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SECURITY-RELATED INFORMATION – WITHHOLD UNDER 2.390

10 CFR 50.59

NL-20-050

June 24, 2020

Mr. Jimi T Yerokun
U.S. Nuclear Regulatory Commission
Director, Division of Reactor Safety
2100 Renaissance Boulevard, Suite 100
King of Prussia, PA 19406-2713

Subject: Response to U.S. Nuclear Regulatory Commission Region I Letter Regarding Algonquin Incremental Market Project Pipeline

Indian Point Nuclear Generating Unit Nos. 2 and 3
NRC Docket Nos. 50-247 and 50-286
Renewed Facility Operating License Nos. DPR-26 and DPR-64

Dear Mr. Yerokun:

The U.S. Nuclear Regulatory Commission (NRC) Expert Evaluation Team identified (Reference 1) certain concerns pertaining to the evaluation of the 42-inch Algonquin Incremental Market (AIM) natural gas transmission pipeline located near the Entergy Nuclear Operations, Inc. (Entergy) Indian Point Nuclear Generating Unit Nos. 2 and 3 (Indian Point Energy Center (IPEC)) plant site. The NRC Team noted that Entergy used optimistic assumptions related to isolation of the pipeline in analyzing the potential impacts to the IPEC site from a postulated rupture of AIM Project pipeline. The NRC requested (Reference 2) Entergy to update the evaluation and supporting analysis of the 42-inch AIM pipeline rupture as necessary and assess the validity and materiality of our assumptions, including the impact of updated information from pipeline operator Enbridge on the time for operators to close valves and the length of pipe that would need to be isolated in the event of a pipe rupture. If an updated external hazards analysis is conducted, NRC asked Entergy to reconcile any differences in the results.

Entergy advised the NRC (Reference 3) that a review of the validity and materiality of the assumptions made in previous analyses of the 42-inch AIM Project Pipeline would be complete by June 30, 2020 and will be available for NRC inspection at that time. Enclosures 1 and 2 contain an updated 10 CFR 50.59 evaluation and the Hazards Evaluation it is based on, respectively.

The updated evaluation in Enclosure 2 calculates the effects of fires and vapor cloud explosions using the BREEZE Incident Analyst 3.0 (2019) model that gives more conservative results. The ALOHA model was not used in this evaluation due to concerns expressed by the NRC team regarding its applicability to the postulated rupture scenario. In summary, the updated analysis further considered the following:

1. In recent discussions, the pipeline owner, Enbridge, advised Entergy that it could take up to 8 minutes to isolate the rupture, and about 11 miles of pipeline were then available for blowdown. This only affects the vapor cloud evaluation since original pressures were assumed in other analyses.

2. As in prior analyses, a double ended rupture was conservatively modeled by using an increased pipe size to account for the area of two segments of pipeline blowing down simultaneously.

3. The generation potential for missiles remained unchanged as the analysis was unaffected by the updated information provided by Enbridge or the use of BREEZE.

4. Sandia National Laboratory (SNL) postulated gas vapor cloud migrations and concluded that a vapor cloud could explode over the Security Owner Controlled Area. This is considered remote and hypothetical because no vapor cloud explosion involving methane has been encountered outdoors. The SNL scenario appears to result from SNL modeling that did not address the turbulent mixing that would occur at the point of release. The vapor cloud scenarios used in the prior analysis were therefore considered appropriate.

5. The updated analysis incorporated more recent US Pipeline and Hazardous Materials Safety Administration (PHMSA) data regarding the rupture of gas pipelines.

The updated evaluation established increased distances at which a jet fire would result in a heat flux of 12.6 kW/m^2 and a vapor cloud explosion would result in a 1.0 psi overpressure. The increased distances, however, still do not result in damage to safety related structures, systems and components.

In addition to re-evaluating the effects of postulated ruptures, the probabilities of rupture and explosion were re-examined using updated data for lines 36 inches diameter and above for pipelines built after 1980. The variations in pipeline wall thickness and other construction details were also considered. The NRC criteria in Regulatory Guide 1.91 for exclusion of an explosion (detonation) from further consideration is a frequency below the 10^{-6}/year when conservative assumptions are made. These criteria are met for the majority of structures, systems and components (SSC) Important to Safety (ITS). However, damage to SSC ITS that do not meet these criteria have been evaluated and will not result in radioactive release. Additionally, there is redundancy in most of these components which assures Safe shutdown is not affected.

Based on the above, there is no change to the prior conclusion that the presence of the 42-inch AIM Project pipeline near IPEC represents no significant reduction in the margin of safety.

The enclosed evaluations supersede and update the following impacted letters:

1. Entergy Letter NL-14-106 "10 C.F.R. 50.59 Safety Evaluation and Supporting Analyses Prepared in Response to the Algonquin Incremental Market Natural Gas Project," (ML14245A110 and ML14245A111), dated August 21, 2014 - Provided the analysis of the 42-inch pipeline that was used for input to the AIM Environmental Impact Statement.

2. Entergy E Mail (ML15168A042), dated December 12, 2014 – Provided the basis for the 3-minute valve closure time.

3. Entergy letter NL-15-030, "Revised 10 C.F.R. 50.59 Safety Evaluation and Supporting Analyses Prepared in Response to the Algonquin Incremental Market Natural Gas Project," (ML15104A660 and ML15104A661), dated April 8, 2015 – Revised the analysis provided in NL-14-106 to reflect the revised above ground location of the 42-inch pipeline.

This letter contains no new regulatory commitments.

Should you have any questions or require additional information, please contact Robert Walpole, Director, IPEC Regulatory and Performance Improvement, at 914-254-6710.

Respectfully,

AJV/sp

References:

1) "Report of the U.S. Nuclear Regulatory Commission Expert Evaluation Team on Concerns Pertaining to Gas Transmission Lines Near the Indian Point Nuclear Power Plant," (ADAMS Accession No. ML20100F635), dated April 8, 2020.

2) NRC Letter to Entergy Nuclear Operations, Inc. (Entergy), "Safety Evaluation and Supporting Analysis Regarding the Algonquin Incremental Market Project Pipeline Near the Indian Point Energy Center, Units 2 and 3," (ADAMS Accession No. ML20113F066), dated April 23, 2020.

3) Entergy Nuclear Operations, Inc. (Entergy) Letter (NL-20-038) to NRC, " Response to U.S. Nuclear Regulatory Commission Region I

Letter Regarding Algonquin Incremental Market Project Pipeline," (ADAMS Accession No. ML20114F481), dated April 23, 2020.

Enclosures:
1) 10 CFR 50.59 Safety Evaluation
2) Hazards Analysis **(SECURITY-RELATED INFORMATION – WITHHOLD UNDER 2.390)**

cc: Document Control Desk, Washington DC
Regional Administrator, NRC Region I
NRC Senior Resident Inspector, Indian Point Energy Center
NRC Senior Project Manager, NRC NRR DORL
President and CEO, NYSERDA (w/o Enlosure 2)
New York State (NYS) Public Service Commission (w/o Enlosure 2)

NL-20-050

Response to U.S. Nuclear Regulatory Commission Region I Letter
Regarding Algonquin Incremental Market Project Pipeline

Enclosure 1

10 CFR 50.59 Safety Analysis

I. OVERVIEW / SIGNATURES[1]

Facility: IP2/IP3 **Evaluation # / Rev. #:** 14-2002-00-EVAL/14-3002-00-Eval, Rev 3

Proposed Change / Document: Installation of a New 42" Natural Gas Pipeline South of IPEC

Description of Change: Installation of New 42" Natural Gas Pipeline South of Gypsum Plant and crossing IPEC Property Near Switchyard / GT2/3 Fuel Oil Storage Tank.
The NRC requested (Reference 12) Entergy to update the evaluation and supporting analyses in Reference 14 as necessary and to assess the validity and materiality of the assumptions made in support of conclusions regarding the consequences of a postulated rupture of the 42-inch gas pipeline. The update is to address the issues raised in the NRC report by an "Expert Evaluation Team" (Reference 13). This revision updates the 50.59 for that updated analysis and supporting evaluation but does not revise the evaluation to reflect completion of the pipeline. The previous 50.59 is not substantially revised since it reflects the prior report that is being updated and the conclusions do not change.

Summary of Evaluation:

The proposed pipeline was evaluated under the criteria of 10 CFR 50.59 and the evaluation shows that current Nuclear Regulatory Commission criteria were satisfied that would permit the pipeline to be installed without a license amendment requiring NRC approval.

Background

The Indian Point Energy Center (IPEC) is traversed by two natural gas pipelines owned and operated by Spectra Entergy. The pipelines are 26 in. and 30 in. in diameter and operated at a pressure of 600-650 psig and 600-750 psig, respectively. The two gas pipelines traverse the owner-controlled area and are physically located closer to Indian Point Unit 3 (IP3) than Indian Point Unit 2 (IP2). The two lines are buried about 3 ft. deep in a trench formed in excavated rock. Portions of the pipelines at the shoreline of the Hudson River exit the trench and are above ground. The nearest approach of the buried portion of the pipelines to safety related structures, systems and components (SSC) is about 400 ft. The nearest above ground portion is approximately 800 ft. from the nearest safety-related structure (diesel generator building).

The initial licensee and the Atomic Energy Commission considered the hazards posed by these pipelines during the initial licensing process of IP3, and determined that the presence of the gas pipelines did not endanger the safe operation of IP3 (Reference 1). Section 2.2 of the AEC's safety evaluation report (SER) for IP3 describes the Staff's conclusions regarding this analysis that the rupture of these gas pipelines would not impair the safe operation of IP3 (Reference 2).

[1] The printed name should be included on the form when using electronic means for signature or if the handwritten signature is illegible. Signatures may be obtained via electronic authentication, manual methods (e.g., ink signature), e-mail, or telecommunication. Signing documents with indication to look at another system for signatures is not acceptable such as "See EC" or "See Asset Suite." Electronic signatures from other systems are only allowed if they are included with the documentation being submitted for capture in eB (e.g., if using an e-mail, attach it to this form; if using Asset Suite, attach a screenshot of the electronic signature(s); if using PCRS, attach a copy of the completed corrective action).

