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UNITED STATES OF AMERICA

NATIONAL TRANSPORTATION SAFETY BOARD

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Investigation of:

PACIFIC GAS & ELECTRIC COMPANY
SEPTEMBER 9, 2010 ACCIDENT
SAN BRUNO, CALIFORNIA

Docket No. DCA-10-MP-008

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Interview of: ROBERT FASSETT

Anaheim Room
Marriott Hotel
San Francisco Airport
1800 Bayshore Highway
Burlingame, California 94010

Friday,
September 17, 2010

The above-captioned matter convened, pursuant to notice, at 3:10 p.m.

BEFORE: KARL GUNTHER
Accident Investigator

APPEARANCES:

KARL GUNTHER, Accident Investigator
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TOM FINCH, State Liaison
PETER J. KATCHMAR, Senior Accident Investigator
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety
Administration

ROBERT FASSETT, Director
Integrity Management and Technical Services
Pacific Gas & Electric Company

GEOFF CALDWELL, Police Sergeant
City of San Bruno Police Department

DEBBIE MAZZANTI, Business Representative
International Brotherhood of Electrical Workers
Local 1245

JOSHUA SPERRY, Senior Union Representative
Engineers and Scientists of California
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McLean, Virginia 22102

I N D E X

I N T E R V I E W

(3:10 p.m.)

MR. GUNTHER: All right. I'm Karl Gunther, investigating an accident in San Bruno, California, that occurred September 9th, 2010. It's our DCA-10-MP-008.

And, as you're aware, you're able to have counsel. And have you chosen someone?

MR. FASSETT: I have.

MR. GUNTHER: Mr. Jaques?

MR. JAQUES: Dane Jaques, on behalf of the witness.

MR. GUNTHER: Okay. I'd like to go around the panel and everybody can introduce themselves.

MR. CALDWELL: Geoff Caldwell, City of San Bruno.

MR. DAUBIN: Brian Daubin, PG&E.

MR. SHORI: Sunil Shori, California Public Utilities Commission.

MR. KATCHMAR: United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration.

MR. GUNTHER: Karl Gunther, NTSB. And, perhaps, later Ravi Chhatre, NTSB.

MS. MAZZANTI: Debbie Mazzanti, IBEW, 1245.

INTERVIEW OF ROBERT FASSETT

BY MR. GUNTHER:

Q. Okay. Now, can I get your name, address, and phone for the record?

A. Sure. It's Robert P. Fassett, 375 North Wiget Lane, Walnut Creek, California 94598.

Q. And your job title?

A. I'm a Gas Engineering Director of Integrity Management and Technical Support.

Q. Okay. And could I get your credentials?

A. I have a bachelor's degree in civil engineering. I am also the National Association of Corrosion Engineers Chairman of the technical group, 041, external corrosion, direct assessment. The team is responsible for the writing and the revision of the international standard known as SP-0502, external corrosion, direct assessment.

Q. Okay. And are you -- do you have OQ under the competence?

A. I do not.

Q. What I'd like you to do is discuss in basic terms the PG&E integrity management program.

A. In general terms, there is -- well, there is a subpart O, the section that follows -- the section of maintenance falls under the definition of high consequence area. There's approximately 1,000 miles of main that falls under that definition. Approximately three-quarters of that is assessed using external corrosion direct assessment. The remaining 250 is assessed using in-line inspection. We -- we pig it at about ~~two~~-

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one, so in order to effective pig our pipelines, we actually pig four times more than the mileage we have to assess, relative to the definition. So there's approximately 1,000 miles of pipe to be pigged.

The program began in 2002 under Presidential signature. The first 10-year assessment -- we have 10 years to assess the pipeline -- is to be completed by December 2012.

Q. And has that been completed yet?

A. No, sir, but we are on schedule to complete.

Q. Okay.

MR. GUNTHER: PHMSA? Mr. Katchmar?

MR. KATCHMAR: You know what? I'm going to let the PUC go first.

MR. GUNTHER: Okay. California PUC?

MR. FASSETT: While they're doing that, I'll add that the program has been audited twice by the CPUC, once in 2005 and again this year.

MR. CHHATRE: I'm Ravi Chhatre. I will go first, an then these two guys can follow.

MR. GUNTHER: Okay. Ravi Chhatre will be next, NTSB.

RJ

BY MR. CHHATRE:

Q. I'm Ravi Chhatre, NTSB. ~~I8E~~ IIC for this accident investigation.

Could you begin by giving some general description of the ECDA and how you do it, internally or consultants, and just give a layman's description of how it is done?

A. External corrosion direct assessment -- we referred to as ECDA -- is one of the three methodologies we're allowed to use relative to the code for assessing pipelines in high consequence areas. There is also in-line inspection and there's hydro-testing.

ECDA is a four-step process. The process beginning with the pre-assessment, the indirect inspection, the direct examination, and then the post-assessment phase.

Q. And how do you do the direct and indirect assessment?

A. That's the second and third phase of the ~~unit~~ process RJ. The first phase is the pre-assessment. The pre-assessment is done. RJ We have -- at PG&E -- field engineers who are assigned to GPS the line. So the responsibility of gathering the data relative to Table 1 and 2 of the ECDA document, 0502 is theirs. RJ We use that as a baseline of information when we go out to collect. It's various things about knowing about age of pipe, how the pipe was made, location of the pipe.

At PG&E, we do it slightly different than others, in that the field engineers also go out and have the pipeline marked and located, and then using GPS to actually shoot the pipeline in. We call that the creation of a control map. We do that because when our contractor comes in to do the indirect inspection, they are also required to GPS it. This way, we establish a control map, so that when the data comes back in, we can make sure that the data they collected is on the line we intended them to collect it.

