Paul M. Blanch PE
Energy Consultant

April 7, 2020

Mr. Mitch Behm
Acting Inspector General
Office of Inspector General
U.S. Department of Transportation
1200 New Jersey Ave SE, 7th Floor
Washington, DC 20590

Subject: PHMSA failed to require compliance with 49 U.S.C. 60101 et seq. and 49 CFR 192.917, 935, 615, and 616

Dear Mr. Behm:

I am a registered Professional Engineer (PE) with more than 50 years of engineering experience. As a PE with considerable nuclear experience, I was retained as a consultant for the New York State Attorney General (AG). My role was to identify any safety issues with the Indian Point nuclear power plants in Buchanan, New York. My effort was related to the proposed 20-year life extension of the operating license for these plants.

During my review of external events (10 CFR 100.21) I identified two interstate gas transmission pipelines, 26" and 30" in diameter, on the Indian Point site. These pipelines were installed in the 1950s. Further investigation revealed that these pipelines are within the jurisdiction of PHMSA and regulated by the provisions of 49 CFR 192 and 49 U.S.C. 60101 et seq.

Over the course of several years I attempted to obtain information from PHMSA through numerous FOIA requests and other communications regarding risk assessments conducted for these pipelines as required by 49 CFR 192.917 and 935. I am also aware that several New York State residents made similar filings and requests. To date, we, as well as the New York State AG's office, were unable to obtain any regulatory compliant risk assessment from PHMSA, Entergy, the Indian Point licensee, or the Nuclear Regulatory Commission (NRC).

On August 21, 2014, Entergy submitted a letter to the NRC providing its analysis of the risks to the nuclear plant for the new 42” diameter, high pressure Algonquin Incremental Market (“AIM”) gas transmission pipeline proposed to also be located at Indian Point in close proximity to critical safety infrastructure (Docket No. CP14-96-000). At that point, I was no longer under contract with the AG’s office.

On December 16, 2015[1] I wrote to Ms. Marie Therese Dominguez, Administrator, U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. In that letter I stated that the proposed 42” diameter Algonquin pipeline did not comply with the provisions of 49 CFR 192.917, 934 and provisions for public awareness and emergency response.

From that date until February 2020, I had several detailed communications with PHMSA and the NRC. I am providing copies of many of those communications as an attachment with this letter. Also during that period, I and other colleagues in our communications with PHMSA, have repeatedly warned that a valid risk assessment has not been performed. PHMSA knows that the analyses by the NRC and Entergy, falsely represented as a “risk assessment” and used as the basis of approval for the siting of the AIM pipeline at Indian Point, utilized unacceptable models and false data, yielding inaccurate results. Yet, with this knowledge, fully supported by numerous experts’ sworn affidavits warning of the catastrophic consequences, PHMSA continues to allow gas to flow in the AIM pipeline.

The following are examples of some of the evasive and misleading responses contained in the February 18, 2016 letter from Marie Therese Dominquez, a PHMSA official:

> “PHMSA and our state pipeline safety program partners take pipeline safety very seriously and work to ensure that natural gas transmission pipelines, such as the AIM Project, are constructed, operated, and maintained in accordance with the federal pipeline safety regulations, particularly Title 49 of the Code of Federal Regulations (C.F.R.), Part 192. PHMSA maintains a rigorous and comprehensive program that includes pipeline operator inspections and enforcement, in addition to setting pipeline safety standards.”

[1] Enclosed has the incorrect date that should be 2015 vs 2014

"…After startup of a pipeline, NY DPS personnel will continue inspections of the operation and maintenance of all jurisdictional pipelines in New York, to verify sustained compliance with the federal pipeline safety regulations. If inspections reveal violations, PHMSA will take enforcement action."

"In your letter, you requested a copy of the risk assessment required under 49 C.F.R. 192.935. PHMSA does not maintain copies of the risk assessments performed by pipeline operators, though they are a part of the documentation that is examined during an inspection."

"Your letter also expressed concern that certain parts of the federal pipeline safety regulations - namely, emergency plans, public awareness programs, and damage prevention programs— were not addressed in any of the documentation filed by FERC or the Nuclear Regulatory Commission. Under federal pipeline safety regulations, operators are required to have operation and maintenance manuals, as well as emergency preparedness plans, damage prevention, and public awareness programs. These plans all must be in place when a pipeline goes into service. Pipeline operators are also required to regularly patrol and perform leak surveys once the pipeline becomes operational. Before a new segment of pipeline can be operated, it must be tested in accordance with Title 49 C.F.R, Subpart J. Spectra's plans, programs, procedures, and records, along with their pipeline facilities, are all subject to inspection by PHMSA and its state agents to ensure that the pipeline facilities are constructed, operated, and maintained in accordance with federal pipeline safety regulations".

PHMSA has never claimed that a risk assessment was conducted or reviewed by the Secretary as required by 49 USC 601 et seq., nor has any evidence of a valid, federally compliant risk assessment been provided. PHMSA has clearly and intentionally avoided answering the concluding paragraph of my December 16, 2015 letter to PHMSA. This paragraph states:

"Would it be possible for PHMSA to provide a copy of the risk assessment along with written confirmation that the AIM pipeline and existing pipelines are in total compliance with DOT Regulations specified in 49 CFR 192 as stated by FERC in its EIS?"

The AIM pipeline was constructed in 2016 and became operational in January 2017. Currently, the 42" diameter AIM pipeline and the idle 26" diameter pipeline at Indian Point are damaged and in need of repair. Yet, PHMSA has not acted, but instead continues to allow the gas to flow through this 42" pipeline that is so damaged that Enbridge planned to purge it in March and re-activate the old damaged 26" pipeline so it could conduct the repair work; all of this in the absence of a federally compliant risk assessment.

The Algonquin Incremental Market Project Final Environmental Impact Statement (FEIS) Algonquin Gas Transmission, LLC Docket No. CP14-96-000 FERC/EIS-0254F Volume I implies compliance with 49 CFR 192 and 49 USC Chapter 601. Full compliance with these requirements is clearly mandated and is a prerequisite to any approvals as stated in Section 1.2.4 below:

> *"PHMSA is the federal agency responsible for administering the national regulatory program to ensure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline under 49 USC Chapter 601. PHMSA's Office of Pipeline Safety (OPS) develops regulations and other approaches to risk management to ensure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. The OPS is responsible for ensuring that Algonquin's proposed facilities are designed, constructed, and operated in compliance with the safety standards that the agency has established for natural gas pipeline facilities."*
>
> *And*
>
> *"Additionally, as discussed further in section 4.12.1, PHMSA is mandated to provide pipeline safety under 49 USC 601*[2]*. PHMSA administers the*

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2 49 U.S. Code § 60109
(1) Requirement. —
Each operator of a gas pipeline facility shall conduct an analysis of the risks to each facility of the operator located in an area identified pursuant to subsection (a)(1) and defined in chapter 192 of title 49, Code of Federal Regulations, including any subsequent modifications, and shall adopt and implement a written integrity management program for such facility to reduce the risks.
And
(9) Review of integrity management programs.—
(A)Review of programs. —
(i) In general. —
The Secretary shall review a risk analysis and integrity management program under paragraph (1) and record the results of that review for use in the next review of an operator's program.

national regulatory program to ensure the safe transportation of natural gas and other hazardous materials by pipeline. PHMSA develops safety regulations and other approaches to risk management that ensure safety in the design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Many of the regulations are written as performance standards that set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve safety."

There are nine additional references to compliance with 49 CFR 192, however, no exceptions to the safety requirements to 49 CFR 192 are discussed within the FEIS.

Based on the above, it appears that PHMSA is avoiding addressing the risk assessments and the "Public Awareness" regulation 49 CFR 192.616 resulting in an increased risk to the residents in the vicinity of the pipelines discussed in the FEIS. Moreover, it fails to assess or comply with Public Awareness requirements stemming from the extensive radioactive damage that would result from a potential pipeline rupture at Indian Point. Furthermore, PHMSA failed to make the "risk assessment" available to the NRC, Entergy, local elected officials, the general public and New York State, which incurred significant expenditures.

49 USC 60109(c)(9)(C) and (10) also clearly designates a safety role for the State of New York by clearly stating:

"(C)Transmittal of programs to state authorities. —
The Secretary ***shall*** *provide a copy of each risk analysis and integrity management program reviewed by the Secretary under this paragraph to any appropriate State authority with which the Secretary has entered into an agreement under section 60106.*

(10)STATE REVIEW OF INTEGRITY MANAGEMENT PLANS.—
A State authority that enters into an agreement pursuant to section 60106, permitting the State authority to review the risk analysis and integrity management program pursuant to paragraph (9), may provide the Secretary with a written assessment of the risk analysis and integrity management program, make recommendations, as appropriate, to address safety concerns not adequately addressed by the operator's risk analysis or integrity management program, and submit documentation explaining the State-proposed revisions. The Secretary shall consider carefully

the State's proposals and work in consultation with the States and operators to address safety concerns."

On February 13, 2020, the Office of the Inspector General (OIG) of the NRC issued a scathing report, Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant Case No. 16-024 that confirms the serious flaws, falsehoods and egregious errors repeatedly outlined by leading nuclear and pipeline experts regarding the so called "risk analyses" performed by the NRC and Entergy. These invalid analyses misrepresented the actual catastrophic risk posed by the 42" diameter, high pressure AIM pipeline and the old Algonquin pipelines adjacent to reactor unit #3 at the Indian Point power plants, yet served as the basis for the approval of the AIM pipeline by the Federal Energy Regulatory Commission (FERC). Indeed, the OIG report stated that the analyses "used backward engineering for a desired result." Taken together, the experts, federal, state, and local officials, emergency responders as well as the public remain gravely concerned about a pipeline explosion damaging critical infrastructure and triggering a spent fuel fire resulting in massive radioactive releases that would affect the Eastern Seaboard.

On March 20, 2020, I participated in a transcribed teleconference with the NRC and PHMSA convened by David Skeen who heads up the NRC investigative team formed at the direction of the NRC's Executive Director for Operations (EDO). The investigative team is required to provide a response within 45 days, by April 9, 2020. PHMSA was formally represented by Mr. Steven Nanny. The purpose of this teleconference was to discuss the agency responsible for conducting a valid risk assessment that could be used by the NRC to evaluate the risk to the Indian Point nuclear facility posed by the three existing Algonquin gas transmission pipelines. Mr. Nanny was not familiar with the PHMSA regulations and could only suggest some type of pressure testing. Consistent with my testimonies, sworn affidavits and other supporting documents I stated in this teleconference that a risk assessment of all the pipelines at Indian Point must be performed in accordance with PHMSA regulations.

I continue to maintain that prior to allowing gas to flow or continue to flow in the pipelines at Indian Point, PHMSA and industry must conduct a valid risk assessment as described in 49 CFR 192.917 and 934. These regulations were developed by both PHMSA and the industry and incorporated into 49 CFR 192 after formal rulemaking and comment resolution.

I have made every effort to obtain a copy of the risk assessment and some type of certification from PHMSA or FERC that the gas pipelines are in compliance with the regulations. My efforts are well documented and can be supplied to your office. They include the following actions and documentation:

- Formally petitioned the NRC under 10 CFR 2.206
- Conducted presentation to FERC with follow-up documentation
- Obtained CEII clearance from FERC for compliance information
- Meeting with NRC's Chairman and Commissioners
- Meetings with Governor Cuomo's office
- Meetings with Congresswoman Lowey
- Meetings with State of NY Legislators
- FOIA requests to PHMSA, NRC and FERC
- Formal/documented communication with FERC and PHMSA administrators
- Meeting with the NRC's Office of Investigation
- Documented telephone conversations with PHMSA's Karen Gentile
- Meetings with and formal investigation by the NRC's Office of the Inspector General
- Telephone meeting with the NRC and PHMSA on March 20, 2021. Summary enclosed.

Despite all of these efforts, PHMSA fails to comply with its most basic pipeline safety requirements, thus concealing the true risk to the other Federal and State agencies also responsible for public safety.

Your immediate investigation is requested to protect millions of people across New York State and the Eastern Seaboard from suffering dire consequences as a result of PHMSA's gross mishandling of this entire matter. The catastrophic danger combined with the lack of compliance with required 49 CFR 192 and 49 U.S.C. 601 warrants immediate action by PHMSA to conduct this risk assessment and inform all potentially impacted persons of the risk and determine if this threat is acceptable.

Your office must consider a recommendation for immediate Corrective Action Order by PHMSA mandated pursuant to 49 U.S.C. 60112[3], "to protect the public,

3 (a)General Authority.—After notice and an opportunity for a hearing, the Secretary of Transportation may decide that a pipeline facility is hazardous if the Secretary decides that—
(1) operation of the facility is or would be hazardous to life, property, or the environment;

property, and the environment from potential hazards" and thus warrants the shutdown and purge of the pipelines until these corrective measures are fully addressed and rectified. The continued operation of the Algonquin pipelines at the Indian Point facility without immediate corrective actions may "likely result in serious harm to life, property and the environment." [4]

I am enclosing Attachment 1 that includes many of my communications with PHMSA, FERC, the NRC along with the recent NRC Inspector General's inquiry related to this issue. Please contact me for any additional documentation.

I formally request your office investigate the above concerns and determine if PHMSA reviewed and verified compliance with 49 CFR 192 and 49 U.S.C. 601 et seq. for all of the gas pipelines in the vicinity of Indian Point. Your office may also want to consider the potential extent of compliance or non-compliance with these very clear regulations.

Sincerely,

Paul M. Blanch

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West Hartford, CT 06117
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860-922-3119

Cc:
Governor Cuomo
Senator Schumer
Senator Gillibrand
Congresswoman Lowey
Congressman Engel
Congressman Maloney

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or the facility is or would be constructed or operated, or a component of the facility is or would be constructed or operated, with equipment, material, or a technique that the Secretary decides is hazardous to life, property, or the environment.

[4] Section 60112 provides for the issuance of a Corrective Action Order without prior opportunity for notice and hearing upon a finding that failure to issue the Order expeditiously will likely result in serious harm to life, property or the environment. In such cases, an opportunity for a hearing will be provided as soon as practicable after the issuance of the Order.

State Senator Harckham
State Senator Mayer
State Senator Stewart-Cousins
State Senator Leroy Comrie
Assemblywoman Galef
Assemblyman Buchwald
Assemblywoman Paulin
Assemblyman Otis
Mr. John Rhodes, Chair NYS DPS
Mr. Tom Congdon, Executive Deputy, NYS DPS
Mr. John Sipos, NYS DPS
Mr. Thomas DiNapoli, NYS Comptroller
Mr. Lemuel Srolovic, Bureau Chief, Environmental Protection Bureau, Office of NYS AG
Mr. Jeremy Magliaro, Office of NYS AG
PHMSA Administrator
Ms. Karen Gentile, PHMSA
Ms. Kristine Svinicki, Chair NRC
Ms. Margaret Doane, NRC EDO
Mr. David Lee, NRC OIG
Mr. David Skeen, NRC
FERC Administrator
Professor David Dorfman

Attachment 1

Communications with PHMSA, FERC, the NRC and recent NRC Inspector General's inquiry.

Attachment 1

Paul M. Blanch
Energy Consultant

December 16, 2014

Ms. Marie Therese Dominguez, Administrator
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
East Building, 2nd Floor
Mail Stop: E27-300
1200 New Jersey Ave., SE
Washington, DC 20590

phmsa.administrator@dot.gov

Dear Ms. Dominguez:

Subject: Risk Assessment for AIM Pipeline and Indian Point, FERC Docket #CP14-96

The NRC Chairman and NRC Staff continue to publically state it performed a confirmatory risk analysis that concludes that in the event of a rupture of the new 42-inch diameter high pressure Spectra gas pipeline, the Indian Point plants could safely be shut down. The NRC partially predicated this statement that the project is in compliance with DOT and PHMSA regulations as defined in 49 CFR 192 and its own analysis based on false information[1] provided to the NRC by Entergy.

I am writing to you to specifically call attention to the fact that I have reviewed Department of Transportation and the Pipeline Hazardous Materials Safety Administration regulations and that 49 CFR 192.935 requires a risk assessment and 49 CFR 192.917 requires the operator to identify potential threats to pipeline integrity and use the threat identification in its integrity program.

49 CFR 192.935 clearly requires a risk assessment by stating:

> *§192.935 What additional preventive and mitigative measures must an operator take?*
>
> *General requirements. An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917) An operator must conduct, in accordance with one of the* ***risk assessment*** ***[emphasis added]*** *approaches in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 5, a* ***risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety [emphasis added].*** *Such additional measures include, but are not limited to, installing Automatic Shut-off Valves*

[1] Letter dated August 21, 2014 from Entergy and Blanch 10 CFR 2.206 petition filed with the NRC on October 15, 2014.

or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

ASME/ANSI B31.8S requires that the risk assessment consider 22 causes that represent potential threats to pipeline integrity, including vandalism. The Spectra AIM pipeline crosses public roads and is clearly marked as required by 49 CFR 192, making them easily identifiable and vulnerable to vandalism.

The final EIS issued by FERC on January 23, 2015 for the AIM Project states:

5.1.12 Reliability and Safety

The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained ***in accordance with or to exceed the PHMSA Minimum Federal Safety Standards in 49 CFR 192[emphasis added].*** *The regulations are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures. The PHMSA specifies material selection and qualification; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion.*

Enclosed is my response to a letter from the Nuclear Regulatory Commission (NRC) dated November 6, 2015. This letter responds to previous communication between the NRC and myself. In this letter the NRC confirms[2] there is no compliance with Part 192.615 for Emergency Preparedness and compliance with Parts 507, 614, 616, 705, 706, 903 has not been addressed in any of the documentation filed by FERC or the NRC

Would it be possible for PHMSA to provide a copy of the risk assessment along with written confirmation that the AIM pipeline and existing pipelines are in total compliance with DOT Regulations specified in 49 CFR 192 as stated by FERC in its EIS?

Sincerely,

Paul M. Blanch

Paul M. Blanch
135 Hyde Rd.
West Hartford, CT 06117
860-236-0326

[2] For example, in response to a direct question the NRC confirmed there are no procedures or training to respond to a gas line event on the Indian Point property.

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

Administrator

1200 New Jersey Ave., S.E.
Washington, DC 20590

February 18, 2016

Mr. Paul M. Blanch
Energy Consultant
135 Hyde Road
West Hartford, CT 06117

Dear Mr Blanch:

Thank you for your e-mail message of December 17, 2015, along with your attached letter, regarding the Algonquin Incremental Market (AIM) Project proposed by Algonquin Gas Transmission, LLC (Algonquin), a subsidiary of Spectra Energy Corp (Spectra). We appreciate your concern for the area's population and the surrounding environment. The mission of the Pipeline and Hazardous Materials Safety Administration (PHMSA) is to protect people and the environment from the risks of hazardous materials transportation. PHMSA administers the national pipeline safety program, which regulates 2.6 million miles of interstate and intrastate pipelines to ensure that pipeline facilities are constructed, operated, and maintained in compliance with Federal pipeline safety regulations.

PHMSA and our state pipeline safety program partners take pipeline safety very seriously and work to ensure that natural gas transmission pipelines, such as the AIM Project, are constructed, operated, and maintained in accordance with the federal pipeline safety regulations, particularly Title 49 of the Code of Federal Regulations (C.F.R.), Part 192. PHMSA maintains a rigorous and comprehensive program that includes pipeline operator inspections and enforcement, in addition to setting pipeline safety standards.

PHMSA works closely with the state pipeline safety programs to carry out our mission. PHMSA works with the New York Department of Public Service (NY DPS) to regulate interstate natural gas pipelines in New York. NY DPS performs inspections on interstate natural gas pipelines in New York, including Spectra's Algonquin pipeline facilities. If any violations of federal regulations are identified, PHMSA will take enforcement action.

Both PHMSA and NY DPS personnel are engaged in the AIM Project. In March 2015, the Federal Energy Regulatory Commission (FERC) issued a Certificate of Public Convenience and Necessity for the AIM Project. This certificate authorizes Spectra to construct and operate the project's facilities in accordance with the conditions set forth by FERC. NY DPS maintains regulatory oversight over new pipeline construction activities in New York. After startup of a pipeline, NY DPS personnel will continue inspections of the operation and maintenance of all jurisdictional pipelines in New York, to verify sustained compliance with the federal pipeline safety regulations. If inspections reveal violations, PHMSA will take enforcement action.

In your letter, you requested a copy of the risk assessment required under 49 C.F.R. § 192.935. PHMSA does not maintain copies of the risk assessments performed by pipeline operators, though they are part of the documentation that is examined during an inspection.

Your letter also expressed concern that certain parts of the federal pipeline safety regulations– namely, emergency plans, public awareness programs, and damage prevention programs— were not addressed in any of the documentation filed by FERC or the Nuclear Regulatory Commission. Under federal pipeline safety regulations, operators are required to have operation and maintenance manuals, as well as emergency preparedness plans, damage prevention, and public awareness programs. These plans all must be in place when a pipeline goes into service. Pipeline operators are also required to regularly patrol and perform leak surveys once the pipeline becomes operational. Before a new segment of pipeline can be operated, it must be tested in accordance with Title 49 C.F.R. Part 192, Subpart J. Spectra's plans, programs, procedures, and records, along with their pipeline facilities, are all subject to inspection by PHMSA and its state agents to ensure that the pipeline facilities are constructed, operated, and maintained in accordance with federal pipeline safety regulations.

I hope that this information has been helpful. Again, thank you for your concern and your attention regarding pipeline safety. If we can be of further assistance, please do not hesitate to contact Karen Gentile, one of our Eastern Region Community Assistance and Technical Services representatives, at 609-433-6650, or via email at Karen.Gentile@dot.gov.

Sincerely,

Marie Therese Dominguez

Marie Therese Dominguez

cc: Kevin Speicher, NYSDPS

Paul M. Blanch
Energy Consultant

11 March 2016

Ms. Marie Therese Dominguez, Administrator
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
East Building, 2nd Floor
Mail Stop: E27-300
1200 New Jersey Ave., SE
Washington, DC 20590

phmsa.administrator@dot.gov

Dear Ms. Dominguez:

On February 18, 2016 I received a letter from you responding to my letter of December 17, 2015. My letter was to seek assurance that the AIM pipeline will be in compliance with all PHMSA's regulations as outlined in 49 CFR 192.

The Governor of New York has recently directed his agencies to perform a risk assessment as required by 49 CFR 192.917, 935 and ASME ANSI B31.8S. This appears to be a duplicative effort, as it is clearly required by PHMSA regulations and a copy should be available to PHMSA and to members of the public.

49 CFR 192.935 clearly states:

> *"An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ ANSI B31.8S (incorporated by reference, see § 192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety."*

Your letter continues:

> *"Under federal pipeline safety regulations, operators are required to have operation and maintenance manuals, as well as emergency preparedness plans, damage prevention, and public awareness programs."*

The NRC has confirmed to me that the operator of Indian Point (Entergy) does not have any emergency preparedness plans or damage protection program for either the new AIM line or the existing lines that are located within 400 feet of vital structures.

Additionally, ASME/ ANSI B31.8S (codified by 49 CFR 192) requires the consideration of damage from vandalism, which must also be addressed in the risk assessment.

I am well aware of what the regulations clearly require however my concern is that Spectra may not be in compliance with these very clear regulations. I am seeking assurance from PHMSA that all of the regulations of 49 CFR 192 are being met.

The entire AIM project was predicated on compliance with these regulations as stated in the FERC EIS dated January 23, 2015. I believe it is PHMSA's responsibility to demonstrate compliance to assure the public of the safety of the new pipeline in the close proximity to the Indian Point nuclear power plants.

Please provide a copy of the required risk assessment along with certification of regulatory compliance.

I also request a clear delineation of responsibilities of PHMSA and the State of New York. The PHMSA website indicates that the State of New York is responsible for assuring compliance with 49 CFR 192 whereas the State believes its responsibilities are limited to inspections only.

I am also copying your FOIA branch to formally request a copy of the risk assessment along with certification that PHMSA has reviewed the AIM project for compliance with 49 CFR 192 and that the design and construction will adhere to these requirements.

Sincerely,

Paul M. Blanch

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U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

Administrator

1200 New Jersey Ave., S.E.
Washington, DC 20590

February 18, 2016

Mr. Paul M. Blanch
Energy Consultant
135 Hyde Road
West Hartford, CT 06117

Dear Mr Blanch:

Thank you for your e-mail message of December 17, 2015, along with your attached letter, regarding the Algonquin Incremental Market (AIM) Project proposed by Algonquin Gas Transmission, LLC (Algonquin), a subsidiary of Spectra Energy Corp (Spectra). We appreciate your concern for the area's population and the surrounding environment. The mission of the Pipeline and Hazardous Materials Safety Administration (PHMSA) is to protect people and the environment from the risks of hazardous materials transportation. PHMSA administers the national pipeline safety program, which regulates 2.6 million miles of interstate and intrastate pipelines to ensure that pipeline facilities are constructed, operated, and maintained in compliance with Federal pipeline safety regulations.

PHMSA and our state pipeline safety program partners take pipeline safety very seriously and work to ensure that natural gas transmission pipelines, such as the AIM Project, are constructed, operated, and maintained in accordance with the federal pipeline safety regulations, particularly Title 49 of the Code of Federal Regulations (C.F.R.), Part 192. PHMSA maintains a rigorous and comprehensive program that includes pipeline operator inspections and enforcement, in addition to setting pipeline safety standards.

PHMSA works closely with the state pipeline safety programs to carry out our mission. PHMSA works with the New York Department of Public Service (NY DPS) to regulate interstate natural gas pipelines in New York. NY DPS performs inspections on interstate natural gas pipelines in New York, including Spectra's Algonquin pipeline facilities. If any violations of federal regulations are identified, PHMSA will take enforcement action.

Both PHMSA and NY DPS personnel are engaged in the AIM Project. In March 2015, the Federal Energy Regulatory Commission (FERC) issued a Certificate of Public Convenience and Necessity for the AIM Project. This certificate authorizes Spectra to construct and operate the project's facilities in accordance with the conditions set forth by FERC. NY DPS maintains regulatory oversight over new pipeline construction activities in New York. After startup of a pipeline, NY DPS personnel will continue inspections of the operation and maintenance of all jurisdictional pipelines in New York, to verify sustained compliance with the federal pipeline safety regulations. If inspections reveal violations, PHMSA will take enforcement action.

In your letter, you requested a copy of the risk assessment required under 49 C.F.R. § 192.935. PHMSA does not maintain copies of the risk assessments performed by pipeline operators, though they are part of the documentation that is examined during an inspection.

Your letter also expressed concern that certain parts of the federal pipeline safety regulations–namely, emergency plans, public awareness programs, and damage prevention programs—were not addressed in any of the documentation filed by FERC or the Nuclear Regulatory Commission. Under federal pipeline safety regulations, operators are required to have operation and maintenance manuals, as well as emergency preparedness plans, damage prevention, and public awareness programs. These plans all must be in place when a pipeline goes into service. Pipeline operators are also required to regularly patrol and perform leak surveys once the pipeline becomes operational. Before a new segment of pipeline can be operated, it must be tested in accordance with Title 49 C.F.R. Part 192, Subpart J. Spectra's plans, programs, procedures, and records, along with their pipeline facilities, are all subject to inspection by PHMSA and its state agents to ensure that the pipeline facilities are constructed, operated, and maintained in accordance with federal pipeline safety regulations.

I hope that this information has been helpful. Again, thank you for your concern and your attention regarding pipeline safety. If we can be of further assistance, please do not hesitate to contact Karen Gentile, one of our Eastern Region Community Assistance and Technical Services representatives, at 609-433-6650, or via email at Karen.Gentile@dot.gov.

Sincerely,

Marie Therese Dominguez

Marie Therese Dominguez

cc: Kevin Speicher, NYSDPS

Paul M. Blanch
Energy Consultant

7 April 2016

Karen Gentile
Community Assistance & Technical Services (CATS) Manager
U.S. Department of Transportation
Pipeline & Hazardous Materials Safety Administration (PHMSA)

Dear Ms. Gentile

Karen.Gentile@dot.gov

This is in response to your email to me dated March 31, 2016 that stated:

> *"Mr. Blanch,*
>
> *Jurisdictional pipeline operators must follow the federal pipeline safety regulations contained in Title 49 Code of Federal Regulations (CFR) Parts 190-199 as well as incorporated by reference (IBR) documents or portions there-of as required by the federal pipeline safety regulations. In carrying out the federal natural gas pipeline safety regulations, particularly Title 49 CFR Part 192, pipeline operators are required to have integrity management programs in accordance with Subpart O – Gas Transmission Pipeline Integrity Management. Pipeline operators must follow the requirements of Subpart O as well as ASME/ANSI B31.8S (IBR, see 192.7) and its appendices, where specified. An operator may also follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between Subpart O and ASME/ANSI B31.8S, the requirements in Subpart O control.*
>
> *Title 49 CFR Part 192 does not require PHMSA or state pipeline safety programs do to risk assessments.*
>
> *The federal pipeline safety regulations require operators to perform risk assessments in accordance the regulations.*
>
> *As I mentioned in our telephone discussion and my follow-up e-mail message to you on March 28th ,there is information on PHMSA's website related gas transmission integrity management.*
>
> *Included in the FAQs section of this website, there is information on time period requirements for integrity management requirements for newly installed pipeline facilities.*
>
> *PHMSA does not issue permits or certifications of compliance. An interstate natural gas pipeline operator's plans, programs, procedures, and records, along with their pipeline facilities, are all subject to inspection by interstate agent and federal regulators to ensure that the pipeline facilities are constructed, operated, and maintained in accordance with the federal pipeline safety regulations. If issues or problems related to non-compliance are found, PHMSA issues compliance actions to achieve and maintain pipeline safety and to insure the pipeline is in compliance with regulations.*
>
> *I hope that this additional information helps address your concerns. Should you have any additional questions, please do not hesitate to contact me.*
>
> *Best regards,*
> *Karen"*

Your statement "*Title 49 CFR Part 192 does not require PHMSA or state pipeline safety programs do to risk assessments*." does not respond to the central issue. I am fully aware this is not the responsibility of PHMSA but it is the responsibility of PHMSA to assure regulations are met. The IRS isn't responsible for filing my taxes but is responsible for assuring compliance with IRS rules and regulations. The IRS requires my signature stating "Under penalties of perjury, I declare that I have examined this return and accompanying schedules and statements, and to the best of my knowledge and belief, they are true, correct, and complete." I would expect nothing less from PHMSA where 20 Million residents are at risk.

How does PHMSA assure compliance when for example, PHMSA, under a FOIA request could not produce or indicate it has reviewed the risk analysis as required by PHMSA's regulations. There are numerous other regulations where PHMSA has indicated compliance but has no documentation.

You continue to state: *"The federal pipeline safety regulations require operators to perform risk assessments in accordance the regulations."* If this is a Regulatory requirement, what assurance does the public have that this requirement has been met? The Nuclear Regulatory Commission reviews, retains and makes its risk assessment available to the public, in spite of its deficiencies.

The EIS approved by FERC states the following about PHMSA's role in this project:

> *"The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained to meet or exceed the Pipeline and Hazardous Materials Safety Administration's Minimum Federal Safety Standards in 49 CFR 192 and other applicable federal and state regulations. The regulations include specifications for material selection and qualifications; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion. By designing and operating the Project in accordance with the applicable standards, the Project would not result in significant increased public safety risk."*

49 CFR 192 clearly requires that a risk assessment meeting the requirements of ASME B31.8 be conducted, yet it appears this has not been done as confirmed by responses to FOIA request to PHMSA and FERC.

In light of the above discussion I request PHMSA respond to the following questions:

- Has a risk assessment been conducted by Spectra for the AIM project?
- How does PHMSA assure compliance with its regulations?
- Has Spectra provided information to PHMSA that it is in compliance with all provisions of 49 CFR 192 including ASME B31.8s? (If so, please provide a copy)
- Has PHMSA reviewed the Spectra compliance documentation for the AIM project?
- Has PHMSA reviewed all potential HCA's as discussed in the FERC EIS?

- Who approved the above quoted FERC statement that formed the basis for the approval of the AIM project? Please provide a copy of this approval provided to FERC.
- Does PHMSA plan to coordinate Spectra's risk assessment to the recent risk assessment ordered by the NY Governor?
- ASME B31.8s requires that vandalism (Terrorism). Has this been coordinated with Homeland Security?
- Has a risk assessment been conducted by the operator of the existing pipelines crossing the Indian Point property?

Again, all I am requesting is that PHMSA, according to its website, is "responsible for regulating and ensuring the safe and secure movement of hazardous materials to industry and consumers by all modes of transportation, including pipelines" and not just assuring the proper regulations are in place.

Please provide me some assurance or documentation that supports the words clearly stated in the EIS issued by FERC that clearly state:

> *"The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained to meet or exceed the Pipeline and Hazardous Materials Safety Administration's Minimum Federal Safety Standards in 49 CFR 192 and other applicable federal and state regulations."*

Your prompt response is appreciated.

Paul M. Blanch

Paul M. Blanch
135 Hyde Rd.
West Hartford, CT 06117
860-236-0326

cc: Governor Cuomo
Senator Schumer
Senator Gillibrand
Senator Markey
Congresswoman Lowey
Congressman Engel
Assemblywoman Galef
FERC Chairman Norman Bay
Marie Therese Dominguez, PHMSA Administrator
Kevin Speicher NYDPS
Mr. John Sipos NYS AG

Paul M. Blanch
Energy Consultant

18 April 2016

Ms. Marie Therese Dominguez, Administrator
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
East Building, 2nd Floor
Mail Stop: E27-300
1200 New Jersey Ave., SE
Washington, DC 2059

phmsa.administrator@dot.gov

Dear Ms. Dominguez

This letter serves to confirm my understanding of our telephone conversation of April 12, 2016. Participants in this call were myself, Ms. Karen Gentile of PHMSA, Ms. Susan Van Dolsen, Ms. Amy Rosmarin and Ms. Emily M. Loughlin, Communications Coordinator, Office of New York Assemblywoman Sandy Galef.

PHMSA states: "Our mission is to protect people and the environment by advancing the safe transportation of energy and other hazardous materials that are essential to our daily lives. To do this, we establish national policy, set and enforce standards, educate, and conduct research to prevent incidents. We also prepare the public and first responders to reduce consequences if an incident does occur."

PHMSA also states: "Achieving regulatory compliance with the pipeline safety regulations is the central goal of the Office of Pipeline Safety's (OPS) enforcement efforts."

To accomplish this mission we expect PHMSA, as an absolute minimum, to enforce existing regulations. Anything less is unacceptable. We are requesting nothing more than regulatory compliance.

According to Ms. Gentile's explanation, PHMSA is not required to verify compliance by the pipeline operator (Spectra) with the any portions of 49 CFR 192 at this time and compliance is not required to be demonstrated until up to one year after the AIM project goes into operation. This was her interpretation of 49 CFR 192.905(c)[1]

We disagree with her interpretation of 49 CFR 192.905 and are very concerned that PHMSA has not enforced the regulation and has no intention of doing so. The regulation requires the applicant to conduct a risk assessment in addition to the other parts of 49 CFR 192. According to the Federal Energy Regulatory Commission's (FERC) Final Environmental Impact Statement (FEIS) released January 23, 2015, all High Concentration Areas (HCAs) for the Algonquin Incremental Market (AIM) project have been identified; therefore some type of risk assessment[2] should have been completed. The only permitted exception would

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1 § 192.905 How does an operator identify a high consequence area?

(a) General. To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in § 192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See appendix E.I. for guidance on identifying high consequence areas.)

(b)(1) Identified sites. An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.
(2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.
(i) Visible marking (e.g., a sign); or
(ii) The site is licensed or registered by a Federal, State, or local government agency; or
(iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

(c) Newly identified areas. When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in § 192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

2 ASME B31.8s Page 5
2.3.3 Risk Assessment.

In this step, the data assembled from the previous step are used to conduct a risk assessment of the pipeline system or segments. Through the integrated evaluation of the information and data collected in the previous step, the risk assessment process identifies the location-specific events and/ or conditions that could lead to a pipeline failure, and provides an understanding of the likelihood and consequences (see para. 3) of an event. The output of a risk assessment should include the nature and location of the most significant risks to the pipeline. Under the prescriptive approach, available data are compared to prescribed criteria (see Nonmandatory Appendix A). Risk assessments are required in order to rank the segments for integrity assessments. The performance- based approach relies on detailed risk assessments.

There are a variety of risk assessment methods that can be applied based on the available data and the nature of the threats. The operator should tailor the method to meet the needs of the system. An initial screening risk assessment can be beneficial in terms of focusing resources on the most important areas to be addressed and where additional data may be of value.

Paragraph 5 provides details on the criteria selection for the prescriptive approach and risk assessment for the performance-based be for "NEWLY IDENTIFIED AREAS" for existing pipelines. Ms. Gentile evaded responding to direct questioning when asked if PHMSA had reviewed the Spectra risk assessment.

The FEIS states that the AIM pipeline would be designed, constructed and operated in accordance with the Nuclear Regulatory Commission (NRC) Regulations as stated in 10 CFR 50 and the PHMSA Regulations as stated in 49 CFR 192. PHMSA was listed as one of the cooperating agencies producing this FEIS. We acknowledge that PHMSA is not a siting agency nor is it a permitting authority on this project; however, PHMSA plays an integral role in FERC's approval of the AIM project. Without PHMSA's approval of regulatory compliance, the authorization of this project would not have been granted. The issuance of FERC's Certificate of Public Convenience and Necessity on March 3, 2015 was predicated on compliance with PHMSA regulations. The FEIS states:

> *"The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained to meet or exceed the Pipeline and Hazardous Materials Safety Administration's Minimum Federal Safety Standards in 49 CFR 192 and other applicable federal and state regulations. The regulations include specifications for material selection and qualifications; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion. By designing and operating the Project in accordance with the applicable standards, the Project would not result in significant increased public safety risk."*

During our conversation, Ms. Gentile repeatedly and unequivocally stated to us that the regulations requiring the operator (Spectra) to conduct a risk assessment do not apply until one year after the pipeline goes into operation, citing 49 CFR 192.905(c). We strongly disagree. The regulations clearly state that a risk assessment is required; the only permitted exception being that for "NEWLY IDENTIFIED AREAS" for existing pipelines.

The NRC regulating nuclear facilities and other "High Risk" industries and other regulators do not wait until after construction of a facility before assessing for risk and compliance. Personally, I would not fly on an airplane knowing it had not been designed and tested in accordance with FAA Regulations, and like PHMSA is an agency under the Department of Transportation.

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approach. The results of this step enable the operator to prioritize the pipeline segments for appropriate actions that will be defined in the integrity management plan. Nonmandatory Appendix A provides the steps to be followed for a prescriptive program.

There is an entire section of the FEIS dedicated to Algonquin's compliance with PHMSA regulation Part 192 on pages 4-259 and 4-262-266 including the location of designated High Consequence Areas (HCA) (Table 4.12-1-2 on p. 4-259) that Algonquin identified according to PHMSA's criteria as part of the FERC process.

The designations of these HCAs are critical to design, construction and maintenance of this new high-pressure AIM natural gas pipeline. PHMSA's citing Part 192.905(c) about HCAs does not apply to the situation. Section (c) refers to only to NEWLY IDENTIFIED HCAs.

We believe that PHMSA's statement about the applicability of the regulations is intentionally misleading to an elected official and members of the public and places millions of persons to an unknown risk.

Subpart O of 49 CFR 192 is part of the regulations and we expect PHMSA to demonstrate how the AIM project complies with these regulations. Please provide some type of assurance that PHMSA has performed its regulatory responsibility that the project is in total compliance with 49 CFR 192 as stated in FERC's FEIS.

We will not accept the word "can inspect" in lieu of verified, certified or inspected for regulatory compliance.

PHMSA's written and teleconference responses indicate that PHMSA assumes compliance with 49 CFR 192 without any documentation and/or inspection. This is exactly the same regulatory philosophy that caused the three reactor meltdowns at Fukushima, Japan. The regulator was told and blindly accepted the assurances from TEPCO that the sea wall was designed to protect the plants in the event of a tsunami. The result was catastrophic due to this regulatory failure. We will not repeat this type of event at Indian Point where the consequences will be orders of magnitude greater.

In a previous email of March 31, 2016 PHMSA referred us to Frequently Asked Questions (FAQs). These questions and responses are not regulations and only reflect the opinions of unnamed individuals and corporations and appear to be intended to address Integrity Management programs for existing lines. It appears Ms. Gentile selected only those FAQs that supported PHMSA's position, however the following is a sample of FAQs that are contrary to PHMSA's opinions.

- *FAQ-26. When must baseline assessments be completed? [05/19/2004]*

All baseline integrity assessments must be completed by December 17, 2012. Assessments for 50% of the pipeline mileage in HCAs must be completed by December 17, 2007. The highest risk segments should be prioritized for early assessment.

- *FAQ-14. When must covered pipeline segments subject to the rule be identified? [05/19/2004]*

  All High Consequence Areas (HCAs) must be identified as part of an operator's initial integrity management framework, which must be completed by December 17, 2004. OPS will expect to see the operator's process for identifying HCAs described in the initial framework.

- *FAQ-72. When must the Baseline Assessment Plan and Framework be completed? [05/20/2004]*

  The Baseline Assessment Plan and the Framework both must be prepared by December 17, 2004.

- *FAQ-20. When must newly identified HCAs be included in the program?*

  Over time, new HCAs may be identified, such as when population distributions change or new sites that are occupied by 20 or more persons are identified. Operators must consider such changes to determine whether new HCAs have been created. A newly-identified HCA must be incorporated into the integrity management program (including the baseline assessment plan) within one year of its identification.

The above responses to FAQs appear to be in direct conflict with Ms. Gentile's personal interpretation of the applicability of 49 CFR 192 to the AIM project.

Presently there are two gas transmission lines in operation within 400 feet of the Indian Point reactor control room. These lines have been in operation since the mid 1950's. Please provide us with assurance that these lines are in compliance with 49 CFR 192 with emphasis on § 192.907.[3]

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[3] § 192.907 What must an operator do to implement this subpart?

Furthermore, the FEIS states (page 4-260) that Algonquin must conduct a risk assessment each year.

> *"Each year Algonquin performs a detailed risk analysis for its* ***entire pipeline system*** ***[Emphasis Added]*** *to identify potential integrity threats to the pipeline and potential consequences in the event of a pipeline failure. This risk analysis, which allows Algonquin to prioritize integrity management activities, such as integrity assessments and additional prevention measures. The risk assessment is performed by subject matter experts using modern risk management tools and techniques to assure the risk assessment process provides an accurate determination of pipeline risks."*

We were not able to obtain any satisfactory answers to our concerns during the teleconference so we request written responses from PHMSA to the following specific issues:

1. Has a risk assessment been performed for the AIM project?
2. Has the risk assessment been performed for the existing lines as stated in the FEIS?
3. Has PHMSA reviewed these risk assessments?
4. Can PHMSA provide us with a copy of the risk assessments and its review?
5. Has PHMSA assured that the AIM project is in total compliance with 49 CFR 192?
6. PHMSA clearly stated to us that the regulations of 49 CFR 192 would not be verified until one year after the AIM project becomes operational. Is this still

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(a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

(b) *Implementation Standards.* In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (incorporated by reference, *see*§ 192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME/ANSI B31.8S, the requirements in this subpart control.

PHMSA's position?

7. What documentation is available to support the PHMSA position as stated in the FEIS?

8. Ms. Gentile stated that PHMSA doesn't keep operator's records. Where are PHMSA's records demonstrating that Spectra's annual risk assessment complied with PHMSA regulations as stated in the FEIS?

9. Why does PHMSA insist that the risk assessment would be required within one year of operation of the pipeline when the HCAs were identified? The HCAs for this project were identified in the FEIS and the regulations require a risk assessment to determine the HCAs.

10. A FOIA[4] request for a copy of the required risk assessment was filed and the response was that PHMSA did not have a copy. Has the risk assessment been completed and reviewed by PHMSA?

11. What assurance does the public have that "the Project would not result in significant increased public safety risk" as clearly stated in the FEIS?

Please provide us with verification, certification, assessment and/or documentation that the AIM project is and will be consistent with all portions of 49 CFR 192 as clearly stated in the FERC FEIS dated January 23, 2015.

Integrity of our gas pipelines is an issue of great concern across the country. A natural gas event in the vicinity of the Indian Point nuclear plants could impact 20 million residents and result in the economic collapse of New York City and possibly the nation.

PHMSA requires specific steps to be undertaken by operators and it is our responsibility as citizens and elected officials to understand what those mandatory steps are and to help make sure that our local operators and regulators are taking the proper steps to prevent the kinds of catastrophic events that occurred in San Bruno and Fukushima.

I strongly urge PHMSA to contact me to arrange a meeting between us to obtain a

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[4] FOIA Control No: 2016-0074 **"**PHMSA conducted a reasonable search and did not locate records responsive to your FOIA request."

better understanding as to the applicability and compliance with the regulations to the AIM project.

I am looking forward to your prompt and direct responses to these vital issues.

Sincerely,

Paul M. Blanch

Paul M. Blanch
135 Hyde Rd.
West Hartford, CT 06117
860-236-0326

Chairman Norman Bay, FERC
Ms. Karen Gentile PHMSA CATS Manager
Senator Kirsten Gillibrand (aide Susan Spear)
Senator Chuck Schumer (aide Cody Peluso)
Senator Markey (Michal Freedhoff)
Congressman Eliot Engel (aide Brian Skretny)
Congresswoman Nita Lowey (aides Pat Keegan and Sara Levine)
Congressman Sean Patrick Maloney
NY State Governor Andrew M. Cuomo
Deputy Secretary Rachel Small
Director, Critical Infrastructure, Brian Wright
Attorney General of New York, Eric Schneiderman
NY State AG Office John Sipos
NY State AG Office Charles Donaldson
Peter Neffenger, Department of Homeland Security
NY State Senator George Latimer
NY State Senator Stewart-Cousins
NY State Senator Liz Krueger
NY State Senator Brad Hoylman
NY State Assemblywoman Sandy Galef
NY State Assemblyman Buchwald
NY State Assemblyman Abinanti
NY State Assemblyman Otis

Teleconference Notes
April 12, 2016

Call with PHMSA Karen Gentile 4/12/16 (Paul Blanch, Amy Rosmarin, Susan Van Dolsen, Emily Loughlin from Assemblywoman Sandy Galef's office)

Karen can provide us with PHMSA and overall inspection process.

