FPL.

L-2014-102
10 CFR 52.3

April 22, 2014

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555-0001

Re: Florida Power & Light Company
Proposed Turkey Point Units 6 and 7
Docket Nos. 52-040 and 52-041
Supplemental Response to NRC Request for Additional Information Letter No. 72
(eRAI 6985) SRP Section 11.02 - Liquid Waste Management Systems

Reference:

FPL Letter L-2013-216 to NRC dated August 9, 2013, Response to Request for Additional Information Letter No. 72 (eRAI 6985) SRP Section 11.02 - Liquid Waste Management Systems

Florida Power & Light Company (FPL) provides, as attachments to this letter, its supplemental response to NRC RAI No. 11.02-6-5 through 11.02-6-11 (eRAI 6985) provided in the referenced letter. The clarifications to the referenced response are indicated by revision bars in the attachments. The attachments identify changes that will be made in a future revision of the Turkey Point Units 6 and 7 Combined License Application (if applicable).

If you have any questions, or need additional information, please contact me at 561-691-7490.

D097
NRO

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 22, 2014.

Sincerely,

William Maher
Senior Licensing Director – New Nuclear Projects

WDM/RFO

Attachment 1: FPL Supplemental Response to NRC RAI No. 11.02-6-5 (eRAI 6985)
Attachment 2: FPL Supplemental Response to NRC RAI No. 11.02-6-6 (eRAI 6985)
Attachment 3: FPL Supplemental Response to NRC RAI No. 11.02-6-7 (eRAI 6985)
Attachment 4: FPL Supplemental Response to NRC RAI No. 11.02-6-8 (eRAI 6985)
Attachment 5: FPL Supplemental Response to NRC RAI No. 11.02-6-9 (eRAI 6985)
Attachment 6: FPL Supplemental Response to NRC RAI No. 11.02-6-10 (eRAI 6985)
Attachment 7: FPL Supplemental Response to NRC RAI No. 11.02-6-11 (eRAI 6985)

cc:
PTN 6 & 7 Project Manager, AP1000 Projects Branch 1, USNRC DNRL/NRO
Regional Administrator, Region II, USNRC
Senior Resident Inspector, USNRC, Turkey Point Plant 3 & 4

NRC RAI Letter No. PTN-RAI-LTR-072 Dated February 20, 2013

SRP Section: 11.02 – Liquid Waste Management System

Supplemental Staff RAI to RAI 11.02-1, 11.02-2, 11.02-3, and 11.02-4.

NRC RAI Number: 11.02-6-5 (eRAI 6985)

[The preamble to this RAI is italicized below.]

In FSAR Rev. 4, Section 11.2.3.5, PTN COL 11.2-2, the applicant proposes a disposal method for liquid radioactive effluents using deep well injection into the Boulder Zone. When compared to routine effluent discharges in surface waters, the radioactivity injected in the Boulder Zone is expected to be isolated from the surface environment and out of reach of traditional radiation exposure scenarios and pathways considered by NRC regulations and guidance. Traditional effluent discharge methods dilute and disperse the radioactivity in the environment, but this disposal method confines the radioactivity into a slow moving and expanding plume with the total inventory of long-lived radionuclides increasing over the operating life of the plant. As a result, radiological assessment methods and assumed exposure scenarios used to quantify radiological impacts and compliance with NRC regulations for effluents discharged in surface water bodies are not directly applicable.

The deep well injection method involves technical and regulatory considerations that are not explicitly addressed under 10 CFR 50.34a, and 50.36a, and 10 CFR Part 50, Appendix I design objectives and ALARA provisions in controlling radioactive effluent releases. Similarly, the requirements of 10 CFR 20.1301 and 20.1302 and 40 CFR Part 190 [under Part 20.1301(e)] in complying with effluent concentration limits and doses to members of the public also do not explicitly address deep well injection. However, the applicant must still meet applicable requirements under these regulations in applying the deep well injection method for waste disposal.

Accordingly, the applicant has performed and provided an analysis in its current application under the provisions of 10 CFR 20.2002, "Method for obtaining approval of proposed disposal procedures." However, the results are presented in a manner that excludes a demonstration of compliance with some NRC requirements and associated guidance on the assumption that the discharge method offers complete isolation of the radioactivity with no radiation exposures to the public. The applicant has not included information sufficient to determine if it meets the requirements of 10 CFR 20.1301, 10 CFR 20.1302, and 10 CFR 20.1406; and numerical

guides, design objectives, and ALARA provisions of 10 CFR Part 50, Appendix I for liquid effluents.

10 CFR 20.2002 provides an applicant with a method to obtain approval for proposed procedures, not otherwise authorized in the regulations, for disposal of licensed material generated in the licensee's activities. Under 10 CFR Part 20.2002, an applicant has to provide (a) a description of the waste, including the chemical and physical properties important to risk evaluation and the proposed manner and conditions of disposal; (b) an analysis of the environment in which wastes will be disposed; (c) the nature and location of other potentially affected licensed and unlicensed facilities; and (d) analyses and procedures to ensure that doses are maintained ALARA and within the dose limits of 10 CFR Part 20. The NRC typically approves Part 20.2002 requests that will result in a dose to a member of the public (including all exposure groups) that is no more than "a few millirem/year" (see SECY-07-0060, Attachment 1, and NUREG-1757, Vol. 1, Rev. 2, Section 15.12). As is noted in the SECY paper, the NRC selected this criterion because it is a fraction of the dose associated with naturally occurring background radiation, a fraction of the annual public dose limit, and an attainable objective in the majority of cases.

In this context, the staff considers its well-established Part 50 light-water-reactor criteria (including those prescribed by Appendix I) in determining whether all releases of radioactive material to the environment are ALARA and what monitoring, design criteria, and other conditions apply. As a result, the staff's evaluation of this disposal method under Part 20.2002 does not preclude the staff from considering the substantial technical requirements, design criteria, technical specifications, monitoring, and annual reporting called for by other provisions of Part 20 and Part 50.

Moreover, the staff notes that there is a need to ensure that NRC and Florida Department of Environmental Protection (FLDEP) requirements, when issued, are not conflicting and do not impose duplicative requirements, such as for radiological monitoring, periodic inspections and testing in confirming the mechanical integrity of the injection and monitoring wells, and requirements for well abandonment and closure at the end of their operational cycles or in the event of well failures and migration of radioactive materials in Upper Floridan aquifers. As a result, there are a number of issues that the staff needs to consider in bridging and integrating these regulatory requirements and NRC acceptance criteria. The issues involve the resolution of geo-hydrological characteristics of the Boulder Zone; use of information described in the construction and testing of the first exploratory and monitoring wells (see FPL reports of Sept. 2012); development of an appropriate radioactive source term confined within an amorphous

plume; development of an approach and method for modeling potential exposure scenarios that consider well failures and intrusion scenarios as expected operational occurrences using current land-use practices for this part of Florida; identification of surrogate criteria in achieving the same regulatory objectives since some of current regulatory requirements do not apply to this disposal method; identification of FLDEP permit conditions that would fulfill or supplement NRC requirements on installation, testing, operation, and environmental monitoring; and insertion of specific license conditions on the design features of injection and monitoring wells whose construction would not be completed before the issuance of the combined license.

RAI Questions on Proposed Deep Well Injection Disposal Method

The information provided in FSAR Rev. 4, Sections 9.2, 10.4.5, and 11.2 and responses to staff RAIs presented in FPL correspondence (May 22, 2012 and July 13, 2012) are not sufficient for the staff to validate and verify the estimated doses of the assumed exposure doses in the FSAR are bounding and acceptable. Without this information, the staff is unable to make a determination that the applicant meets the acceptance criteria in SRP 11.2 and complies with the requirements of 10 CFR 20.2002, 20.1301, 20.1302, and 20.1406, and 10 CFR Part 50, Appendix I numerical guides, design objectives, and ALARA provisions. This supplemental RAI on the proposed deep well injection method consolidates and subsumes the issues identified in prior staff RAIs. As a result, the following RAIs are closed: RAI 11.02-1, 11.02-2, 11.02-3, and 11.02-4.

<u>Question 5</u>

Since the deep well injection system will involve the use of 12 injection wells in relatively close proximity, the applicant is requested to address (1) a rise in pressure given the combined operation of multiple wells, and (2) potential fractures and formation of hydraulic connections, followed by upwelling into the above confining units. Regarding possible failures of well casings, the applicant is requested to describe design features of well casings and joints, and measures that will be implemented in ensuring the mechanical integrity of the injection and monitoring wells over their operational lives. In this context, the applicant is requested to describe plant operations and procedures should any upwelling or failures of the injection system be noted, and whether interim provisions will be made to use backup systems in disposing or storing of radioactive liquid effluents. The applicant should also describe well abandonment procedures, if needed during the lifetime of the license, including steps to confirm the mechanical condition of the wells, and methods and materials that would be used to plug and seal wells.

FPL RESPONSE:

Potential for Pressure Rise and/or Upwelling due to Deep Well Injection System

~~A formation test performed on exploratory well EW-1 demonstrated an average increase in formation pressure of 3 pounds per square inch (psi) at the point of injection at an average injection flow rate of 1,625 gallons per minute (gpm). The maximum anticipated injection rate for the full scale deep injection wells is approximately 7,000 gpm (per well). This rate is approximately 4.3 times the rate at which the EW-1 formation test was performed. Therefore, an increase in formation pressure of approximately 13 psi (3 psi x 4.3) can be anticipated for each deep injection well at a maximum injection flow rate of 7,000 gpm per well. Assuming the following operational parameters:~~

- ~~All 12 injection wells are operating concurrently at a rate of 7,000 gpm, and~~
- ~~there is no dissipation of the increased formation pressure between operating injection wells (a very conservative assumption due to the high transmissivity of the Boulder Zone), and~~
- ~~the cumulative formation pressure is additive for each well,~~

~~results in an anticipated formation pressure increase of approximately 156 psi due to the deep well injection system operation (13 psi x 12 injection wells operating at 7,000 gpm). Note that these are conservative assumptions since it is not anticipated that all 12 injection wells will operate simultaneously.~~

~~The Ghyben-Herzberg principle, which states that freshwater is 1/40^th^ less dense than saltwater (1.00 grams/cm³ versus 1.025 grams/cm³) is used to determine the buoyant force of freshwater in the Boulder Zone. The native water within the Boulder Zone is similar to seawater. While the fluid that will be injected into the deep injection wells under normal operating conditions will have a slightly higher specific gravity than freshwater, the specific gravity of freshwater will be used in this buoyant force calculation. Assuming a 200 foot thickness of the Boulder Zone filled with freshwater, the buoyant force that will be generated will be 5 feet of head (200 feet/40) or approximately 2 psi (5 feet of head/2.31 feet per psi). Therefore, the total pressure increase in the Boulder Zone due to pressure and buoyant forces is approximately 158 psi (156 psi + 2 psi).~~

~~Potential for confining unit fracture and subsequent vertical migration of injected fluid can occur when formation injection pressures, combined with buoyant forces, surpass the mechanical strength of the formation. An equation developed by Hubbert and Willis (Reference 1) is used to predict the minimum bottom hole pressure that could potentially propagate hydraulic fracturing of the formation. The equation is:~~

$$\cancel{p_i = (S_z + 2P_\theta)/3}$$

~~where~~

~~p_i = hydraulic fracturing gradient in psi/foot~~
~~S_z = total lithostatic stress in psi/foot~~
~~P_e = formation fluid pressure in psi/foot~~

~~Utilizing values of 1.0 and 0.46 psi/foot for S_z and P_e, respectively, (representing the theoretical vertical lithostatic and hydrostatic gradients derived from the respective densities of rock and water), a minimum fracture initiation gradient of 0.64 psi/foot is calculated as shown below:~~

$$\cancel{p_i = (1.0 + 2 \times 0.46)/3 = 0.64 \text{ psi/foot}}$$

~~This scenario assumes minimal lateral earth stress. If a depth of 2985 feet below grade (the assumed base of the final casing) is assumed, a pressure of approximately 1910 psi is calculated to represent the minimum bottom-hole pressure that may create hydraulic fracturing, although this is not reasonably expected to occur, using the calculated fracture initiation gradient of 0.64 psi/foot. This pressure is approximately 12 times greater than the previously calculated maximum formation pressure of approximately 158 psi when each of the deep injection wells is operating at the maximum anticipated injection rate of 7000 gpm. Additionally, the calculated minimum bottom-hole pressure that may create hydraulic fracturing at the top of the confining unit is 1,235 psi (0.64 psi/foot x 1,930 feet = 1,235 psi), which is approximately 7.8 times greater than the previously calculated maximum formation pressure of approximately 158 psi. The increase in bottom-hole pressure will be well below the minimum bottom-hole pressure that may create hydraulic fracturing and fracturing will, therefore not be induced.~~

A short-term injection test was performed on deep injection well DIW-1 from February 17, 2014 through February 21, 2014. After the well injection tubing was filled with non-hazardous industrial wastewater from the FPL Turkey Point Unit 5 cooling tower basin (original source Upper Floridan Aquifer) with a measured total dissolved solids value of 3600 mg/L, the down hole formation pressure, ranged from 1327.3 to 1327.8 pounds per square inch gauge (psig) and averaged 1327.5 psig for the 24-hour period prior to beginning injection into DIW-1. The flowrate while injecting into DIW-1 ranged from 6743 to 7455 gallons per minute (gpm) and averaged 7099 gpm for a period of six hours and 37 minutes. The formation pressure ranged from 1329.2 to 1331.5 psig and averaged 1330.9 psig while injecting into DIW-1 at an average flowrate of 7099 gpm. The formation pressure differential, between the pressure during the 24 hour period prior to injection and the pressure while injecting into DIW-1 at an average flowrate of 7099 gpm, was approximately 4 psi. This represents the formation pressure increase due to operation of DIW-1 at a flowrate of 7099 gpm.