In that control map process, the field engineers are walking pretty much every foot of the line. They're taking down topographical information like pavement type, concrete, asphalt, soil. If they notice any other USA marks, like water or electric, they capture that. If they notice any fresh excavations, they capture that, as well.

That information -- all of that information is then used, evaluated by the project engineer, who gets a sense of -- an initial sense of what he thinks the integrity of the line is, what -- kind of develops a hypothesis of where he thinks corrosion may be occurring.

It's also at that phase that he determines or she determines if ECDA is feasible to be used on that. line So he's evaluating the threats that ECDA is designed to assessed.

Generally, a pipeline -- or always a pipeline is not scheduled for ECDA if the risk management team has decided it's not feasible.

So, for example, if there's a long-seam threat on that pipeline, they will not be assigned for ECDA to be used as an assessment.

The second phase is the indirect inspection phase. The indirect inspection phase is performed by a contractor -- performed by a contractor. Generally, if it's over pavement, we use what's known as CIS -- close interval survey. We drill five-eighths holes on 10-foot centers, insert a copper -- copper sulphate probe into the hole to get our pipe soils. We also use what's known as pipeline corrosion mapper, which is a wireless device design to track the current through the pipeline. When we get onto soil, we add what's called DCVG -- direct current voltage gradient -- which is another current-type tool.

The process or concept behind ECDA is if you have an anomaly in the coating, you may have corrosion. So we do a current survey to determine the quality of the coating. We do a pipe-to-soil survey to determine the polarization on the pipeline.

Once that survey is done, we evaluate the data. We have selection criteria that determines, based on the tube tools, their cross-matrix, we have severity criteria that then determines the level of prioritization, to determine where we have to dig, if anywhere.

The code speaks to three general categories of prioritization: immediate, scheduled, and monitored. The immediate for ECDA does not mean immediate action. It means top priority.

Once that's determined, then we line up for where the excavations are required. The excavation, we dig per 0502 what's called a Section 5.10, which is a section that tells us how many excavations we have to dig per priority if it's an immediate, scheduled, or monitor.

We perform those excavations. We have -- in the performance of that excavation, we have a very prescriptive form that we use. We call it Form H. The last time I checked, it was about 12 pages. We take just about every bit of information we can get out of the hole. We require soil samples, we take corrosion product -- if there is any. We take water samples. If any water is in the hole, we take water samples. or KJ If any water is under the coating. We do a full grid evaluation, map the corrosion, if any, calculate remaining strength to determine if any repairs are needed, if any corrosion was found.

Also, although we're not required to do it, we do that inspection after having sandblasted the pipe to do what's called an NACE 10 sandblast pattern. That provides a nice, clean surface. It makes it very easy for us to evaluate any corrosion or any other anomalies on it. It also sets us up to do something that -- that I think we led the industry in doing, which was while that hole is open, we do a full, 360-degree full length of the sandblasted pipe, wet florescent mag particle evaluation of the pipe. That tells us if there's any cracks in the pipe. Although we do not believe we have stress corrosion cracking in our system, we look every time we dig it up, whether we're doing an ECDA direct examination or we're doing an ILI direct examination. We have some 500-plus excavations now where we have full mag particle. Those exposed sections of pipe, we have not found any cracks.

I'm bringing this up, because, as we know, some of us suspect that the seam that failed was a ERW seam. If there was in any of our excavations an ERW seam and it was beginning to crack, the wet particle mag would pick that up.

Once all of the excavations are done, the data is collected, then we go into what's called the post-assessment phase. It's in the post-assessment phase that the standard requires us to evaluate the effectiveness of the process, do we still think ECDA is feasible for that pipeline?

We do -- in that phase, we do what we call long-term integrity management planning, which is not a requirement of the procedure, nor is it a requirement of the code. The long-term integrity management plan is to address the mitigation associated with what we may have found on the pipeline. for example, RJ Sometimes we find that the pipe-to-soils were low, but there is no corrosion at the excavation, so we would require local maintenance to increase the ~~power and~~ current at RJ the rectifiers to bring the pipe-to-soils up, that kind of thing.

That's sort of a Reader's Digest version of the program.

Q. For a Reader's Digest version, it's very good.

A. Thank you.

Q. You said one thing about a thousand miles of transmission pipeline falls into the Integrity Management Program?

A. It falls under the definition of high consequence areas. We have approximately 6,000 miles of what we call transmission pipeline. We defined it initially as anything over 60 pounds. Relative to the program, we use the -- the code definition, and generally anything over 20 percent SMYS, ~~we're~~ or feeding a distribution center.

Q. Would it be automatically classified as a transmission line, irrespective of the size?

A. Correct.

Q. And you said about 700 miles of that 1,000 miles of high consequence area falls under ECDA?

A. Approximately three-quarters.

Q. Approximately. And how is the actual integrity remaining one-fourth of the transmission pipeline?

A. So the code requires initially when you develop your program, you have to do risk calculations for all of the pipelines in your system. And then risk-rank accordingly.

We use a relative risk-ranking methodology. We are moving to a pro-ballistic-based methodology.

Q. Which model do you use for your integrity management?

A. We have an analog equation that was created in-house.

Q. Internally?

A. Yes. That's correct. That equation is evaluated by subject matter experts on an annual basis. Each section of that equation is determined by the subject matter experts, whether it's still weighted properly or not.

