating safely in its current location. Replacing a limited number of trees is the least invasive approach to prevent damage and ensure immediate access to the gas transmission line in an emergency or for important maintenance work. Building a new pipeline at another location is likely to involve the removal of vegetation, along with a series of other potential environmental and community impacts, and would take many years to complete.

Q6: Tree removal is not necessary for the maintenance of these lines this is a red herring by PG&E

Exhibit B

Q1: PG&E notes that planned pipeline projects in Lafayette, like vintage pipeline replacement and shallow pipeline burial, are subject to outcomes of PG&E's Gas Transmission & Storage Rate Case. How do outcomes of the rate case affect planned safety projects in Lafayette? To what extent do rate case outcomes affect prioritization and implementation of safety measures?

PG&E's Gas Investment Planning Department is responsible for the portfolio-level prioritization across all Gas Transmission and Storage projects and programs. On an annual basis, Investment Planning develops a multi-year investment plan that considers both risks and constraints – the objective is to invest in programs that address higher risks while considering execution constraints, such as resource availability, periods of high demand, permitting timeliness and cost. To ensure decisions are being made on a risk-informed basis, Investment Planning utilizes the company's risk-informed budget allocation (RIBA) process.

In establishing the investment plan, Investment Planning works with the subject matter expert (SME) for the programs or projects to determine the appropriate classification of the mitigation and evaluates the RIBA risk score. Classification of the project or program identifies the key drivers for the work, which are used during prioritization, along with the risk scores of each project or program. The classifications include:

- Mandatory
- Compliance
- Commitment
- Customer-Generated (Work at the Request of Others)
- Support
- Interdependent
- None

To develop the risk score, SMEs use available data, system information, and their expertise to determine the potential impact of a program or project on safety, environment, and reliability. This is compiled into the RIBA register to calculate a relative risk score for each mitigation. A RIBA score captures, on a relative basis, the safety, environment, and reliability risk that each project and program aims to mitigate. Investment decision meetings are held with Asset Family Owners who are accountable for making the investment recommendations that are ultimately documented for the Gas Operations Executive Review sessions, held by PG&E's senior executive leadership team.

The outcome of the Gas Transmission and Storage rate case could affect the pace at which PG&E completes work, including work in Lafayette. Maintaining the safety and reliability of our gas system is our top priority; as such, we will and often do spend more than our authorized revenue requirement as necessary.

Q2: What does PG&E perceive as the top safety risks in Lafayette? Please provide quantitative qualification for identification of those risks. How does PG&E prioritize address of these risks? What is PG&E doing to mitigate these risks?

PG&E is required to manage the integrity of its transmission pipelines pursuant to federal code. To prioritize pipeline projects, we use a risk assessment approach that takes into consideration historic and potential threats that could impact the safe operation of the pipeline. These can include corrosion, construction or manufacturing-related defects, third-party damage, incorrect operations and weather-related and outside forces, as well as potential impacts to nearby populations, the environment and reliability.

Risk is evaluated by a dynamic segment or section of pipeline, instead of by city or location. All factors mentioned above have the potential to impact overall pipeline safety on each pipeline section and are equally important to consider when evaluating risk on the system. Each section of pipeline in Lafayette has unique characteristics and geographic makeup and, therefore, there is no one single risk factor that stands apart from the others that can be applied holistically to all pipelines in the City of Lafayette.

PG&E continues to conduct regular patrols, leak surveys, and cathodic protection (corrosion protection) system inspections. Any issue identified as a threat to public safety is always addressed immediately. PG&E does not delay or defer work that is necessary for public safety.

Q3: In the 2019 Gas Transmission and Storage Rate Case papers for 2019, PG&E quantifies the risk of pipeline rupture causes on a scale of 0-1000. PG&E's own risk scoring attributes a red "severe risk" rating of 975 for a rupture caused by a third-party dig-in accident. In comparison, PG&E applies a risk score rating of 58 due to tree risk damage, and admits the occurrence is less than 1 in every 100 years, but PG&E artificially inflated it due to "uncertainty". Why was this number inflated due to uncertainty? If it wasn't inflated, what would the risk score be? (source: https://docs.wixstatic.com/ugd/de4240_66ca1375a327432a86e73c4efdf49796.pdf)

First, PG&E would like to clarify that the risk evaluation tool (RET) scores risk from a scale of 0 – 10,000. With respect to scoring risks, PG&E uses subject matter expertise, available internal and external data, historical industry and PG&E events, and system knowledge to determine the consequence impact and frequency scores. When determining the impact and frequency scores, the evaluation is based on the worst-case probable scenario. These scores are documented in the RET, which then calculates a relative risk score for each risk, referred to as “RET scores.”

The uncertainty regarding the impact of tree roots on the PG&E system made it prudent to increase the frequency score to Level 2. There are high risk trees that remain in cities where damage to a pipeline may present a public safety risk. The current impact to safety is that there could be a potential for multiple serious injuries to the public and to employees. Given the risk exposure, PG&E determined that a frequency of one event occurring between 30 and 100 years was appropriate for this risk.

Q4: Given the above, and given the magnitude of difference between the two (risk score of 58 vs 975), how does PG&E justify safety prioritization of time and resources (PG&E states $500M) towards tree removal over pipeline dig-in incident reduction in California and specifically Lafayette?

The Community Pipeline Safety Initiative and Damage Prevention programs are two separate important initiatives that address different threats to the public and the pipeline system. Both programs are vitally important to public safety within the City of Lafayette and throughout PG&E’s service area. The Community Pipeline Safety Initiative is a six-year, shareholder funded program that reviews the area above and around the natural gas transmission pipeline for items that could delay access for safety crews in an emergency or for important maintenance work. Since this work is shareholder funded, PG&E did not prioritize the Community Pipeline Safety Initiative against the remainder of the portfolio, funded through operating revenue. PG&E does not prioritize tree removal over dig-in incident reduction.

Please note that damage prevention is a long-established business practice that both complies with federal and state regulations and reduces risk to pipelines and the public from excavation activity. PG&E has been investing in its Damage Prevention program and is currently on track to meet top performance for third-party dig-in reductions by the end of 2018. The goal of the Community Pipeline Safety Initiative program includes: vegetation clearing, pipeline marker installation, and structure removal from the gas transmission system right-of-way. After the Community Pipeline Safety Initiative concludes, PG&E will continue to monitor and, when necessary, remove trees and structures. In addition, PG&E patrols its gas transmission pipelines at least quarterly to look for indications of construction activity and other factors affecting pipeline safety and operation.

Q5: In 2014, a house blew up in Carmel while a PG&E crew was working on a gas distribution line. Even though the crew had a valid USA ticket, PG&E had inaccurate pipeline records on file. Subsequently, the CPUC fined PG&E $26M for related record keeping violations and $11M for "dismal" emergency response to the incident. Thankfully nobody was hurt. With this in mind, we are concerned that PG&E reported 13 third-party dig-ins in Lafayette in 2016.
In more than half of the dig-ins, the excavator had a valid USA ticket, meaning they called 811. How did these valid tickets result in dig-in incidents? Who was at fault, and was PG&E mapping/record info correct in each instance? Please list all of the dig-in incidents, location, damage, and repair.

There were 13 third-party gas dig-ins within the City of Lafayette in 2016. Please note that none of these met the threshold of being a CPUC or Department of Transportation (DOT) reportable incident. The table below is a summary of the 2016 dig-ins:

Date	USA Ticket	Cause of Dig-In	At-Fault Party	Repair Method
February 23, 2016	No	No USA Ticket	Excavator	Replaced Partial Service
February 25, 2016	No	No USA Ticket	Excavator	Replaced Partial Service
March 22, 2016	Yes	No Locating Wire and Inaccurate Mapping	PG&E	Replaced Partial Service
March 22, 2016	Yes	No Locating Wire and Inaccurate Mapping	PG&E	Replaced Partial Service
May 11, 2016	Yes	Unknown Tracer Wire Issue	PG&E	Replaced Partial Service
May 13, 2016	No	No USA Ticket	Excavator	Replaced Partial Service
May 18, 2016	Yes	Failure to Dig with Care	Excavator	Deactivated Service
May 20, 2016	Yes	Failure to Dig with Care	Excavator	Replaced Partial Service
July 12, 2016	Yes	Failure to Dig with Care	Excavator	Replaced Partial Service
September 27, 2016	No	No USA Ticket	Excavator	Replaced Partial Service
November 11, 2016	No	No USA Ticket	Excavator	Replaced Partial Service
November 29, 2016	No	No USA Ticket	Excavator	Replaced Partial Service
December 12, 2016	Yes	Failure to Dig with Care	Excavator	Replaced Distribution Main Segment

PG&E limits certain gas pipeline, valve, regulator and station information, including its detailed and extensive construction, maintenance, inspection and testing records, from public disclosure for national security reasons consistent with federal laws that protect this type of information. Therefore, per PG&E's policies, PG&E is unable to provide information about the specific location of these dig-ins. Please note that PG&E makes its pipeline-related records available for inspection at all times by the CPUC.

Q6: How many dig-in accidents were reported in Lafayette in 2017? Please report incident information as requested for 2016 incidents.

There were 14 third-party gas dig-ins within the city of Lafayette in 2017 (PG&E notes that none of these met the threshold of being a CPUC or DOT reportable incident). The table below is a summary of the 2017 dig-ins:

Date	USA Ticket	Cause of Dig-In	At-Fault Party	Repair Method
January 12, 2017	Yes	Under Investigation	To Be Determined	Replaced Partial Service
January 23, 2017	No	No USA Ticket	Excavator	Replaced Partial Service
March 18, 2017	Expired	Failure to Maintain Marks	Excavator	Deactivated Service
March 30, 2017	Yes	Failure to Maintain Marks	Excavator	Replaced Partial Service
May 1, 2017	No	No USA Ticket	Excavator	Replaced Partial Service

Date	USA Ticket	Cause of Dig-In	At-Fault Party	Repair Method
May 16, 2017	No	No USA Ticket	Excavator	Deactivated Service
July 11, 2017	Yes	Failure to Dig with Care	Excavator	Replaced Partial Service
July 23, 2017	No	No USA Ticket	Excavator	Replaced Partial Service
August 24, 2017	No	No USA Ticket	Excavator	Deactivated Service
September 15, 2017	Yes	Inadequate Excavation Practices	Excavator	Replaced Partial Service
October 4, 2017	No	No USA Ticket	Excavator	Replaced Partial Service
October 10, 2017	Yes	Failure to Use Hand Tools	Excavator	Replaced Partial Service
October 17, 2017	No	No USA Ticket	Excavator	Replaced Partial Service
October 27, 2017	Yes	Failure to Maintain Marks, Failure to Request Remark	Excavator	Replaced Entire Service

PG&E limits certain gas pipeline, valve, regulator and station information, including its detailed and extensive construction, maintenance, inspection and testing records, from public disclosure for national security reasons consistent with federal laws that protect this type of information. Therefore, per PG&E's policies, PG&E is unable to provide information about the specific location of these dig-ins. Please note that PG&E makes its pipeline-related records available for inspection at all times by the CPUC.

Q7: Aside from USA ticket system, what else is PG&E doing in our community to mitigate the safety risk of dig-in accidents?

PG&E conducts robust damage prevention public awareness efforts. This consists of educating customers and other key audiences regarding gas safety, excavation rules, laws and best practices. Efforts include, but are not limited to, sending bill inserts in the mail, sending separate emails to customers who receive paperless billing, sending individual separate mailers, running ads in newspapers and on the radio, conducting company-wide campaigns for Call 811 Before You Dig, coordinating Call 811 Before You Dig Workshops and supporting USA S.A.F.E. events that involve educating excavator companies on safe digging practices and recommendations.

PG&E also patrols its gas transmission pipelines at least quarterly to look for indications of construction activity and other factors affecting pipeline safety and operation. In addition, the Community Pipeline Safety Initiative improves line-of-sight of the area above the pipeline and helps prevent third-party dig-ins.

Please note, from 2014 to 2017, PG&E has noted a decline in third-party dig-ins per 1,000 USA tickets submitted.

Q8: On 5/22/18 during the annual shareholders' meeting, Nick Stavropoulos (PG&E company president & COO) said the following in response to a shareholder question about gas pipeline safety:

"Federal regulators for pipelines in the U.S. Department of Transportation have identified that the number one safety issue for transmission pipelines is to defend the right of way--to make sure that the right of way around pipelines is kept clear of incompatible vegetation and structures." (source: https://www.youtube.com/watch?v=lFiIDWJVslI&t=9s).

After reading the above statement by PG&E's president, Tom Finch, PHMSA Western Region Community Liaison, U.S. DOT, provided the following comments:

"1. I do not know of anyone in the DOT who agrees with Nick's statement that "Federal regulators for pipelines in the U.S. Department of Transportation have identified that the number one safety

issue for transmission pipelines is to defend the right of way--to make sure that the right of way around pipelines is kept clear of incompatible vegetation and structures". This does not accurately describe the number one safety issue for U.S. gas transmission pipelines.
2. PHMSA has identified the number one safety issue for U.S. gas transmission pipelines. It is Material/Weld/Equipment Failure.
3. I agree with the [pipeline safety priorities shown in the attachment to this email], and it is my opinion that the top three safety issues for U.S. gas transmission pipelines are:
--Material/Weld/Equipment Failure
--Corrosion
--Incorrect Operation"

Please explain who at the U.S. DOT provided the information that served as the basis for Mr. Stavropoulos's statement above. Please provide a copy of that DOT information.

Making certain the right-of-way (ROW) around pipelines is kept clear of incompatible vegetation and structures is without question one of the priorities for transmission pipelines operators.

As required by 49 CFR Part 192.705 "Transmission lines: Patrolling," each operator is required to have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation. PG&E's Utility Standard TD-4800S establishes requirements to identify abnormal operating conditions (AOCs) (such as ROW encroachments) during operations and maintenance tasks (such as pipeline patrol) to ensure continuing surveillance of PG&E gas transmission and distribution systems to facilitate public safety consistent with 49 CFR Part 192.613 "Continuing surveillance." When an unsafe condition is identified, gas operations personnel must ensure the location is safe until permanent pipeline repairs are complete. When a pipeline is determined to be in unsatisfactory condition by inspection or record review, but no immediate hazard exists, action is taken per PG&E's standards and procedures.

PG&E notes that Federal regulations are not prescriptive and represent a minimum requirement. In addition, SB705 requires California operators to "meet or exceed the minimum standards for safe design, construction, installation, operation, and maintenance of gas transmission and distribution facilities prescribed by regulations issued by the United States Department of Transportation in Part 192 (commencing with Section 192.1) of Title 49 of the Code of Federal Regulations."

Q9: Regarding the above, please investigate the stark difference in the "top transmission pipeline safety issue" according to federal pipeline regulators as conveyed by Mr. Stavropoulos versus by Mr. Finch. Would PG&E now acknowledge that "defending the pipeline ROW/keeping the ROW clear of incompatible vegetation and structures" is not among the top priorities of federal pipeline regulators, and that Nick Stavropoulos's statement was misleading?

Please see the response to question 8 for more information. Keeping the right-of-way clear of incompatible vegetation and structures is a safety issue pipeline operators need to address.

Q10: PHMSA regulations describe in considerable detail what's required for a pipeline operator's integrity management (IM) program (a system of risk analysis and mitigation). For gas transmission pipelines this requirement began in 2004, and its scope applies only to HCAs (a relatively small percentage of total gas transmission mileage). The inadequacy of PG&E's IM program was a major point of criticism in the NTSB's report on San Bruno. According the Pipeline Safety Trust, some pipeline operators have elected to apply IM on their entire system. Following San Bruno, California's PUC added § 961 which mandates, among other things, that gas operators must go beyond what is considered "adequate" to develop and implement gas safety plans that are "consistent with best practices in the gas industry." Has PG&E chosen to broaden the application of IM beyond portions of its transmission lines categorized as HCAs? Why/why not?

PG&E has expanded and broadened its Integrity Management Program since 2010 by implementing Interstate Natural Gas Association America (INGAA)'s guiding principles for pipeline safety. This includes, but is not limited to, applying integrity management principles on areas that are not defined as High Consequence Areas (HCA). Information on the additional INGAA guiding principles can be found in the attached *"INGAA Safety Goals"* document. In addition, PG&E has increased the mileage of HCA on its system from approximately 1,000 to over 1,500 miles.

Q11: Regarding the above, when was the IM plan for applicable portions of Lafayette's pipelines last updated?

PG&E updates its Transmission Integrity Management plan annually. PG&E last updated the plan in December 2017.

Q12: Regarding the above, please provide a list of all threats identified in the most recent IM updates for Lafayette and the risk scores assigned for each threat.

Per federal regulations, PG&E performs a risk assessment approach that takes into consideration historic and potential threats that could impact the safe operation of the pipeline. These can include corrosion, construction or manufacturing-related defects, third-party damage, and weather-related and outside forces, as well as potential impacts to nearby populations, the environment and reliability.

Risk is evaluated by a dynamic segment or section of pipeline, instead of by city or location. All factors mentioned above have the potential to impact overall pipeline safety on each pipeline section and are equally important to consider when evaluating risk on the system. Each section of pipeline in Lafayette has unique characteristics and geographic makeup and therefore there is no one single risk factor that stands apart from the others that can be applied holistically to all pipelines in the City of Lafayette. The risk scores for each pipeline in Lafayette are provided in the response to question 14.

Q13: Regarding the above, please explain the process that was used to calculate these risk scores, including the types and sources of data used.

The process used to calculate risk is governed by the methodology established in ASME B31.8S-2004. Section 4 of this standard includes the data sources that are collected, which cover data elements regarding pipeline attributes, construction, operational and inspection data. Section 5 of this standard covers the risk assessment process. PG&E performs a risk assessment approach that takes into consideration historic and potential threats that could impact the safe operation of the pipeline. These can include corrosion, construction or manufacturing-related defects, third-party damage, and weather-related and outside forces, as well as potential impacts to nearby populations, the environment and reliability.

A copy of ASME B31.8S-2004 is incorporated by reference into 49 CFR Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards) can be accessed here: https://law.resource.org/pub/us/cfr/regulations.gov.docket.03/asme.b31.8s.commentary.pdf

Q14: Regarding the above, please provide a copy of the most recent safety improvement plan for Lafayette's pipelines that resulted from the threat analysis.

In accordance with federal code requirements (49 CFR 192.919), PG&E created a Baseline Assessment Plan (BAP) to document PG&E's gas transmission pipeline threat assessment plans and results. Please see attachment "*Lafayette BAP.xlsx*" for an excerpt of PG&E's BAP that provides information regarding risk, threats, and assessment activities for gas transmission lines within Lafayette.
Please note the following about the BAP:

- The BAP is a general overview of the pipelines, not a detailed pipeline segment view.
- The term "unstable" is used within integrity management to identify pipelines that have not had a pressure test, or for which no documentation supporting a valid historical pressure test is available. The unstable condition designation does not necessarily apply to the entire pipeline; only portions of the route may have the unstable condition. The unstable condition will be addressed through pressure testing following PG&E standards and procedures.
- The threat data listed in the BAP reflect the highest degree of threat assessed on the assessed portion of pipeline regardless of the potential threat's location within or outside of a high consequence area (HCA).

Q15: Regarding the above, please describe the method that PG&E uses to periodically evaluate the effectiveness of its gas IM program and the main changes that have been made to the program over the past five years as a result of this evaluation.

PG&E is continually evaluating its Transmission Integrity Management Program to evaluate its effectiveness. This includes measures of performance indicators per ASME B31.8S for each pipeline threat, benchmarking against industry best practices and working with external entities such as the CPUC and PG&E's Federal Monitor to improve our Transmission Integrity Management Program. Documents that discuss the effectiveness can be found in reports that PG&E publishes and provides to the CPUC and Pipeline and Hazardous Materials Safety Administration (PHMSA) annually, such as the Annual Report 7100.2-1 and the GO-112F Annual Report.

The PHMSA Annual Report 7100.2-1 is publicly available on the PHMSA website here: https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids. Please see attachment "*2017 7100.2-1 Annual Reports*" for PG&E's 2017 transmission reports. The GO-112F annual report is not publicly available; however, PG&E is providing the section of the report that pertains to ASME B31.8S, Chapter 9, Table 9 here (see attachment "*2017 GO-112F Annual Report_123.2(g)*").

PG&E does not have a single report or document that captures the main changes to its program; however, it does list procedural changes in its Changes to our Program section, which can be found in reports that PG&E publishes and provides to the CPUC and PHMSA annually, such as the Gas Transmission and Storage Safety Report. PG&E's most recent Gas Transmission and Storage Safety Report can be found in the attached *"PGE Gas Transmission and Storage Safety Report 2017-02"* document.

Q16: Regarding the above, what are the top three metrics that PG&E uses to assess the effectiveness of its gas IM program?

PG&E uses a number of different measures and approaches to quantify safety. PG&E publishes and provides reports to the CPUC and PHMSA which include the Gas Transmission and Storage Safety Report, Annual Report 7100.2-1, and the GO-112F Annual Report. Within each of these reports, PG&E provides performance metrics, such as leaks and anomalies repaired. PG&E also quantifies its Transmission Integrity Management Program on the metrics required by ASME B31.8S-2004 "Performance Measures".

Q17: Regarding the above, please provide the results for each the past three years according to the above metrics (applicable to PG&E's total gas system, and if, available, applicable to Lafayette)

PG&E uses a number of different measures and approaches to quantify safety. PG&E publishes and provides reports to the CPUC and PHMSA which include the Gas Transmission and Storage Safety

Report, Annual Report 7100.2-1, and the GO-112F Annual Report. Within each of these reports, PG&E provides performance metrics, such as leaks and anomalies repaired. PG&E also quantifies its Transmission Integrity Management Program on the metrics required by ASME B31.8S-2004 “Performance Measures”. Copies of these reports can be found at the following locations:

- PG&E’s most recent Gas Transmission and Storage Safety Report in the attached *“PGE Gas Transmission and Storage Safety Report 2017-02”* document

- The PHMSA Annual report 7100.2-1 can be found here: https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids. See attachment *“2017 7100.2-1 Annual Reports”* for a copy of PG&E’s 2017 transmission reports.

- The GO-112F annual report is not publicly available; however, PG&E is providing the section of the report that pertains to ASME B31.8S, Chapter 9, Table 9 here (see attachment *“2017 GO-112F Annual Report_123.2(g)”*).

Q18: Over the past 20 years, what are the top 7-10 causes of transmission line safety incidents in PG&E’s entire service area? For each cause, what percentage did this cause represent of the total safety incidents?