The short-term injection test data were also examined in the context of the SEAWAT model implemented in the Underground Injection Control operations performance assessment (described in FPL letter L-2014-002 dated January 15, 2014). This modeling was performed to estimate transport over distances on the order of miles and times up to 100 years, which dictated the model design and resolution. The duration and area of influence of the short-term injection test were on a much smaller scale, as dictated by the test objectives. As such, a direct calibration of the model using the short-term injection test data was not attempted. An estimate of aquifer transmissivity was calculated based on an empirical relationship with the specific capacity of the formation, which can be estimated using flow and pressure data from the short-term injection test. The transmissivity calculated from the specific capacity was approximately 205,000 square feet per day. The base case transmissivity used in the SEAWAT modeling was 250,000 square feet per day.

The maximum anticipated injection rate for the deep injection wells during Units 6 & 7 operation is approximately 7000 gpm (per well). This rate is less than the average flowrate described above. However, the formation pressure data obtained while injecting at an average flowrate of 7099 gpm will be used for the pressure calculations presented below to provide a conservative pressure calculation.

Assuming the following operational parameters:

- all 12 injection wells are operating concurrently at a rate of 7000 gpm;
- there is no dissipation of the increased formation pressure between operating injection wells (a very conservative assumption due to the high transmissivity of the Boulder Zone); and
- the cumulative formation pressure is additive for each well,

a formation pressure increase of approximately 48 psi due to the deep well injection system (DIS) operation (4 psi x 12 injection wells operating at 7000 gpm) is anticipated. It is conservative to assume that all 12 wells are operating simultaneously since it is anticipated that two wells will operate when using reclaimed water and nine wells will operate when using saltwater.

The native water within the Boulder Zone is similar to seawater and freshwater is approximately 1/40th less dense than seawater (1.00 grams/cubic centimeter versus 1.025 grams/cubic centimeter). Therefore, the buoyant force of freshwater in feet at the top of the Boulder Zone will be approximately the thickness of the freshwater layer divided by 40. While the fluid that will be injected into the deep injection wells under normal operating conditions will have a slightly higher specific gravity than freshwater, the specific gravity of

freshwater will be used in this buoyant force calculation to provide a conservative approach. Assuming a 200 foot thick layer of the freshwater in the Boulder Zone, the buoyant force that will be generated will be five feet of head (200 feet/40) or approximately 2.2 psi (5 feet of head/2.31 feet per psi). Therefore, the maximum total pressure increase in the Boulder Zone due to pressure and buoyant forces is approximately 50.2 psi (48 psi + 2.2 psi).

Potential for confining unit fracture and subsequent vertical migration of injected fluid can occur when formation injection pressures, combined with buoyant forces, surpass the mechanical strength of the formation. An equation developed by Hubbert and Willis (Reference 1) is used to predict the minimum bottom-hole pressure that could potentially propagate hydraulic fracturing of the formation. The equation is:

$$p_i = (S_z + 2P_o)/3$$

where

p_i = hydraulic fracturing gradient in psi/foot
S_z = total lithostatic stress in psi/foot
P_o = formation fluid pressure in psi/foot

Utilizing values of 1.0 and 0.46 psi/foot, from Reference 1, for S_z and P_o, respectively, (representing the theoretical vertical lithostatic and hydrostatic gradients derived from the respective densities of rock and water), a minimum fracture initiation gradient of 0.64 psi/foot is calculated as shown below:

$$p_i = (1.0 + 2 \times 0.46)/3 = 0.64 \text{ psi/foot}$$

This scenario assumes minimal lateral earth stress. Using the calculated fracture initiation gradient of 0.64 psi/foot and a depth of 2985 feet below grade (the base of DIW-1 final casing), a pressure of 1910.4 psig is calculated to represent the minimum downhole pressure that may create hydraulic fracturing. Subtracting the downhole hydrostatic pressure (1327.5 psig) from the calculated minimum fracture pressure shows that the minimum downhole injection pressure that could cause a fracture is 582.9 psi. This pressure is approximately 12 times greater than the calculated maximum formation differential pressure of 50.2 psi when all of the deep injection wells are operating at the maximum anticipated injection rate of 7000 gpm.

Additionally, the calculated minimum bottom-hole pressure that could cause hydraulic fracturing at the top of the confining unit, determined during the exploratory well drilling to be at 1930 feet below grade, is calculated to be 1235 psig (0.64 psi/foot x 1930 feet = 1235 psig). Subtracting the estimated hydrostatic pressure of 858.3 psig (1930 feet/2985 feet × 1327.5 psig), at the top of the confining unit, from the fracture pressure of 1235 psig, shows that the minimum downhole injection pressure differential that could cause a fracture is approximately 377 psi. This pressure is approximately 7.5 times greater than the calculated maximum formation differential pressure of 50.2 psi when all the injection wells are operating. The increase in bottom-hole pressure will be well below the minimum bottom-hole pressure that may create hydraulic fracturing.

Rule 62-528.415(1)(a), Florida Administrative Code (F.A.C.), prohibits operating an injection well at a pressure that would initiate new fractures or propagate existing fractures in the injection zone, initiate new fractures in the confining zone, or significantly alter the fluid containment capabilities of the confining zone. All future injection wells authorized by Florida Department of Environmental Protection (FDEP) issued Underground Injection Control permits will undergo a similar short term injection test.

Design Features and Construction/Initial Mechanical Integrity Testing of the Deep Injection and Dual Zone Monitoring Wells

Deep Injection Wells

Each of the deep injection wells will be constructed with concentric steel casings to isolate and protect groundwater from injected fluid. Each injection well will be constructed with new and unused 64- (or greater), 54-, 44-, 34-, and 24-inch outside diameter steel casings designed to last for at least 60 years. The 64- (or greater), 54-, 44-, and 34-inch diameter casings will have a minimum wall thickness of 0.375-inches and conform to American Society for Testing and Material (ASTM) 139, Grade B specifications. The final 24-inch diameter casing will have a 0.5-inch wall thickness, will be seamless, and will conform to American Petroleum Institute (API) 5L specifications or ASTM 153 specifications. The well casings are selected to provide protection against casing failure during cementing operations, protect against failure during operation of the well and subsequent pressure tests, and provide sufficient corrosion protection. The 54-, 44-, and 34-inch diameter casings will be encased in cement on both the outside and the inside of the casing to protect against exposure to groundwater. The outside of the 24-inch diameter casing will be encased in cement to protect against exposure to groundwater. A nominal 18-inch diameter fiberglass reinforced plastic (FRP) injection tubing

with a wall thickness of 0.76-inches will be installed inside the 24-inch diameter casing to protect the 24-inch diameter casing from exposure to injected fluids and subsequent corrosion. The annular space between the 24-inch diameter casing and the FRP injection tubing will be filled with a non-hazardous corrosion inhibitor (e.g. one percent Baracor 100 solution) and sealed at the base and top to create a pressure-tight annular space. Thus, each steel casing is either fully encased in cement or, for the 24-inch diameter casing, the outside of the casing is encased in cement while the inside of the casing is protected by a corrosion inhibitor. Figure 1 depicts a typical deep injection well. This schematic is based on the actual subsurface conditions encountered during the installation of deep injection well DIW-1~~exploratory well EW-1~~.

Steel casing installation will take place by welding each casing joint to the subsequent casing joint and then lowering the welded casing joints into the well to a level where the next casing joint can be welded to the previously welded joints. Certified welders will conduct the welding of these joints. Certified welders have passed qualification tests in accordance with Section IX, Article III of the ASME Boiler and Pressure Vessel Code or Standard D1.1 of the American Welding Society (AWS). Welders and operators will be qualified for making groove welds in carbon steel and stainless steel pipe in positions 2G and 5G or 6G for each welding process to be used. Each of the casing joints welds will be visually inspected for defects including weld porosity, weld continuity, absence of cracks or perforations in the weld material or base metal, craters, and undercutting of the base material. The visual inspection will be performed prior to casing being lowered into the well. Each of the steel casing joints will be approximately 40-feet in length. Welding of each casing joint to the previously welded joints will continue until the base of the casing has been lowered to the predetermined elevation. The depth at which the base of the casing will be installed will be determined based on geophysical data. Packer testing data will also be used in determining the depth at which the base of the 34-inch and 24-inch diameter casings will be installed. The elevation of the base of the 34-inch and 24-inch diameter casings will be subject to FDEP approval before installation of these casings. Each steel casing will be fully cemented with ASTM C150, Type II cement from the base of the casing to land surface to prevent movement of fluids into or between Underground Sources of Drinking Water, maintain groundwater quality in aquifers above the injection zone, and protect casings from corrosion.[1] All cementing of the casings will be in accordance with American Water Works Association (AWWA) Standard for Water Wells, A100-06-2006. Temperature

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[1] An "underground source of drinking water" means an "aquifer" or its portion:
(a) Which supplies drinking water for human consumption, is classified by Rule 65-520.410(1), F.A.C., as Class F-I, G-I, or G-II ground water, or contains a total dissolved solids concentration of less than 10,000 mg/L; and
(b) Which is not an exempted aquifer.

logs will be performed following each cement stage that did not result in cement returns at surface to assist in determining the elevation of the top of the previous cement stage. The top of the previous cement stage will then be confirmed by physically tagging the top of the previous cement stage using a cement tremie line. All casings will be centralized to ensure the presence of an adequate annulus around the casing.

Cement bond logging of the 24-inch diameter casing will take place after cementing all but the uppermost 200 to 400-feet of the 24-inch diameter casing in place. The purpose of performing the cement bond log prior to cementing the uppermost 200 to 400-feet of the 24-inch diameter casing is to allow the cement bond logging tool to be calibrated to uncemented casing prior to performing the log.

