ORIGINAL

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April 4, 2007

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Blanca Bayó
Director, Division of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399

Re: Docket No. 060162-EI

Dear Ms. Bayó:

Enclosed for filing in the above referenced docket on behalf of Progress Energy Florida, Inc., are the original and fifteen (15) copies of the following:

- Rebuttal Testimony of Javier J. Portuondo, along with Mr. Portuondo's Exhibit No. __ (JP-3).

I also have included a diskette containing the testimony in Microsoft Word Format. By copy of this letter, copies of the documents listed above have been provided to all persons on the attached certificate of service.

Please acknowledge receipt and filing of the above by stamping the enclosed extra copies of the testimony and attached exhibit and returning them to me. If you have any questions concerning this filing, please contact me at 425-2359.

Thank you for your assistance in connection with this matter.

Very truly yours,

Gary V. Perko
Carolyn S. Raepple
Virginia C. Dailey

Attorneys for PROGRESS ENERGY FLORIDA, INC.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of Progress Energy Florida, Inc.'s Rebuttal Testimony of Javier J. Portuondo in Docket No. 060162-EI have been furnished by hand-delivery (*) or regular U.S. mail to the following this 1st day of April, 2007.

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ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060162-EI

In re: Petition of Progress Energy Florida, Inc.
to recover modular cooling tower costs.

REBUTTAL TESTIMONY OF JAVIER PORTUONDO

April 4, 2007

Q. Please state your name and business address.

A. My name is Javier J. Portuondo. My business address is Post Office Box 1551, Raleigh, North Carolina 27601.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Service Company, LLC, as Director of Regulatory Planning.

Q. Have you previously submitted testimony in this docket?

A. Yes. I provided regulatory support for the Progress Energy's request for recovery of the costs of the modular cooling tower project.

Q. Have any of your responsibilities or duties changed since you last submitted testimony in this docket.

A. No.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to several assertions made by witnesses Patricia Merchant and Thomas Hewson on behalf of the Office of Public Counsel (OPC). In particular, I will respond to the following issues raised by Ms. Merchant and Mr. Hewson:

- Whether the Modular Cooling Tower Project meets the second criterion for recovery under the Environmental Cost Recovery Clause (ECRC) (i.e., whether the effect of the environmental requirement that led to the project was triggered after the company's last test year upon which rates are based);
- Whether the Modular Cooling Tower Project meets the third criterion for ECRC recovery (i.e., whether the costs for the project are recovered in Progress Energy Florida's (PEF's) base rates); and
- Whether the Modular Cooling Tower Project meets the criteria for recovery under the Fuel and Purchase Power Recovery Clause (Fuel Clause) under Commission Order No. 14546.

Q. Are you sponsoring any Exhibits with your rebuttal testimony?

A. Yes. I am sponsoring the Exhibit No. __ (JP-3), which is testimony filed on behalf of PEF in support of its request for ECRC recovery of the costs of PEF's Aboveground Storage Tank Program. That request was approved in PSC Order No.03-1348-FOF-EI, at p. 10.

Q. Do you disagree with Ms. Merchant's statement that "[i]f a cost does not legitimately meet the definition of costs that qualify for a recovery clause, it should be borne through base rates."

A. I do not disagree with this statement. However, it begs the question of whether a cost meets the criteria for recovery under a cost recovery clause. Ms. Merchant goes to great lengths to explain her view of ratemaking theory and when a utility is earning fair rate of return. However, that discussion is largely, if not entirely, irrelevant to the criteria for recovery under the ECRC and the Fuel Clause. In its initial order implementing the ECRC, the Commission specifically rejected OPC's argument that ECRC recovery should be subject to an earnings test under which recovery would be denied if a utility is earning within its allowed return on equity range. <u>See</u> Order No. PSC-94-0044-FOF-EI, at pp. 3-4. Likewise, Order No. 14546 did not establish an earnings test for determining whether "other" non-specified fuel-related costs are recoverable under the Fuel Clause. However, in both orders, the Commission ensured against double-recovery by establishing a criterion that the costs at issue were not anticipated when the utility's base rates were established.

Q. Are you familiar with the eligibility criteria for recovery through the ECRC?

A. Yes. The ECRC, Section 366.8255, Florida Statutes, authorizes the Commission to review and approve recovery of environmental compliance costs prudently incurred by electric utilities. In Order No. PSC-94-0044-FOF-EI, the Commission established the policy that recovery of costs associated with environmental compliance activities should be recoverable through ECRC if:

1) such costs were prudently incurred after April 13, 1993;
2) the activity is legally required to comply with a governmentally imposed environmental regulation that was enacted or became effective, or whose effect was triggered after the company's last test year upon which rates are based; and
3) such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. On pages 4 through 7 of his testimony, Mr. Hewson asserts that the Modular Cooling Tower Project does not meet the second ECRC eligibility criterion because the NPDES permit limitation was "in place" prior to the test year upon which PEF's base rates were based. Do you agree with this assertion?

A. No. As I previously quoted, the relevant language from Order No. PSC-94-0044-FOF-EI states that "the activity must be legally required to comply with a governmentally imposed environmental regulation that was enacted or became effective, *or whose effect was triggered* after the company's last test year upon which rates are based." (emphasis added). Mr. Hewson ignores the italicized language which focuses on when the effect of the environmental requirement was triggered, rather than just the date it was put in place as Mr. Hewson suggests. The Modular Cooling Tower Project satisfies this criterion because the need for the additional cooling water capacity to comply with the NPDES permit limitation was triggered by the unusually high inlet water temperatures during the summer of 2005, which were not fully analyzed until after PEF's MFRs were submitted and its base rates were established/approved in Docket No. 050078. Indeed, the decision to implement the project was not made until February, 2006.

As Commission Staff recognized in its recommendation that the Commission approve PEF's request for ECRC recovery, the Crystal River industrial wastewater permit does not mandate a particular method to meet the thermal limitation. However, the permit legally requires PEF to remain in compliance. Due to the increased cooling water intake temperatures, PEF has two options to maintain compliance: de-rate, and thus decrease the availability of its baseload capacity; or add additional cooling capacity. The Modular Cooling Tower Project provides additional cooling capacity and restores plant capacity to its baseline level and thereby avoids higher alternate fuel or purchase power costs being borne by ratepayers. Although PEF has the option to de-rate its plants to comply with the permit, the Modular Cooling Tower Project is the most cost-effective and beneficial compliance option for PEF's ratepayers.

Q. Has the Commission previously approved ECRC recovery for activities necessary to comply with environmental requirements that were in place prior to the test year upon which PEF's base rates were based?

A. Yes. In Order No. PSC-03-1348-FOF-EI, at p. 9, the Commission approved PEF's request to recover activities necessary to comply with requirements established in 1998 amendments to the Florida Department of Environmental Protection's (FDEP's) above ground storage tank rule. Exhibit No. __ (JP-2) is the testimony of Patricia West that was submitted in support of PEF's request. As Ms. West explained on page 8 of her testimony, although the rule amendments were in place since 1998 (before the test year upon which PEF's then-current rates were based), PEF was not required to undertake any compliance activities to meet with the specific requirements at issue until 2005 and 2010. In other words, the full effect of the pre-existing environmental requirement was not triggered until after PEF's last base rate proceeding. The same logic applies to the Modular Cooling Tower Project because the full effect of the NPDES permit limit was not triggered until after PEF's base rates were established. Prior to that time, there had been no determination that additional cooling water capacity was needed to comply with the NPDES permit limitation.

Mr. Hewson discusses issues like improved station performance and improved unit performance and availability as though these were operational issues that PEF was facing in the operation of Crystal River. This could not be further from the truth. The operational efficiency of the units, but for this climatic issue manifesting itself in the higher than normal cooling water intake temperatures, would not have caused the need for increased cooling water capacity. Mr. Hewson is confusing operational or maintenance activities that would facilitate ongoing, efficient plant operation with a climatic change – something beyond the control of the Company and unanticipated when the NPDES permit limitations were established – which triggered the need to implement incremental compliance measures.

Q. Do you agree with Mr. Hewson's suggestion, at pages 7 and 8 of his testimony, that projects must have a direct effect on delivered fossil fuel prices to be eligible for Fuel Clause recovery under Order No. 14546?

A. No, Order No. 14546 imposes no such limitation. To the contrary, the Commission expressly sought to establish a "flexible" policy to allow for recovery through the fuel clause of expenses that were not anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. <u>See</u> Order No. 14546 at p. 3, 85 FPSC 7:69. In applying this "flexible" policy, the Commission has not sought to limit the types of costs incurred, but rather to ensure a linkage to the types of costs avoided. An excellent example of this is the Commission's decision with regard to FPL's request for recovery of costs associated with the uprate at Turkey point in Order No. PSC-96-1172-FOF-EI issued in Docket No. 96001-EI, at p.9. The costs incurred were of a capital nature and associated with nuclear production, not fossil fuel. Because the project would allow FPL to lower total overall fuel costs by more than the expected cost of the project, the Commission found that the project fell under the scope of Order No. 14546. This Commission precedent indicates that any costs that result in overall fuel savings can be considered fossil fuel-related costs even though they do not have a direct effect on delivered fossil fuel prices.

Q. Do you agree with Mr. Hewson's suggestion that, if the modular cooling tower costs are eligible for Fuel Clause recovery under Order No. 14546, "most operational and maintenance projects" also would qualify?

A. No. Order No. 14546 only allows recovery of costs "which were not recognized or anticipated in the cost levels used to determine current base rates[.]" Most operation and maintenance costs (including costs incurred in planned or unplanned outages) are recognized and anticipated when base rates are determined and in fact are activities meant to repair or replace existing equipment due to natural wear and tear. By contrast, as I previously discussed, the costs of the Modular Cooling Tower Project were not recognized or anticipated in the cost levels used to determine PEF's current base rates. In addition, most if not all of those operation and maintenance projects would not meet the Commission test that fuel savings resulting from the project must exceed the cost incurred to achieve those savings.