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 the susceptibility of IP3 to damage to the pipelines from seismic events. NYPA concluded that the probability of occurrence was low enough that the pipelines could be screened out as a seismic vulnerability. NYPA also considered pipeline ruptures from other causes, such as an inadvertent overpressure condition. Although NYPA stated that a vapor cloud rupture scenario could subject some IP3 structures to overpressures exceeding 1 psi, it concluded that the probability of an accidental leak from the line leading to such an event was extremely low. The NRC Staff's evaluation of the IP3 IPEEE did not identify any concerns with that approach (Reference 4).

In March 2003, questions were raised regarding the safety of the existing natural gas pipelines that pass through the Indian Point site, and suggested that they could be subject to sabotage. At the request of NRC Region I, the NRC Staff reviewed the prior evaluations of the lines and associated potential external hazards to the safe operation of the facility. The Staff's review is documented in an April 25, 2003 NRC internal memorandum (Reference 5). The NRC Staff made an assessment of the risks associated with the potential for large releases of natural gas from the pipelines in the vicinity of IP3 given the statements made in the IP3 IPEEE, and the focus of prior external hazards evaluations on the likelihood of an accidental pipe rupture. The NRC Staff also considered intentional acts to damage the line(s) in its gas pipeline hazard assessment, which is not available to the public for security-related reasons. The NRC's April 25, 2003 memorandum states: "For a large rupture and resulting fire, the staff found that safety-related structures would not be significantly affected. For unconfined vapor cloud ruptures, the staff found that the factors involved to achieve a rupture creating sizeable overpressures make the probability for occurrence very low. However, the NRR staff believes that this aspect should be further evaluated by the Office of Nuclear Safety and Incident Response (NSIR) in conjunction with Region I"

In March 2008, the NRC Staff requested information from Entergy as a result of a concern from a member of the public that there are "weak spots" in the IPEC security defense/structure, including a National Guard security position known as "Point 8." That request included any analyses or calculations supporting Entergy's conclusions regarding the vulnerability of Point 8. In an April 23, 2008 letter (ENOC-08-00021) to the NRC, Entergy explained that Point 8 encompasses the above-ground pressurized gas piping and valves that are part of the Algonquin natural gas pipelines in the Owner Controlled Area (OCA) at IPEC. It noted that although the IPEEE had examined an accidental rupture of the gas pipelines, no evaluation of sabotage on the gas pipelines within Point 8 previously had been performed. Entergy further explained that it had implemented additional compensatory measures to minimize the potential for such an event while it performed the additional assessment requested by NRC. Those measures are described in Entergy's April 23, 2008 letter.

As a follow-up to the Request for Information, Entergy completed an evaluation in August 2008 of the consequences of an assumed rupture of the two gas pipelines as a result of a sabotage on Point 8. IPEC Engineering completed that evaluation using inputs from an analysis performed by Risk Research Group, Inc. In that analysis, which Entergy submitted to the NRC on September 30, 2008 (see ENOC-08-00046), Entergy considered the following hazards created by a postulated breach and rupture of the pressurized aboveground portions of the pipelines: (1) potential missiles, (2) an over-pressurization event, (3) a vapor cloud (or flash) fire, (4) a hypothetical vapor cloud explosion, and (5) a jet fire. Entergy's August 2008 evaluation concluded that "[t]he concern that an attack on Point 8 would result in a lot of damage and casualties is not substantiated to the extent the Security Plan and Safe Shutdown

capabilities of the plants remain assured in the event of an attack and rupture of the exposed portions of the Algonquin natural gas pipelines within Point 8." The IP3 Updated Final Safety Analysis Report (UFSAR), Rev. 3, Section 2.2.2, discusses the pipelines and lists the 2008 report as a reference.

On October 25, 2010, a member of the public filed a 10 C.F.R. § 2.206 petition requesting that the NRC order Entergy to demonstrate that it has the capability to protect the public in the event of a rupture, failure, or fire on the gas pipelines that cross the Indian Point site. The petition also requested that the NRC review all available information, and request any necessary information from Entergy to ensure compliance with all NRC regulatory requirements related to external hazards. In a letter to the petitioner dated March 31, 2011, the NRC stated that it had reviewed previous licensee and NRC reports related to this issue and "did not identify any violations of NRC regulations or any new information that would change the staff's previous conclusion that the pipelines do not endanger the safe or secure operation of IP2 or IP3."

In response to RAI 2015-A-0074 Entergy assumed damage could occur and demonstrated alternate means available.

Proposed AIM Pipeline Expansion Project

Spectra Energy Transmission LLC / Algonquin Gas Transmission, LLC (hereinafter Spectra or AGT) has filed with FERC a proposal to expand its natural gas transmission capacity, discussed above, by installing a new 42-inch diameter pipeline that transmits gas at higher pressures than the current pipelines described above. For purposes of this evaluation, once installed the existing 26-inch pipeline and 30=inch pipeline are assumed to remain in use. The 42-inch pipeline is currently proposed to cross the Hudson River south of Indian Point, be routed on the west side of Broadway where it enters the IPEC owner controlled area before passing under Broadway and near the IPEC switchyard and the Gas Turbine 2/3 Fuel Oil Storage Tank (GT 2/3 FOST) and eventually joining with the existing natural gas pipelines. The proposed routing is referred to in this evaluation as the 'southern route" (The term "southern route" is the term used by Spectra to describe the final selected pipe routing for the new 42-inch pipeline). Only natural gas would be transmitted through these pipelines (Reference 6). In response to certain issues identified by Entergy with regard to the proposed routing of the new 42-in pipeline near IPEC, Spectra has stated that it would take additional design and construction measures on a 3935 foot section of the new pipeline to further limit the potential for adverse effects on the continued safe operation of Indian Point.

While the proposed 42 inch pipeline is further from IP2 and IP3 structures, systems and components (SSC) within the Security Owner Control Area (SOCA) used to control access to the main plant area than the existing pipelines, the new pipeline has a larger diameter than the existing lines and operates at a higher pressure, and therefore is a change to the current licensing basis for external hazards located near IP2 and IP3. The potential effects of the proposed pipeline on IP2 and IP3 have been evaluated using current NRC guidelines. Specifically, the Standard Format and Content Regulatory Guide 1.70 identifies the information to be provided for offsite events that could create a plant hazard. The NUREG 0800 Standard Review Plan (SRP) sections 2.2.1 to 2.2.3 (Rev 3) further discuss information to be assessed against current regulations and the descriptions and evaluations to be considered for acceptability. RG 1.91 Rev 2 provides guidance on how the evaluation should be performed and states the evaluation is to consider structures, systems and components (SSC) important to safety as well as safety related SSCs.

Design and Construction

1) Design

As discussed further below, the proposed southern routing must consider potential adverse effects on SSCs important to safety nearer to the southern route, including the GT 2/3 Fuel Oil Storage Tank (FOST), electrical switchyard (includes lines to and from Indian Point), Emergency Operations Facility (EOF)/ meteorological tower, and the city water tank. Additional features also considered, include the FLEX Storage Building, IP2 and IP3 Steam Generator Mausoleums, and the fuel oil tanker. The design of the 42 inch gas pipeline is to use X-52 to X-65 steel, to require a wall thickness of 0.469 to 0.510 inches, and to bury the pipeline underground with a minimum of 3 feet to the surface from the top of the pipeline (References 7 and 8). Spectra Energy however, has indicated (Reference 8) that, in the area where a postulated pipeline rupture could adversely affect IPEC SSCs ITS, about 3935 feet of the pipeline would be of enhanced design and construction to further limit the already very low potential for a gas pipeline rupture. The pipeline design will incorporate the following additional design and construction features:

- The Pipe Grade will be upgraded to X-70, (70,000 psig minimum yield strength and 82,000 psig minimum tensile strength) and manufactured to API 5L standards like all pipeline. The 0.720 inch wt (thickness in inches), X-70 material operating at the maximum operating pressure (MAOP) of 850 psi is over 40% greater wt than required by the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration 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 to field survey verification of the proposed Algonquin Gas Transmission, LLC (AGT) 42 inch diameter AIM Project pipeline shown in the enclosed report "Consequences of a Postulated Fire and Explosion Following the Release of Natural Gas from the Proposed New AIM 42 inch Pipeline Taking a Southern Route Near IPEC" (hereinafter called Report).

  The following information was provided by Spectra (Reference 8) regarding the design enhancements:

  - The 0.720 inch X-70 piping is virtually impervious to one of the most frequent causes of pipe rupture (excavation). The Pipeline Research Committee International (PRCI) report "Modified Criteria to Evaluate the Remaining Strength of Corroded Pipelines" documents the size of defect required to cause a pipeline rupture, based upon over 100 pipe defect burst tests. ASME B31G "Manual for Determining Remaining Strength of Corroded Pipelines" is a guideline used in the pipeline industry that applies this research to predict pipe defect rupture pressure, including the Modified B31G equation. There is also a PRCI report (PR-244-9729) "Reliability Based Prevention of Mechanical Damage to Pipelines" which is available to the public through the Center for Frontier Engineering Research (C-FER), and Section 6 provides a model, based upon excavator data, which can be used to predict the force required to puncture a pipeline. Puncture force is calculated from Equation 6.4 on p.28 of the referenced PRCI report (PR-244-9729), using a very conservatively low sample ultimate tensile strength of 79,300 psi and a relatively sharp excavator tooth of 0.5 x 1.5 inches. The weight

of the excavator is based upon Figure 6.3 on p.31 of the PRCI report, but the required excavator weight to damage the proposed enhanced piping is so great that it must be extrapolated well beyond the end of the graph. If the curved relationship were continued, it would never reach the 508 kN (kilo newton) force required to puncture the 0.720 inch wall pipe, but by projecting an over-conservative straight line to continue the upper right slope of the curve, an excavator weight of 193 tons at 508 kN would be necessary to damage the enhanced piping. The probability of excavator size comes from Figure 6.1 on p.30 of the PRCI report. This type excavator has not been seen at IPEC as can be demonstrated by the fact the largest Caterpillar backhoe (385CL) is less than half that size at 94 tons

- o The criterion for whether a defect fails as a leak versus a rupture comes from NG-18 research. The "Through Wall Collapse" (TWC) equation was developed many years ago from analyses of numerous full-scale pressure tests of pipe by Dr. Kiefner and others at Battelle. A puncture is nowhere close to the leak-rupture line, so it is very apparent that a puncture of the pipe wall would only cause a leak and would not rupture the pipe.

