UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

May 27, 2020

Mr. John B. Rhodes, Chair
and Executive Officer
New York State Public Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

Dear Mr. Rhodes:

On behalf of the U.S. Nuclear Regulatory Commission (NRC), I am responding to letters dated March 9, 2020, and March 26, 2020, in which you and your staff expressed concerns about natural gas transmission pipelines near the Indian Point nuclear power plant in Westchester County, NY. I share your commitment to assuring public health and safety, including the protection of nuclear power facilities from natural and manmade hazards. As detailed in the enclosure that addresses the specific issues and questions raised in your letter, the NRC staff has confidence based on an updated analysis that ruptures of the pipelines near Indian Point are unlikely. However, should a rupture occur, adequate equipment would be available to shut down the plant and maintain it in a safe condition. I appreciate the ongoing collaboration among the NRC, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration, and your organization as the NRC carries out its vital oversight role of protecting public health and safety.

Please let me know if you have any questions or need additional information. You can contact me or David Skeen, Evaluation Team Lead, at (301) 287-9056.

Sincerely,

Margaret M. Doane

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Date: 2020.05.27 17:56:30 -04'00'

Margaret M. Doane
Executive Director for Operations

Docket Nos. 50-003, 50-247, 50-286

Enclosures:
1. NRC Response to Issues Raised by the New York State Public Service Commission
2. Preexisting Natural Gas Pipelines at Indian Point Site

NRC Response to Issues Raised by the New York State Public Service Commission

Overview of NRC Inspector General's Findings and NRC Response

A recent report by the NRC's Inspector General raised issues with the NRC's analysis of the potential hazard posed by the Algonquin Incremental Market (AIM) Project natural gas pipeline. The NRC took the Inspector General's findings very seriously and commissioned an independent evaluation team made up of both NRC staff and external experts, whose work was peer-reviewed by a member of the NRC's Advisory Committee on Reactor Safeguards.[1] The team completed its report on April 8, 2020, and found that Indian Point remains safe, but that several NRC processes need to be improved and Entergy (the nuclear power plant owner licensed by NRC to operate the facility) needs to revisit some overly optimistic assumptions it made in analyzing the pipeline (Agencywide Documents Access and Management System (ADAMS) Accession No. ML20100F635)). On April 9, 2020, NRC's Executive Director for Operations (EDO) forwarded the team's report to the Commission (ADAMS Accession No. ML20099F775). On April 13, 2020, the EDO tasked the NRC staff to act on each of the team's recommendations (ADAMS Accession Nos. ML20104A723 and ML20104A388).

NRC Response to Issues Raised by the New York State Public Service Commission

The New York State Public Service Commission requested that the NRC conduct a comprehensive and site-wide analysis of all pipelines near the Indian Point facilities. While the evaluation team primarily focused on the AIM pipeline efforts, there have been analyses of the two preexisting pipelines that cross the Indian Point site. These previous analyses concluded that the preexisting pipelines are unlikely to fail and that, if a rupture occurred, there are backup systems onsite at Indian Point that could safely shut down the reactors.[2] In addition, the spent fuel would remain protected, whether it is in the plant's spent fuel pools (which were also analyzed for the heat load of the spent fuel), or out of the pools and in the dry spent fuel storage casks.

While an additional site-specific analysis could address more factors such as site topography, weather, earthquake-initiated pipeline ruptures, and the capabilities of specific equipment and structures on site to withstand pipeline ruptures, the NRC staff has determined that it is unlikely that such an analysis would change the underlying findings of the prior reviews of the pipelines. Given that the risk posed by a potential pipeline rupture near Indian Point is low and is expected to decrease as the reactors transition to decommissioning within the next year, the NRC staff has concluded that conducting such an analysis is not warranted at this time.

The New York State Public Service Commission also requested that the NRC include outside experts in its reviews. The NRC evaluation team had several external participants, including a pipeline safety expert from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and several experts in natural gas modeling and fire

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[1] The ACRS was established by the Atomic Energy Act to review and advise the Commission with regard to the licensing and operation of production and utilization facilities and related safety issues, the adequacy of proposed reactor safety standards, technical and policy issues related to the licensing of evolutionary and passive plant designs, and other matters referred to it by the Commission.
[2] Indian Point Unit 2 permanently ceased operations on April 30, 2020.

risk from the Sandia National Laboratories. These experts on the team identified several areas for improvement, which are all being addressed through taskings assigned to the NRC staff by the EDO in follow up to the team's work. The PHMSA representative also connected the NRC evaluation team with members of the New York State Department of Public Service staff, who provided valuable information on the results of New York State inspections and audits, which had no open issues for the three pipelines near Indian Point. These outside perspectives strengthened the evaluation team's report.

Lastly, the New York State Public Service Commission asked that NRC respond to several questions identified in a June 22, 2018 letter to the Federal Energy Regulatory Commission (ADAMS Accession No. ML18176A367). Responses to these questions appear below.

- **Decommissioning planning:** Indian Point Unit 2 permanently shut down on April 30, 2020, and Unit 3 is expected to permanently cease operations in April 2021. During decommissioning, the NRC continues to have regulatory authority, and the licensee is bound by NRC safety regulations, including Title 10 of the *Code of Federal Regulations*, Section 50.59, "Changes, tests, and experiments." Under this provision, the Indian Point licensees have considered the pipelines in heavy work situations onsite in the past, such as when the steam generators were replaced, and the pipelines will continue to be considered as decommissioning and decontamination work proceeds on site. There is precedent for the NRC verifying that licensees of decommissioning facilities coordinate with pipeline operators to ensure continued safety of both the pipeline and the nuclear facility.[3]

- **Spent fuel pools:** Because the stored spent fuel poses a smaller risk than operating reactor units, the spent fuel pools at Indian Point were not always explicitly addressed in the analyses of the natural gas pipelines near the site. The NRC staff determined, however, that the fuel in these pools would be protected should the pipeline rupture. Both the Unit 2 and Unit 3 pools are seismic Category I reinforced concrete structures, with the fuel stored below ground, shielded by about 20 feet of water above the top of the spent fuel. The potential heat or pressure effects of a pipeline rupture would not be expected to impact the spent fuel stored in the pools. The dry fuel storage casks—also reinforced concrete structures—are further from the pipelines than the reactors and the spent fuel pools and thus would not be expected to see any effects from a potential pipeline rupture.