Whether other, hypothetical activities may be eligible for cost recovery under the ECRC or Fuel Clause depends upon the specific circumstances involved. For example, the Commission previously has approved recovery of capital expenditures for fuel switch projects of the type cited by Mr. Hewson where, under the criteria set forth in Order No. 14546, they would result in fuel cost savings. See, Order Nos. PSC-95-0450-FOF-EI (modifications enabling FPL units to burn a more economic grade of residual fuel oil); PSC-98-0412-FOF-EI (conversion of Suwannee Unit 3 to burn natural gas); and PSC-97-0359-FOF-EI (conversion of FPC units to burn natural gas).

Q. Do you agree with Ms. Merchant's assertion that the costs of the Modular Cooling Tower Project are included in PEF's base rates?

A. No. As I stated in my direct testimony, the Modular Cooling Tower Project was not anticipated when PEF's current base rates were established/approved in Docket No. 050078-EI. The Company's evaluation of the project was prompted by unusually high inlet water temperatures and associated de-rates during the summer of 2005. The analysis leading to a determination that additional cooling was needed occurred throughout the fourth quarter of 2005 and the decision to implement the Project was not made until February 2006. Thus, the costs of the project were not anticipated when the Company submitted its rate case MFRs in April 2005 and are not included in the Company's base rates.

Contrary to Ms. Merchant's suggestion, Exhibit Nos. __ (JP-1) and (JP-2) confirm that the modular cooling tower costs were not anticipated when PEF's current base rates were established/approved. As Ms. Merchant recognizes, line 12 of Exhibit No. __ (JP-1) compares the amounts budgeted to actual expenditures for rental expenses from 2000 through 2006. The balance for both years is zero, demonstrating that PEF had not incurred cooling tower rental costs in 2000 and did not anticipate them in 2006.

Exhibit No. __ (JP-2) shows the monthly in-plant balances for the test year 2006. Prior to 2006 when the Modular Cooling Tower Project was placed into service, PEF had never incurred any capital costs for modular cooling towers. Thus, if the project had been anticipated when the MFRs were submitted, the increase in plant-balance for FERC account 314 reflected in Exhibit No. __ (JP-2) would have had to be large enough to encompass the costs of the project. As stated in my direct testimony, however, the schedule does not show any increases that would accommodate plant additions for the modular cooling towers.

Q. Do you agree with Ms. Merchant's assertion, at pages 17 and 18 of her testimony, that recovery of the modular cooling tower costs would violate the 2005 rate case settlement approved in Docket No. 050078-EI?

A. No. In relevant part, the provision of the settlement referenced by Ms. Merchant states that "PEF will not petition for any *new surcharges* . . . to recover costs that are of a type traditionally and historically would be, or are presently, recovered in base rates." (emphasis added). This provision precludes PEF from petitioning for "*new* surcharges." It does not prevent PEF from recovering newly incurred costs under *existing* cost recovery clauses. Ms. Merchant also points to the "*...traditionally recovered in base rates...*" in Order No. 14546, but does not acknowledge that there are types of costs that have been traditionally and historically recovered through the Fuel Clause as well as ECRC when they are found to meet the respective tests for eligibility. These costs are of a nature that they pass the criteria for recoverability under either clause as discussed in more detail in my pre-filed direct testimony and above and as such have traditionally and historically been recovered through these clauses, not through base rates.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 030007-EI

AUGUST 8, 2003

Q. Please state your name and business address.

A. My name is Patricia Q. West. My business address is 100 Central Avenue, St. Petersburg, Florida, 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Florida, Inc. ("PEF" or "the Company") as Manager of Environmental Projects and Strategy. In that position, I have responsibility for the development of compliance strategies pertaining to new regulatory requirements for energy supply facilities in Florida, North Carolina, South Carolina and Georgia.

Q. Please describe your background and experience in the environmental field.

A. I obtained my B.S. degree in Biology from New College of the University of South Florida in 1983. I was employed by the Polk County Health Department from 1983-1986 and by the Florida Department of Environmental Protection

("DEP") from 1986-1990. At DEP, I was involved in compliance and enforcement efforts associated with petroleum storage facilities. In 1990, I joined Florida Power Corporation as an Environmental Project Manager and then held progressively responsible positions in the company's environmental services department, including the position of team leader for the integration of the environmental functions of Florida Power and Carolina Power and Light. From 2001-2002, I served as Manager of Water Programs in the Environmental Services Section of PEF's Technical Services Department. In 2002, I assumed my current position as Manager of Environmental Programs and Strategy.

Q. What is the purpose of your testimony?

A. My testimony describes two new environmental compliance programs for which Progress Energy is seeking cost recovery in this docket:

- Pipeline Integrity Management Program (No. 3)
- Aboveground Storage Tank Secondary Containment Project (No. 4)

The Company recently filed a petition in Docket No. 030711-EI asking the Commission to determine that the costs of these programs are eligible for recovery through the Environmental Cost Recovery Clause ("ECRC").

Q. Are you familiar with the requirements that environmental costs must meet to be eligible for recovery through the ECRC?

A. Yes. The general requirements are that all expenditures must have been prudently incurred after April 13, 1993; all activities must be legally required to comply with a governmentally imposed environmental requirement which was created, or whose effect was triggered, after the company's last test year on which rates are based; and the company must show that none of the expenditures are being recovered through some other cost recovery mechanism or through base rates. In addition, costs are eligible for recovery only if they were incurred after the date of the petition which seeks a determination of eligibility for cost recovery.

Q. Do these two new programs qualify for cost recovery under these criteria?

A. Yes. As discussed in more detail below, each program was implemented in response to a new environmental requirement which was created, or whose effect was triggered, after the minimum filing requirements (MFRs) were submitted in the Company's last rate case, Docket No. 000824-EI. None of the costs of these programs are being recovered through base rates or any other cost recovery mechanism. Although some costs were incurred in connection with the Pipeline Integrity Management Program before the Company filed its petition in Docket No. 030711-EI, we are seeking recovery only of costs incurred after the date that petition was filed.

PIPELINE INTEGRITY MANAGEMENT PROGRAM

Q. Why is the Company implementing the Pipeline Integrity Management Program?

A. PEF is implementing a Pipeline Integrity Management Program in order to comply with the requirements of U.S. Department of Transportation ("USDOT") Regulation 49 CFR Part 195, as amended effective February 15, 2002. A copy of this new regulation, which was published at 67 Federal Register 2136 (January 16, 2002), is attached at Exhibit ___ (PQW-1).

Q. Is this a new regulatory requirement?

A. Yes. Prior to the February 15, 2002 amendments, the USDOT's pipeline integrity management regulations applied only to operators with 500 miles or more of hazardous liquid and carbon dioxide pipelines that could affect high consequence areas. The amendments which became effective on February 15, 2002 extended the requirements for implementing integrity management to operators, such as PEF who have less than 500 miles of regulated pipelines that could affect high consequence areas. Such operators must now develop and implement a pipeline integrity management program that meets the requirements of the regulation. The objective of this regulation is to improve the integrity of pipeline systems in the U.S. in order to protect public safety and the environment. Additionally, the regulation requires continual assessment and evaluation of pipeline integrity through inspection or testing, data integration and analysis, and follow-up remedial, preventative, and mitigative actions.

Q. What facilities does the Company own that are covered by the new regulation?

A. PEF owns one hazardous liquid pipeline that is subject to the new regulation and must comply with the new requirements. That is the Bartow-Anclote 14-inch hot oil pipeline which extends for 33.3 miles from the Company's Bartow Plant north of St. Petersburg in Pinellas County to its Anclote Plant near Holiday in Pasco County.

Q. What specific activites are required by the new regulation?

A. The new regulation requires PEF to take the following specific actions by the dates indicated:

- November 18, 2002 — Identify each pipeline or pipeline segment that could affect a high consequence area
- February 18, 2003 — Prepare a written integrity management program plan that addresses the risks on each segment of pipeline.
- August 16, 2005 — Conduct an expedited baseline assessment of at least 50% of the pipeline, beginning with the highest risk segment(s).
- February 17, 2009 — Complete the baseline assessment of the entire pipeline.

Q. Has the Company completed the activities that were required by February 18, 2003?

A. Yes. PEF used outside consultants to complete the pipeline identification activity and to prepare the required integrity management program plan. In addition, PEF and its consultants have conducted a Leak Detection Study to determine what modifications are necessary to the Company's existing leak detection system to enable PEF to comply with the on-going monitoring requirements of the new regulations.

These activities were completed prior to the filing of the petition in Docket No. 030711-EI, and the Company has therefore excluded the costs of these activities in calculating the amount for which it is seeking recovery through the ECRC.

Q. Has the Company projected the costs that it will incur for the Pipeline Integrity Management Program in 2003 after the date of filing the petition in Docket No. 030711-EI?

A. We estimate the total project costs for the last half of 2003 to be approximately $990,000 in capital investment and $10,000 in O&M expenses. The capital investment is for the design ($313,690) and implementation ($676,304) of an upgraded leak detection system required to comply with the new regulations. The planned upgrades, which are based on the Leak Detection Study completed in April, 2003, include the acquisition and installation of computer hardware and software for leak detection; modifications to the pipeline system to improve the accuracy, reliability and sensitivity of the existing monitoring and detection system; installation of an additional communications circuit; upgrades to the

Bartow meter station; and related valve and piping work at the Anclote terminus. The O&M expenses include the annual review and update of the integrity management plan and the risk analysis required by the new regulations.

Q. What steps is the Company taking to ensure that the level of expenditures to comply with the new pipeline regulations is reasonable and prudent?