The Modified B31G equation is:

(b) Modified B31G. For $z \le 50$,

$$M = (1 + 0.6275z - 0.003375z^2)^{1/2}$$

For $z > 50$,

$$M = 0.032z + 3.3$$

$$S_F = S_{\text{flow}} \left[\frac{1 - 0.85(d/t)}{1 - 0.85(d/t)/M} \right]$$

$$z = \bar{L}^2/Dt$$

Inputting a 70% depth defect with length of 20' into the above equation produces a minimum failure pressure S_F = 1121 psig, whereas the maximum operating pressure of the pipeline is only 850 psig.

- All pipe is procured from vendors who have passed a stringent quality audit, and full-time mill inspection is performed by AGT during pipe production. AGT pipe specifications require additional quality testing and integrity requirements above and beyond API-5L standards.

- Standard coating for all the pipe will be Fusion Bond Epoxy (FBE) coating 16 mils (thousands of an inch) nominal; 12 -14 mils is industry standard. Coating for the enhanced pipe will be a dual layer with FBE and Abrasion Resistant Overlay ("ARO"). AGT will specify 25 mils of coating, consisting of 16 mils of FBE and 9 mils of ARO. ARO will provide for enhanced protection during installation and provide

additional external corrosion protection. Internal corrosion protection will also be provided (1.5 mils of FBE).

- A physical barrier to impede access to the buried piping will be installed above the enhanced pipe. Installation will include two (2) parallel sets of fiber-reinforced concrete slabs with dimensions of 3 feet wide by 8 feet long by 6 inch thick (a cross-sectional view of the proposed design is provided in Appendix B, Exhibit C of the attached report**)**. Yellow warning tape will be placed at the top of the concrete slabs and another layer 1 foot above the pipe.

- The latest state of the art cathodic protection will be used on the pipeline.

Piping was or will be purchased to AGT Pipe standards ES-PP3.11 and/or ES-PP3D.3. Mill inspection will follow standards IS-IP1.1, IS-IC1.1, and IS-IC2.1. Non-Destructive Examination (“NDE”) will follow APL-5L PSL-2 requirements as well as AGT Standards in the mill. All pipe is tested in the mill in accordance with AGT Standards,

2) Construction

The construction of the new pipeline is not going to result in any issues affecting plant operation. The construction pathway will result in construction under the power lines from the switchyard, but appropriate protective measures will be used to prevent interference with the power lines. The construction pathway will not require construction above the existing gas pipeline and (per Reference 8):

- There will be no blasting for rock removal in the region of the enhanced design pipe.
- The Broadway crossing on the west side of the tank will be made using an open cut installation method. Spectra will ensure that traffic flow is maintained during construction, and access to the Indian Point facility is not impeded.
- Work near electrical power lines will follow industry standard practices and OSHA regulations.
- The enhanced gas pipeline would be buried to a minimum greater depth of 4 feet from the top of the pipeline to the surface and buried 5 feet under Broadway.
- The pipeline coatings will be inspected electronically as the enhanced pipeline is lowered into the ground. A coating fault test is normally performed to detect any faults prior to backfill. In addition, a Direct Current Voltage Gradient (DCVG) survey will be performed to ensure coating integrity following enhanced pipe installation and partial backfill.

Spectra pipe installation welders must be qualified by destructive testing. To maintain their qualification, they must have a qualifying weld inspected via Non Destructive testing and found to be acceptable at intervals not exceeding 6 months. A welder must re-qualify via destructive testing every 2 years. The welder’s qualifications and continuation of qualification must be documented. All pipeline/piping welding procedures shall be qualified by destructive testing. All welding (including temporary welds) will be in compliance with approved welding procedures and performed by an AGT approved qualified welder.

All field welds for enhanced gas pipeline shall also undergo Non Destructive Examination which will include as a minimum 100% radiography of all field butt welds for

Class Locations 1. The normal radiography requirement is 10% of all butt welds. All installed pipe will also undergo a full hydrostatic test in the field after installation to verify pipe integrity per the DOT Code requirements and AGT standards.

3) Ongoing Pipeline Maintenance and Monitoring Activities

Spectra monitors the cathodic protection levels on its pipeline system in accordance with the 49 CFR § 192.465(a): “Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine the 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 years in accordance with 49 CFR § 192.939. Cathodic protection surveys will confirm, at test sites installed along the pipeline, that cathodic protection voltage potentials are maintained at levels necessary to prevent corrosion. Sophisticated inline inspection tools will be run through the pipeline at least once every seven years to identify internal and external corrosion, and other defects. These inspection tools continue to advance and can detect, size and locate pipe anomalies with high accuracy. Any defect noted by a tool run are tracked and corrected as necessary.

The methods used to prevent pipeline overpressure have been successful for many decades at compressor stations. Spectra has stated that it never had a pipeline rupture attributable to over-pressuring a pipeline. There are multiple levels of protection:

- The first level of protection is a precautionary alarm at 5 psi below the maximum allowable operating pressure (MAOP) to alert the Gas Control center in Houston to determine if any action needs to be taken and to ensure conditions are under control.
- The automated control system for the compressor unit is set to ensure that the discharge pressure does not exceed the pipeline MAOP.
- It is extremely rare that pressure ever exceeds MAOP, but if this were to happen, a “critical” alarm would alert the local station attendant and the Gas Control center in Houston to take immediate manual control measures (e.g., slowing or shutting down compressors, adjusting conditions at nearby facilities, etc.) to reduce pressure. These personnel are trained on how to respond to abnormal operating conditions.
- The Stony Point station control system is set to automatically shut down the unit and close the unit isolation valves when pipeline pressure reaches MAOP for 305 consecutive seconds.
- The Stony Point station control system is set to automatically shut down the unit and close the unit isolation valves when pipeline pressure reaches MAOP + 1psig for 10 consecutive seconds.
- The turbine compressor units also have a manufacturer-installed, automatic shutdown system to protect the equipment from damage and the set point on this device is lowered to trigger at 15 psi above MAOP.

- In the very unlikely event that the pressure were to continue to climb, the standard over pressure protection ("OPP") system is in place to automatically shut down all compressors at the station, and this is set at the OPP limit specified in the DOT Code 49 CFR § 192.169 (or 34 psi above MAOP for the new 42 inch pipeline).

- Relief valves are also in place at most compressor stations, as noted, but are part of an older operating strategy and are not relied upon as the primary means of overpressure protection (gas emissions and noise from relief valves are undesirable).

- The pressure control and overpressure devices are reliable, and the accuracy of set points is verified at periodic time intervals in accordance with the DOT Code. Maintenance records are audited by internal teams as well as the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration auditors to ensure compliance.

4) Actions in the event of a rupture

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 reference 14 report.

The next closest isolation valve locations are at the Stony Point Compressor Station mile post 0.0 and at MLV 15 at mile post 10.52. Valve operation follows the requirements of the DOT Code and is tested on a periodic basis to ensure compliance with code requirements.

In April of 2020 the NRC concluded (Reference 13) that the valve closure and length of pipeline used in the latest analysis (Reference14) were non conservative. In a discussion with Enbridge Inc. (Enbridge Inc. acquired Spectra Energy and Algonquin is a subsidy of Spectra) it was established that the maximum time to isolate the 42" pipeline would be 8 minutes and the length of line between outmost closure valves would be about 11 miles of pipe. These values are used in the analysis performed in response to Reference 12.

<u>Evaluation Criteria</u>

The Standard Format and Content Guide (RG 1.70) requires in Section 2.2.3.1 (Determination of Design Basis Events) that design basis events external to the nuclear plant be defined as those accidents that have a probability of occurrence on the order of about 1×10^{-7} per year or

greater and have potential consequences serious enough to affect the safety of the plant to the extent that Part 100 guidelines could be exceeded. It further states:

- "The determination of the probability of occurrence of potential accidents should be based on an analysis of the available statistical data on the frequency of occurrence for the type of accident under consideration and on the transportation accident rates for the mode of transportation used to carry the hazardous material. If the probability of such an accident is on the order of 10^{-7} per year or greater, the accident should be considered a design basis event, and a detailed analysis of the effects of the accident on the plant's safety-related structures and components should be provided."

- Ruptures – Accidents involving detonations of high explosives, munitions, chemicals, or liquid and gaseous fuels should be considered for facilities and activities in the vicinity of the plant where such materials are processed, stored, used, or transported in quantity. Attention should be given to potential accidental ruptures that could produce a blast overpressure on the order of 1 psi or greater at the plant, using recognized quantity-distance relationships. Missiles generated in the rupture should also be considered.

- Flammable Vapor Clouds (Delayed Ignition) – Accidental releases of flammable liquids or vapors that result in the formation of unconfined vapor clouds should be considered. Assuming that no immediate rupture occurs, the extent of the cloud and the concentrations of gas that could reach the plant under "worst-case" meteorological conditions should be determined. An evaluation of the effects on the plant of detonation and deflagration of the vapor cloud should be provided. Missiles generated in the rupture should also be considered.

- Fires – Accidents leading to high heat fluxes or to smoke, and nonflammable gas- or chemical-bearing clouds from the release of materials as the consequence of fires in the vicinity of the plant should be considered. Fires in adjacent industrial and chemical plants and storage facilities and in oil and gas pipelines, brush and forest fires and fires from transportation accidents should be evaluated as events that could lead to high heat fluxes or to the formation of such clouds.

- Missiles Generated by Events near the Site – Identify all missile sources resulting from accidental ruptures in the vicinity of the site. The presence of and operations at nearby industrial, transportation, and military facilities should be considered. Missile sources that should be considered with respect to the site include, among others, pipeline ruptures.

NUREG 0800 is the NRC Standard Review Plan (SRP) which provides the NRC review criteria and acceptance criteria. The current revision of SRP Section 2.2.3 acceptance criteria states

> "Specific SRP acceptance criteria acceptable to meet the relevant requirements of the NRC's regulations identified above are as follows for the review described in this SRP section. The SRP is not a substitute for the NRC's regulations, and compliance with it is not required. However, an applicant is required to identify differences between the design features, analytical techniques, and procedural measures proposed for its facility and the SRP acceptance criteria and evaluate how the proposed alternatives to the SRP acceptance criteria provide acceptable methods of compliance with the NRC regulations.