Paul: Look at AIM pipeline. FEIS statements that pipeline will be in full compliance with regulators. We, as members of the public, want to know how PHMSA assures compliance so that they can make a statement to FERC.

Karen: Statement in NEPA documentation, specifically the EIS, is characteristic of statement found in EIS for proposed pipeline projects. When pipeline operators file application, they substantiate need. PHMSA has no jurisdiction for approving pipelines or siting of pipeline. If pipeline is approved and issued FERC certificate, the statement says that the pipeline must design, construct the pipeline within the federal regulations. Pipeline operator must do it in accordance with federal pipeline safety regulations specific to natural gas transmission pipelines.

Paul: Having worked in nuclear field, the applicant doesn't say it will comply with regulation. The NRC inspects to assure that all requirements are being met. Risk assessment is included in the PHMSA regulation. There is oversight. Has PHMSA assured compliance with that one particular point? Did PHMSA look at whether Spectra complied with regulation?

Karen: FERC issues certificate. Doesn't necessarily mean project will be built. AIM received FERC certificate and Spectra took initiative to proceed with construction activities. Then PHMSA has jurisdiction to inspect pipeline that is being built along with pipeline operators plans, procedures, records and documentation. PHMSA performs inspections and investigations according to code.

Paul: You didn't respond to my question.

Karen: Will get to that phase. We inspect according to the pipeline safety regulations. Timeframes exist about when risk assessment is required by regulations. PHMSA and state partners don't inspect every item. Can be specialized inspections such as new construction in a new area, operator qualifications, integrity management programs (where risk assessment is addressed), integrated inspections using data and information about a specific operator and an inspector can create a specialized inspection, etc. Data driven process to focus on inspection resources on regulatory provisions that address the greatest risk. They are now in the inspection phase of construction. Looking at records (welding), etc. Inspector doesn't typically retain all operator documentation and they retain copies of information that might be used as evidence of potential non-compliance. Don't issue any permits or certification of compliance. Inspecting elements that are contained in the code and make sure operators are doing things in compliance.

Requirement of integrity management part 192 subpart O, operator that has pipeline segments that have been deemed in HCA are required to have integrity management programs for those pipeline facilities. They had a telephone conference on March 28 and discussed that AIM pipeline is not required to follow part 192 subpart O yet. To determine whether they need to follow integrity management they have to identify HCA. Regulations say operator must incorporate new HCA in new baseline assessment within one year of service. Integrity management program is to look at threats to pipeline (type of soil, vandalism, etc.). 192 905 C states newly identified areas could satisfy any of the definitions in 903. Operator must complete evaluation.

Paul: FEIS says will be compliance with regulations. Those regulations require risk assessment and many other things. They must have done a risk assessment. He wants confirmation that PHMSA has not assured that AIM pipeline is in compliance with PHMSA regulations.

Karen: PHMSA doesn't issue certification of compliance. Pipeline operator must certify that they are operating in compliance and PHMSA. Under PHMSA's regulations do not require them to perform an analysis of their HCAs until a year later.

Susan: Spectra supplies HCA information to FERC to prepare FEIS. There is a chart in the FEIS with HCAs listed.

Karen: Pipeline operators do an analysis to determine route and how they might want to build it to make sure that they can meet the pressures that they want to meet. Look at classification and does analysis in planning stages. Operator may try to get ahead by designating HCAs early in the process.

Paul: Statement: True/False: **PHMSA has not assured compliance with its design and construction of regulations 49 CFR 192 at this time (whether its documented or not). Regulations state that PHMSA has the responsibility to the public to assure compliance. Operator is required to comply. Regulator is required to assure they comply. That is the responsibility of a regulatory agency.**

Karen: PHMSA and state inspectors have done inspections of AIM pipeline. **PHMSA does not issue certification of compliance with the regulations. PHMSA has the right to inspect and if we find issues, they have the authority to take action. Inspect to Part 192 to make sure we haven't found any issues of non-compliance. Operator will design, construct and operate pipeline according to 192. PHMSA can inspect records and property of pipeline operator. Can only inspect what is covered by regulations.** Legal interpretations on their website. FAQs are there to help people.

Amy: Given the fact that experts are saying siting of Spectra AIM at Indian Point is a danger, what can PHMSA do to stop construction. What can they do to show it is not in compliance with federal safety regulations?

Karen: Could inspect. Could be fines if immediate safety risk. There is no gas in pipelines to cause a risk yet. PHMSA doesn't approve or site projects. Make sure pipeline operators have plans and procedures in place and are doing things according to their regulations. Example: regulations to bury 3 feet, the operator says it will bury 10 ft. and they require that pipeline operator to adhere to it. They can cite the operator if the operator does not follow its procedures. They don't say whether a pipeline could be built or what mitigation strategies. Their regulations are the same throughout the country as minimum pipeline standards throughout the country.

Paul: If he feels that minimum standards are not being met, does he have any recourse, what can he do?

Karen: If you have concerns about non-compliance with federal standards, please bring it to attention.

Paul: He says he believes Spectra is not in compliance with 1) Code 192 to do risk assessment and 2) Training of local fire brigades.

Karen**: Under federal pipeline safety regulations, plans to include operation and emergency preparedness, public awareness plans, etc. must be available when pipeline goes into service. Required for existing pipelines. Paul says it is not there. Karen says it's required under their regulations and is enforceable. Do perform inspections and inspection information on PHMSA's website. It says when inspections were performed and any actions.**

Paul: Looked and says there have been none on that pipeline.

Karen: Must be tested within federal regulations. Risk assessment is not the same timeframe. 192 Subpart O talks about 1 year for pipeline operator to identify HCA. Risk assessment is focused on the risk to that pipeline. Doesn't look at outside risks. Focused on risks to the pipeline. Looking at threats and hazards that could cause problems.

Susan: Does that include terrorism?

Karen: Requirements are in reference standard ASME B31S incorporated by reference in fed. pipeline safety regulations. Elements include identification of threats to each of covered pipeline segments under integrity management program. May include vandalism and Paul asked whether PHMSA had coordinated with Homeland Security (TSA). She says TSA has developed **security guidelines** for pipeline security management (note they have developed guidelines, not laws).

Susan: **asked for contact at TSA that works with PHMSA. Karen will provide contact at TSA for PHMSA.** Told Karen about Congressman Engel's amendment and also about proposed legislation about requiring DHS to certify that all pipelines will be hardened against cyber-threats and terrorists before they are built instead of waiting until after.

Karen: Rulemaking can be suggested, but it will take time. **They can't impose additional requirements above federal regulations.**

Paul: The problem is non-enforcement of existing regulations. He believes that Spectra is in violation of the regulations and he thinks PHMSA is not enforcing.

Karen: Once again, identification of new HCA is not required for a year. He might want to request a formal interpretation of regulations. You can submit a formal letter of interpretation. 192 Section 905 Paragraph C.

Paul: Reached out to Forrest and that person had no idea.

Karen: **Pipeline operator assesses HCA within a year. Must conduct assessment of their pipeline within newly identified areas as part of their integrity management program. They are subject to inspections. ASME B31.8S talks about risks that need to be assessed. There is no oversight. Pipeline operators are responsible for maintaining the safety of their pipelines and PHMSA just checks on it.**

Paul: What about 192 Section 905 Part B? That doesn't mention one year. Identified sites.

Karen: FAQ 134 and 237. She can't give a formal interpretation. Suggests he submit formal interpretation.

Paul: Can we get a copy of the risk assessment?

Karen: **They don't have it. AIM pipeline not required to have risk assessment at this time. Part O not required at this time.**

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, D.C. 20590

June 20, 2016

Mr. Paul M. Blanch
Energy Consultant
135 Hyde Road
West Hartford, CT 06117

Dear Mr. Blanch:

Thank you for your e-mail message of April 18, 2016, and attached letter regarding your continued concern and questions related to the Algonquin Incremental Market (AIM) Project.

In March 2015, the Federal Energy Regulatory Commission (FERC) issued a Certificate of Public Convenience and Necessity for the AIM Project, authorizing Algonquin to construct and operate the AIM Project in accordance with the conditions set forth by FERC. These conditions include the requirements for the pipeline and aboveground facilities associated with the AIM project to be designed, constructed, operated, and maintained to meet or exceed the Pipeline and Hazardous Materials Safety Administration's (PHMSA) minimum federal pipeline safety standards in Title 49 Code of Federal Regulations (C.F.R.) Part 192 and other applicable federal and state regulations.

To ensure that the AIM Project would meet operational objectives while meeting or exceeding federal pipeline safety design, construction, and testing requirements, Algonquin identified class locations and high consequence areas (HCAs), as well as conducted a risk assessment, for the AIM Project. The class locations along the 3,935 feet running by Indian Point Energy Center (IPEC) include Class 1-3 locations, as defined by the federal pipeline safety regulations. Algonquin has classified this section of pipeline as being in an HCA, requiring Algonquin to comply with the additional requirements contained in Part 192, Subpart O – Gas Transmission Pipeline Integrity Management, when the line becomes operational. Algonquin has committed to incorporating the AIM Project into the overall Spectra Energy Transmission Integrity Management Program, Integrity Management Program Manual, as soon as the AIM project facilities go into service.

Algonquin has designed the 3,935 feet of pipeline by IPEC for the highest, most stringent class location, Class 4, and has committed to implementing additional design enhancements and construction techniques for this portion of pipeline. These enhancements, which exceed the minimum federal pipelines safety standards, include using thicker wall steel pipe (X-70 grade pipe with a 0.720 wall thickness), adding additional corrosion protection, performing nondestructive testing of 100 percent of butt/girth welds, placing valves at closer intervals, installing remotely controlled valves at Station 138+46.5 (MP 2.62) and Station 285+62.9 (MP 5.41), and installing the pipe with additional cover plus a physical reinforced concrete protective barrier above the pipeline. Algonquin has committed to use an experienced construction inspection staff that will provide 100 percent inspection of all welding, coating, and backfilling activities.

Additionally, Algonquin will run an in-line-inspection tool (caliper smart pig) following construction to identify any denting that exceeds the pipeline safety code requirements. These additional measures provide enhanced safety, over and above the federal pipeline safety regulations, to further limit the potential for a pipeline incident on the 42-inch AIM pipeline running near the IPEC. Enclosed are two maps for the area near the IPEC. One map illustrates the pipeline route for the 42-inch AIM Project with identified high consequence areas (enclosure 1) and the other map highlights the 3,935 feet of enhanced pipeline (enclosure 2).

Before the AIM Pipeline can be put into service, the pipeline will be hydrostatically pressure tested in accordance with Part 192, Subpart J – Test Requirements, to verify the integrity and strength of the pipeline at pressures exceeding the maximum allowable operating pressure. In the vicinity of IPEC, Algonquin will perform a pressure test for a minimum duration of eight hours at a test pressure of 1.8 times the maximum allowable operating pressure in accordance with the federal pipeline safety regulations. This pressure testing satisfies the integrity management requirement for a baseline assessment. The records of this testing must be retained by the pipeline operator for the life of the pipeline.

PHMSA and our state pipeline safety program partners take pipeline safety very seriously. We maintain a rigorous and comprehensive program covering pipeline operator inspections and enforcement, in addition to setting pipeline safety standards. While PHMSA does not issue permits or certifications of compliance, PHMSA inspectors or agents authorized by the Associate Administrator for the Office of Pipeline Safety, upon presenting appropriate credentials, are authorized to enter upon, inspect, and examine regulated natural gas pipeline operator's facilities, documentation, and records required by the federal pipeline safety regulations. If issues or problems related to non-compliance are found, PHMSA issues compliance actions to achieve and maintain pipeline safety and to insure the pipeline is in compliance with regulations. PHMSA's Office of Pipeline Safety website maintains pipeline operator information, and includes information on federal inspections and enforcement. www.phmsa.dot.gov/pipeline.

As mentioned in our last correspondence, PHMSA works closely with state pipeline safety programs to carry out our mission. For this project, PHMSA works with the New York Department of Public Service (NY DPS) to regulate interstate natural gas pipelines in New York. The NY DPS performs inspections on interstate natural gas pipelines in New York for PHMSA, including the Spectra Energy Algonquin pipeline facilities. If and when any violations of federal regulations are identified, PHMSA will take enforcement action.

Construction activities for the AIM Project are underway and both PHMSA and NY DPS personnel, along with other state pipeline safety personnel, are engaged in the AIM Project. NY DPS maintains regulatory oversight over new pipeline construction activities in New York and has already conducted several inspections related to the AIM Project. NY DPS began their inspections of the AIM project back in May 2015 and continue through the present. NY DPS conducted their most recent inspection on May 10, 2016. After startup of a pipeline, NY DPS personnel will continue inspections of the operation and maintenance of all jurisdictional pipelines in New York, to verify sustained compliance with the federal pipeline safety regulations. If future inspections reveal violations, PHMSA will take enforcement action.

If you have further questions or need clarification on specific sections of the federal pipeline safety regulations, you are welcome to submit a formal request for interpretation, pursuant to 49 C.F.R. §190.11. The request should be submitted to John Gale, Director, Standards and Rulemaking Division, with a carbon copy to Tewabe Asebe, Transportation Specialist, Standards and Rulemaking Division. Any questions you have related to the Federal Energy Regulatory Commission (FERC) Environmental Impact Statement should be referred to the FERC project manager for the AIM Project, Magdalene Suter, at (202) 502-6463 or via email at Magdalene.Suter@ferc.com.

I hope that this information provides you with assurance that PHMSA and our state partners are closely monitoring the AIM project and will continue regulatory oversight throughout its operation. Thank you again for your continued concern and involvement with pipeline safety and I appreciate you bringing your concerns to our attention. If we can be of further assistance, please do not hesitate to contact Karen Gentile, one of our Eastern Region Community Assistance and Technical Services representatives, at 609-433-6650, or via email at Karen.Gentile@dot.gov.

Sincerely,

Nancy White for
Alan Mayberry

Alan K. Mayberry
Acting Associate Administrator
for Pipeline Safety

cc: Kevin Speicher, NYSDPS
Magdalene Suter, FERC

2 Enclosures

U.S. Department
of Transportation

1200 New Jersey Avenue, S.E.
Washington, D.C. 20590

**Pipeline and Hazardous
Materials Safety Administration**

December 21, 2017
FOIA Control Number: 2018-0039

Transmitted via Electronic Mail to pmblanch@comcast.net – Read Receipt Requested
Paul Blanch
135 Hyde Rd.
West Hartford, CT 06117

Dear Mr. Blanch:

This letter is in regard to your correspondence dated December 20, 2017, appealing the "no records" response to your previously assigned FOIA Control Number 2017-0166. Your appeal was received in this office on December 20, 2017, and has been assigned the new FOIA Control Number **2018-0039.**

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is currently reviewing your appeal and will provide a response to you as soon as possible.

If you have any questions in regard to this matter, please feel free to contact me at 202-366-9832 or by e-mail at amal.deria@dot.gov.

Sincerely,

Attorney Advisor, Office of Chief Counsel
Pipeline and Hazardous Materials Safety Administration
(PHMSA)

CP14-96

ENBRIDGE

ORIGINAL

5400 Westheimer Court
Houston, TX 77056-5310
(713) 627-5400

August 2, 2018

Chairman Kevin J. McIntyre
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Indian Point Energy Center: Algonquin Gas Transmission, LLC Response to New York State Agencies' Letter Regarding Safety Study of Algonquin Natural Gas Pipelines, Westchester County, New York

Dear Chairman McIntyre:

The purpose of this letter is to respond to correspondence dated June 22, 2018, from several New York state agencies (the "New York State Agencies") to the Federal Energy Regulatory Commission ("FERC") requesting that FERC provide additional information, and impose certain restrictions, on the Algonquin Gas Transmission, LLC ("Algonquin") pipelines located near the Indian Point Energy Center ("Indian Point") operated by Entergy Nuclear Operations, Inc. ("Entergy") in Westchester County, New York (the "NY State Agencies Letter"). The New York State Agencies specifically request any safety studies that FERC may have in its possession, so the New York State Agencies can determine whether these studies were sufficient to ensure that the pipelines will not interfere with safe reactor operations, decommissioning, and storage of spent fuel at Indian Point. The New York State Agencies further request that FERC disallow Algonquin from using any additional gas capacity or increased pressure on its pipelines so long as Indian Point remains in operation and the spent fuel remains in pools at Indian Point. The New York State Agencies also request that any requests by Algonquin to increase capacity or pressure on these pipelines be subject to an updated safety analysis to be reviewed by FERC and/or the Nuclear Regulatory Commission ("NRC").

First and foremost, Algonquin is committed to ensuring that it operates all of its pipeline facilities in a safe and responsible manner. In this letter, Algonquin offers additional background regarding the safety measures that it already has in place as well as several observations regarding the issues raised in the NY State Agencies Letter. Algonquin also explains in detail why the issues raised by the New York State Agencies have either already been addressed, or will be addressed, comprehensively by FERC, PHMSA, and the NRC. In fact, these agencies recently engaged in an extensive analysis of potential risks to the Indian Point facility as part of the approval of Algonquin's AIM Project. Furthermore, Algonquin is committed to working with Entergy when Entergy begins to develop its decommissioning plans so that mitigation measures can be identified to ensure that ongoing operation and maintenance of the three Algonquin lines continues safely and in compliance with the applicable federal pipeline safety standards. Lastly, Algonquin does not have a proposal before the Commission that would increase capacity or pressure on the lines in the vicinity of Indian Point. As a result, none of the additional measures proposed by the New York State Agencies are necessary or appropriate and Algonquin respectfully requests that FERC take no action on these requested requirements.

Reference to New York State Agencies Safety Study

In their letter, the New York State Agencies cite as a basis for their requests a certain safety study that was recently commissioned by the New York State Department of Homeland Security and Emergency Services ("DHSES"), Department of Public Service ("DPS"), Department of Health ("DOH"), and the Department of Environmental Conservation ("DEC"). A copy of the New York State Agencies safety study has not been provided to Algonquin, nor was Algonquin consulted in the development of the report, despite the fact that the study reportedly evaluates certain of Algonquin's pipelines located near Indian Point. According to the NY State Agencies Letter, the safety study concludes that the upcoming closure of Indian Point's nuclear reactors and the removal of spent nuclear fuel from the spent fuel pools to on-site dry cask storage will reduce risks related to a potential pipeline incident. The New York State Agencies nevertheless demand that FERC (1) provide additional information to them for further evaluation; (2) disallow Algonquin from using any additional gas capacity or increased pressure on its pipelines so long as Indian Point remains in operation and the spent fuel remains in pools at Indian Point; and (3) request an updated safety analysis for any requests by Algonquin for increased capacity or pressure, to be reviewed by FERC and/or the NRC.

Algonquin is Committed to the Safe Operation of its Existing Pipeline System

As a prudent operator, Algonquin has multiple safety measures in place which address concerns related to the proximity of the Indian Point facility to its pipeline facilities and any potential decommissioning. The two original Algonquin pipelines on the Indian Point property were certificated by the FERC's predecessor, the Federal Power Commission, and installed in 1952 and 1968 across what is now the Indian Point property. The pipeline installed in 1952 was located and operated prior to the construction of the Indian Point facility. The two original pipelines have operated safely and without incident for more than 60 years. The relevant easements incorporate specific protections for these pipelines to address activity in the area, in addition to those required by federal regulations (discussed in more detail below). More recently, Algonquin replaced a portion of the 26-inch diameter pipeline constructed in 1952 with the 42-inch diameter natural gas pipeline for the AIM Project in a location further away from the Indian Point facilities. As detailed below, the AIM Project pipeline was designed and constructed, and is operated and maintained, to meet or exceed federal safety standards and regulations.

In addition to these measures, Algonquin already has in place emergency plans to address potential incidents at Indian Point or external events that could impact Indian Point. Algonquin has instituted extensive cybersecurity and security measures to monitor and protect its facilities. Algonquin has also developed and maintains its own Emergency Response Procedures and Plans in compliance with U.S. Department of Transportation ("DOT") regulations. In conjunction with the Emergency Response Procedures, Algonquin conducts periodic liaison meetings with municipal emergency response officials across its pipeline system, including municipalities in the vicinity of Indian Point.

As part of the certification of the AIM Project, FERC and NRC specifically addressed issues related to construction and operation of pipeline facilities near the Indian Point facility. On March 3, 2015, after vetting for safety, environmental, cultural resources, landowner, and other concerns, FERC issued its Certificate of Public Convenience and Necessity for the AIM project,[1] authorizing Algonquin to construct, operate and maintain the 42-inch diameter pipeline, among other facilities, that traverses the Indian Point property approximately a half-mile away from the Indian Point nuclear facilities.

Pursuant to and in coordination with NRC requirements and procedures, Entergy conducted a methodical and thorough hazards analysis of the then-proposed 42-inch diameter pipeline, including potential impacts on the safe operation of Indian Point and important nearby systems and equipment, to ensure that there are no new or increased hazards resulting from the proximity of the AIM Project pipeline to Indian Point. The Entergy analysis concluded that there would be no additional reduction in safety margins from these components and, therefore, the new pipeline posed minimal or no increased risk to the safe operation of Indian Point.

Additionally, NRC inspectors and staff reviewed Entergy's analysis, conducted an on-site review of the proposed pipeline route, and the NRC's physical scientist performed an independent analysis of the hazards associated with the proposed pipeline. NRC's analysis assumed catastrophic pipeline failure. The NRC's review covered every asset within the outermost fenced area of the facility, including the area with the spent fuel rods. Based on the NRC staff's review of Entergy's analysis and the NRC staff's independent analysis, the NRC staff concurred with Entergy's conclusion that the proposed pipeline does not introduce significant additional risk to Indian Point (specifically, that the "the proposed pipeline does not introduce significant additional risk to safety-related SSCs [structure, system, and component] and SSCs important-to-safety at Indian Point Units 2 and 3."). In addition to conducting its independent analysis, the NRC staff held meetings with concerned parties and their technical experts and considered and rejected a petition concerning the adequacy of the hazards analysis for the planned pipeline.

After extensive analysis of the AIM Project and based on the findings in the analyses conducted by Entergy and the NRC, FERC concluded in its Final Environmental Impact Statement that "[b]ecause of the distance of the proposed Project from the IPEC [Indian Point Energy Center] generating facilities and the avoidance and mitigation measures that it [Algonquin] would implement, the proposed route would not pose any new safety hazards to the IPEC facility." Algonquin's mitigation measures included using thicker pipe that exceeds the most stringent Class 4 requirements, installing concrete slabs over the pipeline, burying the pipeline to a minimum depth of four feet and providing thicker external corrosion protection. The Commission also noted that DOT, which was a cooperating agency, provided no comments regarding NRC's report. In the Certificate Order and on rehearing, FERC specifically addressed potential safety risks related to the Indian Point facility, concluding that the AIM Project can safely operate near Indian Point.[2]

Any challenge to these findings constitutes an impermissible collateral attack on the Certificate Order for the AIM project. It is well established that a party is barred from later challenging the validity of a prior FERC order in a subsequent proceeding other than by a direct appeal.[3]

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[1] *Algonquin Gas Transmission, LLC*, 150 FERC ¶ 61,163 (2015) ("Certificate Order"), *reh'g denied*, 154 FERC ¶ 61,048 (2016) ("Rehearing Order").
[2] Certificate Order at P 107; Rehearing Order at PP 201; 205.
[3] Rockies Exp. Pipeline LLC v. 4.895 Acres of Land, More or Less, 734 F.3d 424, 431 (6th Cir. 2013) (rejecting landowner's claim for damages from eminent domain taking by pipeline as an impermissible

Furthermore, the D.C. Circuit Court of Appeals recently denied petitions to review the AIM project certificate that were focused on safety concerns associated with Indian Point.[4] In upholding the FERC certificate, the Court specifically noted Entergy's evaluation that the AIM project "would pose no additional safety risks to its facility" and the NRC's subsequent "independent analysis" reaching "the same conclusion."[5] Among other points, the Court rejected the concern (raised by challengers in that case) that Entergy and NRC had improperly assumed that gas flow could be terminated within three minutes of an incident; the Court specifically noted that NRC's analysis in fact assumed "continuous gas flow for one hour." The Court ultimately found the Commission's analysis of safety issues "permissibl[e]" and "reasonable," and upheld FERC's decision to "credit the NRC's expert conclusions."[6] The D.C. Circuit's ruling upholding the FERC certificate proceeding is "res judicata," and prevents "readdressing the merits of [these] claims."[7]

The Commission made essential fact findings in the AIM proceeding based on its own analysis, in addition to review by the DOT, the NRC and Entergy. Arguments raised by the New York State Agencies related to the safety of the AIM pipeline, and other attempts to use the letter from the New York State Agencies such as the recent filing by Carolyn Elefant in the AIM Project docket, are improper challenges to the Certificate Order and, to the extent they raise issues presented and resolved in the recent appeal, improper attempts to relitigate issues resolved by the D.C. Circuit. They should be promptly rejected by the Commission.

Based on the overall analysis undertaken to date by the NRC[8], FERC, the D.C. Circuit, Entergy and Algonquin, Algonquin does not believe, and FERC has not ascertained, that there will be any reasonable scenario in which the AIM Project pipeline could damage the Indian Point reactors or spent fuel rods.

FERC has Exclusive Authority to Regulate Pipeline Capacity on the Algonquin Pipeline System

The New York State Agencies maintain that FERC cannot approve any future applications by Algonquin for increased capacity or pressure on the three pipeline segments in close proximity

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collateral attack on the essential fact findings made by the Commission in issuing the certificate order authorizing the pipeline); Williams Nat. Gas Co. v. City of Oklahoma City, 890 F.2d 255, 262 (10th Cir. 1989)) - Thus, a challenger may not collaterally attack the validity of a prior FERC order in a subsequent proceeding. *McCulloch*, 536 F.2d at 913 (quoted in *Howard Electric*, 798 F.2d at 394).

[4] *City of Boston Delegation v. FERC*, No. 16-1081 (D.C. Cir. July 27, 2018) (slip op.).

[5] *Id.* (slip op. at 19).

[6] *Id.* (slip op. at 20-21).

[7] *Nat'l Comm. for New River, Inc. v. FERC*, 433 F.3d 830, 834 (D.C. Cir. 2005).

[8] NRC spokesman Neil Sheehan, spokesman for the NRC, recently stated that the agency's 2014 assessment has not changed.

> *The NRC's role was to ensure the new pipeline would not adversely affect the safety of the Indian Point nuclear power plant. . . . We determined, based on our review of the plant owner's evaluation of the pipeline and our own independent analysis, that the reactors could either continue to safely operate or temporarily shut down if the line were to rupture in the vicinity of the plant. That assessment has not changed.*

Rochester Democrat and Chronicle (New York), July 8, 2018.

to the Indian Point facility. FERC should decline to act on any suggestion that it pre-determine (i) requirements for its analysis of a future project application or (ii) the outcome for a future project.

FERC has exclusive authority over the construction of interstate natural gas pipeline facilities. Therefore, if a pipeline developer files an application at FERC to construct or modify pipeline facilities near Indian Point, FERC will have exclusive authority to review such an application. Any potential safety risks will be analyzed by FERC at that time. Algonquin accordingly asks FERC to refrain from speculating on a yet-to-be-determined project. Further, Algonquin requests FERC not to preemptively bar potential future applications by Algonquin, particularly given that FERC may determine that a project presents no increased risk. FERC recently conducted such an extensive review of the AIM Project pipeline, and its Final Environmental Impact Statement determined that "the project will not result in increased safety impacts at the Indian Point facility."[9] FERC specifically evaluated potential safety risks related to the facilities to reach the conclusion that the "AIM Project can safely operate near Indian Point."[10] And the D.C. Circuit recently rejected challenges to FERC's analysis and conclusions on that point.[11] As noted earlier, there simply is no proceeding pending before FERC to increase the capacity or the pressure of the pipelines adjacent to Indian Point.

Algonquin Commits to Work with Entergy Regarding Appropriate Mitigation Measures for the Decommissioning Phase of the Nuclear Plant

The decommissioning process is governed by the NRC, and Entergy must comply with applicable NRC regulations during its preparation for and implementation of decommissioning efforts. That said, in light of the terms of the Easements, Entergy will not have unfettered use of the easement areas for its decommissioning activities.

Algonquin is proposing to engage Entergy early on in Entergy's planning of its decommissioning plan to ensure that its activities on or in the vicinity of the Algonquin pipelines are consistent with the terms of the easements for such facilities, as well as Algonquin's pipeline safety obligations (addressed further below). Algonquin's pipelines were installed within rights of way granted to it under four (4) easement agreements.[12]

The 1951 Easement, 1965 Easement, and 1967 Easement are all in proximity to the Indian Point facility and relate to the original 26-inch and 30-inch diameter pipelines. The terms of these easements allow Algonquin to operate and maintain its pipelines and provide certain protections to Algonquin for its pipelines. For example, each of the three easements allows Algonquin to remove any obstructions from the easement area "which might interfere with the

[9] Certificate Order at P 107; Rehearing Order at P 201.
[10] Rehearing Order at PP 201; 205.
[11] *City of Boston Delegation, supra* n.4 (slip op. at 18-21).
[12] (1) Grant from Indian Point Corporation dated September 19, 1951, recorded in the Westchester County Clerk's Office at Book 5035, Page 146 (the "1951 Easement"); (2) Grant from Consolidated Edison Company of New York dated April 29, 1965, recorded in the Westchester County Clerk's Office at Book 6517, Page 34 (the "1965 Easement"); (3) Grant from Consolidated Edison Company of New York dated May 5, 1967, recorded in the Westchester County Clerk's Office at Book 6712, Page 401 (the "1967 Easement"); and Grant from Entergy Nuclear Operations, Inc. dated October 22, 2015, recorded in the Westchester County Clerk's Office (the "2015 Easement"; collectively, the "Easements").

right of way." Additionally, the 1965 Easement and 1967 Easement allow that the grantor to cross the pipeline with "heavy equipment and loads." However, the grantor must give "advance notice of the location proposed to be crossed and type of equipment to be used so that Algonquin can outline the specifications and advance protection required for the safety of the pipelines." The intent of these, and other, provisions in the Easements is to allow the grantor with reasonable use of the easement areas, but that Algonquin must be able to review such uses and make a determination as to whether or not such use is reasonable or if it may have the potential to interfere with ongoing pipeline operations. We envision the employment of this process as a part of the decommissioning activities.

Additionally, the NRC will scrutinize Entergy's plans for decommissioning Indian Point when Entergy's specific plans become available. Specifically, the regulations at 10 C.F.R. § 50.82(a)(4)(i) require Entergy to submit a post-shutdown decommissioning activities report (PSDAR) that details planned decommissioning activities to the NRC within two years following Indian Point's permanent cessation of operations. When the PSDAR is completed and available, the NRC will review the PSDAR, make the PSDAR available for public comment, and conduct public meetings regarding Entergy's decommissioning plans.

Given the rights granted to Algonquin under the Easements, Entergy's use of the Easement area during decommissioning activities will, by necessity, contemplate Algonquin's ongoing pipeline operations.

The New York State Agencies' Authority under the Pipeline Safety Act is Limited

The New York State Agencies state in their letter that the NY DPS has been delegated the authority by the federal government to ensure compliance with federal gas pipeline safety standards. To the contrary, the federal Pipeline Safety Act ("PSA") provides for exclusive *federal* authority to regulate the safety of interstate pipelines. 49 U.S.C. § 60101 *et* seq. The Office of Pipeline Safety ("OPS"), within the Pipeline and Hazardous Materials Administration ("PHMSA") of the DOT, may authorize a State to act as its agent to inspect interstate pipelines, but PHMSA retains primary responsibility for enforcement of the regulations. 49 U.S.C. § 60106. As such, DPS is an "Interstate Agent" that may inspect and refer matters to PHMSA, but PHMSA is ultimately responsible for enforcement to ensure compliance with federal gas pipeline safety standards. Id.

PHMSA, acting through OPS, administers and enforces the federal safety standards. PHMSA regulations establish minimum federal safety standards for gas "pipeline facilities," defined as "new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation." 49 C.F.R. §192.3.

In New York, DPS administers its pipeline safety program, and is charged with inspecting portions of interstate natural gas and hazardous liquid pipelines located within New York State on behalf of PHMSA. Although DPS has the authority to conduct the inspections of interstate pipelines located within New York State, PHMSA sets the minimum safety standards and retains all enforcement authority and functions with respect to interstate pipeline companies.

With respect to the NY State Homeland Security, its authority is similarly limited. The federal program for pipeline security issues was initially administered by DOT but since 2002, the federal Transportation Security Administration ("TSA") within the U.S. Department of Homeland Security ("DHS") has been the lead agency. DOT and DHS entered into a memorandum of understanding in 2004 and an annex in 2006 to better delineate coordination of security collaboration. Although TSA is authorized to issue regulations for pipeline security, the agency relies on the industry's voluntary compliance with API Recommended Practice 1164 (Pipeline SCADA Security), TSA's security guidance, best practice recommendations and TSA's ongoing Corporate Security Review Program.

Regardless of which agency enforces the safety and security of Algonquin's pipeline facilities, Algonquin is obligated to operate its natural gas interstate pipeline system in compliance with the PSA and the minimum federal regulations set forth at 49 C.F.R. Parts 191 and 192. The purpose of the PSA and the regulations is to ensure the safe transportation of energy in the United States. As such, the regulations establish requirements concerning construction and design, operations and maintenance. They require that operating pressures be established for pipelines with built-in safety factors, including consideration of class locations that take into account proximity to buildings or areas of human occupancy. 49 C.F.R. § 192.619. They also require that operators develop, implement and maintain Operations and Maintenance (O&M) Plans that must at a minimum include, among other things, continuing surveillance of pipeline facilities, Damage Prevention Programs, Emergency Plans, Public Awareness Plans, Control Room Management Plans, patrolling, leakage surveys, line markers, etc. 49 C.F.R. §§ 192.605, 613 614, 615, 616, 631, 705, 706, 707. Corrosion control programs must also be established in order to meet or exceed regulatory requirements. 49 C.F.R. Part 192, Subpart I.

This portion of the Algonquin system is inspected by Algonquin routinely pursuant to its O&M and other procedures that meet or exceed the federal regulations including through: (a) aerial patrol of its rights of way twice weekly (and has done so for approximately thirty years, weather and mechanical conditions permitting); (b) visual inspections on a monthly basis, including walking the entire pipeline rights of way annually; (c) pipeline corrosion testing annually; (d) internal cleaning of its pipelines annually (referred to as "pigging" the lines); and (e) internal integrity inspection of the pipelines every seven years (last performed on the lines in 2016 and 2017). The 26-inch and 30-inch diameter pipelines are also in an area that Entergy monitors with security cameras, given that they are located behind Entergy's chain link fencing topped with razor wire and jersey barriers.

The very purpose of these regulations is to protect public safety, and in keeping with that, Algonquin, through its right-of-way patrolling and Damage Prevention Plan obligations, is required to identify and address possible threats such as construction activities that may affect the safety and operation of the pipeline. Further, Algonquin maintains a robust physical and cyber security plan to protect against security risks. Additionally, and as noted above, Algonquin has developed and maintains its own Emergency Response Procedures and Plans, which require that Algonquin periodically conduct liaison meetings with municipal emergency response officials across its pipeline system, including municipalities near Indian Point.[13]

[13] The AIM Project FEIS and certificate order acknowledge that the "project's facilities will be designed, constructed, operated, and maintained to meet or exceed the DOT's Minimum Federal Safety Standards set forth in Part 192 of Title 49 of the Code of Federal Regulations and in other applicable federal and

In light of the foregoing considerations, Algonquin respectfully requests that FERC decline to take action on the requests from the New York State Agencies. Many of the concerns that have been raised by the New York State Agencies have already been addressed by FERC, PHMSA and the NRC as part of an extensive analysis of potential risks associated with the Indian Point facility in conjunction with the approval of Algonquin's AIM project. Additionally, prior to Entergy's decommissioning activities, Algonquin will seek to engage Entergy, who, in turn is required to work with the NRC and comply with NRC regulations regarding decommissioning. Algonquin anticipates that these discussions will include consideration of any and all impacts of the proposed decommissioning on the Algonquin right-of-way and pipeline system and an evaluation of the need for any mitigation measures to ensure pipeline safety. Regardless of Entergy's decommissioning plans, Algonquin will continue to operate, maintain and inspect its pipelines in a manner that exceeds the PHMSA regulations in order to ensure their safe operation, including with respect to internal and external line inspection, right-of-way surveillance and leak detection, with emergency and security plans in place. Algonquin is committed to operating a safe pipeline system, as evidenced by its safe operating history, and the company looks forward to coordination with all necessary parties at such time as Entergy contemplates decommissioning of the Indian Point facility. At this time, however, the additional measures requested by the New York State Agencies are neither necessary nor appropriate.

Respectfully submitted,

Patrick J. Hester
Vice President, U.S. Gas Law

cc: Howard Elliott, Administrator, Pipeline and Hazardous Materials Safety Administration
Kristine Svinicki, Chair, Nuclear Regulatory Commission
Mr. John B. Rhodes (New York Department of Public Service)
Mr. Roger Parrino (New York Division of Homeland Security and Emergency Services)
Dr. Howard Zucker (New York Department of Public Health)
Mr. Basil Seggos (New York Department of Environmental Conservation)

state regulations."

STATE OF NEW YORK
OFFICE OF THE ATTORNEY GENERAL

LETITIA JAMES
ATTORNEY GENERAL

DIVISION OF SOCIAL JUSTICE
ENVIRONMENTAL PROTECTION BUREAU

March 19, 2020

VIA CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Honorable Kristine L. Svinicki
Chair
Nuclear Regulatory Commission
Mail Stop O-16 B33Washington, DC 20555-0001

Honorable Neil Chatterjee
Chair
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Honorable Howard Elliott
Administrator
Pipeline and Hazardous Materials Safety Administration
U.S. Dept. of Transportation
1200 New Jersey Avenue, SE
Washington, DC 20590

Re: Algonquin Pipeline Safety and the Indian Point Nuclear Power Plant in Buchanan, NY

Dear Chair Svinicki, Chair Chatterjee, and Administrator Elliott:

On behalf of New York Attorney General Letitia James, we write to request your immediate attention and engagement on a matter of the utmost importance concerning the safe operation of the Algonquin Pipelines near the Indian Point Nuclear Power Plant in Buchanan, New York. While we ask that you to conduct a full, transparent, and timely re-analysis of safety risks of the pipelines associated with Indian Point, we write today to urge your agencies to evaluate in a joint, coordinated, and time-sensitive manner whether any immediate measures are necessary to mitigate potential risks from the operation of the Algonquin Pipeline system and/or the operation of Indian Point. We believe that your agencies have express legal authority to conduct such an evaluation, and that the law and the public safety implications of pipeline accident warrant your prompt action.

As you are likely aware, the Office of the Inspector (OIG) of the U.S. Nuclear Regulatory Commission (NRC) recently called into question the accuracy of the NRC staff's confirmatory safety analyses that purported to evaluate whether the 42-inch Algonquin Incremental Market Project (AIM Project) pipeline would pose safety risks to the components and safe operation of the adjacent Indian Point (See NRC OIG Event Inquiry Case No. 16-024). The OIG found that NRC staff analyses of Indian Point operator Entergy's August 24, 2014 safety evaluation and associated hazards analysis, pursuant to 10 C.F.R. 50.59, contained multiple inaccuracies and misrepresentations, employed incorrect methodologies and models, used invalid assumptions on parameters such as pipeline shutoff capabilities, and deviated from accepted regulatory guidance. The OIG also found that NRC staff does not have a formal process in place to conduct quality assurance or peer reviews of safety assessments. A copy of the OIG report is attached.

By way of background, the Federal Energy Regulatory Commission (FERC) authorized the AIM Project in 2015 contingent upon the pipeline owner – now Enbridge – incorporating additional pipeline safety and mitigation measures prescribed in FERC's Final Environmental Impact Statement for the project. The Pipeline and Hazardous Materials Safety Administration (PHMSA) was a full participant in FERC's environmental review. These FERC-prescribed pipeline safety and mitigation measures were based in-part on the findings of the safety assessments and hazard analyses conducted by Indian Point's owner and operator – Entergy – and the subsequent confirmatory and independent analyses by the NRC. (See FERC Docket No. CP14-96: Order Issuing Certificate [Mar. 3, 2015]). As noted earlier, the OIG report has now called into question the accuracy of both Entergy's and NRC's safety assessments.

In response to the OIG findings, NRC Chair Svinicki instructed NRC staff to examine whether any immediate regulatory action is needed based on information in the OIG report. In addition, Chair Svinicki instructed staff to undertake a review of whether any information in the OIG report demonstrates a need to revisit the NRC staff safety analysis and to provide NRC with the results within 45 days (*See*, Memo to M. Doane, Feb. 24, 2020). At a March 4, 2020 U.S. Senate Committee on Environment and Public Works oversight hearing, Chair Svinicki stated that a task force would be established to assess the issues identified in the OIG report and develop conclusions. NRC has since established an Expert Evaluation Team comprised of representatives from NRC, PHMSA, and Sandia National Labs, to undertake the evaluation.

NRC staff reported on February 26, 2020 that it had conducted an "examination" to determine if immediate regulatory action is needed and found that there is no safety issue warranting immediate regulatory action at either Indian Point Unit 2 or Unit 3 (*See*, Memo to Commissioners, Feb. 26, 2020). However, this NRC staff examination appears to be probabilistic in nature and does not contain a consequence analysis that would likely better inform whether any immediate risk management measures should be instituted at either the AIM Project pipeline or on the Indian Point plant site. Further, that review appears to have focused solely on potential impacts to the reactor core, and only briefly mentions potential impacts to other site infrastructure (e.g., gas turbines, the switchyard) in its discussion of defense-in-depth. The review also does not provide detailed information supporting its conclusion that there is no significant degradation of defense-in-depth at Indian Point from an AIM Project pipeline rupture. Significantly, impacts to the spent fuel pools and the Independent Spent Fuel Storage Installation are omitted from the defense-in-depth discussion and the safety margin analysis. Finally, there is no evidence that NRC staff consulted any staff at PHMSA in their examination into the need for immediate risk mitigation action before issuing the February 26 memorandum.

Nuclear Regulatory Commission

First and foremost, we urge NRC to immediately revisit its initial examination undertaken by staff on February 26 and enlist the assistance of PHMSA and other pipeline safety experts in assessing the current risk profile of the AIM Project pipeline, and its proximity to the components and safe operation of Indian Point. NRC has broad responsibility and authority under the Atomic Energy Act of 1954, 42 U.S.C. § 2011, as amended by the Energy Reorganization Act of 1974, 42 U.S.C. §§ 5801(a), 5843, 5846; to ensure public health and safety, and should exercise that authority here.

Second, we urge the NRC to accept the recommendations of the New York State Department of Public Service in its March 9, 2020 letter to Chairs Svinicki and Chatterjee, and require NRC staff to undertake a new, fulsome safety analysis of all natural gas infrastructure at Indian Point, not only the AIM Project 42-inch gas pipeline that was the subject of the OIG report, but also the 26-inch and 30-inch Algonquin pipelines that are on the Indian Point site in closer proximity to Unit 3 (which will operate through April 2021). In addition to our concern about the proximity of these pipelines to the reactor and supporting equipment – including the spent fuel pool and the Independent Spent Fuel Storage Installation – we also note that the Algonquin pipelines are both over 50 years old (entering service in 1952 and 1965, respectively).

Accordingly, given the serious problems regarding the NRC staff's safety and accident review of the AIM Project pipeline identified in the OIG report, which may similarly taint earlier Entergy and staff safety reviews of the Algonquin 26-inch and 30-inch natural gas pipelines, we urge the NRC to require a new Part 50.59 review of *all 3 pipelines*. These same concerns regarding the Algonquin pipelines were highlighted previously by the State of New York in the context of the Indian Point license renewal proceeding in comments on NRC's Draft Second Supplement to the Final Supplemental Environmental Impact Statement for Indian Point Units 2 and 3, a copy of which is attached for your convenience. *See,* Docket ID NRC-208-0672; Docket Nos. 50-247-LR, 50-286-LR (ML16069A067). Indian Point-specific information can be found in both the Comments themselves (pp. 20-24) and Exhibit B to the Comments, International Safety Research Report No. 13014-01-02 (December 20, 2013)(pp. 28-30).

PHMSA

At the same time, pursuant to its regulatory authority under 49 CFR §190.236 *Emergency orders: Procedures for issuance and rescission*, we call on PHMSA to address the serious questions of pipeline safety related to the AIM Project pipeline implicated in the OIG Report. Specifically, we urge PHMSA to immediately determine whether an unsafe condition or combination of unsafe conditions and practices is present that requires immediate abatement, and to communicate relevant information to the community. In addition to evaluating the AIM Project pipeline, PHMSA's independent analysis should be comprehensive, and include and/or reassess any past FERC, PHMSA, or NRC assessments of the safety of the 26-inch and 30-inch pipelines that also traverse the Indian Point site adjacent to Unit 3.