A. Before beginning to implement the upgraded leak detection system, Progress Energy Florida performed a study to identify the most cost-effective method of bringing the system into compliance with the new regulatory requirements.

As future services are required to comply with the regulations, PEF will identify qualified suppliers of the necessary services. Where possible, competitive bidding will be used to select the lowest cost supplier.

Q. Has any other utility obtained approval of a similar program to comply with the new pipeline integrity management rules?

A. Yes, the Commission approved Florida Power and Light Company"s program for compliance with these new regulations in Order No. PSC-02-1735-FOF-EI, issued in Docket No. 020007-EI.

ABOVEGROUND STORAGE TANK SECONDARY CONTAINMENT

Q. Why is the Company proposing to implement aboveground storage tank secondary containment projects?

A. The Company is required to make improvements to many of its aboveground petroleum storage tanks in order to comply with the provisions of Florida Department of Environmental Protection Rule 62-761.510(3). A copy of that rule is attached as Exhibit ____ (PQW-2). Subsection (d) of that rule requires all internally lined single bottom aboveground storage tanks to be upgraded with secondary containment, including secondary containment for piping in contact with the soil. It also requires that dike field area secondary containment for pre-1998 tanks be upgraded, if necessary, to meet the requirements of Rule 62-761.500(1)(e).

Q. When is the Company required to comply with this rule?

A. Although Rule 62-761.510(3)(d) has been in place since July 13, 1998, it included a delayed effective date of 2010 for installation of secondary containment for the types of storage tanks operated by PEF, and a delayed effective date of 2005 for upgrade of dike field area secondary containment. Because of these delayed implementation dates, PEF has not previously been required to comply with these provisions. Given the lead time for making the necessary improvements at multiple sites, PEF has just begun the process of upgrading those storage facilities to comply with the rule. This activity is expected is to continue until all tanks are upgraded before the end of 2009.

Q. What facilities does the Company operate that must be upgraded to comply with the rule?

A. We have a total of 12 aboveground storage tanks which must be upgraded to comply with the rule. The number of tanks located at each plant site are as follows:

Bartow (1), Bayboro (2), Avon Park (1), Intercession City (2), Turner (1), DeBary (1), University of Florida (1), Suwannee (1), and Anclote (2)

PEF also has secondary containment systems for concrete dike field areas at its Crystal River Units 1 & 2 and Rio Pinar plant sites which must be upgraded to comply with the new requirements for such systems.

Q. When will these compliance activities take place?

A. The installation of a secondary tank bottom at the Turner plant site, the addition of secondary containment for piping at the Bartow plant, and the upgrade of the dike field secondary containment system at the Crystal River Units 1 & 2 plant site have been scheduled for the second half of 2003. The Company is in the final stages of developing a plan to upgrade the remaining storage tanks to comply with the secondary containment provisions of the rule, and is preparing a timetable to ensure that the required improvements are implemented prior to 2010.

Q. Has the Company projected the costs that it will incur for the Above Ground Secondary Tank Projects in 2003 after the date of filing the petition in Docket No. 030711-EI?

A. We estimate the total project costs for the remainder of 2003 to be approximately $693,800 in capital investment. This includes $502,700 for installation of a secondary tank bottom at the Turner plant site, $91,100 for secondary containment of piping at the Bartow site, and $100,000 for lining or coating the dike field secondary containment at Crystal River Units 1 & 2.

Q. What steps are the Company taking to ensure the level of expenditures to bring the storage tanks and dike field area containment systems into compliance with the new rule is reasonable and prudent?

A. In order to ensure that the costs incurred to comply with the new regulation are prudent and reasonable, PEF is using an outside consultant to identify the tanks and piping that are affected by the secondary containment requirements and to develop a plan to achieve compliance with the rule. Project engineering will be performed by internal personnel or by contractors under blanket contracts. Depending on the particular project, construction of the required improvements will be performed either under blanket site or corporate contracts with contractors who were selected using a competitive bidding process, or by contractors selected by project-specific competitive bids.

Q. Has any other utility obtained approval of any similar programs to comply with DEP secondary containment rules?

A. Yes, the Commission previously approved secondary containment programs for Florida Power and Light Company (FPL) in Order No. PSC-1589-FOF-EI, Docket No.930661-EI, for Gulf Power Company in Order No. PSC-97-1047-FOF-EI, Docket No. 970007-EI, and for TECO in Order No. PSC-0408-FOF-EI, Docket No. 980007-EI. The FPL, Gulf Power, and TECO programs were required to ensure compliance with rules (17-762 and 62-762) that preceded the current requirements of Rule 62-761, F.A.C., discussed in PEF's petition.

Q. Does this conclude your testimony?

A. Yes it does.

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 195

[Docket No. RSPA-00-7408; Amdt. No. 195-76]

RIN 2137-AD49

Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With Less Than 500 Miles of Pipelines)

AGENCY: Research and Special Programs Administration (RSPA), U.S. Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: Our regulations for the transportation of hazardous liquids by pipeline require operators with 500 or more miles of regulated pipelines to establish a program for managing the integrity of pipelines that affect high consequence areas. The regulations require continual assessment and evaluation of pipeline integrity through inspection or testing, data integration and analysis, and follow-up remedial, preventive, and mitigative actions. This Final Rule extends those regulations to operators with less than 500 miles of regulated pipelines. We are taking this action because safety recommendations, statutory mandates, and accident analyses indicate that coordinated risk control measures are needed for public safety and environmental protection in addition to compliance with traditional safety standards. Broadening the coverage of the existing regulations will further enhance the protection of high consequence areas against the risk of pipeline failures.

DATES: This Final Rule takes effect February 15, 2002.

FOR FURTHER INFORMATION CONTACT: L. M. Furrow by phone at 202-366-4559, by fax at 202-366-4566, by mail at U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590, or by e-mail at *buck.furrow@rspa.dot.gov*.

SUPPLEMENTARY INFORMATION:

Background

Last year we amended the regulations in 49 CFR part 195 to require each operator who owns or operates 500 or more miles of pipelines subject to part 195 to establish a program for managing the integrity of pipelines that could affect a high consequence area if a leak or rupture occurs (Docket No. RSPA-99-6355; 65 FR 75377; Dec. 1, 2000). High consequence areas include highly populated areas, areas unusually sensitive to environmental damage, and commercially navigable waterways (§ 195.450). Program standards require continual assessment, evaluation, correction, and validation of pipeline integrity (§ 195.452 and appendix C to part 195). The new standards took effect May 29, 2001 (66 FR 9532; Feb. 8, 2001). In addition, in a further rulemaking action (Docket No. RSPA-99-6355), we are revising the repair provisions of § 195.452(h) and clarifying that § 195.452 applies to carbon dioxide pipelines as well as hazardous liquid pipelines.

We did not apply the new program standards to pipelines of operators with less than 500 miles of regulated pipelines primarily because we needed more information about the potential impact of the standards on these operators. We subsequently learned that these operators include, to a large extent, companies with ample resources and capabilities to carry out the standards.

A wide range of persons who submitted comments to Docket No. RSPA-99-6355 supported the need to apply the new program standards to all operators of regulated pipelines that could affect high consequence areas. Based on these comments and the impact information we had collected, we published a Notice of Proposed Rulemaking (NPRM) to extend the program standards to pipelines of operators with less than 500 miles of regulated pipelines (66 FR 15821; March 21, 2001).

The NPRM did not propose any substantive change to the existing program standards. It merely proposed to establish later deadlines for developing programs under § 195.452(b)(1), identifying pipelines under § 195.452(b)(1)(i), completing baseline assessments under § 195.452(d)(1), accepting prior assessments under § 195.452(b)(2), and applying certain time limits on reviewing assessment results under § 195.452(h)(3). We invited interested persons to submit written comments on the proposed rules until May 21, 2001.

Although the NPRM proposed no substantive change to the program standards, in the earlier proceeding (Docket No. RSPA-99-6355), we invited comments until March 31, 2001, on the substance of the standard for remedial action (§ 195.452(h)). As indicated in the NPRM, if § 195.452(h) is changed in that proceeding, the changes will apply to all operators of pipelines to which the program standards apply, including operators covered by the present Final Rule.

Disposition of Comments

This section of the preamble summarizes written comments we received in response to the NPRM. It also describes how we treated those comments in developing the final rules. However, comments related to costs and benefits and the impact of the proposed rules on small entities are addressed in the "Regulatory Analyses and Notices" section of this preamble. If a proposed rule is not mentioned, no significant comments were received on the proposal, and we are adopting the proposed rule as final.

Eight persons submitted comments: a professional organization, the American Society of Safety Engineers (ASSE); a state pipeline safety agency, the Washington Utilities and Transportation Commission (WUTC); a Washington State advisory committee, the Citizens Advisory Committee on Pipeline Safety (CAC); the Small Business Administration (SBA); the Department of Energy (DOE); an engineering firm, Wink, Incorporated (Wink); and two pipeline operators, the Laclede Pipeline Company (Laclede) and the Tosco Corporation (Tosco). ASSE did not comment on specific proposals in the NPRM, but strongly supported our goal of assuring the integrity of pipeline systems. ASSE also said improving pipeline safety would improve the United States' competitive position in the world economy. WUTC, CAC, Tosco, and DOE expressed general support for the NPRM but, along with Wink, suggested changes. DOE also commented on the costs of the proposed rules in their impact on small entities. Laclede opposed the integrity assessment proposal and took issue with our estimate of compliance costs. SBA's comments were limited to the impact of the proposed rules on small entities.