1. Event Probability

   The identification of design-basis events resulting from the presence of hazardous materials or activities in the vicinity of the plant or plants is acceptable if all postulated types of accidents are included for which the expected rate of occurrence of potential exposures resulting radiological dose in excess of the 10 CFR 50.34(a)(1) as it relates to the requirements of 10 CFR Part 100 is estimated to exceed the NRC staff objective of an order of magnitude of 10-7 per year.

   If data are not available to make an accurate estimate of the event probability, an expected rate of occurrence of potential exposures resulting in radiological dose in excess of the 10 CFR 50.34(a)(1) as relates to the requirements of 10 CFR Part 100, by an order of magnitude of 10-6 per year is acceptable if, when combined with reasonable qualitative arguments, the realistic probability can be shown to be lower.

2. Design-Basis Events

   The effects of design-basis events have been adequately considered, in accordance with 10 CFR 100.20(b), if analyses of the effects of those accidents on the safety-related features of the plant or plants have been performed and measures have been taken (e.g., hardening, fire protection) to mitigate the consequences of such events.

The SRP says that the "technical rationale for application of these acceptance criteria to the areas of review addressed by this SRP section is discussed in the following paragraphs:

1. Offsite hazards that have the potential to cause onsite accidents leading to the release of significant quantities of radioactive fission products, and thus pose an undue risk of public exposure, should have a sufficiently low probability of occurrence and should fall within the scope of the low-probability-of-occurrence required by 10 CFR 100.20(b) based on criterion of 10 CFR 50.34(a)(1) as it relates to the requirements of 10 CFR Part 100.

2. Data are often not available to enable the accurate calculation of probabilities because of the low probabilities associated with the events under consideration. Accordingly, the expected rate of occurrence of potential exposures in excess of the 10 CFR 50.34 (a)(1) requirements as they relate to the requirements of 10 CFR Part 100 guidelines by an order of magnitude of 10-6 per year is acceptable if, when combined with reasonable qualitative arguments, the realistic probability can be shown to be lower.

Regulatory Guide ("RG") 1.91 describes methods for nuclear power plant licensees that the NRC Staff finds acceptable for evaluating postulated failures at nearby facilities and transportation routes. One method includes the calculation of minimum safe distance based on estimates of TNT-equivalent mass of potentially explosive materials. Once blast load effects are calculated, the safe distances can be based on peak positive incident overpressure below one pound per square inch, or 1.0 psi for which no significant damage would be expected. The RG goes on to say "If the facility with potentially explosive materials or the transportation routes are closer to SSCs important to safety than the distances computed using Equation (1), the applicant or licensee may show that the risk is acceptably low on the basis of low probability of failures. A demonstration that the rate of exposure to a peak positive incident overpressure in excess of 1.0 psi (6.9 kPa) is less than $1x10^{-6}$ per year when based on conservative assumptions, or $1x10^{-7}$ per year when based on realistic assumptions, is acceptable. Due

consideration should be given to the comparability of the conditions on the route to those of the accident database. If the facility with potentially explosive materials or the transportation routes are closer to SSCs important to safety than the distances computed using Equation (1), the applicant may show through analysis that the risk to the public is acceptably low on the basis of the capability of the safety-related structures to withstand blast and missile effects associated with detonation of the potentially explosive material."

Results of Evaluation of Proposed Southern Route

Pipeline Rupture Event

The potential failure of the proposed new 42 inch pipeline along the more-distant (from IP2 and IP3) southern route has been evaluated for both exposure rates and effects.

The NRC noted in the discussion in RG 1.91, Rev 2, that "The NRC staff determined that if the probability of an failure at a nearby facility or the exposure rate, based on the theory in the Federal Emergency Management Agency's *Handbook of Chemical Hazard Analysis Procedures*, November 2007 (Ref. 11) for material in transit, can be shown to be less than 1x10-7 per year, then the risk of damage caused by failures is sufficiently low" Chapter 11.0 "Probability Analysis Procedures," Section 11.6 "Transportation of Hazardous Materials By Pipeline," has developed a formula for estimating the frequency of pipeline releases considering the size of the pipeline ($\geq$ 20 inches diameter applies to this pipeline), the length of pipe under consideration (about 3935 feet) to exclude damage to the switchyard and the GT 2/3 FOST), and size of the breach (guillotine breaks are considered which is 20% of all breaks).

For the proposed pipeline Reference 14 cited 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).

Consideration of the gas pipeline rupture as a design basis event requires a hazard analysis to be prepared. The hazard analysis must consider the location of safety related and important to safety structures, systems and components (SSCs) relative to the gas pipeline. The acceptance criteria for the hazard analysis considers; if the probability of a gas pipeline rupture is sufficiently low the event may be excluded; if the rupture does not damage the safety related or ITS SSCs then the rupture is acceptable; or, if the safety-related SSCs remain available to safely shutdown the plant and the risk of damage to the SSCs is low, then the risk to the public can be considered acceptable.

If the gas pipeline distances are sufficient to limit overpressure to less than 1.0 psi, the continued capability of safety related structures to withstand the effects of a gas pipeline rupture can be shown.

This hazards analysis in Reference 14 considers the effects of the gas pipeline rupture to involve the approximately 3 miles of pipeline between isolation valves and considers the event to be terminated by manual action within 3 minutes after any pipeline rupture event by closing the closest isolation valves and limiting the event to the gas between these valves. The attached hazard analysis prepared in response to Reference 12 changed requirements to a maximum time to isolate the 42" pipeline of 8 minutes and the length of line between outmost closure valves would be about 11 miles of pipe. Further, local fire departments have been trained in large gasoline fires of the type postulated for IPEC security events and will therefore have the ability to address any secondary fires and fire damage that will be of a lesser size when the gas pipeline flow has been terminated.

Evaluation of significance to margin of safety

The effects on safety related and important to safety (ITS) SSCs from a postulated gas pipeline failure could come from (1) potential missiles, (2) an over-pressurization event, (3) a vapor cloud (or flash) fire, (4) a hypothetical vapor cloud explosion, and (5) a jet fire. The Reference 14 analysis of the effects of a postulated gas pipeline failure and explosion along the southern route near IPEC is consistent with NRC guidance and demonstrates that there will be no damage to safety-related SSCs. However, the Reference 14 analysis also shows that certain SSCs important to safety (i.e., Switchyard with associated transmission lines, Gas Turbine 2/3 Fuel Oil Storage Tank (GT 2/3 FOST), City Water Tank, and Emergency Operations Facility (EOF) and meteorological tower) have to be evaluated for loss under certain postulated rupture scenarios. Entergy is also considering potential impacts to the FLEX Storage Building, the fuel oil tanker, and the IP2 and IP3 steam generator mausoleums.

Regulatory Guide (RG) 1.91 Rev 2 defines an acceptable method for establishing the distances beyond which no adverse effect would occur based on a level of peak positive incident overpressure. The peak overpressure of 1.0 psi (6.9 kPa) is considered to define this distance and can be calculated by

$$R_{min} = Z * W^{1/3}$$

where

Rmin = distance from explosion where P_{so} will equal 1.0 psi (6.9 kPa) (feet or meters)
W = mass of TNT (pounds or kilograms (kg))
Z = scaled distance equal to 45 ($ft/lb^{1/3}$) when R is in feet and W is in pounds
Z = scaled distance equal to 18 ($m/kg^{1/3}$) when R is in meters and W is in kilograms

The report in Reference 14 contains the hazard evaluation which calculates the minimum safe distances from a vapor cloud explosion using the RG 1.91 formula (Table 10). The hazard evaluation also conservatively assumed damage to SSC important to safety from thermal radiation of 12.6 kW/m^2 (Table 4) due to a jet fire (immediate ignition of the release produces a jet fire anchored on the pipeline) and calculated the distance to achieve this value. The hazard analysis also defines the missile hazard based on historical industry pipeline failure data and demonstrates the delayed vapor cloud explosion (deflagration) is not a concern. The hazard evaluation is considered to be very conservative since the methodologies used for calculating the overpressure distance and the selection of the thermal radiation of 12.6 kW/m^2 (the distance that plastic melts / piloted ignition of wood are well below the thermal radiation for building

damage) The hazard analysis in Reference 14 identifies distances beyond which damage is not postulated even in worst case ruptures but these distances are changed by the attached hazard analysis as follows:

Type of Effect Evaluated	Exclusion Distance	Basis
Jet fire	1266 ft (386 m) changes to 1545 ft (473m)	A heat flux of 12.6 kW/m^2 was chosen as a basis for limiting postulated damage
Vapor Cloud explosion (detonation)	1155 ft (352 m) changes to 1391 ft (424m)	A 1.0 psi overpressure will not occur at greater distance
Missile	900 ft (274 m)	The maximum distance that missiles have been observed

The first assessment assumes that these SSCs ITS could be damaged by a postulated explosion and evaluates whether there would be a significant reduction in the margin of safety. The assessment is to quantify potential effects assuming a postulated gas pipeline rupture and does not consider the frequency of a gas pipeline rupture and explosion or the capability of SSC. The assessments in Reference 14 were based on the closest distances from the enhanced and unenhanced pipeline, as follows:

SSC ITS	Closest distance from enhanced gas pipeline	Closest distance non-enhanced gas pipeline
Switchyard	115 ft (35 m)	>1266 ft (386 m)
GT2/3 fuel tank	105 ft (32 m)	>1266 ft (386 m)
City water tank	1336 ft (407 m)	>1266 ft (386 m)
Meteorological tower	Not applicable	>1266 ft (386 m)
EOF	1002 ft (305 m)	>1266 ft (386 m)
SOCA	1580 ft (482 m)	1580 ft (482 m)
Backup Meteorological tower	1844 ft (562 m)	>1266 ft (386 m)
SSC of Interest		
FLEX Building Unit 2 SG Mausoleum Unit 3 SG Mausoleum	1033 ft (315 m) 1440 ft (439 m) Not Applicable	1162 ft (354 m) 1905 ft (581 m) 477 ft (145 m)

The following assessment is applicable to the reports in Reference 14 and the attached report requested by the NRC and discusses the safety significance of a postulated loss of SSCs ITS from a postulated gas pipeline rupture. IP2 is now permanently shutdown with spent fuel located in the spent fuel pit or Independent Spent Fuel Storage Installation but is conservatively assessed as if it was in operation. It concludes 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.