Q. And is the subject matter internal or external? Meaning

outside consultants or PG&E expertise?
A. Within PG&E expertise.
Q. Okay. And --
A. I should add to that, we do have our contractor who works side-by-side with us in the ECDA, and I believe they provide comment on the annual evaluation associated with the corrosion aspect of that equation.
Q. Okay. So the outside contractor performs your surveys?
A. They perform the actual field piece of the indirect inspections.
Q. Okay.
A. And they perform the field piece of the direct examination.
Q. Okay. And do they analyze the data, also? Or you guys do the analysis?
A. The indirect inspection phase, we generated an equation that takes the data -- they create an equation and automatically places it in the appropriate level of severity.
Q. So your ranking -- I'm sorry, go ahead.
A. And then we take that data, evaluate it, determine a couple of things. We want to make sure they're -- the data they collected was on the alignment that we gave them originally.
So then we evaluate to determine whether we agree or not on how the classifications came in. It's auto-generated from a computer, so for the most part it --

Q. So human factor is pretty much kept to a minimum. You have a program that you define annually, correct? And the equation will rank -- or the equation will evaluate the data that the contractor has created?

A. Right. We have appropriate weightings for each factor in the equation and then it's an Excel spreadsheet, basically.

Q. Is the well seam a factor in the equation?

A. Yes.

Q. And what about the fast leak history, is that a factor?

A. Yes.

Q. And how do you classify the ranking? I think you mentioned it, but can you repeat that one more time? I think you said something about immediate repairs.

A. The prioritization in phase three of the ECDA?

Q. Right.

A. The code calls out immediate, scheduled, and monitored.

Q. Okay.

A. We've a "no indication."

Q. Okay. So immediate, longer, and no indication?

A. Immediate, scheduled --

Q. Right.

A. Scheduled is the second one. Monitor is the third one. And we have added a fourth criteria called no indication.

Q. Okay. So, immediate, then scheduled, then monitored and no indication?

A. And then we've added no indication, correct.

Q. Okay. All right.

And then going back to the inspection, are you using hydro or in-line inspection as a criterion for your evaluating the pipeline for risk assessment?

A. We are in general. The first baseline was -- we pretty much tried, if feasible, to pig. We've tried to pig pipelines that are greater than 30 percent ~~smice~~ S.M.Y.S. RJ ~~(ph.)~~. If they're greater than 30 percent ~~smice~~ SMYS RJ and tape ~~coded~~ Coated RJ, I should say, we tried to pig them.

We essentially determined where we could pig first. We determined where we had long seam failure. And whether -- not long seam failure, but where we had long seam threat. Excuse me.

Once you determine where you have long seam threat, then you have to determine whether that's a stable threat or not. If you determine it's not a stable threat, then ECDA and the standard MFL meg flux -- ILI tools are not feasible. So you would have to use hydro tests or you would have to use an ultrasonic pig, which doesn't work very well in the gas business, because that requires moving it in a slug of water or some --

Q. Some conducting material? Is that what you're talking about?

A. Yeah, I was about to finish, though.

Q. I'm sorry.

A. So, in the gas business, because it's a dry pipe and you need a couplent, you have to put the UT in. You have to put water on each side of it, which means a pig on each side of it. So it would be pig, slug of water, UT, pig, slug of water, pig.

The pressures in our line generally aren't sufficient to be able to push that type of tool down the line, so it's not feasible.

The other type of pig, which we have some experience with, is a TFI tool -- transverse field inspection tool. At the time when we were creating the baseline in 2004, that technology was still on the drafting board. It's now out. We've used it. But that technology does not -- is not big enough, I understand. It can't do a 30-inch pipe.
So that leaves you with hydro tests.

Q. So to summary, I guess it's pretty much hydro and direct assessment are the major tools you use?

A. The major tools are in-line inspection and ECDA.

Q. ECDA.

A. I don't believe we have any hydro tests.

Q. Okay.

A. To this point, the long seam threats that we believe we had was -- I think it was restricted to line 21-E, which is a 12-inch line, running up in our northern portion. It's called Sonoma County. And we did that -- I want to say 2008, using the TFI tool.

Q. So your initial baseline assessment for IM program was finished in 2004, you said -- started in --

A. We were required to submit the baseline by 2004, and we did it.

Q. Okay. Did you have to submit your plan to CPUC or PHMSA before you started executing it?

A. No, we had to submit it to them. We didn't have to wait for permission to begin.

Q. Okay. So you could have started simultaneously -- submitted the plan and started your inspections?

A. We started with the framework, to begin the process, to understand how to do it. We worked with industry to develop the procedures which later came to be known as ECDA 0502. We and other operators. We weren't the only ones that provided the information.

Q. And what happens when you submit the RSPA, or PHMSA or CPUC, what are they supposed to do before you start doing monitoring with your plan? Do you require their approval of your plan?

A. I don't believe that the government ever tells you it's okay to use your procedure. They never tell us it's okay. They always say, "Provide us with information. And then when it comes time to audit you, we'll tell you if you have any violations."

Q. Okay.

A. That's been my experience, anyway.

Q. You never got any yea or nay from -- would it be CPUC or

PHMSA?

A. It would be the CPUC. PHMSA assisted. But in the development in our program, because we are also working with industry, we openly shared what we were doing with CPUC and PHMSA came out. We had a mock audit to help train PHMSA auditors on ECDA. They weren't familiar with what it was.