Under proposed §§ 195.452(b)(1) and (b)(1)(i), operators with less than 500 miles of pipelines would have 9 months after the effective date of the final rules to identify all pipeline segments that could affect high consequence areas. They would have 1 year after the effective date to develop a written integrity management program that addresses the risks of those segments. Tosco said the identification of pipeline segments should occur after, not before, integrity management programs are completed, and suggested we allow operators 1 year to complete the identifications. In considering this comment, we noted that operators with 500 or more miles of pipelines have not indicated they expect any significant difficulties in meeting the 9-month identification rule. Tosco's comment does not give us reason to believe the 9-month rule might be too burdensome for operators with less than 500 miles of pipelines. While Tosco is correct that operators will need to have relevant program elements in place to guide them in identifying pipeline segments, we believe 9 months is enough time to complete those elements and to carry out the identifications. The additional 3 months the existing rule provides for program development gives operators enough time to complete program elements other than those concerning identification. We do not think this additional time is also needed to identify pipeline segments.

CAC suggested we require operators to seek input from potentially affected communities in identifying high consequence areas. CAC believed the input would help operators identify areas of population at risk and areas of economic importance. Although we recognize community input is valuable in many situations involving pipelines, particularly in site selection and emergency response, we do not feel it is necessary to mandate that operators seek the input CAC envisioned for two reasons. First, the definition of "high consequence area" in § 195.450 covers CAC's concern about the population-at-risk. That definition refers to areas of high or concentrated population that the U.S. Census Bureau has defined and delineated. Operators should be able to identify these areas quite easily using Census Bureau data. If additional information is needed from community records to complete the identifications, the proposed rule would implicitly obligate operators to seek this information, making an explicit requirement unnecessary. Secondly, the NPRM did not propose to require integrity management of pipelines that could affect areas of economic significance other than commercially navigable waterways. These waterways, which operators also can readily identify without community input, arguably are the nation's foremost economic resources potentially at risk from pipeline spills. Other significant economic resources that may be affected by pipelines are less certain, and we feel the present regulations in Part 195 provide those resources adequate protection against the risk of pipeline spills. Similarly, in directing DOT to require additional inspection of certain pipelines, Congress did not include pipelines that affect economic resources other than commercially navigable waterways (49 U.S.C. 60102(f)(2) and 60109). If in the future there is a need to apply the integrity management rules to pipelines affecting other significant economic resources, we will consider whether operators should seek community input in identifying those resources.

Although we did not adopt CAC's recommendations, it is important to note that in a separate proceeding we are considering the need for regulations on better communication of pipeline information by operators to local officials and the public. We have formed a communications work team, consisting of representatives from environmental and public safety organizations, pipeline companies, and government to aid our own hazardous liquid pipeline safety advisory committee in examining communications issues. Notices of meetings of the work group are published in the **Federal Register**, and minutes of the meetings are posted on this Web site: *http://ops.dot.gov.*

WUTC suggested we require baseline integrity assessments of new pipelines as soon after they are constructed as possible, and for existing pipelines as soon as practicable after the final rules take effect. WUTC stated that early baseline assessment would provide the best basis for comparing subsequent assessment results. The NPRM proposed, in § 195.452(d), that operators with less than 500 miles of pipeline complete baseline assessments within 7 years after the effective date of the final rule, with half the line pipe, selected by risk, assessed within 42 months after the effective date. Alternatively, operators could use as a baseline assessment any qualified integrity assessment completed within the 5 years prior to the effective date. For newly constructed pipelines, hydrostatic testing completed as required by other regulations in Part 195 will fulfill the baseline assessment requirement. Since this testing is normally part of the construction process, it should meet WUTC's objective of early assessment. For existing pipelines, we proposed 7 years to complete baseline assessments because of the volume of assessments, the limited availability of in-line inspection tools, and the time needed to schedule pressure testing to minimize service disruptions. Although we agree with WUTC that earlier baseline assessment would be beneficial, we do not think requiring earlier baseline assessments would be reasonable under present circumstances.

To assure that only qualified persons develop integrity management programs and make program decisions, Wink suggested we require operators to use registered professional engineers with demonstrated technical pipeline expertise and experience. Wink further suggested we require operators to submit their integrity management programs for review by RSPA certified entities. We did not adopt either suggestion because to do so would go beyond the scope of the NPRM. While § 195.452(f)(8) requires operators to use persons qualified to evaluate assessment results and analyze information, the NPRM did not address specific qualifications or program review by certified entities. Based on our experience in other areas of pipeline regulation, we believe operators will use qualified engineers with pipeline experience to assist in developing integrity management programs and recommend critical decisions under the programs. Moreover, persons carrying out regulated assessment and mitigation activities on pipelines are subject to the existing qualification requirements in Subpart G of Part 195. To assure that operators carry out their programs in accordance with the rules, we will use our own engineers and technical specialists to evaluate operators' programs and require changes that may be needed for safety. This type of evaluative process has been satisfactory for other programs and plans required by Part 195. We prefer to continue this approach to assure the quality of integrity management programs rather than establish additional personnel qualifications or a new federal certification program.

Wink asked to what extent operators would have to consider potential terrorist activities in their ongoing assessments of pipeline integrity. Under one of the integrity management program requirements (§ 195.452(e)(1)), operators must schedule integrity assessments based on "all risk factors that reflect the risk conditions on the pipeline." Therefore, if an operator knows or it is reasonable to anticipate that there is a threat to the integrity of the pipeline from terrorist activity, the operator must consider that risk in developing its integrity program. Since the events of September 11, 2001, we are working with DOT, the Department of Energy, the Federal Energy Regulatory Commission, and State agencies, to consider the need for minimum security standards for critical facilities.

Wink postulated that construction permit timing could interfere with an operator's ability to meet remediation deadlines. Section 195.452(h) deals with this potential problem. Under this rule, if justifiable circumstances preclude an operator from meeting specified repair deadlines, the operator may reasonably extend the repair schedule if it temporarily reduces operating pressure to a safe level or notifies us of the delay in making a permanent repair.

Finally, Wink suggested we establish a program review process in which operators would meet with our technical specialists to examine whether the program meets applicable requirements. In response to Wink's first comment, we mentioned we will use our own engineers and technical specialists to evaluate operators' programs and require changes that may be needed for safety. We expect this review process will involve meeting with operators' representatives.

Laclede, who operates a 28-mile propane pipeline serving a gas distribution system, believed it would be unreasonable to apply the proposed integrity assessment requirement (§ 195.452(c)) to its pipeline. Laclede said the design of 70 percent of its pipeline cannot accommodate internal inspection tools, and difficulties in de-watering the line after hydrostatic testing would cause control valve and instrument freeze-ups during critical cold weather periods. Laclede suggested we exempt from internal inspection or hydrostatic testing requirements all pipelines directly serving gas distribution systems if the pipeline is cathodically protected and inspected according to our standards or is equipped with emergency flow restricting or shutdown devices. We did not adopt this comment because providing adequate cathodic protection and meeting current inspection requirements cannot assure a pipeline is free from all potentially harmful defects that internal inspection or hydrostatic testing can disclose, such as mechanical damage or fatigue cracks. Also, while emergency flow restricting or shutdown devices are useful in mitigating the consequences of a pipeline rupture, these devices do nothing to prevent ruptures, which is the purpose of periodic internal inspection or hydrostatic testing. Laclede's comment did not fully explain the particular difficulties in de-watering, or drying, its pipeline after hydrostatic testing. Drying pipelines is not an uncommon problem in the industry and not one we believe makes the proposed testing rule unreasonable. Many companies are available to provide expert drying services, using techniques that depend on operating conditions. However, if an operator's circumstances are so unusual that hydrostatic testing would result in unavoidable damage to pipeline facilities and internal inspection is not a viable alternative, the operator may apply for a waiver of the testing requirement as permitted by 49 U.S.C. 60118.

DOE was concerned that construction of new pipelines within the next few years to meet the growing demand for fossil fuels could tax available technical expertise and equipment needed to meet various assessment deadlines in the existing and proposed rules. DOE said available resources could be stretched to a point where meeting the deadlines would not be possible, or at least not possible without significantly increased costs. Therefore, DOE suggested we expand the present provisions for extending deadlines (*e.g.*, § 195.452(j)(4)) to include situations in which meeting a deadline would result in supply disruptions. We agree that by shifting resources away from new construction or shutting down vital pipelines for hydrostatic testing or repair, supply disruptions could occur. However, at this stage we believe the impact of such an eventuality is too speculative to warrant changing the rules to add supply disruption as an acceptable reason for extending deadlines. Also, over the next few years new technologies might become available that would enable acceptable integrity assessments with no effect on supply. If in the future a supply problem appears more likely, the operator involved may petition us for necessary relief or latitude under the rules.

DOE also commented on our plan to identify high consequence areas on it's National Pipeline Mapping System (NPMS) and to make the information available to the public via the Internet. DOE recommended that before implementing this plan, we fully evaluate issues of critical infrastructure protection. Indeed, we designed the NPMS with infrastructure protection issues in mind. For example, to avoid creating a tool for intentional misuse of information with tragic results, critical pipeline components and operating data would not be shown on the NPMS. However, the events of September 11, 2001, have caused even greater concern about the security of critical infrastructure systems. As a result, the NPMS no longer provides open access to pipeline-related data. These data are only available to pipeline operators and local, state, and federal government officials. More information on the availability of data and how operators and officials can access it is on the NPMS home page: http://www.npms.rspa.dot.gov.

Editing Changes

In a further rulemaking action (Docket No. RSPA–99–6355), we are revising § 195.452(h)(3) to eliminate the possibility that periods specified for reviewing integrity assessment results could cause confusion. This change to § 195.452(h)(3) eliminates the need to revise that section to cover operators with less than 500 miles of regulated pipelines. Therefore, this Final Rule does not include the NPRM's proposed change to § 195.452(h)(3).