- **Regulatory Guide 1.91 analysis:** The Indian Point licensees were not required to evaluate the preexisting pipelines using the guidance outlined in NRC Regulatory Guide 1.91. However, the licensees have addressed the pipelines in detail over the years, from licensing applications in the 1960s, the Individual Plant Examination of External Events (IPEEE) in the 1980s and 1990s, and through an updated analysis in 2015. The 2015 analysis references Regulatory Guide 1.91 and used the overpressure criterion and exposure rates from this guidance to assess pipeline rupture effects.

- **Other ALOHA and Regulatory Guide 1.91 analyses:** Based on a review of final safety analysis reports, the NRC's evaluation team found that the licensee for one other operating nuclear power plant (Dresden Nuclear Power Station) has used ALOHA to evaluate a small natural gas pipeline, and did not identify any concerns with this use. The Dresden licensee used ALOHA and HABIT to model the transport and dispersion of natural gas from a

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[3] See p. 59 of the NRC's safety evaluation report on the Hematite fuel facility decommissioning plan (ADAMS Accession No. ML112101630) and pp. 7-8 of the associated submittal from Westinghouse (ADAMS Accession No. ML110270200).

pipeline rupture toward the plant and found that safety-related equipment was well outside the safe standoff distance. Safety-related structures at Dresden are about 600 feet from the 8-inch pipeline, which is much greater than the Department of Transportation's potential impact radius criterion of under 50 feet. This licensee also concluded through a risk analysis that the estimated frequency of an explosion damaging safety-related equipment is an order of magnitude lower than the frequency in Regulatory Guide 1.91 that would be designated as an "actionable level." The staff did not identify any issues with the licensee's conclusions based on ALOHA.

The evaluation team also found that several applicants for new nuclear power plant licenses or permits used ALOHA to model natural gas cloud formation, dispersion, and flammability. In these cases, the pipelines were thousands of feet or more away from the plant, approximately 10 times greater than the potential impact radii. The staff did not identify any issues with the applicants' conclusions based on the use of ALOHA.

- **Security evaluation:** In 2003, NRC staff recommended that the NRC's security organization evaluate certain aspects of the preexisting pipelines.[4] While this analysis was not immediately conducted given post-September 11 security work ongoing at the time, the NRC staff did conduct a security review in 2011, producing a safeguards-level report and identifying several follow-up questions that were provided to security inspectors for use in baseline inspections of the site security plan. A 2008 analysis of security implications of the preexisting pipelines is summarized in Appendix A to the evaluation team's report.

- **Seismic risk:** In its IPEEE in the late 1990s, the Indian Point licensees considered the potential for earthquakes to damage the preexisting natural gas pipelines and the related consequences. Such events were generally found to have a frequency below the examination's screening criteria and were thus not reviewed in further detail. These analyses are summarized on pp. 60-62 of the evaluation team's report. The licensee also revisited the seismic hazard at Indian Point as part of the response following the Fukushima Dai-ichi nuclear accident, including conducting walkdowns of site features, reevaluating the site's seismic hazard, and completing an expedited seismic evaluation that resulted in modifications to some plant equipment, such as tanks.[5] In more recent analyses, both the NRC and Entergy have postulated a pipeline rupture—regardless of the cause—and considered the effects that such a rupture could have onsite. The evaluation team's risk analysis did not explicitly consider an earthquake initiator, because adding the unlikely event of an earthquake-induced rupture would not significantly change the calculated failure frequency for the natural gas transmission pipelines. In addition, the mitigating equipment onsite is designed and protected against earthquakes.

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[4] See pp. 64-65 of the evaluation team's report, ADAMS Accession No. ML20100F635.
[5] https://www.nrc.gov/reactors/operating/ops-experience/japan/plants/ip3.html

Preexisting Natural Gas Pipelines at Indian Point Site, May 1, 2020

Background

As discussed in Appendix A to the evaluation team's report (Agencywide Documents Access and Management System (ADAMS) Accession No. ML20100F635), 26-inch and 30-inch natural gas transmission pipelines have run underneath the Indian Point site since before the current reactors were licensed to operate. The 26-inch line was installed in 1952, and the 30-inch line was installed in 1965. The licensee for Indian Point Unit 3, which is closest to the pipelines, provided information to the U.S. Atomic Energy Commission (AEC) at the construction permit stage to justify that it was safe to build a nuclear reactor at that location. In approving the construction and operation of Unit 3, the AEC did not raise concerns regarding the pipelines.

In the 1980s, responding to external concerns about Indian Point, both the U.S. Nuclear Regulatory Commission (NRC) and the Indian Point licensees conducted risk assessments of potential accidents that could occur at Indian Point, including an assessment of the hazards posed by the pipelines. The NRC hearings included consideration of the risks from the pipeline, and no conditions on this matter were imposed with respect to Indian Point's further operation. The licensees reassessed the pipelines in the 1990s as part of the Individual Plant Examination for External Events, and also in response to concerns raised in 2008 and 2015. In all cases, the analyses found that there could be impacts from pipeline ruptures on the plant, but that backup equipment could keep the plant safe, and worst-case scenarios were generally not credible.