Q. Right.

A. PG&E was a leader in that process.

Q. And since 2004, were you audited for CPUC for integrity management?

A. We were audited in 2005 and then earlier this year.

Q. Okay. And did you have any comments from CPUC about your baseline assessment program? Did they cite any violations? Did they --

A. In 2005, PHMSA assisted CPUC in the auditing of the program. We received basically a field report out, some four pages of notes, but we never received a final letter.

Q. Okay.

A. In 2010, I think it was in April or May -- the audit -- we have not received a letter. We received some verbal notes.

Q. Okay.

A. At the close of the field meeting.

Q. And you mentioned that you did not -- you have not seen SCC -- external SCC on any of your transmission pipelines that was

excavated, sandblasted --
A. As part of the Subpart O, integrity management, that's correct.
Q. And there's no indication of any SCC on that one?
A. Not in -- subject to check. That's something I looked pretty hurriedly at.
Q. Okay.
A. We've not received any of that as part of the Integrity Management Program.
Q. Okay. What -- are you guys considering any other tools just for the cracks in the seams?
A. Where we have a long seam threat, we're using a TFI tool. We used it on 21-E in Sonoma County in 2008.
Q. And did you see any indications anywhere that you had to repair the pipe or grind it or whatever you had to do?
A. As I recall, we had indications. We've addressed them, but I don't -- other than that, I don't know the specifics, how many there were, how deep they were, that kind of thing.
Q. That's okay. And do you know how that line is different than the rest of our 9,000 or whatever -- miles of pipeline, in terms of either product, pressure, or composition?
A. What line are you referring to?
Q. The line that you said you had indications of SCC -- external SCC.
A. There's no external SCC.

Q. Internal SCC? I thought you said you had indications of internal SCC.

A. No, we had a long-seam threat.

Q. A long-seam threat, okay.

A. So we had a pre-70 ERW pipeline, which is known as low toughness or however you want to call it.

Q. Okay. And there are no indications of SCC, then? Just to make sure I get the correct information --

A. There are no indications of SCC.

Q. Okay. I want to get that in the information package.

Do you ever have any ruptures, leaks in the transmission pipeline in your system? And I'm not referring just to DC lines, but since you are the director, do you know of any occurrences in the past involving a transmission pipeline that had external corrosion, internal corrosion, ruptures or leaks?

A. Well, we have leaks. I don't recall, to my knowledge, ruptures, but I've only been here 20 years and I haven't been on the transmission side of it.

Q. Okay.

A. The only rupture -- there was a rupture in 2001, in Windsor, that I'm familiar with -- Windsor, California. It was third-party damage.

Q. Okay.

A. And then there's the rupture on September 9th, why we're here, that I'm aware of.

Q. Okay.

MR. CHHATRE: I'm done. I have no more questions. Thank you very much.

MR. GUNTHER: PG&E?

BY MR. DAUBIN:

Q. Bob, did we ever receive -- did PG&E ever receive -- from PHMSA or from CPUC any comments on the 2004 baseline?

A. Not that I'm aware of, but I wasn't in the capacity of reviewing that at the time. I was responsible for ECDA, I wasn't responsible for communicating with the Integrity Management Program.

MR. DAUBIN: That's all I have.

MR. GUNTHER: City of San Bruno? IBEW?

MS. MAZZANTI: No.

MR. GUNTHER: PHMSA?

MR. KATCHMAR: Can we go off the record, please.

(Off the record.)

(On the record.)

BY MR. KATCHMAR:

Q. Mr. Fassett, Peter Katchmar with PHMSA.

You mentioned in previous questions that there was a 2005 integrity management inspection with PHMSA and the California PUC, a combined inspection, a combined inspection. And you said you didn't receive an actual enforcement letter or some kind of letter afterwards. But did you receive any issues -- any exit interview for that inspection?

A. We received -- the basic, I think it was a four-page Word document. I forget how many items. But it was comments associated with the whole program. Some of it was what we called ~~R&P~~ RMP-6. That's the baseline plan, an explanation. Some of it was associated with ILI. Some of it ECDA. It was kind of a smorgasbord of comments.

Q. Okay. And did you do anything with those issues?

A. We used those issues -- if there were changes to our program that we agreed with, we incorporated them into the program. Quite a few of them were grammatical things. We had, for example, we had left the word "framework" into it, and they felt that it was a developed enough program where it should be called a procedure or a standard, not a framework. Those kinds of things.

There were some areas that we disagreed with and so we wrote the position papers to support why we disagreed with it. Generally, in those areas, it was not a code violation. It was just their observation or their opinion, and so we stated our opinion as to why we disagreed with their opinion.

And then when it came time -- so we incorporated that into our documents, where appropriate. And when it came time to prepare for the 2010 audit, we went back on that list and ensured that we had addressed it. And if we hadn't addressed it, because of paper, we ensure -- because if we wrote papers, we ensured we had the papers in the audit.

We are compiling, at your request -- and I believe we'll have it today, if not we'll get it to you. We recreated to the best of our ability what was asked of us -- what was commented and what we did with the comments. And you should be receiving it at some point here. It's part of the investigation -- a print-out of that.

Q. Thank you. And you also said something about you used those issues to prepare for the PUC's 2010 audit?

A. Correct. We wanted to make sure we had accounted for the comments provided to us at the last time they audited us.

MR. KATCHMAR: Thank you. That's all have.

MR. GUNTHER: Sunil?

MR. SHORI: Yes, a couple of questions.

BY MR. SHORI:

Q. Line 132, is it pig-able in any portion between Milpitas -- between its start and terminus?

A. It depends on how you define "pig-able." If you mean are there lengths of ~~some~~ Single diameters for some period of length, yes. If you mean is it pig-able meaning a single diameter for what the industry would think at least five to 10 miles to make it effective, no.