FERC

Following consultation with PHMSA and NRC regarding these immediate evaluations, we urge FERC to evaluate whether any invocation of its Administrative, Investigation and/or Enforcement Authority under the Natural Gas Act (15 U.S. Code § 717) is warranted. This would include, potentially, modification of existing orders and other actions to mitigate any presently unidentified risk related to the AIM Project pipeline. Additionally, we believe it is incumbent upon FERC to review its delegation procedures and standards for agency review; proper FERC oversight of the NRC confirmatory safety analysis might have disclosed the problems identified in the OIG Report before the AIM Project pipeline was approved by FERC and placed into service in 2017.

Conclusion

The collective actions and omissions of NRC, FERC, and PHMSA on the AIM Project pipeline has introduced an unacceptable level of uncertainty as to the safe operation of the pipeline – as constructed – as it relates to the safe operation of

Indian Point. Accordingly, this calls into question the adequacy and rigor of prior safety assessments of the existing 26-inch and 30-inch Algonquin pipelines that traverse the Indian Point site adjacent to Unit 3.

We urge that NRC, FERC, and PHMSA undertake a joint and coordinated evaluation on a time-sensitive basis of the three pipelines that run proximate to Indian Point to identify whether any immediate safety measures must be instituted. We believe that your agencies have express legal authority to conduct such an evaluation, and that the law and the public safety implications of pipeline accident warrant your prompt action. Once your agencies have completed these forthwith evaluations, we ask you that you undertake the more comprehensive reassessments outlined herein.

To help ensure credibility in this matter, we also urge that the agencies obtain independent peer review of their comprehensive reassessment findings by a credible third party such as the National Academy of Sciences. Moreover, these agency actions should be conducted transparently and include a meaningful opportunity for public input and information sharing.

On behalf of New York State Attorney General James, we again thank you for your urgent attention to this matter. If you would like to discuss this matter further, please contact Deputy Bureau Chief for Environmental Protection Lisa M. Burianek at (518) 776-2400.

Sincerely yours,

Lemuel M. Srolovic
Bureau Chief
Environmental Protection

Enc.

cc: FERC Commissioners Glick, McNamee
NRC Commissioners Baran, Caputo, Wright
D. Lee, NRC OIG
S. Raimo, Entergy
P. Hester, Enbridge
NYS Dept. of Public Service

OFFICE OF THE INSPECTOR GENERAL

U.S. NUCLEAR REGULATORY COMMISSION

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant

Case No. 16-024

EVENT INQUIRY

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

OFFICE OF THE
INSPECTOR GENERAL

February 13, 2020

MEMORANDUM TO: Chairman Svinicki

FROM: David C. Lee
Deputy Inspector General

SUBJECT: CONCERNS PERTAINING TO GAS TRANSMISSION LINES AT THE INDIAN POINT NUCLEAR POWER PLANT (OIG CASE NO. 16-024)

This accompanies the results of an Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC), event inquiry into concerns pertaining to NRC's oversight of a 42-inch natural gas pipeline that was, at the time, proposed to traverse Indian Point Energy Center (IPEC) property. A citizen stakeholder questioned the adequacy and completeness of the licensee's (Entergy) site hazards analysis and NRC's independent and followup analyses prepared to determine the safety impact on IPEC plant components due to the potential rupture of the proposed high pressure 42-inch gas pipeline. OIG examined an NRC inspection report and underlying analysis used to determine that Entergy appropriately concluded the 42-inch gas pipeline would not introduce significant additional risk at IPEC. OIG also examined NRC's response to the stakeholder's concerns over the 42-inch gas pipeline.

We have also provided this event inquiry report to the appropriate Majority and Ranking Members of Congress with oversight responsibilities for the NRC.

If you have any questions, please contact me, at 301-415-5930, or Rocco J. Pierri, Assistant Inspector General for Investigations, at 301-415-5925.

Attachment: As stated

cc: Commissioner Baran
Commissioner Caputo
Commissioner Wright

Office of the Inspector General

EVENT INQUIRY

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant

Case No. 16-024

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Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant (Case No. 16-024)

Basis and Scope

The Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC), initiated this event inquiry in response to concerns, communicated to OIG, from a citizen stakeholder pertaining to NRC's oversight of a 42-inch natural gas pipeline that was, at the time, proposed to traverse Indian Point Energy Center (IPEC) property. This pipeline, now in operation, was part of the Algonquin Incremental Market (AIM) Project, which proposed to replace certain portions of the existing pipeline and install new pipeline in the northeast United States. NRC's role was to support the Federal Energy Regulatory Commission's (FERC) decision to approve or disapprove the project by providing information to the FERC on the impacts of the AIM Project on IPEC. NRC's findings were documented in its Third-Quarter Integrated Inspection Report issued to Entergy, IPEC's license holder, on November 7, 2014.

In a publicly available Title 10 of the *Code of Federal Regulations* Section 2.206 (10 CFR) petition, dated October 15, 2014, and a letter to NRC dated July 27, 2015, the stakeholder questioned the adequacy and completeness of the licensee's (Entergy) site hazards analysis and NRC's independent and followup analyses prepared to determine the safety impact on IPEC plant components due to the potential rupture of the proposed high pressure 42-inch gas pipeline. The stakeholder also questioned whether (1) NRC misled FERC and the public by claiming to FERC that there was no additional risk associated with the proposed 42-inch gas pipeline, thereby putting at risk 20 million people near IPEC; (2) NRC was aware of material false statements made by Entergy to NRC with respect to the 42-inch gas pipeline; (3) NRC violated its procedures and regulations when analyzing the potential safety impacts from the 42-inch gas pipeline; and (4) NRC is allowing IPEC to operate in an unanalyzed condition.

OIG's event inquiry examined NRC's inspection report and underlying analysis used to determine that Entergy appropriately concluded the 42-inch gas pipeline would not introduce significant risk to safety-related systems, structures, and components; and systems, structures, and components important-to-safety at IPEC. On March 3, 2015, FERC issued an order formally approving the AIM Project. On January 7, 2017, the pipeline went into use.

As part of this event inquiry, OIG also examined NRC's response to the stakeholder's concerns over the 42-inch gas pipeline.

Findings

Finding 1

While FERC's approval of the AIM Project pipeline relied in part on NRC's assessment of Entergy's site hazards analysis and NRC's independent analysis of the impact of a potential rupture of the portion of the pipeline that traversed IPEC property, OIG found (1) NRC's independent analysis was incorrectly portrayed in FERC's approval document as significantly more conservative than it actually was; (2) NRC's inspection report contained inaccuracies suggesting additional analysis had been conducted, when this was not the case; and (3) NRC's underlying independent analysis was conducted using a computer program that the National Oceanic and Atmospheric Administration (NOAA), which developed the program, said it was not designed for. Moreover, the majority of NRC's independent analysis described the impact of a potential rupture on an above ground point on IPEC property that NRC believed presented the most credible risk due to its exposure; however, ultimately the as-built 42-inch pipeline does not come above ground anywhere on IPEC property but does traverse the IPEC property.

OIG also found that NRC decisionmakers had differing understandings of the assumptions and factors driving the analysis conducted by an NRC Physical Scientist, who NRC considered a subject matter expert and who was responsible for conducting, documenting, and communicating his results. While the Physical Scientist attributed his analysis assumptions to OIG as engineering judgment, he did not have a basis for it and did not document a basis or a methodology in his report. When OIG briefed NRC managers on the issues OIG identified in the Physical Scientist's analysis, one noted that because the Physical Scientist conducted multiple calculations with increasing credit for pipeline enhancements, it appeared to be backwards engineering to get a desired result. An NRC senior manager said the Physical Scientist's use of credit for enhanced piping was inappropriate in part because the pipeline enhancements were not intended to mitigate the impact of a blast, but rather to reduce the chances of a rupture in the first place.

Several NRC senior managers said that based on issues identified in this event inquiry pertaining to the Physical Scientist's analysis, it may be prudent to redo the analysis.

Finding 2

OIG found that through the stakeholder's 2.206 petition and associated concerns – which were relevant and on point – NRC was presented an opportunity to reevaluate and confirm work previously conducted that supported the agency's conclusion that Entergy's hazards analysis was reliable. However, NRC failed to thoroughly reexamine the underlying premises of its analyses and did not accurately communicate its analytical work performed.

First, in response to the stakeholder's assertion that it would take longer than 3 minutes for the pipeline operators in Houston, Texas, to close the valves, thereby stopping the

flow of gas, NRC misrepresented the assumptions used in the followup bounding analysis that was conducted to assess the impact of 60 minutes of gas released. While NRC's response to the stakeholder described having conducted an assessment that assumed an infinite source of natural gas with the pipeline valves open for an hour, OIG's investigation found that NRC assessed only 1 minute of gas released. Moreover, NRC never confirmed the validity of the licensee's assumption that the valves could be closed in 3 minutes. OIG contacted the pipeline operator who estimated it would take at least 6 minutes after detection of a leak to close the valves. While the Physical Scientist told OIG he used 1 minute of gas released in his calculations, NRC managers had inconsistent understandings of the amount of mass the Physical Scientist used.

Second, in response to the stakeholder's question of whether NRC performed a validation and verification of NOAA's computer program to ascertain its adequacy for this purpose, NRC stated there was no need for NRC to perform a validation and verification of the computer program. However, OIG contacted NOAA, which confirmed the program is not designed for this purpose.

Third, NRC's response to the stakeholder stated that NRC used the methodology and equations of Regulatory Guide 1.91, NRC's guidance for evaluating postulated explosions near nuclear power plants, "without deviation"; however, OIG found that NRC used a draft regulatory guide in lieu of the final, approved version (which had been issued approximately 2 years prior) and deviated from the approved version in a manner that was less conservative and had an impact on the analysis outcome.

Fourth, the stakeholder asked whether NRC had any quality assurance requirements/procedures for conducting safety related calculations. NRC responded that they do not perform safety related calculations and do not have a quality assurance program for these calculations, but they said a peer review by a qualified NRC engineer was performed on NRC's independent analysis and followup analysis. OIG's investigation revealed that the assigned engineer, who felt there were more qualified people in NRC to do this, performed a limited review that focused mainly on the licensee's hazards analysis and not NRC's analyses.

An NRC senior manager conveyed to OIG that NRC decisionmakers rely on accurate information from the staff to support decisions and communicate accurately to stakeholders and, in this case, another Federal agency. However, NRC managers confirmed they do not have a quality assurance process or a formal peer review process to review this type of assessment.

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant (Case No. 16-024)

Background and Chronology

IPEC is a nuclear power station located on the east bank of the Hudson River in Buchanan, NY, about 24 miles north of New York City, New York. According to IPEC's website, the station's two operating reactors, Unit 2 and Unit 3, supply electricity for about 3 million customers. Unit 1 was shut down in 1974 and is undergoing decommissioning. Units 2 and 3 are scheduled for decommissioning beginning in 2020 and 2021, respectively. Initially licensed to Consolidated Edison Company of New York, Inc., IPEC's current license holder is Entergy Nuclear Operations, Inc. (Entergy), and regulatory oversight for IPEC is provided by the NRC Region I office located in King of Prussia, PA.

Natural gas pipelines have existed on the IPEC owner-controlled property since before plant construction. Algonquin Gas Transmission Company[1] (Algonquin) built a 26-inch diameter natural gas pipeline in 1952 and an adjacent 30-inch natural gas pipeline in 1965, and both traverse IPEC property. As part of the initial licensing basis, the licensee assessed each operating unit for postulated pipeline explosions of both pipelines. The assessment used the measured "shortest distance" from the pipeline to safety-related system, structures, and components (SSCs[2]) as the safe distance to meet NRC regulations. In response to later NRC requests focused on physical security, Entergy expanded the licensing basis to also include above ground sections of the pipelines. The assessments concluded no hazard to safe plant operation if a rupture of the gas pipelines occurred. Licensees are required to adhere to their current licensing basis or request an amendment depending on changes affecting the licensed operation of the plant.

On February 28, 2014, Algonquin applied to FERC to construct, install, operate, and maintain approximately 37 miles of pipeline and related facilities in New York, Connecticut, and Massachusetts. The project was referred to as the Algonquin Incremental Market (AIM) Project and proposed to replace certain portions of existing pipeline and to install new pipeline in other areas. The AIM Project included a stretch of new 42-inch pipeline across IPEC's southern side. This new pipeline would transmit gas at higher pressures than the existing 26- and 30-inch pipelines and would be located further away than the existing pipelines from the plant's safety-related SSCs and Security Owner Controlled Area (SOCA), but closer to eight important to safety (ITS[3]) SSCs. A portion of the 42-inch pipeline crossing IPEC property would be enhanced with more safety features than normal for new pipelines. The closest two

[1] Algonquin is an indirect wholly owned subsidiary of Enbridge Energy Corporation.
[2] Nuclear power plants are designed with SSCs that prevent or mitigate the consequences of postulated accidents which could cause undue risk to the health and safety of the public.
[3] Structures, systems, and components ITS shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

pipeline safety valves (which could be used to shut off gas to the portion of the pipe crossing IPEC property) encompassing the IPEC section of the pipe would be 3 miles apart. The next two closest safety valves, which encompass the 3-mile stretch of pipeline and its two safety valves, would be approximately 15 miles apart.

On April 2 and 23, 2014, NRC and FERC representatives met to discuss the AIM Project, the Federal review process, and regulatory responsibilities. FERC provided an overview of the role of a cooperating agency.[4] NRC declined to become a cooperating agency but agreed to provide appropriate information, as needed, on the impacts of the AIM Project.

On August 6, 2014, FERC issued a draft Environmental Impact Statement (EIS) concerning the impact of the pipeline.[5] FERC concluded that based on its consultation with NRC, Entergy was required to assess any new safety impacts on its IPEC facility and provide its analysis to NRC. NRC's role was to ensure that the IPEC licensee adequately assessed the safety implications of the proposed pipeline at the nuclear site, as well as to determine if the licensee's analysis met the NRC's requirements regarding plant changes.

On August 24, 2014, Entergy completed its 10 CFR 50.59[6] safety evaluation and an associated hazards analysis, which covered the consequences of a fire and explosion following release of natural gas from the proposed new AIM Project 42-inch-diameter pipeline. The 10 CFR 50.59 report noted,

> While the proposed 42-inch pipeline is further from IP2 and IP3 SSCs within the 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.

Because the 10 CFR 50.59 safety evaluation concluded there is a change to the current licensing basis for design basis external hazards, Entergy was required to undertake the associated hazards analysis. Entergy hired a consulting firm to prepare two supporting evaluations referred to as the "hazards analysis." The first evaluation included calculations for the consequences of postulated explosions and fire with missile generation[7] following the release of natural gas from the proposed new 42-inch pipeline

[4] Under the National Environmental Policy Act (NEPA), upon request of a lead agency preparing an EIS, any other Federal agency which has jurisdiction by law shall be a cooperating agency. In addition, any other Federal agency which has special expertise with respect to any environmental issue that should be addressed in the EIS may be a cooperating agency upon request of the lead agency.
[5] NEPA requires Federal agencies prepare an Environmental Impact Statement (EIS) if a proposed major federal action is determined to significantly affect the quality of the human environment.
[6] A 10 CFR 50.59 review is a technical evaluation performed by a licensee to determine if a proposed change to the facility represents a significant modification to the plant design and licensing bases as described in the Final Safety Analysis Report and, therefore, requires NRC approval prior to implementation.
[7] Missile generation are projectiles associated with detonation of potentially explosive material.

at two locations. Location one was the area on the underground piping that measured the shortest distances to the SSCs ITS, as committed to in IPEC's licensing basis. Location two was based on measurements of an above ground pipeline rupture point on the 42-inch pipeline, referred to as the "tie-in[8]" location. Although the above ground location was further away from the plant than the underground location, it was assessed because of the potential impacts from intentional and malicious activity.

For both locations (above and below ground), Entergy measured the shortest distances from the new 42-inch pipeline to several SSCs ITS and developed a table that identified these distances per component.

For Entergy's first evaluation, they used several methodologies and included in their analysis factors for pipeline enhancements such as thicker piping, thicker corrosion protection, greater burial depth, and installation of protective reinforced concrete mats to impede access to the buried piping. Entergy assumed the isolation valves were 3-miles apart and would close within 3 minutes of a pipeline rupture. Entergy claimed to have done the explosion and fire assessments in accordance with NRC Regulatory Guide 1.91, "Evaluations of Explosions Postulated to Occur at Nearby Facilities and on Transportation Routes Near Nuclear Power Plants," Revision 2[9], (RG 1.91) as well as using Areal Locations of Hazardous Atmospheres (ALOHA) and BREEZE computer programs.

Entergy's second evaluation was a statistical analysis of fire and explosions using "best available" accident data for pipeline rupture frequency. This assessment determined Exposure Rates[10] for a failure of the proposed 42-inch pipeline.

As documented in its 10 CFR 50.59 Safety Evaluation and Hazards Analysis, Entergy concluded that the proposed pipeline did not pose a "significant reduction in the margin of safety" for the public and that the change did not require prior NRC approval (i.e., a license amendment). Entergy based this conclusion on pipeline design and installation enhancements, the results from the fire and explosion evaluation, and the exposure rate assessment. However, there were two exceptions that were below NRC's threshold criteria which required additional evaluation. The two exceptions were the meteorological tower and the steam generator storage facility which are SSCs ITS. For these two exceptions, Entergy provided safety justifications. Specifically, for the meteorological tower, Entergy stated it had an alternative means to perform the meteorological function. For the steam generator storage facility, the safety evaluation demonstrated that failure of this component would not exceed the radiation dose limits imposed by NRC guidelines.

In September 2014, NRC Region I performed a permanent plant modification inspection (PMMI) at IPEC. One of several PMMI objectives is to verify that modifications to the

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[8] Pipeline "tie-in" locations are above ground and used for inspection and maintenance throughout the entire pipeline.
[9] Agencywide Documents Access and Management System (ADAMS) Accession Number ML12170A980
[10] Exposure rates are analyses that demonstrate risk.

plant have not affected the safety functions of important safety systems. As one of three samples chosen for this inspection, NRC reviewed the 10 CFR 50.59 safety evaluation and supporting hazards analysis, conducted a walk-down of the proposed pipeline routing, and performed an independent analysis of the potential hazards relative to the new 42-inch pipeline.

An NRC Region I Security Inspector conducted this inspection with support from a Physical Scientist from NRC headquarters Office of New Reactors[11] (NRO), Radiation Protection and Accident Consequences Branch (RPAC). The Physical Scientist was considered an NRC subject matter expert on external hazards. The Region I Security Inspector did the on-site inspection activities while the Physical Scientist was tasked to perform independent confirmatory calculations. The Physical Scientist documented the results of his review in a six-page technical report titled, "Safety Review and Confirmatory Analysis, Entergy's 10 CFR 50.59 Safety Evaluation, Algonquin Incremental Market (AIM) Project, Indian Point Energy Center (IPEC)" (NRC AIM Project Safety Review). This report stated that the Physical Scientist performed independent confirmatory calculations with conservative assumptions and rationale using NRC RG 1.91 methodology and/or the ALOHA computer program to assess an explosion, jet fire, and cloud fire at the above ground point on the pipeline and the closest point (underground). The Physical Scientist's analysis was based on a stretch of pipeline consisting of about 3 miles between isolation valves, of which the enhanced section of pipeline length is identified to be 3,935 feet, and closure of the isolation valves within 3 minutes.

The Physical Scientist concluded that safety-related SSCs inside the SOCA passed the safety criteria, but that nearby SSCs ITS would be affected because the calculated minimum safe distances from the above ground reference point exceeded the safety criteria. To address the exceedance, the report stated,

> The staff finds that the impacts to the SSCs ITS from the proposed new 42-inch pipeline are bounded by the impacts from low probability events of extreme natural phenomena (including seismic activity, tornado winds, and hurricanes) which have been assessed and already addressed in the Indian Point Units 2 and 3 Updated Final Safety Analysis Report.[12]

The Physical Scientist's NRC AIM Project Safety Review was reviewed by the Region I Physical Security Inspector who shortened it into a four-page summary, or "feeder." This "feeder" was approved by two Region I Branch Chiefs and was incorporated into the NRC's Third-Quarter Integrated Inspection Report, issued to Entergy's IPEC Site Vice President on November 7, 2014[13]. The inspection report concluded that the proposed pipeline does not introduce significant additional risk to safety-related SSCs and SSCs ITS at Indian Point Units 2 and 3; and, therefore, the change in the design

[11] On October 13, 2019, NRO was reunified with the Office of Nuclear Reactor Regulation (NRR) and the resulting organization retained the title NRR.
[12] The most recent final safety analysis report (FSAR) includes the plant-specific design-basis information.
[13] ADAMS Accession Number ML14314A052

bases external hazards analysis associated with the proposed pipeline does not require prior NRC review and approval.

As reflected in an Interagency Meeting Summary prepared by FERC, on October 17, 2014, FERC held a conference call with NRC to discuss NRC's review of Entergy's site hazards analysis for IPEC relative to Algonquin's proposed AIM Project. The summary reflects that one FERC staff, one individual from the Natural Resource Group, LLC, and six NRC staff members involved with IPEC attended the conference call. The meeting summary conveyed that NRC had conducted an independent analysis of Entergy's 10 CFR 50.59 submission and an independent confirmatory blast analysis. The summary stated that Algonquin had committed to take additional mitigation measures to enhance the pipeline design and construction, but that NRC's analysis did not allow any credit for these additional mitigation measures and assumed a catastrophic pipeline failure. The summary stated that the review covered everything within the SOCA, which includes everything inside the outer most fenced area of the facility (including the spent fuel rods) and that "based on its review, the NRC came to the same conclusion that Entergy did in its 10 CFR 50.59 submission. Therefore, NRC finds Entergy's 10 CFR 50.59 submission acceptable and has determined that no prior approval from the NRC is needed."

On October 15, 2014[14], a citizen stakeholder submitted a 10 CFR 2.206[15] petition to the NRC requesting the NRC to take enforcement action against Entergy for violating the regulations of 10 CFR 50.9, "Completeness and Accuracy of Information," 10 CFR Part 50, Appendix B, "Quality Assurance Requirements," and 10 CFR 50.59, "Changes, Tests, and Experiments." The stakeholder provided numerous examples and direct quotes from IPEC's 10 CFR 50.59 Safety Evaluation and Hazard Analysis that he believed violated these regulations.

In January 2015, the stakeholder presented his 2.206 concerns before an NRC Petition Review Board (PRB). In the months that followed, the stakeholder continued to submit additional information to support his allegation, including documents from the stakeholder's Freedom of Information Act (FOIA) requests to the NRC.

Also in January 2015, FERC issued its final EIS for the entire pipeline, assessing the potential environmental effects of the construction and operation of the AIM Project in accordance with the requirements of the National Environmental Policy Act. The EIS conveyed the FERC staff's conclusion that "approval of the proposed project would result in some adverse environmental impacts; however, most of these impacts would

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[14] ADAMS Accession Number ML14294A758

[15] 10 CFR 2.206 has been a part of the NRC's regulatory framework since the NRC was established in 1975. Section 2.206 permits any person to file a request to institute a proceeding pursuant to Section 2.202 of 10 CFR to modify, suspend, or revoke a license, or for other action as may be proper (hereinafter referred to in this directive as to take enforcement-related action). Such a request is referred to as a 2.206 petition.

be reduced to less than significant levels with the implementation of Algonquin's proposed mitigation and the additional measures[16] recommended in the final EIS."

The EIS quotes Entergy's Safety Evaluation conclusion that

> …based on the proposed routing of the 42-inch diameter pipeline further from safety related equipment at IPEC, and accounting for the substantial design and installation enhancements agreed to by [Algonquin], the proposed AIM project poses no increased risks to IPEC and there is no significant reduction in the margin of safety.

The EIS also describes NRC's assessment of Entergy's evaluation:

> The NRC has reviewed the site hazards analysis performed by Entergy and has performed an independent confirmatory analysis of the blast analysis as well. The NRC issued its findings in a report dated November 7, 2014. The NRC's analysis did not include factoring in the additional pipeline design measures identified by Entergy and committed to by Algonquin and assumed a pipeline catastrophic failure. The review covered everything within the Security Owner Controlled Area, which includes everything inside the outermost fenced area of the facility (including the area with the spent fuel rods). The NRC concluded that a breach and explosion of the proposed 42-inch-diameter natural gas pipeline would not adversely impact the safe operation of the facility.

On March 3, 2015, FERC's Chairman and Commissioners issued an order formally approving the AIM Project. Page 37 of the order states,

> The NRC reviewed the site hazards analysis performed by Entergy and performed an independent confirmatory analysis of the blast analysis as well. The NRC's analysis did not account for the additional pipeline design measures identified by Entergy and committed to by Algonquin and assumed a pipeline catastrophic failure. The review covered everything within the Security Owner Controlled Area, which encompasses everything inside the outermost fenced area of the facility including the area with the spent fuel rods. The NRC concluded that a breach and explosion of the proposed 42-inch-diameter natural gas pipeline would not adversely impact the safe operation of the Indian Point Facility. Therefore,

[16] Where the pipeline crossed IPEC property, these measures included (1) using internally coated piping that "exceeds the most stringent Class 4 requirements set by the U.S. Department of Transportation (even though this area is predominantly Class 3), (2) installing two parallel sets of fiber-reinforced concrete mats over the pipeline that would act as a physical barrier over the buried pipe, (3) installing yellow warning tape above and below the concrete slabs, (4) burying the pipeline to a minimum depth of 4 feet from the top of the pipeline, and (5) providing thicker external corrosion protection and internal coating.

the final EIS concludes that the project will not result in increased safety impacts at the Indian Point facility.

On April 8, 2015, Entergy submitted a revised 10 CFR 50.59 assessment to the NRC, acknowledging that amended pipeline plans indicated the 42-inch pipe would not come above ground. The revised 10 CFR 50.59 assessment reevaluated the "tie-in" location with the installed piping configuration and concluded that there were no increased risks to IPEC from the proposed AIM Project and the original Safety Evaluation remained bounding.

In April 2015, the stakeholder received a second FOIA response that he believed supported his allegation that Entergy had provided a material false statement regarding Enbridge's ability to close the isolation valves within 3 minutes. The stakeholder requested an opportunity for a second presentation to the PRB which was granted and held on July 15, 2015. During the presentation, it was agreed that the stakeholder would submit remaining questions in writing; subsequently, the stakeholder prepared a written list of 39 questions that he submitted to the NRC on July 27, 2015.

In September 2015[17], the NRC rejected the stakeholder's petition and in November 2015, provided answers to the stakeholder's 39 questions.

On January 7, 2017, the pipeline went into use.

Part I. Problems Identified by OIG With NRC's November 7, 2014, Inspection Report and Underlying Analysis

OIG learned that while FERC relied heavily on NRC's November 7, 2014, inspection report as its basis for determining that IPEC could be safely shut down if a pipeline accident occurred, the underlying analysis for the inspection report was based on

- **A series of NRC calculations – assessing the closest location of the pipeline to plant components at a below ground point – that gave increasing amounts of "credit" for pipeline enhancements until the level of "credit" given resulted in an answer that demonstrated no increased risk, if a rupture occurred, to any safety related SSCs and SSCs ITS inside the SOCA.** In contrast, both FERC's EIS and its March 3, 2015, order approving the AIM Project, state that NRC's analysis did not account for the pipeline enhancements. OIG notes that the approach used by NRC – of crediting enhancements – was less conservative than the approach as described in the FERC documents, which indicated that no credit was given for enhancements.

- **NRC's analysis of the impact of a rupture in a non-existent, above-ground point on the 42-inch pipeline.** OIG learned that the 42-inch pipeline does not go above ground at the "tie-in" location.

[17] ADAMS Accession Number ML15251A023

- **An inaccurate statement in NRC's analysis that although there was increased risk to SSCs ITS outside the SOCA if a pipeline rupture occurred, this was acceptable because these impacts were "bounded" by the impacts of extreme natural phenomena (e.g., tornadoes, hurricanes), which have been assessed and already addressed in the Indian Point Units 2 and 3 Updated Final Safety Analysis Reports (UFSAR)**. OIG learned that these impacts are not addressed in the Indian Point UFSARs.

- **NRC's misguided use of the ALOHA program to assess an explosion, a jet fire, and a cloud fire for the above and below ground portions of the pipeline.** Officials at the National Oceanic and Atmospheric Administration, Office of Response and Restoration Emergency Response Division[18] (NOAA), which created ALOHA, told OIG that ALOHA is not intended to assess impacts of explosions involving the type of "supercritical[19]" gas that would flow through the 42- inch pipe at IPEC. NOAA also told OIG ALOHA cannot assess 3 minutes of gas release prior to valve closure even though NRC's analysis claimed to do so, and it cannot model a double ended pipe break, which NRC also claimed to have done.

  Finally, OIG learned from Enbridge that it would, in fact, take the pipeline operators a minimum of 6 minutes after a leak is detected to manually close the isolation valves and thereby stop the flow of gas into the ruptured portion, and not 3 minutes as NRC claimed to have calculated using ALOHA. Enbridge also told OIG that if there were an explosion near IPEC, operators would shut valves that were approximately 14 miles apart rather than 3 miles apart as NRC assumed in its analysis.

- **OIG also learned that NRC's November 7, 2014, inspection report included an inaccurate statement that as part of NRC's analysis, the agency assessed the impact of "missile generation" that would occur if safe distance was exceeded for SSCs ITS.** Although NRC determined that safe distance was exceeded for SSCs ITS outside the SOCA, OIG learned that the agency did not assess missile generation.

Witness interviews of two FERC headquarters-based engineers assigned to the AIM Project revealed that FERC used NRC's November 7, 2014, inspection report for its Environmental Impact Statement (EIS) and FERC's Commission relied heavily on NRC's expertise to determine if IPEC could be safely shut down in the event of a pipeline accident, for approval of the portion of the AIM Project that crossed IPEC property.

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[18] Department of Commerce, National Oceanic and Atmospheric Administration, National Ocean Service Office of Response and Restoration Emergency Response Division, Seattle, Washington.
[19] Methane gas is in a "supercritical" state at 850 psi and 25° Celsius.

Review of NRC AIM Project Safety Review

The Physical Scientist's NRC AIM Project Safety Review examined the potential impact of a pipe rupture at two points on the pipeline. One point was underground; this was the shortest distance to the SOCA – which is a point addressed in the plant's current licensing basis. The other location, discussed in the next section of this report, also in the current licensing basis, was a site further from the plant where initial AIM Project plans indicated the pipe would come above ground. The Physical Scientist's review concluded that safe distance would not be exceeded for the safety-related SSCs inside the SOCA but would be exceeded for SSCs ITS outside the SOCA. According to his report, pipe failure would not reduce any further the existing safety margins, and would not pose a threat to the safe operation of the plant or safe shutdown because the potential impacts to SSCs ITS outside the SOCA were bounded by previous studies addressed in the licensee's UFSAR. OIG noted that about five pages of the NRC AIM Project Safety Review focused on the above ground point, and about one page focused on the below ground point.

NRC Conducted Multiple Calculations Giving Increasing Amounts of Credit for Pipeline Enhancements Until Answer Envisioned No Added Risk

In reviewing the Physical Scientist's documentary materials supporting his analysis of the nearest point, OIG noted the Physical Scientist conducted a series of calculations on a particular point where the pipeline was enhanced with thicker piping, greater corrosion resistance, deeper burial depth, and protective reinforced concrete mats located above the buried piping. OIG noted that for each calculation, the Physical Scientist made incremental adjustments by giving credit for pipe enhancement features and using the average release instead of maximum release rate for the mass input variable. OIG observed that once the calculation yielded results that met the safe distance requirement, no additional credits were given. The first calculation used maximum release rate and gave no credit for pipeline enhancement features and yielded results that exceeded safe distance for safety related SSCs and SSCs ITS within and outside the SOCA. The second calculation used maximum release rate and gave 65 percent credit for pipeline enhancement features and yielded results that exceeded safe distance for safety related SSCs and SSCs ITS within and outside the SOCA. The third calculation used average release rate and gave no credit for pipeline enhancements. The third calculation for safe distance met requirements for SSCs and SSCs ITS inside the SOCA; however, it exceeded safe distances for SSCs ITS outside the SOCA. The fourth calculation used average release rate and 65 percent credit for pipeline enhancements. Only the fourth calculation met the safe distance requirement for all reference points.

OIG noted that NRC's use of credit for pipe enhancement features as described above contradicts statements in FERC's EIS and March 3, 2015, order approving the AIM Project, which both state that NRC's analysis did not account for the pipeline enhancements.

The Physical Scientist told OIG he relied on his engineering judgment[20] in assigning 65 percent credit for the pipeline safety features and for factoring in average release rate. When asked to explain the basis for assigning 65 percent credit for pipeline enhancements and for using the average release rate, instead of providing any quantitative or empirical data to support his engineering judgment, the Physical Scientist stated, “That is my call. That is my assumption.” Regarding his assigning 65 percent credit for the pipeline safety features, the Physical Scientist told OIG, because the pipeline is underground and has a layer of concrete slaps above, the pipeline will leak at a slower rate than when above ground. “So that’s why one-third might be a reasonable number.” Regarding his substitution of average release for maximum release rate, the Physical Scientist told OIG, “an average value would be more [realistic] than a conservative maximum value” because the gas would release at a slower rate due to the pipe’s underground location. The Physical Scientist added, “At what rate I do not know. The only possible rate it can be is an average rate.” The Physical Scientist told OIG he did not describe the various underground scenarios in his NRC AIM Project Safety Review but included his conclusion that the underground scenario would not adversely impact the safe operation and shutdown of IPEC. He said it would have been “too confusing to address so many scenarios, so many things.”

The Physical Scientist’s Branch Chief at the time, who assigned the Physical Scientist to conduct the review, told OIG he was aware that the Physical Scientist ran many scenarios, but the Physical Scientist did not go over the results or details with him. The Branch Chief said that he knew the Physical Scientist took “65 percent credit” for the pipeline enhancements based on his engineering judgment. When OIG shared the four calculations and results with the fourth calculation not exceeding the minimum safe distance, the Branch Chief said that it appeared, from looking at the Physical Scientist’s scenarios, that the Physical Scientist was backward engineering for a desired result. When OIG shared the statement in FERC’s EIS that described that the NRC’s analysis did not include factoring in the additional pipeline design measures identified by Entergy and committed to by Algonquin, the Branch Chief said that description is contrary because the Physical Scientist did take credit for the pipeline enhancements.

NRC Analyzed a Non-Existent, Above-Ground Point

As noted above, the Physical Scientist also examined a second site further from the plant where initial AIM Project plans indicated the pipe would come above ground. However, OIG learned that while the initial 42-inch pipeline design proposed by Algonquin indicated the new pipeline would come above ground on IPEC property, the final pipeline design and pipeline as built never comes above ground on IPEC property.

OIG spoke with Enbridge regarding several matters under investigation. For the matter of the above ground scenario, Enbridge told OIG that the 42-inch gas pipeline on IPEC property never comes above ground. The only portion above ground is a “pig trap,” also

[20] NUREG 1913, “Design Control in Pursuit of Engineering Excellence, A Quick Reference Guide for NRC Inspectors,” defines engineering judgment as a determination based on prior examples, experience, or observation that has not been subjected to rigorous engineering validation.

known as a “pig station,” which is a configuration of pipes and “tie in” valves that are used for cleaning, maintenance, and inspection. For the pig station near IPEC, the largest diameter pipeline above ground is 26 inches.

OIG learned that while IPEC’s initial 10 CFR 50.59 analysis also assessed the proposed above ground point, on April 8, 2015, IPEC submitted to NRC a revised 10 CFR 50.59 that acknowledged the change-in-design and re-assessed the impact of an explosion on the pig station, using the specific dimensions associated with the as-built piping. Although the revised 10 CFR 50.59 was provided to NRC – approximately 1 month after FERC’s approval of pipeline construction and approximately 20 months before pipeline went into operation – the NRC never conducted further analysis on the actual as-built pipeline, and much of NRC’s analysis remains based on a non-existent, above ground location.

The Physical Scientist told OIG that although he conducted multiple scenarios at the underground closest location to the plant, the above ground location was the basis for his conclusion for the NRC AIM Project Safety Review and the NRC inspection report. The Physical Scientist viewed the above ground point as a more credible location for a potential pipeline rupture since it was exposed on the surface.

The Physical Scientist’s Branch Chief said he was aware that the Physical Scientist used the above ground point in his analysis. The Branch Chief said that Region I looked at the Physical Scientist’s calculations too and he recalled discussions that the calculations were based on the worst hazard to the closest SSCs. Furthermore, the Branch Chief believed some conservatisms were employed by the Physical Scientist in his calculations and modeling, such as catastrophic failure of the pipe closest above ground location to the plant, which should provide for the worst-case scenario.

The NRC IPEC Project Manager who was also assigned as the 2.206 petition manager for the stakeholder’s concerns was not aware that the reported result of the NRC’s independent analysis was primarily based on the above ground location rather than the closest point. The Project Manager, who was NRC’s primary communicator with FERC, told OIG he assumed the reported confirmatory analysis was done at the closest location to the plant for conservatism and to compare with Entergy’s analysis results. The Project Manager clearly recalled that the 42-inch pipeline did not come above ground while on IPEC’s property. The Project Manager said he would have expected the worst-case scenario (e.g., no credit taken for enhancements, maximum release rate, closest point to the plant) to have been assessed and was surprised that it was not.

NRC Incorrectly Stated Impacts Were Bounded by Previous Assessments

OIG also learned that both the NRC AIM Project Safety Review and NRC’s November 7, 2014, inspection report each included an inaccurate statement suggesting that prior analysis indicated that although the current analysis showed risk to the SSCs ITS, these risks were “bounded” by previous studies. Specifically, the two reports

stated that impacts to the SSCs ITS outside the SOCA from both the above ground and below ground points analyzed

> …are bounded by the impacts from low probability events of extreme natural phenomena (including seismic activity, tornado winds, and hurricanes) which have been previously assessed and are addressed in the Indian Points Units 2 and 3 UFSAR. Indian Point Units 2 and 3 would still be able to achieve safe shutdown conditions.

Through review of the Indian Point Units 2 and 3 UFSAR and verification with IPEC officials, OIG learned the UFSAR does not address the bounding effects of extreme natural phenomena on SSCs ITS outside the SOCA. RG 1.91 states that additional analyses are required if SSCs ITS safe distances are not met.

The Physical Scientist recalled reporting that a pipe rupture impacting the SSCs ITS was bounded by more severe accidents such as extreme natural phenomena already evaluated in IPEC's UFSAR. According to the Physical Scientist, he did not conduct additional analysis because he believed the UFSAR already established this analysis.

NRC Used ALOHA to Model Scenarios Outside of ALOHA's Parameters

Based on review of NRC's Project AIM Safety Review and the Physical Scientist's supporting documentation, OIG learned that the Physical Scientist used the ALOHA program to determine the impacts for the jet flame, cloud fire, vapor cloud explosion, and unconfined explosion on IPEC's SSCs related to safety and the SSCs ITS. NOAA officials told OIG that ALOHA is designed for use during accidental chemical spills to help emergency response professionals assess the risk associated with toxic air hazards, thermal radiation from fires, and blast effects. NOAA officials explained that although ALOHA includes an extensive library of chemical property data, and models to assess the rate at which a chemical is released from containment and vaporizes, it has technical limitations.

After reviewing the ALOHA assessments done by the NRC for IPEC, NOAA officials provided OIG several areas of concern because they are outside the technical limitations of ALOHA's capability. First, ALOHA is not intended to assess impacts of explosions involving the type of "supercritical" gas that would flow through the 42-inch pipe at IPEC. According to NOAA officials, the pressure and temperature of the methane gas that the NRC modeled is within the "supercritical" state. OIG provided NOAA officials with the Physical Scientist's ALOHA model assumptions and results. NOAA officials told OIG that a simplified sensitivity assessment they ran, based on the information provided by OIG, resulted in an approximate underestimation of mass of flammable vapor released by 9 percent. This underestimation of mass resulted in a less conservative value.

Second, NOAA officials told OIG that ALOHA lacks the capability to assess 3-minutes of gas release prior to valve closure – although NRC's analysis stated it used a 3-minute valve closure time in its NRC AIM Project Safety Review. According to NOAA, the ALOHA program can assess only two valve scenarios – these are (1) valves closed (i.e., 0 minutes of gas released) or (2) the valves are connected to an infinite source (i.e., 60 minutes of gas released). For the valves closed scenario, ALOHA calculates just the residual gas mass in the pipeline. ALOHA provides several results to include a 1-minute maximum release rate of mass and a total release of mass. Therefore, statements in the Physical Scientist's NRC AIM Project Safety Review describing the estimated impacts that would result from an explosion, jet fire, and cloud fire, "considering manual closure of the isolation valves within 3-minutes," are inaccurate because ALOHA does not have the capability to model this scenario.

Additionally, OIG learned that ALOHA is designed solely for vertical breaks into the atmosphere and surrounding area; it is not designed for horizontal pipe breaks, it is not designed to model buried pipe, and ALOHA cannot model a double ended break where the pipe has broken in the middle and is leaking from both broken ends. The model can calculate the release from one side of the pipeline, but not both sides together.

Finally, OIG learned from Enbridge that it would, in fact, take the company a minimum of 6 minutes after leak detection to seal off the pipe and thereby stop the flow of gas into the ruptured portion, and not 3 minutes as NRC tried to calculate using ALOHA. Enbridge officials also told OIG that in the event of a rupture, operators would seal off approximately 14 miles of the pipeline surrounding the rupture point, and not the 3 miles the Physical Scientist used in his calculations.

The Physical Scientist told OIG he used ALOHA to determine the impacts for the jet flame, cloud fire, vapor cloud explosion, and unconfined explosion on IPEC's SSCs related to safety and the SSCs ITS. The Physical Scientist told OIG he believed ALOHA had been validated by the industry and was an accepted Environmental Protection Agency (EPA) and NOAA model for the analysis conducted.

The Physical Scientist's Branch Chief was not aware of ALOHA's limitations as described by NOAA, and said they caused him concern. He did not recall any discussions with the Physical Scientist about the use of ALOHA.

NRC Inspection Report Incorrectly Stated Missile Generation Was Assessed

OIG compared the language in NRC's November 7, 2014, inspection report description of NRC's "independent calculation results using conservative assumptions and rationale" with the Physical Scientist's calculations and the description in the NRC AIM Project Safety Review. OIG noted that the inspection report states that NRC assessed "missile generation." Specifically, the November 7, 2014, inspection report stated,

> The NRC's Physical Scientist performed an independent analysis of the hazards associated with the proposed pipeline. The analysis was

> performed based on the following conditions and hypothetical scenarios: rupture of the proposed pipeline located near IPEC resulting in an unconfined explosion or jet flame at the source; delayed vapor cloud fire or vapor cloud explosion; and accompanying missile generation.

The NRC AIM Project Safety Review stated,

> The analysis assumed that rupture of the natural gas pipeline may result in an unconfined explosion or jet flame at the source, delayed vapor cloud fire, or vapor cloud explosion. Missile generation may also accompany the rupture/explosion.

However, OIG's review of the Physical Scientist's calculations did not support that missile generation was assessed.

The Physical Scientist told OIG that he did not calculate missile generation because the minimum safe distance did not exceed the SSCs. RG 1.91 suggests that additional analysis, such as missile generation, be done if the minimum safe distance is exceeded for SSCs ITS. However, the Physical Scientist argued that in light of his understanding of RG 1.91, only the SSCs required further analysis if the minimum safe distance was exceeded. The Physical Scientist acknowledged that he did not pay close attention to the wording in RG 1.91 for SSCs ITS.

Interviews of NRC Managers

The Region I Branch Chief, who signed the November 7, 2014, inspection report, confirmed that although Region I reviewed Entergy's initial 10 CFR 50.59 as part of the inspection, Region I relied heavily on the Physical Scientist's NRC AIM Project Safety Review to determine the inspection finding of "no finding" because Region I alone did not have the expertise to make that decision. The Region I Branch Chief believed FERC used NRC's inspection report as one of the bases for its EIS and approval and he believed the Physical Scientist used the most conservative location in his analysis, which he believed was above ground.

In contrast, the Region I Deputy Regional Administrator, who was then the Region I Director of Reactor Safety, said the staff's 10 CFR 50.59 inspection did not rely on the Physical Scientist's calculations for the inspection's outcome. However, the Physical Scientist's work gave the region added confidence that there was no technical issue that Entergy might have missed and therefore no reason to challenge Entergy's conclusion that the new pipeline did not pose an increased risk and warrant a license amendment. The Deputy Regional Administrator said prior to the OIG interview, he had not been aware of the specific assumptions and factors the Physical Scientist had used in his calculations pertaining to the above and below ground scenarios; however, he was comfortable with the Physical Scientist's approach. He said he was confident in the outcome because it was a "very, very conservative approach." Nevertheless, the Deputy Regional Administrator acknowledged that based on the discrepancies

described by OIG, it would be prudent to conduct additional analysis to demonstrate there is no issue or problem.

In a series of meetings with NRC's then-Deputy Executive Director for Reactor Preparedness Programs (DEDR) (now retired), OIG described the discrepancies identified in NRC's AIM Project Safety Review. The DEDR was initially unfamiliar with the specifics of NRC's analysis, but said his understanding was the staff had done a thoughtful review and he was comfortable with the conclusions reached. However, based on the information OIG provided and his subsequent discussions with his technical staff, he told OIG he would be open to assess whether any additional work was needed after having an opportunity to review OIG's report. He said if the staff made any mistakes that raise questions, then "let's demonstrate to ourselves that this does not cast doubt on the overall conclusions that we drew. And, if it does, then we've got some more work to do…."

OIG briefed the current DEDR on the results of this event inquiry. The DEDR, who was familiar with Project AIM because he served as the Region I Regional Administrator in the 2014-2018 timeframe, expressed serious concerns about the issues identified by OIG. Specifically, the DEDR disagreed with the Physical Scientist's use of credits for enhanced piping in his underground calculations because the DEDR said the enhancements were not intended to mitigate the effects of a blast but were intended to reduce the chances of a pipe rupture in the first place (e.g., due to a backhoe or other digging equipment). In addition, the DEDR was concerned that the Physical Scientist did not provide a basis or explanation underlying his "engineering judgment." According to the DEDR, "engineering judgment does not mean winging it."