Because this Final Rule extends the coverage of existing § 195.452 to all operators subject to part 195, there is no need to state in final § 195.452 which operators are subject to § 195.452. Therefore, we edited § 195.452(a) to describe which pipelines are covered by § 195.452 by moving relevant provisions in § 195.452(b)(1) to § 195.452(a). Section 195.452(a) now provides that § 195.452 applies to hazardous liquid and carbon dioxide pipelines that could affect a high consequence area, including pipelines located in a high consequence area unless a risk assessment effectively shows the pipeline could not affect the area.

The NPRM proposed certain compliance dates for covered pipelines that depend on whether the operator of the pipeline owns or operates 500 or more miles of regulated pipelines. Although no one commented on this approach to determining compliance dates, we now recognize the approach could have unintended results. Under the proposed approach, if the miles of regulated pipelines an operator owns or operates changes during the compliance period (through transfer, construction, or abandonment of pipelines), the compliance dates applicable to that operator's covered pipelines could also change. For example, if an operator currently subject to § 195.452 were to reduce its miles of regulated pipelines below 500 during a compliance period for covered pipelines, the operator's covered pipelines would then fall under the later compliance date applicable to operators with less than 500 miles of regulated pipelines. Likewise, covered pipelines of operators who increase their miles of regulated pipelines to 500 or more during a compliance period would become subject to earlier compliance dates. The purpose of the proposed approach to determining compliance dates was merely to establish compliance dates for pipelines covered by the NPRM that are later than the existing compliance dates in § 195.452. We did not intend that the existing or proposed compliance dates change with changes in an operator's regulated pipeline mileage. Rather, we intended to apply the existing and proposed compliance dates to covered pipelines existing on May 29, 2001 (the effective date of existing § 195.452), depending on whether, on that date, the operator owned or operated 500 or more miles of regulated pipelines.

To clarify the application of compliance dates and to eliminate repetitive wording, final § 195.452(a) divides covered pipelines into three categories. The first category includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to part 195. This category of pipelines is subject to the existing compliance dates in § 195.452, and will remain subject to those dates regardless of how many miles of regulated pipelines the present or future operator of the pipelines owns or operates after May 29, 2001. The second category includes pipelines existing on May 29, 2001, that were owned or operated on that date by an operator who owned or operated less than 500 miles of pipeline subject to part 195. This category of pipelines is subject to the later compliance dates proposed in the NPRM for operators with less than 500 miles of regulated pipelines. Like the first category, the compliance dates applicable to the second category of pipelines do not depend on how many miles of regulated pipelines the present or future operator of the pipelines owns or operates after May 29, 2001. The third category of covered pipelines includes pipelines constructed or converted after May 29, 2001. Because these pipelines are not subject to the existing or proposed compliance dates, we have added appropriate dates to §§ 195.452(b)(1), (b)(2)(i), (d)(1), and (h)(3). The dates in paragraphs (b)(1) and (h)(3) provide compliance periods equivalent to periods allowed for Category 1 or 2 pipelines. In paragraph (b)(2)(i), we set the date as the date the pipeline begins operation, because operators should not need any longer time to identify a new or converted pipeline as a covered pipeline. The date the pipeline begins operation is also the compliance date in paragraph (d)(1), because the hydrostatic test part 195 requires on new and converted pipelines before operation will serve as the baseline assessment.

Advisory Committee Consideration

We presented the NPRM for consideration by the Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) at a meeting in Washington, DC on August 13, 2001 (66 FR 35505; July 5, 2001). The THLPSSC is RSPA's statutory advisory committee for hazardous liquid pipeline safety. The committee has 15 members, representing industry, government, and the public. Each member is qualified to consider the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed pipeline safety standards. The committee voted unanimously to approve the rules proposed in the NPRM and the associated evaluation of costs and benefits. A transcript of the August 13 meeting is available in Docket No. RSPA–98–4470.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

We consider this Final Rule to be a non-significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735; October 4,1993). Therefore, the Office of Management and Budget (OMB) has not received a copy of this rulemaking to review. We do not consider this rulemaking to be significant under DOT regulatory policies and procedures (44 FR 11034; Feb. 26, 1979).

This section of the preamble summarizes the findings of the Regulatory Evaluation we prepared for this Final Rule. A copy of the Regulatory Evaluation is in the docket.

Pipeline spills can adversely affect human health and the environment. However, the magnitude of this impact differs from area to area. There are some areas in which the impact of a spill will be more significant than it would be in others due to concentrations of people who could be affected or to the presence of environmental resources that are unusually sensitive to damage. Because of the potential for dire consequences of pipeline failures in certain areas, these areas merit a higher level of protection. We are promulgating this Final Rule to afford the necessary additional protection to these high consequence areas.

Last year we established 49 CFR 195.450 and 195.452, which are new requirements for additional protection of populated areas, commercially navigable waterways, and areas unusually sensitive to environmental damage from pipeline spills (65 FR 75377; Dec.1, 2000). The new requirements apply to pipeline operators who own or operate 500 or more miles of pipeline. This Final Rule extends the same requirements, with modified compliance deadlines, to the remaining operators of regulated pipelines—those that own or operate less than 500 miles of regulated pipeline.

RSPA and the National Transportation Safety Board (NTSB) have conducted many investigations that have highlighted the importance of protecting the public and environmentally sensitive areas from pipeline failures. NTSB has made several recommendations to ensure the integrity of pipelines near populated and environmentally sensitive areas. These recommendations include requiring periodic testing and inspection to identify corrosion and other damage, establishing criteria to determine appropriate intervals for inspections and tests, determining hazards to public safety from electric resistance welded pipe, and requiring installation of automatic or remotely-operated mainline valves on high-pressure lines to provide for rapid shutdown of failed pipelines.

Congress also directed DOT to undertake additional pipeline safety measures in areas of potentially high consequence. These statutory requirements call for new regulations on identifying pipelines in high density population areas, unusually sensitive environmental areas, and commercially navigable waters. They also call for new regulations on periodic inspections of pipelines in these areas with internal inspection devices, and on emergency flow restricting devices.

This Final Rule requires operators to systematically manage pipeline integrity to reduce the potential for failures that could affect high consequence areas (populated areas, unusually sensitive areas, and commercially navigable waterways). Operators must develop and follow an integrity management program to identify pipeline segments that could affect high consequence areas, and continually assess, through internal inspection, pressure testing, or equivalent alternative technology, the integrity of those segments. The program must also evaluate the segments through comprehensive information analysis, remediate integrity problems, and provide additional protection through preventive and mitigative measures, including the use of emergency flow restricting devices.

Existing §§ 195.450 and 195.452 cover an estimated 86.7 percent of the 157,000 miles of regulated hazardous liquid pipeline in the U.S. This Final Rule covers the remaining 13.3 percent. Of this percentage, we estimate this Final Rule will impact approximately 5,440 miles of pipeline. We estimate the cost to operators to develop the necessary programs at approximately $9.94 million, with an additional annual cost for program upkeep and reporting of $1.32 million. An operator's program begins with a baseline assessment plan and a framework that addresses each required program element. The framework indicates how decisions will be made to implement each element. As decisions are made and operators evaluate the effectiveness of the program in protecting high consequence areas, the program will be updated and improved, as needed.

This Final Rule requires a baseline assessment of covered pipeline segments through internal inspection, pressure test, or use of other technology capable of equivalent performance. The baseline assessment must be completed within 7 years after this Final Rule goes into effect. After this baseline assessment, the rule further requires that operators periodically reassess and evaluate pipeline segments to ensure their integrity within a 5-year interval. We estimate the cost of periodic reassessment will generally not occur until the sixth year, unless the baseline assessment indicates significant defects that would require earlier reassessment. Integrating information related to the pipeline's integrity is a key element of the integrity management program. Costs will be incurred in realigning existing data systems to permit integration and in analysis of the integrated data by knowledgeable pipeline safety professionals. The total costs for the information integration requirements in this Final Rule are $6.6 million in the first year and $3.3 million annually thereafter.

This Final Rule requires operators to identify and take preventive or mitigative actions that would enhance public safety or environmental protection, based on a risk analysis of the pipeline segment. One preventive or mitigative action involves installing an emergency flow restricting device on the pipeline segment, if determined necessary. We could not estimate the total cost of installing emergency flow restricting devices because we do not know how many operators will install them. Another action involves evaluating leak detection capability and modifying that capability, if necessary. We do not know how many operators currently have leak detection systems or how many systems will be installed or upgraded as a result of this Final Rule. Therefore, we are unable to estimate the total costs of the leak detection requirements.

As a result of this Final Rule, we expect operators will assess more line pipe than they otherwise would assess. Integrity assessment consists of a baseline assessment, to be conducted within 7 years after the effective date of the final rule, and subsequent reassessment at intervals not to exceed every 5 years. We estimate the cost of additional baseline assessments at approximately $377,000 a year, and the cost of additional reassessments at approximately $531,000 a year. Cost impact will be greater in the sixth and seventh years after the effective date of the final rule due to an overlap between baseline inspection and the initial subsequent inspection. The additional costs in these two years are estimated at $5.26 million.

We cannot easily quantify the benefits of this Final Rule, but we can describe them qualitatively. Issuance of this Final Rule ensures that all operators will perform at least to a baseline safety level and will contribute to an overall higher level of safety and environmental performance nationwide.

The Final Rule will lead to greater uniformity in how risk is evaluated and addressed. It will also provide more clarity in discussions by government, industry and the public about safety and environmental issues, and how the issues can be resolved.

Section 195.452 is written using a performance-based approach. This approach has several advantages. First, it encourages development and use of new technologies. Secondly, it supports operators' development of more formal, structured risk-based programs. Thirdly, it supports continual evaluation of the programs by RSPA and state inspectors. And lastly, it provides greater opportunity for operators to customize their long-term maintenance programs.

Section 195.452 has stimulated the pipeline industry to develop its own consensus standard using a risk-based approach to integrity management. The rule has further fostered development of industry-wide technical standards, such as repair criteria to use following an internal inspection.