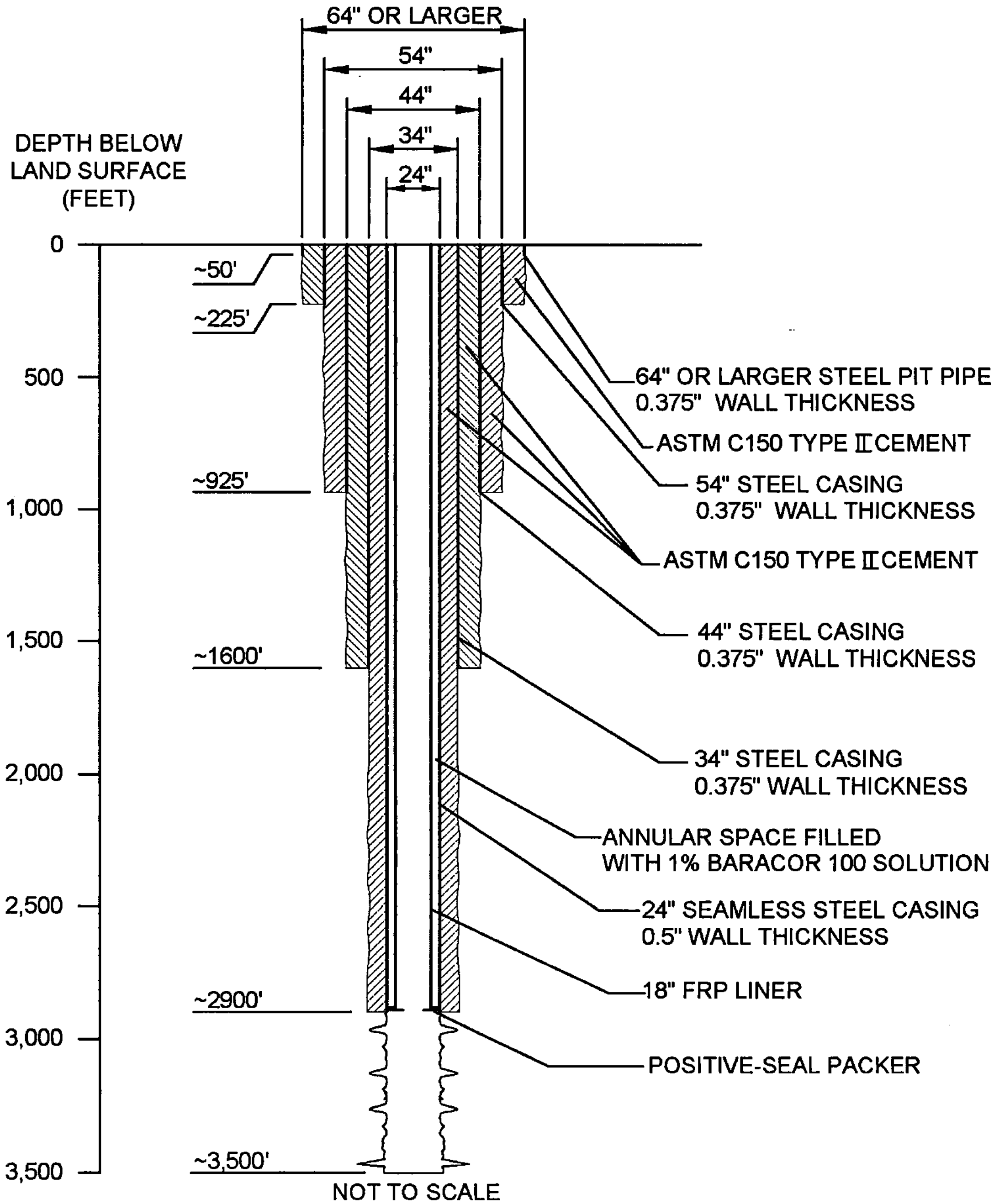

Figure 1 – Deep Injection Well (typical based on DIW-1~~EW-1~~)

The cement bond log will be performed from the base of the 24-inch diameter casing to land surface and will be used to identify the presence of poor cement bonding with casing and/or formation. The uppermost 200 to 400-feet of the 24-inch diameter casing will then be cemented to land surface. Following completion of cementing the 24-inch diameter casing of each deep injection well in place, the casing will undergo a video inspection by lowering a submersible video camera down the inside of the casing to verify the absence of features that could potentially negatively impact the mechanical integrity of the well. The 24-inch diameter casing will also undergo pressure testing at a minimum pressure of 150 psi prior to installation of the nominal 18-inch diameter FRP injection tubing. The 24-inch diameter casing pressure test will be performed by increasing the pressure to a minimum pressure of 150 psi and monitoring the annular pressure for a period of one-hour. A pressure fluctuation of less than five percent at the end of the one-hour test is required for the pressure test to successfully demonstrate a lack of leaks in the 24-inch diameter casing.

The FRP injection tubing will be installed by screwing together threaded FRP injection tubing joints of approximately 30-foot lengths. A non-hazardous compound (TFC-15 thread compound) will be applied to the threads of each FRP pipe joint to assist in the screwing together of the joints and to assist in completing a pressure-tight connection. The FRP injection tubing will be installed to a depth of approximately 10-feet above the base of the 24-inch diameter casing, where it will be seated into a packer to allow a pressure tight seal between the FRP injection tubing and the 24-inch diameter casing. Just prior to seating the FRP injection tubing into the 24-inch diameter casing, the water in annular space between the FRP injection tubing and the 24-inch diameter casing will be displaced with a non-hazardous corrosion inhibitor by pumping the corrosion inhibitor into the annular space from surface. Following completion of seating the FRP injection tubing into the packer near the base of the 24-inch diameter casing, the annular space between the FRP injection tubing and the 24-inch diameter casing will be sealed at surface.

Testing and acceptance criteria that will be used to evaluate the mechanical and hydraulic integrity of the DIS prior to beginning operation of the system are presented below.

Testing prior to beginning operation of the DIS will include mechanical integrity testing of each injection well and hydraulic pressure testing of the pipeline. The purpose of the testing is to evaluate the mechanical and hydraulic integrity of the system prior to being placed into operation. Mechanical integrity testing is defined by FDEP and consists of a video survey, pressure testing of the annular space between the 24-inch diameter casing and the FRP injection tubing, performance of a high-resolution temperature log, and performance of a

radioactive tracer survey. For each test performed acceptance criteria are established to evaluate the results and determine that the well is structurally sound and can perform its function.

Acceptance criteria for each element of the mechanical integrity test are summarized below:

- Video Survey - acceptance criteria is absence of any visual defects in the FRP injection tubing or at the packer at the base of the FRP injection tubing that would negatively impact the mechanical integrity of the injection well.

- High-resolution temperature log - performed to detect leaks in the injection tubing and/or packer at the base of the injection tubing. Acceptance criterion for the high-resolution temperature log is the absence of temperature anomalies that are indicative of a fluid leak in the FRP injection tubing or at the packer at the base of the FRP injection tubing.

- Annular pressure test - performed by increasing the pressure in the annular space to approximately 150 psi and monitoring the annular pressure for a period of one hour. Pressure fluctuation of less than five percent at the end of the monitoring period is required for the annular pressure test to successfully demonstrate a lack of leaks in the annular space.

- Radioactive Tracer Survey - performed to evaluate the integrity of the cement seal at the base of the 24-inch diameter casing. The test is designed to detect the presence of breaches in the cement at the base of the casing that could allow fluid to move from the injection zone along the outside of the 24-inch diameter casing into overlying intervals. Acceptance criterion for the radioactive tracer survey is the absence of evidence for the upward migration of tracer behind the casing.

Additional testing of the DIS to confirm that the system can perform its operational function will include hydrostatic pressure testing of the piping system connecting the pump station to the deep injection wells (1.25 to 1.5 times the system design pressure), testing of the DIS pumps, system valve operation, and instrumentation and control components. System instrumentation (pressure gauges, pressure transducers, and flowmeters) will undergo calibration prior to installation and periodically during operation in accordance with the station testing program. Similarly, all mechanical components will be pre-operationally and inservice tested in accordance with the station testing program.

~~The annular space will then undergo pressure testing at a minimum pressure of 150 psi. The annular space pressure test will test the 24-inch diameter casing, the FRP injection tubing, the packer that seals the annular space near the bottom of the 24-inch diameter casing and the seal of the annular space at surface all at the same time to ensure there are no leaks in the system. Additional testing performed to evaluate the mechanical integrity of the injection wells will include performance of high-resolution temperature logging designed to detect fluid leaks in the FRP injection tubing, performance of a video survey to confirm the absence of features that could potentially negatively impact the mechanical integrity of the well (e.g. FRP injection tubing fracture), and performance of a radioactive tracer survey to evaluate the integrity of the cement seal on the outside of the 24-inch diameter casing at the base of the casing.~~

The interpreted results of the above described video surveys, pressure tests, temperature log, cement bond log, and radioactive tracer survey will be submitted to the FDEP for review and approval prior to short-term injection testing and operation of the deep injection well.

Dual Zone Monitoring Wells

Each of the dual zone monitoring wells will be constructed with concentric steel casings and a final FRP casing. Each monitor well will be constructed with new and unused 44-, 34-, 24-, 16-, and 6.625-inch diameter casings/tubings designed to last at least 60 years. The 44-, 34-, and 24-inch diameter casings will be made of steel with a minimum wall thickness of 0.375 inches and conform to ASTM 139, Grade B specifications. The 16-inch diameter casing will be made of steel and have a 0.5-inch wall thickness, will be seamless, and will conform to API 5L specifications or ASTM 153 specifications. The well casings are selected to provide protection against casing failure during cementing operations and provide sufficient corrosion protection for the life of the well. The 34 and 24-inch diameter casings will be encased in cement on both the outside and the inside of the casing to protect against exposure to groundwater. The outside of the 16-inch diameter casing will be encased in cement to protect against exposure to groundwater. A nominal 6.625-inch diameter FRP casing with a wall thickness of 0.27 inches will serve as the final casing of the well and was selected due to its corrosion resistance. Figure 2 depicts a typical dual zone monitoring well.

Monitor well steel casing installation will take place by welding each casing joint as described above for the injection wells. Certified welders will conduct the welding of these joints. Certified welders have passed qualification tests in accordance with Section IX, Article III of the ASME Boiler and Pressure Vessel Code or Standard D1.1 of the American Welding Society (AWS). Welders and operators will be qualified for making groove welds in carbon steel and stainless

steel pipe in positions 2G and 5G or 6G for each welding process to be used. Each of the welded casing joints will be visually inspected prior to being lowered into the well. The elevation at which the base of each casing will be installed will be determined based on geophysical data. Packer testing results will also be used in determining the depth at which the 16-inch and 6.625-inch diameter casings will be installed. The elevation of the base of the 16-inch and 6.625-inch diameter casings and the monitoring intervals of each dual zone monitor well are subject to FDEP approval before installation of these casings. Each steel casing will be fully cemented with ASTM C150, Type II cement from the base of the casing to land surface as described above for the injection wells. The 6.625-inch diameter FRP casing will be cemented over the interval from the top of the lower monitoring zone to the base of the upper monitoring zone. Temperature logs will be performed following each cement stage that did not result in cement returns at surface to assist in determining the elevation of the top of the previous cement stage. The top of the previous cement stage will then be confirmed by physically tagging the top of the previous cement stage using a cement tremie line.

All casings will be centralized to ensure the presence of an adequate annulus around the casing. Cement bond logging of the 6.625-inch diameter casing will take place after completion of cementing 6.625-inch diameter casing in place. Following completion of cementing the 6.625-inch diameter casing of each dual zone monitor well in place, the 6.625-inch diameter casing will undergo a video inspection by lowering a submersible video camera down the inside of the casing to demonstrate the absence of features that could negatively impact the mechanical integrity of the well. The 6.625-inch diameter casing will also undergo pressure testing at a minimum pressure of 150 psi.

Post-Construction Monitoring and Mechanical Integrity Testing of UIC Wells

FPL will comply with the requirements of Rule 62-528.415, F.A.C. to conduct injection rate and injection pressure monitoring. Rule 62-528.415, F.A.C., (Operation Requirements for Class I and III Wells) requires that the annular space of each deep injection well be pressurized (typically to 40 to 60 psi) and that continuous pressure monitoring of the annular space take place. Continuous injection rate and injection pressure monitoring is also required. The purpose of the annular space pressure monitoring is to allow instantaneous detection of the development of a leak in the FRP injection tubing, 24-inch diameter casing, or the seal at the base or top of the annular space. The annulus pressure will be greater than the pressure within the well so that if a leak did occur, water would flow into the well. Continuous monitoring of the water level of both monitor zones of the dual zone monitor wells is also required. Water level monitoring allows for detection of the development of holes in the uncemented portion of the

final casing of the monitor well and indications of migration of fluids injected into the injection wells into the intervals monitored by the dual zone monitor well.

Water chemistry monitoring will also be performed on both zones of the dual zone monitoring wells in order to detect changes in water chemistry that might be related to migration of the injected fluids.