The evaluation team's recent consideration of the 42-inch Algonquin Incremental Market (AIM) pipeline, which was approved for construction near the Indian Point site in 2015, did not reveal new information about the 26-inch and 30-inch pipelines that would lead the agency to revisit its prior reviews and conclusions. To the contrary, through its coordination with the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), the evaluation team obtained information regarding the ongoing inspection and assessment of all three pipelines, as well as PHSMA data on pipeline accident phenomena, that give the NRC confidence in the safety of Indian Point. While the preexisting 26-inch and 30-inch pipelines are much closer to Indian Point than the AIM pipeline, many of the conclusions drawn by the expert evaluation team about the AIM pipeline also apply to the preexisting lines.

This enclosure summarizes prior analyses and newly obtained information that support the NRC evaluation team's continued conclusion that the Indian Point site can maintain safe operations near the preexisting pipelines.

Pipeline Rupture and Blowdown Likelihood

Design and Construction

West of the Indian Point site, three pipelines cross under the Hudson River and connect at a location on the east bank of the river. Two pipelines cross the Indian Point site, then traverse underground to where they connect with the AIM pipeline east of the site.

- The older, 26-inch line (which is 24 inches in diameter when it crosses the river) is maintained in an idle status by Enbridge (the gas line operator) at a natural gas pressure of 30 to 40 psig and remains isolated from the main pipelines. Although Enbridge does not have any plans to return this line to service, it could be returned to operational status by flipping spectacle blinds at valve sites on either side of the river, if necessary. As such, it is being maintained according to the requirements of 49 CFR Part 192. It has a maximum allowable operating pressure (MAOP) of 674 psig, resulting in a 466-foot potential impact radius using the Department of Transportation equation. This radius, which would only be a concern if the pipeline were flowing gas, includes the security owner-controlled area (SOCA) fence and a primary water storage tank for Unit 3 within its boundary. Other safety-related equipment is outside this radius. Based on drawings obtained from Enbridge, about 30 percent of the pipeline closest to Indian Point has been replaced since its original installation in 1954. The pipe segments are all either 5LX-52 or 5LX-65 pipe with at least 52,000 psi yield strength.

- The 30-inch line, which is slightly further away from the Indian Point units than the 26-inch line, is currently in operation along with the AIM pipeline. It has a MAOP of 750 psig, resulting in a potential impact radius of 567 feet. This radius includes the SOCA fence, certain water tanks, the 138 kV electrical switchyard at Unit 3, and the FLEX building. Other safety-related equipment, such as the Unit 3 emergency diesel generator building, is outside this radius. The pipe segments are all 5LX-52, 5LX-60, or 5LX-65 piping with at least 52,000 psi yield strength.

- The third pipeline crossing under the Hudson River at this location is an out-of-service 24-inch auxiliary line, made from 5LX-52 and 5LX-42 pipe. It ends at the connection area on the east bank of the river near Indian Point and does not cross the Indian Point site. According to Enbridge, it is cut and capped, disconnected from gas service, with 30 to 40 psig of gas pressure inside.

As noted by the piping types listed above, the lines that remain in service are seamless steel pipes (5L designation) with a strength of at least 52,000 psi (X-52 and greater designations). These pipelines were pressure-tested as part of their construction (both initial and on replacement of pipe segments), subjecting the pipeline to a pressure at least 1.5 times MAOP for at least 8 hours. Also, they have a cathodic protection system designed to reduce corrosion.

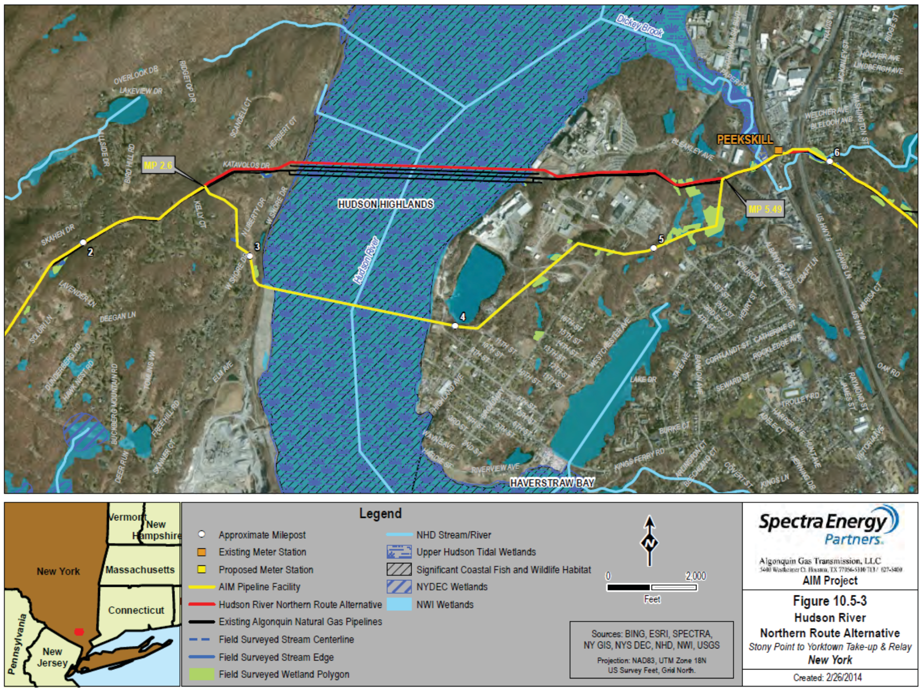

Figure 1. Figure 10.5-3 from the AIM application,[1] showing the AIM pipeline in yellow and the three preexisting pipelines crossing the Hudson River in black.