The Final Rule encourages a balanced program, addressing the range of prevention and mitigation needs and avoiding reliance on any single tool or overemphasis on any single cause of failure. A balanced program will lead to addressing the most significant risks in populated areas, unusually sensitive environmental areas, and commercially navigable waterways, thus improving industry performance in these areas.

The Final Rule requires a verification process that gives RSPA and state inspectors an opportunity to influence the methods of assessment and the interpretation of results. Government monitoring of the adequacy and implementation of this process should expedite the operators' rates of remedial action and reduce the public's exposure to risk.

A particularly significant benefit of this Final Rule involves the information that operators will gather to support decisions. Two essential elements of the integrity management program are the continual assessment and evaluation of pipeline integrity using inspection and testing technology, and the integration and analysis of all available information about the pipeline. The processes of planning, assessment, and evaluation will provide operators with better data to use in determining a pipeline's condition and the location of potential problems that must be addressed. Also, government inspectors will be able to focus on potential risks and consequences that require greater scrutiny and the need for more intensive preventive and mitigation measures.

The public has expressed concern about the danger pipelines may pose to their neighborhoods. The integrity management process leads to greater accountability to the public for both operators and DOT. This accountability is enhanced through our choice of a map-based approach to defining the areas most in need of additional protection—a visual depiction of pipelines in relation to populated areas, unusually sensitive environmental areas, and commercially navigable waterways. The system integrity requirements will assure the public that operators are continually inspecting and evaluating the threats to pipelines that pass through or close to populated areas.

We have not estimated quantitative benefits for the continual integrity management evaluation required by this Final Rule. We do not believe, however, that requiring this comprehensive process, including the reassessment of pipelines every 5 years, will be an undue burden on operators. We believe the added security this assessment will provide and the generally expedited rate of strengthening the pipeline system in high consequence areas are benefit enough to promulgate these requirements.

Laclede commented that we grossly underestimated implementation costs. Laclede notes that our estimate of the cost for all affected operators is $9.64 million, whereas Laclede expects itself to incur costs in excess of $1 million to modify its pipeline. Laclede's estimated costs are to replace piping that can not now be inspected with internal inspection devices. The rule does not require such pipe replacement, and costs for such replacement therefore were not included in the implementation cost estimate. The rule allows use of hydrostatic testing as an alternative to internal inspection. Laclede's replacement of piping to allow passage of internal inspection devices, if undertaken, would be an operational choice based on the company's conclusion that internal inspection would be a better method of assessment than hydrostatic testing. Operators are free to make such operational choices, but they are not required by the rule, and costs associated with pipe replacement are not, therefore, a cost of implementing the rule. We fully considered the costs of hydrostatic testing in the Regulatory Evaluation.

DOE expressed concern that costs associated with shutdown time during assessment or with obtaining permits to conduct repair activities may not have been included in the Regulatory Evaluation. DOE also thought per-mile cost estimates may not be appropriate for operators with only a few miles of pipe. With respect to the impact on small entities, DOE thought the requirements could have an unreasonable impact in some cases.

The values we used to estimate costs for internal inspection and hydrostatic testing were based on detailed studies of both methods that considered all relevant costs. The outcome of those studies are per-mile estimates for conducting assessments. We recognize that costs may be higher for operators that have only a few miles of pipeline, and for whom "fixed" costs of assessment would be amortized over just a few miles. However, we are unable to estimate how many operators may be so affected. Many of the operators subject to this Final Rule are parts of larger companies, as described further in response to Small Business Administration comments, and should not be so affected. We will work with operators who may be unusually impacted, each of whom may request a waiver from particular requirements.

While costs for permitting associated with conducting assessments were included, permitting costs associated with repairs were not estimated. No repair costs were included in the Regulatory Evaluation. This rule does impose time limits on the repair of certain types of defects. Generally, however, repair of conditions that could adversely affect the safe operation of a pipeline is already required by 49 CFR 195.401 and so is not a new requirement in this rule.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), we must consider whether a rulemaking would have a significant impact on a substantial number of small entities. This Final Rule covers only those operators that own or operate less than 500 miles of regulated pipeline. Because of this limitation, only 132 hazardous liquid pipeline operators, covering 13.3 percent of regulated hazardous liquid pipelines, are covered by the Final Rule.

The risks of operating pipelines are similar regardless of the size of the operating company. Accordingly, the need to protect against those risks is also similar, regardless of operator size. We agree with WUTC's comment that "[t]he integrity of the hazardous liquid infrastructure that runs beneath our nation's cities, and crosses our public and private lands, should not be treated differently depending on the amount of pipeline owned or operated by pipeline companies."

We established an artificial cutoff criterion of 500 miles specifically so that we could review further the potential impact and safety needs of smaller operators to see if different treatment was needed. We completed our review and concluded that different treatment was not needed. By this Final Rule, we are establishing the same integrity management requirements for operators with less than 500 miles of pipelines as we established previously for operators with more pipeline mileage. Extending the existing requirements to the remaining operators of regulated pipelines is necessary to ensure the integrity of pipelines which could, if damaged or ruptured, cause significant injury to public safety and the environment.

We preliminarily concluded that there is no disproportionate impact on small businesses, principally because the risks are the same. We examined the companies that operate less than 500 miles of pipelines. A few of these operators are "small businesses" (less than 1500 employees, the Small Business Administration's criterion for defining a small business in the hazardous liquid pipeline industry.) The majority, however, is not. The majority includes larger companies or divisions or subsidiaries of very large national and multi-national companies.

We estimate that 132 operators are potentially subject to the requirements of this Final Rule, because that is the number of operators who paid user fees on less than 500 miles of pipeline in the last fiscal year. This number is a conservative upper bound. Some of these operators are not, in fact, affected by this rulemaking. As noted above, many are divisions or subsidiaries of larger companies. In many cases, the parent companies have other divisions or subsidiaries that operate pipelines and, when all are considered, own or operate more than 500 miles of such pipeline. Those companies, including all their divisions and subsidiaries which may, themselves, operate less than 500 miles of pipeline, are covered by existing § 195.452 and not by this Final Rule. In addition, this Final Rule only covers pipeline segments that could affect a high consequence area. It is possible that some operators, particularly those with only a few miles of pipe, may not operate any segments that could affect such areas. If so, those operators would not be covered by this Final Rule. Nevertheless, we continue to estimate costs on the basis of 132 covered companies, in order to provide a conservative estimate.

SBA thought the NPRM's discussion of the Regulatory Flexibility Act was inadequate. The discussion did not include background and basis information that was in the previous rulemaking applicable to operators with 500 or more miles of regulated pipeline. However, in the present document we have improved our discussion of Regulatory Flexibility Act issues to describe more clearly the basis for concluding that this Final Rule does not disproportionately affect small businesses. SBA's comments are also discussed in detail in the final Regulatory Evaluation, included in the docket.

Therefore, based on the facts available about the anticipated impacts of this rulemaking, I certify, pursuant to section 605 of the Regulatory Flexibility Act (5 U.S.C. 605), that this Final Rule will not have a significant impact on a substantial number of small entities.

Paperwork Reduction Act

This Final Rule contains information collection requirements. As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), we have submitted a copy of the Paperwork Reduction Act Analysis to the OMB for review. The name of the information collection is "Pipeline Integrity Management in High Consequence Areas for Operators with less than 500 miles of pipeline." The purpose of this information collection is designed to require operators of pipelines to develop a program to provide direct integrity testing and evaluation of pipelines in high consequence areas.

No comment submitted in response to the NPRM addressed the information collection requirements.

One hundred and thirty-two operators of hazardous liquid pipelines will be potentially subject to this Final Rule. We estimate that those operators will have to develop integrity management programs taking approximately 2,800 hours per program. Each of the operators will also have to devote 1,000 hours in the first year to integrate data into current management information systems.

Additionally, under this Final Rule, operators will have to update their integrity management programs on a continual basis. We estimate updates will take approximately 330 hours per program, annually. An additional 500 hours per operator is estimated for the requirement to annually integrate data into the operator's current management information systems.

Under the Final Rule, operators may use either hydrostatic testing or an internal inspection tool as a method to assess their pipelines. However, operators may use another technology if they can demonstrate it provides an equivalent understanding of the condition of the line pipe as the other two assessment methods. Operators have to provide RSPA 90-days notice (by mail or facsimile) before using the other technology. We believe that few operators will choose this option. If they do choose an alternative technology, notice preparation should take approximately 1 hour. Because we believe few if any operators will elect to use other technologies, the burden was considered minimal and therefore not calculated.

Additionally, the Final Rule allows operators in particular situations to vary from the 5-year continual reassessment interval or repair schedule if they can provide the necessary justification and supporting documentation. Advance notice would have to be provided to RSPA if an operator does so. The advance notification can be in the form of letter or fax. We believe the burden of a letter or fax is minimal and therefore did not add it to the overall burden hours discussed above.

Organizations and individuals desiring to submit comments on the information collection should direct them to: The Office of Management and Budget, Office of Information and Regulatory Affairs, ATTN: RSPA Desk Officer, 727 Jackson Place, NW, Washington, DC 20503. Please provide the docket number of this action. Comments must be sent within 30 days of the publication of this Final Rule.

OMB is specifically interested in the following issues concerning the information collection:

1. Evaluating whether the collection is necessary for the proper performance of the functions of DOT, including whether the information would have a practical use;

2. Evaluating the accuracy of DOT's estimate of the burden of the collection of information, including the validity of assumptions used;

3. Enhancing the quality, usefulness and clarity of the information to be collected; and minimizing the burden of collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology; *e.g.*, permitting electronic submission of responses.

According to the Paperwork Reduction Act of 1995, no persons are required to respond to a collection of information unless a valid OMB control number is displayed. The OMB control number for this information collection is 2137–0605.

