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15 October 2014

Mr. Mark A. Satorius
Executive Director for Operations
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Mr. Satorius:

SUBJECT:
10 CFR 2.206 Petition Regarding Violations of Regulations

REFERENCE:
10 C.F.R. 50.59 Safety Evaluation and Supporting Analyses Prepared in Response to the Algonquin Incremental Market Natural Gas Project
Indian Point Nuclear Generating Unit Nos. 2 & 3
Docket Nos. 50-247 and 50-286
License Nos. DPR-26 and DPR-64
ML090640863, dated August 21, 2014

I am submitting this 10 CFR 2.206 petition on behalf of myself based upon my review of the above referenced document. It is my belief that Entergy violated the requirements of 10 CFR 50.9 in that the information provided to the Commission is incomplete and inaccurate, violated the quality assurance regulatory requirements specified in Appendix B to 10 CFR Part 50, and violated the safety evaluation requirements of 10 CFR 50.59. Given the obvious deficiencies contained within Entergy's submittal, I believe there may also be a violation of 10 CFR 50.5 "Deliberate Misconduct."

According to the Entergy submittal, the Risk Research Group, Inc prepared the enclosed Hazard Analysis. My review of this "Group" indicated it is a group of one with Mr. David Allen as President. Mr. Allen is a previous employee of New York Power Authority, the previous owner of Indian Point Unit #3.

Mr. Allen's qualifications for this type of vital nuclear and pipeline accident analysis could not be substantiated either by a search of the Internet and NRC ADAMS. My research questions the qualifications on Mr. Allen and his knowledge of risk assessment, Nuclear Regulations and natural gas transmission failures based upon the inaccurate and incomplete information contained within the licensee's submittal. Some of this alleged inaccurate and incomplete information is discussed below. There is no discussion in the information provided as to and structured approach such as Appendix C to §1910.119 – "Compliance Guidelines and Recommendations for Process Safety Management."

The report apparently generated by the Risk Research Group was withheld under 10 CFR 2.390.

I question the compliance with 10 CFR 50 Appendix B, Criteria VII for the suppliers of safety related services that states (emphasis added):

> *VII. Control of Purchased Material, Equipment, and Services*
>
> *Measures shall be established to assure that purchased material, equipment, and* ***services****, whether purchased directly or through contractors and subcontractors, conform to the procurement documents. These measures shall include provisions, as appropriate, for source evaluation and selection,* ***objective evidence of quality furnished by the contractor or subcontractor****,* ***inspection at the contractor or subcontractor source****, and* ***examination of products upon delivery.*** *Documentary evidence that material and equipment conform to the procurement requirements shall be available at the nuclear powerplant or fuel reprocessing plant site prior to installation or* ***use of such material*** *and equipment. This documentary evidence shall be retained at the nuclear powerplant or fuel reprocessing plant site and shall be sufficient to* ***identify the specific requirements, such as codes, standards, or specifications, met by the purchased material and equipment. The effectiveness of the control of quality by contractors and subcontractors shall be assessed by the applicant or designee at intervals consistent with the importance, complexity, and quantity of the product or services.***

It is the licensee's responsibility that compliance with the above is mandated. It's not apparent from Entergy's submittal that these quality assurance regulatory requirements were satisfied with the Hazards Analysis prepared by the Risk Research Group.

Entergy's submittal seems to have also violated the regulatory requirements specified in 10 CFR 50.59 that state:

> *(c)(1) A licensee may make changes in the facility as described in the final safety analysis report (as updated), make changes in the procedures as described in the final safety analysis report (as updated), and conduct tests or experiments not described in the final safety analysis report (as updated) without obtaining a license amendment pursuant to Sec. 50.90 only if:*
> *(i) A change to the technical specifications incorporated in the license is not required, and*
> *(ii) The change, test, or experiment does not meet any of the criteria in paragraph (c)(2) of this section.*
>
> *(2) A licensee shall obtain a license amendment pursuant to Sec. 50.90 prior to implementing a proposed change, test, or experiment if the change, test, or experiment would:*
> *(i) Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the final safety analysis report (as updated);*
> *(ii) Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component (SSC) important to safety previously evaluated in the final safety analysis report (as updated);*
> *(iii) Result in more than a minimal increase in the consequences of an accident previously evaluated in the final safety analysis report (as updated);*
> *(iv) Result in more than a minimal increase in the consequences of a malfunction of an SSC important to safety previously evaluated in the final safety analysis report (as updated);*
> *(v) Create a possibility for an accident of a different type than any previously evaluated in the final safety analysis report (as updated);*
> *(vi) Create a possibility for a malfunction of an SSC important to safety with a different result than any previously evaluated in the final safety analysis report (as updated);*

