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Douglas V. Pickett, Senior Project Manager
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USNRC
King of Prussia, PA

Subject: Questions for NRC from July 15, 2015
PRB Meeting on 10 CFR 2.206 Petition

Dear Mr. Pickett:

Thank you for the opportunity to make a second presentation to the Petition Review Board on July 15, 2015. The PRB clearly stated it would not answer my questions at that time. I am submitting them in writing as you requested and I expect all of my questions be answered in full. In addition to my questions, I have referred to the portions of the documents received via FOIA responses that support the alleged material false statements and the ways in which these false statements impact the NRC's confirmatory analysis.

FOIA response #1[1] contains a summary and handwritten calculations that are not signed, dated, approved, reviewed, etc. Furthermore, an arbitrary and undefined term is added to the equation "Y" that results in a conclusion that grossly underestimates Potential Impact Radius (PIR), therefore the risk to the public.

FOIA response #2[2] contains an email from David Beaulieu dated April 27, 2015, which discusses gas pipeline dynamics. The information in this email directly contradicts the information provided to FERC by the NRC in its confirmatory analysis used in its approval of the AIM project. This internal NRC email primarily addresses the operator response times and the amount

[1] FOIA document #1 [1] https://www.dropbox.com/s/sheyzp8gcfazm1w/FOIAdocument1.pdf?dl=0
[2] FOIA document #2 : https://www.dropbox.com/s/p8pjxrwvh61m5cm/FOIA_Doc2_NRC.pdf?dl=0

of gas that will be released during a rupture. The gas release rate according to this email is close to one million pounds of gas per minute and likely to continue for hours. The result is that the NRC contradicts its own guidance (Regulatory Guide 1.91) for measuring (PIR) and clearly contradicts both the Entergy and the NRC analysis.

We now know from the NRC email of April 27, 2015 that the volume of gas and the amount of time it would take to terminate the gas flow totally undermine the public confidence that Entergy and the NRC are properly operating and regulating the plant. Moreover, because the blast radius, heat flux and vapor clouds effects are very likely underestimated. A long term Station Blackout (SBO) may result. Additionally we are now aware that the fuel oil tanks likely contain flammable material that has not been considered in any analysis.

The ramifications of these undocumented calculations and alleged material false statements are so grave that the NRC must rescind its approval of the pipeline because FERC based its approval of the Spectra Algonquin Incremental Market (AIM) project on the alleged material false statements made to the NRC by Entergy in its analysis dated August 21, 2014 until a truly independent risk analysis is conducted.

The NRC provided its final analysis and approval to FERC in its inspection report dated November 7, 2007. The NRC personnel participating in this inspection have no documented experience in gas line accidents. In fact, the NRC's primary contributor, Mr. Tammara, has no documented experience in gas rupture dynamics or experience with other events such as the San Bruno and other major gas line catastrophes and was not a member of the team conducting the inspection.

Mr. Richard Kuprewicz, a nationally recognized pipeline expert, and others have requested that the NRC endorse an independent, transparent, thorough risk assessment by recognized experts. The public and elected officials, including Senators Charles Schumer and Kirsten Gillibrand and Congresswoman Nita Lowey have also made this request, yet the NRC continues to stand by its confirmatory analysis of November 7, 2014 and refuses any consideration of any independent risk analysis by experts with documented credentials.

After the second presentation to the Petition Review Board, Mr. Richard Kuprewicz wrote to NY Assemblywoman Sandy Galef with a suggested plan for a transient risk analysis "that incorporates the true transient nature of a pipeline rupture capturing the extremely high change in gas rate release with time that reflects the tremendous extremes of a gas transmission pipeline rupture, especially on a 42-inch high pressure pipeline." Mr. Kuprewicz's plan could form the basis for the portion of the independent risk assessment.

Entergy, in its 10 CFR 50.59 analysis, stated that a rupture of the existing buried gas pipeline due to sabotage was not considered in the 2008 risk study conducted by Mr. David Allen that evaluated the potential terrorist threat to the exposed portions of the existing gas lines. Mr. Art Burritt of the NRC confirmed that failure of the existing gas pipeline may impact safety related Structures, Systems and Components (SSCs) at Indian Point located within 400 feet of these SSCs. This is an unanalyzed condition that requires immediate NRC attention. 10 CFR 50.72 requires reporting of this potential event within 8 hours, yet the NRC has not taken any visible actions to address this issue after more than four weeks while the plants continue to operate in an unanalyzed condition.