Q. So even on those straight stretches of fixed diameter, do you have facilities that would allow you to put the pig in and take the pig out?

A. We don't have any pigging facilities on our system. So on that system, there are no pigging facilities, I believe was your question.

Q. Are there any portions of line 132 where you have the long seam identified as a threat?

A. I'd have to look at the data, but I believe there is -- I believe there's some 24-inch ERW on that line, but I'd have to look at the line drawings I gave you. You have that information.

Q. In the segment where the incident occurred, what was the assessment method that you used?

A. ECDA.

Q. And based on that method, did you identify any indications at the location of the incident?

A. Not to my knowledge. None worth digging. If I recall, in 2004, we had some monitors -- or 2005, we had some monitors. I believe it was low pipe-to-soils in the 700 range. The mitigation associated with that section was to raise the rectifier, increase the ~~volt~~ current to the pipeline. In 2009, evaluating that area, the pipe-to-soil were above or more electro-negative than minus 850 off.

(Off the record.)

(On the record.)

BY MR. SHORI:

Q. At the location of the incident, did you have any long seam threats identified as part of your assessment process?

A. I believe the data I provided you shows that our pipeline survey sheets had called that 30-inch seamless pipe.

Q. So is the answer no?

A. What was the question?

Q. Did you have any long seam threat identified at the location of the incident?

A. We did not.

MR. SHORI: Thank you.

MR. GUNTHER: Okay. Ravi?

MR. FASSETT: Just to clarify, it was not identified prior to the incident.

MR. CHHATRE: Just a couple of follow-up questions.

BY MR. CHHATRE:

Q. Your outside consultant, contractor, performs ECDA and then the contractor analyzes the data and send you a report. Is that a correct summary?

A. The contractor has programming that takes each individual data point from the different tools and provides by station essentially -- categorizes relative to the criteria we gave them.

We then take that data and determine where we will excavate.

Q. Okay.

A. They don't decide where we will excavate.

Q. They analyze and they tell you, "This is where we see -- these 10 locations we feel" -- or whatever it may be.

Now, who watches that? Who internally checks that the contractor's work is satisfactory, adequate, correct?

A. So the contractor has a senior engineer that evaluates all of the data. They have 100 percent quality control evaluation of the data to determine it makes sense to them.

Then it comes over to us and our project engineer evaluates that data. He has to do a couple of things. It's not just take the data, but he has to look at that data, look at the selection criteria, look back at the pre-assessment information that he gathered, where he made his initial hypothesis of where he thinks he would be looking. He needs to verify that those two assumptions are still kind of in -- all in a line, if you will.

And then the decisions are made. So he's evaluating all of the data and then the decisions are made where to dig.

Q. Any occasions where -- let me back up.

The person who does that, what's the title would be?

A. He's a ECDA project engineer.

Q. Okay. And does he have corrosion -- I guess training background -- to do that or is this training internally by PG&E? What is the person's background?

A. Well, he's certainly gone through NACE CP-1 through CP-3.

Q. Okay.

A. He was trained by a NACE CP Level 4, who is also a metallurgist. Who also provides the training and support for our newer --

Q. So he's a qualified person to do that job?

A. Yes.

Q. And how do you decide where to excavate? What are PG&E's criteria?

A. The specific criteria is provided in our ~~R&PO~~ R.M.P. RF -9, which I believe we provided to you for evaluation. I don't remember it to the detail that I could speak to it at this point.

Q. Okay. So who made that decision? Obviously not you. Where to excavate --

A. The project engineer.

Q. The project engineer. Would it be the same person who looks at the data or a different person?

A. The same person.

Q. The same person.

A. That person follows it through the entire process.

Q. And he or she responsible for the entire 1,000 miles or 700 miles that are on this pipeline or --

A. We have a risk management department that is responsible for calculating the risk associated with the pipeline, both in ~~HCS~~ H.C.A.'s RF and outside of ~~HCS~~. H.C.A's RF

Q. So the group that does it -- I am trying to find out if there's only one person in the system who makes the decision or if there are a group of people who collectively make that decision. That's what I'm trying to understand.

A. Under integrity management, we have what we call the integrity management team. They're responsible for the actual carrying out of the inspections, whether it's ILI or ECDA or hydro test. That team reports to the manager of integrity management. The manager of integrity management has the team we call the risk management team that reports to her. And there's a team that we call system integrity, which is responsible for the processes associated with distribution of integrity management, as well as the other maintenance processes for transmission, like damage prevention, leak survey, et cetera.

Q. So essentially they do it and then it comes to you for approval?

A. The digs are approved at the manager's level.

Q. Okay.

MR. CHHATRE: Thanks. I have no more questions.

MR. GUNTHER: Okay. PG&E?

MR. FASSETT: You mean CPUC?

MR. GUNTHER: PG&E. City? IBEW?

MS. MAZZANTI: No.

BY MR. GUNTHER:

Q. All right. What I want to do is discuss since the accident and what you have observed on the pipe. What actions have you taken with regard to remediation that -- and, to some extent, to what you can discuss, what actions you have planned to, you know, look at this threat and whatever threats that you may see and try to mitigate before -- you know, before -- well, let's just say to try to mitigate them.