Federal regulations require PG&E to submit incident reports within 30 days of a pipeline incident or accident. The regulations define accidents and incidents, as well as criteria for submitting reports to the Office of Pipeline Safety. The CPUC has also established its own additional reporting requirements in GO 112-F.

More information regarding the data can be found on PHMSA’s website here: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data. Please follow PHMSA’s instructions listed at the bottom of the website and reference the “CAUSE” and “CAUSE_DETAILS” columns within the data.

Q19: Over the past 10 years, please provide a report of all PG&E gas transmission pipeline line safety incidents. Data requested for each incident is:

a. location of event and size of line involved
b. year
c. buried depth of the line and MAOP
d. size of gas release (minor/moderate/major)
e. root cause of the incident
f. how was emergency repair made and how long did repair take
g. was the line shut down to make the repair (if not, why not)
h. how long did it take to make the decision to depressurize the line
i. did the repair involve welding on a pressurized line
j. was the event reported to PHMSA
k. did the event require reporting to PHMSA (based on PHMSA regulations)

Federal regulations require PG&E to submit incident reports within 30 days of a pipeline incident or accident. Regulations define accidents and incidents, as well as criteria for submitting reports to the Office of Pipeline Safety. The CPUC has also established its own additional reporting requirements in GO-112F.

PG&E provided the required information to PHMSA for reporting purposes after the events occurred. Details regarding the data that are captured in these reports, as well as copies of this data, can be found on PHMSA's website here: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.

PG&E has reviewed the January 2010 data on the PHMSA website and recommends referring to the columns listed in the chart below. Please note the requirements for reporting have changed over the years, and as a result, some information may not be available.

Information Description	Column Name in PHMSA Data
Location of event and size of line involved	LOCATION_LATITUDE LOCATION_LONGITUDE PIPE_DIAMETER
Year	LOCAL_DATETIME
Buried depth of the line and Maximum Allowable Operating Pressure (MAOP)	DEPTH_OF_COVER MOP_PSIG
Size of gas release (minor/moderate/major)	UNINTENTIONAL_RELEASE & INTENTIONAL_RELEASE
Root cause of the incident	CAUSE CAUSE_DETAILS
How was emergency repair made and how long did repair take	NARRATIVE RESTART_DATETIME
Was the line shut down to make the repair (if not, why not)	SHUTDOWN_DUE_ACCIDENT_IND SHUTDOWN_EXPLAIN
How long did it take to make the decision to depressurize the line	INCIDENT_IDENTIFIED_DATETIME ON_SITE_DATETIME SHUTDOWN_DATETIME RESTART_DATETIME
Did the repair involve welding on a pressurized line	Repair methods are selected on a case-by-case basis utilizing company procedures and may or may not involve welding on a pressurized pipeline
Was the event reported to PHMSA	Federal regulations require pipeline operators to submit incident reports within 30 days of a pipeline incident or accident
Did the event require reporting to PHMSA (based on PHMSA regulations)	Federal regulation defines accidents and incidents, as well as criteria for submitting reports to the Office of Pipeline Safety

Q20: How does PG&E quantify the risk of the 272 trees in Lafayette, and the improvement to this risk score when these trees are removed? Please explain how PG&E quantifies risk for each gas pipeline threat, including how these risk scores are adjusted to reflect unique circumstances within a local community such as Lafayette, and how historical safety incidents are used in the calculation of risk scores.

PG&E quantifies risk by assigning scores based on maintenance and operating records, assessment results, local site features and conditions, and pipeline attribute information specific to every pipeline section in its system. PG&E utilizes industry incident data from PHMSA as a baseline and applies its own inspection data documented during integrity assessments and maintenance activities to adjust the risk specific to its own assets. This process is performed for all potential risks to the pipeline, including trees located above and around the pipeline. Risk reduction occurs when these conditions causing likelihood of failure are removed.

Q21: The CPUC's Safety and Enforcement Division issued a report on 7/18/14 that was critical of PG&E's risk ranking methodology. In particular, the report says that PG&E "makes strong use of qualitative risk assessments. Staff recommends that PG&E inject additional quantitative rigor into its risk evaluation process. " What are the changes that PG&E has made to its risk modeling/risk evaluation process following this SED recommendation?

Since 2014, PG&E has been engaged in the Safety Modeling Assessment Phase (S-MAP) proceeding with the other California Investor Owned Utilities (IOUs), Intervenors, and the CPUC Safety and Enforcement Division (SED) to determine the future state of the quantitative models. While this proceeding is currently on-going, PG&E made the first step in the transition from qualitative to quantitative by creating probabilistic risk assessment models. While these models are first-generation, PG&E has assessed 22 of the top risks through these models; the methodology and the risk analysis were provided in PG&E's Risk Assessment and Mitigation Phase (RAMP) report filed with the CPUC on November 30, 2017. SED's report filed on March 30, 2018 regarding PG&E RAMP states "[if] there is a theme to the PG&E RAMP, it would be "evolution in modeling tools and continual improvement in approach" as this filing and the process it describes may be characterized as an advance in many regards." The new risk scoring approach was described as "state of the art" by the SED in their report on PG&E's 2017 RAMP filing. The risk management process is currently evolving, and PG&E continues to work with the other California IOUs, Intervenors, and the SED to refine the quantitative models through the S-MAP proceeding.

Q22: During the 5/9/18 PG&E open house in Lafayette, multiple PG&E representatives, and Jesus Soto, SVP of PG&E Gas Operations at the recent annual shareholders meeting, said that other pipeline companies do not allow trees in gas pipeline rights of way, and that PG&E has a "unique situation" with respect to trees currently growing in its transmission line rights of way. That statement is disputed by PHMSA. Please explain how your company came to its conclusion, including the sources of your information about the uniqueness of PG&E's situation. (source: https://www.phmsa.dot.gov/regulations/title49/interp/PI-76-0108 https://www.phmsa.dot.gov/regulations/title49/interp/PI-00-0102 http://pstrust.org/wp-content/uploads/2014/12/Mulligan-Pipeline-Safety-Trust-ROW-Clearing.pdf)

As part of PG&E's Community Pipeline Safety Initiative, PG&E referenced an American Gas Association benchmarking survey, and conducted its own benchmarking of how other operators are approaching vegetation management in the area above and around the natural gas transmission pipeline. What we found is that most other operators maintain a safe and clear area above the pipeline, keeping the area above the pipeline free of structures and vegetation at a minimum of 10 feet and up to 25 feet from the edge of the pipeline. Nevertheless, we understand how important trees are to our communities, which is why we have worked hard to develop an approach that preserves the character of the community.

Q23: PG&E's written materials explaining CPSI for its 5/9/18 Lafayette community open house include this statement: "[CPSI] is based on guidance from state and federal regulators, pipeline safety organizations, industry associations, and other pipeline operators regarding safe uses near natural gas transmission pipelines. These entities all agree on the importance of keeping the area from a minimum of 10 feet and up to 25 feet free of vegetation and other items that could block critical access or damage the pipe."
A 5/14/18 emailed comment from Tom Finch, PHMSA Western Region Community Liaison, said the following:

"1. I am not aware of any federal regulatory agency that has taken the position that 'all agree on the importance of keeping the area from a minimum of 10 feet and up to 25 feet free of vegetation and other items that could block critical access or damage the pipe.'
2. The different guidance coming from PHMSA (which consistently says tree removal is a matter to be negotiated and not mandatory) and PIPA, which appears to have a very different perspective, is that PIPA is a suggested reference document and is not binding as a regulation."

Does PG&E agree that PIPA is not a regulatory agency, but instead is an association of a wide variety of pipeline stakeholders including members of the pipeline industry, the real estate industry, and the public?

The Pipeline Informed Planning Alliance (PIPA) is a stakeholder group sponsored by the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). PIPA stakeholders, including PHMSA, developed industry best practices related to gas transmission pipeline safety.

PIPA's "Partnering to Further Enhance Pipeline Safety in Communities Through Risk-Informed Land Use Planning, Final Report of Recommended Practices", developed in November 2010, states:

> "A clear ROW enables the transmission pipeline operator to conduct inspections and testing to verify pipeline integrity and to perform general maintenance and repairs as needed… Tree roots have the potential to damage pipeline coatings which may contribute to the loss of integrity of the pipeline." (pg. 41)
>
> " The PIPA recommended practices are not mandated by any public or private entity. However, they were developed by task teams of representative stakeholders using a consensus agreement process and the PIPA participants recommend that all stakeholders become aware of and implement the PIPA recommended practices, as appropriate, to reduce risks and ensure the safety of affected communities and transmission pipelines." (pg. 3)

In October 2010, PHMSA issued "Building Safe Communities: Pipeline Risk and its Application to Local Development Decisions", which includes "keeping rights-of-way free from obstructions and encroachments; and following PIPA recommended practices on land use near transmission pipelines" (pg. 9) as ways for stakeholders to practice safe uses of the area above and near gas pipelines.

State and federal regulations, such as 49 CFR 192, represent the minimum safety standards for pipeline operators. PIPA recommended practices go beyond minimum standards and represent best practices.

Q24: Regarding the above, please identify the source of PG&E's statement quoted above that indicates federal regulators "agree on the importance of keeping the area from a minimum of 10 feet and up to 25 feet free of vegetation . . ."

The Pipelines and Informed Planning Alliance (PIPA) is sponsored by the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety. PIPA stakeholders, including PHMSA, developed industry best practices related to gas transmission pipeline safety. PIPA's "Partnering to Further Enhance Pipeline Safety in Communities Through Risk-Informed Land Use Planning, Final Report of Recommended Practices" (November 2010) states:

> "A clear ROW enables the transmission pipeline operator to conduct inspections and testing to verify pipeline integrity and to perform general maintenance and repairs as needed… Tree roots have the potential to damage pipeline coatings which may contribute to the loss of integrity of the pipeline." (p.41)

Please also note, as part of PG&E's Community Pipeline Safety Initiative, PG&E referenced a benchmarking survey done by the American Gas Association and conducted its own benchmarking of how other operators are approaching vegetation management within the right-of-way. What we found is that most other operators maintain a safe and clear area above the pipeline, keeping the right-of-way free of structures and vegetation at a minimum of 10 feet and up to 25 feet from the edge of the pipeline. Nevertheless, we understand how important trees are to our communities, which is why we have worked hard to develop an approach that preserves the character of the community.

Q25: An analysis of PG&E's gas transmission pipeline significant safety incidents reported to PHMSA over the past 30 years (see pages 4, 5 & 17 in link, below) found that significant PG&E incidents averaged 1.2/year from 1986-2011 but averaged 4.7/year in the period 2012-2017, with a rising trend over the past five years. According to this data, in the period following San Bruno (and following PG&E's implementation of an aggressive ROW tree removal program), significant incidents have increased by an average of 400%. The same analysis (p 4) found that PG&E's averages of fatalities, injuries, and property damage reported to PHMSA are all up dramatically in the past four years (2014-2017) compared to the four years immediately prior to San Bruno. In comparing these two periods, total incidents reported to PHMSA are up 186% in the past four years vs 2006-2009, and property damage is up more than 1,000%. When compared to its industry peers, PG&E's overall safety performance using these metrics ranks worst among its peers. Does PG&E agree with PHMSA and the Pipeline Safety Trust that the above metrics rank at the top of the metrics hierarchy for assessing gas pipeline operator safety performance?
(Source: https://docs.wixstatic.com/ugd/de4240_988b8bd6733642a0af64172776fd2803.pdf)

PG&E agrees that PHMSA's reportable incident data is important to the industry as it enables sharing of lessons learned; however, it has limitations for drawing conclusions about operator safety performance. Being able to understand the threats that materialize to cause incidents leads to sharing of preventative measures that can help to prevent such incidents and to avoid future accidents resulting in injuries and fatalities, including those associated with excavation damage. Transmission pipeline incidents that result in injuries and fatalities are uncommon, with the exception of those associated with excavation damage.

For example, from 2014-2017, there were three major incidents that resulted in an increase to the data categories for fatalities, injuries and property damage. In 2014, the Napa earthquake resulted in an incident on PG&E's natural gas transmission pipeline due to strain on the pipeline. This incident resulted in millions of dollars of investment in pipeline repairs and replacement. In 2015, there were two transmission excavation related incidents that resulted in fatalities, injuries and significant expenditure in property damage. In each of these two instances, the excavator failed to notify USA North (811) prior to digging. Together, these three incidents accounted for approximately 83% of the property damages and all of the fatalities and injuries reported in 2014 and 2015.

The table below is PG&E data extracted from the PHMSA website on July 24, 2018. Please note that the property damage amount in Save Lafayette Trees' analysis differed in 2015 and 2017.

PACIFIC GAS and ELECTRIC CO All Incidents, All Pipeline Systems (1): 2006-2018				
Year	**Number**	**Fatalities**	**Injuries**	**Property Damage (A)**
2006	2	0	1	$358,350
2007	3	0	0	$667,500
2008	2	0	0	$114,300
2009	5	0	0	$1,847,000
2010	4	8	51	$558,590,512
2011	5	0	0	$5,569,000
2012	4	0	0	$1,050,710
2013	4	0	0	$1,045,457

PACIFIC GAS and ELECTRIC CO All Incidents, All Pipeline Systems (1): 2006-2018				
Year	**Number**	**Fatalities**	**Injuries**	**Property Damage (A)**
2014	9	0	0	$9,550,814
2015	8	2	15	$9,600,954
2016	6	0	0	$2,052,778
2017	8	0	1	$1,356,251
2018 YTD	0	0	0	$0
Totals	**60**	**10**	**68**	**$591,803,626**

Notes
A. For years 2002 and later, property damage is estimated as the sum of all public and private costs reported in the 30-day incident report. All costs shown are as reported by the operator at the time of the incident.

Sources
1. PHMSA Flagged Incidents File - June 24, 2018. Note: Incidents occurring up to 30 days prior the Incident File source date may not appear in these reports due to the 30-day reporting period allowed by PHMSA regulation.

Q26: Regarding the above, if PG&E agrees with the importance of these metrics in evaluating overall gas safety performance, please explain why there is no mention of these metrics in PG&E's 2017 Gas Safety Plan or in PG&E's 2018 Gas Safety Plan. (Sources: https://www.pge.com/pge_global/common/pdfs/safety/gas-safety/safety-initiatives/pipeline-safety/GasSafetyPlan.pdf and https://www.pge.com/pge_global/common/pdfs/safety/gas-safety/safety-initiatives/pipeline-safety/2018GasSafetyReport.pdf)

PHMSA's reportable incident data provides useful information to the industry; however, the largest threat faced by natural gas operators is third-party damage, making the metric that evaluates third-party damage per 1,000 USA tickets submitted one of the most critical industry safety metrics. Third-party damage often results from contractors, farmers and homeowners excavating prior to calling 811 (a free service) to have underground utilities marked with paint or flags.

A study, "Improving Damage Prevention Technology," published by the U.S. DOT on August 3, 2017, states, "Excavation damage is a leading cause of pipeline accidents resulting in fatalities and injuries." Additionally, the report states, "Nationwide data show that damage to an underground utility line occurs every six minutes because someone began digging without first determining if underground utilities exist in the digging area. Digging without knowing the location of existing underground utilities can result in damage to gas, hazardous liquid, electric, communication, water, and sewer lines. These damages can lead to service disruptions, costly repairs, and sometimes serious injury and death."

The Damage Prevention Program is included in PG&E's 2018 Gas Safety Plan starting on page 28, and PG&E will consider including information regarding reportable incidents in the next annual report.

Q27: Regarding the above, if PG&E does not agree with the importance of these metrics in evaluating overall gas safety performance, please identify the metrics that PG&E believes to be the most important, and provide PG&E's quantified annual results applicable to each of these metrics for the period 1986-2017.

PG&E measures its safety performance beyond using incident data as there are numerous approaches to quantify safety. Other reports PG&E publishes and provides to the CPUC and PHMSA include the Gas Transmission and Storage Safety Report, Annual Report 7100.2-1, and the GO-112F Annual Report. Within each of these reports, PG&E reports performance metrics, such as leaks and anomalies repaired. PG&E also quantifies its Transmission Integrity Management Program on the metrics required by ASME B31.8S-2004 “Performance Measures”.

Q28: Regarding the above, this statement appears in the Introduction (p 1) of PG&E’s 2017 Gas Safety Plan: “PG&E has made great progress in achieving Gas Safety Excellence over the last six years.” Please explain why PG&E failed to mention in this report, and in its 2018 report, its alarming (and accelerating) deterioration in transmission pipeline safety performance over this period as measured by fatalities, injuries, property damage, significant incidents, and total incidents reported to PHMSA. (source: https://www.pge.com/pge_global/common/pdfs/safety/gas-safety/safety-initiatives/pipeline-safety/GasSafetyPlan.pdf)

PG&E’s Gas Safety Plan is prepared in compliance with state regulations and is not intended to replicate incident data reported to PHMSA and the CPUC. The intent of the state regulation is for gas corporations to develop a plan for the safe and reliable operation of their natural gas systems.

In the plan, PG&E shares its progress on key safety initiatives, such as pipeline replacement, strength testing our pipelines, over-pressure protection, damage prevention and emergency response. While PG&E has made progress in Gas Safety Excellence, we believe that our safety work is never complete.

Q29: Regarding the above, the Introduction to PG&E’s annual Gas Safety Plans states, “The purpose of PG&E’s Plan is to demonstrate PG&E’s commitment to safe and reliable operations.” The strategy and plans in this document focus almost entirely on PG&E’s internal processes and metrics associated with those processes, e.g., improvements in transmission control points, miles of pipeline made piggable, and improvements in response time to reports of gas odor. Please provide a copy of any documents that do discuss PG&E’s identification of the deteriorating incident rates mentioned above and the company’s plans for addressing this problem.

PG&E is not aware of any documents that discuss the “identification of the deteriorating incident rates.” From 2014 to 2017, PG&E noted a decline in third-party dig-ins per 1,000 USA tickets. In addition to the metrics presented in the Gas Safety Plan, PG&E publishes and provides to the CPUC and PHMSA include the Gas Transmission and Storage Safety Report, Annual Report 7100.2-1, and the GO-112F Annual Report.

Q30: Regarding the above, what does PG&E’s Integrity Management department believe are the primary contributors to the substantial increase in transmission pipeline incidents referred to above?

As stated in responses to questions 25 through 29, PG&E and its Integrity Management department conclude that gas transmission incident data is important to the industry as it enables the sharing of lessons learned, but this data has limitations in drawing conclusions about operator safety performance. In addition to incident data, PG&E measures its safety performance using metrics reported to PHMSA and CPUC such as the Gas Transmission and Storage Safety Report, Annual Report 7100.2-1 and the GO-112F Annual Report. PG&E’s data supports that the leading cause of PHMSA reportable incidents is excavation damage. A potential reason for the increase could be that the financial threshold for property damage has remained at $50,000 since 1984. As the cost of damage repair continues to increase with inflation, more incidents reach the $50K threshold. Another contributing factor could be the increased excavation experienced throughout PG&E’s service territory. Using Underground Service Alert (USA) tickets as a proxy for excavation activity, since 2009, PG&E has experienced a steady increase each year and is on pace to realize a twofold increase. For example, in 2009 PG&E received 480,000 tickets and in 2017 almost 990,000 tickets were received.

Q31: Regarding the above, what does PG&E's senior management believe are the primary contributors to this substantial increase in incidents since San Bruno?

Please see the response to question 30.

Q32: Regarding the above, what corrective strategy and specific actions has PG&E's senior management initiated in light of the pattern of increasing pipeline incidents since San Bruno?

In 2011, PG&E embarked on a journey to become the safest, most reliable gas company in the United States by implementing several important initiatives and programs. These include:

- **Pipeline Safety Enhancement Plan:** In August 2011, PG&E filed its Pipeline Safety Enhancement Plan (called PSEP) with the CPUC. PSEP outlines steps we will take over the next several years to rigorously verify and upgrade the integrity of our 6,000+ miles of gas transmission pipelines. PSEP will bring our system to the highest standards for transmission pipelines. The PSEP program's ultimate goal is to strength test or replace untested transmission pipelines by the end of 2026. Once completed, PG&E will have a test record for its entire gas transmission pipeline. In 2017, PG&E completed approximately 253 miles of hydrotesting. This work brings PG&E to a total of approximately 1,095 miles hydrotested since 2011. Furthermore, the PSEP plan replaced, automated, and upgraded gas shut-off valves across PG&E's gas transmission system. By the end of 2018, PG&E will have automated 291 valves.

- **Pipeline Centerline Survey:** In 2013, PG&E completed a comprehensive Pipeline Centerline Survey (PLCL) of its gas transmission pipelines using GPS mapping technology. The PLCL captured various data including GPS locations, depth-of-cover measurements, and potential abnormal operating conditions.

- **Community Pipeline Safety Initiative:** The Community Pipeline Safety Initiative was developed as a proactive program that reviews the area above and around the natural gas transmission pipeline for trees or structures that could block access for safety crews in an emergency or for important maintenance work.

- **Legacy Cross Bore Program:** PG&E's Legacy Cross Bore Program was in place to proactively identify and mitigate legacy (existing) cross bores. The Legacy Cross Bore Program focuses on communication of the cross bore program, records research for identifying inspection locations of potential cross bores, as well as video inspection locations and documentation of inspection results.

- **Gas Safety Excellence:** The Gas Safety Excellence Program (GSE) permeates every aspect of PG&E's gas operations and is a strategic framework designed to improve safety, manage risk, drive continuous improvement, and help guide the long-term strategy for Gas Safety. GSE is demonstrated by putting safety and people at the heart of everything, investing in the reliability and integrity of the gas system, and continuously improving the effectiveness and affordability of our processes. GSE is an overlapping combination of three key standards-based programs: Safety Culture, Process Safety, and Asset Management.

  The first pillar of GSE is Safety Culture. When it comes to safety, PG&E believes that its job is never done. The imperative to put safety first drives everything we do, to create a clear understanding by our employees that their actions every day must reflect that priority. PG&E measures its safety culture progress in a variety of ways. For example, PG&E has obtained independent third-party verification of our Company's systems and processes, including the American Petroleum Institute's (API) Recommended Practice (RP) 1173, Pipeline Safety

Management System Requirements. PG&E earned a certificate of compliance to the requirements of API RP 1173 from an independent third-party auditor in November 2015. PG&E is the first company to earn this distinction and will continue to maintain the certification, as with all its certifications, through the recertification process.