Ongoing Evaluation

Both the 26- and 30-inch pipelines are designated by Enbridge as being in a "high consequence area" as they pass the Indian Point site. As discussed in the evaluation team's report, this means that the integrity management requirements in 49 CFR Part 192, Subpart O, apply. Enbridge's integrity management program provides for ongoing risk assessment and inspection of these pipelines.

In accordance with its integrity management program, Enbridge conducts inline inspections on these pipelines to monitor corrosion and deformation. The last inspection of the 26-inch line was in 2016, and the 30-inch line was inspected in two stages in 2014 and 2017; the next inspections are planned at approximately 7-year intervals. Through its inspections, Enbridge identified only one crack-like indication on the pipelines near Indian Point (a dent and area of corrosion near a weld in the 26-inch line). Enbridge completed a timely replacement of this section of pipe, which was outside the high consequence area. The evaluation team's PHMSA member reviewed the most recent inspection results for all three pipelines provided by Enbridge and did not identify issues of concern.

New York State's Department of Public Service inspects these pipelines, as well as the operator's integrity management programs, under an agreement with PHMSA. The state inspectors are not aware of any portions of the preexisting pipelines that do not meet PHMSA construction, operation, or inspection requirements, nor of any safety inspection or enforcement issues with the preexisting pipelines.

[1] Resource Report 10, https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13473930.

Failure Frequency

As discussed in Appendix A and Appendix D to the evaluation team's report, the team developed failure frequency estimates for the 42-inch AIM pipeline based on PHMSA's failure data for certain large (greater than 20-inch diameter) or higher-grade (Class 2, 3, and 4) onshore gas transmission pipelines. The estimated rupture frequency of about 2 x 10^{-5} per year per mile could similarly be applied to the 26- and 30-inch pipelines. The team's peer reviewer mentioned several factors that could further reduce the likelihood of rupture for the 42-inch AIM pipeline (see Appendix E to the evaluation team's report), but the team took no credit for these factors in its risk assessment.

Furthermore, the peer reviewer considered all of the threats to the AIM pipeline, which include both material- or corrosion-related failures and failures caused by outside forces or excavation damage, and how mitigating these threats could reduce the failure frequency. The gas operator's pipeline integrity management program, including the periodic inspections noted above, would be expected to mitigate the risk associated with material- and corrosion-related failures, which together make up about 37 percent of gas transmission failures based on PHMSA data from March 2020. Failures caused by outside forces and excavation damage, which contribute about 28 percent of gas transmission pipeline failures based on this PHMSA data, are unlikely given that the licensee controls all excavation work on its property and that the pipeline area is clearly marked onsite.

Isolation of a Pipeline Rupture

As discussed in the evaluation team's report, the severity of pipeline rupture consequences, such as explosions or fire, depends on the volume of gas that flows out of a ruptured pipe. This volume is a function of how quickly the ruptured section of pipeline can be isolated and the length of the isolated section.

Enbridge constantly monitors the 30-inch pipeline from its Houston gas control center, as it does for the AIM pipeline. The Supervisory Control and Data Acquisition system tracks pressures and other information that would indicate a rupture. Controllers are trained to isolate the ruptured section.

There is a remote-control valve[2] on the 30-inch pipeline east of Indian Point[3] (the location noted in the evaluation team's report, 5.6 miles downstream from the closest valve on the 42-inch AIM pipeline). This valve can be closed by the system controllers in Houston. Similar to the AIM pipeline, Enbridge estimates that gas controllers can diagnose a rupture and close the remote-controlled valve within about 8 minutes. New York State inspectors witnessed remote valve closures on the preexisting pipelines in 2018 and 2019. The inspectors did not observe any issues, and the valves took about 30 seconds to close.

Enbridge noted that a rupture on the 30-inch line near Indian Point could be quickly isolated by closing the remote-controlled valve and performing a fast stop of the Stony Point compressor station across the Hudson River. This would result in approximately 11 miles of pipeline being

[2] Pipeline operators are not required to have automatic or remote-controlled valves on these types of natural gas pipelines under current Department of Transportation regulations. In February 2020, PHMSA published a proposed rule (https://www.regulations.gov/document?D=PHMSA-2013-0255-0005) to consider such requirements for new or fully replaced onshore pipelines.
[3] This valve would also isolate the 26-inch line, which joins the 30-inch line upstream of this valve, if the 26-inch line were in service (which it is not).

isolated. In contrast to the AIM pipeline analyses that referenced a 3-minute valve closure and a specific length of isolated pipeline, Entergy's 2008 and 2015 analyses of the preexisting pipelines did not assume any particular time or distance for isolating a postulated rupture. Entergy stated that the most significant effects occurred at the time of release (which is consistent with PHMSA accident experience), referencing analyses showing that release rate and heat flux decreased over time from initial peak values. Therefore, unless Entergy's review of the assumptions made in its external hazards analysis of the AIM pipeline results in a reanalysis of the hazard, no updates are needed to hazard analyses for the preexisting pipelines.

Pipeline Rupture Consequences

The safety-related equipment at Indian Point is located more than twice the potential impact radius away from the 42-inch AIM pipeline, so the evaluation team did not need to pursue detailed analysis of the consequences of AIM pipeline ruptures on specific plant equipment. Because of the preexisting pipelines' proximity to Indian Point, however, this rule of thumb cannot be applied in this case. The Unit 3 containment building is situated at about 1.5 times the potential impact radius for the 30-inch pipeline, based on its closest approach, and some safety-related equipment and structures are even closer.