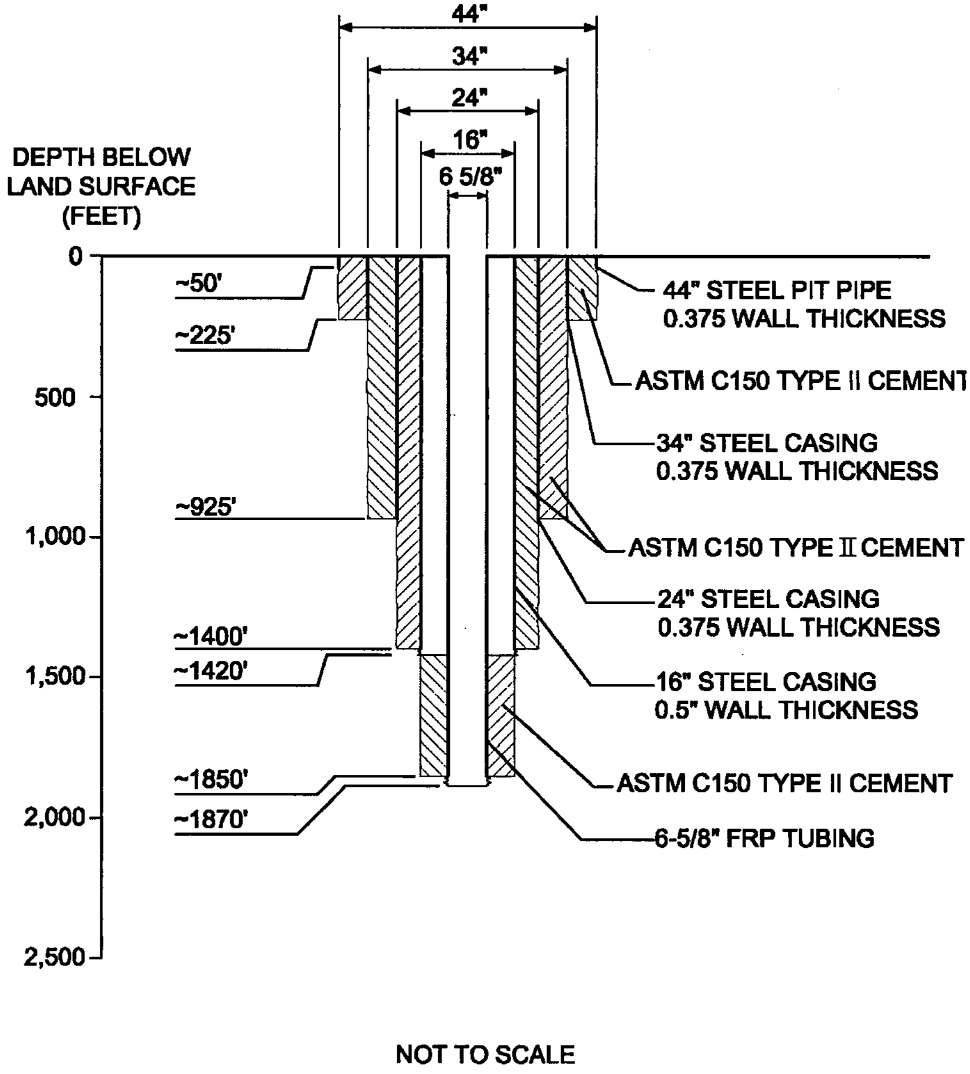

Figure 2 – Dual Zone Monitoring Well (typ.)

Rule 62-528.425, F.A.C., (Monitoring Requirements for Class I and III Wells) requires that each injection well undergo mechanical integrity testing at least every five years. A proposed mechanical integrity testing plan ~~(Note: a permit has not yet been issued for the deep injection well system)~~ is required by FDEP for review and approval prior to beginning each mechanical integrity testi~~ng~~. The injection well undergoing mechanical integrity testing will be temporarily removed from service throughout the testing period. Mechanical integrity testing will consist of a video survey, pressure testing of the annular space between the 24-inch diameter casing and the FRP injection tubing, performance of a high-resolution temperature log, and performance of a radioactive tracer survey. The purpose of the video survey is to allow inspection of the injection tubing, packer at the base of the injection tubing and base of the 24-inch diameter casing. The high-resolution temperature log is performed to detect leaks in the injection tubing and/or packer at the base of the injection tubing. The annular pressure test is performed by increasing the pressure in the annular space to a pressure of approximately 150 psi and monitoring the annular pressure for a period of one hour. A pressure fluctuation of less than five percent at the end of the one-hour monitoring period is required for the annular pressure test to successfully demonstrate a lack of leaks in the annular space.

The interpreted results of the testing will be provided in a summary report to FDEP for review and acceptance. The report will include a compilation and interpretation of the previous five years of injection well annular pressure data, injection pressure and rate data, and water quality of the injected fluid. A compilation and interpretation of the monitoring well water level and water quality data to allow for evaluation of the integrity of the uncemented portion of the monitoring well final casing and indications of upward fluid migration into the monitoring zones is also required to be included in the mechanical integrity testing report.

A radioactive tracer survey was ~~will be~~ conducted on DIW-1 to evaluate the integrity of the cement seal between the rock formation and the outside wall of the 24-inch diameter casing. ~~in each deep injection well.~~ The radioactive tracer survey was ~~will be~~ conducted by first performing a background gamma ray log from the base of the well to land surface. DIW-1 has a total depth (including open hole) of 3230 feet, therefore, the background gamma ray log was conducted from a depth of 3230 feet to land surface. The radioactive tracer survey tool was then removed from the well to allow the ejector port of the radioactive tracer survey tool to be loaded with Iodine-131. The radioactive tracer survey tool was then ~~The ejector port of the radioactive tracer tool will then be loaded with Iodine-131 and~~ lowered into the well to a depth that places the Iodine-131 ejector port of the radioactive tracer survey tool at a depth that corresponds to five feet above the base of the 24-inch diameter casing. While freshwater is injected at a low rate, a slug of Iodine-131 is released from the radioactive tracer survey tool

~~injected~~. The 24-inch diameter casing of DIW-1 is installed to a depth of 2985 feet, therefore, the radioactive tracer survey tool was positioned so that the ejector port on the radioactive tracer survey tool that releases the Iodine-131 was located at a depth of 2980 feet. The radioactive tracer survey tool remained at this depth for a minimum of 30 minutes while gamma ray detectors on the radioactive tracer survey tool monitor gamma ray activity to look for indications of upward migration of Iodine-131 behind the outside wall of the 24-inch diameter casing. The radioactive tracer survey tool was then raised 200 feet while collecting gamma ray data. The radioactive tracer survey tool was then lowered to below a depth of 3165 feet and emptied of any remaining tracer. A gamma ray log was performed as the tool was raised from the total depth of the well to land surface. ~~Gamma ray detectors on the radioactive tracer tool will then be used to monitor gamma ray activity for a 30 minute period to look for indications of upward migration of Iodine-131 behind the outside wall of the 24-inch diameter casing. A gamma ray log will then be performed over the lowermost 200 feet of the 24-inch diameter casing of the well. The radioactive tracer tool will then be lowered to at least 50 feet below the base of the 24-inch diameter casing and emptied of any remaining tracer. The radioactive tracer tool will then be lowered to the base of the well and a gamma ray log will be performed from the base of the well to land surface.~~

~~The interpreted results of the testing discussed above will then be provided to FDEP in a summary report. The report will also include a compilation and interpretation of the previous five years of injection well annular pressure data, injection pressure and rate data and water quality of the injected fluid. A compilation and interpretation of the monitor well water level and water quality data to allow for evaluation of the integrity of the uncemented portion of the monitor well final casing and indications of upward fluid migration into the monitoring zones is also required to be included in the mechanical integrity testing report.~~ Gamma Ray activity above the background levels that would be indicative of the presence of a conduit in the cement seal at the base of the 24-inch diameter final casing was not detected during the radioactive tracer survey. These results confirm the absence of conduits or channels in the cement seal at the base of the 24-inch diameter final casing that would allow migration of injected fluids into overlaying aquifers.

The above summary of the design features of the deep injection and dual zone monitoring wells, proposed construction/initial mechanical integrity testing, and proposed post-construction monitoring and mechanical integrity testing presents both a rigorous design and construction program, along with a thorough initial and operational mechanical integrity testing approach. The design, construction, and mechanical testing of the deep injection and dual zone monitoring wells will be in strict accordance with the requirements of ~~Chapter~~ Rule

62-528, ~~Florida Administrative Code~~F.A.C., and will both minimize the potential for deep injection well failure and ensure proper subsurface monitoring of the DIS (dual zone monitoring wells).

Plant Operation and Procedures to Address Upwelling or Failure(s) of the Deep Well Injection System

~~Although unlikely, there is a small theoretical possibility for fluid, injected into the Boulder Zone via the deep well injection system, to migrate upward through the confining interval. This small theoretical potential would require a breach of all 985 feet of confinement identified at the site. It is not based on a technical determination from site-specific data. In this unlikely event, FDEP would take regulatory action, which historically has taken the form of a Consent Order. Typically, this Consent Order would contain conditions requiring FPL to conduct additional testing of the injection wells including the performance of mechanical integrity testing of the suspect well(s) that might be the source of fluid migration. If one or more of the wells were found to lack mechanical integrity, FPL would be required to remove the well from service until it was repaired. If testing did not reveal the potential source of the upward migration, the Consent Order may stipulate that FPL be required to make modifications to the injection wells, such as deepening the wells and installing a deeper casing, or waste stream, such as making the waste stream as dense as or denser than the native Boulder Zone groundwater. If these measures did not identify the source of the fluid migration or were not to remedy the upward migration of fluid, the deep injection well system would be removed from service and an alternative method of radioactive effluent disposal would be used, such as release to the cooling canal system. It is anticipated that the Consent Order would stipulate a time period (such as within 10 years of issuance of the Consent Order) in which the above items must be accomplished.~~ Three deep injection wells (two active and one backup) are sufficient for disposal of cooling water when makeup is provided by reclaimed water. Subsection 9.2.12.1.2.1.2 indicates that when using saltwater makeup, 11 wells (nine active and two backup) are sufficient for disposal of the cooling water.

If the groundwater monitoring detected an upwelling of the injected fluid into one or more monitoring wells monitoring zones, FPL is required to report this information to FDEP and work with FDEP to remedy the problem. The nature of the remedy would depend upon the cause of the upwelling. If the upwelling was caused by a mechanical integrity problem with one or more of the injection or monitoring wells, FPL would remove the problematic well(s) from service, investigate the nature of the problem, and repair the problematic well(s). FPL would report this repair to FDEP who would approve the repair plan and approve placing the well back in service.
Assuming all of the injection wells are mechanically sound, FPL has no information indicating that the injected fluid would otherwise upwell from the Boulder Zone. However, assuming a hypothetical migration of the injected fluid upward through the confining layer (which assumes a hypothetical breach of all 985 feet of site confinement), the site monitoring wells would detect this upward migration before the migrated fluid entered any aquifer with the potential for public use. In such case, FPL would report this event to FDEP and work with FDEP to remedy the cause of the upward migration.

The remedy would depend upon the suspected cause of the problem, but could include performing additional mechanical integrity or other tests on the injection wells; deepening the injection wells and installing a deeper injection casing; increasing the density of the injected wastestream to equal or exceed the density of the Boulder Zone water; or removing one or more injection wells from service. As provided in FSAR Subsection 9.2.12.1.2.1.1, of the 12 injection wells installed at Turkey Point Units 6 & 7, two active deep injection wells are sufficient for disposal of reclaimed make up cooling water and as indicated in Subsection 9.2.12.1.2.1.1, nine active deep injection wells are sufficient when using saltwater make up cooling water. If any one of the injection wells has to be removed from service, Turkey Point Units 6 & 7 has a sufficient number of backup wells that are available. As part of any remedy, FPL may increase the frequency of the monitoring data collection at the monitoring wells.

Based upon past FDEP practice involving other entities, FDEP would require FPL to enter into a consent order to ensure FDEP had the legal means to compel FPL to undertake the identified remedies. (See e.g., Rule 62-528.435(1), F.A.C., empowering FDEP to order an injection well to be plugged or abandoned if the well poses a threat to waters of the State unless otherwise provided by consent order). The nature of the problem, the remedy required to address the problem, and the potential threat posed by the migration would be factors FDEP would consider in specifying the deadline(s) by which FPL must complete the remedial measures. This deadline(s) would be included in a consent order to ensure legal enforceability.

UIC Well Abandonment Procedures

Plugging and abandonment requirements of a Class I injection well are ~~addressed in~~ mandated in Rule 62-528.435, F.A.C. A proposed plugging and abandonment plan for each Class I injection well is required to be submitted with each Class I injection well construction and operation permit application. Additionally, a FDEP Class I Well Plugging and Abandonment Permit is required prior to plugging and abandoning a Class I injection well. Elements of the proposed plugging and abandonment procedure for each injection well and associated monitor well are discussed in the following paragraphs.