The second pillar in GSE is implementing Process Safety Management. Process Safety Management focuses on preventing low frequency, high consequence incidents and mitigating the consequences. The Process Safety Management system is used for engineering new facilities, modifying existing facilities, maintaining equipment, and ensuring safe operation. The Process Safety Management System contains four foundational blocks: Commit to Process Safety, Understand Hazards and Risk, Manage Risk, and Learn from Experience. PG&E obtained Responsible Care RC 14001, which improves environmental, health, safety, and security performance by integrating a broad-based risk management system in a timely, cost-effective process. PG&E is also moving forward with implementation of API Recommended Practice (RP) 754. RP 754 will help PG&E enhance its process operations and design and identify gaps. It will identify, develop, and implement leading and lagging process safety indicators that will inform on our progress and help drive improvement in safety and reduction of risks and major hazards.

The third pillar in GSE is an Asset Management System. Using the international PAS 55-1 and ISO 55001 standards as guidance, PG&E's asset management system focuses on:

- Identifying and reducing operational risk;
- Maintaining an asset management framework and directing organizational focus on the most important asset risks and opportunities;
- Proactively managing the condition of gas assets; and
- Meeting or exceeding the requirements of federal, state, and local codes, regulations and requirements in an environmentally sustainable manner.

Certifications RP 1173, RC 14001, PAS 55-1 and ISO 55001 are adopted by leading companies worldwide and across a number of industries including water, mining, chemical processing, and transportation. They have helped us make great strides in enhancing our safety and reliability and have significantly improved PG&E's gas operations.
With GSE as a foundation, Gas Operations Senior Leadership develops annual goals through the "Line of Sight" process. This process aligns business strategy with six key themes: Safe, Reliable, Affordable, Customer, People, and Compliance. Related goals and metrics are cascaded throughout the organization to provide each employee a line of sight for how their actions support PG&E's vision and commitment to be the safest, most reliable gas utility in the nation.

While more remains to be done, PG&E has made great progress in achieving Gas Safety Excellence over the last seven years. See attachment "*2017 EOY Gas Ops Progress*" for examples of this progress.

Q33: Save Lafayette Trees recently did a cause analysis for the 86 PG&E gas transmission incidents reported to PHMSA in the period 1984-2017. The analysis relied on PG&E's initial description of incident causes, and its scope covers both significant and other transmission line incidents that PG&E reported to PHMSA. It concluded that, while excavation dig-ins remain the largest overall factor, the steady rise in total incidents has been driven over the last three years by increases in equipment failure, incorrect operation, and material failure. PG&E's 2018 Gas Safety Plan (on p 13) describes the company's Apparent and Root Cause Evaluation studies that are conducted for gas incidents. Please provide copies of the root cause analysis for each of the transmission line incidents reported to PHMSA for the years 2014-2017, and the accompanying identification/implementation of corrective action for each incident (as specified in the company's Learn from Experience pillar of its Process Safety Management System).
(Sources: https://docs.wixstatic.com/ugd/de4240_c263a60d3e834fd0848dd9ce7c4e725e.pdf and https://www.pge.com/pge_global/common/pdfs/safety/gas-safety/safety-initiatives/pipeline-safety/2018GasSafetyReport.pdf)

Federal regulations require PG&E to submit incident reports within 30 days of a pipeline incident or accident. Regulations define accidents and incidents, as well as criteria for submitting reports to the Office of Pipeline Safety. Details regarding the data that are captured in these reports (such as an incident cause), as well as copies of these data, can be found on PHMSA's website here: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.

Please note that PG&E limits certain gas pipeline, valve, regulator and station information, including its detailed and extensive construction, maintenance, inspection and testing records, from public disclosure for national security reasons consistent with federal laws that protect this type of information. Therefore, per PG&E's policies, PG&E is unable to provide internal cause analysis reports. Please note that PG&E makes its pipeline-related records available for inspection at all times by the CPUC.

Q34: Please estimate PG&E's gas safety improvement spending during the six-year period 2012-2017 in the 11 categories below. It is understood that there will be some spending overlap with these categories, and double-counting of spending is okay if needed. The first 7 categories are major causes of transmission pipeline failure; the last 4 categories are some of PG&E's many targeted gas safety improvement programs.

a. Excavation damage/dig-ins
b. Equipment failure
c. Incorrect operation
d. Material failure
e. Corrosion
f. Outside force
g. Earth movement
h. Valve automation
i. Improved ROW marking
j. Increased pipeline piggability (ILI)
k. Pipeline Pathways/CPSI

Please refer to the following:

- See attachment "*Chapter 5 Workpapers_2019 GT&S Rate Case Table 5-1*" for Table 5-1 from PG&E's 2019 Gas Transmission and Storage (GT&S) Rate Case Workpapers Supporting Chapter 5, "Asset Family – Transmission Pipe"; Table 5-1a and Table 5-1b provide a summary of expenses and capital expenditures related to transmission pipelines since 2012.
- See attachment "*Chapter 8 Workpapers_2019 GT&S Rate Case Table 8-1*" for Table 8-1 from PG&E's 2019 GT&S Rate Case Workpapers Supporting Chapter 8, "Corrosion Control"; Table 8-1a and Table 8-1b provide a summary of expenses and capital expenditures related to corrosion control since 2012.
- See attachment "*Chapter 9 Workpapers_2019 GT&S Rate Case Table 9-1*" for Table 9-1 from PG&E's 2019 GT&S Rate Case Workpapers Supporting Chapter 9, "Operations and Maintenance"; Table 9-1 provides a summary of expenses and capital expenditures related to operations and maintenance since 2012.

PG&E's Transmission Pipeline, Corrosion Control, and Operations and Maintenance programs each impact the 7 threat categories in varying manners through use of its multiple programs (including those identified above). Note, we have not specifically aligned the threats across these programs, as there would be significant overlap in costs between threat categories. As such, PG&E recommends evaluating the overall spend for these programs, which have directly or indirectly improved the safety of PG&E's transmission pipeline system.

Please note, the Community Pipeline Safety Initiative is a six-year, shareholder funded program. Since this work is shareholder funded, PG&E did not prioritize this gas safety work against the remainder of the portfolio, which is funded through operating revenue.

Q35: During the PG&E 2018 Annual Shareholders' Meeting in San Francisco, Sumeet Singh, VP of Gas Asset & Risk Management, was asked if implementing other safety projects such as improved inspections would change their risk management equation for tree risks, thereby making tree cutting less necessary. He replied "Yes." Does PG&E stand by his response? Given the upcoming projects scheduled for Lafayette (including automated shut off valves, improved inspections, burying exposed pipelines, and replacement of vintage pipelines), why is tree removal being scheduled when the need for their removal will change after these projects are completed?

Multiple layers of protection are essential to keeping the gas transmission pipelines and the people who live near them safe. In addition to inspecting and testing our pipes, conducting leak surveys and upgrading pipes, we are working with our communities to review the area above and around the natural gas transmission pipeline for items that could block safety crews in an emergency or for important maintenance work. The trees identified as needing to be removed for safety reasons in Lafayette were assessed with the upcoming safety projects in mind. PG&E performs detailed risk analysis to determine threat levels of vegetation near gas transmission (GT) pipelines as outlined in PG&E's Utility Procedure TD-4490P-03, "Vegetation Encroachment Site-Specific Risk Analysis." Data that inform PG&E's risk analysis include:

- Tree species
- Tree diameter at breast height (DBH) at maturity
- Horizontal distance from the tree to the pipeline centerline
- Pipeline depth of cover (DOC)
- Pipe Coating type
- Lightning exposure
- Wind and flooding exposure
- Seismic exposure
- Soil stability
- Pipe diameter
- Date of construction
- Presence and visibility of line markers
- Ability to enter site with emergency vehicles in the event of an emergency or an Integrity Management response

Additionally, the procedure referenced above allows for some of the trees to remain in place with the implementation of additional preventative and mitigative measures (e.g., increased frequency of leak survey and/or patrols).

Q36: According to the Dept of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) national database, there has never been a reportable underground transmission pipeline accident in the United States in the last 20 years. Jesus Soto, VP of Gas Operations at PG&E told us that the rest of the United States does not have trees along the pipeline. Does PG&E stand by the statement that there are no trees along the 300,000 miles of pipeline in the US, or the over 7000 miles in California?
(Source: https://docs.wixstatic.com/ugd/de4240_3a2200235ff24b5f91384d1ecde9c412.pdf)

PG&E interprets this question as indicating there has never been a reportable underground transmission pipeline accident reported to PHMSA in the last 20 years involving trees. However, PG&E has identified seven reportable incidents involving trees (see response to question 53 for further details) since 1986. PG&E also notes that the PHMSA reportable database does not typically include the prevailing conditions that contributed to the direct cause (e.g., a leak from corrosion caused by tree root interaction with pipeline). An example of a typical cause and cause detail from the PHMSA database would be "Corrosion Failure – External Corrosion." With regard to trees along transmission pipelines across the rest of the United States, PG&E reiterates its view that a prudent operator includes right-of-way management as one of the critical pieces of a comprehensive Transmission Integrity Management Program.

Also note, as part of PG&E's Community Pipeline Safety Initiative, PG&E referenced an American Gas Association benchmarking survey, and conducted its own benchmarking of how other operators are approaching vegetation management in the area above and around the natural gas transmission pipeline. What we found is that most other operators maintain a safe and clear area above the pipeline, keeping the area above the pipeline free of structures and vegetation at a minimum of 10 feet and up to 25 feet from the edge of the pipeline.

Q37: Regarding the above, does PG&E have a historical safety reason for tree removal along their underground transmission pipeline? If there is no historical reason, what are PG&E's reasons for believing that trees will cause incidents along the underground transmission pipeline in the future?

The Community Pipeline Safety Initiative is a proactive safety program, and is based on industry best practices, third-party guidance and the studies we commissioned related to tree root and pipeline interaction.

The studies found that at approximately 75% of the 53 sites examined, and at 90% of sites with trees within five feet of the pipeline, tree roots were found to have caused damage to the pipe's external coating. When the external coating is damaged, it can lead to corrosion and leaks. The studies also found that tree roots can wrap around a pipe and cause stress to it, especially during the windstorms that uproot trees and potentially pipes. In addition, below are instances where PG&E has documented tree roots causing damage to gas transmission pipelines:

Pipeline	Location	Date	Description of Damage
L-137A	Eureka	September 2005	Leak
L-142S	Kern	2013	Coating Damage
DFM 1816-01	Santa Cruz	2013	Coating Damage
DFM 1816-01	Aptos	Spring 2014	Pipe Damage (Dent)
L-021E	Healdsburg	October 2014	Coating Damage
DFM 1042-01	Fall River Mills	February 2015	Coating Damage
L-196A	Rio Vista	September 2015	Coating Damage
L-177A	North Valley	October 2015	Coating Damage
L-021D	Sonoma	March 2016	Pipe Damage (Dent)
L-177B	Chico	May 2016	Coating Damage
L-021E	Humboldt	May 2016	Coating Damage

Q38: PG&E is planning on removing trees in recognized areas of landslide and liquefaction potential. How did PG&E measure the risk mitigation of tree removal compared to the potential risk of enhanced ground instability when trees are removed? PG&E concluded that removal of most of the targeted trees along Las Trampas Creek will not impact bank erosion, but that does not account for the balance of the trees that will pose a bank erosion hazard. How does PG&E plan to mitigate this risk that they seem to be introducing to the pipeline?

As part of PG&E's Community Pipeline Safety Initiative, every project is individually reviewed by a team made up of biology, cultural and environmental field specialists. This review includes reviewing landslide and liquefaction potential, along with fault crossings, seismic activity, and levee/erosion areas. When evaluating landslide and liquefaction potential, PG&E uses U.S. Geological Survey (USGS), California Geological Survey (CGS), and LiDAR analysis as resources.

Landslide potential is evaluated based on soil, rock type, slope, mapped slope failures (CGS and PG&E-LiDAR), and Peak Ground Acceleration (PGA). For sections that are susceptible to landslides, such as Las Trampas Creek, PG&E will continue to monitor the areas post-tree removal to confirm continued bank stability and mitigate any identified issues as needed as part of its Geohazard Threat Identification, Monitoring and Mitigation Program.

Liquefaction potential is evaluated based on PGA, soil type, depth of ground water, and documented liquefaction from past earthquakes based in part on mapping by the USGS; liquefaction potential is not affected specifically by the presence or absence of tree roots. Due to Lafayette's general proximity to the Concord Fault, the area is susceptible to liquefaction. PG&E's gas transmission pipelines are generally resistant to earthquake damage and the potentially resulting liquefaction due to the materials from which they are constructed. PG&E has proactive measures in place to monitor and, if needed, mitigate concerns related to liquefaction or other ground movement threats through its Geohazard Threat Identification, Monitoring and Mitigation, Fault Crossing Study and Mitigation, Shallow and Exposed Pipe Monitoring and Mitigation, and Vintage Pipe Replacement Programs.

Please note that while removal of trees may increase the risk of soil erosion and landslides in some instances, this is a site-specific occurrence that depends on the type and size of vegetation, topography and geology, as well as the surface water and groundwater conditions. Additionally, the method of removal (stumping vegetation vs. removing root structures) and change in vegetation density (removal of all vegetation vs. selective or limited removal) may change the impact on the landscape. In Lafayette, the majority of trees initially identified for removal will remain in place with ongoing monitoring. This will leave behind a vegetative cover including leaf litter, grasses, shrubs and adjacent trees, which will limit soil erosion.

Q39: The Dynamic Risk “final report” issued August 30, 2013, contained this caution about the potential for decaying dead tree roots to cause pipeline corrosion:

"One factor not considered in this assessment, and also requires consideration as part of the development of a tree root removal program, is the effect of tree roots that are not alive and have the potential to decompose. It is recognized that the decomposition of organic matter will produce carbon dioxide (C02) and this has the potential to increase the susceptibility to cracking of the outside diameter pipe surface. Further study, assessment and consideration for this phenomenon is required."

The above caution does not appear in Dynamic Risk’s rewrite of their final report, issued January 17, 2014. Instead, this sentence appears in the 2014 report: "There was insufficient data collected in this study to draw any conclusions as to whether the presence of dead tree roots in contact with the pipe has any impact on pipeline integrity." Was there further assessment and consideration for this phenomenon, as required by this report? What is the name of the person(s) who expressed concern about the potential added hazard of dead tree roots in the 2013 study, and why was the 2013 alert about the potential for added corrosion from dead tree roots, and the recommendation to better understand and consider this phenomenon, deleted from the 2014 report?
(Sources: https://docs.wixstatic.com/ugd/de4240_8a5875dbc38747e5a5daf27b1a0b12db.pdf and https://docs.wixstatic.com/ugd/de4240_74429ce370ae4fd8a98af6f50b7b7d67.pdf)

The two reports served different purposes in the development of PG&E's Community Pipeline Safety Initiative and considered different scopes and source data.

The Dynamic Risk report dated August 30, 2013, "Tree Root Interference Threat Analysis," documented a high-level evaluation, based upon literature reviews, integrity threat management considerations, and limited field data of potential threats to buried pipelines resulting from interactions between tree roots and pipelines; and identified general requirements and recommendations for the initial development of PG&E’s Community Pipeline Safety Initiative. The 2013 report’s recommendation for further assessment of the phenomenon of dead tree roots in contact with pipelines was established by the Dynamic Risk personnel involved in the completion of the report. The recommendation for further assessment of the phenomenon was referred to subject matter experts in the fields of corrosion and susceptibility to environmental cracking at Det Norske Veritas, and Det Norske Veritas' subsequent conclusion that insufficient data specific to dead tree roots were available to establish whether contact with dead tree roots impacts pipeline integrity was incorporated into the 2014 report.

The Dynamic Risk report dated January 17, 2014, "Tree Root Interference Assessment," supplemented the 2013 report, incorporating additional source data collected from 53 targeted excavations and additional evaluations performed for PG&E by contractors and subject matter experts including Det Norske Veritas. This additional work confirmed the conclusion of the 2013 report that the presence of tree roots increases a pipeline's susceptibility to external corrosion and environmental cracking by causing damage to the coating.

Q40: Regarding the above, why did CPUC request a copy of the 2013 version of the report, but this version was never distributed? Why are the authors and contributors different for the 2013 and 2014 reports, and why are there so many substantive differences between the two reports?

PG&E records do not indicate that the CPUC has requested or received a copy of the 2013 Dynamic Risk report through PG&E's formal data request process, and PG&E does not have insight into the public availability of any copy of the report that may have been acquired by the CPUC outside of this process. Please note that PG&E makes its records available for inspection at all times by the CPUC, and PG&E will provide a copy of the 2013 report to the CPUC promptly upon request.

PG&E considers the authors of both the 2013 and 2014 reports to be Dynamic Risk; PG&E does not have insight into Dynamic Risk's internal report-preparation role assignments. The reports issued in 2013 and 2014 considered different scopes and source data and served different purposes in the development of PG&E's Community Public Safety Initiative.

Q41: Regarding the above, Table 2 (page 14) indicates that tree removal without root removal is less safe than tree removal with root removal (because of lessened threat from external corrosion/cracking). Why was this information removed from the 2014 version of Dynamic Risk's report?

The report issued in 2014 was not a rewrite of nor a revision to the report issued in 2013. Please see response to question 39 for descriptions and a comparison of the reports issued in 2013 and 2014.

Please note, Table 2 of the Dynamic Risk report issued in 2013 does not indicate that tree removal without root removal is "less safe" than tree removal. This interpretation is inaccurate for the following reasons:

- Table 2 describes the reduction of likelihood of external corrosion and cracking for the tree-only removal option as "Maybe," which indicates that not enough data are available to be able to conclude "Yes" or "No" at this time; a valid direct comparison of the reduction of likelihood of external corrosion and cracking associated with this option with that of any other option cannot be made.
- Table 2 data are generalizations; the degree to which any mitigation option may actually reduce any threat likelihood, absolutely or relative to any other mitigation option, will be site-specific.
- Table 2 is limited to the four example threats listed and does not account for probable effects of each mitigation option on all potential threats; see Table 1 of the report for examples of other threat categories that are not included in Table 2.
- Table 2 does not account for potential damage to the pipeline, the environment, or the public resulting from the excavation activities required to remove the roots as well as the remainder of the tree.

Q42: Regarding the above, what data did PG&E collect and analyze in support of its decision to leave the roots in place of the trees being destroyed adjacent to its transmission lines? Please provide a copy of the analysis.

Dynamic Risk's analyses are documented in the Dynamic Risk reports issued in 2013 and 2014. Please see response for question 39 for descriptions of these reports and the data analyzed therein and response for question 54 for copies of the reports.

Q43: Regarding the above, is there a possibility that PG&E could be introducing further pipeline damage via external corrosion and cracking by implementing the CPSI program in the state of California?

As described in response to question 39, insufficient data were available to draw any conclusions about the effects of the interactions of dead tree roots on pipelines.

Please note, the Dynamic Risk reports issued in 2013 and 2014 both concluded that the continued presence of live and growing roots in the proximity of a pipeline is associated with a high probability of adverse effects on the pipeline; implementation of the Community Pipeline Safety Initiative protects transmission pipelines from external corrosion and environmental cracking damage by eliminating existing and preventing future interactions of growing tree roots with pipelines.

Q44: Regarding the above, a table on page 14 is titled "Examples of Monitoring and/or Mitigation Actions and Effect on the Risk Profile." In that table it looks at the reduction of threat likelihood with different mitigation actions. Tree removal and Root Barrier System provide the exact same benefits in all categories (external corrosion/cracking, lightning, weather/outside force, and fatigue). Given this information why is PG&E claiming removal of trees is the only way to reduce root/pipeline interaction?

PG&E does not believe that removal of trees is the only method available to reduce interactions between tree roots and buried pipelines; rather, PG&E has determined that at this time removal of trees is the available method that is best able to reduce interactions between existing and anticipated tree roots and the existing PG&E gas transmission pipeline system.
Please note, Table 2 of the Dynamic Risk report issued in 2013 does not indicate that tree removal and root barrier system mitigation options provide "the exact same benefits" of threat likelihood reduction. This interpretation is inaccurate for the following reasons:

- Table 2 describes the reduction of likelihood of external corrosion and cracking for both options as "Maybe," which indicates that not enough data are available to be able to conclude "Yes" or "No" at this time; a valid direct comparison of the two options cannot be made.
- Table 2 data are generalizations; the degree to which any mitigation option may actually reduce any threat likelihood, absolutely or relative to any other mitigation option, will be site-specific.
- Table 2 is limited to the four example threats listed and does not account for probable effects of each mitigation option on all potential threats; see Table 1 of the report for examples of other threat categories that are not included in Table 2.

Q45: Regarding the above, the table on page 14 also lists alternative mitigation actions and the expected risk reduction for each alternative. The alternatives listed include (1) tree removal with root removal; (2) tree removal without root removal; (3) deployment of a root barrier system. Alternative 2 (which PG&E chose to implement) is shown in the table to provide the same effect on risk reduction as alternative 3. Alternative 1 is shown in the table to provide better risk reduction than alternatives 2 or 3. Please describe what investigation was made to explore the potential of a root barrier system before the concept of a root barrier system was deleted from the 2014 re-write of Dynamic Risk's 2013 report.

To clarify, no information was "deleted" from the 2014 report; the report issued in 2014 was not a rewrite of nor a revision to the report issued in 2013. Please see response to question 39 for descriptions and a comparison of the reports issued in 2013 and 2014.

PG&E has consulted with certified arborists about the potential use of root barrier systems and has determined that the use of root barrier systems is not a reasonable alternative to tree removal in the context of PG&E's Community Pipeline Safety Initiative for the following reasons:

- Root barrier systems typically are not designed to be installed around gas transmission pipelines but around individual trees. Root barrier systems are most commonly used for the following purposes:
    - To direct roots downward, away from shallow infrastructure such as sidewalks or shallow buried pipelines (not including gas transmission pipelines, which are typically installed at greater depths) or other utilities. Please note, roots directed downward from the surface of the ground become more likely to encounter and interact with gas transmission pipelines.
    - To contain a tree's roots within a specific boundary around the tree, such as within the tree's dripline. As described below, root barrier systems intended to contain roots within a specific boundary around a tree should be installed at the same time as the tree.
- The Community Pipeline Safety Initiative is designed to mitigate interactions of existing trees and existing pipelines, while root barrier systems are best suited for installation at the same time as new pipelines and new trees. Installation of a root barrier system between existing pipelines and trees exposes both to excavation-related threats.
    - Pipelines are exposed to possible mechanical damage that could result in a safety incident.
    - Existing tree roots will be cut or pruned. Roots damaged by pruning can make a tree unstable and more susceptible to disease.
- The installation of a root barrier system does not prevent root regrowth.