A. Okay. So I am not a metallurgist, but I have a background in corrosion and defect assessment. As I've discussed with the team out there -- and I think -- I won't speak for them, but I think folks on the team agree that it's likely the main failure that occurred out there where the pipe was laid open and the edges -- and the middle edges of that four-foot section that was originally just five feet south of the girth weld that broke on the north end, it looks like there was some length of incomplete penetration perhaps on a ERW seam. It looks like there is crack growth, which fractured and with that fracture, ran -- shattered -- partially shattered the girth welds, which would have opened the pipe up. The pipe, then, tore through its original position to the south, and that explosion forced it, broke it off the pipe to the girth weld to the north, blew it into the air and flipped it upside down.

In looking at the data, the data says that that pipeline should have been seamless. In looking at the pipeline, I noticed -- and have shared these comments with the team -- that the two segments which originally would have been to the south of the rupture in orientation where we found it to be to the north -- that there are at least, possibly three -- I don't have the drawings in front of me -- where there's clear signs of DSAW -- double-submersed arc-welded pipe.

There's a section immediately -- relative to the final position -- immediately south of it where there appears to be that final span of what I think is ERW pipe. Some of you agree with me, that may have had a hand-welded repair on the inside.

When I look back at our historical data in what we call gas standard A-11, page 11, we have a sheet in there that gives us a sense from accounting data of what type of pipe we bought when. So it gives us the diameter and the year and it gives us the long seam, and where it knows it gives us the smice.

When I look back for that year, 1956, it says -- from, I think it's '48 to '70 -- it says that historically the only pipe we bought in 30-inch was DSAW. It gave us a range of 42,000 to 52,000 on the smice.

So what we're planning to do -- I think this is a materials issue -- we're doing this as privileged and confidential. We put a team together to kind of keep it quiet, to the degree we can, we -- NTSB has agreed that further investigation is not part of this investigation, but we will certainly share the information. The CPUC will be working with us. CPUC has given us 10 directives, one of which is to perform further assessment on the pipeline. It has not detailed as to what that assessment needs to be.

We're going to start with at least two assessments, as referenced earlier today. We have a team put together to go back to look at all source data and verify what that was, try to rebuild the procurement processes of that day to get a better understanding of where we were buying pipe, how we were buying pipe, where it was coming into, validating -- starting with line 132 -- and I would expect that it will go to line 109 and 101 -- to determine, again, that's a form of assessment. We would call that an -- in ECDA terms, that would be called pre-assessment. It's still knowledge assessment of your pipe. It still gives you a lot of knowledge of what's going on and validates what we already knew. That's one of the things.

The other thing we're going to do is we have a camera -- a crawler camera, a 12-inch crawler camera being flown in from Canada. It has a 6,500 foot tether on it. That's going to allow us to put that camera through the pipe and the intent is to look for a long seam. If our standards are correct -- and I believe they mostly are, based on my experience -- we should be able to see where the DSAW is. And where there isn't DSAW, where there is no obvious internal seam, then that tells me it may be either seamless, Lap RF ~~black~~-welded or ERW-welded pipe. At which point, because the camera has a footage tracker on it, we'll be able to essentially map, navigate, do that on the surface, excavate and determine what kind of pipe we have. And if it's the ERW -- I don't know if we have LAP ~~black~~-welded pipe in that size -- it is our intent to remove that from the pipeline, send that to our third party consultant in Menlo Park, Exponent, at which it will be saved. We'll discuss with the NTSB and with CPUC the protocols -- and PHMSA. I assume it will be the same protocol that you'll be using in Virginia to evaluate this pipe.

MR. GUNTHER: Thank you. Go ahead.

BY MR. KATCHMAR:

Q. Would it make sense to put a transmitter on this camera so that you could track it from the outside of the pipe while it's going in?

A. That's one of the things we will be working with the manufacturer of the camera to do.

We also have cameras within PG&E. We have -- we use a lot of cameras for the nuclear side. We have a very sophisticated department that will be working with us in support of this. Their tethers tend to be shorter. They tend to be four or 500 feet. But, yeah, we're bringing in the best we can to address this.

MR. CHHATRE: Question.

BY MR. CHHATRE:

Q. On the -- you've given the number of excavations you have made in the last -- is it 507 excavations?

A. Some 500 of them.

Q. Five hundred-plus?

A. Plus or minus.

Q. Five hundred-plus. In how many years this happened?

A. Since the IM program started, I think we did our first one --

Q. 2002?

A. -- in 2003.

Q. Okay. So 2003 until sometime in 2010?

A. Yes. And we're still doing them.

Q. Obviously, 500-plus, are you seeing coating -- different types of coatings in different locations?

A. Yeah, we have different types of coatings. Approximately half of our ECDA pipe was installed in the '50s or earlier. Therefore, the majority of that pipe is hot-applied asphalt coating. Some of the younger pipes that were installed in -- I don't remember when we first started using tape. So I'd say starting in late '70s, early '80s, we were using tape and then we transitioned to FBE.

Q. Tape -- what tape are you talking about?

A. Tape-coated.

Q. Tape coating, okay.

A. And then we used fusion-bonded epoxy, which is what we use today. On some of our directional boring crossings, we have other coatings, Power-crete RJ ~~power creek~~ and that kind of thing.

Q. Okay. Those 500-plus excavations, would they be probably in the same kind of percentage in terms of coating?

A. I don't know.

Q. Okay. I'm trying to -- okay, let me ask it a different way.

What kind of coating problems you have observed when you did the excavation? Did you observe the condition of the coating -- or somebody in PG&E observe the condition of the coating?

A. Yeah, generally there are times when the hot-applied asphalt has dis-bonded or easily dis-bonds. To my knowledge, we have not found any shielded tape-coated pipe. We have found dis-bonded tape coat and we have found that with the ECDA tools. To my knowledge, we have not found any cold tar coating. We have some lines that have Somastic coating. That's about it.