- 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 and is analyzed in the Updated Final Safety Analysis Report (UFSAR). The loss of offsite power would result in automatic operation of the Emergency Diesel Generators (EDG) (note the IP2 diesels are no longer required in shutdown) to provide essential power to cool down and shutdown each plant. The loss of offsite power is also considered as an initiator of the station blackout event (SBO) where the three EDG (three for IP2 or three for IP3) at one plant are postulated to fail to start. Both IP2 and IP3 have a separate SBO diesel generator for such an event. The IP2 SBO diesel has a fuel oil supply in the Unit 1 turbine building but depends upon the city water storage tank for initial cooling. The IP3 SBO diesel has local fuel oil supplies and has radiator cooling. The SBO event considers the ability to restore the switchyard in determining the duration for which a SBO is evaluated. However, loss of the switchyard for an extended period of time due to a postulated pipeline rupture does not need to be considered for the SBO. NRC acceptance criteria for SBO (NUMARC 87-00) do not require consideration of low probability events such as severe natural phenomena or pipeline rupture for SBO. Therefore there would be no significant reduction in margin of safety due to loss of the switchyard from the contribution of a switchyard failure due to a gas pipeline rupture.

- A postulated gas pipeline rupture near the GT 2/3 FOST could cause loss of the tank. The purpose of the tank is to provide a supply of fuel oil to the IP2 and IP3 EDG so that they would have an overall 7 day supply of fuel oil (it is presumed that additional fuel oil as well as backup generators could be made available in that time). The function of the GT 2/3 FOST is backed up by the ability to provide fuel oil from outside the plant. The gas pipeline rupture that could cause loss of the GT 2/3 FOST could also result in loss of the switchyard due to their close proximity. This will require the backup fuel oil from offsite to be provided as the primary means of achieving a 7 day fuel oil supply. The gas pipeline rupture could also cause loss of the main access gate to the site directly across from the switchyard but there are other access gates for delivery of the fuel oil. The gate several hundred feet further south (it used to access IP3 when the two units were independent) could be blocked by the rupture since it is not too far from the GT 2/3 FOST. This gate has been blocked with two concrete barriers (a crane could be used to remove them). To the north about 1850 feet is the gate used for access to IP2 when the two sites were independently owned and this gate is expected to be available. It is easily accessible by opening the gates in the owner controlled fence and manually opening the blocking bar used in place of concrete barriers. Although access is feasible, the dependency on the offsite delivery results in a reduction in the margin of safety for the safety related EDG to provide the power for plant shutdown. The tanker that is stored onsite to transport fuel oil from the GT 2/3 FOST is within the damage range but will be relocated to assure availability for all cases where the GT 2/3 FOST remains available. Therefore it is concluded that the reduction in the margin of safety is more significant assuming a pipeline failure that results in the loss of both the switchyard and GT 2/3 FOST. But as discussed below, the substantial additional design and construction enhancements for the pipeline near IPEC make this a very low frequency event and, per NRC acceptance criteria, does not pose a concern to the safe operation of IP2 or IP3.

- A postulated gas pipeline rupture will not cause loss of the city water tank because the distance from the gas pipeline is sufficient to prevent loss of the tank (see above table) since the peak positive incident overpressure will not exceed 1.0 psi and the heat flux will

not exceed 12.6 kW/m^2. The city water tank functions as alternate water supply to the IP2 and IP3 Auxiliary Feedwater Systems. It also serves as a backup for other SSCs, including the IP2 Appendix R / SBO diesel. The rupture of the gas pipeline is not caused by severe natural phenomena or by any postulated plant event and is therefore, not coincident with any plant event requiring the city water tank. Therefore there is no significant reduction in the margin of safety.

- A postulated gas pipeline rupture could cause loss of the important to safety Emergency Operations Facility (EOF) because it can see a heat flux of 12.6 kW/m^2 and be exposed to an overpressure in excess of 1 psi, as well as loss of the meteorological tower which is also within both exclusion distances. The function of the EOF is to act as a central command post for a plant emergency that meets the criteria for emergency responders to assemble. The function of the meteorological tower is to provide weather information in the event of a plant emergency that requires activation of the emergency response organization, it contains instrumentation for Entergy activation of the siren system and communications with the offsite assessment team. No gas pipeline rupture will cause any plant damage meeting the criteria for emergency planning to assemble in the EOF. The EOF is activated for Alert Emergency Level declaration or above. An Unusual Event would likely be declared in the event of a pipeline rupture that results in switchyard failure (Loss of all offsite AC power to 480 V safeguards buses (5A, 2A/3A, 6A) for > 15 min) but the Alert Emergency Level criteria would not be reached. The Reference 14 failure that does damage the meteorological tower would not result in damage to the switchyard. Also, there is a backup meteorological tower (it does not contain the 60 meter and 122 meter instruments), normal means to activate the siren systems from the counties, alternate communications with the assessment teams, and a backup EOF that would not be affected by the rupture. There would therefore be no significant reduction in the margin of safety since the EOF and meteorological tower functions would not be required and backups are available.

- There is no damage to the SOCA which is beyond the exclusion distance for which the effects of the gas pipeline explosion are considered for damage to SSCs. The SOCA boundary was identified for evaluation since the plant safety related SSCs are within the SOCA boundary and the SOCA represents the outer security boundary. Therefore there is no damage to safety related or security required SSCs.

In addition to the SSCs important to safety discussed above, other features have been considered in Reference 14.

- The building for storage of FLEX equipment (used for beyond design basis events) is required to address Fukushima orders. The building is constructed of reinforced concrete and was designed for a tornado overpressure. It does not have a damage potential from vapor cloud detonation because the overall structural capability of the building is designed for 3.0 psi overpressure compared to the predicted overpressure which is only slightly over 1 psi. The FLEX storage building is outside the postulated distance for a missile. The building is within the heat flux distance but the heat flux will not be great enough to affect the concrete and there is no other equipment to be affected.

- The storage of the steam generators replaced on IP2 and IP3 is in mausoleum buildings. The Unit 3 mausoleums are subject to potential damage since they are within the exclusion distance for heat flux, missile damage and overpressure. The Unit 3 building

has 3 foot thick reinforced concrete walls supported by a pile foundation with reinforced concrete pile, an 18 inch (average) thick reinforced concrete roof supported by metal decking and steel beams, and an 8 inch thick reinforced concrete grade slab. Although the structure contains radioactive material, analyses have demonstrated the failure of the structure would not result in releases exceeding the limits in 10 CFR 20 (10 CFR 50.59 analysis dated May 1987). The Unit 2 mausoleum is outside the exclusion distances and a postulated rupture would have no effect.

A rupture of the buried gas pipeline due to a sabotage event is not considered deterministically or in the evaluation of frequency because the NRC regulations do not require the postulation of sabotage on facilities that are not part of the power plant and due to the substantial difficulty of intentionally causing an rupture of underground piping coupled with the extra design features that have been included in the proposed enhanced pipeline design. A gas pipeline rupture of exposed (above-ground) portions of the pipeline due to sabotage, however, has been postulated at IPEC in the past in response to a concern, although there is no regulatory requirement to do so. Consistent with this precedent, a sabotage event is postulated, but limited to considerations of potential sabotage of above ground piping. The above ground piping, however, is sufficiently far from any SSC important to safety so that all SSCs are outside the exclusion areas of the hazard analysis.

A gas pipeline rupture due to natural phenomena was also evaluated and is not considered to represent a credible threat to the pipeline. Tornadoes and hurricanes do not present a threat to the buried pipeline due to winds or missiles. Missile impacts are resisted by the strength of the piping and the 3 to 4 foot depth of the soil. Additionally, the effects of tornado missiles are not part of the IP2 design basis and are restricted to a single missile at IP3. A seismic event has the potential to cause loss of supporting soils due to the potential liquefaction of the underlying soils and susceptibility to other damage that could cause loss of the pipeline. However, due to the rocky soil in this area at relatively shallow depths combined with low seismicity, liquefaction of the underlying soil is not likely (Reference 9). This conclusion and that on page B20 of the Reference 14 blast analysis, which is not being revised, do not change due to the small area of wetlands behind the switchyard. As the cross section shows (Reference 11), the rock is still close to the bottom of the pipe which has a timber mat and sandbags placed around the pipe which is equivalent to a sand base that would normally be backfilled. The distance to the rock varies but is not significant as shown for the length of pipe, so any small potential additional displacement that may be caused by this condition is not considered to be an issue. As a result, the pipeline will be continuously supported along the entire length of burial by the soil and will tend to move in phase with the soil during an earthquake resulting in low stresses. The primary risks from ground movement hazards come from active seismic faults, landslides, long wall mine subsidence, and frost heaves in areas with deep frozen ground, none of which apply along the pipeline in the area near the Indian Point Facility. Therefore, a seismic event is not postulated to adversely affect the buried portion of the pipe.

The potential exists where the 26 / 30 inch pipeline will come together with the 42 inch pipeline for an explosion in one of the three pipelines to cause an explosion in one or more of the other lines. This would be possible in the above ground portion of the pipeline but the blasts would be sequential and this distances are great enough that the effects would be acceptable. Experience has shown that the rupture of one underground pipe would not affect another since the forces are upward. Also the lines are not close enough to even create this possibility until they reach the area where they are brought above ground. Therefore, a postulated simultaneous failure of the buried portions of the existing 26 / 30 inch pipelines and new 42 inch pipeline is not a credible event.