Q46: Dynamic Risk's 2014 report "Tree Root Interference Assessment" refers (in section 11, references) to "Effects of Tree Roots on External Corrosion Control," draft status report, 12/19/2013 by Krajewski, Beavers, and Moghissi. Ref: ftp://ftp2.cpuc.ca.gov/PG&E20150130ResponseToA1312012Ruling/2014/03/SB_GT&S_0264781.pdf Please provide a copy of this 12/19/13 report.

Please see the attachment "*2014 Dynamic Risk Report Attachments*" (beginning on PDF page 107) for a copy of the Det Norske Veritas' report "Effects of Tree Roots on External Corrosion Control" (first issued on December 19, 2013; final revision issued on March 25, 2015).

Q47: The 2014 Dynamic Risk report recommended performing supplementary work on ground penetrating radar to determine if it is an effective means for identifying and characterizing the location and extent of roots near buried pipelines. Please identify what follow-up studies were done in response to this recommendation and provide copies of the study documentation.

PG&E has not conducted further assessment of the effectiveness of ground-penetrating radar (GPR) for the evaluation of tree root interaction with buried pipelines; PG&E already determined that GPR was unlikely to contribute significantly to the Community Pipeline Safety Initiative due to the following inherent system limitations:

- GPR is not likely to detect small roots. Roots must be larger than about 0.6 inches in diameter to be detectable by GPR at typical pipeline depths.
- GPR is not likely to detect roots growing in a vertical orientation rather than a horizontal orientation.
-

Please see attachment *"2014 Dynamic Risk Report Attachments"* (beginning on PDF page 189) for a copy of "Evaluation of Horticultural Factors and Soil Conditions Related to Root Systems Development of Orchard Trees Planted Near Gas Transmission Lines" (Krauter et al, issued December 20, 2013; cited as Reference 7 of the 2014 Dynamic Risk report) for details.

Q48: Please provide the details of PG&E's risk assessment algorithm that results in certain trees in the company's pipeline ROWs to be classified as "unacceptable risk" (thus requiring destruction), versus other trees to be classified as "manageable risk" (requiring monitoring but not destruction). We are seeking the inputs to this algorithm, methods of quantification, and the computational details that result in the classifications described in the preceding sentence.

PG&E calculates risk for all gas transmission pipelines in Lafayette and across its service area in a similar fashion. Many important factors are analyzed in determining manageable versus unacceptable tree risks, such as:

- Tree species
- Distance from the tree to pipeline
- Expected size at full growth
- Distance from the top of the pipeline to ground surface
- Pipeline characteristics (i.e. coating type, pipeline diameter, installation date, operating pressure)
- Weather related and outside forces including lightning, wind loading, seismic activity and soil instability
- The ability of first responders to safely access the pipe in an emergency and during critical maintenance activities
- Impact of a potential safety incident on the population around the pipeline

PG&E developed its risk model by leveraging industry best practices, independent research from the tree root study as described in the Dynamic Risk report issued in 2013, and its own historical inspection and maintenance records. PG&E continues to collect and evaluate information from its ongoing inspection and maintenance records to quantify and validate the risks that trees pose to pipelines. PG&E's risk model has risk factors with associated risk values as outlined above that collectively contribute to a computational overall risk score. The risk score is used to determine whether the tree presents an unacceptable or manageable risk that a prudent operator is required to consider in order to continue to maintain a safe operating pipeline system. Please note, because PG&E's tree risk model analysis is site-specific, and PG&E strives for continuous improvement of the model, input factors, quantification values, and "computational details" are subject to change.

Q49: In a December 1, 2017, letter from Joe Echols of PG&E to Martin Bernal, City Manager of Santa Cruz, titled "Pacific Gas and Electric Company's Undertakings Regarding Tree Removal Within the City of Santa Cruz for the Community Pipeline Safety Initiative", Mr. Echols wrote on page 4:

"PG&E will consider reasonable alternatives for mitigating potential pipeline safety issues, including but not limited to: "..."b) Regular, ongoing monitoring and inspection of pipelines, including possible use of subsurface radar to determine whether, and to the extent to which tree roots have grown into contact with pipelines. c) Root barriers to protect pipeline coating when appropriate. "..."e. Potential pipeline retrofitting to accommodate in-line inspections or other inspection technology."

Why were subsurface radar and root barriers not offered similar "reasonable alternatives" to tree cutting for the City of Lafayette? If PG&E is planning on retrofitting the Lafayette pipelines to accommodate in-line inspections, as PG&E claims, wouldn't this be classified as an alternative for mitigating potential pipelines safety issues, e.g., removing Lafayette trees?

PG&E has considered the potential use of subsurface radar (also known as ground-penetrating radar or GPR) and has determined that the use of GPR is not a reasonable alternative to tree removal in the context of PG&E's Community Pipeline Safety Initiative for the following reasons:

- GPR is not able to detect all roots that may be interacting with and causing or contributing to an unsafe condition on a gas transmission pipeline. Please see response to question 47 for details of GPR technology limitations in the context of PG&E's Community Pipeline Safety Initiative.
- GPR is not a federally-approved assessment tool. It is not equivalent to the three federally-approved monitoring and inspection methods PG&E incorporates in its Transmission Integrity Management Program: in-line inspection (ILI), direct assessment (DA), and strength (pressure) testing.

PG&E has also consulted with certified arborists about the potential use of root barrier systems and has determined that the use of root barrier systems is not a reasonable alternative to tree removal in the context of PG&E's Community Pipeline Safety Initiative for the following reasons:

- Root barrier systems typically are designed to be installed around individual trees, not around gas transmission pipelines.
- Root barrier systems are best suited for installation at the same time as new pipelines and new trees.

Please see response to question 45 for additional details of root barrier system limitations in the context of PG&E's Community Pipeline Safety Initiative.

Please note, retrofitting transmission pipelines to accommodate in-line inspections also requires excavation of the pipeline, exposing pipelines and tree roots to the excavation-related damage described in the response to question 45.

Additionally, while PG&E is concerned about how tree roots can interfere with pipes underground, emergency access to the pipeline and keeping the area clear for safety crews are other reasons for PG&E's gas safety work. This work is about being proactive and preventing safety incidents from occurring. The standards PG&E uses to guide this safety work are based on industry best practices, which can be found in the publicly available report from the U.S. Department of Transportation's Pipelines and Informed Planning Alliance available online at: http://www.ingaa.org/file.aspx?id=11683.

Q50: Please explain the decision to cut the trees and leave the roots remaining in place versus removing the entire tree and root structure.

In general PG&E prefers to leave roots in place because removing the root structure along with the remainder of a tree would involve excavating the pipeline. Excavation of a pipeline for any reason should be performed only when necessary; excavation activities carry inherent risks such as potential interference with or damage to the pipeline itself as well as other nearby infrastructure (i.e., other buried utilities such as water, sewer, and electric facilities) and vegetation, and the increased ground disturbance also significantly increases the environmental impact of the work.

Please note, as described in the responses to questions 39 through 43, insufficient data are available to draw any conclusions about the effects of the interactions of dead tree roots with pipelines, and removing the roots along with the rest of a tree is not known specifically to provide additional benefit. By leaving tree roots intact, PG&E seeks to maximize the known benefits of removing the presence of live and growing roots from the vicinity of a pipeline while minimizing the known excavation-related risks to the pipeline and surrounding environment described here and in response to question 45.

Q51: Over the past 20 years, how many gas transmission line safety incidents caused by tree roots did PG&E report to PHMSA?

PG&E records do not indicate that PG&E has reported any gas transmission pipeline incidents caused by tree roots to PHMSA during the past 20 years. Please see response to question 53 for information about and a link to PHMSA's online pipeline incident database.

Please note, PG&E's Community Pipeline Safety Initiative is intended to prevent gas transmission pipeline safety incidents by eliminating potential risks to the pipeline, such as those caused by tree roots, within the right-of-way and to ensure that the area above the pipeline is safe and clear for access in an emergency or if a required repair is identified during maintenance work.

Q52: Please describe any gas transmission line safety incidents caused by trees in PG&E's service area in the last 20 years that were not reported to PHMSA.

PG&E records do not indicate that PG&E has identified but not reported to PHMSA any gas transmission pipeline incidents caused by tree roots in the past 20 years.

Q53: How many underground gas transmission line safety incidents caused by trees were reported to PHMSA in the last 20 years by any pipeline operator in the U.S.?

A PG&E review of PHMSA's reportable transmission incident data identified at least seven reportable gas transmission pipeline incidents involving trees. Please see the table below for a summary of these incidents.

Year	Pipeline Operator	Summary of Cause
1986	CONSUMERS POWER CO	Lightning travelling through tree roots damaged pipeline
1987	DELHI GAS PIPELINE CORP	Root growth caused leak on pipeline
2003	CENTERPOINT ENERGY PIPELINE SERVICES	Lightning travelling through tree roots damaged pipeline
2003	J - W GATHERING CO	Falling tree struck facilities
2009	DOMINION PEOPLES	Falling tree struck facilities
2009	PANHANDLE EASTERN PIPELINE CO	Falling tree caused erosion under pipeline
2014	ENABLE GAS TRANSMISSION, LLC	Falling tree struck facilities

Data and supporting documentation for PHMSA-reportable pipeline safety events are available on PHMSA's website here: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.

Please note that the PHMSA reportable database does not typically include the prevailing conditions that contributed to the direct cause, such as leak from corrosion caused by tree root interaction with pipeline. An example of a typical cause and cause detail from the PHMSA database would be "Corrosion Failure – External Corrosion."

Q54: During the May 2018 Open House in Lafayette, none of the PG&E experts we spoke with were aware of the 2013 Dynamic Risk Assessment root study. Also, one employee indicated that the 2014 tree root study was updated in 2015. Although these studies lack the scientific weight of being independent and third-party reviewed research, they clearly are having a significant impact on PG&E risk assessment and pipeline ROW decision making. Please provide copies of all versions of this study.

The table below is a summary of the Dynamic Risk reports initially issued in 2013 and 2014. The report issued in 2014 was not a rewrite of or a revision to the report issued in 2013.

Please note, the Dynamic Risk report initially issued in 2014 incorporated the results of a literature review performed by Det Norske Veritas, which included independent and third-party reviewed materials. Please see response to question 55 for details of the literature review.

Report	Revision[1]	Issue Date	Attachment
Tree Root Interference Threat Analysis	1	April 29, 2013	*TRITA_Rev1*
Tree Root Interference Assessment	1	January 17, 2014	*TRIA_Rev1*
	2	February 19, 2014	*TRIA_Rev2*
	3	April 27, 2015	*TRIA_Rev3*[2]

[1] "Revision 1" is the first version of a report issued.
[2] This revision of the report includes "Volume II – Tree Root Interference Assessment Attachments."

Q55: Was the PG&E's 2014 Dynamic Risk Assessment study conducted with the assistance of Bronson Ingemansson who manages the tree removal spreadsheets and algorithms for PG&E's CPSI program? Can PG&E point to any independent, peer-reviewed tree root & pipeline interference study that was conducted in the last 10 years?

Bronson Ingemansson's role in the assessment documented in the 2014 Dynamic Risk report was limited to the following responsibilities:

- Develop the project scope of the assessment
- Identify trees to be included in the assessment
- Serve as PG&E's point of contact for Dynamic Risk and other contractors and subject matter experts

The Dynamic Risk report issued in 2014 incorporated the results of a literature review performed by Det Norske Veritas. Please see attachment "*2014 Dynamic Risk Report Attachments*" (PDF page 107) for a copy of the Det Norske Veritas report "Effects of Tree Roots on External Corrosion Control"; section 2.1 of the Det Norske Veritas report (PDF page 115) is a summary of the literature review, and section 2.2 (PDF page 117) is Det Norske Veritas' list of references. Please note that PG&E does not own the rights to distribute copies of these reference materials.

Q56: What studies have PG&E conducted or that are known to PG&E which describe the benefits of tree roots in the proximity of pipelines, including the lessening of soil erosion, landslides, liquefaction (during earthquakes), and also the benefits of moisture removal from the soils surrounding pipelines?

PG&E has not conducted and is not aware of any studies that indicate that the presence of tree roots in the proximity of gas transmission pipelines, and any resulting interactions, provide a benefit of any kind to either the pipeline or the surrounding environment. As described in the Dynamic Risk report issued in 2013, best practice in the pipeline industry, consistent with the Community Pipeline Safety Initiative and Pipelines and Informed Planning Alliance (PIPA) recommended practices, is to establish a well-defined pipeline right-of-way, both to ensure that vegetation that poses a potential threat to the integrity of the pipeline system does not exist on the right-of-way and to ensure unrestricted access to the pipeline for routine maintenance activities or in the event of an incident. (Highlights of selected industry right-of-way vegetation management programs are summarized in Section 5.3, "Review of Industry Best Practices," of the 2013 Dynamic Risk report.) As the prohibition of vegetation that could interact with pipelines is a consistent best practice in the pipeline industry, studies to evaluate potential benefits of trees on the right-of-way are not known to exist.

Q57: Has PG&E found soil failure in locations where they have previously conducted tree cutting? (One possible example: https://www.youtube.com/watch?v=kphxVkzrNkc)

PG&E records do not indicate that any instances of soil failure caused by vegetation removal along PG&E's gas transmission system have been identified.

Additionally, in May 2017, PG&E conducted a site assessment of several hazard tree locations in close proximity to Las Trampas Creek in Lafayette to evaluate the risk of slope failure subsequent to tree removal. PG&E concluded that for most of the trees in the Las Trampas Creek corridor, it is anticipated that removal will not pose a bank erosion hazard due to their adequate setback distance from the Las Trampas Creek slope break. PG&E will continue to monitor the Las Trampas Creek corridor post-tree removal to confirm continued bank stability and mitigate any identified issues as needed.

Q58: Lafayette's firefighters, fire captains and hazmat professionals reject PG&E's CPSI rationale and have gone on record as saying that gas pressure must be shut off and the gas dissipated before any emergency personnel will enter a live leak area. This procedure is required by federal law per CFR 192.615 which states "Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property." The removal of trees does not provide the safety benefits of automatic or remotely activated shut-off valves on transmission lines, nor is it required by any section of the CFR. How does PG&E explain the fact that first responders in Lafayette consistently dispute PG&E's most frequently cited reason for tree removal? Is PG&E's desire to remove discretionary physical objects near pipelines a safety consideration, or is it a timing consideration to minimize the timeframe of gas flow disruptions to customers?
(Source: https://www.law.cornell.edu/cfr/text/49/192.615)

As a utility provider, it is PG&E's responsibility to address any potential risk identified to keep customers and communities safe. Multiple layers of protection are essential to keeping the gas transmission pipelines and the people who live near them safe. These include inspecting and testing PG&E's pipelines, conducting leak surveys, and upgrading pipelines as warranted. Shutoff valves are another important component of PG&E's emergency response efforts as a reactive response.

When it comes to safety, PG&E also needs to be proactive. Every emergency situation is different. Working together with local first responders, PG&E crews must assess each individual situation and make specific decisions about how best to make the situation safe to protect customers and the public. It is difficult to determine what first responders – whether it is PG&E's safety crews, fire, police, or ambulance – will need in the event of an emergency, which is why it is critical that the area above the pipeline is clear for access.

Q59: Lafayette's March 27, 2017 Tree Cutting Agreement states "PG&E is conducting a community pipeline safety initiative to ensure that first responders and safety crews have immediate access to their pipelines in an emergency..." Also, the 2018 Gas Safety Plan from PG&E states "When a structure is identified in the pipeline right-of-way, PG&E works with the local jurisdiction or property owner to remove and/or relocate the structure outside of the right-of-way and away from the pipeline." The Plaza Park trellis is such a structure and lies directly over the transmission pipeline and is a violation of Utility Standard: TD-4490S which explicitly prohibits "buildings, structures, or foundations" but does not prohibit trees in the right-of-way. It also represents a significant impediment to digging should a rupture occur beneath it. According to documents provided by the City during a Public Request Act, it was communicated to City Staff that PG&E would relocate the line in order to remedy this situation; however, this does not appear to be the case. On what basis was the decision made to ignore this significant obstacle sitting on top of the pipeline? Who made the decision, and why was the designation changed three times from: need to remove, pipeline to be rerouted, to leave in place?
(Source:ftp://ftp2.cpuc.ca.gov/PG&E20150130ResponseToA1312012Ruling/2013/07/SB_GT&S_0263354.pdf)

The decision to leave the trellis in place was made after PG&E performed additional assessments. After confirming pipe depth and coating condition, depth of the trellis footings, and access to the pipe via the grassy areas on each side, PG&E determined that the trellis does not pose a risk to the pipeline, and therefore, may remain in place. PG&E has no plans to move the pipeline at the downtown plaza.

Q60: Regarding the above, why are certain structures, such as the Plaza Park trellis discussed above, and other private structures apparently left on the pipeline, allowed to remain which would significantly hinder the access in the case of an emergency? What are the standards that are applied in making these decisions? Do these standards appear somewhere other than in TD 4490S? If so, please provide a copy of that PG&E standard.

As part of this gas safety work, PG&E works with local residents to review structures located above and around the pipeline. Typically, there is an easement agreement for the area above the pipeline that provides PG&E safe access to the pipe in an emergency or for maintenance work. In general, structures located within the pipeline easement need to be relocated to a safe location away from the pipe.

Similar to our tree-by-tree review, PG&E conducts an in-depth review of each structure and the pipeline in the area to make sure that the structural encroachment does not impede on the ability to monitor, perform maintenance activities or affect the integrity of each pipeline. This includes reviewing the pipeline's integrity management assessment history, the construction practices used to install the structure, and depth of the structure and pipeline. If it is determined that a structure can remain in place, PG&E develops an Encroachment Agreement with the owner and submits it to the CPUC for approval.

PG&E follows TD-4490P-05 "*Structural Encroachment Risk Analysis*" to review structural encroachments to determine any integrity management concerns on the pipeline (similar to the TD-4490P-03 for trees), as well as CPUC General Order GO-112F Section 143.5, which governs encroachments to transmission and distribution gas systems.

In this particular instance, the Plaza Park trellis was reviewed by PG&E's legal and land management teams and it was determined that the trellis was not subjected to the requirements in GO-112F, section 143.5. Regardless of the interpretation of GO-112F section 143.5, PG&E Integrity Management reviews any structure that poses a possible integrity threat to the pipeline (e.g., ground breaking structure above or adjacent to its pipeline) to determine if mitigative activities are warranted. PG&E reviewed the Plaza Park trellis location as described above and concluded that it does not prevent integrity inspections from being conducted nor prevent maintenance activities from being performed. Additionally, previous integrity assessment inspections at this location did not identify this location as an elevated threat.

Please see attachment "*TD-4490P-05*", and refer to CPUC GO-112F, Section 143.5 at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K327/163327660.PDF.

Q61: According to the FAQ in the City Staff Report of March 27, 2017, PG&E is cutting trees for this stated purpose: "We are working with our customers and communities to check the area above the pipeline for any items that could delay safety crews from getting to the pipe in an emergency and making it safe. Items like trees and structures can slow response times and potentially cause damage to the pipe." Why are certain trees being eliminated, but the same size, species, and age tree at a similar distance from the pipeline are NOT being removed from the pipeline? Why is PG&E treating the community's tree in a binary fashion (safe/not-safe)? Could there be further refinement into additional categories, such as "need to explore root interaction" or "leave now but review in near term", etc? (Example sites: the young bay laurels at latitude 37.9462 / longitude -122.1327, (photo: https://goo.gl/4NYUPH), and many mid-sized oaks along the Lafayette-Moraga Trail between cross streets Olivera and Glenside Roads.)

Industry best practice to ensure the safety of the pipeline and the surrounding community is to keep a minimum of 10 feet and up to 25 feet from the pipeline clear. Removing trees near the pipeline also helps ensure safe access in an emergency or for maintenance work and can improve line-of-sight to help prevent dig-ins.

PG&E understands how important trees are to the local community. To ensure only the replacement of trees that pose an emergency access or safety concern, PG&E conducts a review of all trees up to 14 feet from the gas transmission pipeline to determine which trees can remain in place with ongoing monitoring and which trees need to be replaced for safety reasons. The tree-by-tree review analyzes many important factors, such as the tree species, its distance from the pipe, its expected size at full growth, the distance from the top of the pipeline to ground surface, and the ability of first responders to safely access the pipeline in an emergency. The results of the analysis are carefully reviewed by a team of pipeline integrity professionals and engineers, as well as arborists and environmental experts to determine if the tree must be replaced to help ensure emergency access and prevent damage to the pipe, or if it can potentially remain in place with regular monitoring.

Moving forward, PG&E's regular pipeline inspections and patrols will review the trees left in place as part of the Community Pipeline Safety Initiative to determine if they have developed into a safety concern. This could include a change in the tree's health or the stability of soil in the area (which could put the tree at greater risk of falling over and damaging the pipeline) or determine if critical maintenance work is required near the location of the tree.

Q62: In response to CPSI pushback, PG&E has stated: "There are many reasons why it is important to have direct and immediate access to the area above a pipeline. The way we approach pipeline access is similar to why cars cannot park in front of a fire hydrant. While fire trucks do not need to regularly access the fire hydrant, when they do, they need immediate and unblocked access. In an emergency or natural disaster, trees located over or around an underground pipe can delay access by first responders and slow response times. Every second counts in an emergency."

Knowing that an excavator and team is not readily available in the case of an emergency, how many seconds would it take, and what equipment and teams would be required, to excavate a section in the middle of St. Mary's Road? How many seconds would it take, and what equipment and teams would be required to excavate around a 10-20" DBH tree, the median size of tree in Lafayette scheduled for removal? (Source: https://www.pge.com/includes/docs/pdfs/about/environment/ButteCountyCPSITownHallFollowUpAugust2015.pdf)

It is impossible to precisely predict how many seconds it would take for an emergency excavation, as situations can vary based on the severity, time of day, and other factors such as ground conditions, depth of cover, and the size of the pipeline. In a typical emergency excavation, a response team of three to12 people would be deployed, which would include general construction, field services, gas pipeline operations and maintenance (GPOM), traffic control and various other lines of business. Equipment required to complete this work would include:

- Backhoe or excavator
- Crew trucks with excavation and gas isolation equipment
- Operations crew vehicles (if the pipeline is being isolated with valving and for other activities such as welding and external coating)
- Other large trucks such as x-ray trucks, dump trucks, and pipe flatbed trucks

In an emergency situation involving a gas leak, PG&E will remove trees in close proximity using the safest possible methods. The process of removing trees depends on the size of the tree, the severity of the emergency, equipment limitations, and equipment/personnel access. Typically, in a non-emergency situation, PG&E would operate a combustion engine chain saw; however, if there was a risk of ignition posed by the chain saw, limiting its use would be required. In an emergency situation, hand tools would need to be utilized or the area would need to be made safe before combustion engine tools could be used.