With regard to inaccuracies in NRC's November 7, 2014, inspection report (i.e., SSCs ITS bounded by UFSAR and that missile generation was examined), the DEDR said these factual errors were unacceptable and did not meet his expectations. The DEDR was concerned about information NRC had publicly communicated, especially in an agency decision document. The DEDR said if there were inaccuracies in an inspection report "that other agencies are relying on," there may be a need to clarify and amend the record.

With regard to NOAA's estimate that NRC's analysis underrepresented the mass of gas released in all scenarios by approximately 9 percent which resulted in a less conservative value, the DEDR remarked he would expect the users of a code to understand the code's parameters and he was concerned about the non-conservative results.

With regard to IPEC's revised 10 CFR 50.59 safety evaluation based on the 42-inch pipe not coming above ground in the final pipeline design, the DEDR assumed his inspectors were aware and had reviewed and assessed the impact of the design change. He was not concerned that the 42-inch pipe did not come above the ground because an above-ground explosion would have a more far reaching impact than a

below ground explosion at the same location. Therefore, the DEDR said the Physical Scientist's initial assessment of the above ground point was bounding.

In summary, the DEDR stated that NRC management has to rely on the information provided to them by the agency's technical experts. He said this information needs to be accurate and robust for sound decisionmaking. He commented that while communication can be challenging, in these matters, it needs to be sufficiently clear to allow for sound agency decisions.

Part II. NRC's Response to Stakeholder Concerns Over Project AIM Pipeline

NRC followed its 10 CFR 2.206 petition process in reviewing and responding to a citizen stakeholder's specific concerns about the impact of the new pipeline on IPEC property, which resulted in NRC's formal rejection of the stakeholder's concerns reflected in the original petition and in the stakeholder's associated correspondence to NRC. However, OIG learned that in communicating its decision to the stakeholder, NRC provided an inaccurate description of the work NRC conducted to assess the stakeholder's concerns. The investigation also revealed that NRC provided inaccurate information in response to the stakeholder's questions to NRC concerning the agency's NRC AIM Project Safety Review.

Specifically, the stakeholder challenged

- **Both Entergy's and the Physical Scientist's assumption, in their respective assessments, that the pipeline valves could be closed in 3 minutes.** The stakeholder asserted that it would not be possible for the valves to be closed within 3 minutes and questioned why NRC did not inform FERC that the fundamental assumptions and calculations were inaccurate. The stakeholder also asserted that Entergy violated 10 CFR 50.9 by providing a material false statement concerning the 3-minute valve closure times to the NRC in its 10 CFR 50.59 safety evaluation.

  OIG learned from Enbridge (the pipeline company) that it would take at least 6 minutes to close the valves after a leak is detected. The investigation also revealed that in response to the stakeholder's concern about a material false statement regarding the 3-minute closure time, NRC chose to conduct a 60-minute bounding analysis, and inaccurately described the results of its followup calculation. This analysis was used to refute the stakeholder's allegation of a material false statement.

- **NRC's use of ALOHA to assess the impact of pipe rupture on IPEC.** The stakeholder questioned why NRC would use ALOHA, which, according to the stakeholder, "is prohibited for use for a gas pipeline rupture [and] not referenced in RG 1.91, to calculate the blast radius of a rupture that could have a devastating impact to the more than 20 million persons residing in the vicinity of

Indian Point." The stakeholder also asked whether NRC performed a validation and verification of the ALOHA program to ascertain its accuracy.

OIG's investigation revealed that NRC informed the stakeholder that a validation and verification of ALOHA was not necessary. However, as noted previously in this report, NOAA, which created ALOHA, told OIG the program was not designed to assess the scenarios used by NRC to support the NRC AIM Project Safety Review.

- **NRC's deviation from RG 1.91 in calculating blast radius.** The stakeholder asserted that NRC modified the equation for calculating the blast radius in RG 1.91 and asked why NRC failed to provide a basis for deviation from the regulatory guide.

  Although NRC's response to the stakeholder claimed NRC used RG 1.91, Revision 2, without deviation, OIG's investigation identified that NRC deviated from RG 1.91 in a manner that was less conservative and had an impact on the outcome.

- **The quality assurance process used by NRC to verify the results of the NRC AIM Project Safety Review and followup assessment.** The stakeholder asked whether NRC has any quality assurance requirements/procedures for conducting safety related calculations.

  NRC responded to the stakeholder that NRC does not perform safety related calculations and does not have a quality assurance program for these calculations; however, they said a peer review by a qualified NRC engineer was performed on the NRC AIM Project Safety Review and followup assessment. OIG's investigation revealed the assigned engineer believed there were better qualified NRC staff to do the review and he performed only a limited review.

OIG Review of Correspondence

OIG reviewed correspondence between the citizen stakeholder and NRC dated October 15, 2014, through November 6, 2015, reflecting the stakeholder's concerns, and NRC's responses, about the safety impact on IPEC due to Enbridge's proposed 42-inch diameter natural gas pipeline that would traverse a portion of the owner-controlled property at IPEC. In at least four letters to NRC and two presentations to the NRC Petition Review Board (PRB), the stakeholder raised concerns and provided his technical analysis to support his questions. The NRC responded with correspondence that documented the agency's position.

On October 15, 2014, the stakeholder submitted a 10 CFR 2.206 petition requesting enforcement action against Entergy. This process is the primary mechanism by which the public can request NRC take enforcement-type action related to licensees or licensed activities. In the petition, the stakeholder stated that the hazards analysis,

prepared by the licensee to determine the safety impact on IPEC due to the proposed pipeline, is inadequate and incomplete, which violates several regulations including 10 CFR 50.9, “Completeness and Accuracy of Information” and 10 CFR 50.59, “Changes, tests, and experiments.”

NRC responded to the stakeholder’s 2.206 petition by assigning a PRB to review the stakeholder’s concerns. Throughout the petition process, the stakeholder was informed of the staff’s progress primarily by the NRC IPEC Project Manager, who was assigned to be the Petition Manager. The stakeholder was also provided an opportunity to present to the PRB on two occasions. These actions align with guidance in Management Directive 8.11, “Review Process for 10 CFR 2.206 Petitions.”

On January 28, 2015, the stakeholder made his first presentation before the PRB and provided clarifying and supplemental information in support of his petition. During this presentation, the stakeholder was accompanied by an individual with expertise in gas pipeline operation and safety management.

Subsequent to that presentation, NRC informed the stakeholder that the PRB’s initial recommendation was to reject the petition because the staff had previously reviewed and resolved the items identified in his petition.

Prior to learning of the PRB’s initial recommendation, the stakeholder submitted a FOIA request for all documents related to the proposed 42-inch gas pipeline for IPEC. After receiving the FOIA responses, the stakeholder communicated additional concerns to the NRC PRB, as well as the Commission, that included potential flaws with the staff’s confirmatory analysis used to conclude there would be no hazard to safe plant operation if a rupture of the gas pipelines occurred at IPEC.

On July 15, 2015[21], the stakeholder made a second presentation before the PRB. The purpose of that meeting was to allow the stakeholder to comment on the initial recommendation of the PRB and to provide supplementary information to his petition. At this presentation, the stakeholder provided additional evidence to support his concerns with (1) NRC’s use of the computer program ALOHA, (2) deviations from RG 1.91 equations, and (3) valve closure time assumption – which the stakeholder declared as a material false statement.

Following the second presentation, the PRB met to determine whether the new information provided sufficient details to change or modify the initial recommendation.

In NRC correspondence dated September 9, 2015, the stakeholder was informed that the PRB recommended to reject the petition on the basis that all identified issues had been previously reviewed and resolved. NRC’s letter stated the PRB recommendation was reviewed and approved by senior management of the Office of Nuclear Reactor Regulation. As agreed during the second presentation before the PRB, the NRC

[21] ADAMS Accession Number ML15251A050

committed to providing responses to the 39 written questions from the stakeholder under separate correspondence.

On November 6[22], 2015, the NRC responded to each of the stakeholder's 39 questions. The staff concluded that based on the review of Entergy's 10 CFR 50.59 hazards analysis and the NRC's independent calculation results using conservative assumptions and rationale, Entergy had appropriately concluded that the proposed pipeline does not introduce more than minimal additional risk to IPEC, and therefore, the changes in the external hazards analysis associated with the proposed pipeline did not require prior NRC review and approval.

Additionally, the staff began its November 6, 2015, correspondence with a summary of several of the stakeholder's concerns. Of particular relevance to this case are

- For the assumption of a 3-minute isolation valve closure time that the stakeholder characterized as a material false statement (potential 10 CFR 50.9 violation) the NRC claimed it performed a bounding sensitivity analysis for two scenarios, one for 3 minutes of gas release and another for 60 minutes of gas release. NRC reported the result of the 60-minute bounding sensitivity analysis was only marginally different from the 3-minute valve closure assumption. According to the NRC, "the staff concluded that valve closure times do not have a significant impact on the site hazards analysis, and the licensee's assumption of a 3-minute valve closure time does not have a material impact on that analysis."

- Regarding the alleged inaccurate and incomplete 10 CFR 50.59 hazards analysis prepared by Entergy, NRC stated it disagreed with the stakeholder's assertions. The agency reported that the staff stood by the initial conclusion, as documented in the November 7, 2014, inspection report, that a potential rupture of the proposed pipeline posed no threat to the safe operation of the plant or safe shutdown of the plant.

- With respect to the NRC withdrawing its findings to FERC that the proposed pipeline would not present an unacceptable risk to IPEC, NRC stated that the staff performed a thorough review of Entergy's 10 CFR 50.59 site hazards analysis and performed its own independent confirmatory analysis that is in agreement with the licensee's results. "The NRC has no basis to withdraw its previous conclusions to FERC," the letter stated.

Assumption that Pipeline Valves Could Be Closed in 3 Minutes and NRC's Followup Analysis

In correspondence dated January 28, 2015, and July 27, 2015, the stakeholder alleged that Entergy's site hazards analysis has a material false statement because the analysis assumed that pipeline operators located in Houston, Texas, would be able to recognize

[22] ADAMS Accession Number ML15287A257

a pipe rupture from pressure sensors located in the pipeline and take appropriate actions to close the pipeline isolation valves within 3 minutes.

During the January 28, 2015, PRB meeting, an individual with expertise in pipeline safety presented to the PRB the technical rationale[23] as to why significantly more time would elapse before valve closure could be activated by the Houston-based pipeline operators. According to this expert, the main signal to close valves is a significant decrease in pipeline pressure. For example, this individual posed that if you have 15 miles of high-pressure gas pipeline, it would not go to zero pressure instantly – it might be 20 minutes before the operators can recognize the valves need to be closed.

In response to this concern, the PRB asked for a "bounding sensitivity analysis" to be conducted. The PRB sought to test what the impact would be with 60-minutes of gas being released, with the assumption that if safety margins were not exceeded for 60-minutes, then they would not be exceeded for 3 minutes. The Physical Scientist who prepared the NRC AIM Project Safety Review was assigned to conduct this task and docketed his report on March 19, 2015, in the Agencywide Documents Access and Management System (ADAMS). According to the report's conclusion,

> The analysis assumed that following a complete pipeline rupture, the pipeline provides an infinite source of natural gas and the pipeline isolation valves do not close for an hour. Based on this analysis, the NRC staff has determined that there are only minimal changes to the peak overpressure calculation and the heat flux calculation. Therefore, the staff concludes that pipeline isolation valve closure times are inconsequential and the previous staff conclusions that the proposed 42-inch diameter natural gas pipeline at the Indian Point site does not represent an undue risk and that the plant could safely shut down following a postulated pipeline rupture remain valid.

This conclusion was communicated to the stakeholder in NRC's correspondence dated November 6, 2015. This response conveyed that the staff considered one scenario where the isolation valves were assumed to close within 3-minutes, and a second scenario that "assumed the release of gas for a full hour with the unbroken end of pipe connected to an infinite source." The letter stated, "the staff concluded that valve closure times do not have a significant impact on the site hazards analysis, and the licensee's assumption of a 3-minute valve closure time does not have a material impact on that analysis."

OIG reviewed the Physical Scientist's calculations for both the initial Project AIM Safety Review and his work done in response to the PRB's followup request and determined that NRC's November 6, 2015, correspondence inaccurately described the work done by the Physical Scientist. Although ALOHA does have the capability to assess

[23] According to the expert, the laws of thermodynamics provide the basis for pipe line rupture systemic dynamics that sustain pressure in the system before the compressor station recognizes a rupture.

60 minutes of gas released with an infinite source as well as the gas released in the first minute, as noted earlier in this report, it does not have the capability to assess 3 minutes of gas release prior to valve closure. In fact, OIG determined that the Physical Scientist used the 1-minute maximum gas release rate from ALOHA for both the 3-minute scenario assessed in the NRC AIM Project Safety Review and the 60-minute scenario conducted in response to the PRB request.

The Physical Scientist acknowledged to OIG that he used the 1-minute maximum release rate for his 3-minute analysis in the NRC AIM Project Safety Review and in his followup analysis to the PRB request. He said he ran ALOHA for 60 minutes and got results for both the total amount of mass released for 60-minutes and the 1-minute maximum release. However, he added he used the 1-minute mass value in his calculations because he considered it more realistic. According to the Physical Scientist, he used engineering judgment based on his understanding that methane is lighter than air and rises and disperses quickly. Furthermore, the Physical Scientist said he reported out his results to the PRB as he described them in the NRC AIM Project Safety Review and Confirmatory Analysis. The Physical Scientist told OIG that he believed he accurately communicated to the PRB what he did and "how they interpreted it, I do not know."

While the Physical Scientist's Branch Chief told OIG he thought the Physical Scientist had used the 60-minutes total mass in the equation, the IPEC Project Manager who wrote the November 6, 2015, correspondence, told OIG he was aware that the Physical Scientist had used 1 minute. According to the Physical Scientist's Branch Chief, the mass value used by the Physical Scientist is not necessarily the issue; however, the value chosen needs to be communicated accurately and transparent to the public.

NRC's Use of ALOHA to Assess Impact of Pipe Rupture on IPEC

In communications with the NRC, the stakeholder questioned the use of ALOHA to assess the quantity of gas released in a pipeline rupture. His rationale for questioning this was his belief that ALOHA cannot be used since it cannot model gas release from a pipe that has broken in the middle and is leaking from both broken ends and is not referenced in RG 1.91. The stakeholder also asked whether NRC performed a validation and verification of the ALOHA program to ascertain its accuracy.

In a letter dated November 6, 2015, to the stakeholder, the NRC responded,

> There is no need for the NRC staff to perform a validation and verification of the ALOHA computer program. ALOHA has been measured against similar computer models and the results are considered comparable.

This letter conveyed NRC staff believed ALOHA was an adequate program to use for their assessments. Additionally, the letter conveyed that NRC was aware of the pipe break limitation. The letter explained how the staff modeled its independent analysis to

address this limitation by doubling the predicted gas release from the upstream side of a pipe break to account for flow escaping from both sides of the break. The letter stated this was a conservative approach.

As described previously in this report, OIG learned from the developers of ALOHA (NOAA) that ALOHA does not model double-ended breaks plus several other limitations that the NRC failed to consider.

Further, OIG reviewed the Physical Scientist's calculations and observed that, contrary to the information conveyed in NRC's November 6, 2015, letter to the stakeholder, the Physical Scientist did not double the predicted gas release for the majority of calculations performed to support the November 7, 2014, NRC inspection report. He also did not double the predicted gas release when conducting the "60-minute bounding analysis" in response to the stakeholder's questions about the 3-minute valve closure time.

In contrast to NRC's assertion in its letter to the stakeholder that it doubled the mass in its independent and followup analyses, the Physical Scientist confirmed to OIG that he doubled the predicted gas release only for the underground scenario assessed during his NRC AIM Project Safety Review (where he also took 65 percent credit for the enhanced piping). The Physical Scientist acknowledged he did not double the mass when assessing the impact of a rupture above ground. The Physical Scientist said he accurately described to his management his assumptions and rationale (i.e., doubled the predicted gas release only for the underground scenario where he took 65 percent credit for enhanced piping and did not double the predicted gas release in other scenarios), and added, "but whether they absorb exactly that detail, everything, I'm not sure."

The IPEC Project Manager told OIG he knew ALOHA calculates flow only from one direction. Contrary to what the Physical Scientist told OIG, the IPEC Project Manager said it was his understanding that to compensate for this limitation, the Physical Scientist doubled the predicted gas release amounts for all results reflected in the November 7, 2014, inspection report to account for a double-ended break. The IPEC Project Manager told OIG that NRC did not provide calculations to FERC but talked them through the inspection report.

Also in contrast to the Physical Scientist's explanation to OIG, the Physical Scientist's Branch Chief told OIG it was his understanding the Physical Scientist doubled the mass value from ALOHA for both the above ground and below ground calculations. Also for the 60-minute bounding calculation, the Branch Chief said he thought the Physical Scientist assumed a double ended break. The Branch Chief recalled a meeting regarding IPEC with Federal and State Government officials where participants questioned this area and NRC discussed doubling the mass value to be conservative.

NRC's Deviation from RG 1.91 in Calculating the Blast Radius

In correspondence to NRC dated July 27, 2015, the stakeholder questioned NRC's adherence to RG 1.91 used to calculate the blast radius or safe distance. NRC Regulatory Guide (RG) 1.91, "Evaluations of Explosions Postulated to Occur at Nearby Facilities and on Transportation Routes Near Nuclear Power Plants," is the staff's guidance document for evaluating the impact of explosions from nearby transportation routes. This guidance defines an acceptable methodology for calculating safe distances beyond which no adverse effect would occur on nuclear plant safety components.

The stakeholder questioned why the NRC either modified and/or ignored its primary guidance, RG 1.91, and specifically questioned an undefined input parameter "Y" and the lack of a significant change in the results when the gas release continued for 60-minutes instead of 3 minutes. The stakeholder, using RG 1.91 equations, alleged the blast radius will increase by a factor of 2.71, or 3,000 feet, for the 60-minute assessment.

In correspondence dated November 6, 2015, the NRC reported,

> RG 1.91 is the staff's guidance document for evaluating the impact of explosions from nearby facilities and transportation routes. Entergy and the NRC used the methodology and equations of RG 1.91, without deviation, to determine the blast radius of 1.0 psi. No other methodology was used.

Additionally, the staff described that the "Y" represents the yield factor for methane as stated in Table 1 of RG 1.91. Regarding the stakeholder's concern with the lack of significant difference between the 3-minute and 60-minute valve closure assessments, the NRC reported,

> The NRC staff disagrees with the above extrapolation of the blast radius from 1,100 to 3,000 feet. As discussed in the response to question 4, it is a misapplication of Equation (1) of RG 1.91 to extrapolate a 3-minute gas pipeline release to a 1-hour gas pipeline release by multiplying the available mass by a factor of 20 and taking the cube root. Multiplying the calculated safe distances by a factor of 2.71 (i.e., the cube root of 20), ignores buoyancy of natural gas and artificially assumes that the entire amount of gas released over an hour will remain confined and available for an explosion. Thus, the above argument extending the calculated safe distance of 1,100 feet to 3,000 feet is flawed.

OIG reviewed the Physical Scientist's calculations and determined the Physical Scientist did use RG 1.91 Table 1's Y value for methane. As noted previously in this report, the lack of significance for the 3-minute versus 60-minute valve closure assessments was due to 1-minute of mass that was used for both assessments.

However, OIG noted that although NRC said its assessment did not deviate from RG 1.91 methodology, in fact, the RG 1.91 calculations for the underground and above ground locations did deviate from RG 1.91 equations. Specifically, the Physical Scientist used a different denominator – resulting in less conservative results. The applicable RG 1.91 equation has the pre-set denominator of 4420 kJ/kg and the Physical Scientist used 4500 kJ/kg.

During the course of several interviews with OIG, the Physical Scientist provided varying explanations as to why he used 4500 kJ/kg for the denominator. None of his explanations were consistent with RG 1.91, Revision 2, which NRC claimed had been used without deviation. First, he said he rounded the denominator (4420 kJ/kg) to 4500 kJ/kg because he considered it a generally used "nominal value," whereas the 4420 kJ/kg was the "precise value" and his change of values was "not going to make that much difference." In a second attempt to explain to OIG his basis for using 4500 kJ/kg, the Physical Scientist provided a draft of RG 1.91 that preceded Revision 2, which contained the pre-set denominator of 4500 kJ/kg. (OIG notes that RG 1.91, Revision 2, had been approved in April 2013, more than 1 year prior to the Physical Scientist's independent analysis.) He also provided NRC fire protection references that use a denominator of 4500 kJ/kg. The Physical Scientist also admitted he typically uses the 4500 kJ/kg denominator in similar safety assessments related to other NRC licensed nuclear facilities.

The Physical Scientist did not consider his use of 4500 kJ/kg a deviation from RG 1.91 and as such did not inform NRC management of the change in the denominator. However, the Physical Scientist agreed that following an NRC regulatory guide without deviation meant following it as written to include applying "equations as they are."

The Physical Scientist's Branch Chief agreed that changing the denominator was a deviation from RG 1.91. He added that because the conversion factor was changed to a larger number, the results were less conservative, and this was an issue that should be addressed. He also said that if you deviate from RG 1.91, it should be in the more conservative direction and should be documented and communicated to all involved because if the deviations are not communicated, it would be assumed that the RG was used as written. According to the Physical Scientist's Branch Chief, the use of a larger denominator than prescribed in RG 1.91, in combination with 1-minute of mass (as discussed previously in this report), undermined the ability of the NRC to add conservatism for safety assurance.

The IPEC Project Manager was unaware that the denominator was changed and agreed that changing the pre-set denominator modified the equation. According to the IPEC Project Manager, the Physical Scientist reported that the equations in RG 1.91 were used as is and unchanged. The IPEC Project Manager explained to OIG that raising the pre-set denominator made the result less conservative. He was not aware of any flexibility that existed in RG 1.91 for using other values. He had no explanation as to why someone would use anything other than the values in RG 1.91 equations.

Quality Assurance Process Used by NRC To Verify the Results of the AIM Project Safety Review and Followup Assessment

In correspondence dated July 27, 2015, the stakeholder questioned NRC's quality assurance process for verifying safety related calculations. In correspondence dated November 6, 2015, the NRC responded to the stakeholder that the NRC staff does not perform "safety-related" calculations and does not have a quality assurance process for such calculations. The letter stated,

> The NRC does not perform "safety-related calculations." Therefore, the NRC staff does not have specific procedures for performing calculations used to support inspections or to perform confirmatory analysis. The term, "safety related calculations" implies formal calculations performed by licensees for the design of NRC regulated facilities. Safety-related calculations by licensees must be performed in accordance with approved plant procedures and associated quality control. Calculations performed by the staff do not require the same level of documentation and are performed as needed to support independent confirmatory analysis.

NRC's letter conveyed that in response to the stakeholder's concerns, the staff performed an independent analysis that received a peer review by a qualified NRC engineer.

OIG learned that a headquarters Reactor Oversight Process (ROP) Engineer was assigned to peer review the Physical Scientist's analysis. The ROP Engineer told OIG he was selected while attending an Executive Leadership Team meeting after he mentioned he previously worked for Bechtel Power performing hazards analysis calculations and had used ALOHA. He said he told the Executive Leadership Team there was a Region IV staff member with better qualifications to conduct the review; however, an NRC senior manager assigned the ROP Engineer to the task.

According to the ROP Engineer, he spent approximately 8 hours conducting this review, and about "99 percent" of his time was focused on reviewing the licensee's 10 CFR 50.59 safety evaluation. He said there is no formal process for conducting a peer review. He said his approach was to talk to the Physical Scientist who described his process to him; download ALOHA from the Internet; and apply the Physical Scientist's assumptions and numbers in ALOHA, which seemed reasonable to him; and he came up with similar results. Then he wrote his conclusion that the independent analysis performed by the Physical Scientist used acceptable methodologies and realistic conservative assumptions and the conclusions matched the licensee's. The ROP Engineer said that he wrote his review summary in such a way that it "sent signals" that his check was an unofficial peer review from one individual to another – similar to inspectors sharing notes. The ROP Engineer said he was uncomfortable performing this peer review since the NRC does not have a defendable, formal process in place to conduct quality assurance or peer reviews.

The IPEC Project Manager was aware that the NRC did a peer review to determine if the Physical Scientist's calculation looked reasonable. The IPEC Project Manager recalled that the peer reviewer was qualified to do the peer review since he had experience working with ALOHA in the past.

OIG learned from the Physical Scientist's Branch Chief that typically peer reviews are not done. However, due to the high visibility of this situation, to include the stakeholder, NRC management decided to task another knowledgeable NRC staff member with "taking a hard look" at the Physical Scientist's calculations. The Physical Scientist's Branch Chief remembered that the peer reviewer did not identify any problems.

Interviews of NRC Managers

The Region I Deputy Regional Administrator, who was then the Region I Director of Reactor Safety, was aware that 60 minutes of gas release was not used for the bounding analysis, but that the amount assessed was something between 0 and 60 minutes. While he initially stated he thought the Physical Scientist used a number of conservatisms in his assessment that made this situation "more safe," later in the interview he acknowledged there might be a need to reassess. The Region I Deputy Regional Administrator also told OIG that he was not aware the Physical Scientist made a change from the RG 1.91 equations. However, he could not speak to a potential change in the denominator since he did not know why the Physical Scientist would do that. However, if it was done, the NRC should have documented it and why the change was made.

NRC's then-Deputy Executive Director for Reactor Preparedness Programs (DEDR) (now retired), told OIG he would expect the information that NRC documented and provided to the stakeholder to align with the staff's actual work for the NRC AIM Project Safety Review. He also said he would be disappointed if the NRC used a draft regulatory guide. Regarding the peer review, he told OIG that without talking to the ROP Engineer who conducted the review, he did not have a sense of how thorough it was. However, based on the description provided by OIG, and given stakeholder attention to this issue and NRC's reliance on the Physical Scientist's assessment, NRC should have done a better job with the peer review.

The current DEDR said he thought the Physical Scientist had assessed 3 minutes of gas release and 60 minutes of gas release; however, based on the information provided by OIG (i.e., that only 1 minute of gas release was assessed under both scenarios), the DEDR said he was very concerned. He recalled the stakeholder's question about whether the pipe could actually be sealed off in 3 minutes, given the operators' location in Houston; he said this was why NRC chose to assess an hour because it would be a "very bounding analysis." However, he said, "what you are presenting to me here is not." He also recalled the stakeholder challenging the similarity of NRC's results for the 3-minute and 60-minute analyses, and based on discussion with OIG, he now recognized why the results were so similar (i.e., only 1 minute of mass was used for each scenario).

Regarding the Physical Scientist's use of a draft version of RG 1.91, the current DEDR said the Physical Scientist should not have used a draft, especially when there was an approved guide available. The DEDR also said he would not have expected the Physical Scientist to round the denominator unless it was a conscious decision to be more conservative. However, he noted, in this case the rounding was in the non-conservative direction and was not documented or explained.

Regarding the "peer review," the DEDR said it did not "sound like what was asserted as a peer review was really well thought out." OIG told the DEDR there were two NRC gas plume experts in Region IV and the DEDR said he was inclined to have them recalculate the blast radius and compare the outcome to the results that NRC has relied upon. According to the DEDR, "it goes to the materiality…this all raises a lot of questions."

In response to OIG's question about whether IPEC is operating in an unanalyzed condition due to risks posed by the new 42-inch pipeline, the DEDR said, "The only reason I would hesitate…to just jump in and say we are in an unanalyzed condition is Entergy did analyze it. I have questions about how well we validated their analysis, so I think we have more work to do, but I don't think I would say they are in an unanalyzed condition at this point."

HOTLINE NUMBER:
1-800-233-3497

THE OFFICE OF THE
INSPECTOR GENERAL

Attention: Hotline Program
Mail Stop O5E13
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Rockville, MD 20852-2738

OFFICE OF THE INSPECTOR GENERAL

U.S. NUCLEAR REGULATORY COMMISSION

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant

Case No. 16-024

EVENT INQUIRY

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

OFFICE OF THE
INSPECTOR GENERAL

February 13, 2020

MEMORANDUM TO: Chairman Svinicki

FROM: David C. Lee
Deputy Inspector General

SUBJECT: CONCERNS PERTAINING TO GAS TRANSMISSION LINES AT THE INDIAN POINT NUCLEAR POWER PLANT (OIG CASE NO. 16-024)

This accompanies the results of an Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC), event inquiry into concerns pertaining to NRC's oversight of a 42-inch natural gas pipeline that was, at the time, proposed to traverse Indian Point Energy Center (IPEC) property. A citizen stakeholder questioned the adequacy and completeness of the licensee's (Entergy) site hazards analysis and NRC's independent and followup analyses prepared to determine the safety impact on IPEC plant components due to the potential rupture of the proposed high pressure 42-inch gas pipeline. OIG examined an NRC inspection report and underlying analysis used to determine that Entergy appropriately concluded the 42-inch gas pipeline would not introduce significant additional risk at IPEC. OIG also examined NRC's response to the stakeholder's concerns over the 42-inch gas pipeline.

We have also provided this event inquiry report to the appropriate Majority and Ranking Members of Congress with oversight responsibilities for the NRC.

If you have any questions, please contact me, at 301-415-5930, or Rocco J. Pierri, Assistant Inspector General for Investigations, at 301-415-5925.

Attachment: As stated

cc: Commissioner Baran
Commissioner Caputo
Commissioner Wright

Office of the Inspector General

EVENT INQUIRY

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant

Case No. 16-024

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Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant (Case No. 16-024)

Basis and Scope

The Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC), initiated this event inquiry in response to concerns, communicated to OIG, from a citizen stakeholder pertaining to NRC's oversight of a 42-inch natural gas pipeline that was, at the time, proposed to traverse Indian Point Energy Center (IPEC) property. This pipeline, now in operation, was part of the Algonquin Incremental Market (AIM) Project, which proposed to replace certain portions of the existing pipeline and install new pipeline in the northeast United States. NRC's role was to support the Federal Energy Regulatory Commission's (FERC) decision to approve or disapprove the project by providing information to the FERC on the impacts of the AIM Project on IPEC. NRC's findings were documented in its Third-Quarter Integrated Inspection Report issued to Entergy, IPEC's license holder, on November 7, 2014.

In a publicly available Title 10 of the *Code of Federal Regulations* Section 2.206 (10 CFR) petition, dated October 15, 2014, and a letter to NRC dated July 27, 2015, the stakeholder questioned the adequacy and completeness of the licensee's (Entergy) site hazards analysis and NRC's independent and followup analyses prepared to determine the safety impact on IPEC plant components due to the potential rupture of the proposed high pressure 42-inch gas pipeline. The stakeholder also questioned whether (1) NRC misled FERC and the public by claiming to FERC that there was no additional risk associated with the proposed 42-inch gas pipeline, thereby putting at risk 20 million people near IPEC; (2) NRC was aware of material false statements made by Entergy to NRC with respect to the 42-inch gas pipeline; (3) NRC violated its procedures and regulations when analyzing the potential safety impacts from the 42-inch gas pipeline; and (4) NRC is allowing IPEC to operate in an unanalyzed condition.

OIG's event inquiry examined NRC's inspection report and underlying analysis used to determine that Entergy appropriately concluded the 42-inch gas pipeline would not introduce significant risk to safety-related systems, structures, and components; and systems, structures, and components important-to-safety at IPEC. On March 3, 2015, FERC issued an order formally approving the AIM Project. On January 7, 2017, the pipeline went into use.

As part of this event inquiry, OIG also examined NRC's response to the stakeholder's concerns over the 42-inch gas pipeline.

Findings

Finding 1

While FERC's approval of the AIM Project pipeline relied in part on NRC's assessment of Entergy's site hazards analysis and NRC's independent analysis of the impact of a potential rupture of the portion of the pipeline that traversed IPEC property, OIG found (1) NRC's independent analysis was incorrectly portrayed in FERC's approval document as significantly more conservative than it actually was; (2) NRC's inspection report contained inaccuracies suggesting additional analysis had been conducted, when this was not the case; and (3) NRC's underlying independent analysis was conducted using a computer program that the National Oceanic and Atmospheric Administration (NOAA), which developed the program, said it was not designed for. Moreover, the majority of NRC's independent analysis described the impact of a potential rupture on an above ground point on IPEC property that NRC believed presented the most credible risk due to its exposure; however, ultimately the as-built 42-inch pipeline does not come above ground anywhere on IPEC property but does traverse the IPEC property.

OIG also found that NRC decisionmakers had differing understandings of the assumptions and factors driving the analysis conducted by an NRC Physical Scientist, who NRC considered a subject matter expert and who was responsible for conducting, documenting, and communicating his results. While the Physical Scientist attributed his analysis assumptions to OIG as engineering judgment, he did not have a basis for it and did not document a basis or a methodology in his report. When OIG briefed NRC managers on the issues OIG identified in the Physical Scientist's analysis, one noted that because the Physical Scientist conducted multiple calculations with increasing credit for pipeline enhancements, it appeared to be backwards engineering to get a desired result. An NRC senior manager said the Physical Scientist's use of credit for enhanced piping was inappropriate in part because the pipeline enhancements were not intended to mitigate the impact of a blast, but rather to reduce the chances of a rupture in the first place.

Several NRC senior managers said that based on issues identified in this event inquiry pertaining to the Physical Scientist's analysis, it may be prudent to redo the analysis.

Finding 2

OIG found that through the stakeholder's 2.206 petition and associated concerns – which were relevant and on point – NRC was presented an opportunity to reevaluate and confirm work previously conducted that supported the agency's conclusion that Entergy's hazards analysis was reliable. However, NRC failed to thoroughly reexamine the underlying premises of its analyses and did not accurately communicate its analytical work performed.

First, in response to the stakeholder's assertion that it would take longer than 3 minutes for the pipeline operators in Houston, Texas, to close the valves, thereby stopping the

flow of gas, NRC misrepresented the assumptions used in the followup bounding analysis that was conducted to assess the impact of 60 minutes of gas released. While NRC's response to the stakeholder described having conducted an assessment that assumed an infinite source of natural gas with the pipeline valves open for an hour, OIG's investigation found that NRC assessed only 1 minute of gas released. Moreover, NRC never confirmed the validity of the licensee's assumption that the valves could be closed in 3 minutes. OIG contacted the pipeline operator who estimated it would take at least 6 minutes after detection of a leak to close the valves. While the Physical Scientist told OIG he used 1 minute of gas released in his calculations, NRC managers had inconsistent understandings of the amount of mass the Physical Scientist used.

Second, in response to the stakeholder's question of whether NRC performed a validation and verification of NOAA's computer program to ascertain its adequacy for this purpose, NRC stated there was no need for NRC to perform a validation and verification of the computer program. However, OIG contacted NOAA, which confirmed the program is not designed for this purpose.

Third, NRC's response to the stakeholder stated that NRC used the methodology and equations of Regulatory Guide 1.91, NRC's guidance for evaluating postulated explosions near nuclear power plants, "without deviation"; however, OIG found that NRC used a draft regulatory guide in lieu of the final, approved version (which had been issued approximately 2 years prior) and deviated from the approved version in a manner that was less conservative and had an impact on the analysis outcome.

Fourth, the stakeholder asked whether NRC had any quality assurance requirements/procedures for conducting safety related calculations. NRC responded that they do not perform safety related calculations and do not have a quality assurance program for these calculations, but they said a peer review by a qualified NRC engineer was performed on NRC's independent analysis and followup analysis. OIG's investigation revealed that the assigned engineer, who felt there were more qualified people in NRC to do this, performed a limited review that focused mainly on the licensee's hazards analysis and not NRC's analyses.

An NRC senior manager conveyed to OIG that NRC decisionmakers rely on accurate information from the staff to support decisions and communicate accurately to stakeholders and, in this case, another Federal agency. However, NRC managers confirmed they do not have a quality assurance process or a formal peer review process to review this type of assessment.

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant (Case No. 16-024)

Background and Chronology

IPEC is a nuclear power station located on the east bank of the Hudson River in Buchanan, NY, about 24 miles north of New York City, New York. According to IPEC's website, the station's two operating reactors, Unit 2 and Unit 3, supply electricity for about 3 million customers. Unit 1 was shut down in 1974 and is undergoing decommissioning. Units 2 and 3 are scheduled for decommissioning beginning in 2020 and 2021, respectively. Initially licensed to Consolidated Edison Company of New York, Inc., IPEC's current license holder is Entergy Nuclear Operations, Inc. (Entergy), and regulatory oversight for IPEC is provided by the NRC Region I office located in King of Prussia, PA.

Natural gas pipelines have existed on the IPEC owner-controlled property since before plant construction. Algonquin Gas Transmission Company[1] (Algonquin) built a 26-inch diameter natural gas pipeline in 1952 and an adjacent 30-inch natural gas pipeline in 1965, and both traverse IPEC property. As part of the initial licensing basis, the licensee assessed each operating unit for postulated pipeline explosions of both pipelines. The assessment used the measured "shortest distance" from the pipeline to safety-related system, structures, and components (SSCs[2]) as the safe distance to meet NRC regulations. In response to later NRC requests focused on physical security, Entergy expanded the licensing basis to also include above ground sections of the pipelines. The assessments concluded no hazard to safe plant operation if a rupture of the gas pipelines occurred. Licensees are required to adhere to their current licensing basis or request an amendment depending on changes affecting the licensed operation of the plant.

On February 28, 2014, Algonquin applied to FERC to construct, install, operate, and maintain approximately 37 miles of pipeline and related facilities in New York, Connecticut, and Massachusetts. The project was referred to as the Algonquin Incremental Market (AIM) Project and proposed to replace certain portions of existing pipeline and to install new pipeline in other areas. The AIM Project included a stretch of new 42-inch pipeline across IPEC's southern side. This new pipeline would transmit gas at higher pressures than the existing 26- and 30-inch pipelines and would be located further away than the existing pipelines from the plant's safety-related SSCs and Security Owner Controlled Area (SOCA), but closer to eight important to safety (ITS[3]) SSCs. A portion of the 42-inch pipeline crossing IPEC property would be enhanced with more safety features than normal for new pipelines. The closest two

[1] Algonquin is an indirect wholly owned subsidiary of Enbridge Energy Corporation.
[2] Nuclear power plants are designed with SSCs that prevent or mitigate the consequences of postulated accidents which could cause undue risk to the health and safety of the public.
[3] Structures, systems, and components ITS shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

pipeline safety valves (which could be used to shut off gas to the portion of the pipe crossing IPEC property) encompassing the IPEC section of the pipe would be 3 miles apart. The next two closest safety valves, which encompass the 3-mile stretch of pipeline and its two safety valves, would be approximately 15 miles apart.

On April 2 and 23, 2014, NRC and FERC representatives met to discuss the AIM Project, the Federal review process, and regulatory responsibilities. FERC provided an overview of the role of a cooperating agency.[4] NRC declined to become a cooperating agency but agreed to provide appropriate information, as needed, on the impacts of the AIM Project.

On August 6, 2014, FERC issued a draft Environmental Impact Statement (EIS) concerning the impact of the pipeline.[5] FERC concluded that based on its consultation with NRC, Entergy was required to assess any new safety impacts on its IPEC facility and provide its analysis to NRC. NRC's role was to ensure that the IPEC licensee adequately assessed the safety implications of the proposed pipeline at the nuclear site, as well as to determine if the licensee's analysis met the NRC's requirements regarding plant changes.

On August 24, 2014, Entergy completed its 10 CFR 50.59[6] safety evaluation and an associated hazards analysis, which covered the consequences of a fire and explosion following release of natural gas from the proposed new AIM Project 42-inch-diameter pipeline. The 10 CFR 50.59 report noted,

> While the proposed 42-inch pipeline is further from IP2 and IP3 SSCs within the 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.

Because the 10 CFR 50.59 safety evaluation concluded there is a change to the current licensing basis for design basis external hazards, Entergy was required to undertake the associated hazards analysis. Entergy hired a consulting firm to prepare two supporting evaluations referred to as the "hazards analysis." The first evaluation included calculations for the consequences of postulated explosions and fire with missile generation[7] following the release of natural gas from the proposed new 42-inch pipeline

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[4] Under the National Environmental Policy Act (NEPA), upon request of a lead agency preparing an EIS, any other Federal agency which has jurisdiction by law shall be a cooperating agency. In addition, any other Federal agency which has special expertise with respect to any environmental issue that should be addressed in the EIS may be a cooperating agency upon request of the lead agency.
[5] NEPA requires Federal agencies prepare an Environmental Impact Statement (EIS) if a proposed major federal action is determined to significantly affect the quality of the human environment.
[6] A 10 CFR 50.59 review is a technical evaluation performed by a licensee to determine if a proposed change to the facility represents a significant modification to the plant design and licensing bases as described in the Final Safety Analysis Report and, therefore, requires NRC approval prior to implementation.
[7] Missile generation are projectiles associated with detonation of potentially explosive material.

at two locations. Location one was the area on the underground piping that measured the shortest distances to the SSCs ITS, as committed to in IPEC's licensing basis. Location two was based on measurements of an above ground pipeline rupture point on the 42-inch pipeline, referred to as the "tie-in[8]" location. Although the above ground location was further away from the plant than the underground location, it was assessed because of the potential impacts from intentional and malicious activity.

For both locations (above and below ground), Entergy measured the shortest distances from the new 42-inch pipeline to several SSCs ITS and developed a table that identified these distances per component.

For Entergy's first evaluation, they used several methodologies and included in their analysis factors for pipeline enhancements such as thicker piping, thicker corrosion protection, greater burial depth, and installation of protective reinforced concrete mats to impede access to the buried piping. Entergy assumed the isolation valves were 3-miles apart and would close within 3 minutes of a pipeline rupture. Entergy claimed to have done the explosion and fire assessments in accordance with NRC Regulatory Guide 1.91, "Evaluations of Explosions Postulated to Occur at Nearby Facilities and on Transportation Routes Near Nuclear Power Plants," Revision 2[9], (RG 1.91) as well as using Areal Locations of Hazardous Atmospheres (ALOHA) and BREEZE computer programs.

Entergy's second evaluation was a statistical analysis of fire and explosions using "best available" accident data for pipeline rupture frequency. This assessment determined Exposure Rates[10] for a failure of the proposed 42-inch pipeline.

As documented in its 10 CFR 50.59 Safety Evaluation and Hazards Analysis, Entergy concluded that the proposed pipeline did not pose a "significant reduction in the margin of safety" for the public and that the change did not require prior NRC approval (i.e., a license amendment). Entergy based this conclusion on pipeline design and installation enhancements, the results from the fire and explosion evaluation, and the exposure rate assessment. However, there were two exceptions that were below NRC's threshold criteria which required additional evaluation. The two exceptions were the meteorological tower and the steam generator storage facility which are SSCs ITS. For these two exceptions, Entergy provided safety justifications. Specifically, for the meteorological tower, Entergy stated it had an alternative means to perform the meteorological function. For the steam generator storage facility, the safety evaluation demonstrated that failure of this component would not exceed the radiation dose limits imposed by NRC guidelines.

In September 2014, NRC Region I performed a permanent plant modification inspection (PMMI) at IPEC. One of several PMMI objectives is to verify that modifications to the

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[8] Pipeline "tie-in" locations are above ground and used for inspection and maintenance throughout the entire pipeline.
[9] Agencywide Documents Access and Management System (ADAMS) Accession Number ML12170A980
[10] Exposure rates are analyses that demonstrate risk.

plant have not affected the safety functions of important safety systems. As one of three samples chosen for this inspection, NRC reviewed the 10 CFR 50.59 safety evaluation and supporting hazards analysis, conducted a walk-down of the proposed pipeline routing, and performed an independent analysis of the potential hazards relative to the new 42-inch pipeline.

An NRC Region I Security Inspector conducted this inspection with support from a Physical Scientist from NRC headquarters Office of New Reactors[11] (NRO), Radiation Protection and Accident Consequences Branch (RPAC). The Physical Scientist was considered an NRC subject matter expert on external hazards. The Region I Security Inspector did the on-site inspection activities while the Physical Scientist was tasked to perform independent confirmatory calculations. The Physical Scientist documented the results of his review in a six-page technical report titled, "Safety Review and Confirmatory Analysis, Entergy's 10 CFR 50.59 Safety Evaluation, Algonquin Incremental Market (AIM) Project, Indian Point Energy Center (IPEC)" (NRC AIM Project Safety Review). This report stated that the Physical Scientist performed independent confirmatory calculations with conservative assumptions and rationale using NRC RG 1.91 methodology and/or the ALOHA computer program to assess an explosion, jet fire, and cloud fire at the above ground point on the pipeline and the closest point (underground). The Physical Scientist's analysis was based on a stretch of pipeline consisting of about 3 miles between isolation valves, of which the enhanced section of pipeline length is identified to be 3,935 feet, and closure of the isolation valves within 3 minutes.

The Physical Scientist concluded that safety-related SSCs inside the SOCA passed the safety criteria, but that nearby SSCs ITS would be affected because the calculated minimum safe distances from the above ground reference point exceeded the safety criteria. To address the exceedance, the report stated,

> The staff finds that the impacts to the SSCs ITS from the proposed new 42-inch pipeline are bounded by the impacts from low probability events of extreme natural phenomena (including seismic activity, tornado winds, and hurricanes) which have been assessed and already addressed in the Indian Point Units 2 and 3 Updated Final Safety Analysis Report.[12]

The Physical Scientist's NRC AIM Project Safety Review was reviewed by the Region I Physical Security Inspector who shortened it into a four-page summary, or "feeder." This "feeder" was approved by two Region I Branch Chiefs and was incorporated into the NRC's Third-Quarter Integrated Inspection Report, issued to Entergy's IPEC Site Vice President on November 7, 2014[13]. The inspection report concluded that the proposed pipeline does not introduce significant additional risk to safety-related SSCs and SSCs ITS at Indian Point Units 2 and 3; and, therefore, the change in the design

[11] On October 13, 2019, NRO was reunified with the Office of Nuclear Reactor Regulation (NRR) and the resulting organization retained the title NRR.
[12] The most recent final safety analysis report (FSAR) includes the plant-specific design-basis information.
[13] ADAMS Accession Number ML14314A052

bases external hazards analysis associated with the proposed pipeline does not require prior NRC review and approval.