Executive Order 13084

This Final Rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13084 ("Consultation and Coordination with Indian Tribal Governments"). Because this proposed rule does not significantly or uniquely affect the communities of the Indian tribal governments and does not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Executive Order 13132

This Final Rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13132 ("Federalism"). This Final Rule does not adopt any regulation that: (1) Has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government; (2) imposes substantial direct compliance costs on state and local governments; or (3) preempts state law. Therefore, the consultation and funding requirements of Executive Order 13132 (64 FR 43255, Aug. 10, 1999) do not apply. In a public meeting we held on November 18–19, 1999, we invited the National Association of Pipeline Safety Representatives (NAPSR), which includes State pipeline safety regulators, to participate in a general discussion on pipeline integrity. Again in January, and February 2000, we held conference calls with NAPSR, to receive its input before proposing an integrity management rule.

Impact on Business Processes and Computer Systems

We do not want to impose new requirements that would mandate business process changes when the resources necessary to implement those requirements would otherwise be applied to "Y2K" or related computer problems. This Final Rule does not mandate business process changes or require modifications to computer systems. Because the final rules will not affect the ability of organizations to respond to those problems, we are not delaying the effectiveness of the requirements.

Unfunded Mandates Reform Act of 1995

This Final Rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of $100 million or more to either state, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the NPRM.

National Environmental Policy Act

We have analyzed the Final Rule in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR parts 1500–1508), and DOT Order 5610.1D. We have determined that this action will not significantly affect the quality of the human environment.

The Environmental Assessment (available in the Docket) determined that the combined impacts of the initial baseline assessment (pressure testing or internal inspection), the subsequent periodic assessments, and additional preventive and mitigative measures that may be implemented to protect high consequence areas will result in positive environmental impacts. The number of incidents and the environmental damage from failures in and near high consequence areas are likely to be reduced. However, from a national perspective, the impact is not expected to be significant for the pipeline operators covered by the Final Rule. The following discussion summarizes the analysis provided in the Environmental Assessment.

Many operators covered by the Final Rule (those operating less than 500 miles of regulated pipeline) already have internal inspection and pressure testing programs that cover most, if not all, of their pipeline systems. These operators typically place a high priority on the pipeline's proximity to populated areas, commercially navigable waterways, and environmental resources when making decisions about where and when to inspect and test pipelines. As a result, some high consequence areas have already been recently assessed, and a large fraction of remaining locations would probably have been assessed in the next several years without the Final Rule. The most tangible impact will be to ensure assessments are performed for those line segments that could affect a high consequence area that are not currently being internally inspected or pressure tested, and ensuring that integrity is maintained through an integrity management program that requires periodic assessments in these locations. Because hazardous liquid pipeline failure rates are low, and because the total pipeline mileage operated by operators with less than 500 miles of pipeline that could affect high consequence areas is small, the Final Rule has only a small effect on the likelihood of pipeline failure in these locations.

The Final Rule will result in more frequent integrity assessments of line segments that could affect high consequence areas than most operators are currently conducting (due to the 5-year interval required for periodic assessment). However, if the operator identifies and repairs significant problems discovered during the baseline inspection, and has in place solid risk controls to prevent corrosion and other threats, as they must, the benefits of assessing every 5 years versus the longer intervals operators more typically employ are not expected to be significant.

The Final Rule requires operators to conduct an integrated evaluation of all potential threats to pipeline integrity, and to consider and take preventive or mitigative risk control measures to provide enhanced protection. If there is a vulnerability to a particular failure cause, like third-party damage, these evaluations should identify additional risk controls to address these threats. Some operators covered by the Final Rule already perform integrity evaluations or formal risk assessments that consider the environmental sensitivity and impacts on population. These evaluations have already led to additional risk controls beyond existing requirements to improve protection for these locations. For these operators, it is expected that additional risk controls will be limited and customized to site-specific conditions that the operator may not have previously recognized.

Finally, an important, although less tangible, benefit of the Final Rule will be to establish requirements for operator integrity management programs that assure a more comprehensive and integrated evaluation of pipeline system integrity in high consequence areas. In effect, this will codify and bring an appropriate level of uniformity to the integrity management programs some operators are currently implementing. It will also require operators who have limited, or no, integrity management programs to raise their level of performance.

We expect this Final Rule to provide a more consistent, and overall, a higher level of protection for high consequence areas across the nation. Even though there is a benefit, we have concluded that it is not significant, and, therefore, have issued a finding of no significant impact.

Executive Order 13211

This rulemaking is not a "Significant energy action" under Executive Order 13211. It is not a significant regulatory action under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, this rulemaking has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

List of Subjects in 49 CFR Part 195

Carbon dioxide, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, we are amending 49 CFR part 195 as follows:

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

1. The authority citation for part 195 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60118; and 49 CFR 1.53.

Subpart F—Operation and Maintenance

2. In § 195.452, paragraphs (a), (b), (d) heading, (d)(1), and (d)(2) are revised and paragraph (d) introductory text is added to read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

(a) *Which pipelines are covered by this section?* This section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. (Appendix C of this part provides guidance on determining if a pipeline could affect a high consequence area.) Covered pipelines are categorized as follows:

(1) Category 1 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to this part.

(2) Category 2 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to this part.

(3) Category 3 includes pipelines constructed or converted after May 29, 2001.

(b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:

(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1	March 31, 2002.
Category 2	February 18, 2003.
Category 3	1 year after the date the pipeline begins operation.

(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1	December 31, 2001.
Category 2	November 18, 2002.
Category 3	Date the pipeline begins operation.

(3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.

(4) Include in the program a framework that—

(i) Addresses each element of the integrity management program under paragraph (f) of this section, including continual integrity assessment and evaluation under paragraph (j) of this section; and

(ii) Initially indicates how decisions will be made to implement each element.

(5) Implement and follow the program.

(6) Follow recognized industry practices in carrying out this section, unless—

(i) This section specifies otherwise; or

(ii) The operator demonstrates that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection.

* * * * *

(d) *When must operators complete baseline assessments?* Operators must complete baseline assessments as follows:

(1) *Time periods.* Complete assessments before the following deadlines:

If the pipeline is:	Then complete baseline assessments not later than the following date according to a schedule that prioritizes assessments:	And assess at least 50 percent of the line pipe on an expedited basis, beginning with the highest risk pipe, not later than:
Category 1	March 31, 2008	September 30, 2004.
Category 2	February 17, 2009	August 16, 2005.
Category 3	Date the pipeline begins operation	Not applicable.

(2) *Prior assessment.* To satisfy the requirements of paragraph (c)(1)(i) of this section for pipelines in the first column of the following table, operators may use integrity assessments conducted after the date in the second column, if the integrity assessment method complies with this section. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to paragraph (j)(3) of this section. The table follows:

Pipeline	Date
Category 1	January 1, 1996.
Category 2	December 18, 2006

* * * * *

Issued in Washington, DC, on January 8, 2002.

Ellen G. Engleman,

Administrator.

[FR Doc. 02–858 Filed 1–15–02; 8:45 am]

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2. Bulk product piping that is in contact with the soil shall have secondary containment.

3. Remote fill piping that is in contact with the soil shall have secondary containment.

4. The following integral piping systems are exempt from the requirements for secondary containment:

a. Integral piping that is in contact with the soil, and that is connected to storage tanks containing high viscosity regulated substances; and

b. Vertical fill pipes equipped with a drop tube.

Specific Authority 376.303 FS.
Law Implemented 376.303 FS.
History--New 12-10-90, Amended 5-4-92, Formerly 17-761.500, Amended 9-30-96, 7-13-98.

62-761.510 Performance Standards for Category-A and Category-B Storage Tank Systems.

(1) General. This section provides deadlines for Category-A and Category-B storage tank systems to meet the standards for Category-C storage tank systems in accordance with Rule 62-761.500, F.A.C.

(a) Installation:

1. Installation shall be completed by the deadlines specified in Table UST and Table AST. However, if installation or upgrade activities are initiated before the deadlines, work can continue after the deadlines, provided that all work is completed within 90 days of:

a. Contract execution; or

b. Receipt of construction approval or permits.

2. Installation is considered to have begun if:

a. All federal, state, and local approvals or permits have been obtained or applied for to begin physical construction for installation of the system; or

b. Contractual obligations have been made for installation of the system which cannot be canceled or modified without substantial economic loss, provided that such obligations are pursued diligently in good faith to achieve the requirements of this rule.

(b) By December 31, 1998:

1. All pressurized small diameter piping systems connected to dispensers shall have shear valves or emergency shutoff valves installed in accordance with Rule 62-761.500(4)(c), F.A.C.

2. Cathodic protection test stations shall be installed in accordance with Rule 62-761.500(1)(f)1. and (2)(b)2. F.A.C., for cathodically protected UST or AST systems without test stations.

3. Fillboxes shall be color coded in accordance with Rule 62-761.500(2)(d)1., F.A.C.

4. ASTs that have been reinstalled as USTs, and USTs that have been reinstalled as ASTs, shall meet the requirements of Rule 62-761.500, F.A.C.

(c) After July 13, 1998, a closure assessment shall be performed in accordance with Rule 62-761.800(4), F.A.C., before the installation of dispenser liners, piping sumps, or secondary containment of tanks and integral piping.

(d) Valves meeting the requirements of Section 2-1.7 of NFPA 30A, shall be installed by January 13, 1999 on any storage tank system located at an elevation that produces a gravity head on the dispenser or on small diameter piping.

(e) Small diameter piping transporting regulated substances over surface waters of the state shall have secondary containment by December 31, 2004.

(2) Underground storage tank systems.

(a) UST Category-A single-walled tanks or underground single-walled piping shall be considered to be protected from corrosion if the tank or piping was constructed with corrosion resistant materials, initially installed with cathodic protection, or had cathodic protection or internal lining installed before June 30, 1992.