In addition, in an emergency situation, PG&E will often have to excavate in order to reach the pipe, and nearby trees can create a hazardous situation depending on the proximity of the tree to the pipe. Excavating next to trees is often avoided due to possible tree instability. If anchor roots are severed in an effort to access the pipe without removing the tree, the tree could become unstable and further increase the amount of time for response, delaying access for emergency response personnel and the effort to make the emergency situation safe.

Q63: Regarding the above, why does “every second count” when the correct procedure is to shut off gas pipeline flow before any repairs are made?

Multiple layers of protection are essential to safe pipeline operations. That’s why we are inspecting and testing our pipes, conducting leak surveys and upgrading pipes. Shutoff valves are another important component of our emergency response efforts, but they are reactive response.

When it comes to safety, we also need to be proactive. Every emergency situation is different, and working together with local first responders, PG&E crews must assess each individual situation and make specific decisions about how best to make the situation safe and protect our customers. We can't foresee what first responders – whether it's our safety crews, fire, police, or ambulance – will need if something goes wrong, which is why it is critical that the area above the pipeline is clear for access. This gas safety work will also help prevent damage to the pipe from tree roots and create a line-of-sight for the area above the pipeline to reduce third party dig-ins.

Q64: A significant number of Lafayette trees identified as “unacceptable risk” fall into this category primarily because their location interferes with PG&E’s need for immediate pipeline access in the event of a pipeline emergency. How many of the 272 unacceptable risk trees in Lafayette are on this list more because they interfere with emergency pipeline access rather than the potential threat of the tree roots to pipeline integrity?

Emergency access is one of more than a dozen criteria incorporated into PG&E’s tree-by-tree review. Other determining factors include, but are not limited to, distance from the tree to pipe, tree species and expected size at full maturity, depth of the pipeline, and ability to access the pipeline in an emergency.

For trees on private property, access is the primary criteria for determining if a tree poses a safety concern. This is due to the different access challenges backyards pose for safety crews, such as fences and other barriers that can delay emergency access. As part of the Community Pipeline Safety Initiative, 94 trees on private property are located too close to the pipeline and need to be removed for safety reasons.

Q65: Regarding the above, please provide the decision criteria that PG&E uses to place a tree in the unacceptable risk category due to emergency access concerns.

The information used to support the risk category that trees provide both a hindrance to access pipelines during an emergency and delay the response time to address the emergency condition were developed by evaluating industry best practices, third party guidance from the Pipeline Informed Planning Alliance (PIPA) and Interstate Natural Gas Association of America (INGAA), as well as interviews and conversations with first responders, including PG&E crews who perform the work. The ability of first responders to safely access the pipeline in an emergency is just one of several criteria pipeline safety experts review when determining if a tree needs to be replaced for safety reasons. The tree-by-tree review also includes factors such as the tree species, its distance from the pipe, its expected size at full growth and the distance from the top of the pipeline to ground surface.

Please note, when reviewing trees on private property, emergency access is a primary criteria for determining if a tree poses a safety concern. This is due to the different access challenges backyards pose for safety crews, such as fences and other barriers.

Please refer to the response to question 143 for the PG&E standards and procedures pertaining to the tree-by-tree review.

Q66: In May 2017, PG&E's spokesperson Jeff Smith explained on a local TV news segment for Lafayette that PG&E needs to remove trees in order to dig out a section of a pipe in the case of an emergency and then said, "we actually squeeze it off with a gigantic pair of pliers". Does PG&E stand by this explanation of how they treat a rupture to a high-pressure steel gas transmission pipeline rupture? What are the steps for repairing a significant rupture, including gas shut-off, dispelling gas, excavation, repair, etc?
(Source: http://abc7news.com/news/lafayette-residents-push-back-against-pg-e-tree-removal/1970139/)

Squeezing is one potential method to stop a leak, which is most commonly used on plastic distribution assets. Please note this is not typical for high-pressure steel gas transmission pipeline. PG&E utilizes pre-determined isolation valves on transmission lines to isolate a section of pipelines. Repair steps for significant loss of gas events vary depending on the incident and corrective steps required to repair the pipeline, which could include, but not limited to replacing the pipeline and welding a sleeve.

Q67: Over the past year (e.g., at the May 9 open house in Lafayette, at the May 30 Pipeline Safety Trust workshop in Richmond, and in an August 2017 meeting in Lafayette), PG&E experts have given diverse and conflicting answers to the question, “In the event of a gas transmission line emergency, does PG&E routinely depressurize the line before attempting to make repairs?” The answers have ranged from, “Yes, we first shut the line down,” to “Every leak is different. We often don’t shut the line down, even when there are very large leaks . . . we actually weld on live (pressurized) transmission lines,” to “These days we no longer need to attempt repairs on live lines. We’ve developed methods to avoid this.” Please clarify PG&E’s operating standards applicable to transmission line gas emergencies--when should the line be depressurized? When should an emergency repair be attempted on a leaking, pressurized transmission line? In the past five years, what percentage of the time has an emergency fix been attempted on a live transmission line, rather than first depressurizing the line? Please provide a copy of PG&E’s operating standards that cover this topic.

Depending on the specific details of the circumstances, all three of the responses quoted above could be a correct response when repairing a leak on a transmission line. Leak repairs are unique and require judgment in determining the most prudent method of repair, and repair methods for transmission leaks include techniques for welding on live lines as well as techniques that require the line to be taken out of service.

The safety of our customers and communities is our top priority. PG&E has developed a Company Emergency Response Plan (CERP) and a Gas Emergency Response Plan (GERP), a subset of the CERP, to ensure a safe, efficient and coordinated response to emergencies affecting both PG&E’s gas transmission and distribution systems. PG&E limits certain critical energy infrastructure information from public disclosure for national security reasons consistent with federal laws that protect this type of information. Therefore, per PG&E’s policies, PG&E is unable to provide a copy of the GERP. Please note that the CERP is reviewed and updated annually in accordance with CPUC GO-166.

Per PG&E’s GERP, PG&E personnel perform leak repairs on gas transmission lines using various approaches depending on the situation. Certain situations will require a gas shut-down prior to repairs, while other situations can involve repairs by using fittings or performing live welding while the line is pressurized. During an emergency, PG&E’s Gas System Planning (GSP) department will provide hydraulic planning and modeling support for an immediate make-safe resolution. GSP addresses the need for shutting portions of the system by determining the best method for system isolation to lessen impacts to customers on the remaining portions of the gas system.

As each incident varies in scope, severity, and duration, Gas Operations must be able to adapt in its response. Repairing, restoring, and returning the gas system to normal can involve various actions depending on the situation. PG&E strives to provide safe and reliable gas service to our customers by choosing repair methods that maintain a dependable gas system.

PG&E is unable to provide the percentage of time that it has performed an emergency repair on a pressurized gas transmission line as this data is not readily available.

Q68: PG&E's CPSI flyer distributed to many Lafayette residents' homes in May 2017 explained the importance of immediate access for first responders in the event of a gas transmission line emergency. The flyer said, "Trees can block safety crews from getting to gas pipelines in an emergency or natural disaster, when every second counts." However, leading up to the summer of 2018 when PG&E had the choice of routing the length of its 6000 ft higher-capacity gas transmission line under St. Mary's Rd or along the parallel Lamorinda Trail (where immediate access could be considerably better), it chose the traffic-disrupting path under St Mary's Rd. This choice is especially perplexing in light of a 2011 gas transmission leak that occurred at a point where the pipeline merely intersected a roadway in Novato. Here is an extract from PG&E's report to PHMSA about this incident:

"Unfortunately, the source of the leak was not at either side of the roadway but appears to be located somewhere under the roadway. Due to the location of the leak it is not feasible to attempt to repair the leak. A new pipe will be installed under the roadway to replace the leaking pipe. Construction is scheduled to begin 10/19/11." [one month after discovery of the leak]

Please explain how positioning a new 6000 ft section of pipeline under St Mary's Rd will result in first responders having immediate access to the pipeline in the event of a gas pipeline emergency (when "every second counts").

PG&E performed a routing study for this pipeline relocation alignment. Based on the study, the existing route on St. Mary's Road was selected instead of the trail nearby due to the landslide prone areas on the trail that could place the pipeline in unstable conditions. The existing alignment is preferred for constructability and is compatible with PG&E's existing land rights. The existing location and alignment also provides direct access for emergency responders from St. Mary's Road in the event of an emergency.

The 2011 leak repair in Novato was located within a pipe casing that crossed perpendicular to a highway that was much more congested than St. Mary's Road. Therefore, PG&E decided to replace the pipeline instead of removing the casing and attempting to repair the leak.

Q69: What is the width of the construction ROW that PG&E is using to install the replacement line this summer along St Mary's Rd? What is the minimum width of the construction ROW that PG&E has prior experience with for installing a 12" diameter transmission line where the circumstances required absolute minimum impact during construction on the pipeline corridor?

PG&E used an approximately 36-foot wide working strip to install the replacement for DFM 3001-01 along St. Mary's Road this summer. The width of a working strip varies for multiple reasons, such as traffic, terrain, other utilities, and dimensions vary on a case-by-case basis. Note, a 36-foot wide working strip is the general guideline for installation of a 12-inch diameter transmission line.

Q70: Regarding the above, please explain the routing considerations and thinking that went into the choice to route the new line under St Mary's Rd rather than along Lamorinda Trail (which closely parallels the road).

PG&E performed a routing study for this pipeline relocation alignment. Based on the study, the existing route on St. Mary's Road was selected instead of the trail nearby due to the landslide prone areas on the trail that could place the pipeline in unstable conditions. The existing alignment is preferred for constructability and is compatible with PG&E's existing land rights.

Q71: In 2017, PG&E proudly announced their new "best-in-class training environment" training facility in Winters, CA. Given that trees have been given as a reason for implementing the $500 Million CPSI program, what training is being provided for dealing with pipeline ruptures caused by tree roots?

(Source: http://www.pgecurrents.com/2017/09/27/pge-opens-new-academy-to-train-gas-safety-workforce-of-the-future/)

PG&E's gas training program includes several courses related to gas pipeline safety and emergency response procedures. The trainings focus on how to detect leaks and how to respond to different types of emergencies, regardless of the cause. PG&E courses include, but are not limited to:

- Leak Survey Detection and Grading
- Leak Pinpointing
- Plastics Basics
- Gas Service Representative (GSR) Leak Grading
- Steel Squeeze
- Squeeze Steel Pipe ¾ to 2 inch
- Automated Valve Emergency Response
- Ground Patrol
- Awareness of Haz-Gas Immediately Dangerous to Life or Health (IDLH) Atmospheres
- Working in Hazardous Gaseous Atmosphere Practical (Pressure Demand Equipment)
- Gas Emergency Response Plan (GERP) Awareness and Team Training

Q72: In the May 2018 CPSI Open House in Lafayette's Veterans Memorial Center, PG&E displayed large placards to support the tree-cutting program, including a quote and photograph of Contra Costa Fire Chief, Jeff Carmen. The only purpose to show his photograph, name and position was to imply that Chief Carmen endorses the CPSI program. On the contrary, he wrote in an email on May 9: "Please don't confuse my statement that I somehow endorse PG&E's tree removal program. I simply support the initiative to provide first responders access to pipelines. The way PG&E is implementing their program is outside of my expertise." Why did PG&E purposely mislead the Lafayette public in this regard?

Throughout PG&E's service area, PG&E works closely with first responders, including fire, police, and community emergency response teams (CERT), to share information on gas pipelines and coordinate on all PG&E's gas safety programs in the region. What we've found is that many first responders agree with the industry best practice of keeping the area above and around the natural gas transmission pipeline clear.

Q73: If PG&E conducts twice-yearly patrols of their pipeline, why was the 4' exposed segment of pipeline near Beechwood Dr. not known to the PG&E representatives, including a PG&E land-use employee, when residents walked the trail with them in May 2017? And why wasn't it known to PG&E despite Lafayette residents submitting this pipeline exposure over 10 years ago? Can PG&E provide patrolling records that include when the exposed pipeline was first identified? Why only after Save Lafayette Trees efforts did this pipeline repair become a scheduled project?

PG&E performs patrols of the gas transmission pipeline at least quarterly, and conducts leak surveys of the pipeline twice a year.

In regards to your question about the section of exposed pipeline on the side of the Lafayette-Moraga Regional Trail near Beechwood Drive, PG&E identified this section in patrol records in 2011. PG&E's pipeline patrol re-inspected this section in early 2013 and later re-inspected in 2015.

In 2014, PG&E's Transmission Integrity Management Program reviewed the location and incorporated the site into its Shallow and Exposed Pipe Program to monitor and determine mitigative actions. PG&E discussed mitigation measures with the City and East Bay Regional Park District. We were unfortunately unable to reach an agreement with the agency on a mitigation plan at that time. In the interim this location has been continually monitored and inspected per PG&E's Atmospheric Corrosion Program to determine any changes in condition that warrant further mitigative activity. The last inspection (performed June 2017) did not identify any immediate pipeline integrity concerns requiring mitigation. We are currently working with East Bay Regional Parks District to finalize plans to cover this segment of pipeline and expect mitigation to take place in 2019.

Q74: A PG&E representative said at the May 2018 Open House that they patrol the gas pipeline 2x a year. In the August 2017 Pipeline Report for Lafayette, it says, "aerial patrol is performed, at a minimum, quarterly" and later says "PG&E often patrols its gas transmission pipelines monthly", all which are contradictory. Please provide patrol records for the past 10 years so we can determine how often the pipelines in Lafayette have been historically patrolled and how they have been patrolled.

PG&E aerial patrolled its gas transmission pipelines in Lafayette at least quarterly from 2007 through the third quarter of 2012. Beginning in the fourth quarter of 2012, PG&E aerial patrolled its gas transmission pipelines in Lafayette at least monthly. Beginning in the fourth quarter of 2015, PG&E also ground patrolled areas obscured by vegetation at least quarterly. PG&E continues to aerial patrol at least quarterly (often monthly, weather permitting) and ground patrol at least quarterly.

PG&E limits certain gas pipeline, valve, regulator and station information, including its detailed and extensive construction, maintenance, inspection and testing records, from public disclosure for national security reasons consistent with federal laws that protect this type of information. Therefore, per PG&E's policies, PG&E is unable to provide its pipeline patrol records. Please note that PG&E makes its pipeline-related records available for inspection at all times by the CPUC.

Q75: What are the advantages and what are the disadvantages of ground/foot patrolling of transmission pipeline in Lafayette? What are the advantages and disadvantages of aerial patrolling in Lafayette? What is the determined schedule for each type of patrol in Lafayette?

PG&E patrols its gas transmission pipelines to look for indications of construction activity and other factors affecting pipeline safety and operation. Ground patrols are able to review areas obscured by vegetation. Aerial patrols can help review remote areas and areas where ground patrol has restricted access.

In Lafayette, approximately 12 miles of transmission pipeline are aerial patrolled quarterly (and often monthly). This includes nearly a mile of pipeline in densely populated areas, also known as high consequence areas (HCAs), that is aerial patrolled biweekly. In addition, approximately four miles of pipeline obscured by vegetation are ground patrolled quarterly.

Q76: If PG&E has not "pig" inspected any pipeline in Lafayette, and DFM 3001-01 has not been strength tested for 30 years, nor has it been inspected with direct assessment (as confirmed in

PG&E's August 2017 report) and the pipeline characteristics are such that these welds were only visually inspected (as confirmed by PG&E representatives), how can PG&E determine the integrity of the Lafayette-Moraga Trail pipeline with any assurance?
(Source: https://www.law.cornell.edu/cfr/text/49/192.921 and https://docs.wixstatic.com/ugd/de4240_093fdc41fe814b1ba3fa9dfc4994cc1f.pdf)

PG&E utilizes a combination of integrity assessments and maintenance and inspections to manage the integrity of transmission pipelines in Lafayette. Having traceable, verifiable and complete strength test records for the pipelines within Lafayette regardless of when the test was conducted validates the Maximum Allowable Operating Pressure (MAOP) at which the pipeline can operate. The preventative and mitigative (P&M) activities include increased frequency of leak survey and pipeline patrol. Please note PG&E plans to perform direct assessment prior to 2026 for DFM 3001-01 in Lafayette.

Q77: All pipelines in Lafayette were initially installed in the late 1940s or early 1950s. PG&E reports strength testing of lines only starting in 1963 and later, presumably as newer segments of the lines were added. Can PG&E provide integrity testing results specifically for the older segments of pipeline?
(Source: https://www.law.cornell.edu/cfr/text/49/192.619 and D1106107 NTSB rec post SB)

Please see the Pipeline Information Report for integrity assessment results for the transmission pipeline system in Lafayette. In 1961, state regulations began requiring strength testing of gas transmission pipelines prior to placing a pipeline in service. In certain circumstances, pipelines were strength tested prior to 1961. PG&E plans to strength test any gas transmission lines that have not been tested in Lafayette by 2026. Please note that these projects are based on current plans, and those plans are subject to change due to a range of factors including, but not limited to, permitting, material availability, availability of new technologies and outcomes of PG&E's Gas Transmission & Storage Rate Case.

Q78: After San Bruno, the NTSB recommended and the CPUC ordered PG&E to search for all specs, testing, and related records for pipeline system components such as pipe segments, valves, fittings, weld seams in Class 3 locations and Class 1 and 2 High Consequence Areas (HCA). What are the class location and High Consequence Area (HCA) designations in Lafayette? If Lafayette qualifies as any class location or HCA subject to these orders by the CPUC, can PG&E show that they have these records for Lafayette and that these records are traceable, verifiable, and complete? In 2011, at a related CPUC hearing, then Sr. Vice President for Gas Engineering and Operations was quoted as saying: "What you want to know is everything that's in the ground before you start conducting that test, so that you don't put yourself in a situation where you've led to unintended consequences by pressuring that pipe up."
(Source CPUC D11-06-017 https://docs.wixstatic.com/ugd/de4240_37b0ff35e65840fcbc95b1cfd6c3c70d.pdf)

Since 2010, PG&E has completed the records collection and Maximum Allowable Operating Pressure (MAOP) validation of PG&E's entire gas transmission pipeline system, including the gas transmission system operating in Lafayette. During PG&E's MAOP Validation Project, the information from PG&E's traceable, verifiable, and complete documents were combined with engineering analysis, any necessary conservative engineering assumptions, and field-investigations to create the Pipeline Features Lists (PFLs) that contain specifications for pipeline features, such as valves, and the pipeline itself. Because PG&E's gas system is constantly changing, PG&E is continuing to work on the MAOP validation to ensure it is accurate and high quality.

Please see the table below for the class location and high consequence area (HCA) designations for the transmission pipelines within the City of Lafayette.

Line	Class Location Designation(s) Within Lafayette	HCA Designation(s) Within Lafayette
DFM 3001-01	Class 3	Some HCA
DFM 3002-01	Class 1, Class 3	No HCA
L-191-1	Class 1, Class 3	Some HCA
L-191A	Class 3	Some HCA
L-191B	Class 1, Class 3	Some HCA

Please note that PG&E limits certain gas pipeline, valve, regulator and station information, including its detailed and extensive construction, maintenance, inspection and testing records, from public disclosure for national security reasons consistent with federal laws that protect this type of information Therefore, per PG&E's policies, PG&E is unable to provide the requested records.

Q79: Related to above, the PUC requested operators to determine Maximum Allowable Operating Pressure (MAOP) on the weakest section of the pipeline component to ensure safe operation. Can PG&E demonstrate that pipeline MAOP in Lafayette is determined by this requirement?

Since 2010, PG&E has completed the records collection and Maximum Allowable Operating Pressure (MAOP) validation of PG&E's entire gas transmission pipeline system, including the gas transmission system operating in Lafayette. During the MAOP Validation Project, the information from PG&E's traceable, verifiable, and complete documents were combined with engineering analysis, any necessary conservative engineering assumptions, and field-investigations to create the Pipeline Features Lists (PFLs) that contain specifications for pipeline features, such as valves, and the pipeline itself.

In cases where records did not meet the standards of being considered "traceable, verifiable, and complete", PG&E took appropriate actions, such as lowering MAOP where needed, and is performing the necessary strength testing to verify the operating margin of safety of these pipelines, consistent with CPUC section 958. Because PG&E's gas system is constantly changing, PG&E is continuing to work on the MAOP validation to ensure it is accurate and high quality. Additionally, upon installation of any new pipeline, PG&E will determine the MAOP in accordance with 49 CFR Part 192.619.

Q80: This summer, PG&E is replacing a 4" transmission pipeline segment in Lafayette, along St. Mary's Rd., with a 12" pipeline segment, reported by PG&E to increase service capacity to customers in Moraga. The current MAOP is 170 psig. Why is the psig so much lower on this line relative to other pipelines in Lafayette? How does the new 12" pipeline impact the MAOP of the line?

PG&E's replacement project on St. Mary's Road will increase the system capacity (not pressure) of DFM 3001-01 by replacing a segment of 4-inch pipe with 12-inch pipe. The maximum allowable operating pressure (MAOP) will remain unchanged at 170 pounds per square inch gauge (psig) after the replacement. Once the 12-inch pipeline replacement is completed, the current operating pressure will be adequate to maintain reliable service to the customers served by this pipeline.

Q81: PG&E states pipelines are upgraded based upon risk. For those pipelines that risk cannot be assessed, (i.e. no strength testing, no ILI because of low MAOP), how does PG&E determine need of upgrade for safe operation? Does PG&E have plans to increase MAOP to optimize line service in Lamorinda area and/or better accommodate testing ability?

PG&E is required to manage the integrity of its transmission pipelines pursuant to federal code. To prioritize gas transmission pipeline projects, we use a risk assessment approach that takes into consideration historic and potential threats that could impact the safe operation of the pipeline. These can include corrosion, construction or manufacturing-related defects, third-party damage, incorrect operations and weather-related and outside forces, as well as potential impacts to nearby populations, the environment and reliability.

PG&E currently does not have plans to increase MAOP of its transmission pipelines in Lafayette.

Q82: How does PG&E plan to test for internal corrosion on all of Lafayette lines, first one installed in 1947, and not tested completely, or tested at all, in that timeframe? Engineers cannot do in-line inspection on lines with low operating pressures. Will the MAOP be increased with the placement of the new 12" pipeline?