Q. Now, in any case -- in any of the situations, there are 200-plus -- 500-plus -- were there any corrosion associated with the coating problems? I mean are you guys keeping track of that?

A. How do you define "associated with"?

Q. Meaning -- those 500-plus cases, to sandblast you have to remove the coating. You first excavated. Did you examine the coating from the outside before you removed it? Condition of the coating is what I'm talking about.

A. Yes, we look at the condition of the coating. All of that information is kept on Form H.

Q. Form H?

A. Yeah. Which is referenced in the binders that you have.

Q. Okay.

A. And is discussed in the procedure.

Q. And, I guess, my next question is, depending on the coating condition, have you observed any general corrosion fittings underneath those coatings?

A. Yes.

Q. And in the coating condition, what kind of actions did you have to mitigate that?

A. Generally there's enough remaining strength in the pipe where repairs are not required.

Q. And that would be decided based on -- do you do the calculations on the remaining strength? Is that how you determine that you don't need to do anything on that?

A. Yes, we use KAPPA or R-strength.

Q. Okay. And so in most of the cases you're seeing no repair or corrective actions are necessary?

A. Correct. There have been some repairs, but in most cases, if there was corrosion found, it was not deep enough to require repair.

Q. Was any of that captured in the ~~DCBG~~ DCVG RJ?

A. Was any of what captured in that?

Q. The corrosion damage underneath the coating. Was it picked up in any shape or form in the --

A. We would have done it generally, because we believe there is corrosion there. That's why we would have excavated there.

Q. Oh, okay. So part of your excavation, I guess selection criteria, is the location that may be more prone to corrosion? I think what you're saying that your consultant didn't dictate where you can excavate. You decided.

A. We have criteria, it's established in there, as to what's an immediate. So I'm running off of memory. If you have a close interval survey and it has minus 500 only, that's enough to -- just on its own is to call it as an immediate. And then there's, you know, some sense of more electro-positive than 850, with some sense of current evaluation from the PCM, could give you an immediate or a scheduled. All of that is laid out in the procedure. I don't have it memorized.

Q. That's okay.

BY MR. DAUBIN:

Q. So Bob -- Brian Daubin, PG&E. Was it safe to say that the ECDA digs that you have are based on criteria and the prioritization of the results from ECDA?

A. From the results of the indirect --

Q. Assessment?

A. -- assessment, yes.

MR. DAUBIN: Thanks.

MR. CHHATRE: That helps. That helps.

BY MR. CHHATRE:

Q. And any leaks -- either external or internal leaks -- on the transmission lines?

A. Are there any leaks on the transmission lines?

Q. Past leaks.

A. The what?

Q. In the past history, since -- this goes back to 2002.

A. Yes, there are leaks.

Q. And can you --

A. And there's repairs.

Q. I'm sorry?

A. There's leaks and there's repairs.

Q. Okay. And --

A. We generally don't -- even though technically we can leave an open leak on a transmission line, depending on the grade, we don't typically do that. We pretty much repair all leaks on the transmission line.

Q. And can you describe -- maybe give me a couple of examples of what the leaks look like or what the cause was or do you do a root cause on those?

A. If we did a root cause, it would be in our records. The kinds of corrosion we see, is that what you're asking?

Q. Um-hum.

A. So we see classic rock impingement-type corrosion. We see general corrosion, general corrosion with pitting in it. That type of thing.

MR. CHHATRE: Okay. Thanks. I'm done.

MR. GUNTHER: Okay. Anybody have any more questions?

BY MR. KATCHMAR:

Chapi RJ

Q. Bob, to use KAPPA, don't they need to use ~~Sharpe~~ ~~(ph.)~~

values to plug in that?

A. No, if you have them, it helps. But you don't have to.

Q. Okay.

A. KAPPA was John's -- John Kiefner was funded through industry, PRCI, to create R-string. Industry funded it and then PRCI, even though they received funding from industry and, I believe, from the government, turned around and started charging people for it. That annoyed John. He wrote KAPPA and put it out on the internet.

Q. Right.

A. KAPPA is essentially ~~R-string~~ R-Streng.

Q. I've used it. That's why I asked the question.

Could you please go over your -- just in general terms, your risk assessment for line segments that could affect HCAs and how that's evolved from the first list to today?

A. I'll do my best, but I haven't been directly involved in the creation.

We use -- we started with Method One, which is all Class Threes and Class Two and Class One, where 50 or more people -- 20 or more people congregated 50 or more days out of the year. Not to be continuous.

And then we had -- because we had a GIS system, we purchased aerial photography and were able to use Method Two, which is the potential impact radius, calculation. It's a moving, potential impact radius, which is referred to as a Siefert Circle, ASME B318-S and I don't remember if it's in Subpart O, but it says you can do assessments by B318-S and it's in B318-S.

So we use that method to determine what segments of the line need to be addressed. Did that explain your question?

MR. GUNTHER: Off the record.

(Off the record.)

(On the record.)

BY MR. KATCHMAR:

Q. Okay. Could you go into a little more detail about how your risk assessments -- or baseline assessments -- I guess it's risk assessments changed between your 2002 and 2004 and 2005 --

A. Sure. So, as I mentioned earlier, Subpart O requires us to calculate the risk of all of our segments. And I think -- I'm going off memory, but I think there's ~~40,000~~ 20,000 ft transmission segments and somewhere to that, plus or minus, in GIS.

So we run the calculation, evaluate it. We actually started risk management in '99, prior to Subpart O.