(vii) Result in a design basis limit for a fission product barrier as described in the FSAR (as updated) being exceeded or altered; or
(viii) Result in a departure from a method of evaluation described in the FSAR (as updated) used in establishing the design bases or in the safety analyses.

As discussed below, inaccurate and incomplete information in Entergy's submittal result in its 50.59 safety evaluation being defective.

The Indian Point Unit 3 FSAR revision submitted to the NRC in 2011 includes the following statement with respect to the existing gas lines.

> *"A subsequent evaluation in 2008, (Reference 1), discussed the consequences of a pipeline rupture and the potential impact of that event on the sites Protected Area, Vital Areas, the Security Plan, safe shutdown, and other non-safety related structures, such as the waterfront warehouse. The hazards created by a breach and explosion of the pressurized above ground portions of the pipeline include: a. potential missiles,*
> *b. an over-pressurization event,*
> *c. a vapor cloud or flash fire,*
> *d. a hypothetical vapor cloud explosion, and*
> *e. a jet fire.*
> *A simultaneous rupture and ignition of both gas mains at the above ground locations inside the owner controlled area (OCA) is postulated to be the worst case scenario since this event will result in the most significant release of gas volume and have the potential to contribute to the largest potential fire. An attempt to uncover, breach and ignite a buried portion of the pipeline was* ***not considered feasible****. The report concluded that the event would not damage any safety related structure and there are no adverse effects on the gas pipeline event on vital areas, safe shutdown equipment, IPEC Security Plan, or essential personnel. Some damage to non-vital structures or non-essential personnel in the area of the pipeline may occur."*

I interpret the words "not considered feasible" to mean not "credible" as used in 10 CFR 50 with the probability of this event occurring to be zero or less than 10^{-7} per year. NRC Regulatory Guide 1.70 supports this assumption.

The following is a list of statements in Entergy's submittal that may contain incomplete and inaccurate information.

- Entergy stated (emphasis in yellow added):

> Algonquin pipelines, but the Project also includes the installation of new 42-inch diameter pipeline near the southern boundary of IPEC to replace the existing 26-inch pipeline in vicinity of IPEC which will remain in place but idled. On February 28, 2014, AGT filed a formal application with the Federal Energy Regulatory Commission ("FERC" or "Agency") related to the AIM Project (Reference 1).

This line abandonment is located within the controlled area and may impact plant safety but is not analyzed or discussed as required by 49 CFR §192.727 "Abandonment or deactivation of facilities." Entergy's submittal is therefore incomplete.

- Entergy stated (emphasis in yellow added):

> Accordingly, while such occurrences are unlikely, Entergy must analyze any increased risk and consequences of such events prior to FERC's approval of the project. Entergy further noted that, depending on the results of the analysis, prior NRC review and approval of the new hazards analysis could be required before the project can be approved by FERC. FERC

This appears to be an inaccurate statement. Entergy attempts to discuss and minimize the probability of the accident there is no discussion of the potential consequences of this event.

- Entergy stated (emphasis in yellow added):

> installation enhancements for piping routed near IPEC. These enhancements include, but are not limited to, thicker piping, thicker corrosion protection, greater burial depth, and installation of protective reinforced concrete mats to impede access to the buried piping.

The addition of concrete mats may generate missiles that may impact the safe operation of Indian Point. This is not analyzed. Entergy's submittal is incomplete in this regard.

- Entergy stated (emphasis in yellow added):

> As documented in the attached Hazards Analyses, Entergy has concluded that based on the proposed routing of the 42-inch pipeline further from safety related equipment at IPEC and accounting for the substantial design and installation enhancements agreed to by AGT, the proposed AIM Project poses no increased risks to IPEC and there is no significant reduction in the margin of safety. Accordingly, as documented in the enclosed 10 C.F.R. § 50.59 Safety Evaluation, Entergy has concluded that the change in the design basis external hazards analysis associated with the proposed AIM Project does not require prior NRC approval.

and

> As noted above, Entergy has determined that there are no increased risks to Indian Point and, pursuant to 10 CFR § 50.59, has concluded that prior NRC review and approval is not required.