PG&E assesses internal corrosion risk by evaluating the sources of gas or liquids into the pipeline system. Each gas source is tested and is required to meet PG&E's Gas Rule 21 for gas quality. Any free liquids that are found in drips and/or filters or from pig runs are tested for the presence of water or other corrosive constituents.

Additionally, PG&E plans to complete its assessment for internal corrosion on the pipelines within Lafayette by the end of 2027.

Please note the Maximum Allowable Operating Pressure (MAOP) of the new pipeline along St. Mary's Road will remain unchanged at 170 psig after the replacement.

Q83: Lafayette's gas transmission lines were installed over multiple years (dating back to 1947 for some sections). Some sections of these lines were never pressure tested. Some sections were designed, manufactured, and installed before the advent of California's 1961 pipeline safety laws. Please provide the following details for each Lafayette pipeline section that has never been pressure tested:

a. Name of the line
b. Year this section was installed
c. Length of untested section
d. Geographic location of this section
e. Nominal diameter
f. MAOP
g. Weld type
h. Wall thickness
i. Coating type
j. Does this section potentially have "vintage pipeline features" that might make it better suited for replacement?
k. Class location (if multiple, provide details)
l. HCA (yes/no) (if both, provide details)
m. Date when pressure testing will be done on this section

Please refer to the table below for pipeline information for sections of major transmission pipelines in Lafayette of which PG&E does not have a traceable, verifiable, and complete record of strength test.

Name of the line	L-191-1	L-191B	DFM 3001-01	DFM 3002-01
Year untested section(s) was installed	1952, 1962, 1970	1947, 1959	1947, 1954, 1962, 1963, 1965	1953, 1954, 1957, 1965
Length of untested sections (total within	~1.1 miles	~0.73 miles	~2.279 miles	~2.3 miles

Lafayette City boundaries)				
Geographic location of this section	*	*	*	*
Nominal diameter (inches)	10, 12	8	4	6, 8
MAOP (psig)	268, 283, 338	283	170	182
Weld type	Seamless, Electric Resistance Weld	Electric Resistance Weld, Lap Weld[β]	Seamless, Electric Resistance Weld[β], Furnace Butt Weld[β]	Lap Weld[β], Spiral Weld[β], Electric Resistance Weld[β]
Wall thickness (inches)	0.188, 0.219, 0.250, 0.356	0.188, 0.260	0.0830[β], 0.148[β], 0.2030[β], 0.250	0.156[β], 0.168[β], 0.203[β], 0.280[β], 0.316
Coating type	HAA, Other (Double Wrapped), Unknown[β]	Other (Double Wrapped), Unknown[β]	HAA, Tape, Unknown[β]	HAA, Tape, Other (Double Wrapped), Unknown[β]
Does this section potentially have "vintage pipeline features" that might make it better suited for replacement?	MP 26.1-26.3 has a planned project[¥]	No projects have been identified[¥]	MP 2.02-3.11 has planned projects[¥]	No projects have been identified[¥]
Class location(s)	1, 3	1, 3	3	1, 3
HCA (yes/no)	Yes/No	No	Yes/No	Yes/No
Date when pressure testing will be done on this section	α	α	α	α

[*]PG&E limits certain gas pipeline, valve, regulator and station information, including its detailed and extensive construction, maintenance, inspection and testing records, from public disclosure for national security reasons consistent with federal laws that protect this type of information. Therefore, per PG&E's policies, PG&E is unable to provide geographical locations of its pipeline sections. Please note that PG&E makes its pipeline-related records available for inspection at all times by the CPUC. PG&E also provides information about its gas facilities to local jurisdictions that have emergency response responsibilities, such as fire and police departments, through a web portal.

[¥]These sections of pipe may have vintage features; however, the presence of vintage features alone do not pose an integrity concern. Only vintage features that interact with significant ground movement make it more suitable for replacement. Absent ground movement, these features can be monitored and managed without replacement.

[α]PG&E plans to strength test all sections of untested gas transmission pipeline in Lafayette by end of 2026.

[β]PG&E applies Historical Procurement Practices / Sound Engineering Analysis to unknown specifications.

Please note, all of L-191A in Lafayette has been successfully strength tested.

Q84: Federal standards state that gas transmission pipelines should be installed under at least 36" of soil. How many instances has PG&E recorded soils depths that do not meet this threshold?

At what distance intervals are measurements taken along the 11 miles of PG&E gas transmission pipelines in Lafayette? When were these measurements made, and would they be any different if measured today?

Federal requirements, per 49 CFR Part 192.327, pertain to requirements for pipelines at installation and vary depending on soil type and class location. Please note pipeline depths may vary significantly along the length of the pipeline and are subject to change as land leveling and construction activities can affect the amount of cover. Without digging and exposing a pipeline, it is not possible to determine the exact depth at specific locations. Please always call 811 (a free service) at least two working days in advance of any digging or landscaping project to allow crews to mark the location of all underground utilities before any work begins.

However, in 2013, PG&E conducted a system-wide survey of our gas transmission pipelines, which included gathering the depth of the pipeline. The average interval for gathering the pipeline depth was 200 feet for relatively rural areas, and an interval of 100 feet or less for more urbanized areas. This exceeds federal and state requirements. In Lafayette, PG&E gathered the pipeline depth measurements at an average interval of approximately 85 feet, and at closer intervals where conditions allowed for safe access.

For areas where the pipeline is shallow, PG&E has implemented a Shallow and Exposed Pipe Program to identify, prioritize, and mitigate pipeline locations that have insufficient cover and are potentially vulnerable to exposure from third party damage and/or land movement. Routine maintenance allows PG&E to continuously monitor the pipeline condition, and when external factors such as grading, vandalism, or erosion are observed, a project will be created to mitigate the integrity concern.

Q85: In the Gas Operations Data Response document provided on 5/1/2017, PG&E stated on page 3 that the depth of cover is "1.1 feet to approximately 8.9 feet for Line 191-1 near the Lafayette Moraga Regional Trail" and "1.6 feet to approximately 11.5 feet for DFM 3001-01 near the Lafayette-Moraga Trail". Given that residents have reported seeing the exposed pipeline near Beechwood Drive over 10 years ago, how old are these measurements?

The pipeline depth of cover at each tree identified for removal along the Lafayette-Moraga Regional Trail was gathered summer/fall 2017. Please note pipeline depths may vary significantly along the length of the pipeline and are subject to change as land leveling and construction activities can affect the amount of cover. Without digging and exposing a pipeline, it is not possible to determine the exact depth of the pipe at specific locations.

In regards to your question about the section of exposed pipeline on the side of the Lafayette-Moraga Regional Trail near Beechwood Drive, PG&E identified this section in patrol records in 2011. PG&E's pipeline patrol re-inspected this section in early 2013 and later re-inspected in 2015.

In 2014, PG&E's Transmission Integrity Management Program reviewed the location and incorporated the site into its Shallow and Exposed Pipe Program to monitor and potential mitigation measures were discussed with the City and East Bay Regional Park District. We were unfortunately unable to reach an agreement with the agency on a mitigation plan at that time. In the interim this location has been continually monitored and inspected per PG&E's Atmospheric Corrosion Program to determine any changes in condition that warrant further mitigative activity. The last inspection (performed June 2017) did not identify any immediate pipeline integrity concerns requiring mitigation. We are currently working with East Bay Regional Parks District to finalize plans to cover this segment of pipeline and we expect it to take place in 2019.

Q86: What amount of water and subsequent side-force pressure is acceptable on PG&E's transmission pipelines, such as seen on the 4' section of exposed pipeline near Beechwood Drive during the 2017/2018 rainstorms, and years prior?

PG&E considers multiple variables when reviewing external loading conditions on the pipeline, including pipeline material properties and characteristics, exposure extent and length, soil properties, and timing or frequency of applied stresses.

PG&E inspected this section of exposed pipe near Beechwood Drive during the heavy storm season of 2016/2017, and there was very little water in the culvert, making it unlikely that there would be enough water flow to cause a side force stress concern to this pipe section. Additionally, this section was further inspected after the 2017/2018 rainstorms, and no coating damage was observed.

Q87: What risk does PG&E see from exposed pipelines in residential neighborhoods, including atmospheric corrosion, vandalism, falling branches, automotive accidents, etc?

PG&E manages all pipelines in Lafayette and across its geographic territory following federal code requirements. PG&E uses a risk assessment approach that takes into consideration historic and potential threats that could impact the safe operation of the pipeline. These can include corrosion, construction or manufacturing-related defects, third-party damage, incorrect operations and weather-related and outside forces, as well as potential impacts to nearby populations, the environment and reliability.

In regards to exposed pipelines, PG&E has implemented a Shallow and Exposed Pipe Program to identify, prioritize, monitor and if necessary mitigate pipeline locations that have insufficient cover and are (potentially) vulnerable to exposure from third party damage and/or land movement. Routine maintenance allows PG&E to continuously monitor the pipeline condition, when external factors such as grading, vandalism, or erosion are observed, a project will be created to mitigate the integrity concern. Please also see response to question 89 for PG&E's Risk Register scores of various threats to exposed pipelines.

Q88: Is PG&E aware that on multiple occasions, and most recently on May 28, 2018, early morning explosions in Lafayette have woken up residents, and that police suspect that these explosions are an intentional act using "illegal fireworks" or possible "a small pipe bomb" by individuals who have never been caught? Thankfully most of the transmission pipeline is buried, but what is the potential for a serious gas accident should someone criminally place such a bomb at the site of the exposed 4' of pipeline along the Lafayette-Moraga Trail?
(Source: https://news24-680.com/2018/06/11/not-sewer-gas-or-truck-doors-banging-shut-lafayette-police-say-pre-dawn-blasts-are-intentional-act/)

As part of PG&E's ongoing maintenance, we are regularly inspecting and testing the pipe, and if any issues are identified through these efforts, PG&E takes immediate steps to address them. PG&E takes system security threats seriously and strongly encourages customers to report any suspicious activity in the vicinity of PG&E's gas and electric facilities to law enforcement personnel by dialing 911 and to PG&E.

Q89: What internal risk score (via PG&E's Risk Register) does PG&E put on exposed pipeline compared to trees?
(Source: https://docs.wixstatic.com/ugd/de4240_66ca1375a327432a86e73c4efdf49796.pdf)

Please refer to table below for PG&E's Risk Register scores for a number of threats to pipelines. Note, PG&E does not track all possible pipeline threats in the Risk Register.

Threat	Score
Weather-Related Outside Force - Pipe Span Damage*	553
Third-Party / Mechanical Damage - Exposed Pipe	310
Third-Party / Mechanical Damage - Vandalism	97
Weather Related & Outside Forces - Tree	32

DMS062 - Natural Forces - Wind or Winter Storm	5

**Pipe spans are sections of the pipeline that often "span across" geographical features above ground, such as above a creek crossing or large canyon. An example of span damage due to Weather-Related Outside Force could be a heavy rain or flood that could cause settlement in underlying soils and add extreme loading to the span.*

It is our responsibility as a utility provider to provide safe and reliable gas service to our customers, and to address any potential safety risk that we have identified.

Q90: One Lafayette resident has reported seeing an exposed pipeline in Lafayette that is not the recognized 4' segment near Lucille Drive. This resident gave us the general location which does match the pipeline location per PG&E's information. Given PG&E's extensive patrolling and need to monitor for external atmospheric corrosion, what is the location of this exposed pipeline, and how was it remedied to eliminate the chance of corrosion and vandalism?

PG&E has several exposed spans in Lafayette that it monitors for corrosion under its Span Inspection Program every three years. PG&E also has Atmospheric Corrosion and Shallow and Exposed Pipe programs to monitor and mitigate the risks of exposed pipe. Any pipe that requires mitigation is prioritized following an engineering review. In addition, PG&E regularly patrols, inspects and performs routine maintenance activities on its pipeline to ensure the pipeline continues to operate safely.

Regarding the location of all of PG&E's exposed spans in Lafayette, please note that PG&E limits certain gas pipeline, valve, regulator and station information, including its detailed and extensive construction, maintenance, inspection and testing records, from public disclosure for national security reasons consistent with federal laws that protect this type of information. Therefore, per PG&E's policies, PG&E is unable to provide the requested locations of its exposed pipelines.

Q91: Recognizing that dig-ins are the most frequent cause of accidents in PG&E's transmission pipelines, and PG&E conducts twice-yearly inspections, why is line 3001-01 in Lafayette without any visible markers in long stretches? And why are the markers we found along Las Trampas so covered with vegetation, it took residents walking the pipeline three attempts to find & uncover them?

PG&E plans to install line of sight markers throughout the pipeline system (including Lafayette) beginning in 2019. PG&E is also working to identify locations on DFM 3001-01 that require additional pipeline markers, with installation planned for 2018 and 2019.

Q92: What are the pipeline marking standards, including spacing between markings and visibility in transmission line ROW, that the best gas industry performers (lowest rate of excavation incidents) have adopted? Please provide copies. To what extent does transmission pipeline marking in Lafayette conform with the marking standards being used by the industry's best performers? Which best-industry performers/marking standards are being referenced here? (Source: https://www.law.cornell.edu/cfr/text/49/195.410)

PG&E's procedures require installation of pipeline markers within line-of-sight where feasible. Please see attachment *"TD-4412P-09"* for a copy of PG&E's Gas Pipeline Markers and Indicators procedure (TD-4412P-09), and attachment "*TD-4412B-018*" for a copy of the Changes to Gas Pipeline Markers and Indicators Bulletin (TD-4412B-018).

PG&E is working to identify locations on DFM 3001-001 that require additional pipeline markers, with installation planned for 2018 and 2019.

Please note, PG&E obtains benchmarking data from third parties pursuant to confidentiality and non-disclosure agreements and therefore is unable to share information on other pipeline operators' pipeline marker practices.

Q93: During a pipeline safety workshop in Richmond on May 30, 2018, representatives from Kinder Morgan said that their company's standards for pipeline ROW marking require that when an observer stands at one marker, the next markers (both upstream and downstream) must be clearly visible. When asked about PG&E's marking standards, Andy Wells (PG&E Gas Emergency Preparedness) said that PG&E had the same standard. Please provide a copy of PG&E standards covering ROW and pipeline marking requirements.

PG&E's procedures require installation of pipeline markers within line-of-sight where feasible. Please see attachment *"TD-4412P-09"* for a copy of PG&E's Gas Pipeline Markers and Indicators procedure (TD-4412P-09), and attachment *"TD-4412B-018"* for a copy of PG&E's Changes to Gas Pipeline Markers and Indicators. bulletin (TD-4412B-018).

PG&E plans to install line of sight markers throughout the pipeline system (including Lafayette) beginning in 2019. PG&E has expedited work on identifying locations on DFM 3001-001 that require additional pipeline markers, with installation planned for 2018 and 2019.

Q94: Which pipeline operators in the U.S. have the best performance in terms of managing dig-in incidents? Over the past four years, how does PG&E's transmission line dig-in incident rate compare to these best performers? Please answer this using these two metrics: dig-ins per 1,000 tickets and dig-ins per million miles of transmission line. (The latter metric is PHMSA's preferred approach when comparing operator dig-in performance across different regions of the country.)

Third-party dig-ins are a significant cause of damage to PG&E's pipelines. Pipeline patrol is a critical preventative practice to help PG&E protect pipelines and improve safety. PG&E only uses dig-ins per 1,000 USA tickets to track dig-in reduction rates. From 2014 to 2017, PG&E has noted a decline in third-party dig-ins per 1,000 USA tickets as shown in the following table:

Year	Dig-Ins Per 1,000 USA Tickets*
2014	2.42
2015	2.11
2016	2.02
2017	1.89

*These ratios represent dig-ins on both transmission and distribution lines.

PG&E obtains benchmarking data from third parties; however, pursuant to confidentiality and non-disclosure agreements, PG&E is unable to share how its dig-in rate compares with that of other pipeline operators in the United States.

Q95: Please describe best practice benchmarking in the area of dig-in prevention that PG&E has conducted with the industry's best performers over the past four years. What changes has this led to at PG&E? What further changes are planned in light of (1) what has been learned from benchmarking, and (2) PG&E's continued performance erosion with respect to dig-ins (using the metric of incidents/mm miles of transmission line)?

Between 2014 to 2017, PG&E has experienced a 21% decline in the ratio of third-party dig-ins per 1,000 tickets; see response to question 94 for additional information regarding dig-in ratios between 2014 and 2017. PG&E continues to engage in robust damage prevention efforts, through direct safe excavation training to homeowners and professional building contractors, marketing campaigns focused on 811/safe excavation practices, process improvements and the use of emerging technologies to improve locate &

mark efforts and working with internal and external stakeholders to support legislative changes related to reducing the incidence of unsafe excavations.

Please note, PG&E obtains benchmarking data from third parties pursuant to confidentiality and non-disclosure agreements and therefore is unable to share how its dig-in rate compares to other pipeline operators in the U.S.

Q96: According to PG&E’s Pipeline Safety Guide 2017: "PG&E’s Valve Automation Program is designed to accelerate emergency response in the event of gas transmission pipeline rupture. This program builds upon the scope and principles in PG&E’s Pipeline Safety Enhancement Plan. The Pipeline Safety Enhancement plan replaced, automated, and upgraded gas shut-off valves across PG&E’s gas transmission system from 2011-2014 and the Pipeline Safety Enhancement Plan’s scope of work was completed in 2015. In 2016, an additional 18 valves were installed through the 2015-2018 Gas Transmission and Storage Rate Case Valve Automation Program, expanding the Company’s ability to shut-in pipeline sections over widespread urban areas including the San Francisco Peninsula and the North Bay, further providing for public safety in the event of a dig-in or rupture. The Valve Automation Program allows the transmission pipeline to be rapidly isolated through remote and automatic control valve technology. Installation of automated isolation capability on major pipelines in heavily populated areas may reduce property damage and danger to emergency personnel and the public in the event of a pipeline rupture.” Given this statement by PG&E, why is PG&E prioritizing tree cutting in Lafayette over valve automation?

PG&E is working every day to improve the safety and reliability of our natural gas system. This includes looking at every part of our pipelines, from valves to distribution lines, to identify and address any potential safety concerns. Over the last six years, we have implemented important changes in our gas safety operations, including enhancing the testing and inspections of our gas transmission pipeline and ensuring multiple layers of protection are in place to keep our customers safe. These layers include not only our Valve Automation Program but also our Community Pipeline Safety Initiative.

In the event of an emergency, PG&E can use manual main line or automated valves to isolate sections of pipeline. PG&E's Valve Automation Program and decision tree for where to install automated valves was developed with input from several industry and fire/first responder experts, and has been approved by the CPUC. While automated shutoff valves are an important component of our emergency response efforts, they are a reactive response. Shutting off the flow of gas can affect customers like hospitals, schools, and care facilities that rely on safe and reliable gas service, which is why we only want to use the valves when absolutely necessary.

PG&E's Valve Automation Program and Community Pipeline Safety Initiative are independent programs and both are being implemented throughout our service area concurrently.

Q97: PG&E apparently replaced an “Inoperable and Hard-to-Operate Valve” near the Lafayette Reservoir entrance this year. Does PG&E have record of when it became aware of the non-operational valve? What kind of valve is installed in this location?

PG&E determined the valve was inoperable on February 28, 2017, and replaced it with a ball valve on November 14, 2017.

Q98: How is Lafayette's safety improved by PG&E installing a manual valve at S. Lucille Drive to facilitate operations when an automatic or remote valve would enable quicker shutoff in case of an emergency?

PG&E is installing a manual valve at South Lucille Lane, as it does not meet the criteria for valve automation, in addition to installing an automated valve near the intersection of Olympic Oaks Drive and Olympic Boulevard, which is upstream of the valve near South Lucille Lane.

PG&E uses a decision tree approved by the CPUC to identify appropriate locations for valve automation throughout its gas system. Please refer to Figure 4-3, "Decision Tree – Population Density" on Page 4-11 of the attached document "*Valve Automation Program*" for additional information on PG&E's Valve Automation Program. It was initially proposed to and approved by the CPUC in PG&E's Pipeline Safety Enhancement Plan (PSEP) and re-approved in PG&E's 2015 Gas Transmission and Storage rate case. The decision tree takes into consideration the proximity of populations and potential seismic events, among other factors.

Q99: How does PG&E measure the time it would take a crew to manually shut-off the new S. Lucille Drive shut-off valve, in the event of an emergency? How does time-of-day commute traffic and the knowledge that there are only one or two entry points to that community from Lafayette affect that timing?

For manual valves, we cannot estimate an approximate response time, as it depends on variables, such as, day of week, time of day, surrounding traffic conditions, and type of emergency.

In the event that field personnel are delayed due to traffic, PG&E's Gas Control Center can notify the responsible 911 Emergency Response Center to request an escort to expedite the arrival of field personnel to the location of the emergency, per PG&E's Gas Control 911 Notification Process.

Q100: Assume a pipeline is struck by a construction crew at Lafayette-Moraga Trail, adjacent to the busy Lafayette Community Center. Since there are no automatic shut-off valves, how would PG&E today stop the gas pressure at the accident site, allowing first responders to enter the accident area, and what is the time estimate for this gas shut-off?

PG&E's Gas Control Center has a pressure monitoring point at South Lucille Lane and has the ability to detect a potential pipeline leak through a decrease in pressure in the area. Following Emergency Response Procedures, Gas Control would notify the responsible field personnel and 911 emergency response center to respond immediately to the scene to isolate the leak. PG&E would use manual shut off valves located at different locations in the area of the hypothetical line strike to isolate the area. For manual valves, approximate response time can vary due to variables such as, day of week, time of day, surrounding traffic conditions, and type of emergency.

Please note it is the responsibility of the excavator to have a valid Underground Service Alert (USA) ticket during excavation near any utility and to notify PG&E of any damage to its facilities per state regulations.

Q101: Is the planned 2021 installation of two automated valves in Lafayette guaranteed to happen?

PG&E plans to install one automated valve in Lafayette by 2021. PG&E notes that the original plan was to install two automated valves. However, after further evaluation only one automated valve will be needed to shut-off gas in the area during an emergency or for important maintenance work. Please note that PG&E's future work is based on current plans, and those plans are subject to change due to a range of factors, including permitting, material availability, availability of new technologies, and outcomes of PG&E's 2019 Gas Transmission & Storage Rate Case.