Questions:

1. Please identify the missing information in FOIA document 1, including the date, author, approval chain, reviewers and the NRC's procedure for conducting safety related calculations.

2. In FOIA document 1, the NRC in its risk calculation modifies equation #1 of RG 1.91 by inserting an undefined term "Y". What is this undefined term and why was it used? Its impact may be significant.

3. Please provide the specific qualifications of the personnel conducting the inspection that provided the basis for the approval of the AIM project to FERC on November 7, 2014.

4. In FOIA document 2, the NRC stated that the PIR would not be significantly impacted should the gas release continue for one hour

instead of 3 minutes. Equation #1[3] of Regulatory Guide 1.91, that calculates the blast radius, directly contradicts this statement and predicts the PIR will be increased by a factor of 2.71 with a new PIR of about 3000 feet. How can the NRC ignore its own primary guidance?

5. Will the NRC agree to an independent risk assessment prior to allowing any further construction on the project and any further disturbance to land? The composition of the team conducting the independent risk assessment must include nuclear and gas experts and there must be representation of stakeholders, including the public and impacted residents, as well as local, state and federal elected officials. The NRC may elect to be a part of this risk analysis team.

6. When will the NRC conduct a thorough safety analysis of the existing 63-year old buried pipeline, which by Mr. Burritt's own admission, this failure is likely to impact vital structures without any documented analysis?

A. Pipeline Integrity

The NRC Petition Review Board stated in a letter dated April 28, 2015 to me: (ML15124A027) "The pipeline isolation valves are constructed under criteria developed by the U.S. Department of Transportation (DOT). Therefore, the petitioner's concerns regarding the safety class of the isolation valves should be directed to DOT." The NRC has no authority to delegate nuclear safety to the DOT. The operations, integrity, and inspections of these valves are partially designed "*to prevent or mitigate the consequences of accidents which could result in potential offsite exposures"* to the environment and are therefore safety related. See 10 CFR 50.2 below.

> ***10 CFR 50.2 Definitions***
>
> *Safety-related structures, systems and components means those structures, systems and components that are relied upon to*

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[3] $$R_{min} = Z * W^{\frac{1}{3}}$$

> *remain functional during and following design basis events to assure:*
> *(1) The integrity of the reactor coolant pressure boundary*
> *(2) The capability to shut down the reactor and maintain it in a safe shutdown condition; or*
> *(3) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the applicable guideline exposures set forth in § 50.34(a)(1) or § 100.11 of this chapter, as applicable.*

<u>Questions:</u>

7. How will the NRC assure nuclear safety and impose NRC Regulations on the design and construction of the proposed AIM project?

8. How will the NRC assure that the valves, piping, control systems and leak detection systems and other vital components meet the following NRC Regulations:

    - Quality Assurance
    - Redundancy
    - Environmental Qualification
    - In-Service-Inspections
    - ASME codes
    - Technical Specifications
    - Emergency response
    - Operator training
    - Other NRC Regulations for safety related components

B. Valve closure time

Entergy, in its analysis, stated the gas flow would be terminated within 3 minutes, should a rupture occur. I believe this to be a material false statement.

The Entergy 10 CFR 50.59 safety evaluation confirmatory analysis (EN-LI-101 ATT-9.1, Rev.11) states, "The existing pipeline automation and control system, which would be used for the proposed new 42-inch pipeline near IPEC, does not provide for an automatic isolation of the closest upstream and downstream mainline valves upon the detection of a pipeline rupture.

The two closest actuated valves are located at milepost 2.61 on the west side of the Hudson River and at milepost 5.47 just east of IPEC. They would require an operator to take action to close these valves. The system, however, is monitored 24 hours a day and an alarm would immediately alert the control point operator, located in Houston, Texas, of an event and isolation would be initiated. This would result in all of the gas between these valves at the time of closure being able to vent or burn. The estimated time to respond to the alarm (less than one minute) and the closure time of the valves (about one minute) was used as the basis for an assumed closure time of three minutes for the analysis performed in the attached report."