Frequency of Events

The prior discussion indicates that the new gas pipeline represents no potential damage to safety related SSC but a gas pipeline rupture could cause potential damage to SSCs ITS closer to the proposed southern route. The discussion also assesses the effects on the safety margin for protection of the public for a postulated gas pipeline rupture. The following information from Reference 14 shows that the frequency of postulated gas pipeline ruptures that could damage SSCs ITS are, based in part on the enhanced design and installation features, sufficiently low and do not result in a significant reduction in the margin of safety. This is because they are excluded from consideration in accordance with NRC guidance due to the very low frequency of a gas pipeline rupture that could damage these SSCs ITS and because the frequency is sufficiently low that the undamaged safety related SSCs can be credited with safely shutting down the plant, or because the SSCs are not within the distance where they could be damaged. The one exception to this being the Meteorological Tower, which is above 10-6/yr. however, there is a backup Meteorological Tower and other means of obtaining meteorological data (e.g., NOAA)

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 frequency of damage to the various SSCs ITS is calculated by the length of pipeline exposure and the frequency of occurrence of the types of events. The results are as follows:

SSC ITS	Event	Frequency / year
Switchyard	Jet fire	7.23E-7
	Vapor Cloud explosion	5.52E-8
	Missile	1.32E-7
GT2/3 fuel tank / switchyard	Jet fire	5.20E-7
	Vapor Cloud explosion	4.25E-8
GT2/3 fuel tank	Missile	1.51E-8
City water tank	Jet fire	Outside damage distance
	Vapor Cloud explosion	Outside damage distance
	Missile	Outside damage distance
Meteorological tower	Jet fire	1.86E-6
	Vapor Cloud explosion	1.51E-7
	Missile	2.06E-9
EOF	Jet fire	4.02E-7
	Vapor Cloud explosion	2.79E-8
	Missile	Outside damage distance
SOCA	Jet fire	Outside damage distance
	Vapor Cloud explosion	Outside damage distance
	Missile	Outside damage distance
Backup Meteorological tower	Jet fire	Outside damage distance
	Vapor Cloud explosion	Outside damage distance
	Missile	Outside damage distance
City Water Tank	Jet fire	Outside damage distance

	Vapor Cloud explosion	Outside damage distance
	Missile	Outside damage distance
Other SSC of Interest		
FLEX Building	Jet fire	No exposed instruments for 12.kW/m^2 to damage
	Vapor Cloud explosion	Overpressure 1.19 psi building design for 3.0 psi
	Missile	Outside damage distance
Unit 2 SG Mausoleum	Jet fire	Outside damage distance
	Vapor Cloud explosion	Outside damage distance
	Missile	Outside damage distance
Unit 3 SG Mausoleum	Jet fire	1.38E-6 (for thermal radiation that would damage the building)
	Vapor Cloud explosion	1.95E-7
	Missile	3.83E-8

Conclusion

Based on the considerations discussed above, the potential for an increase in risk to the public is acceptably low on the basis of:

- there is no damage to safety related SSC or plant security from a postulated pipeline rupture;

- the effect on SSCs ITS of a postulated gas pipeline rupture would not have a significant effect on plant safety because:

  - The SSCs ITS have been shown to be sufficiently far away from a postulated gas pipeline failure so as to be unaffected by the failure, or

  - Based on the agreed-upon pipeline design and construction enhancements, the low frequency of a gas pipeline rupture would preclude consideration of rupture with damage to SSC ITS, with the exception of the Meteorological Tower where frequency is greater that 10E-6. The meteorological tower, is not required for shutdown and the undamaged safety related SSCs can be credited with safely shutting down the plant. The meteorological tower also has backup capability and other means of obtaining meteorological data are available (e.g., NOAA).

Therefore there is no significant reduction in the margin of safety with regard to public safety.

Supplement

Reference 10 identified additional tie-in details for the gas pipelines which are part of the project to install the 42 inch pipeline. A sabotage event was postulated during the initial evaluation, but limited to considerations of potential sabotage of above ground piping. Based on information available when the pipeline was first evaluated, the sabotage event was based on the 42 inch pipeline above ground where it would tie into the existing 26 inch and 30 inch existing pipelines.

Reference 10 provided a detailed scaled and dimensioned piping layout drawing for the proposed tie-in configuration depicting the proposed aboveground piping and additional underground interconnecting piping. These details were evaluated in Appendix C of the attached Hazards Analysis. The new drawing shows the 30 inch line and the 26 inch line with a cross tie to the 42 inch line. The 26 inch line is above ground only at the point where it ends at a receiving pig trap (used for receiving pigs). There are no 30 inch or 42 inch pipelines above ground. The following piping sections are above ground:

- A 12 inch equalizing line with 12 inch risers on both sides of a normally open mainline valve in the 42 inch line;
- 10 inch blowdown risers on both sides of the normally closed 26 inch valve and the two 30 inch cross-tie valves that connect the pipelines;
- The lead-in pipe and barrel of the pig receiver (part of the pigging station) for the 26 inch pipeline (the 26 inch valve and barred tee are buried);
- Actuators for the 26 inch, 30 inch and 42 inch valves;
- A 10 inch line that connects the pig receiver to the 30 inch pipeline via the cross ties;
- A 2 inch blow-off riser on the inlet side of the 26 inch pig receiver valve and a short section of 2 inch pipe to connect the upstream 2 inch riser to the 2 inch equalizing line; and
- The 2 inch equalizing line where it comes above ground to connect to the pig receiver.

During normal operation the 30 inch and 42 inch pipelines are in service but other operating scenarios are possible. Consistent with the sabotage postulated for the 42 inch pipe, an assessment of the simultaneous rupture of the above ground piping due to sabotage was performed for each operating scenario (see Appendix C to the Hazards Evaluation). The major assumptions in this analysis were:

- The initial release pressure is assumed conservatively to be the Maximum Allowable Operating Pressure (MAOP) of all the pipe lines (865 psia, 765 psia, or 689 psia for the 42 inch, 30 inch and 26 inch pipelines, respectively). With cross ties closed, the pressure within the 26” line, the cross-ties between the pipelines and the pig receiver, is assumed to be 689 psia. When cross-ties are open, the initial release pressure is assumed to be the lower of the MAOPs of the pipelines involved.

- In all cases, the rupture is conservatively assumed to involve a guillotine failure although all but one release will be single-sided since below-ground pipelines are the sole source of natural gas supplying the blowdown risers on each side of each closed valve.

- It is conservatively assumed that the sabotage event that ruptures the piping will also destroy the actuators of the below-ground isolation or cross-tie valve (s). This will preclude the subsequent operation of the below-ground isolation or cross-tie valve (s) (valves will remain in their last position as dictated by the prevailing mode of operation) which will not be available to mitigate the release. This may serve to prolong the release but will not increase the consequences as discussed in Appendix C.

- The evaluations were performed for multiple simultaneous releases by calculating the releases individually and adding the resultant heat fluxes and overpressures. There were several exceptions where multiple releases occurring in close proximity from a single piece of pipeline or interconnected piping were combined into a single release

with the same total cross-sectional area. This approach is taken since the release at one point will diminish releases at all other points by reducing the driving pressures behind them.

The worst case scenario from the Reference 14, Appendix C analysis is the rupture of all above ground components during pigging operations in the 26 inch pipeline. The combined heat flux from the multiple jet fires is 9.18 kW / m^2 and the combined overpressure from the detonation is 0.649 psi relative to the switchyard (the closest SSC ITS). These values are bounded by the original results calculated in Rev 0 of the safety evaluation for sabotage of above ground piping. Therefore, the conservative evaluation of multiple pipe ruptures has demonstrated that the updated piping tie-in details provided, although different than what was initially evaluated, are of no safety significance since the effects of sabotage on above ground piping are bounded by the consequences of the sabotage event assumed in Rev 0 of the safety evaluation.

It is concluded that the detailed piping tie-ins provided in Reference 10 have no affect on safety related or important to safety structures, systems and components. Since “SSCs ITS have been shown to be sufficiently far away from a postulated gas pipeline failure so as to be unaffected” there “is no significant reduction in the margin of safety with regard to public safety.”

Reevaluation to Address NRC Request

The NRC requested (Reference 12) Entergy to update the evaluation and supporting analyses In Reference 14 as necessary and to assess the validity and materiality of the assumptions made in support of conclusions regarding the consequences of a postulated rupture of the 42-inch gas pipeline. The update is to address the issues raised in the NRC report by an "Expert Evaluation Team" (Reference 13). This revision updates the 50.59 for that updated analysis and supporting evaluation but does not revise the evaluation to reflect completion of the pipeline. The previous 50.59 is not substantially revised since it reflects the prior report that is being updated.

Determination of Reevaluation Scope

As a result of an Event Inquiry due to stakeholder concerns regarding the safety of the Indian Point Energy Center (IPEC) with respect to the newly installed AIM 42” gas pipeline, the NRC Office of Inspector General (OIG) performed a review of the NRC’s internal handling of this issue, including a review of the NRCs original independent analysis on the effects the new pipeline may have on the safety of IPEC. In addition, the OIG also reviewed the Entergy Report in Reference 14. In response to this Event Inquiry, the NRC’s Executive Director for Operations tasked a team of NRC and external experts to review the findings in the Event Inquiry and to prepare a report that could be submitted to the NRC Commission [Reference 13]. The team determined that, even though Entergy and the NRC made some optimistic assumptions in analyzing potential rupture of the 42-inch natural gas transmission pipeline, the Indian Point reactors remain safe. It did, however, recommend that Entergy be asked to assess the importance of these assumptions to its original conclusions and update its analysis, if needed. This revision to the safety analysis reflects that reassessment in the enclosed report and addresses the NRC issues as follows:

- Where and how assumptions as to the time required to isolate a pipeline rupture and the length of pipeline that will be blown down were used.

- The calculation of the pipeline rupture rate. Regardless of any conclusions drawn here, this rate and the upper bound to the probability of detonation of methane will be updated, making use of PHMSA and other data collected since preparation of the original hazard analysis report.
- How the use of ALOHA and TNT equivalency models affects predictions as to the consequences of vapor cloud explosions.
- How the dispersion of methane released from the ruptured pipeline is modeled, whether a dense cloud might envelop or drift towards the SOCA and whether and how a vapor cloud explosion occurs.

The attached evaluation (Reference 16) addresses these issues and the results are discussed in this 50.59 revision.

Results of Reevaluation

The original hazard analysis was revised as discussed above. Specifically:

- Pipeline rupture frequencies were updated making use of the pipeline population and rupture data gathered by the PHMSA for the period 2014-2020.

- The probability of ignition natural gas releases after pipeline rupture and an upper-bound probability of a vapor cloud explosion involving detonation were updated using the new PHMSA data.