(b) UST Category-B systems.

1. All tanks containing pollutants, installed or constructed at a facility after June 30, 1992, shall have secondary containment.

2. All tanks containing hazardous substances, installed or constructed at a facility after January 1, 1991, shall have secondary containment.

(c) Small diameter integral piping in contact with the soil that is connected to UST systems shall have secondary containment if installed after December 10, 1990.

(d) By December 31 of the appropriate year shown in Table UST below, all storage tank systems shall meet the performance standards of Rule 62-761.500, F.A.C., or be permanently closed in accordance with Rule 62-761.800(3), F.A.C.

TABLE UST

Year Tank or Integral Piping Installed	1989	1992	1995	1998	2004	2009
+Before 1970	O	B		ACFL	D	E
+1970 - 1975		SBL		ACF	D	E
+I976 - 1980		B	SL	ACF	D	E
+1981 - 09/01/84		B		ACFL	D	E
+09/02/84 – 06/30/92		B		ACFL	D	E
+Other*		B		ACFL	D	E

Key to Table UST

* = All systems with a capacity between 110 gallons and 550 gallons, all marine fueling facilities as defined in Section 376.031, F.S., and those systems of greater than 550 gallon capacity that use less than 1,000 gallons per month or 10,000 gallons per year.

A =

(1) Small diameter piping that was protected from corrosion by June 30, 1992, shall have:

(a) For pressurized piping, line leak detectors with automatic shutoff, or flow restriction in accordance with Rule 62-761.640(3)(d), F.A.C.; or

(b) For suction integral piping:

1. Secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C.;

2. A single check valve installed in accordance with Rule 62-761.610(4)(a)3., F.A.C.;

3. An annual line tightness test in accordance with Rule 62-761.610(4)(a)1., F.A.C.; or

4. External monthly monitoring or release detection in accordance with Rule 62-761.610(4)(a)1.b., F.A.C.

(2) Bulk product piping in contact with soil shall be upgraded with secondary containment unless the piping is:

(a) Constructed of corrosion resistant materials or upgraded with cathodic protection; and

(b) Tested on an annual basis in accordance with API RP 1110, ASME B31.4, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C.

B = Vehicular fuel petroleum storage tank systems shall be upgraded with spill containment.

C = Secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C., shall be required for the following:

(1) Concrete storage tanks;

(2) Hazardous substance storage tank systems; and

(3) For pollutant storage tank systems, the storage tank or small diameter piping not protected from corrosion by June 30, 1992.

D = (1) Secondary containment shall be installed for small diameter piping extending over surface waters.

(2) Secondary containment for remote fill-pipes associated with Category-A and Category-B systems.

E = Pollutant storage tanks and small diameter piping protected from corrosion on or before June 30, 1992, and all manifolded piping, shall be upgraded with secondary containment.

F =

(1) Storage tank systems, excluding vehicular fuel petroleum storage tank systems, shall be upgraded with spill containment, dispenser liners (as applicable), and overfill protection.

(2) Unless contained within secondary containment, swing-joints and flex-connectors that are not protected from corrosion shall be protected from corrosion. Facilities that have pressurized small diameter piping and that have not met the foregoing standard on or before July 13, 1998 shall protect the submersible turbine pump from corrosion or provide corrosion protection for the submersible turbine pump if the pump is not installed within secondary containment. Corrosion protection is not required for the submersible turbine pump riser.

L =

(1) Category-A USTs and their integral piping systems that contain vehicular fuel, and that are not protected from corrosion, shall have secondary containment, or be upgraded with secondary containment in accordance with Rule 62-761.500, F.A.C.

(2) Dispenser liners and overfill protection equipment shall be installed at UST Category-A systems containing vehicular fuel.

O = UST Category-A vehicular fuel storage tank systems subject to Chapter 17-61, F.A.C.,(1984), shall be retrofitted for corrosion protection.

S = Secondary containment for storage tanks and integral piping not protected from corrosion.

(3) Aboveground storage tank systems.

(a) All storage tank systems with tanks having capacities greater than 550 gallons that contain vehicular fuel and that were subject to Chapter 17-61, F.A.C., shall have met the requirements of such chapter by January 1, 1990.

(b) AST Category-B tanks, with the exception of tanks exempt under Rule 62-761.500(3)(c)1., F.A.C., installed or constructed at a facility after March 12, 1991, shall have secondary containment for the tank.

(c) Integral piping that is in contact with the soil and that is connected to AST systems shall have secondary containment if installed after March 12, 1991. For integral piping that is exempt under Rule 62-761.500(4)(e)4., F.A.C., it is not required to install secondary containment.

(d) By January 1 of the appropriate year shown in Table AST below, unless specified otherwise, all AST Category-A and Category-B storage tank systems shall meet the following requirements or be permanently closed in accordance with Rule 62-761.800(3), F.A.C.

TABLE AST

Year Tank or Integral Piping Installed	1993	2000	2005	2010
+Before July 13, 1998	P	TVX	W	U

Key to Table AST

P = With the exception of high viscosity bulk product piping, bulk product piping in contact with soil and not in secondary containment shall be tested in accordance with API RP 1110, ASME B31.4, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C. Such testing shall be performed annually thereafter.

T =

(1) With the exception of siting and material construction standards, Category-A and Category-B systems shall meet the performance standards of Rule 62-761.500, F.A.C. In addition:

(a) Storage tank system construction standards that include cathodic protection remain applicable; and

(b) Storage tanks where the entire bottom of the tank is in contact with concrete do not have to seal the concrete beneath the tank until such time that the tank bottom is replaced. However, concrete secondary containment systems designed in accordance with Rule 62-761.500(1)(e)3., F.A.C., do not have to be sealed.

(2) Category-A bulk product piping in contact with the soil shall be upgraded with secondary containment, unless:

(a) A structural evaluation is performed in accordance with API 570, as specified in "U" (2)(b), of Table AST, and results of the structural evaluation indicate that the bulk product piping has remaining useful life; or

(b) The integral piping conveys high viscosity regulated substances, that are exempt from secondary containment in accordance with Rule 62-761.500(4)(e) 4., F.A.C.; or

(c) The integral piping is protected from corrosion and is tested annually in accordance with ASME B31.4, API 1110, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C. This piping shall have secondary containment by January 1, 2010, in accordance with "U" of Table AST.

(3) Initial internal and external inspections, examinations, and tests for each tank shall be performed in accordance with API Standard 653, and an appropriate reinspection interval for each tank shall be established in accordance with API Standard 653. If any deficiency is discovered during the inspections, the person performing the evaluation of the tank in accordance with API 653 must verify that the tank is ready for service before the storage tank is put back into service. This verification must be documented in the internal inspection records. Future tests for each tank shall be performed in accordance with the inspection interval established in accordance with API 653 (1996). Baseline inspections already conducted according to the API Standard 653 (1991) will be accepted.

(4) As an alternative to installing secondary containment underneath an AST Category-A or Category-B storage tank, the interior bottom of the tank and at least 18 inches up the sides may be internally lined in accordance with API RP 652. Secondary containment must nonetheless be installed in the dike field area and be continuously bonded to the perimeter of the tank foundation.

U =

(1) All internally lined single bottom storage tanks, with the exception of tanks exempt under Rule 62-761.500(3)(c)1., F.A.C., shall be upgraded with secondary containment.

(2) All AST Category-A bulk product piping in contact with the soil , except for piping exempt from secondary containment requirements under Rule 62-761.500(4)(e)4. F.A.C., shall be:

(a) Upgraded with secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C.; or

(b) Instead of being upgraded with secondary containment, be evaluated for structural integrity by:

1. Establishing and maintaining the piping inspection intervals in accordance with API 570, Section 4-2, by January 1, 2000;

2. Determining the remaining life of the system in accordance with API 570, Section 5.0, by January 1, 2000. If the determination indicates that the piping:

a. Must be repaired, then the piping shall be repaired within three months of the determination in accordance with API 570 and Rule 62-761.700, F.A.C.;

b. Is leaking, then the piping must be immediately taken out of operation. If the piping cannot be repaired, it must be closed or upgraded with secondary containment within one year of the determination;

c. Is not leaking, but has corroded to a point where it no longer has structural integrity, then the piping shall be closed, or upgraded with secondary containment by January 1, 2000; or

d. Has remaining useful life, then the piping shall be closed or upgraded with secondary containment when the API 570 inspection and remaining life determination data indicates that closure or replacement is necessary.

3. Providing a certification by a professional engineer registered in the State of Florida that the evaluation meets the above criteria.

V =

(1) Secondary containment for cut and cover or concrete storage tanks.

(2) Spill containment in accordance with Rule 62-761.500(1)(c), F.A.C.

(3) Dispenser liners for shop-fabricated tanks in accordance with Rule 62-761.500(3)(e), F.A.C.

(4) Secondary containment in accordance with Rule 62-761.500(1)(e) and (3)(c), F.A.C., for dike field areas of facilities with shop-fabricated tanks having dike field area secondary containment that is constructed of concrete or installed with synthetic liners not meeting these requirements.

W =

(1) Secondary containment in accordance with Rule 62-761.500(1)(e) and (3)(c), F.A.C., for dike field areas of facilities with field-erected tanks having dike field area secondary containment that is constructed of concrete or installed with synthetic liners not meeting these requirements.

(2) Secondary containment for small diameter piping extending over surface waters.

(3) Secondary containment for small diameter petroleum contact water piping in contact with the soil.

X = Deadline to determine integrity of single wall bulk product piping with an API 570 structural integrity evaluation in accordance with the option for Category-A systems in "U" of Table AST.

Specific Authority 376.303 FS. Law Implemented 376.303-376.3072 FS. History--New 12-10-90, Amended 5-4-92, Formerly 17-761.510, Amended 9-30-96, 07-13-98.