The present FSAR clearly states that and accident is "not considered feasible" and this most recent analysis concludes an accident is, in fact a probability. Entergy's submittal is inaccurate on this point.

- Entergy stated:

> On September 27, 1997 the New York Power Authority (NYPA) submitted the Individual Plant Examination of External Events (IPEEE) report for IP3 (Reference 3). In that report, it evaluated t

The IPEEE is not a part of the Current Licensing Basis (10 CFR 54.3). A more recent update to the FSAR seems to contradict this IPEEE.

- Entergy stated (emphasis in yellow added):

> Natural Gas Pipeline Minimum Federal Safety Standards (49 CFR Part 192) (the "DOT Code"). The resulting wt exceeds Class 4 requirements, the most stringent DOT Code classification. The actual length of the enhanced portion of the gas pipeline will be subject

This statement is in direct conflict with the Spectra DEIS and application that clearly states these lines in the vicinity of Indian Point are Class 2 and 3.

- Entergy stated (emphasis in yellow added):

> cathodic protection meets the requirements of 49 CFR § 192.463." Spectra also performs an assessment of its pipeline system in high consequence areas in accordance with 49 CFR § 192.921, which will include IPEC. Subsequent reassessments are done at a maximum of 7

According to Spectra's documents it does not consider the vicinity of Indian Point to be a High Consequence area, and only imposes the Class 2 and 3 requirements of 49 CFR 192.

- Entergy stated (emphasis in yellow added):

> pipelines do not impair the safe operation of IPEC. The proposed AIM Project, however, expands the existing AGT system, including pipeline capacity and pressure. Thus, the poten for increased nuclear safety risks, including in terms of the probability and consequences of potential malfunction or failure of the expanded natural gas pipeline near IPEC, must be evaluated and found to be acceptable in accordance with applicable NRC regulations. Accordingly, while such occurrences are unlikely, Entergy must analyze any increased risk a consequences of such events prior to FERC's approval of the project. Entergy further noted that, depending on the results of the analysis, prior NRC review and approval of the new hazards analysis could be required before the project can be approved by FERC. FERC

This statement is in direct conflict with the DEIS. According to Spectra these lines are only designed to Class 2 or 3 requirements as defined in 19 CFR.

- Entergy stated (emphasis in yellow added):

> As noted above, Entergy has determined that there are no increased risks to Indian Point and, pursuant to 10 CFR § 50.59, has concluded that prior NRC review and approval is not required.

This is an unsupported statement. This analysis (and previous analysis) were conducted with apparent disregard for compliance with 10 CFR 50 Appendix B by an individual with little knowledge of pipeline and nuclear safety requirements.

Entergy stated (emphasis in yellow added):

> For the proposed pipeline, the FEMA "Handbook of Chemical Hazard Analysis Procedures" identifies (page 11-28) the accident rate for pipelines with diameters greater than or equal to 20 inches is 5E-4 releases per year-mile. The length of pipe that could affect the SSC important to safety is greater than the enhanced gas pipeline of 3935 feet or 0.745 miles. This length corresponds to the probability of 3.73E-4. This value is not used to assess the 42 inch gas pipeline but is used to conclude that the rupture of the gas pipeline must be considered as a design basis event under NRC guidance. The value is not used to assess the gas pipeline because the data base from which frequency is determined is not applicable to this gas pipeline (it includes mostly pipelines of steel but also considers pipes of other materials, considers pressure of up to several thousand pounds per square inch (psi), pipes of various different diameters, and pipes of older and less rigorous design).

and

> The frequency of a pipeline explosion was evaluated using industry data and correlating it to more recent data. The frequency of a pipeline rupture and enhanced pipeline rupture is 1.32E-5 per mile-year and 1.98E-6 per mile-year, respectively. These are considered conservative values. The

Entergy appears to ignore the FEMA handbook and provides no justification to reduce the probability of a line rupture from 5^{-4} to 1.98^{-6}. The "enhanced pipeline" may actually increase the probability and consequences of a pipe rupture.