Jet Fires and Explosions

In the Reference 14 hazard analysis, a detailed development of a pipeline rupture frequency was presented. This development made use of 2002-2014 PHMSA pipeline rupture and population data and other data that were used to characterize the effect of enhancements on the pipeline rupture rate. Similarly, PHMA data were used to calculate an upper bound to the probability of detonation after pipeline rupture. In light of the availability of more recent PHMSA and European data, the pipeline rupture frequency and an upper bound to the probability of detonation after pipeline rupture was recalculated. It continues to be reasonable, however, to reduce the pipeline rupture frequency to reflect the enhancements made to the pipeline. This was supported by the work of the peer reviewer to the Expert Evaluation Team. The attached hazard analysis assesses the frequency using US data for all natural gas transmission pipelines with a diameter of 36" or more regardless of the wall thickness, coating thickness, cover depth and other enhancement. Because segments of the AIM pipeline near IPEC will be a design-enhanced, state-of-the-art installation, and reflect improvements in manufacture achieved in recent decades, a lower rupture frequency will apply to these segments of the AIM pipeline. While US data do not allow a direct correlation to calculate the probability impact of the enhanced pipeline features, European Data, US PMHSA data, and UK studies support a reduction in predicted pipeline rupture. The average rupture frequency of all pipelines installed in or after 1980 with a diameter of 36" or more is ~ 1.00×10^{-5} /mile.yr. Applying these probabilities (defects in fabrication or construction and 3rd party excavation for enhanced construction) to the pipeline rupture events of concern the calculated frequency of pipeline rupture and ignition is 1.065×10^{-6} /mile.yr and the frequency of pipeline rupture followed hypothetically by a detonation is 5.25×10^{-8} /mile.yr.

These frequencies apply to the pipeline rupture events of concern. In calculating exposure rates, the lengths of pipeline that lie within specific distances of the SSCs of concern are determined. It is assumed that if pipelines were to rupture along these lengths and fire, overpressure or missile damage were to ensue, damage to the SSC is possible. These predictions pertaining to the exposure rates for fire and explosion following a pipeline rupture are highly conservative in that the assumptions made in calculating the distances at which overpressures and high heat fluxes can reach are conservative. Accordingly, it can be concluded that the pipeline satisfies NRC criteria pertaining to explosion (detonation) risk as, with few exceptions, the predicted frequency of any postulated event is below the 10^{-6}/year criterion established in Regulatory Guide 1.91 for circumstances in which conservative assumptions are made. The exceptions are the switchyard, FLEX building, met tower and Unit 3 steam generator mausoleum, which could suffer damage from thermal radiation if a failure of the pipeline is postulated to occur. The switchyard risk is well below the risk of loss of offsite power from other sources. The met tower has alternate means to obtain data. The FLEX building and mausoleum are both of rugged construction with no outside instrumentation. Note that because of the proximity of the switchyard and GT2/3 storage tank, the same pipeline rupture event might cause high heat fluxes or overpressures exceeding 1 psi in both the switchyard and GT2/3 storage tank.

Missiles

Given their proximity to the pipeline the switchyard, GT2/3 diesel fuel storage tank, Unit 3 steam generator mausoleum and meteorological tower must all be considered as being potentially vulnerable to missile damage should the pipeline rupture close to these SSC's. All other targets of concern lie outside the 274 m (900 ft) distance that missiles can be thrown. The frequency of pipeline rupture and missile generation can be predicted as the product of the pipeline rupture frequency (1.50 x 10^{-6}/mile.yr for the enhanced pipeline) and the conditional probability of missile generation in a pipeline rupture (0.54). The resulting frequency is 8.10 x 10^{-7}/mile.yr. In the absence of enhancements, the frequency of pipeline rupture and missile generation is 5.40 x 10^{-6}/mile.yr (a rupture frequency of 1.00 x 10^{-5}/mile.yr multiplied by a 0.54 probability of missile generation). These frequencies cannot be applied, however, without assigning a probability that the missile would strike an object of concern. An upper bound estimate of this probability can be obtained by estimating the angle subtended by the object at its closest point to the pipeline—ignoring the possibility that missiles will fall short of or fly over the object and assuming that missiles are equally likely to be thrown in all directions.

- Missile Generation

The generation of missiles was addressed in the original analyses, Changes in the assumptions as to the time taken to close the isolation valves and the length of pipeline to be blow down will have no effect upon missile generation or the damage missiles might cause

- The consequences of jet fires were recalculated making use of a more sophisticated model now present in the BREEZE software that allows us to set the inclination of the flame.

The models within BREEZE Incident Analyst 3.0 software used to characterize the anticipated and hypothetical consequences of the release of natural gas from the pipeline crossing near the IPEC site and the basis for the selection of these models are listed below:

Scenario	Model	Basis for Selection
Jet flame	BREEZE: Gas Research Institute	This model addresses fires that may result from the leak or rupture of a pipeline containing a compressed gas.
Cloud dispersion (extent of flammable cloud)	BREEZE: SLAB	The maximum cloud centerline concentrations predicted using this simpler model appear reasonable when compared to predictions made using Computational Fluid Dynamics [23]. Earlier, Hanna, et al. stated that the SLAB model demonstrates consistently good behavior across all comparisons with observations.
Vapor cloud explosion	BREEZE: US Army TNT Equivalence model	This model comprises the implementation of equations 1 to 4 presented in Regulatory Guide 1.91. The predictions closely match those calculated using the equations. The TNT Equivalence model is best used with point sources; for vapor cloud explosions it has deficiencies in that it gives an overprediction of overpressures in the near field, underprediction in the far field and a shorter duration than is encountered
	BREEZE: TNO Multi-energy model	This model is a simple and practical method used for vapor cloud explosions. It is based on the premise that a vapor cloud explosion can occur only within that portion of a flammable vapor that is partially confined. It remedies the deficiencies in the Army TNT Equivalence model.

In the Report, SNL, in its role as consultant to the Expert Evaluation Team, took issue with the use of ALOHA software by the NRC noting that it does not model supercritical flow or double ended pipe rupture (this would require the use of Computational Fluid Dynamics (CFD). A comparison of the predictions made for ethylene in a supercritical state using CFD or models with real gas equations and the simple ideal gas model showed the simple model was reasonable and conservative. It was concluded that the use of the simple model was reasonable. In the original hazard analysis, guillotine rupture with a double ended release was assumed. This conservatively ignores lesser ruptures and the effects of the blowdown from two sides on each other. The release rate was assumed to be twice the single sided pipe release. This is equivalent to a pipeline 1.414 times the diameter of the 42" pipe. Therefore no changes to the original hazard analysis was required to model a double sided rupture or supercritical flow.

In a jet fire the consequences of a release are bounded by the consequences calculated for the initial release. As this initial release rate will not be affected by the subsequent closure of the isolation valves , no changes need be made to the assessment of the likelihood and consequences of jet fires in response to the changed assumptions as to the time taken to close the isolation valves and the length of pipeline to be blow down.

The jet fire is reevaluated by the new models assuming immediate ignition of the release, possibly caused by sparks created as ejected metal pieces or rocks rubbing together, will result in a jet fire anchored on the pipeline with a flame that might rise ~ 328 feet (100 m) or more; delayed ignition might result in a vapor cloud fire that burns back to the pipeline and ends up as a jet fire. To be conservative, the jet is assumed to emerge at an angle of 60^o to the horizontal here. In general, the threshold for damage caused by jet flames and thermal radiation is 12.6 kW/m^2, the heat flux at which exposed plastic melts and damage to instrumentation and electrical equipment can be anticipated. The jet flame created by ignition of a double-sided full bore release of natural gas following the guillotine rupture of the 42” pipeline will result in a thermal flux of 12.6 kW/m^2 at a distance of 473 m (1545 ft) from the point of rupture assuming the jet emerges at an angle of 60^o from the horizontal, a wind speed of 3 m/s and a Pasquill class D air stability. This predicted impact distance is conservative being based on the average release rate in the minute after rupture.

There will be no damage to equipment within the SOCA. Considering next possible damage to the meteorological tower, the GT2/3 diesel fuel storage tank, the city water tank, the FLEX building, the EOF, the steam generator mausoleums and switchyard, all located outside the SOCA, as a result of the rupture of a pipeline and jet fire at the closest points to these items, damage is assumed to occur. This damage might result from engulfment in flames (e.g., in the event of a jet fire initiated on the pipeline directly impinging on the GT2/3 fuel tank and switchyard) and intense thermal radiation that might damage switchyard equipment and, for the fuel tank, cause a tank vent fire. Damage to the IP2 steam generator mausoleum and FLEX building is unlikely due to their robust design and lack of outdoor instrumentation. The meteorological tower and EOF instrumentation could be lost but both have backups.

- The consequences of a hypothetical vapor cloud explosion involving detonation occurring within the turbulent jet created after pipeline rupture were revised to make this prediction still more conservative: the mass of methane assumed to contribute to the blast is the mass present, within flammable limits, immediately after pipeline rupture rather than the average mass present in the jet in the first minutes after rupture.

A vapor cloud or flash fire is a transient fire resulting from the delayed ignition of a cloud of flammable gas without significant flame acceleration as a result of turbulence. Although the size of a methane vapor cloud and the duration of its passage will be affected by the duration of the release and volume that will be blown down after isolating valves close, no new calculations are required because as no significant overpressures result from a cloud fire and, because the fire generally lasts for less than a minute, the integrity of structures or equipment engulfed in or exposed to cloud fires will not be challenged and such a fire will not contribute to a core damage event at Indian Point..

Vapor cloud explosions involving a drifting dense cloud of methane were modeled using the TNO multi-energy model as implemented within BREEZE Incident Analyst software assuming that the rupture is not isolated, the volume of flammable material potentially involved in an explosion being the volume of the cloud in the belt of trees immediately to the north of the pipeline right-of-way. The assumption of explosions arising in belts of trees is conservative

particularly as, under the conditions in which a flammable vapor cloud might be created—later in the release when pipeline pressure was low and choked flow and a high velocity jet no longer prevailed or when the release does not blow away soil atop the pipeline—the mass flow rate from the rupture and so too the likelihood that the release will behave as a dense gas would be low. The consequences are: 0.71 psi at closest system, structure or component important to safety in the SOCA—the PWST; 1.25 psi at the meteorological tower; 2.0 psi at the switchyard boundary; 2.3 psi at GT2/3; 1.17 psi at the FLEX building; 1.53 psi at the EOF; 1.3 psi at the city water tank; 1.14 psi at the Unit 2 steam generator mausoleum; and 0.94 psi at the Unit 3 steam generator.