In the email of April 27, 2015 (FOIA document 2) from David Beaulieu to NRC staff, including Mr. Douglas Pickett, the premise for the 3-minute timeframe for remote valve closure was re-evaluated. It concurs with Mr. Kuprewicz's statement during the first petition review call on January 28, 2015, that a pressure drop may not be identified right away. The Beaulieu email cites a report from the Oak Ridge National Laboratory, "The time between a pipeline break and RCV closure can vary from about 3 minutes for immediate leak or rupture detection to hours if field confirmation of the break is necessary to validate the closure decision."

The NRC based its recommendation to FERC on the 3-minute remote closure time. This NRC internal document is more than sufficient to grant my petition as it substantiates the submission of information contrary to the requirements of 10 CFR 50.9.

Mr. Kuprewicz reviewed the FOIA documents in preparation for the PRB call and wrote an email to me on July 14, 2015 in which he stated:

> "Rupture will always be a full bore rupture, releasing at both ends of the open pipes as the fracture mechanics forces throw tons of buried pipe steel out of the ground yielding very large craters (the location of the rupture at these pressures should be performed at a site nearest the plant).
>
> The location of the rupture so close to an upstream compressor station will mask pressure loss indications for quite some time, as mass release significantly exceeds the flow rate in the pipeline before rupture. Pressure loss indication will not be the primary indicator of a pipeline rupture for quite some time.

Right now I believe, very high heat fluxes will be the most likely scenario that may impact equipment to safely shutdown the plant, though blast forces cannot at this time be evaluated on these various structures, my experience would suggest blast is not controlling on the facility though you have a better understand of specific plant safety equipment location needed to cool down the facility.

The repeated attempts to convey that an analysis of a rupture at this site near the plant on the 42-inch actually reflects the actual rupture case reflects a serious lack, even negligent (a term I don't use lightly in public) attempt, to properly analyze a 42-inch pipeline rupture scenario, on this line at this site, on this system.

Any critical independent analysis should clearly define the base case scenario and pipeline operating conditions (flow, pressure) before trying to defend any resulting conclusions."

<u>Questions:</u>

9. How many valves are required to be closed should a rupture occur in either the proposed or the existing gas lines.

10. Are all of these valves remotely operated?

11. Is a single failure[4] considered?

12. Why has the NRC not informed FERC that the fundamental assumptions and calculations were inaccurate?

13. Has the NRC staff reviewed the piping and instrumentation (P&IDs) diagrams for the new gas line showing valves, pressure, flow and leak detection instruments? If so, please describe. Does the design meet all NRC requirements to assure all regulations, codes and standards are being properly applied and met?

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[4] *Single failure*. A single failure means an occurrence which results in the loss of capability of a component to perform its intended safety functions. Multiple failures resulting from a single occurrence are considered to be a single failure. Fluid and electric systems are considered to be designed against an assumed single failure if neither (1) a single failure of any active component (assuming passive components function properly) nor (2) a single failure of a passive component (assuming active components function properly), results in a loss of the capability of the system to perform its safety functions.

14. Has the NRC evaluated Spectra's procedures and operator response times and ability to detect a significant loss of integrity of a major gas line?

15. Has the NRC evaluated Spectra's safety record with regard to pipeline leaks and incidents? A Spectra pipeline ruptured in the Arkansas River[5] on May 31, 2015 and the company did not know about it for over 24 hours.

16. Why, as stated by the NRC in the Petition Review Board call on July 15, 2015, did the NRC not look at the 30" San Bruno pipeline rupture incident in 2010, or other major gas line ruptures documented by the NTSB, when doing the confirmatory analysis of the 42" diameter AIM pipeline?

17. What historical data did the NRC use in its confirmatory analysis to evaluate the risk of rupture of the 42-inch diameter high-pressure pipeline?