Entergy stated (emphasis in yellow added):

> The existing pipeline automation and control system, which will 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 mile post 2.61 on the west side of the Hudson River and at mile post 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 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.

This closure time is more than an order of magnitude less than other similar events investigated by the National Transportation Safety Board (NTSB). According to the NTSB, a typical time to terminate the gas flow ranges from 30 minutes to three hours. This proposed line is larger than other line accidents investigated by the NTSB. Identification of rupture of larger lines is more difficult and isolation times will be significantly longer. The NTSB has not identified any closure times of transmission lines occurring in less than 30 minutes.

I have consulted with Richard B. Kuprewicz, President Accufacts, Inc. a world recognized pipeline expert, requesting his comments on the Entergy letter. His comments are below and restated with his permission.

> *"From my detailed review, Entergy¹s letter to the NRC contains numerous errors that are either an attempt to deceive decision makers, or reflect an incredible lack of pipeline experience, in appreciating the real risks associated with a large 42-inch gas transmission pipeline rupture in a very sensitive area. The proposed 42-inch is not like the existing smaller diameter 24, 26, or 30-inch pipelines, and any attempt to dismiss such a large pipeline as similar are (SIC) extremely irresponsible."*
>
> *"It is my advice that the NRC needs to review the real impact of a worst-case 42-inch gas pipeline rupture in the vicinity of the IPEC facility . . ."*
>
> *"The NRC may not recognize nor appreciate the true actual impact zone associated with a 42-inch gas pipeline rupture (multiple blasts and very high heat fluxes - disregard the 3 minute assumption in the Entergy letter).* ***Just dismissing very real risk (no matter how minor the risks may seem, as posed in Entergy¹s letter) with such grave consequences such as loss of nuclear containment in southern New York, command a clear, thorough evaluation and review that is truly independent and factual.*** *I further find that the NRC's comments to FERC based on the Entergy site hazard analysis for the 42-inch line to be highly inadequate at this time. The NRC and FERC should adequately demonstrate that any conclusions they reach, that there is no increase in risks to IPEC from the 42-inch pipeline, be adequately and publicly demonstrated."*
>
> *"It does not help the situation that critical information utilized to reach important decisions pertaining to the 42-inch pipeline may be* ***misleading or false.*** *This can be very difficult for interveners and interested parties to this Docket filing who are under such arbitrary accelerated deadlines."*

In its submission to the NRC dated August 21, 2014 Entergy in included a copy of its 50.59 Evaluation addressing the requirements of 10 CFR 50.59.

Below I compare Entergy's 50.59 evaluation and where I believe it contains incomplete and inaccurate information and possibly Deliberate Misconduct as defined in 10 CFR 50.5.

Restated below are Entergy's response from its submittal and my comments following each of the eight criteria of 10 CFR 50.59.

Does the proposed Change:

1. Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the UFSAR? ☐ Yes ☒ No

   BASIS:

   Currently, a 26 inch and 30 inch pipeline traverse the site along a route just south of the protected area and the effects of a rupture of that pipeline has been evaluated. The addition of a 42 inch pipeline south of the IPEC property that crosses IPEC property near the GT 2/3 Fuel Oil Storage Tank (FOST) and Buchanan substation creates the possibility of a gas pipeline rupture. Gas pipelines have a low frequency of rupture. The new gas pipeline has been designed with the latest methodology and a significant portion has been enhanced with additional features (e.g., deeper burial, thicker pipe, stronger materials, positive means to prevent excavation and abrasion resistance coating) intended to further reduce the frequency of gas pipeline rupture in the area of Structures Systems and Components (SSC) important to safety (ITS). The frequency is sufficiently low that the new gas pipeline will not result in more than a minimal increase in the frequency of occurrence of an accident (gas pipeline rupture) currently evaluated in the UFSAR.

Comment: This accident was analyzed in the FSAR and "not considered feasible" or credible. Even this deficient new analysis concludes a pipe rupture of a buried line has a failure probability of greater than 10E-6. This is inaccurate information.

2. Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component important to safety previously evaluated in the UFSAR? ☐ Yes ☒ No

   BASIS:

   A rupture of the new gas pipeline could be the cause of a malfunction of a SSC previously evaluated. The new gas pipeline has been routed where a gas pipeline rupture could not cause malfunction of a safety related SSC or security provisions and therefore there would be no increase in the likelihood of damage to those SSC. The routing is where a postulated rupture could cause a malfunction of SSC's ITS (Switchyard with associated transmission lines, Gas Turbine 2/3 Fuel Oil Storage Tank (GT 2/3 FOST), and Emergency Operations Facility (EOF) and meteorological tower) due to proximity. The likelihood of a gas pipeline rupture causing malfunction of SSC ITS will be minimized by the gas pipeline design and maintenance as well as the enhancement of a substantial portion of that gas pipeline routed near the SSC ITS. The increase in likelihood of a gas pipeline rupture affecting the SSCs ITS has been determined to have a very low frequency. As a result, this new pipeline is not considered to result in a more than minimal increase in the likelihood of occurrence of a malfunction of a SSCs important to safety previously evaluated in the UFSAR.

A rupture of the new or existing buried gas transmission lines may impact systems previously evaluated in the UFSAR for example, secondary fires as a result of more than a million gallons of Gas Turbine Fuel Oil (GTFO) and safety related systems and other structures (SSC) located within close proximity to the gas transmission lines.

Both the switchyard and the GTFO tanks are located within 120 feet of the gas line and other components and structures are located within the blast and fire distance of the gas lines. This is inaccurate and incomplete information.

3. Result in more than a minimal increase in the consequences of an accident previously evaluated in the UFSAR?

☐ Yes
☒ No

BASIS:

The rupture of the gas pipeline previously considered in the UFSAR assessed if it could result in loss of safety related SSCs. This is the rupture of the 26 inch and 30 inch gas pipelines which were previously evaluated as acceptable during the original Licensing stage, and as during the performance of the IPEEE as of acceptably low probability. It was evaluated for an aboveground rupture as a potential security event and the evaluation concluded the effects were acceptable. The evaluation of the consequences of these prior ruptures showed there was no damage to safety related SSCs. The effects of a gas pipeline rupture of the new 42 inch gas pipeline were evaluated to determine whether the consequences of the previous evaluations were increased. The evaluation showed there was no damage to safety related SSCs due to gas pipeline rupture and therefore there is no increase in consequences. The evaluation, performed using methodologies consistent with the current NRC guidance, looked at the effects on SSC important to safety as well as safety related SSC. The evaluation shows that, due to the proximity of the proposed southern route to SSCs ITS, there was a potential for damage. However, it also showed that the damage frequency was sufficiently low, according to NRC criteria, that it was acceptable. Additionally, the evaluation of SSCs ITS was not an accident previously considered. Therefore there is no increase in consequences since the safety related SSCs are not damaged and the effects of damage to SSCs ITS were not previously evaluated and are acceptable. As a result, it can be concluded that this activity will not result in a more than minimal increase in the consequence of previously evaluated accidents.

The present UFSAR analysis states that this type of accident “is not feasible.” The new analysis now considers this accident has a probability of greater than 10E-6 and is therefore more than a “minimal increase.” This is an inaccurate statement and may be “willful misconduct.”

4. Result in more than a minimal increase in the consequences of a malfunction of a structure, system, or component important to safety previously evaluated in the UFSAR?

☐ Yes
☒ No

BASIS:

The effects of a rupture in the new 42 inch gas pipeline have been evaluated to determine the effects on SSCs ITS. The evaluation shows the frequency of a rupture affecting a SSCs ITS have been reduced to where a rupture will have no more than a minimal increase in the consequences of malfunction of the SSCs ITS affected. Natural phenomena with a probability greater than the rupture of the gas pipeline can damage the SSCs ITS that the postulated gas pipeline rupture can affect. The ability of the plant to safely shutdown and maintain cold shutdown has been assessed with this damage. There is a minimal increase in the consequence of a malfunction of the SCCs since a gas pipeline rupture has the lower frequency. Therefore, this activity will not result in a more than minimal increase in the consequences of a malfunction of a SSCs important to safety previously evaluated in the UFSAR.

The most recent analysis states it reviews and reports on the consequences of a pipeline accident, however the summary provided provides no information about the potential consequences of the pipeline accident.