Deep Injection Well Plugging and Abandonment Procedure

1. Lower the hydrostatic head of the well to below land surface with a brine solution.

2. Conduct a caliper log of the entire well.

3. Remove the FRP injection tubing from the injection well.

4. Place limestone gravel with an average diameter not larger than one inch down the injection well to fill the open hole from the bottom of the well up to a depth of approximately 20 feet below the base of the final casing. Confirm the depth of the top of gravel with a physical tag of the gravel using a grout pipe.

5. Place ASTM C150, Type II neat cement, through a grout pipe, from approximately 20 feet below the base of the 24-inch diameter casing of the injection well to land surface. For all cement stages that do not result in cement returns to surface, physically tag the top of the previous cement stage with a grout pipe prior to pumping the next cement stage to ensure that no portions of the well remain uncemented. Continue pumping cement stages until the entire well casing has been filled with neat cement and cement has reached land surface.

Dual Zone Monitoring Well Plugging and Abandonment Procedure

1. Lower the hydrostatic head of both monitor zones to below land surface with a brine solution.

2. Place ASTM C150, Type II neat cement in the deep monitoring zone through grout pipe from the base of the monitoring zone to land surface. For all cement stages that do not result in cement returns to surface, physically tag the top of the previous cement stage with a grout pipe prior to pumping the next cement stage to ensure that no portions of the well remain uncemented. Continue pumping cement stages until the entire 6.625-inch diameter casing has been filled with neat cement and cement has reached land surface.

3. Place ASTM C150, Type II neat cement in the upper monitoring zone through tremie pipe from the base of the monitoring zone to land surface. For all cement stages that do not result in cement returns to surface, physically tag the top of the previous cement stage with a tremie pipe prior to pumping the next cement stage to ensure that no portions of the well remain uncemented. Continue pumping cement stages until the entire 16-inch diameter casing has been filled with neat cement and cement has reached land surface.

FPL must submit an abandonment and plugging plan to FDEP for review and approval prior to plugging or abandoning any of the injection wells per the requirements of Rule 62-528.435(2), F.A.C. Note that the items discussed in this response are proposed and are contingent on the conditions of the FDEP permit.

This response is PLANT SPECIFIC.

References:

1. Hubbert, M.K., and D.G. Willis, 1972. *Mechanics of Hydraulic Fracturing*. MemAm. Assoc. Pet. Geolo., 18. pp 239-257.

ASSOCIATED COLA REVISIONS:

~~None.~~Refer to the response to NRC RAI No. 11.02-6-6.

ASSOCIATED ENCLOSURES:

None

NRC RAI Letter No. PTN-RAI-LTR-072 Dated February 20, 2013

SRP Section: 11.02 – Liquid Waste Management Systems

Supplemental Staff RAI to RAI 11.02-1, 11.02-2, 11.02-3, and 11.02-4.

NRC RAI Number: 11.02-6-6 (eRAI 6985)

[Refer to Attachment 1 for the preamble to this RAI.]

Question 6

With respect to injection flow and dilution flow rates, the applicant is requested to reconcile differences in stated flow rates and citations for the location of such information. For example, FSAR Tier 2, Rev. 4, Section 11.2.3.5 refers to FSAR Section 9.2.6.2.1 for details on deep well injection, but this FSAR section addresses the treatment of sanitary wastes. While FSAR Tier 2, Rev. 4, Section 11.2.3.5 identifies dilution flow rates for the disposal of liquid effluents by deep well injection in assessing radiological impacts, it does not refer to a specific FSAR section for design specific information, such as FSAR Tier 2, Section 9.2 or 10.4.5. A review of ER, Rev. 4, Section 5.2.3.2.4 indicates that the stated flow rates are 12,500 gpm and 58,000 gpm, which are consistent with ER Rev. 4, Table 3.3-1 under normal and maximum cases. However, FSAR Rev. 4, Section 2.4.12.2.1.3 refers to peak and operational injection rates, with a stated 14,000 gpm for reclaimed water and 62,500 gpm for seawater as implied normal operational flow rates. These injection rates are driven, in part, by FLDEP specifications on maximum linear velocities and friction loss and injection pressures, but such details and limitations on the design basis are not described in the FSAR. Accordingly, it is not clear which injection flow rates form the FSAR design basis, and whether the stated injection flow rates reflect the information presented in FPL's September 2012 report on the construction and testing of the first exploratory well. The applicant is requested to review and revise the FSAR and include in its revision a description of the DWI system and flow schematics, essential operational features and characteristics, and design basis of deep well injection flow rates when using reclaimed water and seawater and qualify the operational conditions for each, as expected normal operation versus peak or maximum conditions, and their justifications in modeling radiological impacts.

FPL RESPONSE:

There are two sources of makeup water for the circulating water system (CWS) – reclaimed water (primary) and saltwater from the radial collector wells (backup). The saltwater backup source is expected to be used not more than 60 days ~~per calendar year~~ in any consecutive 12-month period. The saltwater backup source will be used only when the primary water source is not of sufficient quality or quantity. The deep injection well flow is comprised of the blowdown from the cooling tower circulating water system, additional dilution from the Reclaimed Water Treatment Facility (primary source only), and discharge flow from the sanitary waste treatment plant and wastewater retention basin during normal plant operation. ~~The alternate dilution water, which is only required when reclaimed water is used as the cooling water source, will be provided from either the makeup water reservoir or the radial collector wells~~. Figure 1 depicts the proposed locations of the deep injection wells and dual zone monitoring wells.

The reclaimed water supply from the Miami Dade South District Wastewater Treatment Plant to FPL Reclaimed Water Treatment Facility is approximately 50,500 gpm (72.72 mgd). The output of the FPL Reclaimed Water Treatment Facility provides approximately 9750 gpm for future FPL use and approximately 40,686 gpm to the makeup water reservoir for use as cooling water makeup and alternate dilution flow to Units 6 & 7. The reclaimed water from the makeup water reservoir will supply the cooling towers with makeup to replace water lost through cooling tower evaporation, drift and blowdown (28,800, 7, and 9593 gpm, respectively) and an alternate dilution flow rate of approximately 2286 gpm. The requirement to provide alternate dilution flow when using reclaimed water is based on a 12,000 gpm dilution flow requirement for two units (6000 gpm dilution flow per unit). The cooling tower blowdown flow to the blowdown sump is approximately 9714 gpm (includes 121 gpm service water tower blowdown) for both units and therefore an additional alternate dilution flow of 2286 gpm is required to supply the total 12,000 gpm requirement. The 2286 gpm alternate dilution flow will be supplied from the makeup water reservoir to the blowdown sump.

The makeup water reservoir will have a capacity of approximately 275 to 300 million gallons of reclaimed water and consequently is capable of supplying the plant makeup and alternate dilution flow requirements for approximately 5 days of full power operation of both units with no replenishment from the FPL Reclaimed Water Treatment Facility. The final available capacity of the makeup water reservoir will be based on the final design of the reservoir, the cooling tower supporting structures and other ancillary equipment, and may vary the total available reservoir capacity within 10 to 15 percent of the value stated above.

When using saltwater as cooling water makeup there will be sufficient blowdown from the cooling towers (approximately 58,000 gpm) to supply the 12,000 gpm dilution flow requirement and no alternate dilution is required. Reclaimed water from the makeup water reservoir may be available as an alternate supply of water when using saltwater but is not required to meet the 12,000 gpm plant effluent dilution requirements due to the volume of blowdown from the cooling towers. To maintain the water chemistry of the makeup water reservoir as close as possible to reclaimed water, saltwater makeup to the cooling towers will be supplied directly into the cooling tower basins and not into the makeup water reservoir.

Figure 2 is a schematic which depicts all of the waste streams relevant to the deep well injection system (DIS). Figure 2 of the RAI response will be used to replace the system description in FSAR Figure 9.2-203 and will be titled the same as Figure 2. FSAR Figure 9.2-203 has been revised to include the typical installation locations for system air/vacuum release valves, vents, and drains. The DIS piping system connecting the injection wells to the pump station has not been designed; therefore, the final location and spacing of the air/vacuum release valves, vents, and drains on the piping system have not been determined.

The estimated makeup water flow rate is 38,400 gpm when reclaimed water is used for CWS makeup. Based on four cycles of concentration in the CWS and additional dilution to maintain 10 CFR Part 20 criteria (6000 gpm dilution flow per AP 1000 Unit), the resultant total flow to all of the deep injection wells is approximately 12,500 gpm (normal) and approximately 13,000 gpm (maximum) for both units. A minimum of two deep injection wells will be used resulting in estimated normal and maximum flow rate per injection well of approximately 6250 gpm and 6500 gpm, respectively.

The estimated makeup water flow rate is 86,400 gpm when saltwater is used for cooling water makeup. Based on one and a half cycles of concentration in the CWS (additional dilution of the radioactive effluent is not required), the resultant total flow to the deep injection wells is nominally 58,000 gpm (normal) and 59,000 gpm (maximum) for both units. A minimum of nine

deep injection wells will be used, resulting in an estimated normal and maximum flow rate per injection well of approximately 6445 gpm and 6555 gpm, respectively.

The maximum linear injection velocity of 10 feet per second (fps) into the deep injection well is based on Florida Department of Environmental Protection (FDEP) Underground Injection Control (UIC) Rule 62-528.415(1)(f)2, F.A.C., ~~and the inside diameter of the final casing and not the results of exploratory well EW-1 testing. Based on an inside diameter of the final casing of 23-inches, the linear injection velocity per injection well for reclaimed and saltwater is less than 10 fps~~ which requires that the maximum fluid velocity of injected fluid inside an injection well not exceed a flow velocity of 10 fps except as provided by Rule 62-528.415(1)(f)3, F.A.C., which allows a velocity of 12 fps during planned testing, maintenance or emergency condition when one or more of the wells are taken out of service. While Rule 62-529.415(1)(f), F.A.C., does not specify the point of measuring the fluid injection velocity, prior FDEP practice is to base the 10 fps fluid velocity limit on the inside diameter of the final casing and not that of the FRP injection liner. Using an inside diameter of 23 inches (the inside diameter of the 24-inch outside diameter final casing), the maximum allowable injection rate into one of the proposed injection wells is calculated as follows from Reference 1:

$$V = \frac{0.4085 \times Q}{d^2} \qquad (1)$$

where V = fluid velocity in fps
Q = flow rate in gallon per minute (gpm)
d = pipe inside diameter in inches

Rearranging the equation to calculate flow rate:

$$Q = \frac{V \times d^2}{0.4085} \qquad (2)$$

Solving the equation using a fluid velocity of 10 fps and a final casing inside pipe diameter of 23 inches yields the following results:

$$Q = \frac{10 \text{ fps} \times 23 \text{ inches}^2}{0.4085} \qquad (3)$$

Q = 12,950 gpm

Therefore, the maximum allowable injection rate into a single proposed injection well in accordance with Rule 62-528.415(1)(f)2, F.A.C., is approximately 12,950 gpm, which is significantly greater than the anticipated injection rates while operating Units 6 & 7 using reclaimed or saltwater for cooling tower makeup. A minimum of two deep injection wells will be used when operating with reclaimed water, resulting in estimated normal and maximum flow rate per injection well of approximately 6250 gpm and 6500 gpm, respectively.

The estimated makeup water flow rate is 86,400 gpm when saltwater is used for cooling water makeup. Based on one and a half cycles of concentration in the CWS (additional dilution of the radioactive effluent is not required), the resultant total flow to the deep injection wells is nominally 58,000 gpm (normal) and 59,000 gpm (maximum) for both units. A minimum of nine deep injection wells will be used, resulting in an estimated normal and maximum flow rate per injection well of approximately 6445 gpm and 6555 gpm, respectively.
The actual injection velocity inside the FRP injection tubing when injecting at the maximum anticipated rate of 6555 gpm is calculated below.

$$V = \frac{0.4085 \times Q}{d^2} \qquad (4)$$

where V = fluid velocity in fps
Q = flow rate in gallon per minute (gpm)
d = pipe inside diameter in inches

Solving the equation using an injection rate of 6555 gpm and an inside pipe diameter of 16.62 inches yields the following results:

$$V = \frac{0.4085 \times 6555 \text{ gpm}}{(16.62 \text{ inches})^2} \qquad (5)$$

$$V = 9.7 \text{ fps}$$

Therefore, injection fluid velocity will be approximately 10 fps inside the FRP injection tubing when operating at the maximum anticipated injection rate into a single injection well.