D. Blast radius

Regulatory Guide 1.91 contains an equation #1[6] for determining the blast radius or Potential Impact Radius. According to Entergy's and the NRC's analyses, both Entergy and the NRC calculate the blast radius from a rupture of a 42 inch diameter pipeline operating at 850 psi in the range of approximately 1100 feet.

If the amount of gas released continues for one hour instead of 3 minutes about 20 times more gas will be released. According to the NRC's own equation #1, this alone will increase the blast radius from about 1100 feet to about 3000 feet without any consideration of vapor clouds or heat flux.

Furthermore, the June 29, 2006 letter from the NRC to me addresses reference #6[7] "Risk Analysis of Natural Gas Pipeline: Case Study of a

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[5] http://www.arktimes.com/ArkansasBlog/archives/2015/06/08/spectra-energy-working-to-recover-400-ft-of-lost-pipeline-after-blast-on-arkansas-river

[6] $R_{min} = Z * W^{\frac{1}{3}}$

[7] http://r.search.yahoo.com/_ylt=A0LEVvYtRLJVfm4ASbknnIlQ;_ylu=X3oDMTByOHZyb21tBGNvbG8DYmYxBHBvcwMxBHZ0aWQDBHNlYwNzcg--

Generic Pipeline," Chiara Vianello", Giuseppe Maschio Università di Padova, DIPIC – Dip. di Principi e Impianti Chimici di Ingneria Chimica Via Marzolo 9 – 35131 Padova, Italy" that projects a PIR approaching 8000 feet.

According to the Entergy report of August 21, 2014, the two SSC Important to Safety (ITS) structures closest the new AIM pipeline are the switchyard (115 ft.) and the GT2/3 fuel tank (105 ft.). The report states, "a loss of the SSCs important to safety would not result in a significant decrease in the margin of safety provided for public health and safety except for the assumed loss of the switchyard and GT 2/3 FOST which are more significant SSCs ITS." However, the evaluation then continues, "a postulated gas pipeline rupture near the switchyard could cause total loss of the switchyard of the type that could occur with low probability events such as extreme natural phenomena (e.g. earthquake, tornado winds/missiles, hurricanes, etc.) that the switchyard is not protected against. The potential loss of the switchyard can result in loss of offsite power to the plant and result in a generator or turbine trip with or without fast bus transfer to the turbine generator bus. This is considered a relatively high probability event…" The report goes on to analyze the loss of back-up power and Entergy concludes that design enhancements reduce risk, however this risk reduction is not analytically supported.

The conclusion in the report is not supported by the NRC regulations and is refuted in its internal documents, references and citations. There most certainly is a risk of complete loss of power, failure of back-up generation, loss of the access road and the city water tank and the risk of a full system failure must be evaluated in a thorough, transparent, independent risk assessment. Entergy may have analyzed the loss of the switchyard and the FOST independently, but not due to a single initiating event.

Questions

18. Why would the NRC revert to such an obscure reference #6 that is not even cited in RG 1.91?

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19. Why does PIR radius range from 800 to 8000 feet depending on reference used? Why did the NRC use the smaller radius when assessing risk?

20. Why do the NRC and Entergy use very different formulas to calculate blast radius, both claiming compliance with RG 1.91?

21. Why did the NRC modify the equation for calculating the blast radius in RG 1.91?

22. RG 1.91 specifically states "Methods and solutions that differ from those set forth in regulatory guides will be deemed acceptable if they provide a basis for the findings required for the issuance or continuance of a permit or license by the Commission." These calculations and methods differ from the Regulatory Guide. Did the NRC use RG 1.91, as the sole reference for evaluating explosions postulated to occur at nearby facilities and on transportation routes near nuclear power plants?

23. Why did Entergy and the NRC fail to provide a basis for deviation from the Regulatory Guide?

24. Why would the NRC use the EPA computer program (ALOHA), which is prohibited for use for a gas pipeline rupture, not referenced in RG 1.91, to calculate the blast radius of a rupture that could have a devastating impact to the more than 20 million persons residing in the vicinity of Indian Point?