We put -- using that analog equation, we put number values on them. They're relative risk values, they're not probabilistic. It's more about this pipe looks worse than this other pipe, which looks better than the other pipe, but not as bad as the first pipe type of concept.

So we have -- and we can provide kind of a general graph of how many segments we had in which level of risk priority. So we had taken -- for high risk, for example, I believe that it's the number of 1,950 to 3,500, or somewhere in that area. And we have a graph that we can produce that shows what it looked like in 2001 and what it looks like in 2009, after a series of mitigation. Not just integrity management mitigation, but we have what we call the risk management program, which we take from that list as we continue to drive down risk, because of all of the mitigation we perform on it through DA and ILI.

We drive that down through a program we call Risk Management Top 100. That's an annual capital investment in some portion of the top 100 highest risk pipelines.

And that calls for -- sometimes that calls for replacement. Sometimes that calls for doing close interval survey or evaluation to get more information about just how accurate that risk calculation is. That helps to drive down the risk of the pipeline.

So we are -- because it is a deterministic or relativistic methodology, and because you have a continuous integrity management program after you get done with the survey, you're required to come back at least seven years later and do it again. You are effectively driving the risk to zero, because you will continuously drive this.

So what may have been -- what may have been in 2001 the top 100 ran from 3,200 points to 3,500 points, or whatever -- 3,200 to 3,500 -- you look at the top 100 today and it will be far lower than that.

As I recall at one point, the graph has 120 segments that had a risk of like 1,950 in 2001, and if you look at it today, there's like 10 segments that have a risk of 1,950 on it. And we can break that down in points of 50, and we have that aspect.

So between integrity management and between this Risk Management Top 100 program, we have consistently driven the risk of the pipelines down year over year and we can show you graphical form, if you like.

Q. So suffice it to say with a relativistic approach, you always have a hundred in the top risks?

A. Yes.

MR. KATCHMAR: Thank you.

MR. GUNTHER: All right. Any more questions?

MR. CHHATRE: I guess one question and it really deals with this one piece of paper that was, I guess, referred to by the media all of the time with the Vice Chairman and with my meeting with the Governor.

BY MR. CHHATRE:

Q. What is that piece of paper that PG&E submitted to either -- I think the CPUC or somebody about its risk? There is some paper -- what is the document that PG&E has submitted -- and I'm not sure -- where it classifies some high-risk pipeline very nearby, going north of the rupture site?

A. I'm assuming it comes from the top 100 list. I have not seen that document. I've heard about it. I have not seen it myself. I've been involved in this investigation.

MR. CHHATRE: Do you -- do you have the document? Does anybody know which document it is and how do we get a copy of it?

MR. SHORI: A request was placed and I haven't seen it. So I know a request was placed. I'll look into getting a copy of it.

BY MR. CHHATRE:

Q. Maybe it is easier for both PG&E and CPUC to do it simultaneously, rather than waiting for one another. Obviously, you do not recall sending it. You do not -- you have no knowledge of it. So somebody at PG&E sent it, and I thought maybe it was integrity management. Because the language sounds like --

A. It would have been the integrity management group. But I have not been functioning in that capacity since Friday, the 10th.

Q. I understand. Would you please find out and get us --

A. It's on the request list. We are working on it.

Q. I understand. But how do we expedite getting that document? Because I'm getting calls left and right.

MR. DAUBIN: Ravi, what's the request, though? I don't understand, because --

MR. FASSETT: Are we off the record?

COURT REPORTER: No.

MR. CHHATRE: Can you go off the record?

(Off the record.)

(On the record.)

MR. GUNTHER: Are there any more questions? Okay.

Is there anything that you haven't told us that you think in your judgment we should know?

MR. FASSETT: We've discussed the camera inspection, remediation. We've talked about the other team we've got looking at mapping source data for the assessment. There's also something we think may have happened out there. And this flaw was built into the pipeline back in the '50s, it had to be at the factory. So something triggered it.

I think there may have been some kind of geologic event, perhaps, that occurred. Whether it's settling of the pipe, undermining the pipe from leaking water main, leaking sewer, something, put -- I think may have put that pipeline into span, to some degree, had it settle.

What I can't tell -- it's difficult to tell from the way that pipe landed, I can't tell where the long seam was relative to the IntraDose or the ExtraDose of that bend.

MR. GUNTHER: We've got measurements.

MR. FASSETT: So if we could recreate that and get some sense of how much stress may have been on that, which could have propagated the pipe -- something triggered that. This thing couldn't sit there for 50 years and not have addressed this before.

MR. GUNTHER: The lab will match it up and we will find out.

MR. FASSETT: Okay. That's what I had to offer. That's was my --

MR. GUNTHER: Okay. And would you like to make a statement for the record?

MR. FASSETT: No, thank you.

MR. GUNTHER: Okay. Now, we're off the record and we're done.

(Whereupon, the interview was concluded.)

[redacted]

CERTIFICATE

This is to certify that the attached proceeding before the

NATIONAL TRANSPORTATION SAFETY BOARD

IN THE MATTER OF:	PACIFIC GAS & ELECTRIC COMPANY SEPTEMBER 9, 2010 ACCIDENT SAN BRUNO, CALIFORNIA Interview of Robert Fassett
DOCKET NUMBER:	DCA-10-MP-008
PLACE:	Burlingame, California
DATE:	September 17, 2010

was held according to the record, and that this is the original, complete, true and accurate transcript which has been compared to the recording accomplished at the hearing.

[redacted]/10

Richard Friant
Official Reporter