In calculating the consequences of a hypothetical detonation within the turbulent jet, we assume the detonation to be centered about the point of rupture. Vapor cloud explosions within the turbulent jet were modeled using US Army TNT equivalent explosion model as implemented within BREEZE Incident Analyst. The minimum safe distances beyond which the overpressure will not exceed 1 psi were also calculated using equation (1) in RG 1.91. The explosion involves the mass of methane between the upper and lower flammable limits in the turbulent methane jet created by a rupture of the pipeline. A comparison of the minimum safe distances calculated using equation (1) in the Regulatory Guide and the implementation of the US Army TNT equivalency model in Breeze Incident Analyst shows small but consistent discrepancies. These are the result of a higher energy of explosion being assumed for TNT in the latter model. The consequences are: 0.58 psi at closest system, structure or component important to safety in the SOCA—the PWST; 3.6 psi at the meteorological tower; 80 psi at the switchyard boundary; 99 psi at GT2/3, 1.4 psi at the FLEX building, 1.5 psi at the EOF, 0.9 psi at the city water tank, 0.85 psi at the Unit 2 steam generator mausoleum, and 4.5 psi at the Unit 3 steam generator mausoleum assuming rupture at the closest points from the pipeline to these structures. High values are an overprediction of the model in the near field

- Whether the creation of a dense gas cloud of methane is possible is discussed in more detail and new calculations as to the consequences of such an event and a subsequent vapor cloud explosion are calculated using the TNO multi-energy model.

Considering next the creation of flammable dense phase gas clouds, empirical evidence does not support this (Reference 15). The Expert Evaluation Team noted that PHMSA pipeline accident investigators *agreed that methane gas under high pressures could initially be heavier than air* (as a result of expansion cooling) *when being released after a pipeline rupture. In their experience, however, although the dense methane gas might initially pool in the crater resulting from the rupture, as the methane gas expands and leaves the crater, it would become lighter than air.* Intense turbulent mixing and air entrainment would limit the area in which any gas cloud would be flammable. While SNL did indeed predict such a cloud, it acknowledged that its intent was to model dispersion in the far field but not near the release. They also noted that the release they modeled occurred above ground rather than in the trench or crater created as soil is blown away from around the ruptured pipeline. Now as noted earlier, methane will emerge in choked flow from the ruptured pipeline in a high velocity momentum jet that will entrain air and so will be diluted to below methane's lower flammable limit. Using Computational Fluid Dynamics the simulated dispersion of natural gas from a buried pipeline demonstrated that a high velocity jet would be created, the greater the pipeline pressure, the greater the height reached by the jet. The flammable region was shown to lie within the jet, at a short distance from the jet axis for releases occurring over a wide range of pipeline pressures. As wind speeds increase, the furthest distance the flammable region reaches from the point of rupture first increases as the jet bends and then starts to decrease with increasing gas dispersion. Similarly, it was shown methane concentrations along the jet axis fall below the flammable range at

pressure dependent distances from the point of rupture (e.g., > 120 m (for a release at 725 psia). These simulations would therefore suggest that methane will exit the jet below its flammable range. Where the rupture fails to blow away soil atop the buried pipeline or the pipeline pressure has fallen so that choked flow no longer prevails, the flow rate of the methane emerging would be such that methane would no longer be flammable at distances exceeding ~ 100 m from the point of rupture.

It was concluded that the two vapor cloud explosion scenarios modeled in the hazard analysis are appropriate: a vapor cloud explosion occurring in the turbulent jet and, possibly, an explosion within the belts of trees adjacent to the pipeline right of way.

Conclusion

The risk to IPEC is limited because IP2 is permanently defueled and IP3 is scheduled to be permanently defueled within a year. Being permanently defueled reduces the risk associated with postulated damages.

Based on the considerations discussed above, the potential for an increase in risk to the public due to the 42 inch pipeline using new models and assumptions is acceptably low on the basis of:

- there is no damage to safety related SSC or plant security from a postulated pipeline rupture;
- the effect on SSCs ITS of a postulated gas pipeline rupture would not have a significant effect on plant safety because:
  - The predicted frequency of any postulated event is below the 10^{-6}/year criterion established in Regulatory Guide 1.91 for circumstances in which conservative assumptions are made. The exceptions are the switchyard, FLEX building, met tower and Unit 3 steam generator mausoleum, which could suffer damage from thermal radiation if a failure of the pipeline is postulated to occur. These are either robust structures, have backup facilities or are within current design capabilities.
  - The potential damage to SSCs ITS have been shown to be not required for shutdown and the undamaged safety related SSCs can be credited with safely shutting down the plant.

<u>References</u>

(1) Preliminary Safety Analysis Report (PSAR) for IP3, dated August 30, 1968, ADAMS Accession No. ML093480204 (“Gas Pipeline Fire” describing the design and construction of the gas lines., operation and maintenance practices, postulated failure modes, and standoff distances provided to determine safety-related structures would not be affected).

(2) Safety Evaluation Report dated September 21, 1973, ADAMS Accession No. ML072260465.

(3) New York Power Authority letter to NRC (IPN-97-132) Regarding Indian Point 3 Nuclear Power Plant – Individual Plant Examination of External Events (IPEEE), dated September 26, 1997.

(4) Letter to M Kansler regarding “Review of Individual Plant Examination of External Events (TAC NO. M83632),”’ dated February 15, 2001

(5) Memorandum from Richard J. Laufer, Chief, Section 1, Project Directorate 1, Division of Licensing Project Management Office of Nuclear Reactor Regulation, NRC, to Peter Eselgroth, Chief, Branch 2, Division of Reactor Projects, Region 1, NRC, “Subject: Review of Natural Gas Hazards, Indian Point Nuclear Generating Unit Nos. 2 and 3 (TAC Nos. MB8090 and MB8091)” (Apr. 25, 2003) (ADAMS Accession No. ML11223A040).

(6) Berk Donaldson, Algonquin Gas Transmission, LLC letter to Ms Kimberly D Bose, FERC regarding *Algonquin Gas Transmission, LLC*, Docket No. CP14-96-000, Abbreviated Application for a Certificate of Public Convenience and Necessity and for Related Authorizations, dated February 28, 2014

(7) Timothy C O’Brien, Spectra, E mail to Charles A. Moore, Morgan Lewis& Brockius, LLP, dated July 29, 20124

(8) Spectra Energy (Algonquin Gas Transmission) memorandum to Energy regarding Response to Entergy Document entitled “Pipeline Enhancements Being Evaluated to Mitigate a Pipeline Failure” dated July 29, 2014.

(9) “Enercon Report of Liquefaction Potential Assessment” dated June 26, 2014 (IP-RPT-14-00010)

(10) Spectra Energy (Algonquin Gas Transmission) letter to Entergy Regarding Algonquin Gas Transmission, LLC, AIM Project – updated piping modifications drawing for tie-in near Bleakley Avenue, Buchanan, NY dated January 16, 2015

(11) Spectra Energy (Algonquin Gas Transmission) drawing WBS CE000030.021 “BOG TOPO Sta 273+50 to 280+50”, dated February 24, 2016

(12) NRC letter to Entergy Nuclear Operation, Inc. (Entergy), "Safety Evaluation and Supporting Analysis Regarding the Algonquin Incremental Market Project Pipeline Near the Indian Point Energy Center, Units 2 and 3," (ADAMS Accession No. ML20113F066), dated April 23, 2020.

(13) "Report of the U.S. Nuclear Regulatory Commission (NRC) Expert Evaluation Team on Concerns Pertaining to Gas Transmission Lines Near the Indian Point Nuclear Power Plant," (Adams Accession No. ML20100F635), dated April 8, 2020.

(14) Entergy Nuclear Operations, Inc. (Entergy) Letter to NRC (NL-15-30) Regarding Revised 10 C.F.R. 50.59 Safety Evaluation and Supporting Analyses Prepared in Response to the Algonquin Incremental Market Natural Gas Project," (Adams Accession No. ML15104A660 and ML15104A661), dated April 8, 2015.

(15) UK Health and Safety Executive, “Review of Vapor Cloud Explosion Incidents”, Research Report RR1113, 2017.

(16) "Consequences of a Postulated Fire and Explosion Following the Release of Natural Gas from the New AIM 42" Pipeline Taking a Southern Route Near IPEC," The Risk Research Group, dated June 8, 2020.

Is the validity of this Evaluation dependent on any other change? ☐ **Yes** ☒ **No**

If "Yes," list the required changes/submittals. The changes covered by this 50.59 Evaluation cannot be implemented without approval of the other identified changes (e.g., license amendment request). Establish an appropriate notification mechanism to ensure this action is completed.

Based on the results of this 50.59 Evaluation, does the proposed change require prior NRC approval? ☐ **Yes** ☒ **No**

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Name (print) / Signature / Company / Department / Date

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Chairman's Name (print) / Signature / Date [GGNS P-33633, P-34230, & P-34420; W3 P-151]
2000-08
OSRC Meeting #

2 Either the Preparer or Reviewer will be a current Entergy employee.
3 If required by Section 5.1[2].

II. 50.59 EVALUATION [10 CFR 50.59(c)(2)]

Does the proposed Change being evaluated represent a change to a method of evaluation ONLY? If "Yes," Questions 1 – 7 are not applicable; answer only Question 8. If "No," answer all questions below.

☐ Yes
☒ No

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. A reassessment of the 42" gas pipeline shows that the updated frequency will not change this conclusion.

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 reassessment of the 42" gas pipeline shows that the updated frequency will not change this conclusion.

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 and there were adequate alternatives where damage assumed. 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. A reassessment of the 42" gas pipeline shows that the updated frequency and consequences will not change this conclusion.

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. A reassessment of the 42" gas pipeline shows that the updated frequency and consequences will not change this conclusion.

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.

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.

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.

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. A reassessment of the 42" gas pipeline uses updated analytical models and existing NRC criteria which will not change this conclusion.

If any of the above questions is checked "Yes," obtain NRC approval prior to implementing the change by initiating a change to the Operating License in accordance with NMM Procedure EN-LI-103.