Q102: In 2007, Contra Costa County began requiring automatic gas shut-off devices in all new buildings and in existing buildings upon sale/significant modification. The purpose of this

requirement is to reduce the risk of fire/explosion in the event of a major earthquake. Does PG&E agree that the above requirement is a prudent step to improve community safety?

PG&E currently has a neutral stance toward customer-owned seismic shutoff valves. If a customer installs an excess flow shutoff valve or earthquake-actuated gas shutoff valve, the valve must be certified by the State of California. A licensed plumbing contractor must install it according to the manufacturer's instructions. PG&E does not install or service seismic-actuated or excess flow gas shutoff valves, and does not recommend specific contractors for installation.

Excess flow gas shutoff valves and earthquake-actuated gas shutoff valves must be installed on the building's gas houseline piping. This pipeline is the gas pipe that connects your appliances to the gas meter downstream of the utility point of delivery. It is located after the PG&E gas shutoff valve, pressure regulator, meter, and the service tee. No attachments or connections of any kind are allowed on the utility facilities before the point where the service tee connects to the gas houseline piping. After installation, the valve must not obstruct any gas operations or PG&E services in or around:

- Piping
- Gas service shutoff valves
- Gas meters
- Gas pressure regulating equipment

The State of California requires approval for all excess flow gas shutoff valves and earthquake-actuated gas shutoff valves used within the state. Visit the PG&E Gas Shutoff Devices webpage for more information (https://www.pge.com/en_US/residential/outages/planning-and-preparedness/safety-and-preparedness/gas-shutoff-devices/gas-shutoff-devices.page). Section 2.5 of the PG&E Greenbook Manual provides additional guidance for customer-owned and installed gas service piping, valves, and automatic shutoff devices. See www.pge.com/greenbook.

Q103: Regarding the above, over the past 20 years, U.S. pipeline operators reported to PHMSA 47 transmission pipeline safety incidents where the cause was attributed to earth movement (2.3% of all incidents reported). What was PG&E's transmission line incident rate due to earth movement in this period?

Based on a review of PHMSA's reportable transmission incident data, since 1984, three gas transmission incidents have occurred on the PG&E system due to earth movement.

Q104: Regarding the above, what percentage of PG&E's transmission line valves are manual, as opposed to automatic/remotely controlled? How has this percentage changed in the period 2010-2018?

There are over 13,200 valves on PG&E's transmission pipeline system, of which over 300 were automated through the Valve Automation Program, which began in 2011.

Q105: Regarding the above, does PG&E agree that pipeline safety risk due to earth movement is a relevant consideration that weighs in favor of installing automatic/remotely controlled valves on transmission lines, and particularly when installing new and replacement lines in populated areas such as Lafayette?

PG&E agrees that earth movement is a relevant consideration for installation of automatic shutoff valves (ASVs) and remote controlled valves (RCVs). As a part of its Valve Automation Program, PG&E automates valves on pipelines that cross active earthquake faults where there is a large potential impact on the customer population.

PG&E uses a decision tree approved by the CPUC to identify appropriate locations for valve automation throughout its gas system. Please refer to Figure 4-3, "Decision Tree – Population Density" on Page 4-11 of the attachment "*Valve Automation Program*" for additional information on PG&E's Valve Automation Program. It was initially proposed to and approved by the CPUC in PG&E's Pipeline Safety Enhancement Plan (PSEP) and re-approved in PG&E's 2015 Gas Transmission and Storage rate case. The decision tree takes into consideration the proximity of populations and potential seismic events, among other factors.

Q106: In the 2010 San Bruno explosion, the NTSB said it took more than 90 minutes to shut down the gas supply, and NTSB experts concluded that this likely increased the community damage. In 2011, Rep. Jackie Speier introduced a bill in Congress that would require natural gas pipeline operators to install automatic or remote shutoff valves in all urban areas and within 10 miles of high-risk earthquake faults. The NTSB concluded as part of its San Bruno investigation that auto/remote controlled valves should be installed in HCAs and in class 3 & 4 locations; the 2011 Federal Gas Safety Act (signed into law January 2012) specifies auto/remote controlled valves for new and replacement gas transmission lines. Are explosions a more common event on transmission lines than on distribution lines when an unintentional gas release occurs?

PG&E's decision tree for where to install automated valves was developed with input from several industry and fire (first responder) experts and has been approved by the CPUC. It takes into consideration the proximity to populations and potential seismic events, among other factors. PG&E plans to install one new automated valve on Line 191-1 near the intersection of Olympic Oaks Drive and Olympic Boulevard by 2021. In the event of a major emergency or natural disaster, PG&E can use the mainline valves in Lafayette to shut off gas and isolate the pipelines in an emergency.

While automated shutoff valves are an important component of PG&E's emergency response efforts, they are a reactive response. Shutting off the flow of gas can affect customers like hospitals, schools and care facilities that rely on safe and reliable gas service, which is why PG&E only wants to use the valves when absolutely necessary and is focused on proactive safety efforts.

Major pipeline incidents are not a common event on gas transmission or gas distribution pipelines. When an unintentional gas release occurs, the natural gas typically will vent to the atmosphere due to the buoyant nature of natural gas (lighter than air). In order for the gas to ignite, there must be an ignition source present and a specific gas-to-air ratio.

PG&E has a comprehensive inspection and monitoring program to ensure the longevity and safe operation of its natural gas transmission system. PG&E regularly conducts patrols, leak surveys, and cathodic protection (corrosion protection) system inspections for PG&E's natural gas pipelines. If any issues are identified as a risk to public safety, PG&E takes steps right away to address them.

Q107: Regarding the above, does PG&E agree that automatic/remotely controlled valves on transmission lines can improve community safety?

Multiple layers of protection are essential to keeping the gas transmission pipelines and the people who live near them safe. That is why we are inspecting and testing our pipes, conducting leak surveys and upgrading pipes. Shutoff valves are another important component of our emergency response.

There are two types of automated shutoff valves recognized within the natural gas industry: remote control valves (RCVs), which can be operated remotely from PG&E's 24/7 Gas Control Center, and automatic shutoff valves (ASVs), which will close automatically as a result of rapidly falling pipeline pressures and/or increased flow at the valve location and can also be operated remotely from PG&E's Gas Control Center.

While shutoff valves are an important component of our emergency response efforts, they are a reactive response. Shutting off the flow of gas can affect customers like hospitals, schools and care facilities that rely on safe and reliable gas service, which is why we only want to use the valves when absolutely necessary and are also focused on proactive safety measures that will prevent safety incidents from occurring in the first place.

Q108: Regarding the above, does the San Bruno community that was most impacted by the 2010 transmission line explosion now have automatic/remotely controlled valves installed to enable fast shut-off in the event of an emergency?

Based on the pipeline size and maximum operating pressure, the pipeline on St. Mary's Road does not meet the decision tree criteria for valve automation.

As noted above, PG&E uses a decision tree approved by the CPUC to identify appropriate locations for valve automation throughout its gas system. Please refer to Figure 4-3, "Decision Tree – Population Density" on Page 4-11 of the attachment *"Valve Automation Program"* for additional information on PG&E's Valve Automation Program. It was initially proposed to and approved by the CPUC in PG&E's Pipeline Safety Enhancement Plan (PSEP) and re-approved in PG&E's 2015 Gas Transmission and Storage rate case. The decision tree takes into consideration the proximity of populations and potential seismic events, among other factors.

Q109: Regarding the above, why is PG&E planning to install manual valves as part of its St Mary's Road pipeline replacement project?

Based on the pipeline size and maximum operating pressure, the pipeline on St. Mary's Road does not meet the decision tree criteria for valve automation.

As noted above, PG&E uses a decision tree approved by the CPUC to identify appropriate locations for valve automation throughout its gas system. Please refer to Figure 4-3, "Decision Tree – Population Density" on Page 4-11 of the attachment "*Valve Automation Program*" for additional information on PG&E's Valve Automation Program. It was initially proposed to and approved by the CPUC in PG&E's Pipeline Safety Enhancement Plan (PSEP) and re-approved in PG&E's 2015 Gas Transmission and Storage rate case. The decision tree takes into consideration the proximity of populations and potential seismic events, among other factors.

Q110: How many sectionalizing block valves are currently installed in Lafayette's transmission lines to provide timely shut-off in the event of an emergency? What are the distances along each pipeline segment between these valves, and the associated federal classification for each segment (e.g., HCA, class 2, etc.)?

PG&E follows 49 CFR Part 192.179(2) for valve spacing, which states that each point of a transmission pipeline in a Class 3 location must be within four miles of a valve. PG&E pipelines in Lafayette are in Class 3 and adhere to this regulation.

Q111: Which block valves in Lafayette will not accommodate in-line inspection as currently configured?

The pipelines in Lafayette are operating at a pressure lower than currently available In-line Inspection (ILI) tools can successfully operate. As such, valves that may need to be removed for the passage of an ILI tool have not been identified. Prior to conducting an ILI, PG&E will perform a feasibility study to determine any features that need to be replaced to accommodate ILI tools and will initiate projects to replace them as necessary. For lower-pressure pipelines where ILI is unfeasible, like those in Lafayette, we use other federally-approved direct assessment or strength test methods to conduct pipeline integrity assessments.

Q112: PG&E plans to replace the transmission line manual shut-off valve located near Reliez Station Road and Olympic with a remotely controlled valve within the next two years. Over the past five years, how many auto valves has PG&E installed in its transmission lines? How many remotely controlled valves?

PG&E uses a decision tree approved by the CPUC to identify appropriate locations for valve automation throughout its natural gas system. Since 2010, PG&E has installed more than 300 automated valves throughout the service area, which include 288 RCVs.

Q113: Regarding the above, what are the considerations that most often drive the selection of auto vs remotely controlled valves on transmission lines in PG&E's system?

There are two types of automated shutoff valves recognized within the natural gas industry: remote controlled Valves (RCVs), which can be operated remotely from PG&E's 24/7 Gas Control Center, and automatic shutoff valves (ASVs) that will close automatically as a result of rapidly falling pipeline pressures and/or low pipeline pressure at the valve location and can also be operated remotely from PG&E's Gas Control Center.

PG&E's gas transmission Valve Automation Program predominately uses RCV technology and control, with a few exceptions. For example, PG&E may install ASVs (rather than RSVs) where large diameter (typically greater than 20 inches in diameter), high pressure (greater than 200 psig) pipelines located within urban areas cross major active faults, such as the San Andreas, Hayward, and Calaveras faults. PG&E's Valve Automation Program and decision tree for where to install automated shutoff valves was developed with input from several industry and fire (first responder) experts and has been approved by the CPUC.

Q114: Regarding the above, can a modern auto valve accommodate a remote signal to close in essentially the same fashion as a remotely controlled valve?

Both remote controlled valves (RCVs) and automatic shutoff valves (ASVs) can be operated remotely from PG&E's Gas Control Center. ASVs will also close automatically as a result of rapidly falling pipeline pressures and/or increased flow at the valve location.

Q115: Regarding the above, why has a remotely controlled valve been chosen over an auto valve for Reliez Station Rd and Olympic Blvd?

PG&E uses a decision tree approved by the CPUC to identify appropriate locations for valve automation throughout its natural gas system. PG&E installed a remote control valve (RCV) on the pipeline at Reliez Station Road and Olympic Boulevard, as this location does not meet the decision tree criteria for installation of an automatic shutoff valve (ASV) because it does not cross a major fault.

Q116: What are PG&E's standards for placing an automated (automatic or remote-controlled) valve in new or reconstructed transmission pipeline installations? --In what ways are these standards different for Class 1-4 and HCA locations?

PG&E uses a decision tree approved by the CPUC, in combination with practical engineering judgement, to identify appropriate locations for valve automation throughout its gas system. Please refer to Figure 4-3, "Decision Tree – Population Density" on Page 4-11 of the attachment document "*Valve Automation*

Program" for additional information on PG&E's Valve Automation Program. It was initially proposed to and approved by the CPUC in PG&E's Pipeline Safety Enhancement Plan (PSEP) and re-approved in PG&E's 2015 Gas Transmission and Storage rate case. The decision tree takes into consideration the proximity of populations and potential seismic events, among other factors.

In addition, PG&E's standard TD-4810S, "Gas Transmission Integrity Management Program" references PG&E's Valve Automation Program, which was incorporated into the Pipeline Safety Enhancement Program. These programs provide the decision-making process, including risk-based methodology, for placing ASVs and RCVs on transmission lines to comply with 49 CFR Part 192.935. Considerations for placement are also included in TD-4810S.

Q117: PG&E confirmed that the valve that will be installed in the summer of 2018 at S. Lucille and St. Mary's Road will be a manually operated valve to help facilitate future maintenance. However, in other communities manually operated valves are being replaced with automate valves. One example:

"As part of its Pipeline Safety Initiative, PG&E is installing an automated gas valve system located on South Novato Boulevard across from Cowbarn Lane. This system includes above ground valve assemblies that are remotely controlled via a wireless antenna connection—allowing PG&E to shut-off the flow of natural gas through its pipelines in the event of an emergency. This is one of many safety improvements PG&E is making to its natural gas system throughout California. "(Source: http://novato.org/about-novato/hot-topics/pg-e-community-pipeline-safety-initiative).

What type of valve is being replace at S. Lucille Lane? Why is this safety improvement being made in Novato, but not in Lafayette and Moraga?

PG&E uses a decision tree approved by the CPUC to identify the type of valve needed throughout its gas system. PG&E will install manual valves at this location on the pipeline at South Lucille Lane, as this location does not meet the decision tree criteria for valve automation, based on pipe size and maximum operating pressure.

Q118: Have there been, or is there currently, any instances of inadequate cathodic protection in Lafayette? Please list the incidents.

At this time, there are no instances of inadequate cathodic protection in Lafayette. There was one instance previously in Lafayette where PG&E did not meet its cathodic protection (CP) requirements per federal regulations. This occurred on Line 191-1, near the intersection of Deer Hill Road and Oak Hill Road to the intersection of Moraga Boulevard and Foy Drive. PG&E remediated the issue on August 23, 2016.

Q119: Safety incidents on PG&E's transmission lines have been increasing in recent years, based on PHMSA data. What role does cathodic protection play in mitigating this risk?

Cathodic protection (CP) reduces the risk of external corrosion on buried or submerged metallic piping systems. According to the PHMSA database, from 2009 to 2017, PG&E reported four significant incidents related to external corrosion.

Details regarding these incidents can be found on PHMSA's website. For the most current data, please navigate to the following link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.

Q120: How often does PG&E verify the proper functioning of the cathodic protection system on each of Lafayette's transmission lines? How does this frequency compare with PG&E standards and PHMSA regulations?

For transmission pipelines, including those in Lafayette, PG&E monitors cathodic protection current sources (rectifiers, critical bonds and other sources of protective current) bimonthly and cathodic protection pipe-to-soil (P/S) monitoring points annually. This frequency aligns with the requirements of both 49 CFR Part 192.465 and PG&E's standards.

Q121: What the benefits of installing continuous monitoring (telemetry to central monitoring station) of the cathodic protection system? What is restraining the installation of such a system for Lafayette's transmission lines?

Continuous monitoring of cathodic protection allows for increased understanding and reporting of potential external corrosion protection issues. PG&E has already installed and is utilizing continuous monitoring on its transmission cathodic protection systems, including those in Lafayette, and plans to implement the same monitoring on its distribution cathodic protection over the next four years.

While monitoring for external corrosion is a critical gas safety program, multiple layers of protection are essential to keeping the gas transmission pipelines and the people who live near them safe. That is why we are working together with our customers and communities to review the area above and around natural gas transmission pipelines for items such as trees and structures that could delay access for safety crews in an emergency or for important maintenance work.

Q122: Cathodic coupon stations were newly installed last year along the Lafayette-Moraga Trail after residents raised safety concerns regarding the transmission pipeline. We're glad PG&E is responding to our safety concerns, but what was your reason for installing these stations at this time? What was your rationale for the locations selected? What benefits/potential benefits do you associate with this change? What other locations within Lafayette might benefit from a similar upgrade?

In order to protect the pipeline system from corrosion, pipes are cathodically protected as mandated by federal pipeline safety regulations. The regulations require the Cathodic Protection (CP) system to be monitored at regular intervals such that "each pipeline under cathodic protection…must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection." PG&E's current interpretation of this requirement is that a test station or contact point should be monitored approximately once every mile along an existing transmission pipeline. Additionally, for newly installed transmission pipelines, PG&E requires test stations to be installed approximately every half mile.

In accordance with our standards, PG&E is installing additional monitoring points in areas where the distance between test sites is greater than approximately one mile. Increasing the number of test stations along PG&E's transmission pipelines will provide greater visibility into the status of the cathodic protection for pipelines and also assist in locating the pipeline when requested by Underground Service Alert. Please note, in 2018 PG&E plans to add one additional CP monitoring point in Lafayette.

Q123: In PG&E's May 2018 Open House information packet, (page 2), 11 instances of coating being damaged in the past 13 years is provided as "evidence" that tree roots cause pipeline corrosion, however this information doesn't give a complete picture. What is the TOTAL number of coating damages, any cause (rocks, earth movement, age of coating, etc), reported during the last 13 years along PG&E's entire gas transmission pipelines, and what were the causes of these incidences? Please rank cause of damage to pipeline by frequency.
(Source: https://docs.wixstatic.com/ugd/de4240_e8e518be538e4df5be6f01e4cb58bc2d.pdf)

PG&E does not have the database nor the processes to review and analyze the specific data as requested at this time. While PG&E records indicate that the 11 instances of damage have occurred on PG&E's gas transmission pipelines due to vegetation, the list of instances was not exhaustive and would require extensive additional review to complete. For more information regarding tree root damage analysis, please refer to the 2013 and 2014 Tree Root Studies and the responses to questions 51, 52, and 53 above.

Q124: Regarding the above, what were the species of trees that caused this damage? what is the depth of pipeline in each instance, and distance from tree? Type of soil? Were there any instances of actual pipeline corrosion?

PG&E does not have the database nor the processes to analyze the specific data as requested at this time. While PG&E records indicate that the 11 instances of damage have occurred on PG&E's gas transmission pipelines due to vegetation, PG&E records did not indicate the species of trees that caused the damage, the depth of the pipeline, the distance from the tree, or the type of soil. There were instances of corrosion identified at the locations where tree roots damaged the pipelines protective coating. Even though a direct cause analysis was not performed to determine whether or not the corrosion identified was specifically caused by the tree roots, a failure in the protective coating increases the susceptibility for corrosion to occur. For more information regarding tree root damage analysis, please refer to the 2013 and 2014 Tree Root Studies and the responses to questions 51, 52, and 53 above.

Q125: Regarding the above, how were these instances discovered by PG&E?

The 11 instances of coating damage due to tree roots referenced on page 2 of PG&E's May 2018 Open House information packet were discovered as part of PG&E's Gas Operations maintenance activities and the Transmission Integrity Management Program.

Q126: During the May 2018 PG&E Open House in Lafayette, PG&E representatives said that the current standard for pipeline coating is an enamel epoxy that is installed during fabrication. What studies has PG&E conducted on tree root interference with this type of coating? What were the findings and recommendations from these studies?

PG&E did not include epoxy coatings in its tree root study since application of this coating type is relatively recent within the PG&E system and the trees near these portions of the system had not grown to a sufficient size to qualify for the study.

Q127: According to the 2014 Dynamic Risk Assessment report: "While additional investigation of the impact of tree roots on various coating types is warranted, the current data indicates PG&E can consider coating as an attribute for predicting the interaction with tree roots. Of the 45 sites where the external coating types were either hot applied asphalt or coal tar enamel, coating damage was identified at 38 sites (or 84%). For the 8 remaining sites where the external coating type was polyethylene tape, 2 sites (25%) identified coating damage. The reason for this difference was not resolved as part of this study." Given the extreme differences in root/coating interaction based on the type of coating, with tape being more protective than asphalt, what is the coating type at each proposed tree-removal location? What additional investigation has happened since this report was released?

In the cases studied, the asphaltic coating types were perceived to have a greater damage susceptibility; however, several factors could be the cause of this. These factors include the increased toughness of the tape coating membrane relative to asphaltic coating, the time period of installation, the material itself (i.e. polyethylene vs. asphalt/felt), or a different failure mode (e.g. disbonding rather than direct penetration). A relevant finding of the study was that all coatings studied were susceptible to failure due to pipe and root interaction and the predictability of tree root interactions with buried pipelines is difficult given the numerous attributes that influence the result.

PG&E's pipeline database system contains coating type information for all its pipelines, however, where coating type is unknown, PG&E uses a conservative assumption based upon subject matter expertise. Therefore, PG&E does include the coating type risk in its risk assessment.

PG&E continues to collect information through its routine maintenance activities and integrity assessments which supports the presence of trees roots interacting with various pipeline coating systems.

Q128: In the April 23, 2018 presentation to Lafayette City Council, PG&E showed a slide titled "Pipeline Scope and Background" which characterized DFM 3001-01 as follows: "The existing welded steel pipelines in Lafayette are considered critical infrastructure and were installed along St. Mary's Road in 1952. Pipe installed in this era was welded before modern radiography was used to inspect welds and as such the welding inspection was only visual. Additionally, modern manufacturing practices are far superior to those of that historic era." In fact, numerous City of Lafayette communications confirms this project is to "replace the aging pipeline." If PG&E is replacing this pipeline from S. Lucile to Rheem, in part due to age and construction concerns, how is PG&E unconcerned with the remainder of the same pipeline with the same characteristics, north of S. Lucile to downtown Lafayette?

PG&E manages all pipelines in Lafayette and across its service areas in a similar fashion. Pipeline projects are based on the risk identified on each section with assessment and mitigation practices designed to reduce those risks. While age is a consideration in determining the risk of a pipeline, it is not the only consideration. The integrity of all transmission pipelines in Lafayette will continue to be managed through PG&E's Transmission Integrity Management Program.

Please note, the pipeline replacement project from S. Lucile Lane to Rheem Boulevard has multiple drivers that are unique to the section of pipeline being addressed. This section of pipeline is not only subject to the vintage pipe replacement program, but also a pipeline capacity issue to address future load growth on the pipeline system.

Q129: What are the top five transmission pipeline maintenance practices that impinge on pipeline lifespan? Please quantify the potential lifespan-shortening effect for each of the maintenance practices if they are not followed.

Transmission pipeline maintenance practices are not intended to "impinge on pipeline lifespan." Maintenance practices are designed to prevent, detect, or mitigate risk on the pipeline. PG&E cannot calculate the effect of each maintenance practice on pipeline longevity independently.