As discussed in Section 2.5 of the evaluation team's report, recent PHMSA accident data for pipeline ruptures indicates that despite the "rule of thumb" of 1.5 to 2 times the potential impact radius, accident damage has only been seen within about 1.1 times the potential impact radius. Figure 2 shows the 30-inch pipeline in blue, with potential impact circles in orange, as well as yellow circles with radii 1.1 times the potential impact radius. Three circles are shown—one on the left centering on an above-ground location near Indian Point that was evaluated in prior licensee analyses, one on the right centering at a change in piping class location where a difference in pipe material could be expected, and one in the middle that is the closest approach of the pipeline to the plant.

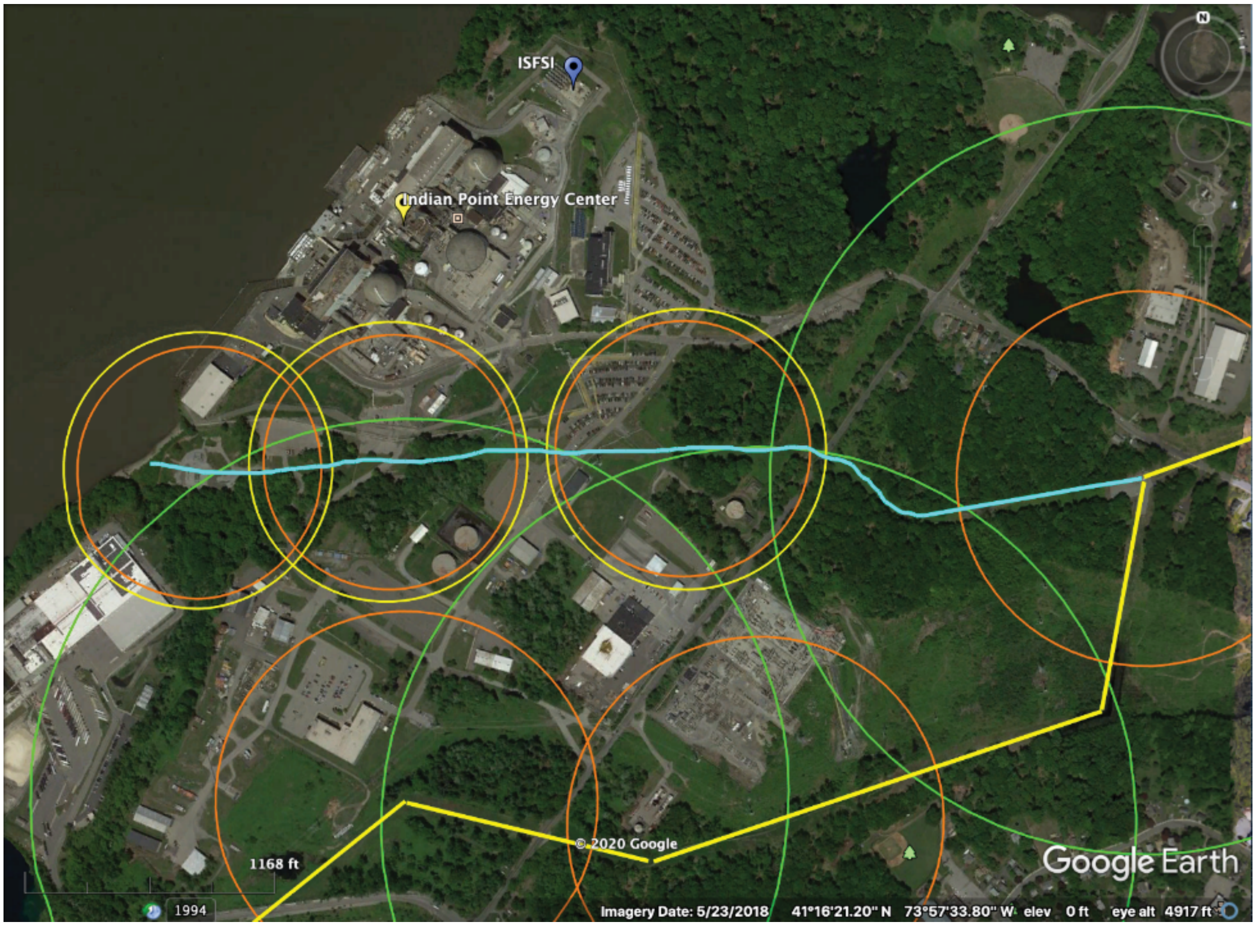

Figure 2. Locations of 30- and 26-inch preexisting pipelines (in blue) and 42-inch AIM pipeline (in yellow). Circles show approximate extent of potential impact radius (in orange), as well as 1.1 times that radius (in yellow near the preexisting pipelines) and 2 times that radius (in green near the AIM pipeline).

Given this proximity, licensees and the NRC have conducted detailed analyses of postulated pipeline ruptures since the earliest days of Indian Point. These analyses are summarized in Appendix A to the evaluation team's report. The most recent analyses, using updated software and current equipment layouts, were conducted by Entergy in 2008 and 2015.[4]

Entergy Analysis

In 2008 and 2015, Entergy evaluated the consequence of failures of the pipelines at an above-ground location. Entergy found that important structures, systems, and components (SSCs) were all outside the range of damaging heat flux or overpressurization if a pipe rupture occurred at this location. The security plan already accounted for the loss of certain SSCs that could be damaged in such an incident. The only important structure inside this circle was the FLEX building, shown in Figure 3, which is at the edge of the potential impact circle. This building is a reinforced concrete structure that Entergy said was designed for tornado winds and missiles and "unlikely to suffer damage." The FLEX equipment would be needed only in an extreme accident scenario that necessitated backup power, water supplies, or other equipment stored there.

[4] See pp. 62-64 of the evaluation team's report.