As discussed previously, reclaimed water is the primary source of makeup cooling water, with saltwater used as a backup. For the purposes of injectate travel in the subsurface and dose modeling for the operational life of Units 6 & 7, operational parameters such as makeup water source (reclaimed or saltwater), time period for different makeup water source use, and unit outage schedule were all considered in the analysis of radionuclide fate and transport in the subsurface. These operational flow rates serve as data input to the groundwater model used in the determination of receptor radiological dose in the ~~forthcoming~~ response to RAI 6985, Questions 11.02-6-1 and 11.02-6-2.

As described in FPL letter L-2014-002 (Attachment page 7), FPL would maintain the required minimum dilution factor to control liquid radwaste discharges arising from the release of WLS monitor tank contents:

> "The activity concentration of the radwaste portion of the effluent would be controlled to 10 CFR Part 20, Appendix B, effluent concentration limits (ECLs) at the blowdown sump discharge by specifying and maintaining flow rates corresponding to at least the minimum dilution factor (DF). The required minimum DF is calculated and applied prior to the release of liquid radwaste (batch is the only release mode anticipated) to ensure the activity concentration of the mixture complies with 10 CFR Part 20, Appendix B, ECLs. Implementation of the liquid radwaste effluent control program will be in accordance with the Turkey Point Units 6 & 7 Offsite Dose Calculation Manual (ODCM), which will be available for inspection prior to initial fuel load as shown in FSAR Table 13.4-201."

This requirement will be added to FSAR Sections 11.2 and 11.5 as indicated in the Associated COLA Revisions section of this response.

FSAR Subsection 11.2.3.5 will be revised as part of eRAI 6985 Question 11.02-6-2. FSAR Subsection 2.4.12.2.1.3 was previously revised to state the operational range of flow rates for reclaimed water and saltwater. FSAR Subsection 9.2.12 will be added to provide injection system design and operational parameters, including flow details, essential operational features and characteristics, expected normal operation versus peak or maximum conditions, and design basis of deep well injection flow rates when using reclaimed water and seawater.

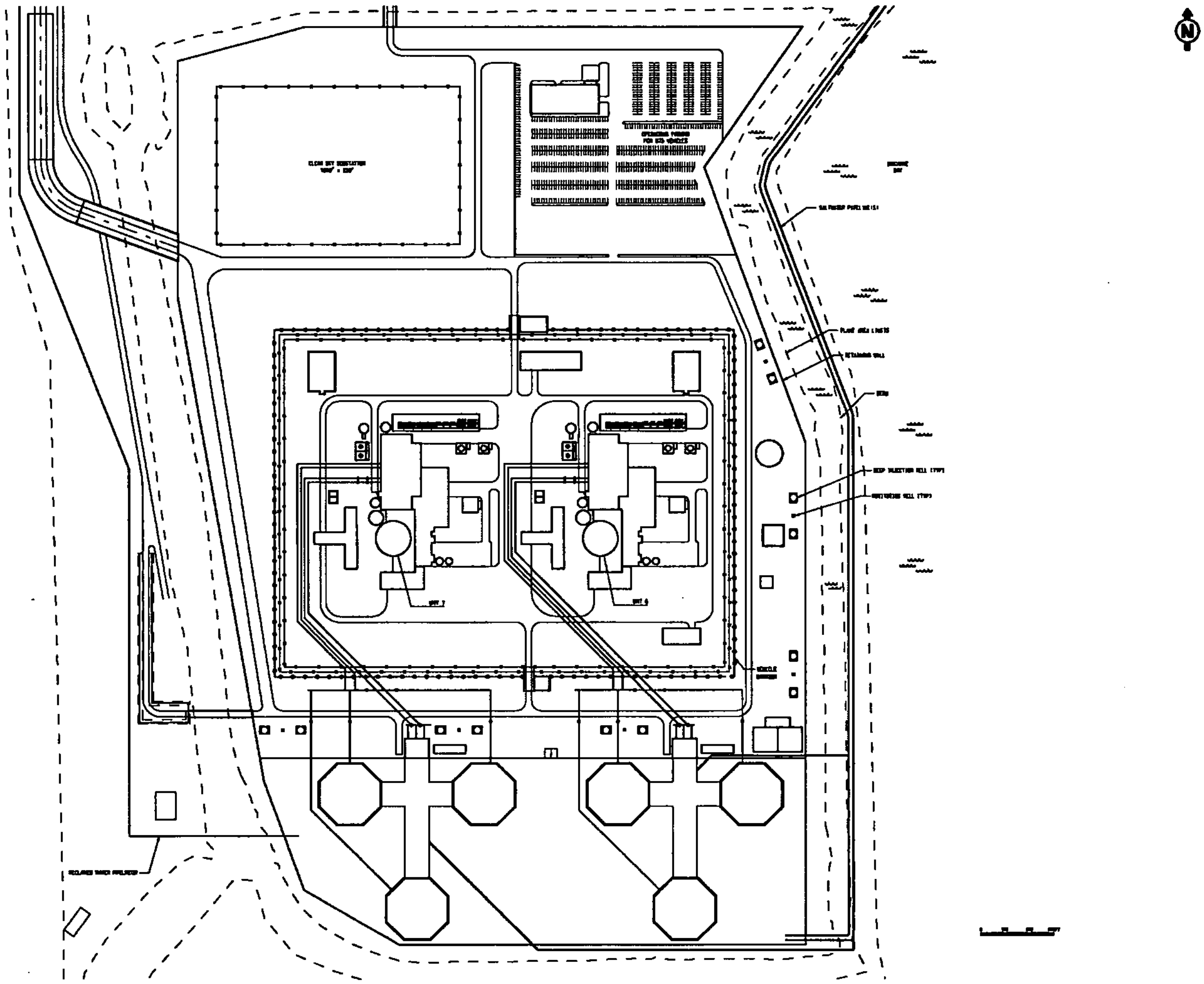

Figure 1 – Proposed Locations of Deep Injection Wells and Dual Zone Monitoring Wells

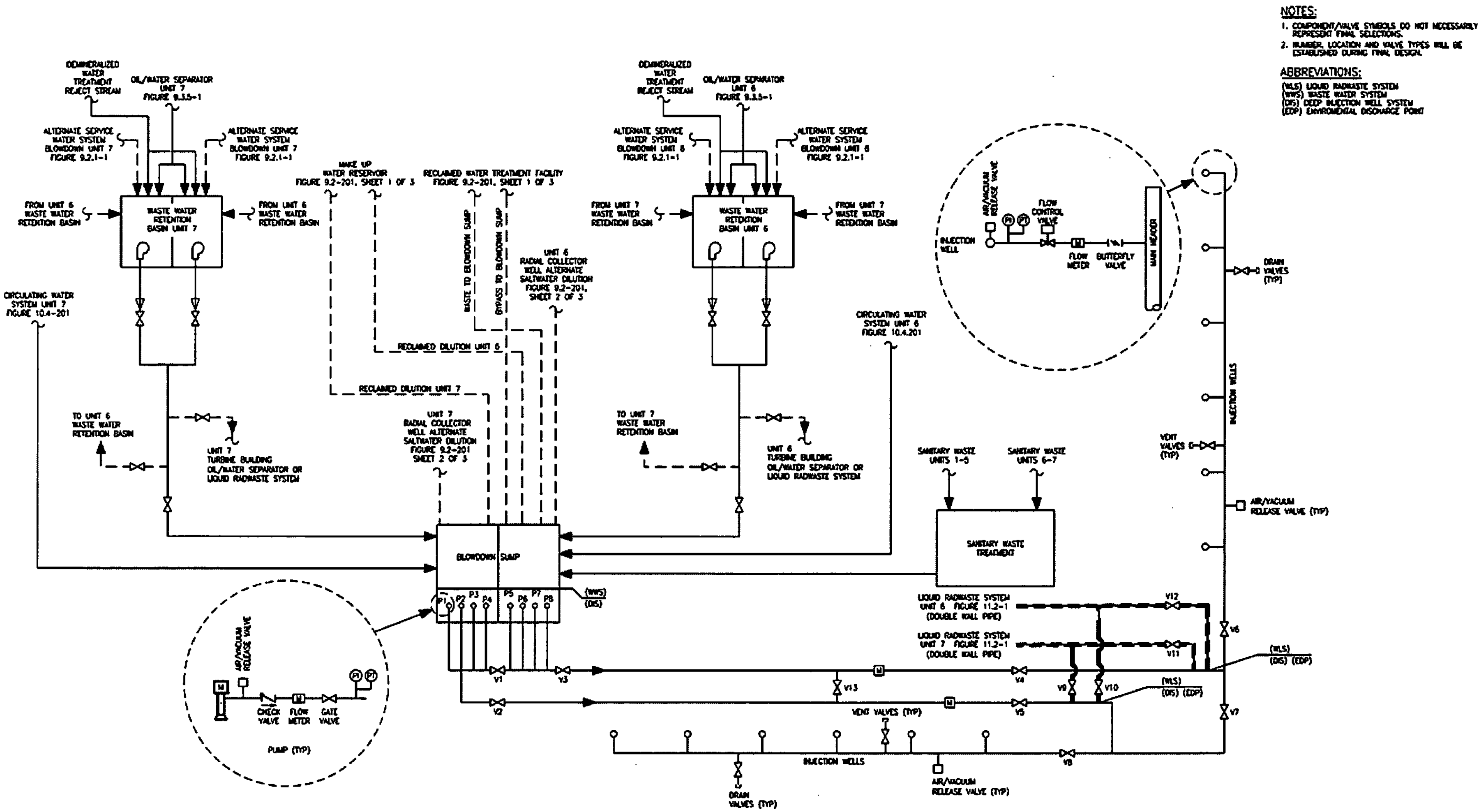

Figure 2 – Liquid Waste Stream Collection and Disposal Schematic (Typical)

This response is PLANT SPECIFIC.

References:

1. King, 1954. *Handbook of Hydraulics,* 4th Edition McGraw-Hill Book Company, Inc, page 6-2

ASSOCIATED COLA REVISIONS:

The following revisions were made in COLA Revision 5 as denoted by revision bars. Additional changes, designated by differences in font color and style (insertions shown in bold red font and deletions shown as strikethrough), will be made in a future COLA revision:

Table 1.7-201 was revised in COLA revision 5 as shown below:

Table 1.7-201 AP1000 System Designators and System Diagrams

Designator	System	FSAR Section	FSAR Figure
CWS	Circulating Water System	10.4.5	10.4-201
RWS	Raw Water System	9.2.11	9.2-201
DIS	Deep Well Injection System	9.2.12	9.2-203
ZBS	Offsite Power System One-Line Diagram	8.2.1	8.2-201
	Switchyard General Arrangement	8.2.1	8.2-202

Table 1.8-201 (Sheet 1 of 2) was revised in COLA Revision 5 as follows:

Table 1.8-201 (Sheet 1 of 2) Summary of FSAR Departures from the DCD

Departure Number	Departure Description Summary	FSAR Section or Subsection
STD DEP 1.1-1	An administrative departure is established to identify instances where the renumbering of FSAR sections is necessary to effectively include content consistent with RG 1.206, as well as NUREG-0800.(a)	2.1.1 2.1.4 2.2.1 2.2.4 2.4.1 2.4.15 2.5 2.5.6 9.2.11 9.2.12 9.2.13 9.2.14 9.5.1.8 9.5.1.9 13.1 13.1.4 13.5 13.5.3 13.7 17.5 17.6 17.7 17.8

Table 1.8-202 was revised in COLA Revision 5 as shown below:

Table 1.8-202 (Sheet 5 of 9) COL Item Tabulation

COL Item	Subject	DCD Subsection	FSAR Section(s)	COL Applicant (A), Holder (H), Or Both (B)
6.4-2	Procedures for Training for Control Room Habitability	6.4.7	6.4.3 6.4.7	A
6.6-1	Inspection Programs	6.6.9.1	6.6 6.6.1 6.6.3.1 6.6.3.2 6.6.3.3 6.6.4 6.6.6 6.6.9.1	A
6.6-2	Construction Activities	6.6.9.2	6.6.2 6.6.9.2	A
7.1-1	Setpoint Calculations for Protective Functions	7.1.6.1	7.1.6.1	B
7.5-1	Post Accident Monitoring	7.5.5	7.5.2 7.5.3.5 7.5.5	A
8.2-1	Offsite Electrical Power	8.2.5	8.2.1 8.2.1.1 8.2.1.2 8.2.1.3 8.2.1.4 8.2.5	A
8.2-2	Technical Interfaces	8.2.5	8.2.1.2.1 8.2.2 8.2.5	A
8.3-1	Grounding and Lightning Protection	8.3.3	8.3.1.1.7 8.3.1.1.8 8.3.3	A
8.3-2	Onsite Electrical Power Plant Procedures	8.3.3	8.3.1.1.2.4 8.3.1.1.6 8.3.2.1.4 8.3.3	A
9.1-5	Inservice Inspection Program of Cranes	9.1.6.5	9.1.4.4 9.1.5.4 9.1.6.5	A
9.1-6	Radiation Monitor	9.1.6.6	9.1.4.3.8 9.1.5.3 9.1.6.6	A
9.1-7	Metamic Monitoring Program	9.1.6.7	9.1.6.7	H
9.2-1	Potable Water	9.2.11.1	9.2.5.2.1 9.2.5.3 9.2.13.1	A
9.2-2	Wastewater Retention Basins	9.2.11.2	9.2.9.2.2 9.2.9.5 9.2.13.2	A
9.3-1	Air Systems (NUREG-0933 Issue 43)	9.3.7	9.3.7	A
9.4-1	Ventilation Systems Operations	9.4.12	9.4.1.4 9.4.7.4 9.4.12	A