As reflected in an Interagency Meeting Summary prepared by FERC, on October 17, 2014, FERC held a conference call with NRC to discuss NRC's review of Entergy's site hazards analysis for IPEC relative to Algonquin's proposed AIM Project. The summary reflects that one FERC staff, one individual from the Natural Resource Group, LLC, and six NRC staff members involved with IPEC attended the conference call. The meeting summary conveyed that NRC had conducted an independent analysis of Entergy's 10 CFR 50.59 submission and an independent confirmatory blast analysis. The summary stated that Algonquin had committed to take additional mitigation measures to enhance the pipeline design and construction, but that NRC's analysis did not allow any credit for these additional mitigation measures and assumed a catastrophic pipeline failure. The summary stated that the review covered everything within the SOCA, which includes everything inside the outer most fenced area of the facility (including the spent fuel rods) and that "based on its review, the NRC came to the same conclusion that Entergy did in its 10 CFR 50.59 submission. Therefore, NRC finds Entergy's 10 CFR 50.59 submission acceptable and has determined that no prior approval from the NRC is needed."

On October 15, 2014[14], a citizen stakeholder submitted a 10 CFR 2.206[15] petition to the NRC requesting the NRC to take enforcement action against Entergy for violating the regulations of 10 CFR 50.9, "Completeness and Accuracy of Information," 10 CFR Part 50, Appendix B, "Quality Assurance Requirements," and 10 CFR 50.59, "Changes, Tests, and Experiments." The stakeholder provided numerous examples and direct quotes from IPEC's 10 CFR 50.59 Safety Evaluation and Hazard Analysis that he believed violated these regulations.

In January 2015, the stakeholder presented his 2.206 concerns before an NRC Petition Review Board (PRB). In the months that followed, the stakeholder continued to submit additional information to support his allegation, including documents from the stakeholder's Freedom of Information Act (FOIA) requests to the NRC.

Also in January 2015, FERC issued its final EIS for the entire pipeline, assessing the potential environmental effects of the construction and operation of the AIM Project in accordance with the requirements of the National Environmental Policy Act. The EIS conveyed the FERC staff's conclusion that "approval of the proposed project would result in some adverse environmental impacts; however, most of these impacts would

[14] ADAMS Accession Number ML14294A758

[15] 10 CFR 2.206 has been a part of the NRC's regulatory framework since the NRC was established in 1975. Section 2.206 permits any person to file a request to institute a proceeding pursuant to Section 2.202 of 10 CFR to modify, suspend, or revoke a license, or for other action as may be proper (hereinafter referred to in this directive as to take enforcement-related action). Such a request is referred to as a 2.206 petition.

be reduced to less than significant levels with the implementation of Algonquin's proposed mitigation and the additional measures[16] recommended in the final EIS."

The EIS quotes Entergy's Safety Evaluation conclusion that

> …based on the proposed routing of the 42-inch diameter pipeline further from safety related equipment at IPEC, and accounting for the substantial design and installation enhancements agreed to by [Algonquin], the proposed AIM project poses no increased risks to IPEC and there is no significant reduction in the margin of safety.

The EIS also describes NRC's assessment of Entergy's evaluation:

> The NRC has reviewed the site hazards analysis performed by Entergy and has performed an independent confirmatory analysis of the blast analysis as well. The NRC issued its findings in a report dated November 7, 2014. The NRC's analysis did not include factoring in the additional pipeline design measures identified by Entergy and committed to by Algonquin and assumed a pipeline catastrophic failure. The review covered everything within the Security Owner Controlled Area, which includes everything inside the outermost fenced area of the facility (including the area with the spent fuel rods). The NRC concluded that a breach and explosion of the proposed 42-inch-diameter natural gas pipeline would not adversely impact the safe operation of the facility.

On March 3, 2015, FERC's Chairman and Commissioners issued an order formally approving the AIM Project. Page 37 of the order states,

> The NRC reviewed the site hazards analysis performed by Entergy and performed an independent confirmatory analysis of the blast analysis as well. The NRC's analysis did not account for the additional pipeline design measures identified by Entergy and committed to by Algonquin and assumed a pipeline catastrophic failure. The review covered everything within the Security Owner Controlled Area, which encompasses everything inside the outermost fenced area of the facility including the area with the spent fuel rods. The NRC concluded that a breach and explosion of the proposed 42-inch-diameter natural gas pipeline would not adversely impact the safe operation of the Indian Point Facility. Therefore,

[16] Where the pipeline crossed IPEC property, these measures included (1) using internally coated piping that "exceeds the most stringent Class 4 requirements set by the U.S. Department of Transportation (even though this area is predominantly Class 3), (2) installing two parallel sets of fiber-reinforced concrete mats over the pipeline that would act as a physical barrier over the buried pipe, (3) installing yellow warning tape above and below the concrete slabs, (4) burying the pipeline to a minimum depth of 4 feet from the top of the pipeline, and (5) providing thicker external corrosion protection and internal coating.

the final EIS concludes that the project will not result in increased safety impacts at the Indian Point facility.

On April 8, 2015, Entergy submitted a revised 10 CFR 50.59 assessment to the NRC, acknowledging that amended pipeline plans indicated the 42-inch pipe would not come above ground. The revised 10 CFR 50.59 assessment reevaluated the "tie-in" location with the installed piping configuration and concluded that there were no increased risks to IPEC from the proposed AIM Project and the original Safety Evaluation remained bounding.

In April 2015, the stakeholder received a second FOIA response that he believed supported his allegation that Entergy had provided a material false statement regarding Enbridge's ability to close the isolation valves within 3 minutes. The stakeholder requested an opportunity for a second presentation to the PRB which was granted and held on July 15, 2015. During the presentation, it was agreed that the stakeholder would submit remaining questions in writing; subsequently, the stakeholder prepared a written list of 39 questions that he submitted to the NRC on July 27, 2015.

In September 2015[17], the NRC rejected the stakeholder's petition and in November 2015, provided answers to the stakeholder's 39 questions.

On January 7, 2017, the pipeline went into use.

Part I. Problems Identified by OIG With NRC's November 7, 2014, Inspection Report and Underlying Analysis

OIG learned that while FERC relied heavily on NRC's November 7, 2014, inspection report as its basis for determining that IPEC could be safely shut down if a pipeline accident occurred, the underlying analysis for the inspection report was based on

- **A series of NRC calculations – assessing the closest location of the pipeline to plant components at a below ground point – that gave increasing amounts of "credit" for pipeline enhancements until the level of "credit" given resulted in an answer that demonstrated no increased risk, if a rupture occurred, to any safety related SSCs and SSCs ITS inside the SOCA.** In contrast, both FERC's EIS and its March 3, 2015, order approving the AIM Project, state that NRC's analysis did not account for the pipeline enhancements. OIG notes that the approach used by NRC – of crediting enhancements – was less conservative than the approach as described in the FERC documents, which indicated that no credit was given for enhancements.

- **NRC's analysis of the impact of a rupture in a non-existent, above-ground point on the 42-inch pipeline.** OIG learned that the 42-inch pipeline does not go above ground at the "tie-in" location.

[17] ADAMS Accession Number ML15251A023

- **An inaccurate statement in NRC's analysis that although there was increased risk to SSCs ITS outside the SOCA if a pipeline rupture occurred, this was acceptable because these impacts were "bounded" by the impacts of extreme natural phenomena (e.g., tornadoes, hurricanes), which have been assessed and already addressed in the Indian Point Units 2 and 3 Updated Final Safety Analysis Reports (UFSAR)**. OIG learned that these impacts are not addressed in the Indian Point UFSARs.

- **NRC's misguided use of the ALOHA program to assess an explosion, a jet fire, and a cloud fire for the above and below ground portions of the pipeline.** Officials at the National Oceanic and Atmospheric Administration, Office of Response and Restoration Emergency Response Division[18] (NOAA), which created ALOHA, told OIG that ALOHA is not intended to assess impacts of explosions involving the type of "supercritical[19]" gas that would flow through the 42- inch pipe at IPEC. NOAA also told OIG ALOHA cannot assess 3 minutes of gas release prior to valve closure even though NRC's analysis claimed to do so, and it cannot model a double ended pipe break, which NRC also claimed to have done.

  Finally, OIG learned from Enbridge that it would, in fact, take the pipeline operators a minimum of 6 minutes after a leak is detected to manually close the isolation valves and thereby stop the flow of gas into the ruptured portion, and not 3 minutes as NRC claimed to have calculated using ALOHA. Enbridge also told OIG that if there were an explosion near IPEC, operators would shut valves that were approximately 14 miles apart rather than 3 miles apart as NRC assumed in its analysis.

- **OIG also learned that NRC's November 7, 2014, inspection report included an inaccurate statement that as part of NRC's analysis, the agency assessed the impact of "missile generation" that would occur if safe distance was exceeded for SSCs ITS.** Although NRC determined that safe distance was exceeded for SSCs ITS outside the SOCA, OIG learned that the agency did not assess missile generation.

Witness interviews of two FERC headquarters-based engineers assigned to the AIM Project revealed that FERC used NRC's November 7, 2014, inspection report for its Environmental Impact Statement (EIS) and FERC's Commission relied heavily on NRC's expertise to determine if IPEC could be safely shut down in the event of a pipeline accident, for approval of the portion of the AIM Project that crossed IPEC property.

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[18] Department of Commerce, National Oceanic and Atmospheric Administration, National Ocean Service Office of Response and Restoration Emergency Response Division, Seattle, Washington.
[19] Methane gas is in a "supercritical" state at 850 psi and 25° Celsius.

Review of NRC AIM Project Safety Review

The Physical Scientist's NRC AIM Project Safety Review examined the potential impact of a pipe rupture at two points on the pipeline. One point was underground; this was the shortest distance to the SOCA – which is a point addressed in the plant's current licensing basis. The other location, discussed in the next section of this report, also in the current licensing basis, was a site further from the plant where initial AIM Project plans indicated the pipe would come above ground. The Physical Scientist's review concluded that safe distance would not be exceeded for the safety-related SSCs inside the SOCA but would be exceeded for SSCs ITS outside the SOCA. According to his report, pipe failure would not reduce any further the existing safety margins, and would not pose a threat to the safe operation of the plant or safe shutdown because the potential impacts to SSCs ITS outside the SOCA were bounded by previous studies addressed in the licensee's UFSAR. OIG noted that about five pages of the NRC AIM Project Safety Review focused on the above ground point, and about one page focused on the below ground point.

NRC Conducted Multiple Calculations Giving Increasing Amounts of Credit for Pipeline Enhancements Until Answer Envisioned No Added Risk

In reviewing the Physical Scientist's documentary materials supporting his analysis of the nearest point, OIG noted the Physical Scientist conducted a series of calculations on a particular point where the pipeline was enhanced with thicker piping, greater corrosion resistance, deeper burial depth, and protective reinforced concrete mats located above the buried piping. OIG noted that for each calculation, the Physical Scientist made incremental adjustments by giving credit for pipe enhancement features and using the average release instead of maximum release rate for the mass input variable. OIG observed that once the calculation yielded results that met the safe distance requirement, no additional credits were given. The first calculation used maximum release rate and gave no credit for pipeline enhancement features and yielded results that exceeded safe distance for safety related SSCs and SSCs ITS within and outside the SOCA. The second calculation used maximum release rate and gave 65 percent credit for pipeline enhancement features and yielded results that exceeded safe distance for safety related SSCs and SSCs ITS within and outside the SOCA. The third calculation used average release rate and gave no credit for pipeline enhancements. The third calculation for safe distance met requirements for SSCs and SSCs ITS inside the SOCA; however, it exceeded safe distances for SSCs ITS outside the SOCA. The fourth calculation used average release rate and 65 percent credit for pipeline enhancements. Only the fourth calculation met the safe distance requirement for all reference points.

OIG noted that NRC's use of credit for pipe enhancement features as described above contradicts statements in FERC's EIS and March 3, 2015, order approving the AIM Project, which both state that NRC's analysis did not account for the pipeline enhancements.

The Physical Scientist told OIG he relied on his engineering judgment[20] in assigning 65 percent credit for the pipeline safety features and for factoring in average release rate. When asked to explain the basis for assigning 65 percent credit for pipeline enhancements and for using the average release rate, instead of providing any quantitative or empirical data to support his engineering judgment, the Physical Scientist stated, “That is my call. That is my assumption.” Regarding his assigning 65 percent credit for the pipeline safety features, the Physical Scientist told OIG, because the pipeline is underground and has a layer of concrete slaps above, the pipeline will leak at a slower rate than when above ground. “So that’s why one-third might be a reasonable number.” Regarding his substitution of average release for maximum release rate, the Physical Scientist told OIG, “an average value would be more [realistic] than a conservative maximum value” because the gas would release at a slower rate due to the pipe’s underground location. The Physical Scientist added, “At what rate I do not know. The only possible rate it can be is an average rate.” The Physical Scientist told OIG he did not describe the various underground scenarios in his NRC AIM Project Safety Review but included his conclusion that the underground scenario would not adversely impact the safe operation and shutdown of IPEC. He said it would have been “too confusing to address so many scenarios, so many things.”

The Physical Scientist’s Branch Chief at the time, who assigned the Physical Scientist to conduct the review, told OIG he was aware that the Physical Scientist ran many scenarios, but the Physical Scientist did not go over the results or details with him. The Branch Chief said that he knew the Physical Scientist took “65 percent credit” for the pipeline enhancements based on his engineering judgment. When OIG shared the four calculations and results with the fourth calculation not exceeding the minimum safe distance, the Branch Chief said that it appeared, from looking at the Physical Scientist’s scenarios, that the Physical Scientist was backward engineering for a desired result. When OIG shared the statement in FERC’s EIS that described that the NRC’s analysis did not include factoring in the additional pipeline design measures identified by Entergy and committed to by Algonquin, the Branch Chief said that description is contrary because the Physical Scientist did take credit for the pipeline enhancements.

NRC Analyzed a Non-Existent, Above-Ground Point

As noted above, the Physical Scientist also examined a second site further from the plant where initial AIM Project plans indicated the pipe would come above ground. However, OIG learned that while the initial 42-inch pipeline design proposed by Algonquin indicated the new pipeline would come above ground on IPEC property, the final pipeline design and pipeline as built never comes above ground on IPEC property.

OIG spoke with Enbridge regarding several matters under investigation. For the matter of the above ground scenario, Enbridge told OIG that the 42-inch gas pipeline on IPEC property never comes above ground. The only portion above ground is a “pig trap,” also

[20] NUREG 1913, “Design Control in Pursuit of Engineering Excellence, A Quick Reference Guide for NRC Inspectors,” defines engineering judgment as a determination based on prior examples, experience, or observation that has not been subjected to rigorous engineering validation.

known as a "pig station," which is a configuration of pipes and "tie in" valves that are used for cleaning, maintenance, and inspection. For the pig station near IPEC, the largest diameter pipeline above ground is 26 inches.

OIG learned that while IPEC's initial 10 CFR 50.59 analysis also assessed the proposed above ground point, on April 8, 2015, IPEC submitted to NRC a revised 10 CFR 50.59 that acknowledged the change-in-design and re-assessed the impact of an explosion on the pig station, using the specific dimensions associated with the as-built piping. Although the revised 10 CFR 50.59 was provided to NRC – approximately 1 month after FERC's approval of pipeline construction and approximately 20 months before pipeline went into operation – the NRC never conducted further analysis on the actual as-built pipeline, and much of NRC's analysis remains based on a non-existent, above ground location.

The Physical Scientist told OIG that although he conducted multiple scenarios at the underground closest location to the plant, the above ground location was the basis for his conclusion for the NRC AIM Project Safety Review and the NRC inspection report. The Physical Scientist viewed the above ground point as a more credible location for a potential pipeline rupture since it was exposed on the surface.

The Physical Scientist's Branch Chief said he was aware that the Physical Scientist used the above ground point in his analysis. The Branch Chief said that Region I looked at the Physical Scientist's calculations too and he recalled discussions that the calculations were based on the worst hazard to the closest SSCs. Furthermore, the Branch Chief believed some conservatisms were employed by the Physical Scientist in his calculations and modeling, such as catastrophic failure of the pipe closest above ground location to the plant, which should provide for the worst-case scenario.

The NRC IPEC Project Manager who was also assigned as the 2.206 petition manager for the stakeholder's concerns was not aware that the reported result of the NRC's independent analysis was primarily based on the above ground location rather than the closest point. The Project Manager, who was NRC's primary communicator with FERC, told OIG he assumed the reported confirmatory analysis was done at the closest location to the plant for conservatism and to compare with Entergy's analysis results. The Project Manager clearly recalled that the 42-inch pipeline did not come above ground while on IPEC's property. The Project Manager said he would have expected the worst-case scenario (e.g., no credit taken for enhancements, maximum release rate, closest point to the plant) to have been assessed and was surprised that it was not.

NRC Incorrectly Stated Impacts Were Bounded by Previous Assessments

OIG also learned that both the NRC AIM Project Safety Review and NRC's November 7, 2014, inspection report each included an inaccurate statement suggesting that prior analysis indicated that although the current analysis showed risk to the SSCs ITS, these risks were "bounded" by previous studies. Specifically, the two reports

stated that impacts to the SSCs ITS outside the SOCA from both the above ground and below ground points analyzed

> …are bounded by the impacts from low probability events of extreme natural phenomena (including seismic activity, tornado winds, and hurricanes) which have been previously assessed and are addressed in the Indian Points Units 2 and 3 UFSAR. Indian Point Units 2 and 3 would still be able to achieve safe shutdown conditions.

Through review of the Indian Point Units 2 and 3 UFSAR and verification with IPEC officials, OIG learned the UFSAR does not address the bounding effects of extreme natural phenomena on SSCs ITS outside the SOCA. RG 1.91 states that additional analyses are required if SSCs ITS safe distances are not met.

The Physical Scientist recalled reporting that a pipe rupture impacting the SSCs ITS was bounded by more severe accidents such as extreme natural phenomena already evaluated in IPEC's UFSAR. According to the Physical Scientist, he did not conduct additional analysis because he believed the UFSAR already established this analysis.

NRC Used ALOHA to Model Scenarios Outside of ALOHA's Parameters

Based on review of NRC's Project AIM Safety Review and the Physical Scientist's supporting documentation, OIG learned that the Physical Scientist used the ALOHA program to determine the impacts for the jet flame, cloud fire, vapor cloud explosion, and unconfined explosion on IPEC's SSCs related to safety and the SSCs ITS. NOAA officials told OIG that ALOHA is designed for use during accidental chemical spills to help emergency response professionals assess the risk associated with toxic air hazards, thermal radiation from fires, and blast effects. NOAA officials explained that although ALOHA includes an extensive library of chemical property data, and models to assess the rate at which a chemical is released from containment and vaporizes, it has technical limitations.

After reviewing the ALOHA assessments done by the NRC for IPEC, NOAA officials provided OIG several areas of concern because they are outside the technical limitations of ALOHA's capability. First, ALOHA is not intended to assess impacts of explosions involving the type of "supercritical" gas that would flow through the 42-inch pipe at IPEC. According to NOAA officials, the pressure and temperature of the methane gas that the NRC modeled is within the "supercritical" state. OIG provided NOAA officials with the Physical Scientist's ALOHA model assumptions and results. NOAA officials told OIG that a simplified sensitivity assessment they ran, based on the information provided by OIG, resulted in an approximate underestimation of mass of flammable vapor released by 9 percent. This underestimation of mass resulted in a less conservative value.

Second, NOAA officials told OIG that ALOHA lacks the capability to assess 3-minutes of gas release prior to valve closure – although NRC's analysis stated it used a 3-minute valve closure time in its NRC AIM Project Safety Review. According to NOAA, the ALOHA program can assess only two valve scenarios – these are (1) valves closed (i.e., 0 minutes of gas released) or (2) the valves are connected to an infinite source (i.e., 60 minutes of gas released). For the valves closed scenario, ALOHA calculates just the residual gas mass in the pipeline. ALOHA provides several results to include a 1-minute maximum release rate of mass and a total release of mass. Therefore, statements in the Physical Scientist's NRC AIM Project Safety Review describing the estimated impacts that would result from an explosion, jet fire, and cloud fire, "considering manual closure of the isolation valves within 3-minutes," are inaccurate because ALOHA does not have the capability to model this scenario.

Additionally, OIG learned that ALOHA is designed solely for vertical breaks into the atmosphere and surrounding area; it is not designed for horizontal pipe breaks, it is not designed to model buried pipe, and ALOHA cannot model a double ended break where the pipe has broken in the middle and is leaking from both broken ends. The model can calculate the release from one side of the pipeline, but not both sides together.

Finally, OIG learned from Enbridge that it would, in fact, take the company a minimum of 6 minutes after leak detection to seal off the pipe and thereby stop the flow of gas into the ruptured portion, and not 3 minutes as NRC tried to calculate using ALOHA. Enbridge officials also told OIG that in the event of a rupture, operators would seal off approximately 14 miles of the pipeline surrounding the rupture point, and not the 3 miles the Physical Scientist used in his calculations.

The Physical Scientist told OIG he used ALOHA to determine the impacts for the jet flame, cloud fire, vapor cloud explosion, and unconfined explosion on IPEC's SSCs related to safety and the SSCs ITS. The Physical Scientist told OIG he believed ALOHA had been validated by the industry and was an accepted Environmental Protection Agency (EPA) and NOAA model for the analysis conducted.

The Physical Scientist's Branch Chief was not aware of ALOHA's limitations as described by NOAA, and said they caused him concern. He did not recall any discussions with the Physical Scientist about the use of ALOHA.

NRC Inspection Report Incorrectly Stated Missile Generation Was Assessed

OIG compared the language in NRC's November 7, 2014, inspection report description of NRC's "independent calculation results using conservative assumptions and rationale" with the Physical Scientist's calculations and the description in the NRC AIM Project Safety Review. OIG noted that the inspection report states that NRC assessed "missile generation." Specifically, the November 7, 2014, inspection report stated,

> The NRC's Physical Scientist performed an independent analysis of the hazards associated with the proposed pipeline. The analysis was

> performed based on the following conditions and hypothetical scenarios: rupture of the proposed pipeline located near IPEC resulting in an unconfined explosion or jet flame at the source; delayed vapor cloud fire or vapor cloud explosion; and accompanying missile generation.

The NRC AIM Project Safety Review stated,

> The analysis assumed that rupture of the natural gas pipeline may result in an unconfined explosion or jet flame at the source, delayed vapor cloud fire, or vapor cloud explosion. Missile generation may also accompany the rupture/explosion.

However, OIG's review of the Physical Scientist's calculations did not support that missile generation was assessed.

The Physical Scientist told OIG that he did not calculate missile generation because the minimum safe distance did not exceed the SSCs. RG 1.91 suggests that additional analysis, such as missile generation, be done if the minimum safe distance is exceeded for SSCs ITS. However, the Physical Scientist argued that in light of his understanding of RG 1.91, only the SSCs required further analysis if the minimum safe distance was exceeded. The Physical Scientist acknowledged that he did not pay close attention to the wording in RG 1.91 for SSCs ITS.

Interviews of NRC Managers

The Region I Branch Chief, who signed the November 7, 2014, inspection report, confirmed that although Region I reviewed Entergy's initial 10 CFR 50.59 as part of the inspection, Region I relied heavily on the Physical Scientist's NRC AIM Project Safety Review to determine the inspection finding of "no finding" because Region I alone did not have the expertise to make that decision. The Region I Branch Chief believed FERC used NRC's inspection report as one of the bases for its EIS and approval and he believed the Physical Scientist used the most conservative location in his analysis, which he believed was above ground.

In contrast, the Region I Deputy Regional Administrator, who was then the Region I Director of Reactor Safety, said the staff's 10 CFR 50.59 inspection did not rely on the Physical Scientist's calculations for the inspection's outcome. However, the Physical Scientist's work gave the region added confidence that there was no technical issue that Entergy might have missed and therefore no reason to challenge Entergy's conclusion that the new pipeline did not pose an increased risk and warrant a license amendment. The Deputy Regional Administrator said prior to the OIG interview, he had not been aware of the specific assumptions and factors the Physical Scientist had used in his calculations pertaining to the above and below ground scenarios; however, he was comfortable with the Physical Scientist's approach. He said he was confident in the outcome because it was a "very, very conservative approach." Nevertheless, the Deputy Regional Administrator acknowledged that based on the discrepancies

described by OIG, it would be prudent to conduct additional analysis to demonstrate there is no issue or problem.

In a series of meetings with NRC's then-Deputy Executive Director for Reactor Preparedness Programs (DEDR) (now retired), OIG described the discrepancies identified in NRC's AIM Project Safety Review. The DEDR was initially unfamiliar with the specifics of NRC's analysis, but said his understanding was the staff had done a thoughtful review and he was comfortable with the conclusions reached. However, based on the information OIG provided and his subsequent discussions with his technical staff, he told OIG he would be open to assess whether any additional work was needed after having an opportunity to review OIG's report. He said if the staff made any mistakes that raise questions, then "let's demonstrate to ourselves that this does not cast doubt on the overall conclusions that we drew. And, if it does, then we've got some more work to do…."

OIG briefed the current DEDR on the results of this event inquiry. The DEDR, who was familiar with Project AIM because he served as the Region I Regional Administrator in the 2014-2018 timeframe, expressed serious concerns about the issues identified by OIG. Specifically, the DEDR disagreed with the Physical Scientist's use of credits for enhanced piping in his underground calculations because the DEDR said the enhancements were not intended to mitigate the effects of a blast but were intended to reduce the chances of a pipe rupture in the first place (e.g., due to a backhoe or other digging equipment). In addition, the DEDR was concerned that the Physical Scientist did not provide a basis or explanation underlying his "engineering judgment." According to the DEDR, "engineering judgment does not mean winging it."

With regard to inaccuracies in NRC's November 7, 2014, inspection report (i.e., SSCs ITS bounded by UFSAR and that missile generation was examined), the DEDR said these factual errors were unacceptable and did not meet his expectations. The DEDR was concerned about information NRC had publicly communicated, especially in an agency decision document. The DEDR said if there were inaccuracies in an inspection report "that other agencies are relying on," there may be a need to clarify and amend the record.

With regard to NOAA's estimate that NRC's analysis underrepresented the mass of gas released in all scenarios by approximately 9 percent which resulted in a less conservative value, the DEDR remarked he would expect the users of a code to understand the code's parameters and he was concerned about the non-conservative results.

With regard to IPEC's revised 10 CFR 50.59 safety evaluation based on the 42-inch pipe not coming above ground in the final pipeline design, the DEDR assumed his inspectors were aware and had reviewed and assessed the impact of the design change. He was not concerned that the 42-inch pipe did not come above the ground because an above-ground explosion would have a more far reaching impact than a

below ground explosion at the same location. Therefore, the DEDR said the Physical Scientist's initial assessment of the above ground point was bounding.

In summary, the DEDR stated that NRC management has to rely on the information provided to them by the agency's technical experts. He said this information needs to be accurate and robust for sound decisionmaking. He commented that while communication can be challenging, in these matters, it needs to be sufficiently clear to allow for sound agency decisions.

Part II. NRC's Response to Stakeholder Concerns Over Project AIM Pipeline

NRC followed its 10 CFR 2.206 petition process in reviewing and responding to a citizen stakeholder's specific concerns about the impact of the new pipeline on IPEC property, which resulted in NRC's formal rejection of the stakeholder's concerns reflected in the original petition and in the stakeholder's associated correspondence to NRC. However, OIG learned that in communicating its decision to the stakeholder, NRC provided an inaccurate description of the work NRC conducted to assess the stakeholder's concerns. The investigation also revealed that NRC provided inaccurate information in response to the stakeholder's questions to NRC concerning the agency's NRC AIM Project Safety Review.

Specifically, the stakeholder challenged

- **Both Entergy's and the Physical Scientist's assumption, in their respective assessments, that the pipeline valves could be closed in 3 minutes.** The stakeholder asserted that it would not be possible for the valves to be closed within 3 minutes and questioned why NRC did not inform FERC that the fundamental assumptions and calculations were inaccurate. The stakeholder also asserted that Entergy violated 10 CFR 50.9 by providing a material false statement concerning the 3-minute valve closure times to the NRC in its 10 CFR 50.59 safety evaluation.

  OIG learned from Enbridge (the pipeline company) that it would take at least 6 minutes to close the valves after a leak is detected. The investigation also revealed that in response to the stakeholder's concern about a material false statement regarding the 3-minute closure time, NRC chose to conduct a 60-minute bounding analysis, and inaccurately described the results of its followup calculation. This analysis was used to refute the stakeholder's allegation of a material false statement.

- **NRC's use of ALOHA to assess the impact of pipe rupture on IPEC.** The stakeholder questioned why NRC would use ALOHA, which, according to the stakeholder, "is prohibited for use for a gas pipeline rupture [and] not referenced in RG 1.91, to calculate the blast radius of a rupture that could have a devastating impact to the more than 20 million persons residing in the vicinity of

Indian Point." The stakeholder also asked whether NRC performed a validation and verification of the ALOHA program to ascertain its accuracy.

OIG's investigation revealed that NRC informed the stakeholder that a validation and verification of ALOHA was not necessary. However, as noted previously in this report, NOAA, which created ALOHA, told OIG the program was not designed to assess the scenarios used by NRC to support the NRC AIM Project Safety Review.

- **NRC's deviation from RG 1.91 in calculating blast radius.** The stakeholder asserted that NRC modified the equation for calculating the blast radius in RG 1.91 and asked why NRC failed to provide a basis for deviation from the regulatory guide.

  Although NRC's response to the stakeholder claimed NRC used RG 1.91, Revision 2, without deviation, OIG's investigation identified that NRC deviated from RG 1.91 in a manner that was less conservative and had an impact on the outcome.

- **The quality assurance process used by NRC to verify the results of the NRC AIM Project Safety Review and followup assessment.** The stakeholder asked whether NRC has any quality assurance requirements/procedures for conducting safety related calculations.

  NRC responded to the stakeholder that NRC does not perform safety related calculations and does not have a quality assurance program for these calculations; however, they said a peer review by a qualified NRC engineer was performed on the NRC AIM Project Safety Review and followup assessment. OIG's investigation revealed the assigned engineer believed there were better qualified NRC staff to do the review and he performed only a limited review.

OIG Review of Correspondence

OIG reviewed correspondence between the citizen stakeholder and NRC dated October 15, 2014, through November 6, 2015, reflecting the stakeholder's concerns, and NRC's responses, about the safety impact on IPEC due to Enbridge's proposed 42-inch diameter natural gas pipeline that would traverse a portion of the owner-controlled property at IPEC. In at least four letters to NRC and two presentations to the NRC Petition Review Board (PRB), the stakeholder raised concerns and provided his technical analysis to support his questions. The NRC responded with correspondence that documented the agency's position.

On October 15, 2014, the stakeholder submitted a 10 CFR 2.206 petition requesting enforcement action against Entergy. This process is the primary mechanism by which the public can request NRC take enforcement-type action related to licensees or licensed activities. In the petition, the stakeholder stated that the hazards analysis,

prepared by the licensee to determine the safety impact on IPEC due to the proposed pipeline, is inadequate and incomplete, which violates several regulations including 10 CFR 50.9, “Completeness and Accuracy of Information” and 10 CFR 50.59, “Changes, tests, and experiments.”

NRC responded to the stakeholder’s 2.206 petition by assigning a PRB to review the stakeholder’s concerns. Throughout the petition process, the stakeholder was informed of the staff’s progress primarily by the NRC IPEC Project Manager, who was assigned to be the Petition Manager. The stakeholder was also provided an opportunity to present to the PRB on two occasions. These actions align with guidance in Management Directive 8.11, “Review Process for 10 CFR 2.206 Petitions.”

On January 28, 2015, the stakeholder made his first presentation before the PRB and provided clarifying and supplemental information in support of his petition. During this presentation, the stakeholder was accompanied by an individual with expertise in gas pipeline operation and safety management.

Subsequent to that presentation, NRC informed the stakeholder that the PRB’s initial recommendation was to reject the petition because the staff had previously reviewed and resolved the items identified in his petition.

Prior to learning of the PRB’s initial recommendation, the stakeholder submitted a FOIA request for all documents related to the proposed 42-inch gas pipeline for IPEC. After receiving the FOIA responses, the stakeholder communicated additional concerns to the NRC PRB, as well as the Commission, that included potential flaws with the staff’s confirmatory analysis used to conclude there would be no hazard to safe plant operation if a rupture of the gas pipelines occurred at IPEC.

On July 15, 2015[21], the stakeholder made a second presentation before the PRB. The purpose of that meeting was to allow the stakeholder to comment on the initial recommendation of the PRB and to provide supplementary information to his petition. At this presentation, the stakeholder provided additional evidence to support his concerns with (1) NRC’s use of the computer program ALOHA, (2) deviations from RG 1.91 equations, and (3) valve closure time assumption – which the stakeholder declared as a material false statement.

Following the second presentation, the PRB met to determine whether the new information provided sufficient details to change or modify the initial recommendation.

In NRC correspondence dated September 9, 2015, the stakeholder was informed that the PRB recommended to reject the petition on the basis that all identified issues had been previously reviewed and resolved. NRC’s letter stated the PRB recommendation was reviewed and approved by senior management of the Office of Nuclear Reactor Regulation. As agreed during the second presentation before the PRB, the NRC

[21] ADAMS Accession Number ML15251A050

committed to providing responses to the 39 written questions from the stakeholder under separate correspondence.

On November 6[22], 2015, the NRC responded to each of the stakeholder's 39 questions. The staff concluded that based on the review of Entergy's 10 CFR 50.59 hazards analysis and the NRC's independent calculation results using conservative assumptions and rationale, Entergy had appropriately concluded that the proposed pipeline does not introduce more than minimal additional risk to IPEC, and therefore, the changes in the external hazards analysis associated with the proposed pipeline did not require prior NRC review and approval.

Additionally, the staff began its November 6, 2015, correspondence with a summary of several of the stakeholder's concerns. Of particular relevance to this case are

- For the assumption of a 3-minute isolation valve closure time that the stakeholder characterized as a material false statement (potential 10 CFR 50.9 violation) the NRC claimed it performed a bounding sensitivity analysis for two scenarios, one for 3 minutes of gas release and another for 60 minutes of gas release. NRC reported the result of the 60-minute bounding sensitivity analysis was only marginally different from the 3-minute valve closure assumption. According to the NRC, "the staff concluded that valve closure times do not have a significant impact on the site hazards analysis, and the licensee's assumption of a 3-minute valve closure time does not have a material impact on that analysis."

- Regarding the alleged inaccurate and incomplete 10 CFR 50.59 hazards analysis prepared by Entergy, NRC stated it disagreed with the stakeholder's assertions. The agency reported that the staff stood by the initial conclusion, as documented in the November 7, 2014, inspection report, that a potential rupture of the proposed pipeline posed no threat to the safe operation of the plant or safe shutdown of the plant.

- With respect to the NRC withdrawing its findings to FERC that the proposed pipeline would not present an unacceptable risk to IPEC, NRC stated that the staff performed a thorough review of Entergy's 10 CFR 50.59 site hazards analysis and performed its own independent confirmatory analysis that is in agreement with the licensee's results. "The NRC has no basis to withdraw its previous conclusions to FERC," the letter stated.

Assumption that Pipeline Valves Could Be Closed in 3 Minutes and NRC's Followup Analysis

In correspondence dated January 28, 2015, and July 27, 2015, the stakeholder alleged that Entergy's site hazards analysis has a material false statement because the analysis assumed that pipeline operators located in Houston, Texas, would be able to recognize

[22] ADAMS Accession Number ML15287A257

a pipe rupture from pressure sensors located in the pipeline and take appropriate actions to close the pipeline isolation valves within 3 minutes.

During the January 28, 2015, PRB meeting, an individual with expertise in pipeline safety presented to the PRB the technical rationale[23] as to why significantly more time would elapse before valve closure could be activated by the Houston-based pipeline operators. According to this expert, the main signal to close valves is a significant decrease in pipeline pressure. For example, this individual posed that if you have 15 miles of high-pressure gas pipeline, it would not go to zero pressure instantly – it might be 20 minutes before the operators can recognize the valves need to be closed.

In response to this concern, the PRB asked for a "bounding sensitivity analysis" to be conducted. The PRB sought to test what the impact would be with 60-minutes of gas being released, with the assumption that if safety margins were not exceeded for 60-minutes, then they would not be exceeded for 3 minutes. The Physical Scientist who prepared the NRC AIM Project Safety Review was assigned to conduct this task and docketed his report on March 19, 2015, in the Agencywide Documents Access and Management System (ADAMS). According to the report's conclusion,

> The analysis assumed that following a complete pipeline rupture, the pipeline provides an infinite source of natural gas and the pipeline isolation valves do not close for an hour. Based on this analysis, the NRC staff has determined that there are only minimal changes to the peak overpressure calculation and the heat flux calculation. Therefore, the staff concludes that pipeline isolation valve closure times are inconsequential and the previous staff conclusions that the proposed 42-inch diameter natural gas pipeline at the Indian Point site does not represent an undue risk and that the plant could safely shut down following a postulated pipeline rupture remain valid.

This conclusion was communicated to the stakeholder in NRC's correspondence dated November 6, 2015. This response conveyed that the staff considered one scenario where the isolation valves were assumed to close within 3-minutes, and a second scenario that "assumed the release of gas for a full hour with the unbroken end of pipe connected to an infinite source." The letter stated, "the staff concluded that valve closure times do not have a significant impact on the site hazards analysis, and the licensee's assumption of a 3-minute valve closure time does not have a material impact on that analysis."

OIG reviewed the Physical Scientist's calculations for both the initial Project AIM Safety Review and his work done in response to the PRB's followup request and determined that NRC's November 6, 2015, correspondence inaccurately described the work done by the Physical Scientist. Although ALOHA does have the capability to assess

[23] According to the expert, the laws of thermodynamics provide the basis for pipe line rupture systemic dynamics that sustain pressure in the system before the compressor station recognizes a rupture.

60 minutes of gas released with an infinite source as well as the gas released in the first minute, as noted earlier in this report, it does not have the capability to assess 3 minutes of gas release prior to valve closure. In fact, OIG determined that the Physical Scientist used the 1-minute maximum gas release rate from ALOHA for both the 3-minute scenario assessed in the NRC AIM Project Safety Review and the 60-minute scenario conducted in response to the PRB request.

The Physical Scientist acknowledged to OIG that he used the 1-minute maximum release rate for his 3-minute analysis in the NRC AIM Project Safety Review and in his followup analysis to the PRB request. He said he ran ALOHA for 60 minutes and got results for both the total amount of mass released for 60-minutes and the 1-minute maximum release. However, he added he used the 1-minute mass value in his calculations because he considered it more realistic. According to the Physical Scientist, he used engineering judgment based on his understanding that methane is lighter than air and rises and disperses quickly. Furthermore, the Physical Scientist said he reported out his results to the PRB as he described them in the NRC AIM Project Safety Review and Confirmatory Analysis. The Physical Scientist told OIG that he believed he accurately communicated to the PRB what he did and "how they interpreted it, I do not know."

While the Physical Scientist's Branch Chief told OIG he thought the Physical Scientist had used the 60-minutes total mass in the equation, the IPEC Project Manager who wrote the November 6, 2015, correspondence, told OIG he was aware that the Physical Scientist had used 1 minute. According to the Physical Scientist's Branch Chief, the mass value used by the Physical Scientist is not necessarily the issue; however, the value chosen needs to be communicated accurately and transparent to the public.

NRC's Use of ALOHA to Assess Impact of Pipe Rupture on IPEC

In communications with the NRC, the stakeholder questioned the use of ALOHA to assess the quantity of gas released in a pipeline rupture. His rationale for questioning this was his belief that ALOHA cannot be used since it cannot model gas release from a pipe that has broken in the middle and is leaking from both broken ends and is not referenced in RG 1.91. The stakeholder also asked whether NRC performed a validation and verification of the ALOHA program to ascertain its accuracy.

In a letter dated November 6, 2015, to the stakeholder, the NRC responded,

> There is no need for the NRC staff to perform a validation and verification of the ALOHA computer program. ALOHA has been measured against similar computer models and the results are considered comparable.

This letter conveyed NRC staff believed ALOHA was an adequate program to use for their assessments. Additionally, the letter conveyed that NRC was aware of the pipe break limitation. The letter explained how the staff modeled its independent analysis to

address this limitation by doubling the predicted gas release from the upstream side of a pipe break to account for flow escaping from both sides of the break. The letter stated this was a conservative approach.

As described previously in this report, OIG learned from the developers of ALOHA (NOAA) that ALOHA does not model double-ended breaks plus several other limitations that the NRC failed to consider.

Further, OIG reviewed the Physical Scientist's calculations and observed that, contrary to the information conveyed in NRC's November 6, 2015, letter to the stakeholder, the Physical Scientist did not double the predicted gas release for the majority of calculations performed to support the November 7, 2014, NRC inspection report. He also did not double the predicted gas release when conducting the "60-minute bounding analysis" in response to the stakeholder's questions about the 3-minute valve closure time.

In contrast to NRC's assertion in its letter to the stakeholder that it doubled the mass in its independent and followup analyses, the Physical Scientist confirmed to OIG that he doubled the predicted gas release only for the underground scenario assessed during his NRC AIM Project Safety Review (where he also took 65 percent credit for the enhanced piping). The Physical Scientist acknowledged he did not double the mass when assessing the impact of a rupture above ground. The Physical Scientist said he accurately described to his management his assumptions and rationale (i.e., doubled the predicted gas release only for the underground scenario where he took 65 percent credit for enhanced piping and did not double the predicted gas release in other scenarios), and added, "but whether they absorb exactly that detail, everything, I'm not sure."

The IPEC Project Manager told OIG he knew ALOHA calculates flow only from one direction. Contrary to what the Physical Scientist told OIG, the IPEC Project Manager said it was his understanding that to compensate for this limitation, the Physical Scientist doubled the predicted gas release amounts for all results reflected in the November 7, 2014, inspection report to account for a double-ended break. The IPEC Project Manager told OIG that NRC did not provide calculations to FERC but talked them through the inspection report.

Also in contrast to the Physical Scientist's explanation to OIG, the Physical Scientist's Branch Chief told OIG it was his understanding the Physical Scientist doubled the mass value from ALOHA for both the above ground and below ground calculations. Also for the 60-minute bounding calculation, the Branch Chief said he thought the Physical Scientist assumed a double ended break. The Branch Chief recalled a meeting regarding IPEC with Federal and State Government officials where participants questioned this area and NRC discussed doubling the mass value to be conservative.

NRC's Deviation from RG 1.91 in Calculating the Blast Radius

In correspondence to NRC dated July 27, 2015, the stakeholder questioned NRC's adherence to RG 1.91 used to calculate the blast radius or safe distance. NRC Regulatory Guide (RG) 1.91, "Evaluations of Explosions Postulated to Occur at Nearby Facilities and on Transportation Routes Near Nuclear Power Plants," is the staff's guidance document for evaluating the impact of explosions from nearby transportation routes. This guidance defines an acceptable methodology for calculating safe distances beyond which no adverse effect would occur on nuclear plant safety components.

The stakeholder questioned why the NRC either modified and/or ignored its primary guidance, RG 1.91, and specifically questioned an undefined input parameter "Y" and the lack of a significant change in the results when the gas release continued for 60-minutes instead of 3 minutes. The stakeholder, using RG 1.91 equations, alleged the blast radius will increase by a factor of 2.71, or 3,000 feet, for the 60-minute assessment.

In correspondence dated November 6, 2015, the NRC reported,

> RG 1.91 is the staff's guidance document for evaluating the impact of explosions from nearby facilities and transportation routes. Entergy and the NRC used the methodology and equations of RG 1.91, without deviation, to determine the blast radius of 1.0 psi. No other methodology was used.

Additionally, the staff described that the "Y" represents the yield factor for methane as stated in Table 1 of RG 1.91. Regarding the stakeholder's concern with the lack of significant difference between the 3-minute and 60-minute valve closure assessments, the NRC reported,

> The NRC staff disagrees with the above extrapolation of the blast radius from 1,100 to 3,000 feet. As discussed in the response to question 4, it is a misapplication of Equation (1) of RG 1.91 to extrapolate a 3-minute gas pipeline release to a 1-hour gas pipeline release by multiplying the available mass by a factor of 20 and taking the cube root. Multiplying the calculated safe distances by a factor of 2.71 (i.e., the cube root of 20), ignores buoyancy of natural gas and artificially assumes that the entire amount of gas released over an hour will remain confined and available for an explosion. Thus, the above argument extending the calculated safe distance of 1,100 feet to 3,000 feet is flawed.

OIG reviewed the Physical Scientist's calculations and determined the Physical Scientist did use RG 1.91 Table 1's Y value for methane. As noted previously in this report, the lack of significance for the 3-minute versus 60-minute valve closure assessments was due to 1-minute of mass that was used for both assessments.

However, OIG noted that although NRC said its assessment did not deviate from RG 1.91 methodology, in fact, the RG 1.91 calculations for the underground and above ground locations did deviate from RG 1.91 equations. Specifically, the Physical Scientist used a different denominator – resulting in less conservative results. The applicable RG 1.91 equation has the pre-set denominator of 4420 kJ/kg and the Physical Scientist used 4500 kJ/kg.