Figure 3. Image of the thick concrete walls of the FLEX building at Indian Point. This building had previously been used for low-level radioactive waste storage.

In 2015, Entergy evaluated the effects of a rupture of the 30-inch pipeline at its closest approach to SSCs at Indian Point (along the whole length of pipeline). The analysis showed that there could be overpressurization above 1 psi out to about 900 feet from the pipeline and heat flux above 12.6 kW/m^2 out to about 830 feet. These distances did not account for elevation effects and shielding, which could reduce heat flux or pressures. As shown in Figure 4, the main safety-related area of the plant is about 30 feet downhill from the pipeline location, which would make it less likely that rising smoke or natural gas would reach these locations.

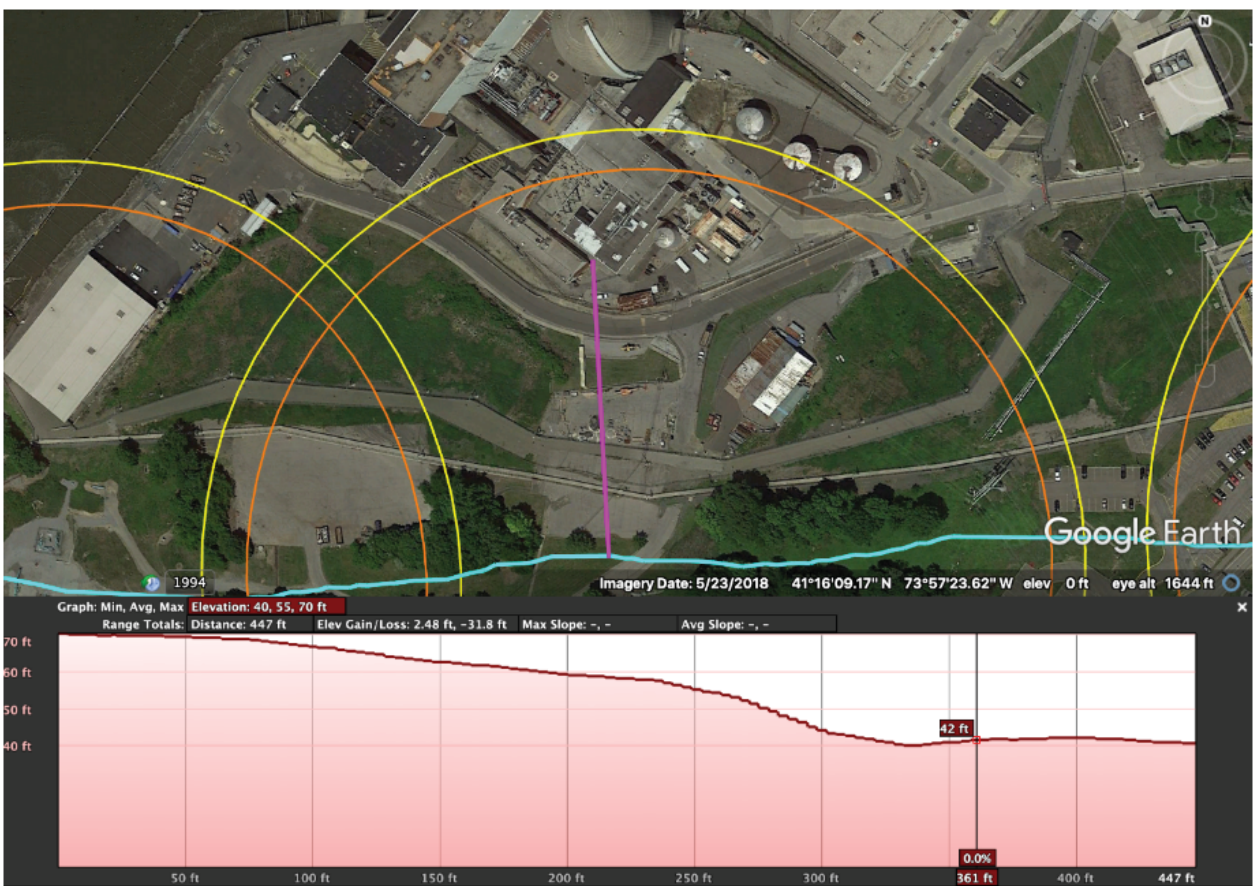

Figure 4. Approximate elevation difference between preexisting pipeline location (blue line) and Unit 3 structures.

Entergy considered certain thresholds for impacts on Indian Point SSCs within this approximate 900-foot radius:

- At a heat flux of less than 12.6 kW/m^2 heat flux, all SSCs would remain available. Above 12.6 kW/m^2, external instruments (such as tank levels) would be damaged, though the water-filled tanks themselves could withstand a high heat flux of 23-60 kW/m^2 and still be functional. Safety-related or hardened concrete structures could withstand a heat flux of up to 31.5 kW/m^2.
- At an overpressure of less than 1.0 psi, all SSCs would remain available. Structures that had been evaluated for tornado effects could withstand an overpressure of 3 psi.