Table 1.8-202 (Sheet 8 of 9) COL Item Tabulation

COL Item	Subject	DCD Subsection	FSAR Section(s)	COL Applicant (A), Holder (H), Or Both (B)
14.4-2	Test Specifics and Procedures	14.4.2	14.4.2	H
14.4-3	Conduct of Test Program	14.4.3	14.4.3	H
14.4-4	Review and Evaluation of Test Results	14.4.4	14.2.3.2 14.4.4	H
14.4-5	Testing Interface Requirements	14.4.5	14.2.9.4.15 14.2.9.4.22 to 14.2.9.4.28 14.2.10.4.29 14.4.5	A

Revisions to FSAR Subsection 2.4.12.2.1.3 were made in COLA Revision 5 as shown below. Additional changes designated by differences in font color and style (insertions in bold red font and deletions shown as strikethrough) will be made in a future COLA revision:

- Porous. The Boulder Zone has well developed secondary porosity.

- Highly transmissive. The transmissivity of the Boulder Zone may be up to 24.6E06 square feet per day in some locations. As discussed below, however, within approximately ten miles of the Turkey Point site, the Boulder Zone transmissivity values are very likely between 60,000 square feet per day and 600,000 square feet per day (References 262 and 263).

  The analysis by Meyer (Reference 262) was based on tidal fluctuations in a well located over 20 miles north of the Turkey Point site, in an aquifer that was estimated to be 15 feet thick, with a porosity of 50 percent.

  The very high transmissivity value estimated by Singh, et al (Reference 263) was based on time-drawdown data from only one monitor well, during one pump test. The drawdown in the monitoring well located 107 feet from the pumped well was only approximately ten percent of background tidal fluctuations. Therefore, accurate drawdown values were difficult to determine. Furthermore, large transient oscillations produced by the pump made the first ten minutes of the drawdown and recovery data unusable. The early-time data were discarded and were not used in the analysis. The authors cautioned that the late-time data was "matched somewhat arbitrarily on the flattened portion of the Theis type curve."

  Other tests conducted at this same location on nine different wells completed to the Boulder Zone (including nine injection tests, one withdrawal test and one step-drawdown test)

showed the average transmissivity was 351,059 square feet per day, ranging from 84,480 square feet per day to 780,000 square feet per day. The observations discussed above on the limitations of the test and the additional test results from other wells at the same site suggest considerable uncertainty in the very high transmissivity value reported by Singh, et al (Reference 263).

~~At the Turkey Point site, the Boulder Zone injection test gave an average transmissivity value of 73,471 square feet per day, with an estimated range from 67,820 square feet per day to 80,151 square feet per day. A four-step injection test conducted at the Florida Keys Aqueduct Authority site (Reference 264) located approximately 10 miles west of the Turkey Point site gives transmissivity values between 53,730 square feet per day and 69,574 square feet per day. Data from Boulder Zone test wells within approximately 10 miles of the Turkey Point site suggest a range of transmissivity between 60,000 square feet per day and 600,000 square feet per day; the best estimate for the average value is approximately 250,000 square feet per day.~~

During the construction of the Turkey Point Units 6 & 7 exploratory well, EW-1, a Boulder Zone formation test was performed, and the results gave an average transmissivity value of 73,471 square feet per day, with an estimated range from 67,820 square feet per day to 80,151 square feet per day.

Following construction of the exploratory well and issuance of the FDEP Permit to convert the exploratory well to deep injection well, DIW-1, a short-term injection test was performed. After the well injection tubing was filled with non-hazardous industrial wastewater from the FPL Turkey Point Unit 5 cooling tower basin (original source Upper Floridan Aquifer) with a measured Total Dissolved Solids value of 3600 mg/L, the down hole formation pressure ranged from 1327.3 to 1327.8 pounds per square inch gauge (psig) and averaged 1327.5 psig for the 24-hour period prior to beginning injection into DIW-1. The flowrate while injecting into DIW-1 ranged from 6743 to 7455 gallons per minute (gpm) and averaged 7099 gpm for a period of six hours and 37 minutes. The formation pressure ranged from 1329.2 to 1331.5 psig and averaged 1330.9 psig while injecting into DIW-1 at an average flowrate of 7099 gpm. The formation pressure differential, between the pressure during the 24 hour period prior to injection and the pressure while injecting into DIW-1 at an average flowrate of 7099 gpm, was approximately 4 psi. This represents the formation pressure increase due to operation of DIW-1 at a flowrate of 7099 gpm. Using the formation pressure increase of 4 psi and a flowrate of 7099 gpm yields a formation specific capacity of 768 gpm/foot [7099 gpm ÷ (4 × 2.31 feet per psig) = 768 gpm/foot].

An estimated transmissivity of the injection zone using the empirical relationship derived from the Jacob method where specific capacity is equal to transmissivity divided by 2000 (Reference 265) was calculated.

Formation specific capacity = T ÷ 2000

where T = transmissivity in gallons per day per foot (gpd/foot)

T= 768 gpm/ft (formation specific capacity) × 2000=1,536,000gpd/foot

T= approximately 205,000 feet ^{2}/day

A four-step injection test conducted at the Florida Keys Aqueduct Authority site (Reference 264) located about ten miles west of the Turkey Point site gives transmissivity values between 53,730 square feet per day and 69,574 square feet per day. Data from Boulder Zone test wells within approximately ten miles of the Turkey Point site suggest a range of transmissivity between 60,000 square feet per day and 600,000 square feet per day; the best estimate for the average value is approximately 250,000 square feet per day.

Revisions to FSAR Subsection 2.4.12.2.1.3 were made in COLA Revision 5 as shown below. Additional changes designated by differences in font color and style (insertions in bold red font and deletions shown as strikethrough) will be made in a future COLA revision:

The wastewater disposal requirements for Units 6 & 7 are a combined total of approximately 18 million gallons per day when using only reclaimed water from the MDWASD as a cooling water source, and as high as 85 million gallons per day when using only saltwater from radial collector wells as a cooling water source. Therefore, the combined disposal volumes are between 18 and 85 million gallons per day when using a combination of reclaimed and saltwater for cooling. For purposes of providing upper bounds for the project, a disposal capacity of 85 million gallons per day is assumed. Based on this disposal capacity, the deep injection wells consist of ten primary wells and two backup wells for use during routine maintenance or in the event of unscheduled shutdowns. Exploratory well EW-1 **was** ~~will be~~ converted to **DIW-1 as** one of the Class I Industrial deep injection wells **after demonstrating** ~~if~~ the geology and hydrogeology of the site **was** ~~is determined to be~~ appropriate for deep well injection. As part of the injection permit, a dual-zone monitoring well was also installed. The deep injection wells will be regulated by and fully comply with the requirements of Rule 62-528**,** ~~of the~~ F.A.C**.** (Reference 229) and applicable FDEP rules.

Revisions to FSAR 2.4.12.6, References, were made in COLA Revision 5 as shown below:

262. Meyer, F., *Evaluation of Hydraulic Characteristics of a Deep Artesian Aquifer from Natural Water-Level Fluctuations, Miami, Florida,* Report of Investigations No. 75, U.S. Geological Survey and Bureau of Geology, Florida Department of Natural Resources, Tallahassee, Florida, 1974.

263. Singh U., G. Eichler, C. Sproul, and J. Garcia, *Pump Testing Boulder Zone Aquifer, South Florida,* Journal Hydraulic Engineering, Vol. 109, No. 8, pp. 1152-1160, August 1983.

264. AECOM, *Engineer Report on the Construction & Testing of Deep Injection Well IW-1 and Dual Zone Monitoring Well MW-1 at J. Robert Dean WTP, Florida City, FL,* Prepared for Florida Keys Aqueduct Authority, December 2009.

265 Driscoll, Groundwater and Wells 2nd Edition: Johnson Filtration Systems, St. Paul, Mn., 1986.

Revisions to FSAR Subsection 3.2.1.3 were made in COLA Revision 5 as shown below:

3.2.1.3 Classification of Building Structures

Add the following text to the end of DCD Subsection 3.2.1.3:

The seismic classification of the deep well injection system is provided in Table 3.2-201. (LMA PTN SUP 3.2-1)

The following section was added to FSAR Subsection 3.2.2 in COLA Revision 5 as shown below:

See Table 3.2-202 for the classification of the deep well injection system. (LMA PTN SUP 3.2-2)

The following Table 3.2-201 was added to COLA Revision 5 as shown below (LMA PTN SUP 3.2-1):

Table 3.2-201
Seismic Classification of Building Structures

Structure	Category[(a)]
Deep Well Injection System	NS

C-I – Seismic Category I
C-II – Seismic Category II
NS – Non-Seismic

(a) Within the broad definition of seismic Category I and II structures, this system contains structural subsystems the failure of which would not impair the capability for safe shutdown.

The following new Table 3.2-202 was added to COLA Revision 5 as shown below. Additional changes designated by differences in font color and style (insertions shown in bold red font and deletions shown as strikethrough) will be made in a future COLA revision (LMA PTN SUP 3.2-2):

Table 3.2-202

AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Deep Well Injection System (DIS)			**NS[(a)]**		Location : Yard
System Components are Class E					

(a) The Liquid Radwaste System (WLS) terminates at the point at which the radwaste enters the DIS in the discharge stream from the blowdown sump, which is the point of dilution for the PTN Units 6 & 7 site. Refer to Figure 9.2-203

FSAR Subsection 9.2.9.2.2 was revised in COLA revision 5 as follows:

Blowdown Sump

The blowdown sump is a lined concrete structure common to Units 6 & 7 that receives wastewater from the wastewater retention basins of both units, circulating water system (CWS) blowdown from both units, and effluent from the sanitary treatment facility. The blowdown sump is located southeast of the units near the makeup water reservoir. In the absence of CWS blowdown, dilution flow can be supplied to the blowdown sump from the raw water system (reclaimed water or saltwater sources). The waste stream from the blowdown sump is pumped to the deep injection wells. The pumps, downstream piping and injection wells are part of the deep well injection system (DIS) described in Subsection 9.2.12. The blowdown sump, injection pumping station and associated piping to the injection wells is sized with adequate capacity to accommodate the highest expected influent flow rate to the blowdown sump without overflowing of the sump.

FSAR Subsection 9.2.11 was revised in COLA revision 5 as shown below:

Add the following subsections after DCD Subsection 9.2.10. DCD Subsections 9.2.11 and 9.2.12 are renumbered as Subsections 9.2.13 and 9.2.14, respectively.

FSAR Subsection 9.2.11.4 was revised in COLA revision 5 as shown below:

9.2.11.4 Safety Evaluation

The RWS has no safety-related function and therefore requires no nuclear safety evaluation.

The RWS does not have the potential to be a flow path for radioactive fluids. The RWS has no direct interconnection with any system that contains licensed radioactive fluids. The liquid radwaste effluent interface is at a point in the DIS that prevents the effluent from entering the RWS.

FSAR Subsection 9.2.12 was added in COLA revision 5 as shown below. Additional changes designated by differences in font color and style (insertions shown in bold red font and deletions shown as strikethrough) will be made in a future COLA revision as follows:

9.2.12 DEEP WELL INJECTION SYSTEM (LMA STD DEP 1.1-1)

The DIS provides underground disposal of plant wastewater, including CWS blowdown and liquid radwaste, into the Boulder Zone. The system consists of 12 deep injection wells, 6 dual-zone monitoring wells, piping, valving, pumps, and instrumentation for system operational monitoring.