Pipeline operators manage the integrity of transmission pipelines through application of appropriate maintenance and inspection practices, which vary by pipeline. 49 CFR Part 192 and the CPUC's GO-112F prescribe minimum safety standards; however, the assignment of appropriate maintenance and inspection practices is based on integration of pipeline design, operating information and continual monitoring.

These maintenance practices and preventative measures are intended to mitigate potential integrity threats and allow pipeline operators the opportunity to address any issues before they could result in a safety concern. In 2012, a report to the Interstate Natural Gas Association of America (INGAA) stated "A well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely." This report may be accessed using the following link: http://www.ingaa.org/file.aspx?id=19307.

Q130: One finding of the NTSB after San Bruno was the fact the pipeline was "fabricated at an unknown facility to no known specification". Please tell us where the Lafayette pipelines were fabricated, and to what specification.
(Source: https://www.pipelinelaw.com/wp-content/uploads/sites/24/2013/07/NTSB_Final_SB_Report.pdf)

The physical location of pipeline fabrication of each transmission pipeline is not a criterion that PG&E captures and maintains. Pipelines are typically fabricated for install in the vicinity of the final ground installation location. If the question is regarding pipeline manufacturer, pipelines located within the city boundaries of Lafayette were manufactured by companies such as Tenaris, Northwest Pipe, and Alliance Tubular; however, rather than focusing on where a pipeline was fabricated or the manufacturer, PG&E focuses on the pipeline's fitness for service.

Regulations were formally established within the State of California in 1961 that required strength testing of gas transmission pipelines prior to placing a pipeline in service. In certain circumstances, pipelines were strength tested prior to 1961. PG&E plans to strength test any gas transmission lines that have not been tested in Lafayette by 2026. Please note that these projects are based on current plans, and those plans are subject to change due to a range of factors (e.g., permitting, material availability, availability of new technologies, outcomes of PG&E's Gas Transmission & Storage Rate Case, etc.). PG&E utilizes a combination of integrity assessments and maintenance and inspections to manage the integrity on transmission pipelines in Lafayette. The preventative and mitigative (P&M) activities include increased frequency for leak survey and pipeline patrol.

Q131: The effects of wrinkle bends on the long-term integrity of pipelines are a recognized concern in the industry. According to a 2009 article in Pipeline and Gas Technology magazine, "At the time, contractors commonly used a process of conforming steel pipe to the surrounding topography by forcefully compressing the pipe to create a bend in it. This technique created what have come to be known as "wrinkle bends" in the pipe." Are there any wrinkle bends in any of the pipelines in Lafayette?
(Sources: http://compositerepairstudy.com/downloads/Evaluating_the_effects_of_wrinkle_bends_(September_2009).pdf and http://www.naturalgasintel.com/articles/89168-southern-seeks-to-iron-out-wrinkle-bend-hazards-on-pipe-system)

There are no known wrinkle bends on gas transmission pipelines in Lafayette.

Q132: PG&E reports that Lafayette pipeline includes Electric Resistance Welds (ERW), Furnace Butt Welds, Lap Welds, Seamless and Spiral weld types. Low frequency ERW, Furnace Butt, and Lap welds are known to be of poor quality and are obsolete. As PG&E reports, in-line inspection (ILI) is not currently available to Lafayette. How has PG&E been historically testing integrity of these seam welds to regulatory standard? (source: 192.241 weld inspection)

Longitudinal seam welds are managed through establishing an appropriate design factor and strength testing of the pipeline. As mentioned in response to question 77, all transmission pipelines not previously tested within Lafayette are planned to have a strength test performed by 2026 (based on current plans; however, PG&E notes that those plans are subject to change due to a range of factors such as permitting, material availability, availability of new technologies, outcomes of PG&E's Gas Transmission & Storage Rate Case, etc.).

Please note that 49 CFR Part 192.241 is not applicable as it relates to fabrication welds, such as girth welds, whereas the seam welds described (e.g., Electric Resistance Welds (ERW), Furnace Butt Welds, etc.) are longitudinal seam welds made by the manufacturer.

Q133: According to PG&E's May 2018 Open House document, "The U.S. Department of Transportation's Pipeline & Hazardous Materials Safety Administration, for example, states that the life of a pipeline is virtually endless if it is constructed and maintained correctly. That's one of the reasons why this gas safety program is so important." Given the answers to other questions listed here regarding construction of older pipeline, untested welds, no in-line inspections, lack of strength testing for over 30 years, as well as self-reported lapses in cathodic protection, what assurance does PG&E have that each pipeline in Lafayette is safe and free of latent hazards? (source: https://docs.wixstatic.com/ugd/de4240_e8e518be538e4df5be6f01e4cb58bc2d.pdf)

PG&E is in the process of modernizing its pipeline system. While many projects are planned in and around Lafayette, in the interim, PG&E continues to ensure the ongoing safety of all our transmission pipelines with a rigorous monitoring and inspection program that includes patrols, leak surveys and cathodic (corrosion) protection inspection in accordance with federal regulations. The pipeline system is also monitored 24/7 via PG&E's Gas Transmission Control Center. Real-time information allows the company to anticipate and respond to public safety concerns and ensure system reliability.

As part of PG&E's Transmission Integrity Management Program, a risk assessment is performed annually to assess the overall risk identified on the pipelines across the system. Risk prioritization is reviewed on an annual basis, and based on any changes, PG&E updates the plans for replacement, in-line inspection, or strength testing programs, as appropriate.

Q134: In 2010, PG&E transmission line 132 in San Bruno exploded as the result of a defective longitudinal seam weld. Twenty-two years before this (in 1988), line 132 experienced a leak attributable to a defective longitudinal seam weld at a point about 9 miles south of the 2010 rupture. The repair in 1988 involved replacing about 12 feet of line 132. Four years after the 1988 incident (in 1992), a defective longitudinal seam weld was detected in another part of line 132 when a tie-in girth weld was x-rayed. In light of the serious nature of the 1988 defect (which provided evidence of longitudinal seam welds in line 132), why wasn't an aggressive risk assessment and mitigation program immediately initiated for all of line 132, including the section located in San Bruno?
(Source: https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf)

As part of the investigation into the San Bruno Rupture and Fire, the NTSB published a report in 2011 that described PG&E's practices and issued NTSB Safety Recommendation P-11-029. This Recommendation was given the status "CLOSED – ACCEPTABLE ACTION" in 2013 based on the fact PG&E had revised its Integrity Management (IM) program, which now includes an updated risk model and risk assessment methodology, consideration of all defect and leak data for the life of each pipeline, and an improved self-assessment process. The NTSB's 2011 report can be found online at https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf. The NTSB's summation of Safety Recommendation P-11-029 can be found online at https://www.ntsb.gov/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-11-029.

Q135: Regarding the above, can state-of-the-art In-Line Inspection (ILI) technology in 2018 detect the kind of defect that was present in San Bruno line 132 in 2010?

Circumferential Magnetic Flux Leakage (MFL) has the ability to detect the kind of defect that was present in Line-132. However, the ability to successfully deploy the tool is dependent on the geometric configuration of a pipeline and its operating pressure.

Q136: Regarding the above, has line 132 been retrofitted to enable use of In-Line Inspection (ILI)? How much of the line is ILI capable? When was this capability added for each segment of line 132?

PG&E retrofitted parts of Line 132 in 2014 and 2015 for ILI. Line 132 is currently capable of ILI for approximately 38 miles, from Milpitas to San Bruno.

Q137: Are there any "pups" on Lafayette pipeline that have manufacture and/or installation dates from the 1950s? If so, which lines are these pups incorporated into? (NTSB says pups from 1956 did not meet industry quality control or welding standards then in effect; 5 out of 6 pups on SB Line 132 were sub-standard, either overlooked or ignored; one pup ruptured, causing the explosion). What is PG&E's level of confidence about its answer regarding use of pups in Lafayette's lines?
(Source:
https://www.ntsb.gov/news/events/Pages/Pacific_Gas_and_Electric_Company_Natural_Gas_Transmission_Pipeline_Rupture_and_Fire_San_Bruno_California.aspx)

PG&E has not identified any "pups" in the gas transmission pipeline system in Lafayette in its system of record (GT-GIS/PFL). Should PG&E identify any "pups", an engineering assessment will be performed to evaluate their risk to the system.

Q138: PG&E's information about San Bruno Line 132 was both inaccurate and incomplete. Why should the city of Lafayette and Lafayette residents believe that PG&E's records about Lafayette gas transmission lines installed in the same era provide reliable, complete, and accurate information?

PG&E has completed the records collection and Maximum Allowable Operating Pressure (MAOP) validation of PG&E's entire gas transmission pipeline system. During an intense 3-year effort, PG&E digitized more than 3.2 million historic As-built job records. In cases where records did not meet the standards of being considered "traceable, verifiable, and complete", PG&E took appropriate actions, such as lowering MAOP where needed, and is performing the necessary strength testing to verify the operating margin of safety of these pipelines, consistent with CPUC 958.

Q139: Federal law requires that gas pipeline operators adhere to the legally recorded easement agreements between PG&E and the property owner to determine what activities are explicitly allowed in the easement. What language in the easements where PG&E operates in Lafayette explicitly allow for tree removal?

PG&E generally acquires rights-of-ways or easements that authorize the use and operation of natural gas pipelines on private property. Those rights-of-way assure that PG&E has ready access to its pipelines for safety reasons, including maintenance, testing and monitoring the pipelines. This includes the right to access the pipeline for all purposes and to prevent any interference with pipeline operations. Please note that the language that appears in PG&E's easements may vary, as the easements were acquired over time.

Q140: Removal of trees are known to increase the risk of soil erosion and landslides. Lafayette is prone to this type of land movement during wet winter months. What studies can PG&E provide that will reassure us that removal of roots holding pipelines in place will not make conditions for erosion, landslides, and liquefaction worse?

Removal of trees may increase the risk of soil erosion and landslides in some instances, but this is a site-specific occurrence that depends on the type and size of vegetation, topography and geology, as well as the surface water and groundwater conditions. Additionally, the method of removal (stumping vegetation vs. removing root structures) and change in vegetation density (removing all vegetation vs. selective or limited removal) may change the effect on the landscape.

In Lafayette, the majority of trees initially identified for removal will remain in place with ongoing monitoring. This will leave behind a vegetative cover including leaf litter, grasses, shrubs and adjacent trees, which will limit soil erosion. Each project is provided with a specific erosion and sediment control plan, which references various best management practices. In addition, tree roots will not be removed as part of this gas safety work. Please note PG&E does not rely upon tree roots to hold its pipelines in place.

Since erosion is a site-specific issue, areas with proposed tree removal should be assessed on a case-by-case basis. Liquefaction is a specific phenomenon by which saturated soil loses strength due to rapid increase in pore pressure (e.g., during seismic shaking). This process can occur regardless of the presence of tree roots.

Q141: During a 2017 walk with Lafayette residents, PG&E employee Joey Perez answered the question "Won't land become more unstable with tree removal?" by saying that they assume after time, and by the time tree roots decompose in a few years, other trees will take root and help stabilize the slope. Please explain the thinking behind this answer. Is PG&E counting on the continued encroachment of its right of way in order to maintain land structure integrity?

In general, any land could become unstable depending on a myriad of criteria, including slope, rainfall, soil type, disturbance, and other factors. Specifically regarding the potential land instability of the area along the Lafayette-Moraga Trail, the additional roots mentioned by Mr. Perez that will help stabilize the slope refer to the existing groundcover roots currently onsite. The herbaceous groundcover will continue to exist and likely occupy all available rooting area within the first 18 inches of soil, possibly deeper. The presence of the groundcover will also help to deflect direct precipitation impact to the soil and help stabilize the slope. PG&E will not depend on the continued encroachment of its right-of-way to maintain land structure integrity, but PG&E will continue to monitor the area and mitigate any soil erosion by providing stabilization as needed.

Q142: We asked pipeline expert Richard Kuprewicz, president of Accufacts, about the need for cutting down trees, and he is on the record stating in an email 9/3/17: "Something else is going on here and safety isn't the major reason, because the bulk of the arguments are, shall we say, bogus. Nothing like trying to steal a pipeline ROW. In some states that would be very illegal..." Why do independent pipeline experts dispute PG&E's rationale for tree cutting?

The Community Pipeline Safety Initiative is a proactive safety program, and is based on industry best practices, third-party guidance and the studies we commissioned related tree root and pipeline interaction.

PIPA is a stakeholder group sponsored by the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA). PIPA stakeholders, including PHMSA, developed industry best practices related to gas transmission pipeline safety. PIPA's "Partnering to Further Enhance Pipeline Safety in Communities Through Risk-Informed Land Use Planning, Final Report of Recommended Practices", developed in November 2010, states:

> "A clear ROW enables the transmission pipeline operator to conduct inspections and testing to verify pipeline integrity and to perform general maintenance and repairs as needed… Tree roots have the potential to damage pipeline coatings which may contribute to the loss of integrity of the pipeline." (pg. 41)
>
> "The PIPA recommended practices are not mandated by any public or private entity. However, they were developed by task teams of representative stakeholders using a consensus agreement process and the PIPA participants recommend that all stakeholders become aware of and implement the PIPA recommended practices, as appropriate, to reduce risks and ensure the safety of affected communities and transmission pipelines." (pg. 3)

Please see attachment "*PIPA Report Final 20101117*" for a full copy of this report.

In October 2010, PHMSA issued "Building Safe Communities: Pipeline Risk and its Application to Local Development Decisions", which includes "keeping rights-of-way free from obstructions and encroachments; and following PIPA recommended practices on land use near transmission pipelines" (pg. 9) as ways for stakeholders to practice safe uses near gas pipelines. Please see attachment "*PHMSA Building Safe Communities"* for a full copy of this report.

Q143: On 6/19/13, Roland Trevino approved PG&E's Utility Standard TD-4490S pertaining to "Pipeline Rights-of-way Management." Is this the current version of this standard, or has it been superseded? If it has been superseded, please provide a copy of the current standard pertaining to this topic. (Source: ftp://ftp2.cpuc.ca.gov/PG&E20150130ResponseToA1312012Ruling/2013/07/SB_GT&S_0263354.pdf)

Please see attachment *"TD-4490S"* for the current version of PG&E's Gas Pipeline Encroachment Management standard (TD-4490S), published June 21, 2017. In addition, please see attachment *"TD4490P-03"* for the current version of PG&E Vegetation Encroachment Site-Specific Analysis procedure (TD-4490P-03), published June 21, 2017.

Q144: Regarding the above, TD-4490S requires removal of trees larger than 8" diameter that are within 10 ft of the outer edge of a gas transmission pipeline, and removal of trees larger than 36" diameter that are within 14 ft. Tree removal timing is subject to decisions by Integrity Management personnel. In the city of Lafayette, PG&E initially identified more than 1,000 trees that were designated as "unacceptable risk" and designated for removal. Later, PG&E concluded that the Lafayette trees it regarded as unacceptable risk were those within 5 ft of the pipeline, and this reduced the total number designated for removal to 272. Have the roughly 750 trees that were removed from the unacceptable risk category merely been placed in a "delayed removal" status per Section 2.6 of the standard, or have these trees been exempted from removal per Section 6.1 of the standard?

PG&E's regular pipeline inspections and patrols will continue to review the trees left in place as part of the Community Pipeline Safety Initiative. In the future, it may be determined that some trees have developed into a safety concern and need to be removed. This could include a change in the tree's health or the stability of soil in the area, which could put the tree at greater risk of falling over and damaging the pipeline, or if critical maintenance work is required near the location of the tree.

Q145: Regarding the above, if some of the trees discussed above have been exempted from removal, please provide a copy of the documentation describing the rationale for the exemptions and the analysis supporting these decisions, as required by Section 6.2 of TD-4490S.

In Lafayette, it was determined that most trees may remain in place with ongoing monitoring based on the results of PG&E's tree-by-tree review. Determining factors include, but are not limited to, distance from the tree to the pipe, tree species and expected size at full maturity, depth of the pipeline, and ability to access the pipeline in an emergency.

During the summer and fall of 2017, PG&E performed a survey of the Lafayette-Moraga Regional Trail and found that the pipeline depth was deeper in some areas than previously recorded. Given the pipeline depth at these locations, there is less potential for the tree roots to damage the external coating of the pipeline and expose it to corrosion or leaks, as such some trees may remain in place with ongoing monitoring.

PG&E limits certain gas pipeline, valve, regulator and station information, including its detailed and extensive construction, maintenance, inspection and testing records, from public disclosure for national security reasons consistent with federal laws that protect this type of information. Please note that PG&E makes its pipeline-related records available for inspection at all times by the CPUC.

Q146: Given that the St. Mary's Road pipeline replacement is being installed on a corridor that was described by PG&E as being only 22' in width, and that one of the benefits of replacing this line is to replace pipelines with unknown welds and aging infrastructure, why hasn't PG&E seriously considered replacement of similar aged pipelines in Lafayette located in areas of similar access width, such as on the Lafayette-Moraga Trail, downtown, and the Reservoir Rim Trail?

PG&E prioritizes pipe replacement projects based on the overall risk identified on the pipeline. Other sections of pipeline within Lafayette currently not prioritized for replacement will continued to be managed through the Transmission Integrity Management Program using a variety of assessment techniques such as In-Line Inspection, Strength Testing or Direct Assessment. Should the risk prioritization change (which is reviewed on an annual basis), PG&E will update the pipe replacement prioritization accordingly.

Q147: Why did PG&E divert $100 Million in gas safety and operations money and spend it on other purposes, including stockholder profit and executive bonuses, as disclosed by a CPUC audit? (Source: https://www.sfgate.com/bayarea/article/PG-E-diverted-safety-money-for-profit-bonuses-2500175.php)

PG&E is taking steps every day to strengthen and improve the safety of our natural gas system, which serves more than four million customers in Northern and Central California. Over the last several years, we have implemented important changes in our gas safety operations, including enhancing the testing and inspection of our 6,750-miles of gas transmission pipeline. We have spent billions to enhance pipeline safety and strengthen our gas infrastructure. Over the last several years, we've:

- Used industry-leading technology to strength test over 1,090 miles of transmission pipeline
- Replaced over 200 miles of transmission pipeline
- Installed over 290 new automated safety valves
- Validated the maximum operating pressure for all 6,750 miles of transmission pipeline
- Implemented a new gas leak detection technology that is 1,000 times more sensitive than before

In addition, we've built a new gas operations control center from which we can monitor the entire system and respond more quickly and effectively to emergencies.

Q148: Does PG&E acknowledge that, according to the Code of Federal Regulations, specifically Title 49 CFR 192 and the US Department of Transportation's Pipeline and Hazardous Materials Administration, there is no legal requirement to remove trees along gas transmission pipelines, and that this is a discretionary program being implemented by PG&E? Does PG&E dispute the fact that this tree removal program benefits are for potential ongoing maintenance accessibility and ease of visual patrolling by aircraft?

(Source: https://www.phmsa.dot.gov/regulations/title49/interp/PI-76-0108 https://www.phmsa.dot.gov/regulations/title49/interp/PI-00-0102 http://pstrust.org/wp-content/uploads/2014/12/Mulligan-Pipeline-Safety-Trust-ROW-Clearing.pdf)

PG&E notes that Federal regulations are not prescriptive and represent a minimum requirement. In addition, SB705 requires California operators to "meet or exceed the minimum standards for safe design, construction, installation, operation, and maintenance of gas transmission and distribution facilities prescribed by regulations issued by the United States Department of Transportation in Part 192 (commencing with Section 192.1) of Title 49 of the Code of Federal Regulations."

In addition, PG&E is implementing its Community Pipeline Safety Initiative to improve community safety by helping ensure safety crews have access to the pipeline in an emergency and for important maintenance work. Patrol is required to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation. The methods of patrolling include walking, driving, flying, or other appropriate means of traversing the right-of-way, which is dependent on the most effective method to identify the specific site conditions. Varying site conditions may influence the most appropriate method for patrolling (i.e., topography or accessibility). Anything that is observed or potentially identified to be a safety related issue is followed up on the ground if ground patrol was not the initial method of patrolling. Being able to walk the line on foot is a core component of PG&E's comprehensive pipeline inspection and monitoring program. Even after this important safety work in Lafayette, we will be performing foot patrols of our line due to the canopy that will be left in place.

As noted in response to question 4, the Community Pipeline Safety Initiative began seven years ago as a commitment to improve safety near the pipelines and is a shareholder funded project to improve PG&E's rights-of-way. Tree removal is part of the Community Pipeline Safety Initiative, which is a 6-year program to re-establish safe pipelines. Other work activities in the Community Pipeline Safety Initiative include: vegetation clearing, tree removal, pipeline marker installation; and structure removal from the gas transmission system right-of-way. After the Community Pipeline Safety Initiative concludes, an ongoing vegetation management program will continue to monitor and, when necessary, remove trees and structures.

Q149: What assurances does PG&E give us that pipeline maintenance operations are performed per pipeline safety law requirements?

Standards and procedures are written to ensure that PG&E follows federal and state requirements related to pipeline maintenance and operations. All maintenance operations are performed by qualified personnel at PG&E as required by 49 CFR Part 192 Subpart N.

PG&E's Gas Operations has quality assurance (QA) and quality control (QC) programs which serve to assess the quality performance of field employees in following the company's standards and procedures when performing work. QA and QC assess work being performed in the field and the documentation associated with the work performed to ensure the work was completed when required and in accordance with established standards and procedures. Any findings from these QA and QC assessments are communicated to Gas Operations leadership and corrective actions identified, as appropriate.

In addition, the CPUC performs regular audits to ensure that maintenance operations are performed in accordance with these requirements.

Q150: Save Lafayette Trees is applying for a federal grant from the Department of Transportation, specifically, the Pipeline Safety Information Grants to Communities: Technical Assistance Grants (TAG), that provide funding for technical assistance to local communities and groups for technical assistance related to pipeline safety. The TAG purpose states: "Pipeline Safety is a shared responsibility and informed communities play a vital role in the safety and reliability of pipeline operations." Our application includes allowances for a 3rd party technical engineer / analysis of pipeline safety risks in Lafayette and objective to work collaboratively with community, municipality, utility, and agency stakeholders that have common interest in optimal pipeline safety in Lafayette and building relationships between stakeholders. The goals of the TAG project include creating a basis to rebuild trust in PG&E and pipeline maintenance operations in Lafayette. Whether or not we receive the grant, could PG&E commit to work with us on this shared goal? Is PG&E willing to designate a PG&E employee that can represent the organization in these efforts?

PG&E welcomes the opportunity to further discuss with the City and other stakeholders, including local community members and the CPUC, on how we can continue to work together to enhance pipeline safety.