In general, Entergy found that equipment that might be damaged would have undamaged backups, would be backup equipment itself, or would be otherwise not essential. For example, a city water tank could be damaged by a rupture near its location, but a rupture at that location would not be expected to affect safety-related sources of water that could be aligned to serve the same purposes. The most significant damage could be to power sources, such as the emergency diesel generators (which were assumed to fail if there was high heat flux at their air intakes) or offsite power lines. Entergy described the various cross-tie and backup capabilities that could provide power for a safe shutdown of the units. These capabilities include:

- **Large diesel generators at both units referred to as "Appendix R diesels,"** designed for station blackout and fire protection (10 CFR Part 50, Appendix R) requirements. They are designed to provide power for shutting down their designated units after a fire or a loss of all alternating current power. A procedure exists for the operators to align either unit's Appendix R diesel to the Unit 3 480 V safety buses. The Unit 3 Appendix R diesel, as well as the autotransformer for the Unit 2 Appendix R diesel, are over 1000 feet away from the preexisting pipelines, on the opposite side of containment. They are shielded by the large reinforced concrete containment building and other large buildings, as well as behind the rock face of the hill that is cut away on the east side of the containment building. The Unit 2 Appendix R diesel itself is in the portion of the Unit 2 turbine building that was originally associated with Unit 1, beyond the Unit 3 Appendix R diesel and over 1100 feet away from the preexisting pipelines. Figure 5 indicates the locations of these diesel generators.

- **A 138 kV crosstie underground between Unit 2 and Unit 3**. A procedure exists for operators to restore power if the offsite power connection and the emergency diesel generators for Unit 3 were disabled after a pipeline rupture. Entergy noted the associated above-ground bus and duct work in the 138 kV switchyard, but stated the connections were considered available based on the elevation (e.g., as shown in Figure 4) and shielding from heat flux and overpressure.

- **A 13.8 kV underground offsite power feeder** from the main Buchanan switchyard. A procedure exists for the operators to restore power from this source to the 6900 V buses in the turbine building.

Additional detail on these power sources can be found in the Indian Point Unit 3 updated final safety analysis report.[5]

[5] Chapter 8 (ADAMS Accession No. ML17299A209) and Chapter 8 drawings (ADAMS Accession No. ML17299A210).

Entergy concluded that an unlikely pipeline rupture would not prevent the safe shutdown of the plant, and that the original licensing basis was met. Entergy also observed that updated analyses such as those it conducted in 2008 and 2015 were not required at the time of original licensing (before Regulatory Guide 1.91 existed or addressed pipelines).

NRC Inspection

After Entergy conducted its analysis in 2015, the NRC conducted an onsite inspection to independently assess the vulnerability of and potential impact to Indian Point's SSCs following a postulated rupture of the preexisting pipeline, and to verify that the units would be able to maintain safe shutdown capability. The inspector physically inspected the pipeline right-of-way on Entergy's property to assess right-of-way markers, vegetation and plant life, potential odors, line-of-sight and approximate distances to plant SSCs, and the condition of the surrounding terrain (including any nearby excavations or construction activities). The NRC inspector observed portions of ongoing gas pipeline maintenance activities by Spectra (the gas operator at the time) personnel on Entergy property at the above-ground portion of the preexisting pipelines, and discussed gas pipeline preventive and corrective maintenance, including safety precautions, with Spectra personnel at the job site.

The inspector also conducted inspections inside the protected area to assess potential vulnerabilities to Unit 2 and Unit 3 SSCs and reviewed line-of-sight projections to the gas pipelines from within the protected area at each potential SSC of interest. SSCs evaluated included city water tank, the Unit 2 emergency diesel generator building, both units' refueling water storage tanks, the air intake louvers for the Unit 3 diesel generators, the Unit 3 primary water storage tank, the Unit 3 condensate storage tank, the Unit 3 fire water storage tanks, the Unit 3 fuel storage building and backup spent fuel pool cooling system skid, the outage support building rooftop, the Unit 3 138 kV switchyard, the Unit 3 transformer yard, the Appendix R diesel generators and transformers, and the exterior of the Unit 3 auxiliary boiler feedwater pump house.

Because Unit 3 is closer to the gas pipeline, the inspector performed a detailed onsite review of the applicable procedures developed to respond to design basis electrical transients to ensure that electrical power supplies were available to place and maintain Unit 3 in a safe shutdown condition given the worst-case postulated scenarios related to rupture of the pipeline. The inspector independently verified that procedures were readily available to operators in the Unit 3 control room and discussed procedure use, awareness, quality, and training with Unit 3 operators. In addition, the inspector walked down the Unit 3 control room instrumentation panels and discussed available indications of electrical power sources and voltages with control room operators. The NRC inspector concluded that necessary equipment would remain available and procedures are in place to ensure that safe shutdown capability is maintained.

Spent Fuel Considerations

Entergy's assessments focused mainly on safe shutdown of the reactors, not on the much lower risk posed by stored spent fuel onsite. The dry storage location (noted as independent spent fuel storage installation (ISFSI) in Figure 2) is very far away from all three pipelines. The spent fuel pool for Unit 3 is closer to the preexisting pipeline. If there were a pipeline rupture at the closest point to the spent fuel pool, the fuel building would be outside the potential impact radius for the 30-inch pipeline but just within the radius that (in known accidents) might see effects from fire or explosion. Entergy calculated a heat flux of 14 kW/m^2 and an overpressure of under 2 psi at this location. Entergy noted that the pool itself is reinforced concrete and designed to be tornado proof and withstand tornado missiles. The calculated heat flux could damage the siding, but Entergy stated that the building had been evaluated for such damage and the spent fuel pool would not be negatively affected. Therefore, Entergy had no fuel safety concerns. The spent fuel pool for Unit 2 is on the other side of Unit 3 (away from the pipeline) and therefore would be protected from the effects of overpressure and heat flux.

Gas Leak Concerns

Concerns have also been raised about pipeline leaks (not ruptures) that could transport natural gas to the Indian Point site and cause issues inside plant structures. It is possible that the above-ground connections located southwest of Unit 3 could leak without rupturing. If so, the buoyant nature of such leaking gas (as distinct from the rupture dynamics that could cause heavier-than-air gas clouds described in the evaluation team's report), combined with the local terrain, make it highly unlikely that flammable amounts of natural gas would reach important structures onsite. Figure 5 shows the terrain across a path from the above-ground portion of the preexisting pipelines to the Indian Point site, including an approximately 15-foot hill followed by about a 35-foot drop to site grade.