5. Create a possibility for an accident of a different type than any previously evaluated in the UFSAR?

☐ Yes
☒ No

BASIS:

The previously considered rupture of the 26 and 30 inch pipelines is considered a similar accident. A rupture of the new 42 inch gas pipeline has been evaluated and would not result in damage to a safety related SSC but could result in damage to SSC important to safety (Buchanan switchyard, the GT2/3 storage tank, and the EOF / meteorological tower). Loss of these components could not create the possibility of an accident of a different type than previously evaluated since their loss has previously been evaluated. There are no other changes to the plant operations, operating procedures or site activities that could possibly create an accident of a different type than previously evaluated. As a result, this activity does not create a possibility for an accident of a different type than previously evaluated in the UFSAR.

Given the proximity of the GTFO tanks to the proposed new lines, a rupture and resulting fire has not been previously considered. This is a new type of accident that has not been previously evaluated in the USFAR.

6. Create a possibility for a malfunction of a structure, system, or component important to safety with a different result than any previously evaluated in the UFSAR?

☐ Yes
☒ No

BASIS:

A rupture of the new 42 inch gas pipeline has been evaluated and would not result in damage to a safety related SSC but could result in damage to SSCs ITS. The potential for damage could not result in a malfunction with a different result that any previously considered in the UFSAR because the potential damage is not different than previously evaluated and there is no damage to safety related SSC. Rupture of the pipeline is postulated to occur in normal operation since it is not postulated to occur as a result of a plant accident or natural phenomena. The malfunction of SSCs ITS that could be affected by the gas pipeline is no different than those previously considered in the UFSAR. That failure is just a loss of the component since there is no interface with safety related SSC. Therefore the malfunction of the affected components would not have a different result than the rupture of these components as previously evaluated.

The GTFO tanks are located about 100 feet above many SSCs. The flow possibly a million gallons of flaming GTFO and its impact on SSCs has not been evaluated.

7. Result in a design basis limit for a fission product barrier as described in the UFSAR being exceeded or altered?

☐ Yes
☒ No

BASIS:

A rupture of the new 42 inch gas pipeline has been evaluated and would not result in damage to a safety related SSC and damage to a ITS would not affect the ability to safely shutdown. The postulated rupture of the new 42" gas pipline has no impact on fission product barriers. Therefore there will be no fission product barrier design basis limit approached.

The answer to this question cannot be properly evaluated until all analysis are completed.

8. Result in a departure from a method of evaluation described in the UFSAR used in establishing the design bases or in the safety analyses?

☐ Yes
☒ No

BASIS:

This activity installs a new gas pipeline routed south of the IPEC plant and partially on IPEC property. The UFSAR describes past evaluations of pipeline rupture but does not discuss the methodology. The new evaluation of the potential for rupture uses methodology consistent with past evaluations and approved by NRC and evaluates the frequency of rupture using methodology consistent with the NRC criteria. Therefore, it is concluded there is no departure from past methodologies used for the plant and does not depart from a method of analysis contained in the UFSAR.

The methodology described in the UFSAR and its conclusions are deficient. The previous methodology is not consistent with NRC criteria and apparently was not conducted using within the requirements of 10 CFR 50 Appendix B.

Requested actions:

The NRC should take enforcement action for providing inaccurate and incomplete information to the NRC "10 CFR 50.9 Completeness and accuracy of information" violating the quality assurance requirements of Appendix B to 10 CFR Part 50, and violating the safety evaluation requirements of 10 CFR 50.59.

The NRC should issued a Demand for Information to Entergy seeking this licensee's explanation why the violations noted above do not also constitute violation of 10 CFR 50.5, "Deliberate misconduct."

The NRC should issue a Demand for Information to Entergy seeking the results from a new and realistic risk/hazard analysis consistent with the guidance provided within OSHA Appendix C to §1910.119 – "Compliance Guidelines and Recommendations for Process Safety Management[1]."

The NRC should issue a Demand for Information to Entergy attesting to the completeness and accuracy a previously report[2] submitted to the NRC. This report formed the bases for the rejection of my 10 CFR 2.206 petition dated October 2010.

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[1] https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_id=9763&p_table=STANDARDS

[2] IP-PRT-08-00032, "Consequences of Fire and Explosion Following the Release of Natural Gas from Pipelines Adjacent to Indian Point", by David Allen, Risk Research Group, August 2008.