During the course of several interviews with OIG, the Physical Scientist provided varying explanations as to why he used 4500 kJ/kg for the denominator. None of his explanations were consistent with RG 1.91, Revision 2, which NRC claimed had been used without deviation. First, he said he rounded the denominator (4420 kJ/kg) to 4500 kJ/kg because he considered it a generally used "nominal value," whereas the 4420 kJ/kg was the "precise value" and his change of values was "not going to make that much difference." In a second attempt to explain to OIG his basis for using 4500 kJ/kg, the Physical Scientist provided a draft of RG 1.91 that preceded Revision 2, which contained the pre-set denominator of 4500 kJ/kg. (OIG notes that RG 1.91, Revision 2, had been approved in April 2013, more than 1 year prior to the Physical Scientist's independent analysis.) He also provided NRC fire protection references that use a denominator of 4500 kJ/kg. The Physical Scientist also admitted he typically uses the 4500 kJ/kg denominator in similar safety assessments related to other NRC licensed nuclear facilities.

The Physical Scientist did not consider his use of 4500 kJ/kg a deviation from RG 1.91 and as such did not inform NRC management of the change in the denominator. However, the Physical Scientist agreed that following an NRC regulatory guide without deviation meant following it as written to include applying "equations as they are."

The Physical Scientist's Branch Chief agreed that changing the denominator was a deviation from RG 1.91. He added that because the conversion factor was changed to a larger number, the results were less conservative, and this was an issue that should be addressed. He also said that if you deviate from RG 1.91, it should be in the more conservative direction and should be documented and communicated to all involved because if the deviations are not communicated, it would be assumed that the RG was used as written. According to the Physical Scientist's Branch Chief, the use of a larger denominator than prescribed in RG 1.91, in combination with 1-minute of mass (as discussed previously in this report), undermined the ability of the NRC to add conservatism for safety assurance.

The IPEC Project Manager was unaware that the denominator was changed and agreed that changing the pre-set denominator modified the equation. According to the IPEC Project Manager, the Physical Scientist reported that the equations in RG 1.91 were used as is and unchanged. The IPEC Project Manager explained to OIG that raising the pre-set denominator made the result less conservative. He was not aware of any flexibility that existed in RG 1.91 for using other values. He had no explanation as to why someone would use anything other than the values in RG 1.91 equations.

Quality Assurance Process Used by NRC To Verify the Results of the AIM Project Safety Review and Followup Assessment

In correspondence dated July 27, 2015, the stakeholder questioned NRC's quality assurance process for verifying safety related calculations. In correspondence dated November 6, 2015, the NRC responded to the stakeholder that the NRC staff does not perform "safety-related" calculations and does not have a quality assurance process for such calculations. The letter stated,

> The NRC does not perform "safety-related calculations." Therefore, the NRC staff does not have specific procedures for performing calculations used to support inspections or to perform confirmatory analysis. The term, "safety related calculations" implies formal calculations performed by licensees for the design of NRC regulated facilities. Safety-related calculations by licensees must be performed in accordance with approved plant procedures and associated quality control. Calculations performed by the staff do not require the same level of documentation and are performed as needed to support independent confirmatory analysis.

NRC's letter conveyed that in response to the stakeholder's concerns, the staff performed an independent analysis that received a peer review by a qualified NRC engineer.

OIG learned that a headquarters Reactor Oversight Process (ROP) Engineer was assigned to peer review the Physical Scientist's analysis. The ROP Engineer told OIG he was selected while attending an Executive Leadership Team meeting after he mentioned he previously worked for Bechtel Power performing hazards analysis calculations and had used ALOHA. He said he told the Executive Leadership Team there was a Region IV staff member with better qualifications to conduct the review; however, an NRC senior manager assigned the ROP Engineer to the task.

According to the ROP Engineer, he spent approximately 8 hours conducting this review, and about "99 percent" of his time was focused on reviewing the licensee's 10 CFR 50.59 safety evaluation. He said there is no formal process for conducting a peer review. He said his approach was to talk to the Physical Scientist who described his process to him; download ALOHA from the Internet; and apply the Physical Scientist's assumptions and numbers in ALOHA, which seemed reasonable to him; and he came up with similar results. Then he wrote his conclusion that the independent analysis performed by the Physical Scientist used acceptable methodologies and realistic conservative assumptions and the conclusions matched the licensee's. The ROP Engineer said that he wrote his review summary in such a way that it "sent signals" that his check was an unofficial peer review from one individual to another – similar to inspectors sharing notes. The ROP Engineer said he was uncomfortable performing this peer review since the NRC does not have a defendable, formal process in place to conduct quality assurance or peer reviews.

The IPEC Project Manager was aware that the NRC did a peer review to determine if the Physical Scientist's calculation looked reasonable. The IPEC Project Manager recalled that the peer reviewer was qualified to do the peer review since he had experience working with ALOHA in the past.

OIG learned from the Physical Scientist's Branch Chief that typically peer reviews are not done. However, due to the high visibility of this situation, to include the stakeholder, NRC management decided to task another knowledgeable NRC staff member with "taking a hard look" at the Physical Scientist's calculations. The Physical Scientist's Branch Chief remembered that the peer reviewer did not identify any problems.

Interviews of NRC Managers

The Region I Deputy Regional Administrator, who was then the Region I Director of Reactor Safety, was aware that 60 minutes of gas release was not used for the bounding analysis, but that the amount assessed was something between 0 and 60 minutes. While he initially stated he thought the Physical Scientist used a number of conservatisms in his assessment that made this situation "more safe," later in the interview he acknowledged there might be a need to reassess. The Region I Deputy Regional Administrator also told OIG that he was not aware the Physical Scientist made a change from the RG 1.91 equations. However, he could not speak to a potential change in the denominator since he did not know why the Physical Scientist would do that. However, if it was done, the NRC should have documented it and why the change was made.

NRC's then-Deputy Executive Director for Reactor Preparedness Programs (DEDR) (now retired), told OIG he would expect the information that NRC documented and provided to the stakeholder to align with the staff's actual work for the NRC AIM Project Safety Review. He also said he would be disappointed if the NRC used a draft regulatory guide. Regarding the peer review, he told OIG that without talking to the ROP Engineer who conducted the review, he did not have a sense of how thorough it was. However, based on the description provided by OIG, and given stakeholder attention to this issue and NRC's reliance on the Physical Scientist's assessment, NRC should have done a better job with the peer review.

The current DEDR said he thought the Physical Scientist had assessed 3 minutes of gas release and 60 minutes of gas release; however, based on the information provided by OIG (i.e., that only 1 minute of gas release was assessed under both scenarios), the DEDR said he was very concerned. He recalled the stakeholder's question about whether the pipe could actually be sealed off in 3 minutes, given the operators' location in Houston; he said this was why NRC chose to assess an hour because it would be a "very bounding analysis." However, he said, "what you are presenting to me here is not." He also recalled the stakeholder challenging the similarity of NRC's results for the 3-minute and 60-minute analyses, and based on discussion with OIG, he now recognized why the results were so similar (i.e., only 1 minute of mass was used for each scenario).

Regarding the Physical Scientist's use of a draft version of RG 1.91, the current DEDR said the Physical Scientist should not have used a draft, especially when there was an approved guide available. The DEDR also said he would not have expected the Physical Scientist to round the denominator unless it was a conscious decision to be more conservative. However, he noted, in this case the rounding was in the non-conservative direction and was not documented or explained.

Regarding the "peer review," the DEDR said it did not "sound like what was asserted as a peer review was really well thought out." OIG told the DEDR there were two NRC gas plume experts in Region IV and the DEDR said he was inclined to have them recalculate the blast radius and compare the outcome to the results that NRC has relied upon. According to the DEDR, "it goes to the materiality…this all raises a lot of questions."

In response to OIG's question about whether IPEC is operating in an unanalyzed condition due to risks posed by the new 42-inch pipeline, the DEDR said, "The only reason I would hesitate…to just jump in and say we are in an unanalyzed condition is Entergy did analyze it. I have questions about how well we validated their analysis, so I think we have more work to do, but I don't think I would say they are in an unanalyzed condition at this point."

HOTLINE NUMBER:
1-800-233-3497

THE OFFICE OF THE INSPECTOR GENERAL

Attention: Hotline Program
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ALGONQUIN GAS TRANSMISSION, LLC
5400 Westheimer Court
Houston, Texas 77056

March 17, 2020

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

RE: Response to State Senator Harckham, Docket No. CP14-96-000

Dear Ms. Bose:

Algonquin Gas Transmission, LLC ("Algonquin") submits this response to the letter dated March 9, 2020, from New York State Senator Harckham to Chairman Chatterjee ("March 9 Letter") requesting an immediate shutdown of the Algonquin Incremental Market ("AIM") Project pipeline. The March 9 Letter provides no basis for the Commission to consider such a request, and based on updated safety information from the U.S. Nuclear Regulatory Commission ("NRC") discussed below, there is no issue with respect to the pipeline's route near the Indian Point facility requiring a shutdown of the AIM Project pipeline. Algonquin also corrects various statements in the March 9 letter and identifies additional information from the Commission's certificate process for the AIM Project demonstrating that no further action is required by the Commission.[1]

Algonquin clarifies that the subject pipeline does not "cross" the Indian Point nuclear plant owned by Entergy Nuclear Indian Point 1, LLC, *et al*. ("Entergy"), nor is it "running under" the plant. Rather, the pipeline traverses Entergy's property more than "1,600 feet from the power plant structures, with other road, parking, and industrial/commercial land, uses in between."[2]

Contrary to the suggestion that "no one really know[s] how safe"[3] the AIM Project pipeline is, the design, construction and operation of this proposed pipeline was the subject of focused inquiry and extensive review during the Federal Energy Regulatory Commission ("FERC") certificate process, including a third party safety evaluation. Specifically, Algonquin provided information regarding the extensive design and installation enhancements and mitigation measures along the entire segment of pipeline, thereby demonstrating that the pipeline would exceed the safety standards established by the Pipeline and Hazardous Materials Safety Administration. These measures included installing the pipeline at a minimum depth of five feet and installing concrete slabs over the pipe as a physical barrier where the pipe would lie closest to the Indian Point facility. These enhancements and measures were explicitly recognized by FERC in its approval of the AIM Project and, furthermore, allowed Entergy to conclude in its Safety Evaluation that "the AIM Project poses no increased risks to the Indian Point facility."[4] Nothing has changed in the pipeline

[1] Comments of New York State Senator Peter B. Harkham, Docket No. CP14-96-000 (submitted Mar. 9, 2020) ("Harkham Letter").
[2] Final Environmental Impact Statement, Docket No. CP14-96-000 at p. 4-159 (issued Jan. 23, 2015).
[3] Harkham Letter at 2.
[4] *Algonquin Gas Transmission, LLC*, 150 FERC ¶ 61,163 at P 106 (2015);

design or construction or subsequent operation that would require the FERC to revisit its findings in the certificate.

The request in the March 9 Letter is based not on a change in circumstances that presents a new safety risk from the AIM Project pipeline but rather on a report issued by the NRC Office of the Inspector General ("OIG") on February 13, 2020, regarding an earlier analysis by the NRC. Notably, although the OIG report found certain inaccuracies and misstatements in the NRC's analysis of the AIM Project facilities in proximity to Entergy's Indian Point facility, the report did not make any finding regarding the risk associated with the pipeline.[5] Furthermore, at the direction of the Chairman of the NRC in a memorandum dated February 24, 2020, the NRC staff recently examined the need for immediate regulatory action.[6] In the subsequent response provided on February 26, 2020, the Executive Director for Operations described the NRC staff's analysis, which was explicit that "there is no safety issue warranting immediate regulatory action at either Unit 2 or Unit 3.[7] Specifically, the NRC staff concluded that there is "[n]o significant degradation of defense in depth nor loss of safety margins" and that the "risk of pipeline explosions at IPC are smaller than the [applicable] risk action thresholds."[8]

Given the safety measures and standards established and observed for the AIM Project pipeline and the determination of the NRC staff that there is no safety issue at the Indian Point facility warranting further action by the NRC, there is no basis for the Commission to take the actions requested by State Senator Harckham.

Should you have any questions, please contact the undersigned at (713) 627-5215.

Sincerely,

/s/ *Steven E. Hellman*
Steven E. Hellman
Associate General Counsel

cc: Chairman Chatterjee

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[5] The report is included as Attachment A (also available at https://www.nrc.gov/docs/ML2005/ML20056F095.pdf).
[6] See Attachment B (also available at https://www.nrc.gov/docs/ML2005/ML20057E265.pdf).
[7] See Attachment C (also available at https://www.nrc.gov/docs/ML2005/ML20058D088.pdf).
[8] *Id*. at 3.

ATTACHMENT A

OFFICE OF THE INSPECTOR GENERAL

U.S. NUCLEAR REGULATORY COMMISSION

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant

Case No. 16-024

EVENT INQUIRY

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

OFFICE OF THE
INSPECTOR GENERAL

February 13, 2020

MEMORANDUM TO: Chairman Svinicki

FROM: David C. Lee
Deputy Inspector General

SUBJECT: CONCERNS PERTAINING TO GAS TRANSMISSION LINES AT THE INDIAN POINT NUCLEAR POWER PLANT (OIG CASE NO. 16-024)

This accompanies the results of an Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC), event inquiry into concerns pertaining to NRC's oversight of a 42-inch natural gas pipeline that was, at the time, proposed to traverse Indian Point Energy Center (IPEC) property. A citizen stakeholder questioned the adequacy and completeness of the licensee's (Entergy) site hazards analysis and NRC's independent and followup analyses prepared to determine the safety impact on IPEC plant components due to the potential rupture of the proposed high pressure 42-inch gas pipeline. OIG examined an NRC inspection report and underlying analysis used to determine that Entergy appropriately concluded the 42-inch gas pipeline would not introduce significant additional risk at IPEC. OIG also examined NRC's response to the stakeholder's concerns over the 42-inch gas pipeline.

We have also provided this event inquiry report to the appropriate Majority and Ranking Members of Congress with oversight responsibilities for the NRC.

If you have any questions, please contact me, at 301-415-5930, or Rocco J. Pierri, Assistant Inspector General for Investigations, at 301-415-5925.

Attachment: As stated

cc: Commissioner Baran
Commissioner Caputo
Commissioner Wright

Office of the Inspector General

EVENT INQUIRY

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant

Case No. 16-024

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Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant (Case No. 16-024)

Basis and Scope

The Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC), initiated this event inquiry in response to concerns, communicated to OIG, from a citizen stakeholder pertaining to NRC's oversight of a 42-inch natural gas pipeline that was, at the time, proposed to traverse Indian Point Energy Center (IPEC) property. This pipeline, now in operation, was part of the Algonquin Incremental Market (AIM) Project, which proposed to replace certain portions of the existing pipeline and install new pipeline in the northeast United States. NRC's role was to support the Federal Energy Regulatory Commission's (FERC) decision to approve or disapprove the project by providing information to the FERC on the impacts of the AIM Project on IPEC. NRC's findings were documented in its Third-Quarter Integrated Inspection Report issued to Entergy, IPEC's license holder, on November 7, 2014.

In a publicly available Title 10 of the *Code of Federal Regulations* Section 2.206 (10 CFR) petition, dated October 15, 2014, and a letter to NRC dated July 27, 2015, the stakeholder questioned the adequacy and completeness of the licensee's (Entergy) site hazards analysis and NRC's independent and followup analyses prepared to determine the safety impact on IPEC plant components due to the potential rupture of the proposed high pressure 42-inch gas pipeline. The stakeholder also questioned whether (1) NRC misled FERC and the public by claiming to FERC that there was no additional risk associated with the proposed 42-inch gas pipeline, thereby putting at risk 20 million people near IPEC; (2) NRC was aware of material false statements made by Entergy to NRC with respect to the 42-inch gas pipeline; (3) NRC violated its procedures and regulations when analyzing the potential safety impacts from the 42-inch gas pipeline; and (4) NRC is allowing IPEC to operate in an unanalyzed condition.

OIG's event inquiry examined NRC's inspection report and underlying analysis used to determine that Entergy appropriately concluded the 42-inch gas pipeline would not introduce significant risk to safety-related systems, structures, and components; and systems, structures, and components important-to-safety at IPEC. On March 3, 2015, FERC issued an order formally approving the AIM Project. On January 7, 2017, the pipeline went into use.

As part of this event inquiry, OIG also examined NRC's response to the stakeholder's concerns over the 42-inch gas pipeline.

Findings

Finding 1

While FERC's approval of the AIM Project pipeline relied in part on NRC's assessment of Entergy's site hazards analysis and NRC's independent analysis of the impact of a potential rupture of the portion of the pipeline that traversed IPEC property, OIG found (1) NRC's independent analysis was incorrectly portrayed in FERC's approval document as significantly more conservative than it actually was; (2) NRC's inspection report contained inaccuracies suggesting additional analysis had been conducted, when this was not the case; and (3) NRC's underlying independent analysis was conducted using a computer program that the National Oceanic and Atmospheric Administration (NOAA), which developed the program, said it was not designed for. Moreover, the majority of NRC's independent analysis described the impact of a potential rupture on an above ground point on IPEC property that NRC believed presented the most credible risk due to its exposure; however, ultimately the as-built 42-inch pipeline does not come above ground anywhere on IPEC property but does traverse the IPEC property.

OIG also found that NRC decisionmakers had differing understandings of the assumptions and factors driving the analysis conducted by an NRC Physical Scientist, who NRC considered a subject matter expert and who was responsible for conducting, documenting, and communicating his results. While the Physical Scientist attributed his analysis assumptions to OIG as engineering judgment, he did not have a basis for it and did not document a basis or a methodology in his report. When OIG briefed NRC managers on the issues OIG identified in the Physical Scientist's analysis, one noted that because the Physical Scientist conducted multiple calculations with increasing credit for pipeline enhancements, it appeared to be backwards engineering to get a desired result. An NRC senior manager said the Physical Scientist's use of credit for enhanced piping was inappropriate in part because the pipeline enhancements were not intended to mitigate the impact of a blast, but rather to reduce the chances of a rupture in the first place.

Several NRC senior managers said that based on issues identified in this event inquiry pertaining to the Physical Scientist's analysis, it may be prudent to redo the analysis.

Finding 2

OIG found that through the stakeholder's 2.206 petition and associated concerns – which were relevant and on point – NRC was presented an opportunity to reevaluate and confirm work previously conducted that supported the agency's conclusion that Entergy's hazards analysis was reliable. However, NRC failed to thoroughly reexamine the underlying premises of its analyses and did not accurately communicate its analytical work performed.

First, in response to the stakeholder's assertion that it would take longer than 3 minutes for the pipeline operators in Houston, Texas, to close the valves, thereby stopping the

flow of gas, NRC misrepresented the assumptions used in the followup bounding analysis that was conducted to assess the impact of 60 minutes of gas released. While NRC's response to the stakeholder described having conducted an assessment that assumed an infinite source of natural gas with the pipeline valves open for an hour, OIG's investigation found that NRC assessed only 1 minute of gas released. Moreover, NRC never confirmed the validity of the licensee's assumption that the valves could be closed in 3 minutes. OIG contacted the pipeline operator who estimated it would take at least 6 minutes after detection of a leak to close the valves. While the Physical Scientist told OIG he used 1 minute of gas released in his calculations, NRC managers had inconsistent understandings of the amount of mass the Physical Scientist used.

Second, in response to the stakeholder's question of whether NRC performed a validation and verification of NOAA's computer program to ascertain its adequacy for this purpose, NRC stated there was no need for NRC to perform a validation and verification of the computer program. However, OIG contacted NOAA, which confirmed the program is not designed for this purpose.

Third, NRC's response to the stakeholder stated that NRC used the methodology and equations of Regulatory Guide 1.91, NRC's guidance for evaluating postulated explosions near nuclear power plants, "without deviation"; however, OIG found that NRC used a draft regulatory guide in lieu of the final, approved version (which had been issued approximately 2 years prior) and deviated from the approved version in a manner that was less conservative and had an impact on the analysis outcome.

Fourth, the stakeholder asked whether NRC had any quality assurance requirements/procedures for conducting safety related calculations. NRC responded that they do not perform safety related calculations and do not have a quality assurance program for these calculations, but they said a peer review by a qualified NRC engineer was performed on NRC's independent analysis and followup analysis. OIG's investigation revealed that the assigned engineer, who felt there were more qualified people in NRC to do this, performed a limited review that focused mainly on the licensee's hazards analysis and not NRC's analyses.

An NRC senior manager conveyed to OIG that NRC decisionmakers rely on accurate information from the staff to support decisions and communicate accurately to stakeholders and, in this case, another Federal agency. However, NRC managers confirmed they do not have a quality assurance process or a formal peer review process to review this type of assessment.

Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant (Case No. 16-024)

Background and Chronology

IPEC is a nuclear power station located on the east bank of the Hudson River in Buchanan, NY, about 24 miles north of New York City, New York. According to IPEC's website, the station's two operating reactors, Unit 2 and Unit 3, supply electricity for about 3 million customers. Unit 1 was shut down in 1974 and is undergoing decommissioning. Units 2 and 3 are scheduled for decommissioning beginning in 2020 and 2021, respectively. Initially licensed to Consolidated Edison Company of New York, Inc., IPEC's current license holder is Entergy Nuclear Operations, Inc. (Entergy), and regulatory oversight for IPEC is provided by the NRC Region I office located in King of Prussia, PA.

Natural gas pipelines have existed on the IPEC owner-controlled property since before plant construction. Algonquin Gas Transmission Company[1] (Algonquin) built a 26-inch diameter natural gas pipeline in 1952 and an adjacent 30-inch natural gas pipeline in 1965, and both traverse IPEC property. As part of the initial licensing basis, the licensee assessed each operating unit for postulated pipeline explosions of both pipelines. The assessment used the measured "shortest distance" from the pipeline to safety-related system, structures, and components (SSCs[2]) as the safe distance to meet NRC regulations. In response to later NRC requests focused on physical security, Entergy expanded the licensing basis to also include above ground sections of the pipelines. The assessments concluded no hazard to safe plant operation if a rupture of the gas pipelines occurred. Licensees are required to adhere to their current licensing basis or request an amendment depending on changes affecting the licensed operation of the plant.

On February 28, 2014, Algonquin applied to FERC to construct, install, operate, and maintain approximately 37 miles of pipeline and related facilities in New York, Connecticut, and Massachusetts. The project was referred to as the Algonquin Incremental Market (AIM) Project and proposed to replace certain portions of existing pipeline and to install new pipeline in other areas. The AIM Project included a stretch of new 42-inch pipeline across IPEC's southern side. This new pipeline would transmit gas at higher pressures than the existing 26- and 30-inch pipelines and would be located further away than the existing pipelines from the plant's safety-related SSCs and Security Owner Controlled Area (SOCA), but closer to eight important to safety (ITS[3]) SSCs. A portion of the 42-inch pipeline crossing IPEC property would be enhanced with more safety features than normal for new pipelines. The closest two

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[1] Algonquin is an indirect wholly owned subsidiary of Enbridge Energy Corporation.
[2] Nuclear power plants are designed with SSCs that prevent or mitigate the consequences of postulated accidents which could cause undue risk to the health and safety of the public.
[3] Structures, systems, and components ITS shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

pipeline safety valves (which could be used to shut off gas to the portion of the pipe crossing IPEC property) encompassing the IPEC section of the pipe would be 3 miles apart. The next two closest safety valves, which encompass the 3-mile stretch of pipeline and its two safety valves, would be approximately 15 miles apart.

On April 2 and 23, 2014, NRC and FERC representatives met to discuss the AIM Project, the Federal review process, and regulatory responsibilities. FERC provided an overview of the role of a cooperating agency.[4] NRC declined to become a cooperating agency but agreed to provide appropriate information, as needed, on the impacts of the AIM Project.

On August 6, 2014, FERC issued a draft Environmental Impact Statement (EIS) concerning the impact of the pipeline.[5] FERC concluded that based on its consultation with NRC, Entergy was required to assess any new safety impacts on its IPEC facility and provide its analysis to NRC. NRC's role was to ensure that the IPEC licensee adequately assessed the safety implications of the proposed pipeline at the nuclear site, as well as to determine if the licensee's analysis met the NRC's requirements regarding plant changes.

On August 24, 2014, Entergy completed its 10 CFR 50.59[6] safety evaluation and an associated hazards analysis, which covered the consequences of a fire and explosion following release of natural gas from the proposed new AIM Project 42-inch-diameter pipeline. The 10 CFR 50.59 report noted,

> While the proposed 42-inch pipeline is further from IP2 and IP3 SSCs within the 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.

Because the 10 CFR 50.59 safety evaluation concluded there is a change to the current licensing basis for design basis external hazards, Entergy was required to undertake the associated hazards analysis. Entergy hired a consulting firm to prepare two supporting evaluations referred to as the "hazards analysis." The first evaluation included calculations for the consequences of postulated explosions and fire with missile generation[7] following the release of natural gas from the proposed new 42-inch pipeline

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[4] Under the National Environmental Policy Act (NEPA), upon request of a lead agency preparing an EIS, any other Federal agency which has jurisdiction by law shall be a cooperating agency. In addition, any other Federal agency which has special expertise with respect to any environmental issue that should be addressed in the EIS may be a cooperating agency upon request of the lead agency.

[5] NEPA requires Federal agencies prepare an Environmental Impact Statement (EIS) if a proposed major federal action is determined to significantly affect the quality of the human environment.

[6] A 10 CFR 50.59 review is a technical evaluation performed by a licensee to determine if a proposed change to the facility represents a significant modification to the plant design and licensing bases as described in the Final Safety Analysis Report and, therefore, requires NRC approval prior to implementation.

[7] Missile generation are projectiles associated with detonation of potentially explosive material.

at two locations. Location one was the area on the underground piping that measured the shortest distances to the SSCs ITS, as committed to in IPEC's licensing basis. Location two was based on measurements of an above ground pipeline rupture point on the 42-inch pipeline, referred to as the "tie-in[8]" location. Although the above ground location was further away from the plant than the underground location, it was assessed because of the potential impacts from intentional and malicious activity.

For both locations (above and below ground), Entergy measured the shortest distances from the new 42-inch pipeline to several SSCs ITS and developed a table that identified these distances per component.

For Entergy's first evaluation, they used several methodologies and included in their analysis factors for pipeline enhancements such as thicker piping, thicker corrosion protection, greater burial depth, and installation of protective reinforced concrete mats to impede access to the buried piping. Entergy assumed the isolation valves were 3-miles apart and would close within 3 minutes of a pipeline rupture. Entergy claimed to have done the explosion and fire assessments in accordance with NRC Regulatory Guide 1.91, "Evaluations of Explosions Postulated to Occur at Nearby Facilities and on Transportation Routes Near Nuclear Power Plants," Revision 2[9], (RG 1.91) as well as using Areal Locations of Hazardous Atmospheres (ALOHA) and BREEZE computer programs.

Entergy's second evaluation was a statistical analysis of fire and explosions using "best available" accident data for pipeline rupture frequency. This assessment determined Exposure Rates[10] for a failure of the proposed 42-inch pipeline.

As documented in its 10 CFR 50.59 Safety Evaluation and Hazards Analysis, Entergy concluded that the proposed pipeline did not pose a "significant reduction in the margin of safety" for the public and that the change did not require prior NRC approval (i.e., a license amendment). Entergy based this conclusion on pipeline design and installation enhancements, the results from the fire and explosion evaluation, and the exposure rate assessment. However, there were two exceptions that were below NRC's threshold criteria which required additional evaluation. The two exceptions were the meteorological tower and the steam generator storage facility which are SSCs ITS. For these two exceptions, Entergy provided safety justifications. Specifically, for the meteorological tower, Entergy stated it had an alternative means to perform the meteorological function. For the steam generator storage facility, the safety evaluation demonstrated that failure of this component would not exceed the radiation dose limits imposed by NRC guidelines.

In September 2014, NRC Region I performed a permanent plant modification inspection (PMMI) at IPEC. One of several PMMI objectives is to verify that modifications to the

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[8] Pipeline "tie-in" locations are above ground and used for inspection and maintenance throughout the entire pipeline.
[9] Agencywide Documents Access and Management System (ADAMS) Accession Number ML12170A980
[10] Exposure rates are analyses that demonstrate risk.

plant have not affected the safety functions of important safety systems. As one of three samples chosen for this inspection, NRC reviewed the 10 CFR 50.59 safety evaluation and supporting hazards analysis, conducted a walk-down of the proposed pipeline routing, and performed an independent analysis of the potential hazards relative to the new 42-inch pipeline.

An NRC Region I Security Inspector conducted this inspection with support from a Physical Scientist from NRC headquarters Office of New Reactors[11] (NRO), Radiation Protection and Accident Consequences Branch (RPAC). The Physical Scientist was considered an NRC subject matter expert on external hazards. The Region I Security Inspector did the on-site inspection activities while the Physical Scientist was tasked to perform independent confirmatory calculations. The Physical Scientist documented the results of his review in a six-page technical report titled, "Safety Review and Confirmatory Analysis, Entergy's 10 CFR 50.59 Safety Evaluation, Algonquin Incremental Market (AIM) Project, Indian Point Energy Center (IPEC)" (NRC AIM Project Safety Review). This report stated that the Physical Scientist performed independent confirmatory calculations with conservative assumptions and rationale using NRC RG 1.91 methodology and/or the ALOHA computer program to assess an explosion, jet fire, and cloud fire at the above ground point on the pipeline and the closest point (underground). The Physical Scientist's analysis was based on a stretch of pipeline consisting of about 3 miles between isolation valves, of which the enhanced section of pipeline length is identified to be 3,935 feet, and closure of the isolation valves within 3 minutes.

The Physical Scientist concluded that safety-related SSCs inside the SOCA passed the safety criteria, but that nearby SSCs ITS would be affected because the calculated minimum safe distances from the above ground reference point exceeded the safety criteria. To address the exceedance, the report stated,

> The staff finds that the impacts to the SSCs ITS from the proposed new 42-inch pipeline are bounded by the impacts from low probability events of extreme natural phenomena (including seismic activity, tornado winds, and hurricanes) which have been assessed and already addressed in the Indian Point Units 2 and 3 Updated Final Safety Analysis Report.[12]

The Physical Scientist's NRC AIM Project Safety Review was reviewed by the Region I Physical Security Inspector who shortened it into a four-page summary, or "feeder." This "feeder" was approved by two Region I Branch Chiefs and was incorporated into the NRC's Third-Quarter Integrated Inspection Report, issued to Entergy's IPEC Site Vice President on November 7, 2014[13]. The inspection report concluded that the proposed pipeline does not introduce significant additional risk to safety-related SSCs and SSCs ITS at Indian Point Units 2 and 3; and, therefore, the change in the design

[11] On October 13, 2019, NRO was reunified with the Office of Nuclear Reactor Regulation (NRR) and the resulting organization retained the title NRR.
[12] The most recent final safety analysis report (FSAR) includes the plant-specific design-basis information.
[13] ADAMS Accession Number ML14314A052

bases external hazards analysis associated with the proposed pipeline does not require prior NRC review and approval.

As reflected in an Interagency Meeting Summary prepared by FERC, on October 17, 2014, FERC held a conference call with NRC to discuss NRC's review of Entergy's site hazards analysis for IPEC relative to Algonquin's proposed AIM Project. The summary reflects that one FERC staff, one individual from the Natural Resource Group, LLC, and six NRC staff members involved with IPEC attended the conference call. The meeting summary conveyed that NRC had conducted an independent analysis of Entergy's 10 CFR 50.59 submission and an independent confirmatory blast analysis. The summary stated that Algonquin had committed to take additional mitigation measures to enhance the pipeline design and construction, but that NRC's analysis did not allow any credit for these additional mitigation measures and assumed a catastrophic pipeline failure. The summary stated that the review covered everything within the SOCA, which includes everything inside the outer most fenced area of the facility (including the spent fuel rods) and that "based on its review, the NRC came to the same conclusion that Entergy did in its 10 CFR 50.59 submission. Therefore, NRC finds Entergy's 10 CFR 50.59 submission acceptable and has determined that no prior approval from the NRC is needed."

On October 15, 2014[14], a citizen stakeholder submitted a 10 CFR 2.206[15] petition to the NRC requesting the NRC to take enforcement action against Entergy for violating the regulations of 10 CFR 50.9, "Completeness and Accuracy of Information," 10 CFR Part 50, Appendix B, "Quality Assurance Requirements," and 10 CFR 50.59, "Changes, Tests, and Experiments." The stakeholder provided numerous examples and direct quotes from IPEC's 10 CFR 50.59 Safety Evaluation and Hazard Analysis that he believed violated these regulations.

In January 2015, the stakeholder presented his 2.206 concerns before an NRC Petition Review Board (PRB). In the months that followed, the stakeholder continued to submit additional information to support his allegation, including documents from the stakeholder's Freedom of Information Act (FOIA) requests to the NRC.

Also in January 2015, FERC issued its final EIS for the entire pipeline, assessing the potential environmental effects of the construction and operation of the AIM Project in accordance with the requirements of the National Environmental Policy Act. The EIS conveyed the FERC staff's conclusion that "approval of the proposed project would result in some adverse environmental impacts; however, most of these impacts would

[14] ADAMS Accession Number ML14294A758

[15] 10 CFR 2.206 has been a part of the NRC's regulatory framework since the NRC was established in 1975. Section 2.206 permits any person to file a request to institute a proceeding pursuant to Section 2.202 of 10 CFR to modify, suspend, or revoke a license, or for other action as may be proper (hereinafter referred to in this directive as to take enforcement-related action). Such a request is referred to as a 2.206 petition.

be reduced to less than significant levels with the implementation of Algonquin's proposed mitigation and the additional measures[16] recommended in the final EIS."

The EIS quotes Entergy's Safety Evaluation conclusion that

> …based on the proposed routing of the 42-inch diameter pipeline further from safety related equipment at IPEC, and accounting for the substantial design and installation enhancements agreed to by [Algonquin], the proposed AIM project poses no increased risks to IPEC and there is no significant reduction in the margin of safety.

The EIS also describes NRC's assessment of Entergy's evaluation:

> The NRC has reviewed the site hazards analysis performed by Entergy and has performed an independent confirmatory analysis of the blast analysis as well. The NRC issued its findings in a report dated November 7, 2014. The NRC's analysis did not include factoring in the additional pipeline design measures identified by Entergy and committed to by Algonquin and assumed a pipeline catastrophic failure. The review covered everything within the Security Owner Controlled Area, which includes everything inside the outermost fenced area of the facility (including the area with the spent fuel rods). The NRC concluded that a breach and explosion of the proposed 42-inch-diameter natural gas pipeline would not adversely impact the safe operation of the facility.

On March 3, 2015, FERC's Chairman and Commissioners issued an order formally approving the AIM Project. Page 37 of the order states,

> The NRC reviewed the site hazards analysis performed by Entergy and performed an independent confirmatory analysis of the blast analysis as well. The NRC's analysis did not account for the additional pipeline design measures identified by Entergy and committed to by Algonquin and assumed a pipeline catastrophic failure. The review covered everything within the Security Owner Controlled Area, which encompasses everything inside the outermost fenced area of the facility including the area with the spent fuel rods. The NRC concluded that a breach and explosion of the proposed 42-inch-diameter natural gas pipeline would not adversely impact the safe operation of the Indian Point Facility. Therefore,

[16] Where the pipeline crossed IPEC property, these measures included (1) using internally coated piping that "exceeds the most stringent Class 4 requirements set by the U.S. Department of Transportation (even though this area is predominantly Class 3), (2) installing two parallel sets of fiber-reinforced concrete mats over the pipeline that would act as a physical barrier over the buried pipe, (3) installing yellow warning tape above and below the concrete slabs, (4) burying the pipeline to a minimum depth of 4 feet from the top of the pipeline, and (5) providing thicker external corrosion protection and internal coating.

the final EIS concludes that the project will not result in increased safety impacts at the Indian Point facility.

On April 8, 2015, Entergy submitted a revised 10 CFR 50.59 assessment to the NRC, acknowledging that amended pipeline plans indicated the 42-inch pipe would not come above ground. The revised 10 CFR 50.59 assessment reevaluated the “tie-in” location with the installed piping configuration and concluded that there were no increased risks to IPEC from the proposed AIM Project and the original Safety Evaluation remained bounding.

In April 2015, the stakeholder received a second FOIA response that he believed supported his allegation that Entergy had provided a material false statement regarding Enbridge’s ability to close the isolation valves within 3 minutes. The stakeholder requested an opportunity for a second presentation to the PRB which was granted and held on July 15, 2015. During the presentation, it was agreed that the stakeholder would submit remaining questions in writing; subsequently, the stakeholder prepared a written list of 39 questions that he submitted to the NRC on July 27, 2015.

In September 2015[17], the NRC rejected the stakeholder’s petition and in November 2015, provided answers to the stakeholder’s 39 questions.

On January 7, 2017, the pipeline went into use.

Part I. Problems Identified by OIG With NRC’s November 7, 2014, Inspection Report and Underlying Analysis

OIG learned that while FERC relied heavily on NRC’s November 7, 2014, inspection report as its basis for determining that IPEC could be safely shut down if a pipeline accident occurred, the underlying analysis for the inspection report was based on

- **A series of NRC calculations – assessing the closest location of the pipeline to plant components at a below ground point – that gave increasing amounts of “credit” for pipeline enhancements until the level of “credit” given resulted in an answer that demonstrated no increased risk, if a rupture occurred, to any safety related SSCs and SSCs ITS inside the SOCA.** In contrast, both FERC’s EIS and its March 3, 2015, order approving the AIM Project, state that NRC’s analysis did not account for the pipeline enhancements. OIG notes that the approach used by NRC – of crediting enhancements – was less conservative than the approach as described in the FERC documents, which indicated that no credit was given for enhancements.

- **NRC’s analysis of the impact of a rupture in a non-existent, above-ground point on the 42-inch pipeline.** OIG learned that the 42-inch pipeline does not go above ground at the “tie-in” location.

[17] ADAMS Accession Number ML15251A023

- **An inaccurate statement in NRC's analysis that although there was increased risk to SSCs ITS outside the SOCA if a pipeline rupture occurred, this was acceptable because these impacts were "bounded" by the impacts of extreme natural phenomena (e.g., tornadoes, hurricanes), which have been assessed and already addressed in the Indian Point Units 2 and 3 Updated Final Safety Analysis Reports (UFSAR)**. OIG learned that these impacts are not addressed in the Indian Point UFSARs.

- **NRC's misguided use of the ALOHA program to assess an explosion, a jet fire, and a cloud fire for the above and below ground portions of the pipeline.** Officials at the National Oceanic and Atmospheric Administration, Office of Response and Restoration Emergency Response Division[18] (NOAA), which created ALOHA, told OIG that ALOHA is not intended to assess impacts of explosions involving the type of "supercritical[19]" gas that would flow through the 42- inch pipe at IPEC. NOAA also told OIG ALOHA cannot assess 3 minutes of gas release prior to valve closure even though NRC's analysis claimed to do so, and it cannot model a double ended pipe break, which NRC also claimed to have done.

  Finally, OIG learned from Enbridge that it would, in fact, take the pipeline operators a minimum of 6 minutes after a leak is detected to manually close the isolation valves and thereby stop the flow of gas into the ruptured portion, and not 3 minutes as NRC claimed to have calculated using ALOHA. Enbridge also told OIG that if there were an explosion near IPEC, operators would shut valves that were approximately 14 miles apart rather than 3 miles apart as NRC assumed in its analysis.

- **OIG also learned that NRC's November 7, 2014, inspection report included an inaccurate statement that as part of NRC's analysis, the agency assessed the impact of "missile generation" that would occur if safe distance was exceeded for SSCs ITS.** Although NRC determined that safe distance was exceeded for SSCs ITS outside the SOCA, OIG learned that the agency did not assess missile generation.

Witness interviews of two FERC headquarters-based engineers assigned to the AIM Project revealed that FERC used NRC's November 7, 2014, inspection report for its Environmental Impact Statement (EIS) and FERC's Commission relied heavily on NRC's expertise to determine if IPEC could be safely shut down in the event of a pipeline accident, for approval of the portion of the AIM Project that crossed IPEC property.

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[18] Department of Commerce, National Oceanic and Atmospheric Administration, National Ocean Service Office of Response and Restoration Emergency Response Division, Seattle, Washington.
[19] Methane gas is in a "supercritical" state at 850 psi and 25° Celsius.

Review of NRC AIM Project Safety Review

The Physical Scientist's NRC AIM Project Safety Review examined the potential impact of a pipe rupture at two points on the pipeline. One point was underground; this was the shortest distance to the SOCA – which is a point addressed in the plant's current licensing basis. The other location, discussed in the next section of this report, also in the current licensing basis, was a site further from the plant where initial AIM Project plans indicated the pipe would come above ground. The Physical Scientist's review concluded that safe distance would not be exceeded for the safety-related SSCs inside the SOCA but would be exceeded for SSCs ITS outside the SOCA. According to his report, pipe failure would not reduce any further the existing safety margins, and would not pose a threat to the safe operation of the plant or safe shutdown because the potential impacts to SSCs ITS outside the SOCA were bounded by previous studies addressed in the licensee's UFSAR. OIG noted that about five pages of the NRC AIM Project Safety Review focused on the above ground point, and about one page focused on the below ground point.

NRC Conducted Multiple Calculations Giving Increasing Amounts of Credit for Pipeline Enhancements Until Answer Envisioned No Added Risk

In reviewing the Physical Scientist's documentary materials supporting his analysis of the nearest point, OIG noted the Physical Scientist conducted a series of calculations on a particular point where the pipeline was enhanced with thicker piping, greater corrosion resistance, deeper burial depth, and protective reinforced concrete mats located above the buried piping. OIG noted that for each calculation, the Physical Scientist made incremental adjustments by giving credit for pipe enhancement features and using the average release instead of maximum release rate for the mass input variable. OIG observed that once the calculation yielded results that met the safe distance requirement, no additional credits were given. The first calculation used maximum release rate and gave no credit for pipeline enhancement features and yielded results that exceeded safe distance for safety related SSCs and SSCs ITS within and outside the SOCA. The second calculation used maximum release rate and gave 65 percent credit for pipeline enhancement features and yielded results that exceeded safe distance for safety related SSCs and SSCs ITS within and outside the SOCA. The third calculation used average release rate and gave no credit for pipeline enhancements. The third calculation for safe distance met requirements for SSCs and SSCs ITS inside the SOCA; however, it exceeded safe distances for SSCs ITS outside the SOCA. The fourth calculation used average release rate and 65 percent credit for pipeline enhancements. Only the fourth calculation met the safe distance requirement for all reference points.

OIG noted that NRC's use of credit for pipe enhancement features as described above contradicts statements in FERC's EIS and March 3, 2015, order approving the AIM Project, which both state that NRC's analysis did not account for the pipeline enhancements.

The Physical Scientist told OIG he relied on his engineering judgment[20] in assigning 65 percent credit for the pipeline safety features and for factoring in average release rate. When asked to explain the basis for assigning 65 percent credit for pipeline enhancements and for using the average release rate, instead of providing any quantitative or empirical data to support his engineering judgment, the Physical Scientist stated, "That is my call. That is my assumption." Regarding his assigning 65 percent credit for the pipeline safety features, the Physical Scientist told OIG, because the pipeline is underground and has a layer of concrete slaps above, the pipeline will leak at a slower rate than when above ground. "So that's why one-third might be a reasonable number." Regarding his substitution of average release for maximum release rate, the Physical Scientist told OIG, "an average value would be more [realistic] than a conservative maximum value" because the gas would release at a slower rate due to the pipe's underground location. The Physical Scientist added, "At what rate I do not know. The only possible rate it can be is an average rate." The Physical Scientist told OIG he did not describe the various underground scenarios in his NRC AIM Project Safety Review but included his conclusion that the underground scenario would not adversely impact the safe operation and shutdown of IPEC. He said it would have been "too confusing to address so many scenarios, so many things."

The Physical Scientist's Branch Chief at the time, who assigned the Physical Scientist to conduct the review, told OIG he was aware that the Physical Scientist ran many scenarios, but the Physical Scientist did not go over the results or details with him. The Branch Chief said that he knew the Physical Scientist took "65 percent credit" for the pipeline enhancements based on his engineering judgment. When OIG shared the four calculations and results with the fourth calculation not exceeding the minimum safe distance, the Branch Chief said that it appeared, from looking at the Physical Scientist's scenarios, that the Physical Scientist was backward engineering for a desired result. When OIG shared the statement in FERC's EIS that described that the NRC's analysis did not include factoring in the additional pipeline design measures identified by Entergy and committed to by Algonquin, the Branch Chief said that description is contrary because the Physical Scientist did take credit for the pipeline enhancements.

NRC Analyzed a Non-Existent, Above-Ground Point

As noted above, the Physical Scientist also examined a second site further from the plant where initial AIM Project plans indicated the pipe would come above ground. However, OIG learned that while the initial 42-inch pipeline design proposed by Algonquin indicated the new pipeline would come above ground on IPEC property, the final pipeline design and pipeline as built never comes above ground on IPEC property.

OIG spoke with Enbridge regarding several matters under investigation. For the matter of the above ground scenario, Enbridge told OIG that the 42-inch gas pipeline on IPEC property never comes above ground. The only portion above ground is a "pig trap," also

[20] NUREG 1913, "Design Control in Pursuit of Engineering Excellence, A Quick Reference Guide for NRC Inspectors," defines engineering judgment as a determination based on prior examples, experience, or observation that has not been subjected to rigorous engineering validation.

known as a “pig station,” which is a configuration of pipes and “tie in” valves that are used for cleaning, maintenance, and inspection. For the pig station near IPEC, the largest diameter pipeline above ground is 26 inches.