At Unit 3, the closer unit to the preexisting pipelines, air intakes for important structures and equipment are situated such that natural gas would not be expected to enter and cause harm. For example, the control room fresh air intakes are in the east wall of the control building (see Figure 5), opposite from the pipelines, protected by concrete walls and an electrical tunnel above. The 480 V electrical switchgear room, another important location, is on the lowest (below-grade) level of the control building, and its ventilation comes from the turbine building, which is further away from the pipelines. Given the highly unlikely nature of onsite consequences considering these terrain and onsite configurations, further detailed review of these issues was not conducted.

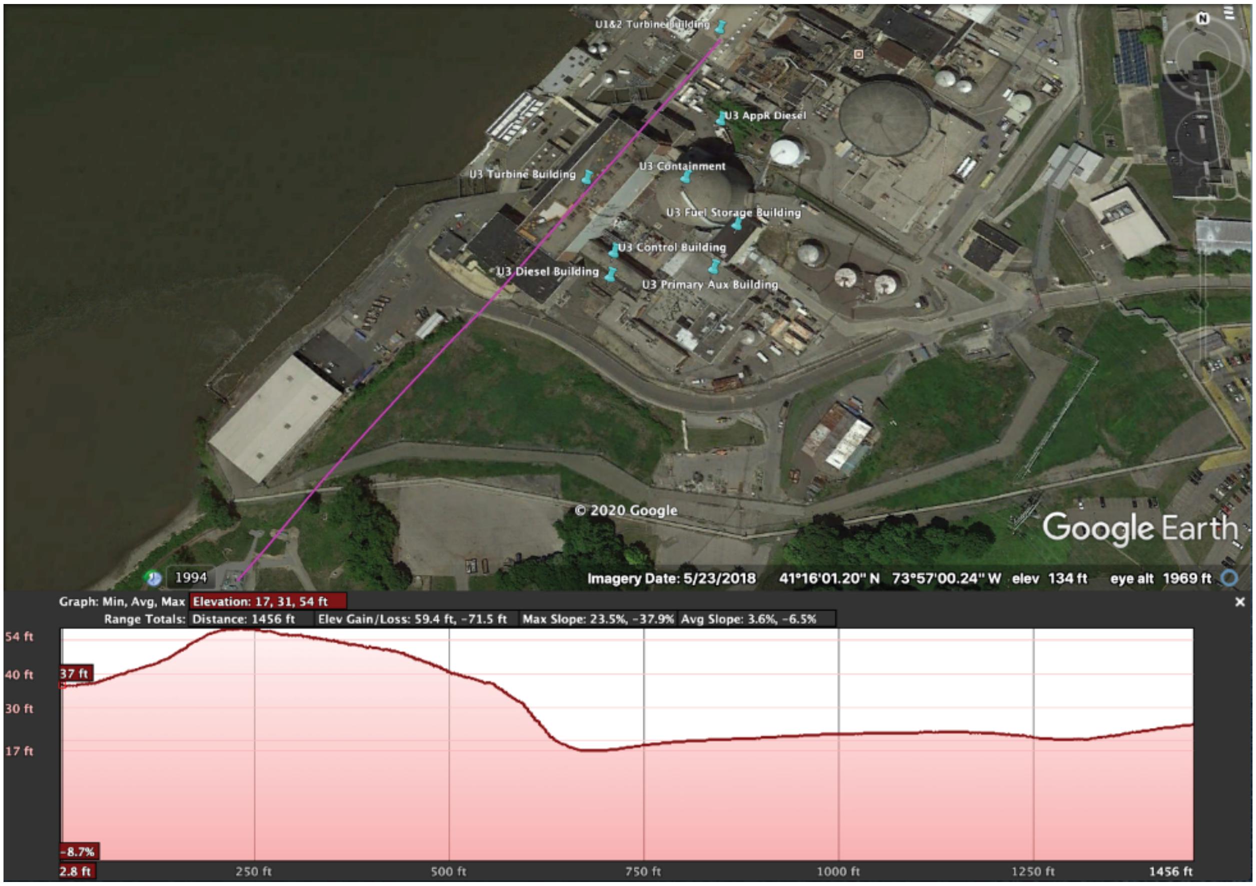

Figure 5. Terrain between above-ground location of preexisting pipelines and the Indian Point site.

Conclusions

The preexisting pipelines near Indian Point were considered at initial licensing, as well as in several reanalyses discussed in Appendix A to the evaluation team's report and in this document. In all cases, the licensee, AEC, or NRC found that the pipelines did not pose a significant safety hazard to the safe shutdown of the Indian Point units or to the stored spent fuel.

Under NRC regulations, new requirements or staff positions (such as a regulatory guide) cannot be imposed on a reactor licensee unless the provisions of 10 CFR 50.109, "Backfitting," are met. The NRC will always require backfitting if it is necessary to ensure that the facility provides adequate protection to the health and safety of the public. Given the multiple evaluations of these issues at initial licensing (and beyond) and the safe operation of Indian Point for many decades, the NRC has found that there is adequate protection of the health and safety of the public and is not pursuing backfitting on these grounds. Backfitting can also be considered if the change would provide a substantial safety enhancement for which the costs are justified by the increased protection. Given the low likelihood of a pipeline rupture, the results of previous analyses of the potential hazards posed by the gas pipelines, and the transition of Indian Point into an even lower-risk status during decommissioning, it is not likely that a substantial safety enhancement could be afforded through backfitting. The NRC is not pursuing such action at this time.