25. Has the NRC performed a validation and verification of the ALOHA program to ascertain its accuracy

E. Blast Impact

The NRC's email from April 27, 2015 states the quantity of gas released in a pipeline rupture is calculated by the same prohibited ALOHA program as 376,000 kg in the first minute and a release of 200,000 kg in the next two minutes (accounting for the pressure drop) and 100,000 kg after the valve closure. In the first four minutes, the amount of energy released is equal to that from the atomic bombs dropped on Japan in 1945. Once more the use and results of ALOHA for this calculation is questionable however assuming these numbers are correct:

26. Why would the NRC allow tons of TNT equivalent to be transported per minute through a nuclear site putting the entire Hudson Valley, and its residents and infrastructure at stake without a detailed analysis?

27. Why does the NRC continue to ignore potential major amounts of flammable material in the fuel oil storage tanks? Why has the NRC refused to respond directly to questions about the contents of these tanks?

F. Vapor Clouds

RG 1.91 cites "International Atomic Energy Agency, Safety Standards Series, Safety Guide No. NS-G-3.1, "External Human Induced Events in Site Evaluation for Nuclear Power Plants, 2002, Vienna Austria" as a reference. This International Standard addresses vapor cloud explosions and states: "In some States (Countries) an SDV in the range of 8–10 km is used for the sources of hazardous clouds."

Apparently the IAEA considers the danger from vapor clouds to range out to beyond 8 Km, yet the NRC has no problem locating major gas transmission lines within 400 feet of vital structures of two operating 1000 Mwe nuclear plants located in one of the most densely populated areas in the world.

28. Fully recognizing this is not a regulation but only a statement and that most of the world avoids gas lines within 8 to 10 Km from nuclear plants, how can the NRC justify locating gas lines within 400 feet of vital structures without any justification or explanation?

29. Why wasn't an explanation from an IAEA document included in the analysis? How did the NRC evaluate the potential for vapor cloud explosions while totally ignoring its own guidance provided in RG 1.91 and its references?

G. General Concerns

Questions:

30. I have reviewed both the Entergy and NRC calculations and did not see any calculations discussing heat flux. How did the NRC calculate the impact of heat flux, vapor cloud explosions and possible secondary fires such as from the "abandoned" fuel oil storage tanks?

31. Please explain why the probability of failure and risk for the existing gas line is less than that of the new gas line. Indian Point's Final Safety Analysis (FSAR), approved by the NRC states that a failure of the existing buried gas transmission lines is "not feasible" which, to me means it is significantly less than 10^{-7} failures per year. How can the proposed AIM pipeline realistically have a higher failure probability than the existing 63-year old line that has no documented inspection history?

32. Entergy, in its analysis, considers the potential for AIM gas line ruptures to be a Design Basis Event (DBE). The existing old gas lines are much closer to vital SSC's and the failure of these lines is intuitively much higher. Why does Entergy and the NRC not consider these lines to be a potential DBE and associated requirements imposed?

33. Has the NRC reviewed Spectra's operating and inspection procedures to assure the integrity of the existing Algonquin gas transmission system?

34. Are Entergy operators at Indian Point trained in how to address an explosion/fire/gas release from existing the lines or even aware of the location of the lines at Indian Point or knowledgeable about the risks associated with these 63-year-old lines?

35. Do Entergy and Spectra coordinate safety and emergency response training? How often is training conducted? Does the NRC review these training procedures?

36. What actions will the NRC take to respond to the existing pipelines' unanalyzed condition?

37. Has the NRC reviewed Entergy's existing and proposed emergency procedures for the local Buchanan volunteer fire brigade to deal with a major rupture and resulting fires at the Indian Point facility? Has the NRC discussed the ability and/or inability to provide adequate fire services with the local Buchanan volunteer fire brigade? If not, why? If so, how adequate does the NRC deem the Buchanan volunteer fire brigade is in addressing a pipeline rupture at Indian Point?

38. Did the NRC receive and review[8] the Piping, Instrumentation and flow diagrams of the proposed and the existing gas transmission lines?

39. Does the NRC have any Quality Assurance requirements/procedures for conducting safety related calculations? If so, what are they?

Sincerely,

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[8] A FOIA request was filed with FERC for all communication between the NRC and FERC. These were not included and not identified as being withheld.