OIG learned that while IPEC’s initial 10 CFR 50.59 analysis also assessed the proposed above ground point, on April 8, 2015, IPEC submitted to NRC a revised 10 CFR 50.59 that acknowledged the change-in-design and re-assessed the impact of an explosion on the pig station, using the specific dimensions associated with the as-built piping. Although the revised 10 CFR 50.59 was provided to NRC – approximately 1 month after FERC’s approval of pipeline construction and approximately 20 months before pipeline went into operation – the NRC never conducted further analysis on the actual as-built pipeline, and much of NRC’s analysis remains based on a non-existent, above ground location.

The Physical Scientist told OIG that although he conducted multiple scenarios at the underground closest location to the plant, the above ground location was the basis for his conclusion for the NRC AIM Project Safety Review and the NRC inspection report. The Physical Scientist viewed the above ground point as a more credible location for a potential pipeline rupture since it was exposed on the surface.

The Physical Scientist’s Branch Chief said he was aware that the Physical Scientist used the above ground point in his analysis. The Branch Chief said that Region I looked at the Physical Scientist’s calculations too and he recalled discussions that the calculations were based on the worst hazard to the closest SSCs. Furthermore, the Branch Chief believed some conservatisms were employed by the Physical Scientist in his calculations and modeling, such as catastrophic failure of the pipe closest above ground location to the plant, which should provide for the worst-case scenario.

The NRC IPEC Project Manager who was also assigned as the 2.206 petition manager for the stakeholder’s concerns was not aware that the reported result of the NRC’s independent analysis was primarily based on the above ground location rather than the closest point. The Project Manager, who was NRC’s primary communicator with FERC, told OIG he assumed the reported confirmatory analysis was done at the closest location to the plant for conservatism and to compare with Entergy’s analysis results. The Project Manager clearly recalled that the 42-inch pipeline did not come above ground while on IPEC’s property. The Project Manager said he would have expected the worst-case scenario (e.g., no credit taken for enhancements, maximum release rate, closest point to the plant) to have been assessed and was surprised that it was not.

NRC Incorrectly Stated Impacts Were Bounded by Previous Assessments

OIG also learned that both the NRC AIM Project Safety Review and NRC’s November 7, 2014, inspection report each included an inaccurate statement suggesting that prior analysis indicated that although the current analysis showed risk to the SSCs ITS, these risks were “bounded” by previous studies. Specifically, the two reports

stated that impacts to the SSCs ITS outside the SOCA from both the above ground and below ground points analyzed

> …are bounded by the impacts from low probability events of extreme natural phenomena (including seismic activity, tornado winds, and hurricanes) which have been previously assessed and are addressed in the Indian Points Units 2 and 3 UFSAR. Indian Point Units 2 and 3 would still be able to achieve safe shutdown conditions.

Through review of the Indian Point Units 2 and 3 UFSAR and verification with IPEC officials, OIG learned the UFSAR does not address the bounding effects of extreme natural phenomena on SSCs ITS outside the SOCA. RG 1.91 states that additional analyses are required if SSCs ITS safe distances are not met.

The Physical Scientist recalled reporting that a pipe rupture impacting the SSCs ITS was bounded by more severe accidents such as extreme natural phenomena already evaluated in IPEC's UFSAR. According to the Physical Scientist, he did not conduct additional analysis because he believed the UFSAR already established this analysis.

NRC Used ALOHA to Model Scenarios Outside of ALOHA's Parameters

Based on review of NRC's Project AIM Safety Review and the Physical Scientist's supporting documentation, OIG learned that the Physical Scientist used the ALOHA program to determine the impacts for the jet flame, cloud fire, vapor cloud explosion, and unconfined explosion on IPEC's SSCs related to safety and the SSCs ITS. NOAA officials told OIG that ALOHA is designed for use during accidental chemical spills to help emergency response professionals assess the risk associated with toxic air hazards, thermal radiation from fires, and blast effects. NOAA officials explained that although ALOHA includes an extensive library of chemical property data, and models to assess the rate at which a chemical is released from containment and vaporizes, it has technical limitations.

After reviewing the ALOHA assessments done by the NRC for IPEC, NOAA officials provided OIG several areas of concern because they are outside the technical limitations of ALOHA's capability. First, ALOHA is not intended to assess impacts of explosions involving the type of "supercritical" gas that would flow through the 42-inch pipe at IPEC. According to NOAA officials, the pressure and temperature of the methane gas that the NRC modeled is within the "supercritical" state. OIG provided NOAA officials with the Physical Scientist's ALOHA model assumptions and results. NOAA officials told OIG that a simplified sensitivity assessment they ran, based on the information provided by OIG, resulted in an approximate underestimation of mass of flammable vapor released by 9 percent. This underestimation of mass resulted in a less conservative value.

Second, NOAA officials told OIG that ALOHA lacks the capability to assess 3-minutes of gas release prior to valve closure – although NRC's analysis stated it used a 3-minute valve closure time in its NRC AIM Project Safety Review. According to NOAA, the ALOHA program can assess only two valve scenarios – these are (1) valves closed (i.e., 0 minutes of gas released) or (2) the valves are connected to an infinite source (i.e., 60 minutes of gas released). For the valves closed scenario, ALOHA calculates just the residual gas mass in the pipeline. ALOHA provides several results to include a 1-minute maximum release rate of mass and a total release of mass. Therefore, statements in the Physical Scientist's NRC AIM Project Safety Review describing the estimated impacts that would result from an explosion, jet fire, and cloud fire, "considering manual closure of the isolation valves within 3-minutes," are inaccurate because ALOHA does not have the capability to model this scenario.

Additionally, OIG learned that ALOHA is designed solely for vertical breaks into the atmosphere and surrounding area; it is not designed for horizontal pipe breaks, it is not designed to model buried pipe, and ALOHA cannot model a double ended break where the pipe has broken in the middle and is leaking from both broken ends. The model can calculate the release from one side of the pipeline, but not both sides together.

Finally, OIG learned from Enbridge that it would, in fact, take the company a minimum of 6 minutes after leak detection to seal off the pipe and thereby stop the flow of gas into the ruptured portion, and not 3 minutes as NRC tried to calculate using ALOHA. Enbridge officials also told OIG that in the event of a rupture, operators would seal off approximately 14 miles of the pipeline surrounding the rupture point, and not the 3 miles the Physical Scientist used in his calculations.

The Physical Scientist told OIG he used ALOHA to determine the impacts for the jet flame, cloud fire, vapor cloud explosion, and unconfined explosion on IPEC's SSCs related to safety and the SSCs ITS. The Physical Scientist told OIG he believed ALOHA had been validated by the industry and was an accepted Environmental Protection Agency (EPA) and NOAA model for the analysis conducted.

The Physical Scientist's Branch Chief was not aware of ALOHA's limitations as described by NOAA, and said they caused him concern. He did not recall any discussions with the Physical Scientist about the use of ALOHA.

NRC Inspection Report Incorrectly Stated Missile Generation Was Assessed

OIG compared the language in NRC's November 7, 2014, inspection report description of NRC's "independent calculation results using conservative assumptions and rationale" with the Physical Scientist's calculations and the description in the NRC AIM Project Safety Review. OIG noted that the inspection report states that NRC assessed "missile generation." Specifically, the November 7, 2014, inspection report stated,

> The NRC's Physical Scientist performed an independent analysis of the hazards associated with the proposed pipeline. The analysis was

> performed based on the following conditions and hypothetical scenarios: rupture of the proposed pipeline located near IPEC resulting in an unconfined explosion or jet flame at the source; delayed vapor cloud fire or vapor cloud explosion; and accompanying missile generation.

The NRC AIM Project Safety Review stated,

> The analysis assumed that rupture of the natural gas pipeline may result in an unconfined explosion or jet flame at the source, delayed vapor cloud fire, or vapor cloud explosion. Missile generation may also accompany the rupture/explosion.

However, OIG's review of the Physical Scientist's calculations did not support that missile generation was assessed.

The Physical Scientist told OIG that he did not calculate missile generation because the minimum safe distance did not exceed the SSCs. RG 1.91 suggests that additional analysis, such as missile generation, be done if the minimum safe distance is exceeded for SSCs ITS. However, the Physical Scientist argued that in light of his understanding of RG 1.91, only the SSCs required further analysis if the minimum safe distance was exceeded. The Physical Scientist acknowledged that he did not pay close attention to the wording in RG 1.91 for SSCs ITS.

Interviews of NRC Managers

The Region I Branch Chief, who signed the November 7, 2014, inspection report, confirmed that although Region I reviewed Entergy's initial 10 CFR 50.59 as part of the inspection, Region I relied heavily on the Physical Scientist's NRC AIM Project Safety Review to determine the inspection finding of "no finding" because Region I alone did not have the expertise to make that decision. The Region I Branch Chief believed FERC used NRC's inspection report as one of the bases for its EIS and approval and he believed the Physical Scientist used the most conservative location in his analysis, which he believed was above ground.

In contrast, the Region I Deputy Regional Administrator, who was then the Region I Director of Reactor Safety, said the staff's 10 CFR 50.59 inspection did not rely on the Physical Scientist's calculations for the inspection's outcome. However, the Physical Scientist's work gave the region added confidence that there was no technical issue that Entergy might have missed and therefore no reason to challenge Entergy's conclusion that the new pipeline did not pose an increased risk and warrant a license amendment. The Deputy Regional Administrator said prior to the OIG interview, he had not been aware of the specific assumptions and factors the Physical Scientist had used in his calculations pertaining to the above and below ground scenarios; however, he was comfortable with the Physical Scientist's approach. He said he was confident in the outcome because it was a "very, very conservative approach." Nevertheless, the Deputy Regional Administrator acknowledged that based on the discrepancies

described by OIG, it would be prudent to conduct additional analysis to demonstrate there is no issue or problem.

In a series of meetings with NRC's then-Deputy Executive Director for Reactor Preparedness Programs (DEDR) (now retired), OIG described the discrepancies identified in NRC's AIM Project Safety Review. The DEDR was initially unfamiliar with the specifics of NRC's analysis, but said his understanding was the staff had done a thoughtful review and he was comfortable with the conclusions reached. However, based on the information OIG provided and his subsequent discussions with his technical staff, he told OIG he would be open to assess whether any additional work was needed after having an opportunity to review OIG's report. He said if the staff made any mistakes that raise questions, then "let's demonstrate to ourselves that this does not cast doubt on the overall conclusions that we drew. And, if it does, then we've got some more work to do…."

OIG briefed the current DEDR on the results of this event inquiry. The DEDR, who was familiar with Project AIM because he served as the Region I Regional Administrator in the 2014-2018 timeframe, expressed serious concerns about the issues identified by OIG. Specifically, the DEDR disagreed with the Physical Scientist's use of credits for enhanced piping in his underground calculations because the DEDR said the enhancements were not intended to mitigate the effects of a blast but were intended to reduce the chances of a pipe rupture in the first place (e.g., due to a backhoe or other digging equipment). In addition, the DEDR was concerned that the Physical Scientist did not provide a basis or explanation underlying his "engineering judgment." According to the DEDR, "engineering judgment does not mean winging it."

With regard to inaccuracies in NRC's November 7, 2014, inspection report (i.e., SSCs ITS bounded by UFSAR and that missile generation was examined), the DEDR said these factual errors were unacceptable and did not meet his expectations. The DEDR was concerned about information NRC had publicly communicated, especially in an agency decision document. The DEDR said if there were inaccuracies in an inspection report "that other agencies are relying on," there may be a need to clarify and amend the record.

With regard to NOAA's estimate that NRC's analysis underrepresented the mass of gas released in all scenarios by approximately 9 percent which resulted in a less conservative value, the DEDR remarked he would expect the users of a code to understand the code's parameters and he was concerned about the non-conservative results.

With regard to IPEC's revised 10 CFR 50.59 safety evaluation based on the 42-inch pipe not coming above ground in the final pipeline design, the DEDR assumed his inspectors were aware and had reviewed and assessed the impact of the design change. He was not concerned that the 42-inch pipe did not come above the ground because an above-ground explosion would have a more far reaching impact than a

below ground explosion at the same location. Therefore, the DEDR said the Physical Scientist's initial assessment of the above ground point was bounding.

In summary, the DEDR stated that NRC management has to rely on the information provided to them by the agency's technical experts. He said this information needs to be accurate and robust for sound decisionmaking. He commented that while communication can be challenging, in these matters, it needs to be sufficiently clear to allow for sound agency decisions.

<u>Part II. NRC's Response to Stakeholder Concerns Over Project AIM Pipeline</u>

NRC followed its 10 CFR 2.206 petition process in reviewing and responding to a citizen stakeholder's specific concerns about the impact of the new pipeline on IPEC property, which resulted in NRC's formal rejection of the stakeholder's concerns reflected in the original petition and in the stakeholder's associated correspondence to NRC. However, OIG learned that in communicating its decision to the stakeholder, NRC provided an inaccurate description of the work NRC conducted to assess the stakeholder's concerns. The investigation also revealed that NRC provided inaccurate information in response to the stakeholder's questions to NRC concerning the agency's NRC AIM Project Safety Review.

Specifically, the stakeholder challenged

- **Both Entergy's and the Physical Scientist's assumption, in their respective assessments, that the pipeline valves could be closed in 3 minutes.** The stakeholder asserted that it would not be possible for the valves to be closed within 3 minutes and questioned why NRC did not inform FERC that the fundamental assumptions and calculations were inaccurate. The stakeholder also asserted that Entergy violated 10 CFR 50.9 by providing a material false statement concerning the 3-minute valve closure times to the NRC in its 10 CFR 50.59 safety evaluation.

  OIG learned from Enbridge (the pipeline company) that it would take at least 6 minutes to close the valves after a leak is detected. The investigation also revealed that in response to the stakeholder's concern about a material false statement regarding the 3-minute closure time, NRC chose to conduct a 60-minute bounding analysis, and inaccurately described the results of its followup calculation. This analysis was used to refute the stakeholder's allegation of a material false statement.

- **NRC's use of ALOHA to assess the impact of pipe rupture on IPEC.** The stakeholder questioned why NRC would use ALOHA, which, according to the stakeholder, "is prohibited for use for a gas pipeline rupture [and] not referenced in RG 1.91, to calculate the blast radius of a rupture that could have a devastating impact to the more than 20 million persons residing in the vicinity of

Indian Point." The stakeholder also asked whether NRC performed a validation and verification of the ALOHA program to ascertain its accuracy.

OIG's investigation revealed that NRC informed the stakeholder that a validation and verification of ALOHA was not necessary. However, as noted previously in this report, NOAA, which created ALOHA, told OIG the program was not designed to assess the scenarios used by NRC to support the NRC AIM Project Safety Review.

- **NRC's deviation from RG 1.91 in calculating blast radius.** The stakeholder asserted that NRC modified the equation for calculating the blast radius in RG 1.91 and asked why NRC failed to provide a basis for deviation from the regulatory guide.

  Although NRC's response to the stakeholder claimed NRC used RG 1.91, Revision 2, without deviation, OIG's investigation identified that NRC deviated from RG 1.91 in a manner that was less conservative and had an impact on the outcome.

- **The quality assurance process used by NRC to verify the results of the NRC AIM Project Safety Review and followup assessment.** The stakeholder asked whether NRC has any quality assurance requirements/procedures for conducting safety related calculations.

  NRC responded to the stakeholder that NRC does not perform safety related calculations and does not have a quality assurance program for these calculations; however, they said a peer review by a qualified NRC engineer was performed on the NRC AIM Project Safety Review and followup assessment. OIG's investigation revealed the assigned engineer believed there were better qualified NRC staff to do the review and he performed only a limited review.

OIG Review of Correspondence

OIG reviewed correspondence between the citizen stakeholder and NRC dated October 15, 2014, through November 6, 2015, reflecting the stakeholder's concerns, and NRC's responses, about the safety impact on IPEC due to Enbridge's proposed 42-inch diameter natural gas pipeline that would traverse a portion of the owner-controlled property at IPEC. In at least four letters to NRC and two presentations to the NRC Petition Review Board (PRB), the stakeholder raised concerns and provided his technical analysis to support his questions. The NRC responded with correspondence that documented the agency's position.

On October 15, 2014, the stakeholder submitted a 10 CFR 2.206 petition requesting enforcement action against Entergy. This process is the primary mechanism by which the public can request NRC take enforcement-type action related to licensees or licensed activities. In the petition, the stakeholder stated that the hazards analysis,

prepared by the licensee to determine the safety impact on IPEC due to the proposed pipeline, is inadequate and incomplete, which violates several regulations including 10 CFR 50.9, “Completeness and Accuracy of Information” and 10 CFR 50.59, “Changes, tests, and experiments.”

NRC responded to the stakeholder’s 2.206 petition by assigning a PRB to review the stakeholder’s concerns. Throughout the petition process, the stakeholder was informed of the staff’s progress primarily by the NRC IPEC Project Manager, who was assigned to be the Petition Manager. The stakeholder was also provided an opportunity to present to the PRB on two occasions. These actions align with guidance in Management Directive 8.11, “Review Process for 10 CFR 2.206 Petitions.”

On January 28, 2015, the stakeholder made his first presentation before the PRB and provided clarifying and supplemental information in support of his petition. During this presentation, the stakeholder was accompanied by an individual with expertise in gas pipeline operation and safety management.

Subsequent to that presentation, NRC informed the stakeholder that the PRB’s initial recommendation was to reject the petition because the staff had previously reviewed and resolved the items identified in his petition.

Prior to learning of the PRB’s initial recommendation, the stakeholder submitted a FOIA request for all documents related to the proposed 42-inch gas pipeline for IPEC. After receiving the FOIA responses, the stakeholder communicated additional concerns to the NRC PRB, as well as the Commission, that included potential flaws with the staff’s confirmatory analysis used to conclude there would be no hazard to safe plant operation if a rupture of the gas pipelines occurred at IPEC.

On July 15, 2015[21], the stakeholder made a second presentation before the PRB. The purpose of that meeting was to allow the stakeholder to comment on the initial recommendation of the PRB and to provide supplementary information to his petition. At this presentation, the stakeholder provided additional evidence to support his concerns with (1) NRC’s use of the computer program ALOHA, (2) deviations from RG 1.91 equations, and (3) valve closure time assumption – which the stakeholder declared as a material false statement.

Following the second presentation, the PRB met to determine whether the new information provided sufficient details to change or modify the initial recommendation.

In NRC correspondence dated September 9, 2015, the stakeholder was informed that the PRB recommended to reject the petition on the basis that all identified issues had been previously reviewed and resolved. NRC’s letter stated the PRB recommendation was reviewed and approved by senior management of the Office of Nuclear Reactor Regulation. As agreed during the second presentation before the PRB, the NRC

[21] ADAMS Accession Number ML15251A050

committed to providing responses to the 39 written questions from the stakeholder under separate correspondence.

On November 6[22], 2015, the NRC responded to each of the stakeholder's 39 questions. The staff concluded that based on the review of Entergy's 10 CFR 50.59 hazards analysis and the NRC's independent calculation results using conservative assumptions and rationale, Entergy had appropriately concluded that the proposed pipeline does not introduce more than minimal additional risk to IPEC, and therefore, the changes in the external hazards analysis associated with the proposed pipeline did not require prior NRC review and approval.

Additionally, the staff began its November 6, 2015, correspondence with a summary of several of the stakeholder's concerns. Of particular relevance to this case are

- For the assumption of a 3-minute isolation valve closure time that the stakeholder characterized as a material false statement (potential 10 CFR 50.9 violation) the NRC claimed it performed a bounding sensitivity analysis for two scenarios, one for 3 minutes of gas release and another for 60 minutes of gas release. NRC reported the result of the 60-minute bounding sensitivity analysis was only marginally different from the 3-minute valve closure assumption. According to the NRC, "the staff concluded that valve closure times do not have a significant impact on the site hazards analysis, and the licensee's assumption of a 3-minute valve closure time does not have a material impact on that analysis."

- Regarding the alleged inaccurate and incomplete 10 CFR 50.59 hazards analysis prepared by Entergy, NRC stated it disagreed with the stakeholder's assertions. The agency reported that the staff stood by the initial conclusion, as documented in the November 7, 2014, inspection report, that a potential rupture of the proposed pipeline posed no threat to the safe operation of the plant or safe shutdown of the plant.

- With respect to the NRC withdrawing its findings to FERC that the proposed pipeline would not present an unacceptable risk to IPEC, NRC stated that the staff performed a thorough review of Entergy's 10 CFR 50.59 site hazards analysis and performed its own independent confirmatory analysis that is in agreement with the licensee's results. "The NRC has no basis to withdraw its previous conclusions to FERC," the letter stated.

Assumption that Pipeline Valves Could Be Closed in 3 Minutes and NRC's Followup Analysis

In correspondence dated January 28, 2015, and July 27, 2015, the stakeholder alleged that Entergy's site hazards analysis has a material false statement because the analysis assumed that pipeline operators located in Houston, Texas, would be able to recognize

[22] ADAMS Accession Number ML15287A257

a pipe rupture from pressure sensors located in the pipeline and take appropriate actions to close the pipeline isolation valves within 3 minutes.

During the January 28, 2015, PRB meeting, an individual with expertise in pipeline safety presented to the PRB the technical rationale[23] as to why significantly more time would elapse before valve closure could be activated by the Houston-based pipeline operators. According to this expert, the main signal to close valves is a significant decrease in pipeline pressure. For example, this individual posed that if you have 15 miles of high-pressure gas pipeline, it would not go to zero pressure instantly – it might be 20 minutes before the operators can recognize the valves need to be closed.

In response to this concern, the PRB asked for a “bounding sensitivity analysis” to be conducted. The PRB sought to test what the impact would be with 60-minutes of gas being released, with the assumption that if safety margins were not exceeded for 60-minutes, then they would not be exceeded for 3 minutes. The Physical Scientist who prepared the NRC AIM Project Safety Review was assigned to conduct this task and docketed his report on March 19, 2015, in the Agencywide Documents Access and Management System (ADAMS). According to the report’s conclusion,

> The analysis assumed that following a complete pipeline rupture, the pipeline provides an infinite source of natural gas and the pipeline isolation valves do not close for an hour. Based on this analysis, the NRC staff has determined that there are only minimal changes to the peak overpressure calculation and the heat flux calculation. Therefore, the staff concludes that pipeline isolation valve closure times are inconsequential and the previous staff conclusions that the proposed 42-inch diameter natural gas pipeline at the Indian Point site does not represent an undue risk and that the plant could safely shut down following a postulated pipeline rupture remain valid.

This conclusion was communicated to the stakeholder in NRC’s correspondence dated November 6, 2015. This response conveyed that the staff considered one scenario where the isolation valves were assumed to close within 3-minutes, and a second scenario that “assumed the release of gas for a full hour with the unbroken end of pipe connected to an infinite source.” The letter stated, “the staff concluded that valve closure times do not have a significant impact on the site hazards analysis, and the licensee’s assumption of a 3-minute valve closure time does not have a material impact on that analysis.”

OIG reviewed the Physical Scientist’s calculations for both the initial Project AIM Safety Review and his work done in response to the PRB’s followup request and determined that NRC’s November 6, 2015, correspondence inaccurately described the work done by the Physical Scientist. Although ALOHA does have the capability to assess

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[23] According to the expert, the laws of thermodynamics provide the basis for pipe line rupture systemic dynamics that sustain pressure in the system before the compressor station recognizes a rupture.

60 minutes of gas released with an infinite source as well as the gas released in the first minute, as noted earlier in this report, it does not have the capability to assess 3 minutes of gas release prior to valve closure. In fact, OIG determined that the Physical Scientist used the 1-minute maximum gas release rate from ALOHA for both the 3-minute scenario assessed in the NRC AIM Project Safety Review and the 60-minute scenario conducted in response to the PRB request.

The Physical Scientist acknowledged to OIG that he used the 1-minute maximum release rate for his 3-minute analysis in the NRC AIM Project Safety Review and in his followup analysis to the PRB request. He said he ran ALOHA for 60 minutes and got results for both the total amount of mass released for 60-minutes and the 1-minute maximum release. However, he added he used the 1-minute mass value in his calculations because he considered it more realistic. According to the Physical Scientist, he used engineering judgment based on his understanding that methane is lighter than air and rises and disperses quickly. Furthermore, the Physical Scientist said he reported out his results to the PRB as he described them in the NRC AIM Project Safety Review and Confirmatory Analysis. The Physical Scientist told OIG that he believed he accurately communicated to the PRB what he did and "how they interpreted it, I do not know."

While the Physical Scientist's Branch Chief told OIG he thought the Physical Scientist had used the 60-minutes total mass in the equation, the IPEC Project Manager who wrote the November 6, 2015, correspondence, told OIG he was aware that the Physical Scientist had used 1 minute. According to the Physical Scientist's Branch Chief, the mass value used by the Physical Scientist is not necessarily the issue; however, the value chosen needs to be communicated accurately and transparent to the public.

NRC's Use of ALOHA to Assess Impact of Pipe Rupture on IPEC

In communications with the NRC, the stakeholder questioned the use of ALOHA to assess the quantity of gas released in a pipeline rupture. His rationale for questioning this was his belief that ALOHA cannot be used since it cannot model gas release from a pipe that has broken in the middle and is leaking from both broken ends and is not referenced in RG 1.91. The stakeholder also asked whether NRC performed a validation and verification of the ALOHA program to ascertain its accuracy.

In a letter dated November 6, 2015, to the stakeholder, the NRC responded,

> There is no need for the NRC staff to perform a validation and verification of the ALOHA computer program. ALOHA has been measured against similar computer models and the results are considered comparable.

This letter conveyed NRC staff believed ALOHA was an adequate program to use for their assessments. Additionally, the letter conveyed that NRC was aware of the pipe break limitation. The letter explained how the staff modeled its independent analysis to

address this limitation by doubling the predicted gas release from the upstream side of a pipe break to account for flow escaping from both sides of the break. The letter stated this was a conservative approach.

As described previously in this report, OIG learned from the developers of ALOHA (NOAA) that ALOHA does not model double-ended breaks plus several other limitations that the NRC failed to consider.

Further, OIG reviewed the Physical Scientist's calculations and observed that, contrary to the information conveyed in NRC's November 6, 2015, letter to the stakeholder, the Physical Scientist did not double the predicted gas release for the majority of calculations performed to support the November 7, 2014, NRC inspection report. He also did not double the predicted gas release when conducting the "60-minute bounding analysis" in response to the stakeholder's questions about the 3-minute valve closure time.

In contrast to NRC's assertion in its letter to the stakeholder that it doubled the mass in its independent and followup analyses, the Physical Scientist confirmed to OIG that he doubled the predicted gas release only for the underground scenario assessed during his NRC AIM Project Safety Review (where he also took 65 percent credit for the enhanced piping). The Physical Scientist acknowledged he did not double the mass when assessing the impact of a rupture above ground. The Physical Scientist said he accurately described to his management his assumptions and rationale (i.e., doubled the predicted gas release only for the underground scenario where he took 65 percent credit for enhanced piping and did not double the predicted gas release in other scenarios), and added, "but whether they absorb exactly that detail, everything, I'm not sure."

The IPEC Project Manager told OIG he knew ALOHA calculates flow only from one direction. Contrary to what the Physical Scientist told OIG, the IPEC Project Manager said it was his understanding that to compensate for this limitation, the Physical Scientist doubled the predicted gas release amounts for all results reflected in the November 7, 2014, inspection report to account for a double-ended break. The IPEC Project Manager told OIG that NRC did not provide calculations to FERC but talked them through the inspection report.

Also in contrast to the Physical Scientist's explanation to OIG, the Physical Scientist's Branch Chief told OIG it was his understanding the Physical Scientist doubled the mass value from ALOHA for both the above ground and below ground calculations. Also for the 60-minute bounding calculation, the Branch Chief said he thought the Physical Scientist assumed a double ended break. The Branch Chief recalled a meeting regarding IPEC with Federal and State Government officials where participants questioned this area and NRC discussed doubling the mass value to be conservative.

NRC’s Deviation from RG 1.91 in Calculating the Blast Radius

In correspondence to NRC dated July 27, 2015, the stakeholder questioned NRC’s adherence to RG 1.91 used to calculate the blast radius or safe distance. NRC Regulatory Guide (RG) 1.91, "Evaluations of Explosions Postulated to Occur at Nearby Facilities and on Transportation Routes Near Nuclear Power Plants," is the staff's guidance document for evaluating the impact of explosions from nearby transportation routes. This guidance defines an acceptable methodology for calculating safe distances beyond which no adverse effect would occur on nuclear plant safety components.

The stakeholder questioned why the NRC either modified and/or ignored its primary guidance, RG 1.91, and specifically questioned an undefined input parameter "Y" and the lack of a significant change in the results when the gas release continued for 60-minutes instead of 3 minutes. The stakeholder, using RG 1.91 equations, alleged the blast radius will increase by a factor of 2.71, or 3,000 feet, for the 60-minute assessment.

In correspondence dated November 6, 2015, the NRC reported,

> RG 1.91 is the staff's guidance document for evaluating the impact of explosions from nearby facilities and transportation routes. Entergy and the NRC used the methodology and equations of RG 1.91, without deviation, to determine the blast radius of 1.0 psi. No other methodology was used.

Additionally, the staff described that the “Y” represents the yield factor for methane as stated in Table 1 of RG 1.91. Regarding the stakeholder’s concern with the lack of significant difference between the 3-minute and 60-minute valve closure assessments, the NRC reported,

> The NRC staff disagrees with the above extrapolation of the blast radius from 1,100 to 3,000 feet. As discussed in the response to question 4, it is a misapplication of Equation (1) of RG 1.91 to extrapolate a 3-minute gas pipeline release to a 1-hour gas pipeline release by multiplying the available mass by a factor of 20 and taking the cube root. Multiplying the calculated safe distances by a factor of 2.71 (i.e., the cube root of 20), ignores buoyancy of natural gas and artificially assumes that the entire amount of gas released over an hour will remain confined and available for an explosion. Thus, the above argument extending the calculated safe distance of 1,100 feet to 3,000 feet is flawed.

OIG reviewed the Physical Scientist’s calculations and determined the Physical Scientist did use RG 1.91 Table 1’s Y value for methane. As noted previously in this report, the lack of significance for the 3-minute versus 60-minute valve closure assessments was due to 1-minute of mass that was used for both assessments.

However, OIG noted that although NRC said its assessment did not deviate from RG 1.91 methodology, in fact, the RG 1.91 calculations for the underground and above ground locations did deviate from RG 1.91 equations. Specifically, the Physical Scientist used a different denominator – resulting in less conservative results. The applicable RG 1.91 equation has the pre-set denominator of 4420 kJ/kg and the Physical Scientist used 4500 kJ/kg.

During the course of several interviews with OIG, the Physical Scientist provided varying explanations as to why he used 4500 kJ/kg for the denominator. None of his explanations were consistent with RG 1.91, Revision 2, which NRC claimed had been used without deviation. First, he said he rounded the denominator (4420 kJ/kg) to 4500 kJ/kg because he considered it a generally used "nominal value," whereas the 4420 kJ/kg was the "precise value" and his change of values was "not going to make that much difference." In a second attempt to explain to OIG his basis for using 4500 kJ/kg, the Physical Scientist provided a draft of RG 1.91 that preceded Revision 2, which contained the pre-set denominator of 4500 kJ/kg. (OIG notes that RG 1.91, Revision 2, had been approved in April 2013, more than 1 year prior to the Physical Scientist's independent analysis.) He also provided NRC fire protection references that use a denominator of 4500 kJ/kg. The Physical Scientist also admitted he typically uses the 4500 kJ/kg denominator in similar safety assessments related to other NRC licensed nuclear facilities.

The Physical Scientist did not consider his use of 4500 kJ/kg a deviation from RG 1.91 and as such did not inform NRC management of the change in the denominator. However, the Physical Scientist agreed that following an NRC regulatory guide without deviation meant following it as written to include applying "equations as they are."

The Physical Scientist's Branch Chief agreed that changing the denominator was a deviation from RG 1.91. He added that because the conversion factor was changed to a larger number, the results were less conservative, and this was an issue that should be addressed. He also said that if you deviate from RG 1.91, it should be in the more conservative direction and should be documented and communicated to all involved because if the deviations are not communicated, it would be assumed that the RG was used as written. According to the Physical Scientist's Branch Chief, the use of a larger denominator than prescribed in RG 1.91, in combination with 1-minute of mass (as discussed previously in this report), undermined the ability of the NRC to add conservatism for safety assurance.

The IPEC Project Manager was unaware that the denominator was changed and agreed that changing the pre-set denominator modified the equation. According to the IPEC Project Manager, the Physical Scientist reported that the equations in RG 1.91 were used as is and unchanged. The IPEC Project Manager explained to OIG that raising the pre-set denominator made the result less conservative. He was not aware of any flexibility that existed in RG 1.91 for using other values. He had no explanation as to why someone would use anything other than the values in RG 1.91 equations.

Quality Assurance Process Used by NRC To Verify the Results of the AIM Project Safety Review and Followup Assessment

In correspondence dated July 27, 2015, the stakeholder questioned NRC's quality assurance process for verifying safety related calculations. In correspondence dated November 6, 2015, the NRC responded to the stakeholder that the NRC staff does not perform "safety-related" calculations and does not have a quality assurance process for such calculations. The letter stated,

> The NRC does not perform "safety-related calculations." Therefore, the NRC staff does not have specific procedures for performing calculations used to support inspections or to perform confirmatory analysis. The term, "safety related calculations" implies formal calculations performed by licensees for the design of NRC regulated facilities. Safety-related calculations by licensees must be performed in accordance with approved plant procedures and associated quality control. Calculations performed by the staff do not require the same level of documentation and are performed as needed to support independent confirmatory analysis.

NRC's letter conveyed that in response to the stakeholder's concerns, the staff performed an independent analysis that received a peer review by a qualified NRC engineer.

OIG learned that a headquarters Reactor Oversight Process (ROP) Engineer was assigned to peer review the Physical Scientist's analysis. The ROP Engineer told OIG he was selected while attending an Executive Leadership Team meeting after he mentioned he previously worked for Bechtel Power performing hazards analysis calculations and had used ALOHA. He said he told the Executive Leadership Team there was a Region IV staff member with better qualifications to conduct the review; however, an NRC senior manager assigned the ROP Engineer to the task.

According to the ROP Engineer, he spent approximately 8 hours conducting this review, and about "99 percent" of his time was focused on reviewing the licensee's 10 CFR 50.59 safety evaluation. He said there is no formal process for conducting a peer review. He said his approach was to talk to the Physical Scientist who described his process to him; download ALOHA from the Internet; and apply the Physical Scientist's assumptions and numbers in ALOHA, which seemed reasonable to him; and he came up with similar results. Then he wrote his conclusion that the independent analysis performed by the Physical Scientist used acceptable methodologies and realistic conservative assumptions and the conclusions matched the licensee's. The ROP Engineer said that he wrote his review summary in such a way that it "sent signals" that his check was an unofficial peer review from one individual to another – similar to inspectors sharing notes. The ROP Engineer said he was uncomfortable performing this peer review since the NRC does not have a defendable, formal process in place to conduct quality assurance or peer reviews.

The IPEC Project Manager was aware that the NRC did a peer review to determine if the Physical Scientist's calculation looked reasonable. The IPEC Project Manager recalled that the peer reviewer was qualified to do the peer review since he had experience working with ALOHA in the past.

OIG learned from the Physical Scientist's Branch Chief that typically peer reviews are not done. However, due to the high visibility of this situation, to include the stakeholder, NRC management decided to task another knowledgeable NRC staff member with "taking a hard look" at the Physical Scientist's calculations. The Physical Scientist's Branch Chief remembered that the peer reviewer did not identify any problems.

Interviews of NRC Managers

The Region I Deputy Regional Administrator, who was then the Region I Director of Reactor Safety, was aware that 60 minutes of gas release was not used for the bounding analysis, but that the amount assessed was something between 0 and 60 minutes. While he initially stated he thought the Physical Scientist used a number of conservatisms in his assessment that made this situation "more safe," later in the interview he acknowledged there might be a need to reassess. The Region I Deputy Regional Administrator also told OIG that he was not aware the Physical Scientist made a change from the RG 1.91 equations. However, he could not speak to a potential change in the denominator since he did not know why the Physical Scientist would do that. However, if it was done, the NRC should have documented it and why the change was made.

NRC's then-Deputy Executive Director for Reactor Preparedness Programs (DEDR) (now retired), told OIG he would expect the information that NRC documented and provided to the stakeholder to align with the staff's actual work for the NRC AIM Project Safety Review. He also said he would be disappointed if the NRC used a draft regulatory guide. Regarding the peer review, he told OIG that without talking to the ROP Engineer who conducted the review, he did not have a sense of how thorough it was. However, based on the description provided by OIG, and given stakeholder attention to this issue and NRC's reliance on the Physical Scientist's assessment, NRC should have done a better job with the peer review.

The current DEDR said he thought the Physical Scientist had assessed 3 minutes of gas release and 60 minutes of gas release; however, based on the information provided by OIG (i.e., that only 1 minute of gas release was assessed under both scenarios), the DEDR said he was very concerned. He recalled the stakeholder's question about whether the pipe could actually be sealed off in 3 minutes, given the operators' location in Houston; he said this was why NRC chose to assess an hour because it would be a "very bounding analysis." However, he said, "what you are presenting to me here is not." He also recalled the stakeholder challenging the similarity of NRC's results for the 3-minute and 60-minute analyses, and based on discussion with OIG, he now recognized why the results were so similar (i.e., only 1 minute of mass was used for each scenario).

Regarding the Physical Scientist's use of a draft version of RG 1.91, the current DEDR said the Physical Scientist should not have used a draft, especially when there was an approved guide available. The DEDR also said he would not have expected the Physical Scientist to round the denominator unless it was a conscious decision to be more conservative. However, he noted, in this case the rounding was in the non-conservative direction and was not documented or explained.

Regarding the "peer review," the DEDR said it did not "sound like what was asserted as a peer review was really well thought out." OIG told the DEDR there were two NRC gas plume experts in Region IV and the DEDR said he was inclined to have them recalculate the blast radius and compare the outcome to the results that NRC has relied upon. According to the DEDR, "it goes to the materiality…this all raises a lot of questions."

In response to OIG's question about whether IPEC is operating in an unanalyzed condition due to risks posed by the new 42-inch pipeline, the DEDR said, "The only reason I would hesitate…to just jump in and say we are in an unanalyzed condition is Entergy did analyze it. I have questions about how well we validated their analysis, so I think we have more work to do, but I don't think I would say they are in an unanalyzed condition at this point."

HOTLINE NUMBER:
1-800-233-3497

THE OFFICE OF THE INSPECTOR GENERAL

Attention: Hotline Program
Mail Stop O5E13
11555 Rockville Pike
Rockville, MD 20852-2738

ATTACHMENT B

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

CHAIRMAN

February 24, 2020

MEMORANDUM TO: Margaret M. Doane
Executive Director for Operations

FROM: Kristine L. Svinicki

SUBJECT: CONCERNS PERTAINING TO GAS TRANSMISSION LINES AT THE INDIAN POINT NUCLEAR POWER PLANT

The U.S. Nuclear Regulatory Commission (NRC) Office of the Inspector General (OIG) recently provided me its Event Inquiry, "Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant" (Case No. 16-024). In that report the OIG raises concerns regarding (1) the NRC's safety analysis that supported the Federal Energy Regulatory Commission's determination to approve modifications to gas pipelines at Indian Point and (2) the NRC's response to a petition filed under 10 C.F.R. § 2.206 on this topic.

I direct that the NRC staff promptly examine whether any immediate regulatory action is needed based on information in the OIG report and promptly inform the Commission of the results of that examination and what actions, if any, the staff plans to take. If the staff determines that no immediate regulatory action is warranted, the staff should provide the Commission with the staff's basis for that conclusion. In addition to the staff's prompt examination of the need for immediate action, the staff should undertake a review of whether any information in the OIG report demonstrates that the staff should revisit either the safety analysis or its response to the section 2.206 petition. The staff should also evaluate whether any modifications to agency practice or procedures are needed or appropriate based on the OIG report. Finally, the staff should provide the Commission with the results of this review within 45 days of the date of this memorandum.

cc: Commissioner Baran
Commissioner Caputo
Commissioner Wright
A. Vietti-Cook, SECY
M. Zobler, OGC
D. Lee, OIG

ATTACHMENT C

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

February 26, 2020

MEMORANDUM TO: Chairman Svinicki
Commissioner Baran
Commissioner Caputo
Commissioner Wright

FROM: Margaret M. Doane **/RA/**
Executive Director for Operations

SUBJECT: CONCERNS PERTAINING TO GAS TRANSMISSION LINES AT THE INDIAN POINT NUCLEAR POWER PLANT: DETERMINATION NOT TO TAKE IMMEDIATE ACTION

This memorandum responds to the Chairman's February 24, 2020, direction to the Executive Director for Operations (EDO) to address matters raised in the Nuclear Regulatory Commission (NRC) Office of the Inspector General (OIG) report, Event Inquiry, "Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant" (Case No. 16-024). In that memorandum, the Chairman directed the prompt examination to determine if immediate regulatory action is needed based on information in the OIG report and to promptly inform the Commission of the results of that examination and what actions, if any, the staff plans to take. For the following reasons, I have determined that there is no need for immediate regulatory action.

In response to the Chairman's direction, I tasked Dr. Mirela Gavrilas to examine the information in the OIG report (advance copy) and evaluate promptly whether immediate action is warranted. Dr. Gavrilas was not involved in the matter in question in the OIG report. Dr. Gavrilas received her Ph.D. in nuclear engineering from the Massachusetts Institute of Technology and has decades of experience in nuclear power plant safety.

The determination on whether immediate action is needed was performed in accordance with the agency procedure used to respond to nuclear power plant emergent issues. This procedure is found in section 4.2.1 of LIC-504 Rev. 4 "Integrated Risk-Informed Decision-Making Process for Emergent Issues" (Agencywide Documents Access and Management System Accession No.: ML14035A143). After reviewing the findings in the OIG report and the technical aspects of the 42-inch gas line that traverses the Indian Point Energy Center property (IPEC), Dr. Gavrilas has determined that there is no safety issue warranting immediate regulatory action at either Unit 2 or Unit 3.

This conclusion is based on the following summary findings that are explained in more detail in the attached enclosure:

- There is no significant degradation to defense-in-depth at either unit.
- There is no significant loss of safety margin at either unit.
- There is no high-risk impact at either unit from internal or external events, as all risk metrics are under the prescribed thresholds.

I have assigned David Skeen to lead a team of experts to respond to the remaining issues in the Chairman's memorandum, including the direction to provide the Commission with the results of a staff review within 45 days of the date of the memorandum. Mr. Skeen has been a member of the Senior Executive Service for more than a decade, and previously served as the director of the Japan Lessons-Learned Directorate. In that capacity, he had a key role in evaluating the safety of the U.S. nuclear power plant fleet in response to the events at the Fukushima Daiichi nuclear power plant caused by the Great Tōhoku earthquake and tsunami. Mr. Skeen was not involved in the matters addressed in the OIG report.

As is contemplated under the procedure, LIC-504, during the course of the team's review, the team will be mindful of the need to assess any new emergent issues.

Enclosure:
Evaluation of Emergent Information
Pertaining to Gas Transmission Lines
at the Indian Point Nuclear Power Plant

cc: SECY
OGC
OIG
OPA
D. Skeen

SUBJECT: CONCERNS PERTAINING TO GAS TRANSMISSION LINES AT THE INDIAN POINT NUCLEAR POWER PLANT: DETERMINATION NOT TO TAKE IMMEDIATE ACTION DATED FEBRUARY 26, 2020.

ADAMS Accession Number: ML20058D088

OFFICE	OEDO	NRR	OGC	EDO
NAME	DJackson	MGavrilas	MZobler	MDoane
DATE	2/26/2020	2/26/2020	2/26/2020	2/26/2020

OFFICIAL RECORD COPY

Evaluation of Emergent Information Pertaining to
Gas Transmission Lines at the Indian Point Nuclear Power Plant

This evaluation is in response to the Chairman's tasking of February 24, 2020, to determine if immediate regulatory action is necessary. This prompt evaluation was performed in accordance with Section 4.21 of Office of Nuclear Reactor Regulation (NRR) office instruction LIC-504 Rev. 4 "Integrated Risk-Informed Decision-Making Process for Emergent Issues" (Agencywide Documents Access and Management System (ADAMS) Accession No.: ML14035A143) within 24 hours of the request.

Defense-in-Depth

LIC-504 states that additional regulatory action may be required to place or maintain the plant in a safe condition if defense-in-depth is significantly degraded (e.g., multiple barriers are moderately to significantly degraded, functional redundancy or diversity is significantly compromised, or vulnerability to single failures is significantly increased).

While a pipe rupture could impact certain structures on the site (e.g., gas turbine fuel oil tanks, the switchyard, emergency operations facility, FLEX equipment storage building), the pipeline is located approximately 1500 ft (rev 2) from the nearest safety related structure and barriers to radioactive release (i.e., the fuel cladding, reactor coolant system pressure boundary, and containment) would be maintained. Impacts to nearby structures could affect the plant response measures or the probability of additional initiators. However, there are still multiple diverse barriers and mitigation measures in place to minimize the challenges to the plant, preventing events from progressing to core damage, containing the radioactive source term, and ensuring emergency preparedness capabilities. Impacts on structures in the proximity of the explosion do not significantly degrade defense in depth.

Safety Margins

LIC-504 states that additional regulatory action may be required to place or maintain the plant in a safe condition if there is significant loss of safety margin (e.g., the calculated ASME code structural factors for a component are equal to or less than 1). Regulatory Guide 1.174 also indicates that safety margins are adequate if (1) the codes and standards or their alternatives approved for use by the NRC are met and (2) licensing basis safety analysis acceptance criteria are met.

A pipe rupture does not affect the plant's compliance with codes and standards. Compliance with the plant's technical specifications ensures adequate margin is maintained against design basis accidents.

Risk Assessment

Assumptions and Inputs:

Appendix F in the Federal Emergency Management Agency (FEMA) "Handbook of Chemical Hazard Analysis Procedures" 1989-626-095-10575, 1989 (ref 1) identifies accident rates for pipelines with a diameter greater than 20 inches at 5E-4 accidents per year per pipeline mile. The FEMA Handbook also states that only 20% of events constitute large pipe ruptures.

Based on this probability, the frequency of pipeline rupture is calculated assuming 3935 ft of pipeline are near the site. This is equal to (3935 ft / (5280 ft / mi)) = 0.745 mi of pipeline (ref 2). The frequency of pipeline ruptures is therefore:

$$\text{Frequency of pipeline rupture} = \text{Failure rate} * \text{rupture percentage of failures} * \text{pipeline length}$$

$$\text{Frequency of pipeline rupture}$$
$$= (5 * 10^{-4} \text{ failures/year/pipeline mile})(0.2 \text{ complete ruptures/failure })(0.745 \text{ pipeline miles})$$

$$\text{Frequency of pipeline rupture} = 7.45 * 10^{-5}$$

The values of risk to be compared against the risk action thresholds provided in LIC-504 are calculated by making three conservative assumptions:

- All complete ruptures lead directly to core damage.
- The "as-is" condition exists for 45 days (the duration of the Chairman's tasking memo).
- Large early release probability is 0.1 of the core damage probability.

Under these assumptions:

- The conditional core damage frequency (CCDF) can be calculated as the frequency of a pipeline ruptures times the probability that a pipeline rupture leads to core damage, or:
$$(7.45 * 10^{-5}) * (1) = 7.45 * 10^{-5}$$
- The conditional large early release frequency (CLERF) is calculated as 0.1 of the conditional core damage probability or:
$$(7.45 * 10^{-5}) * (0.1) = 7.45 * 10^{-6}$$
- The incremental conditional core damage probability (ICCDP) in the 45-day window can be calculated by multiplying the conditional core damage probability, the initiating event frequency, and the duration of the condition, or:
$$(1) * (7.45 * 10^{-5} \text{ events/year}) * (45 \text{ days}/365 \text{ days/year}) = 9.18 * 10^{-6}$$
- The incremental large early release probability (ICLERP) can be calculated as 0.1 of the incremental conditional core damage probability, or:
$$(9.18 * 10^{-6}) * (0.1) = 9.18 * 10^{-7}$$

These values can be compared against the risk action thresholds in LIC-504:

Parameter	LIC-504 Risk Action Threshold	Calculated Value
CCDF	1E-3	7.45E-5*
CLERF	1E-4	7.45E-6
ICCDP	5E-5	9.18E-6
ICLERP	5E-6	9.18E-7

Discussion:

The numbers provided above represent median estimates of the conditional core damage probability and large early release probability. However, they were calculated assuming various conservatisms, some of which are enumerated in the table below.

Source of Conservatism	Effect
Large pipe ruptures lead to deflagrations or detonations. The FEMA Handbook notes that "in the event that there is a failure in a pipeline, most often the outcome is a small leak."	1 order of magnitude
Assumptions on pipeline failure rates were structured around studies performed in the 1980s. Since then, codes and standards have improved and probabilities of failure would be less than those assumed. The probability of failure for this specific section of pipeline is reduced since it was constructed to specifications that exceed current code requirements and was covered with concrete planks to prevent inadvertent damage from digging.	1 order of magnitude (or greater)
The analysis assumes that pipeline failures lead directly to core damage. In reality, a pipeline explosion would not directly cause damage to the reactor core, though it could damage safety-related equipment that may be needed to prevent core damage if another initiating event were to occur at the same time.	3 orders of magnitude (or greater)

Thus, the calculated values for CCDF of 7.45E-5, CLERF of 7.45E-6, ICCDP of 9.18E-6, and ICLERP of 9.18E-7 represent upper bound estimates, and there are several orders of magnitude of conservatism separating these values from more realistic estimates.

<u>Conclusions</u>

No significant degradation of defense in depth nor loss of safety margins were identified. The evaluation above shows that the CCDF, CLERF, ICCDP, and ICLERP values associated with pipeline explosions at IPEC are smaller than the LIC-504 risk action thresholds. Therefore, no immediate regulatory action is required to maintain the plant in a safe condition.

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* Note that this is a conservatively bounding value for a station blackout initiated by a pipeline explosion because it does not account for various factors, such as the limited line of sight between the explosion and the diesel generator buildings.

References

1. Safety Evaluation Performed by Entergy Under 10 CFR 50.59 (ADAMS Accession No. ML14253A339), August 21, 2014
2. FEMA “Handbook of Chemical Hazard Analysis Procedures,” Appendix F, 1989-626-095-10575, 1989

Paul M. Blanch PE
Energy Consultant

23 March 2020

David Skeen
United States Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear David:

I have reviewed the following document (ML20078L380) from the NRC:

Briefing on Agency Practice and Procedure Issues:
U.S. Nuclear Regulatory Commission (NRC) Expert Evaluation Team on the
Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant
March 18, 2020

It appears the team's direction is to have Sandia National Laboratories preform a risk analysis. I have no problem with this approach however I question "analyzing natural gas pipeline rupture phenomena and consequences" as the sole guidance when there is clear federal law and regulations how to evaluate the pipelines' impact on public safety. Anything less than full compliance with laws and regulations is unacceptable.

It is the clear mission that PHMSA has the sole responsibility for pipeline safety oversight similar to the NRC's role nuclear safety oversight, although past actions by both agencies actions have been questionable.

Restated PHMSA's mission is:

> *PHMSA's mission is to <u>protect people</u> and the environment by advancing the safe transportation of energy and other hazardous materials that are essential to our daily lives. To do this, the agency establishes national policy, sets and <u>enforces standards</u>, educates, and conducts research to prevent incidents.*

And the NRC's mission is:

> *The U.S. Nuclear Regulatory Commission regulates the Nation's civilian use of byproduct, source, and special nuclear materials <u>to ensure adequate protection of the public health and safety</u>, to promote the common defense and security, and to protect the environment.*

Both PHMSA and the NRC allegedly accomplish their missions by assuring compliance with its regulations. (10 CFR 50 and 49 CFR 192 et seq)

It is not within the NRC's jurisdiction to assure that pipelines comply with federal regulations any more than PHMSA assuring compliance with NRC's regulations.

It is however the NRC's responsibility to assure the pipelines do not challenge its mission of providing "… *adequate protection of the public health and safety…*"

From the enclosed direction it appears the NRC it about to charter Sandia National Laboratories to conduct yet one more "risk assessment." We have had risk assessments conducted by Entergy, Algonquin, NRC, PHMSA, the State of New York and me. None of these risk assessments followed any established criteria or contained any direction or acceptance criteria. There is regulatory and industry consensus of conducting a risk assessment and that is specified in 49 CFR 192.917 and 935 and the Pipeline Safety Act of 2016. This is the only accepted methodology for conducting a risk assessment of gas lines.

While I have no issues with Sandia, they must comply with these well-established regulations, established by rulemaking and incorporated into federal regulations.

There is only one means to achieve a valid risk assessment for the pipelines and that is dictated by the Pipeline Safety Act of 2016 and 49 CFR 192. Specifically, 49 CFR 192.917 and 935 provide detailed requirements for a risk assessment and compliance

It is my position that a risk assessment be conducted following the Pipeline Safety Act of 2016 and 49 CFR 192. The result must then be reviewed by Sandia Laboratory for compliance and then the NRC makes the determination of "reasonable assurance of adequate protection of public health and safety…" PHMSA should also concur the assessment is in compliance with its regulations.

My letter of February 25, 2016 to the Inspector General outlined my concerns with the NRC's handling of the issues associated safety issues related to the gas lines at Indian Point.

I expect your team to address these significant issues. Specifically, the issues addressed in my letter to the IG as follows: (pasted from my letter to the OIG)

- The NRC violated its procedures and regulations in multiple ways when analyzing, approving, submitting and overseeing Spectra Energy's Algonquin Incremental Market (AIM) project and existing gas pipeline at Indian Point.
- The NRC staff is aware of docketed false statements made by Entergy to the NRC with respect to this issue, violating NRC directives, did not refer the matter of false statements by a licensee to the NRC's Office of Investigations.
- The NRC knowingly misled FERC and the public, thereby putting at risk 20 million people in the vicinity of Indian Point, by claiming to FERC that there was no additional risk associated with the proposed new 42-inch gas pipeline. The analysis relied upon by the NRC staff was not conducted in accordance with established industry standards.
- In June 2015, the NRC verbally rejected, without adequate review, my allegation that the Indian Point plants were operating in an unanalyzed condition by claiming these issues have been addressed. This is a false statement by the NRC Staff. The staff rewrote my allegation to fit its desired conclusion thereby circumventing the material facts and evidence I had presented.
- The NRC provided its final approval to FERC and stated that the inspectors "performed an independent analysis" and "the NRC staff concluded that safety-related SSCs inside the SOCA would not be exposed to conditions exceeding the threshold for damage." No persons on the inspection team had any experience with gas line dynamics or piping and instrument diagrams of the proposed gas line. The NRC's "expert" was not part of the inspection team.

Requested Investigation:

The following areas, among others, related to the NRC's regulation of and its handling of allegations and petitions questioning the safety of the natural gas lines proposed and buried gas lines in the near proximity of Indian Point Nuclear Power Plant warrant an immediate investigation by your Office of the Inspector General (OIG):

1. Did the NRC follow its guidance of MD 8.11 for 10 CFR 2.206 petitions when rejected my petition for consideration with 46 documented open and unresolved issues?

2. My October 2014 10 CFR 2.206 petition alleged deliberate misconduct and inaccurate information provided by Entergy to the NRC. Were these allegations and other instances of alleged false statements by Entergy referred to and investigated by the Office of Investigations as required by MD 8.11?

3. Why did, and still does NRC fail to consider the possible flammable content of the million gallon fuel oil tanks?

4. Was my allegation of June 2015 properly handled consistent with past NRC practices and MD 8.5?

5. Has the buried section of the existing gas lines been analyzed for possible impact on the control room, switchgear room and other vital structures?

6. Have the dynamics of the new pipeline been properly analyzed considering the thermodynamics of the gas system, leak detection, compressor dynamics, historic events and piping system interconnections?

7. Was an accepted industry methodology employed for a risk assessment as provided in 29 CFR Appendix C to § 1910.119 – "Compliance Guidelines and Recommendations for Process Safety Management" or similar methodology?

I expect your team to address these issues that were not addressed by the Inspector General's report.

I have extensive experience at Millstone, Maine Yankee and Indian Point with "Safety Culture" and a limited knowledge of Root Cause Analysis.

If these types of culture problems were identified at an NRC licensee facility, the NRC would impose its Inspection Procedure 95003 for a total assessment of the culture problem. One vivid example of this culture is the NRC's failure to take any action against Entergy for clear violations of 10 CFR 50.5 and 50.9 related to deliberate mis-conduct and supplying the NRC with inaccurate and incomplete information.
Rather than trimming the poison ivy, the NRC needs a complete evaluation of its culture that I have personally observed over the past 30 years. My personal opinion is that the NRC's

safety culture is in dire need of a formal assessment, repair and can only be addressed by the imposition of an evaluation similar to IP 95003

The AIM pipeline may present a risk to the plants however I believe the risk with the most significant consequences is from the existing lines running adjacent to the Unit #3 control and switchgear rooms. These lines are located in a High Consequence Area (HCA) therefore require a risk assessment as dictated by Pipeline Safety Act of 2016 and 49 CFR 192.

A loss of the control and switchgear rooms will compromise reactor and spent fuel pool integrity with no provisions to recover, even with the post Fukushima changes.

I am in full agreement with the New York letter to the NRC Chair with the exception of "…we urge the NEC to require a new Part 50.59 review of all 3 pipelines." "Changes, tests, and experiments." A Part 50.59 review is not appropriate at this time.

During the 3/20/20 meeting I believe I stated the plants are still operating in an unanalyzed condition, in spite of the EDO's position taken from an inapplicable, 30-year old document. The statement by the EDO and the Chair's statement to Congress must be clarified as it provided mis-leading information by failing to consider today's failure rates and potential consequences.

My concerns with the risk analysis will only be satisfied when this analysis is conducted by an independent party such as Sandia Laboratory and reviewed the National Academy of Sciences as recommended by the New York Office of the Attorney General**.** This review will assure compliance with applicable United States Codes and regulations specified in 49 CFR 192.

On a directly related matter are there any plans to place the 26" line back in service in the future and if so, would the utility be obligated to conduct a new risk analysis or 50.59 evaluation prior to restoring flow in the line given that there are open questions regarding the adequacy of the previous risk assessment/ 50.59 evaluation?

From my perspective from my review of the FEIS there is more protection provided to the American bittern, pied-billed grebe, savannah sparrow, red bat, eastern cougar, ground beetle, American kestrel, eastern box turtle, eastern hognose snake, Jefferson salamander "complex," pine barrens tiger beetle and human remains than for the living humans residing within the potential radius of the AIM pipeline.

For your information questions have been raised related to the applicability of various regulations of 49 CFR 192. I am enclosing Attachment 1 to this letter that are excerpts from the Final Environmental Impact Statement (FEIS) that discusses a sampling of these commitments to 49 CFR 192 designed to protect the public and the environment.

Sincerely,

Paul M. Blanch

Paul M. Blanch
135 Hyde Rd.
West Hartford, CT 06117
860-922-3119

Attachment 1

49 CFR 192 statements from FEIS

Note there are no discussions contained within this document for compliance with individual parts of 49 CFR 192

4.12.1 Safety Standards

PHMSA is mandated to provide pipeline safety under 49 USC Chapter 601. The OPS administers the national regulatory program to ensure the safe transportation of natural gas and other hazardous materials by pipeline. It develops safety regulations and other approaches to risk management that ensure safety in the design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Many of the regulations are written as performance standards that set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve the required safety standard. PHMSA ensures that people and the environment are protected from the risk of pipeline incidents. This work is shared with state agency partners and others at the federal, state, and local level. PHMSA provides for a state agency to assume all aspects of the safety program for intrastate facilities by adopting and enforcing the federal standards. A state may also act as PHMSA's agent to inspect interstate facilities within its boundaries; however, PHMSA is responsible for enforcement actions. For the AIM Project, New York and Connecticut are interstate agents that have been delegated authority to inspect interstate natural gas pipeline facilities. OPS federal inspectors perform inspections on interstate natural gas pipeline facilities in Massachusetts and Rhode Island.

PHMSA pipeline standards are published in 49 CFR Parts 190–199. Part 192 of 49 CFR specifically addresses natural gas pipeline safety issues. Under a Memorandum of Understanding on Natural Gas Transportation Facilities (Memorandum) dated January 15, 1993 between PHMSA and the FERC, PHMSA has the exclusive authority to promulgate federal safety standards used in the transportation of natural gas. Section 157.14(a)(9)(vi) of the FERC's regulations require that an applicant certify that it will design, install, inspect, test, construct, operate, replace, and maintain the facility for which a Certificate is requested in accordance with federal safety standards and plans for maintenance and inspection. Alternatively, an applicant must certify that it has been granted a waiver of the requirements of the safety standards by PHMSA in accordance with section 3(e) of the Natural Gas Pipeline Safety Act. The FERC accepts this certification and does not impose additional safety standards. If the Commission becomes aware of an existing or potential safety problem, there is a provision in the Memorandum to promptly alert PHMSA. The Memorandum also provides for referring complaints and inquiries made by state and local governments and the general public involving safety matters related to pipelines under the Commission's jurisdiction.

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The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained to meet or exceed the Pipeline and Hazardous Materials Safety Administration's Minimum Federal Safety Standards in 49 CFR 192 and other applicable federal and state regulations. The regulations include specifications for material selection and qualifications;

2.3 CONSTRUCTION PROCEDURES

The AIM Project would be designed, constructed, operated, and maintained to conform to, or exceed, the minimum federal safety standard requirements of PHMSA in 49 CFR 192,[4] and other applicable federal and state regulations, including U.S. Department of Labor, Occupational Safety and Health Administration (OSHA) requirements. These regulations are intended to ensure adequate protection for the public. Among other design standards, Part 192 specifies pipeline material and qualification, minimum design requirements, and protection from internal, external, and atmospheric corrosion.

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[4] Pipe design regulations for steel pipe are contained in subpart C, Part 192. Section 192.105 contains a design formula for the pipeline's design pressure. Sections 192.107 through 192.115 contain the components of the design formula, including yield strength, wall thickness, design factor, longitudinal joint factor, and temperature derating factor, which are adjusted according to the project design conditions, such as pipe manufacturing specifications, steel specifications, class location, and operating conditions. Pipeline operating regulations are contained in subpart L, Part 192.

2-15

Each weld is inspected by an independent certified Non Destruction Test technician to ensure its structural integrity is consistent with 49 CFR 192 of PHMSA's regulations. X-ray or ultrasonic images are taken and processed on site for virtually instantaneous results. Those welds that do not meet the Algonquin's specifications would be repaired or replaced and re-inspected.

The pipeline is coated to prevent corrosion. The pipe lengths would be coated (usually with a heat-applied epoxy) at a coating mill prior to being delivered to the Project. The ends of each piece are left bare to allow for welding. After welding, the weld area is field coated by the coating crew. Because pipeline coatings are electrically insulating, the coating is inspected using equipment that emits an electric charge to ensure there are no locations on the pipeline with a defect in the coating.

2-23

2.6 OPERATION, MAINTENANCE, AND SAFETY CONTROLS

Algonquin would operate and maintain the newly constructed pipeline facilities in the same manner as they currently operate and maintain their existing systems in compliance with PHMSA regulations provided in 49 CFR 192, the FERC guidance at 18 CFR 380.15, and the maintenance provisions in Algonquin's E&SCP. Algonquin would add three full-time permanent workers for operation of the proposed and modified facilities.

Based on the identified estimated emissions from operation of the proposed Project facilities and review of the modeling analysis, the Project would result in continued compliance with the national ambient air quality standards (NAAQS), which are protective of human health, including children, the elderly, and sensitive populations (see section 4.11.1). The Project facilities would also be designed, constructed, operated, and maintained in accordance with or to exceed PHMSA's minimum federal safety standards in 49 CFR 192. These regulations, which are intended to protect the public and to prevent natural gas facility accidents and failures, apply to all areas along the proposed pipeline routes regardless of the presence or absence of minority or low income populations.

The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained in accordance with or to exceed PHMSA's Minimum Federal Safety Standards in 49 CFR 192. The regulations are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures. PHMSA specifies material selection and qualification; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion.

Algonquin would hydrostatically test the new pipeline segments in accordance with PHMSA pipeline safety regulations in 49 CFR 192 prior to placing the pipeline facilities into service. Algonquin estimates a need for a total of about 10,082,645 gallons of water to conduct the hydrostatic testing for the Project (9,610,245 gallons for pipeline testing and 472,400 gallons for aboveground facilities). Most of this water would be obtained from municipal sources, but some would be appropriated from the old Verplanck Quarry Lake in New York. However, to our knowledge none of the projects listed in table 4.13-1 would be expected to use water from the Old Verplanck Quarry Lake at the same time or at all. Following testing of the pipeline, the water would be discharged into dewatering structures located in upland areas and within the construction work area in accordance with the AIM Project E&SCP and the hydrostatic testing BMPs provided by agencies. Therefore, long-term impacts on surface water sources would not be anticipated as a result of hydrostatic testing activities, and we expect the cumulative impacts of the projects listed in table 4.13-1 on surface and groundwater resources to be minor.

4.13.9 Reliability and Safety

Impact on reliability and public safety would be mitigated through the use of the PHMSA Minimum Federal Safety Standards in Title 49 CFR 192, which are intended to protect the public and to prevent natural gas facility accidents and failures. In addition, Algonquin's construction contractors would be required to comply with the OSHA Safety and Health Regulations for Construction in Title 29 CFR 1926. We received several comments about potential cumulative impacts relative to safety between the proposed Project and WPP's proposed West Point Transmission Project. We evaluated the risk associated with constructing and operating transmission lines and natural gas pipelines in close proximity in section 4.12.3. It is not uncommon for natural gas pipeline facilities to parallel existing utility rights-of-ways, including electric transmission rights-of-way and there are established methods for minimizing the risks of these configurations. Algonquin has conducted surveys and collected information on the location and size of existing power line structures within the proposed right-of-way corridors, tower footing locations and dimensions, and wire heights (lowest point between towers) and would design or modify its construction technique on the AIM Project with sufficient offsets to eliminate the risk of heavy construction equipment interfering with overhead high-voltage electric transmission lines during construction and operation. Where possible, Algonquin would offset its pipeline trench by 50 feet to avoid any potential damage to electric transmission towers; and in those areas that this offset could not be

4-303

5.1.12 Reliability and Safety

The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained in accordance with or to exceed the PHMSA Minimum Federal Safety Standards in 49 CFR 192. The regulations are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures. The PHMSA specifies material selection and qualification; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion.

5-16

The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained to meet or exceed the Pipeline and Hazardous Materials Safety Administration's Minimum Federal Safety Standards in 49 CFR 192 and other applicable federal and state regulations. The regulations include specifications for material selection and qualifications; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion. By designing and operating the Project in accordance with the applicable standards, the Project would not result in significant increased public safety risk.

2.3 CONSTRUCTION PROCEDURES

The AIM Project would be designed, constructed, operated, and maintained to conform to, or exceed, the minimum federal safety standard requirements of PHMSA in 49 CFR 192,[4] and other applicable federal and state regulations, including U.S. Department of Labor, Occupational Safety and Health Administration (OSHA) requirements. These regulations are intended to ensure adequate protection for the public. Among other design standards, Part 192 specifies pipeline material and qualification, minimum design requirements, and protection from internal, external, and atmospheric corrosion.

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5-16

1.2.4 U.S. Department of Transportation – Pipeline and Hazardous Materials Safety Administration

PHMSA is the federal agency responsible for administering the national regulatory program to ensure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline under 49 USC Chapter 601. PHMSA's Office of Pipeline Safety (OPS) develops regulations and other approaches to risk management to ensure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. The OPS is responsible for ensuring that Algonquin's proposed facilities are designed, constructed, and operated in compliance with the safety standards that the agency has established for natural gas pipeline facilities.

2.3.2 Aboveground Facility Construction Procedures

The AIM Project aboveground facilities would be constructed in compliance with the same federal regulations and guidelines as the pipeline facilities, and in accordance with the specific requirements of applicable federal and state approvals. Construction activities associated with these facilities would include clearing, grading, installing concrete foundations, erecting metal buildings, and installing piping, metering facilities, and appurtenances. Initial work at the new M&R stations would focus on preparing the sites for equipment staging, fabrication, and construction. Following foundation work, station equipment and structures would be brought to the site and installed, using any necessary trailers or cranes for delivery and installation. Equipment testing and start-up activities would occur on a concurrent basis.

Although Algonquin has stated that sufficient qualified EIs would be available to implement their environmental inspection program, it has agreed to participate in a third-party Environmental Compliance Monitoring Program for sensitive environmental areas of the AIM Project. Under this program, Algonquin would fund a contractor, to be selected and managed by the FERC staff, to provide environmental compliance monitoring services. The FERC Third-party Compliance Monitor would provide daily reports to the FERC staff on compliance issues and make recommendations to the FERC Project Manager on how to deal with compliance issues and construction changes, should they arise. FERC staff would also conduct periodic inspections. As discussed in section 4.0, use of a third-party Environmental Compliance Monitoring Program would be particularly appropriate along the Haverstraw to Stony Point Take-up and Relay, Stony Point to Yorktown Take-up and Relay, Southeast to MLV 19 Take-up and Relay, and West Roxbury Lateral segments and related aboveground facilities due to concerns about construction in residential and commercial areas, the Hudson River crossing, and potential blasting. Development of the program would occur prior to construction.

2.6 OPERATION, MAINTENANCE, AND SAFETY CONTROLS

Algonquin would operate and maintain the newly constructed pipeline facilities in the same manner as they currently operate and maintain their existing systems in compliance with PHMSA regulations provided in 49 CFR 192, the FERC guidance at 18 CFR 380.15, and the maintenance provisions in Algonquin's E&SCP. Algonquin would add three full-time permanent workers for operation of the proposed and modified facilities.

As shown on figure 4.3.2-1, the Croton Watershed would be crossed by the Stony Point to Yorktown Take-up and Relay segment between MPs 10.0 and 12.3 in the Town of Cortlandt and by the Southeast to MLV-19 Take-up and Relay segment between MPs 0.0 and 0.1 in the Town of Southeast. Algonquin would sequence construction activities to minimize the amount and duration of an open right-of-way within the watershed. Algonquin would use a separate construction crew to work in the 2.3-mile-long stretch within the watershed and has also committed to an environmental inspection and compliance monitoring program to monitor and enforce compliance with all permit conditions to protect the environment during construction (see section 2.5). In addition, Algonquin is working with the NYCDEP to develop a Stormwater Pollution Prevention Plan (SWPPP) that addresses NYCDEP's requirements for constructing within a New York City watershed.

8. Beginning with the filing of its Implementation Plan, Algonquin shall file updated status reports **on a weekly basis for the AIM Project until all construction and restoration activities are complete**. On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

    a. an update on Algonquin's efforts to obtain the necessary federal authorizations;

    b. the current construction status of each spread of the Project, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally sensitive areas;

    c. a listing of all problems encountered and each instance of noncompliance observed by the EI(s) during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);

    d. a description of the corrective actions implemented in response to all instances of noncompliance, and their cost;

    e. the effectiveness of all corrective actions implemented;

11. **Within 30 days of placing the authorized facilities for the Project into service, Algonquin** shall file an affirmative statement, certified by a senior company official:

a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or

b. identifying which of the Certificate conditions Algonquin has complied with or will comply with. This statement shall also identify any areas affected by the Project where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

The FERC is the federal agency responsible for authorizing interstate natural gas transmission facilities under the Natural Gas Act, and is the lead federal agency for the preparation of this EIS in compliance with the requirements of the National Environmental Policy Act. The U.S. Environmental Protection Agency, the U.S. Army Corps of Engineers (USACE), and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration, participated as cooperating agencies in the preparation of the EIS. A cooperating agency has jurisdiction by law or has special expertise with respect to environmental resource issues associated with a project.

Paul M. Blanch PE
Energy Consultant

23 March 2020

David Skeen
United States Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear David:

I have reviewed the following document (ML20078L380) from the NRC:

Briefing on Agency Practice and Procedure Issues:
U.S. Nuclear Regulatory Commission (NRC) Expert Evaluation Team on the
Concerns Pertaining to Gas Transmission Lines at the Indian Point Nuclear Power Plant
March 18, 2020

It appears the team's direction is to have Sandia National Laboratories preform a risk analysis. I have no problem with this approach however I question "analyzing natural gas pipeline rupture phenomena and consequences" as the sole guidance when there is clear federal law and regulations how to evaluate the pipelines' impact on public safety. Anything less than full compliance with laws and regulations is unacceptable.

It is the clear mission that PHMSA has the sole responsibility for pipeline safety oversight similar to the NRC's role nuclear safety oversight, although past actions by both agencies actions have been questionable.

Restated PHMSA's mission is:

> *PHMSA's mission is to <u>protect people</u> and the environment by advancing the safe transportation of energy and other hazardous materials that are essential to our daily lives. To do this, the agency establishes national policy, sets and <u>enforces standards</u>, educates, and conducts research to prevent incidents.*

And the NRC's mission is:

> *The U.S. Nuclear Regulatory Commission regulates the Nation's civilian use of byproduct, source, and special nuclear materials <u>to ensure adequate protection of the public health and safety</u>, to promote the common defense and security, and to protect the environment.*

Both PHMSA and the NRC allegedly accomplish their missions by assuring compliance with its regulations. (10 CFR 50 and 49 CFR 192 et seq)

It is not within the NRC's jurisdiction to assure that pipelines comply with federal regulations any more than PHMSA assuring compliance with NRC's regulations.

It is however the NRC's responsibility to assure the pipelines do not challenge its mission of providing "… *adequate protection of the public health and safety…*"

From the enclosed direction it appears the NRC it about to charter Sandia National Laboratories to conduct yet one more "risk assessment." We have had risk assessments conducted by Entergy, Algonquin, NRC, PHMSA, the State of New York and me. None of these risk assessments followed any established criteria or contained any direction or acceptance criteria. There is regulatory and industry consensus of conducting a risk assessment and that is specified in 49 CFR 192.917 and 935 and the Pipeline Safety Act of 2016. This is the only accepted methodology for conducting a risk assessment of gas lines.

While I have no issues with Sandia, they must comply with these well-established regulations, established by rulemaking and incorporated into federal regulations.

There is only one means to achieve a valid risk assessment for the pipelines and that is dictated by the Pipeline Safety Act of 2016 and 49 CFR 192. Specifically, 49 CFR 192.917 and 935 provide detailed requirements for a risk assessment and compliance

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7. Was an accepted industry methodology employed for a risk assessment as provided in 29 CFR Appendix C to § 1910.119 – "Compliance Guidelines and Recommendations for Process Safety Management" or similar methodology?

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safety culture is in dire need of a formal assessment, repair and can only be addressed by the imposition of an evaluation similar to IP 95003

The AIM pipeline may present a risk to the plants however I believe the risk with the most significant consequences is from the existing lines running adjacent to the Unit #3 control and switchgear rooms. These lines are located in a High Consequence Area (HCA) therefore require a risk assessment as dictated by Pipeline Safety Act of 2016 and 49 CFR 192.

A loss of the control and switchgear rooms will compromise reactor and spent fuel pool integrity with no provisions to recover, even with the post Fukushima changes.

I am in full agreement with the New York letter to the NRC Chair with the exception of "…we urge the NEC to require a new Part 50.59 review of all 3 pipelines." "Changes, tests, and experiments." A Part 50.59 review is not appropriate at this time.

During the 3/20/20 meeting I believe I stated the plants are still operating in an unanalyzed condition, in spite of the EDO's position taken from an inapplicable, 30-year old document. The statement by the EDO and the Chair's statement to Congress must be clarified as it provided mis-leading information by failing to consider today's failure rates and potential consequences.

My concerns with the risk analysis will only be satisfied when this analysis is conducted by an independent party such as Sandia Laboratory and reviewed the National Academy of Sciences as recommended by the New York Office of the Attorney General**.** This review will assure compliance with applicable United States Codes and regulations specified in 49 CFR 192.

On a directly related matter are there any plans to place the 26" line back in service in the future and if so, would the utility be obligated to conduct a new risk analysis or 50.59 evaluation prior to restoring flow in the line given that there are open questions regarding the adequacy of the previous risk assessment/ 50.59 evaluation?

From my perspective from my review of the FEIS there is more protection provided to the American bittern, pied-billed grebe, savannah sparrow, red bat, eastern cougar, ground beetle, American kestrel, eastern box turtle, eastern hognose snake, Jefferson salamander "complex," pine barrens tiger beetle and human remains than for the living humans residing within the potential radius of the AIM pipeline.

For your information questions have been raised related to the applicability of various regulations of 49 CFR 192. I am enclosing Attachment 1 to this letter that are excerpts from the Final Environmental Impact Statement (FEIS) that discusses a sampling of these commitments to 49 CFR 192 designed to protect the public and the environment.

Sincerely,

Paul M. Blanch

Paul M. Blanch
135 Hyde Rd.
West Hartford, CT 06117
860-922-3119

Attachment 1

49 CFR 192 statements from FEIS

Note there are no discussions contained within this document for compliance with individual parts of 49 CFR 192

4.12.1 Safety Standards

PHMSA is mandated to provide pipeline safety under 49 USC Chapter 601. The OPS administers the national regulatory program to ensure the safe transportation of natural gas and other hazardous materials by pipeline. It develops safety regulations and other approaches to risk management that ensure safety in the design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Many of the regulations are written as performance standards that set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve the required safety standard. PHMSA ensures that people and the environment are protected from the risk of pipeline incidents. This work is shared with state agency partners and others at the federal, state, and local level. PHMSA provides for a state agency to assume all aspects of the safety program for intrastate facilities by adopting and enforcing the federal standards. A state may also act as PHMSA's agent to inspect interstate facilities within its boundaries; however, PHMSA is responsible for enforcement actions. For the AIM Project, New York and Connecticut are interstate agents that have been delegated authority to inspect interstate natural gas pipeline facilities. OPS federal inspectors perform inspections on interstate natural gas pipeline facilities in Massachusetts and Rhode Island.

PHMSA pipeline standards are published in 49 CFR Parts 190–199. Part 192 of 49 CFR specifically addresses natural gas pipeline safety issues. Under a Memorandum of Understanding on Natural Gas Transportation Facilities (Memorandum) dated January 15, 1993 between PHMSA and the FERC, PHMSA has the exclusive authority to promulgate federal safety standards used in the transportation of natural gas. Section 157.14(a)(9)(vi) of the FERC's regulations require that an applicant certify that it will design, install, inspect, test, construct, operate, replace, and maintain the facility for which a Certificate is requested in accordance with federal safety standards and plans for maintenance and inspection. Alternatively, an applicant must certify that it has been granted a waiver of the requirements of the safety standards by PHMSA in accordance with section 3(e) of the Natural Gas Pipeline Safety Act. The FERC accepts this certification and does not impose additional safety standards. If the Commission becomes aware of an existing or potential safety problem, there is a provision in the Memorandum to promptly alert PHMSA. The Memorandum also provides for referring complaints and inquiries made by state and local governments and the general public involving safety matters related to pipelines under the Commission's jurisdiction.

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The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained to meet or exceed the Pipeline and Hazardous Materials Safety Administration's Minimum Federal Safety Standards in 49 CFR 192 and other applicable federal and state regulations. The regulations include specifications for material selection and qualifications;

2.3 CONSTRUCTION PROCEDURES

The AIM Project would be designed, constructed, operated, and maintained to conform to, or exceed, the minimum federal safety standard requirements of PHMSA in 49 CFR 192,[4] and other applicable federal and state regulations, including U.S. Department of Labor, Occupational Safety and Health Administration (OSHA) requirements. These regulations are intended to ensure adequate protection for the public. Among other design standards, Part 192 specifies pipeline material and qualification, minimum design requirements, and protection from internal, external, and atmospheric corrosion.

[4] Pipe design regulations for steel pipe are contained in subpart C, Part 192. Section 192.105 contains a design formula for the pipeline's design pressure. Sections 192.107 through 192.115 contain the components of the design formula, including yield strength, wall thickness, design factor, longitudinal joint factor, and temperature derating factor, which are adjusted according to the project design conditions, such as pipe manufacturing specifications, steel specifications, class location, and operating conditions. Pipeline operating regulations are contained in subpart L, Part 192.

2-15

Each weld is inspected by an independent certified Non Destruction Test technician to ensure its structural integrity is consistent with 49 CFR 192 of PHMSA's regulations. X-ray or ultrasonic images are taken and processed on site for virtually instantaneous results. Those welds that do not meet the Algonquin's specifications would be repaired or replaced and re-inspected.

The pipeline is coated to prevent corrosion. The pipe lengths would be coated (usually with a heat-applied epoxy) at a coating mill prior to being delivered to the Project. The ends of each piece are left bare to allow for welding. After welding, the weld area is field coated by the coating crew. Because pipeline coatings are electrically insulating, the coating is inspected using equipment that emits an electric charge to ensure there are no locations on the pipeline with a defect in the coating.

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2.6 OPERATION, MAINTENANCE, AND SAFETY CONTROLS

Algonquin would operate and maintain the newly constructed pipeline facilities in the same manner as they currently operate and maintain their existing systems in compliance with PHMSA regulations provided in 49 CFR 192, the FERC guidance at 18 CFR 380.15, and the maintenance provisions in Algonquin's E&SCP. Algonquin would add three full-time permanent workers for operation of the proposed and modified facilities.

Based on the identified estimated emissions from operation of the proposed Project facilities and review of the modeling analysis, the Project would result in continued compliance with the national ambient air quality standards (NAAQS), which are protective of human health, including children, the elderly, and sensitive populations (see section 4.11.1). The Project facilities would also be designed, constructed, operated, and maintained in accordance with or to exceed PHMSA's minimum federal safety standards in 49 CFR 192. These regulations, which are intended to protect the public and to prevent natural gas facility accidents and failures, apply to all areas along the proposed pipeline routes regardless of the presence or absence of minority or low income populations.

The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained in accordance with or to exceed PHMSA's Minimum Federal Safety Standards in 49 CFR 192. The regulations are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures. PHMSA specifies material selection and qualification; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion.

Algonquin would hydrostatically test the new pipeline segments in accordance with PHMSA pipeline safety regulations in 49 CFR 192 prior to placing the pipeline facilities into service. Algonquin estimates a need for a total of about 10,082,645 gallons of water to conduct the hydrostatic testing for the Project (9,610,245 gallons for pipeline testing and 472,400 gallons for aboveground facilities). Most of this water would be obtained from municipal sources, but some would be appropriated from the old Verplanck Quarry Lake in New York. However, to our knowledge none of the projects listed in table 4.13-1 would be expected to use water from the Old Verplanck Quarry Lake at the same time or at all. Following testing of the pipeline, the water would be discharged into dewatering structures located in upland areas and within the construction work area in accordance with the AIM Project E&SCP and the hydrostatic testing BMPs provided by agencies. Therefore, long-term impacts on surface water sources would not be anticipated as a result of hydrostatic testing activities, and we expect the cumulative impacts of the projects listed in table 4.13-1 on surface and groundwater resources to be minor.

4.13.9 Reliability and Safety

Impact on reliability and public safety would be mitigated through the use of the PHMSA Minimum Federal Safety Standards in Title 49 CFR 192, which are intended to protect the public and to prevent natural gas facility accidents and failures. In addition, Algonquin's construction contractors would be required to comply with the OSHA Safety and Health Regulations for Construction in Title 29 CFR 1926. We received several comments about potential cumulative impacts relative to safety between the proposed Project and WPP's proposed West Point Transmission Project. We evaluated the risk associated with constructing and operating transmission lines and natural gas pipelines in close proximity in section 4.12.3. It is not uncommon for natural gas pipeline facilities to parallel existing utility rights-of-ways, including electric transmission rights-of-way and there are established methods for minimizing the risks of these configurations. Algonquin has conducted surveys and collected information on the location and size of existing power line structures within the proposed right-of-way corridors, tower footing locations and dimensions, and wire heights (lowest point between towers) and would design or modify its construction technique on the AIM Project with sufficient offsets to eliminate the risk of heavy construction equipment interfering with overhead high-voltage electric transmission lines during construction and operation. Where possible, Algonquin would offset its pipeline trench by 50 feet to avoid any potential damage to electric transmission towers; and in those areas that this offset could not be

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5.1.12 Reliability and Safety

The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained in accordance with or to exceed the PHMSA Minimum Federal Safety Standards in 49 CFR 192. The regulations are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures. The PHMSA specifies material selection and qualification; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion.

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The pipeline and aboveground facilities associated with the AIM Project would be designed, constructed, operated, and maintained to meet or exceed the Pipeline and Hazardous Materials Safety Administration's Minimum Federal Safety Standards in 49 CFR 192 and other applicable federal and state regulations. The regulations include specifications for material selection and qualifications; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion. By designing and operating the Project in accordance with the applicable standards, the Project would not result in significant increased public safety risk.

2.3 CONSTRUCTION PROCEDURES

The AIM Project would be designed, constructed, operated, and maintained to conform to, or exceed, the minimum federal safety standard requirements of PHMSA in 49 CFR 192,[4] and other applicable federal and state regulations, including U.S. Department of Labor, Occupational Safety and Health Administration (OSHA) requirements. These regulations are intended to ensure adequate protection for the public. Among other design standards, Part 192 specifies pipeline material and qualification, minimum design requirements, and protection from internal, external, and atmospheric corrosion.

2.6 OPERATION, MAINTENANCE, AND SAFETY CONTROLS

Algonquin would operate and maintain the newly constructed pipeline facilities in the same manner as they currently operate and maintain their existing systems in compliance with PHMSA regulations provided in 49 CFR 192, the FERC guidance at 18 CFR 380.15, and the maintenance provisions in Algonquin's E&SCP. Algonquin would add three full-time permanent workers for operation of the proposed and modified facilities.

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4.13.9 Reliability and Safety

Impact on reliability and public safety would be mitigated through the use of the PHMSA Minimum Federal Safety Standards in Title 49 CFR 192, which are intended to protect the public and to prevent natural gas facility accidents and failures. In addition, Algonquin's construction contractors would be required to comply with the OSHA Safety and Health Regulations for Construction in Title 29 CFR 1926. We received several comments about potential cumulative impacts relative to safety between the proposed Project and WPP's proposed West Point Transmission Project. We evaluated the risk associated with constructing and operating transmission lines and natural gas pipelines in close proximity in section 4.12.3. It is not uncommon for natural gas pipeline facilities to parallel existing utility rights-of-ways, including electric transmission rights-of-way and there are established methods for minimizing the risks of these configurations. Algonquin has conducted surveys and collected information on the location and size of existing power line structures within the proposed right-of-way corridors, tower footing locations and dimensions, and wire heights (lowest point between towers) and would design or modify its construction technique on the AIM Project with sufficient offsets to eliminate the risk of heavy construction equipment interfering with overhead high-voltage electric transmission lines during construction and operation. Where possible, Algonquin would offset its pipeline trench by 50 feet to avoid any potential damage to electric transmission towers; and in those areas that this offset could not be

4-303

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1.2.4 U.S. Department of Transportation – Pipeline and Hazardous Materials Safety Administration

PHMSA is the federal agency responsible for administering the national regulatory program to ensure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline under 49 USC Chapter 601. PHMSA's Office of Pipeline Safety (OPS) develops regulations and other approaches to risk management to ensure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. The OPS is responsible for ensuring that Algonquin's proposed facilities are designed, constructed, and operated in compliance with the safety standards that the agency has established for natural gas pipeline facilities.

2.3.2 Aboveground Facility Construction Procedures

The AIM Project aboveground facilities would be constructed in compliance with the same federal regulations and guidelines as the pipeline facilities, and in accordance with the specific requirements of applicable federal and state approvals. Construction activities associated with these facilities would include clearing, grading, installing concrete foundations, erecting metal buildings, and installing piping, metering facilities, and appurtenances. Initial work at the new M&R stations would focus on preparing the sites for equipment staging, fabrication, and construction. Following foundation work, station equipment and structures would be brought to the site and installed, using any necessary trailers or cranes for delivery and installation. Equipment testing and start-up activities would occur on a concurrent basis.

Although Algonquin has stated that sufficient qualified EIs would be available to implement their environmental inspection program, it has agreed to participate in a third-party Environmental Compliance Monitoring Program for sensitive environmental areas of the AIM Project. Under this program, Algonquin would fund a contractor, to be selected and managed by the FERC staff, to provide environmental compliance monitoring services. The FERC Third-party Compliance Monitor would provide daily reports to the FERC staff on compliance issues and make recommendations to the FERC Project Manager on how to deal with compliance issues and construction changes, should they arise. FERC staff would also conduct periodic inspections. As discussed in section 4.0, use of a third-party Environmental Compliance Monitoring Program would be particularly appropriate along the Haverstraw to Stony Point Take-up and Relay, Stony Point to Yorktown Take-up and Relay, Southeast to MLV 19 Take-up and Relay, and West Roxbury Lateral segments and related aboveground facilities due to concerns about construction in residential and commercial areas, the Hudson River crossing, and potential blasting. Development of the program would occur prior to construction.

2.6 OPERATION, MAINTENANCE, AND SAFETY CONTROLS

Algonquin would operate and maintain the newly constructed pipeline facilities in the same manner as they currently operate and maintain their existing systems in compliance with PHMSA regulations provided in 49 CFR 192, the FERC guidance at 18 CFR 380.15, and the maintenance provisions in Algonquin's E&SCP. Algonquin would add three full-time permanent workers for operation of the proposed and modified facilities.

As shown on figure 4.3.2-1, the Croton Watershed would be crossed by the Stony Point to Yorktown Take-up and Relay segment between MPs 10.0 and 12.3 in the Town of Cortlandt and by the Southeast to MLV-19 Take-up and Relay segment between MPs 0.0 and 0.1 in the Town of Southeast. Algonquin would sequence construction activities to minimize the amount and duration of an open right-of-way within the watershed. Algonquin would use a separate construction crew to work in the 2.3-mile-long stretch within the watershed and has also committed to an environmental inspection and compliance monitoring program to monitor and enforce compliance with all permit conditions to protect the environment during construction (see section 2.5). In addition, Algonquin is working with the NYCDEP to develop a Stormwater Pollution Prevention Plan (SWPPP) that addresses NYCDEP's requirements for constructing within a New York City watershed.

8. Beginning with the filing of its Implementation Plan, Algonquin shall file updated status reports **on a weekly basis for the AIM Project until all construction and restoration activities are complete**. On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

   a. an update on Algonquin's efforts to obtain the necessary federal authorizations;

   b. the current construction status of each spread of the Project, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally sensitive areas;

   c. a listing of all problems encountered and each instance of noncompliance observed by the EI(s) during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);

   d. a description of the corrective actions implemented in response to all instances of noncompliance, and their cost;

   e. the effectiveness of all corrective actions implemented;

11. **Within 30 days of placing the authorized facilities for the Project into service, Algonquin** shall file an affirmative statement, certified by a senior company official:

   a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or

   b. identifying which of the Certificate conditions Algonquin has complied with or will comply with. This statement shall also identify any areas affected by the Project where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

The FERC is the federal agency responsible for authorizing interstate natural gas transmission facilities under the Natural Gas Act, and is the lead federal agency for the preparation of this EIS in compliance with the requirements of the National Environmental Policy Act. The U.S. Environmental Protection Agency, the U.S. Army Corps of Engineers (USACE), and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration, participated as cooperating agencies in the preparation of the EIS. A cooperating agency has jurisdiction by law or has special expertise with respect to environmental resource issues associated with a project.