Dilution of the liquid radwaste is initiated as the radwaste enters the DIS in the discharge stream from the blowdown sump. The content of the blowdown sump is a combination of waste streams largely comprised of reclaimed water or saltwater from circulating water system blowdown during plant operation or from the alternate dilution flow paths when circulating water system blowdown is not sufficient or available for dilution. The DIS is shown in Figure 9.2-203. (LMA PTN SUP 9.2-2)

The alternate dilution flow, when using reclaimed water as the cooling water makeup source, is reclaimed water supplied from the makeup water reservoir. The makeup water reservoir is a concrete structure that contains between 275 and 300 million gallons of reclaimed water that is available for use as makeup for the cooling tower evaporative, drift, and blowdown losses and the alternate dilution flow to achieve the 12,000 gpm dilution requirement. The reservoir contains approximately 5 days of makeup water to supply both units' cooling towers operating at full power.

9.2.12.1 Design Basis

9.2.12.1.1 Safety Design Basis

The DIS has no safety-related function and therefore has no nuclear safety design basis.

Failure of the DIS does not affect the ability of safety-related systems to perform their intended function. The DIS functions to dispose and confine plant wastewater in the Boulder Zone.

The DIS is the flow path for liquid radwaste and liquid nonradioactive waste discharge.

9.2.12.1.2 Power Generation Design Basis

9.2.12.1.2.1 Normal Operation

DIS operations maintain the required minimum dilution factor to control the concentrations of liquid radwaste discharges arising from the release of WLS monitor tank contents. The activity concentration of the radwaste portion of the effluent is controlled to 10 CFR Part 20, Appendix B, effluent concentration limits (ECLs) by specifying and maintaining flow rates at the blowdown sump discharge corresponding to at least the minimum dilution factor (DF). The required minimum DF is calculated and applied prior to the release of liquid radwaste (batch is the only release mode anticipated) to ensure the activity concentration of the mixture complies with 10 CFR Part 20, Appendix B, ECLs. Implementation of the liquid radwaste effluent control program is in accordance with the Turkey Point Units 6 & 7 Offsite Dose Calculation Manual (ODCM), an operational program identified in FSAR Table 13.4-201.

9.2.12.1.2.1.1 Reclaimed Water

The deep well injection flow rate when 100 percent reclaimed water is in use for cooling is approximately 12,500 gallons per minute (gpm) (normal) and 13,000 gpm (maximum) for both units. The liquid radwaste component of this flow rate is 3 gpm (normal) and 150 gpm (maximum) for both units. Three deep injection wells are sufficient for operation with reclaimed water – two active and one as a backup.

9.2.12.1.2.1.2 Saltwater

The deep injection well flow rate when 100 percent saltwater is in use for cooling is nominally approximately 58,000 gpm (normal) and 59,000 gpm (maximum) for both units. The liquid radwaste component of this flow rate is 3 gpm (nominal) and 150 gpm (maximum) for both

units. Eleven deep injection wells are sufficient for operation with saltwater – nine active and two as backup.

9.2.12.1.2.2 Outage Mode Operation

Refer to FSAR Section 9.2.12.1.2.1.

~~A minimum of 6000 gpm dilution flow will be provided during outage mode operation when discharging liquid radwaste from a single unit (12,000 gpm minimum if discharging from two units) to ensure the annual total quantity of radioactive material released meets the 10 CFR Part 20 effluent concentration limits, the annual offsite dose limits in 10 CFR 50 Appendix I, and any local requirements. If the minimum dilution flow is unavailable, the liquid radwaste discharge rate can be reduced to maintain acceptable concentrations.~~

9.2.12.2 System Description

The following system and component descriptions are typical. The actual system and components may vary.

9.2.12.2.1 General Description

The **proposed** location of the deep injection wells and dual zone monitoring wells **are** ~~is~~ depicted on Figure 9.2-202. The **liquid waste stream collection and disposal** ~~DIS process~~ schematic is shown in Figure 9.2-203. Classification of components and equipment for the DIS is given in Section 3.2. The operation of the deep well injection system is identical for both reclaimed and saltwater – only the number of deep injection wells used differs. Additional valving and system monitoring is required for the system when saltwater is used as a makeup water since more deep injection wells are required, due to the higher flow rates.

9.2.12.2.2 Component Description

Deep Injection Wells

Each of the deep injection wells is constructed with concentric steel casings to isolate and protect groundwater from injected fluid. Each injection well is constructed with new and unused 64- (or greater), 54-, 44-, 34-, and 24-inch outside diameter steel casings designed to last for the life expectancy of the well. The 64- (or greater), 54-, 44-, and 34-inch diameter casings have a minimum wall thickness of 0.375-inches and conform to American Society for Testing and Material (ASTM) 139, Grade B specifications. The final 24-inch diameter casing has a

0.5-inch wall thickness, is seamless, and conforms to American Petroleum Institute (API) 5L specifications or ASTM 153 specifications. The well casings are selected to provide protection against casing failure during cementing operations, protect against failure during operation of the well and subsequent pressure tests, and provide sufficient corrosion protection. The 54-, 44-, and 34-inch diameter casings are encased in cement on both the outside and the inside of the casing to protect against exposure to groundwater. The outside of the 24-inch diameter casing is encased in cement to protect against exposure to groundwater. A nominal 18-inch diameter fiberglass reinforced plastic (FRP) injection tubing with a wall thickness of 0.76-inches is installed inside the 24-inch diameter casing to protect the 24-inch diameter casing from exposure to injected fluids and subsequent corrosion. The annular space between the 24-inch diameter casing and the FRP injection tubing will be filled with a non-hazardous corrosion inhibitor and sealed at the base and top to create a pressure-tight annular space. Figure 9.2-204 depicts a typical deep injection well. This schematic is based on actual conditions observed at ~~Exploratory Well EW-1~~**Deep Injection Well DIW-1**.

Dual Zone Monitoring Wells

Each of the dual zone monitor wells is constructed with concentric steel casings and a final FRP casing. Each monitor well is constructed with new and unused 44-, 34-, 24-, 16-, and 6.625-inch diameter casings/tubings designed to last for the life expectancy of the well. The 44-, 34-, and 24-inch diameter casings are made of steel with a minimum wall thickness of 0.375 inches and conform to ASTM 139, Grade B specifications. The 16-inch diameter casing is made of steel and has a 0.5-inch wall thickness, is seamless, and conforms to API 5L specifications or ASTM 153 specifications. The well casings are selected to provide protection against casing failure during cementing operations and provide sufficient corrosion protection for the life of the well. The 34-and 24-inch diameter casings are encased in cement on both the outside and the inside of the casing to protect against exposure to groundwater. The outside of the 16-inch diameter casing is encased in cement to protect against exposure to groundwater. A nominal 6.625-inch diameter FRP casing with a wall thickness of 0.27 inches serves as the final casing of the well is selected due to its corrosion resistance. Figure 9.2-205 depicts a typical dual zone monitoring well.

The typical sampling system and associated equipment used for the dual zone monitoring wells are described below. The upper monitor zone sampling system is equipped with a surface-mounted centrifugal pump and the pump for the lower monitoring zone sampling system is a submersible turbine pump installed inside the lower monitor zone casing via a drop pipe. The pumps are connected to purge piping and have a totalizing flowmeter on each purge piping line. The totalizing flowmeters

allow measurement of the volume of water that has been purged from the monitoring zones for each sampling event. A separate purge piping line and totalizing flowmeter is utilized for each monitoring zone to ensure against comingling of monitoring zone fluids. The purge water holding tank is located near the dual-zone monitoring well or on the containment pad of one of its two associated injection wells. The purge piping is buried as it leaves the monitoring well containment pad and either leads to the existing cooling canal system where it is released or it leads to a purge water holding tank. The upper zone and lower zone purge lines flow into the holding tank when the monitoring zones are being purged in preparation for sample collection. The holding tank is equipped with a pump and water level regulating system to ensure that the holding tank capacity is not exceeded. A pump is used to pump water from the holding tank to one of the associated deep injection wells, where it is pumped down the injection well and into the injection zone. The purge piping for each monitor zone is also connected to a sample collection sink that is located either on the monitor well containment pad or on the containment pad of one of the associated injection wells.

Considering the large depth of confining strata present above the injection zone (approximately 985 feet for DIW-1), it is highly unlikely that plant-derived radioactive contamination would be found in water produced in either monitor zone of the dual-zone monitor well. However, if plant-derived radioactive contamination is detected, the affected water will be pumped to a purge water holding tank and then pumped down one of the injection wells.

Piping

Piping from the blowdown sump dilution connection point is routed to the deep injection wells and distributed in two branches; one branch is oriented in a north-south direction and located to the east of Unit 6. The second branch is oriented in the east-west direction and located to the south of Units 6 & 7.

The injectate piping connecting the pump station to the deep injection wells consist of a main line from the pump station that passes near each injection well and injectate feeder lines that connect the main line to each deep injection well. The piping is constructed of ~~either high density polyethylene (HDPE) or~~ steel. The pipe diameter closest to the blowdown sump is approximately 60-inches in diameter and the pipe diameter at the last well in a branch is approximately 24-inches in diameter.

Valves

There are multiple valves on each deep injection well. This valving consists of an 18-inch diameter gate valve located on the wellhead approximately three feet above where the injection well exits the ground, and an 18-inch diameter butterfly valve located on the horizontal run of surface pipe on the concrete well pad. **Air/v**~~V~~acuum **release valves** ~~breakers~~ are provided at the appropriate location on each branch of the blowdown sump discharge piping.

The air/vacuum release valves are designed for the specific application and the level of service expected during operation. The injection lines on the operating wells remain full of water during operation, minimizing the number of times the valves are required to change position. Operating procedures provide the appropriate instructions to ensure actions are implemented correctly to limit or avoid pressure surges in the system. The valves are included in the preventive maintenance program to ensure the valves are checked periodically and maintained within acceptable parameters.

Redundant isolation valves are installed on the injectate main line to allow isolation of the main line in the case of damage or failure to this line. Each injectate feeder line is equipped with redundant isolation valves where the injectate feeder lines connect to the main line to allow for the isolation of each individual injectate feeder line. Electronic remotely operated valves will isolate deep injection wells.

Vent valves are installed at required locations on each branch line. Vent valves are included to remove air either coming out of solution or air introduced by the **air/**vacuum **release valves** ~~breakers~~ in the event that air is not swept out of the line during system startup. During normal operation, the vent lines are capped and the vent valves locked closed to prevent inadvertent operation. The vents are manually operated, as needed, for pump startup.

9.2.12.3 System Operation

The DIS operates during normal modes of operation, including startup, power operation, cooldown, shutdown, and refueling.

Dilution water is available during all modes of plant operation to maintain a minimum 6000 gpm dilution rate for each unit discharging liquid radwaste. The DIS designed to accommodate the blowdown sump discharge flow rates for either source of CWS makeup water - reclaimed water or saltwater. The blowdown flow rate is determined by the number of deep injection wells used.

9.2.12.4 Safety Evaluation

The DIS has no safety-related function and therefore requires no nuclear safety evaluation.

The ~~DIS is a~~ **deep well injection system is the** flow path for liquid radwaste discharges. Valving is provided to prevent or minimize the potential for radioactive fluid release to the environment due to damage to the above grade piping or operational issues with the deep injection wells. **Section 11.2 describes the potential releases to the environment and includes the evaluation of these postulated releases.**

9.2.12.5 Tests and Inspections

Initial test requirements for the DIS are described in Subsection 14.2.9.4.28.

System performance and structural and pressure integrity of system components is demonstrated by operation of the system, monitoring of system parameters such as flow and pressure, and visual inspections.

9.2.12.6 Instrumentation Applications

Continuous injection rate and injection pressure monitoring is performed at each deep injection well in service. Continuous monitoring of the water level of both monitor zones of the dual zone monitor wells is also performed. The data is transmitted to each control room where it is continuously monitored.

Radiological and chemical monitoring is also performed at each operational deep injection well and dual zone monitor well to assess system performance and to monitor confinement in the subsurface. **Sections 11.2 and 11.5 describe the radiation monitoring controls governing the discharge to the deep well injection system.**

FSAR Figures 9.2-202, 9.2-203, 9.2-204 and 9.2-205 were added in COLA revision 5 as shown below. Additional changes designated by differences in font color and style (insertions shown in bold red font and deletions shown as strikethrough) will be made in a future COLA revision as follows (Note FSAR Figure 9.2-203 will be revised in a future COLA revision as shown below):

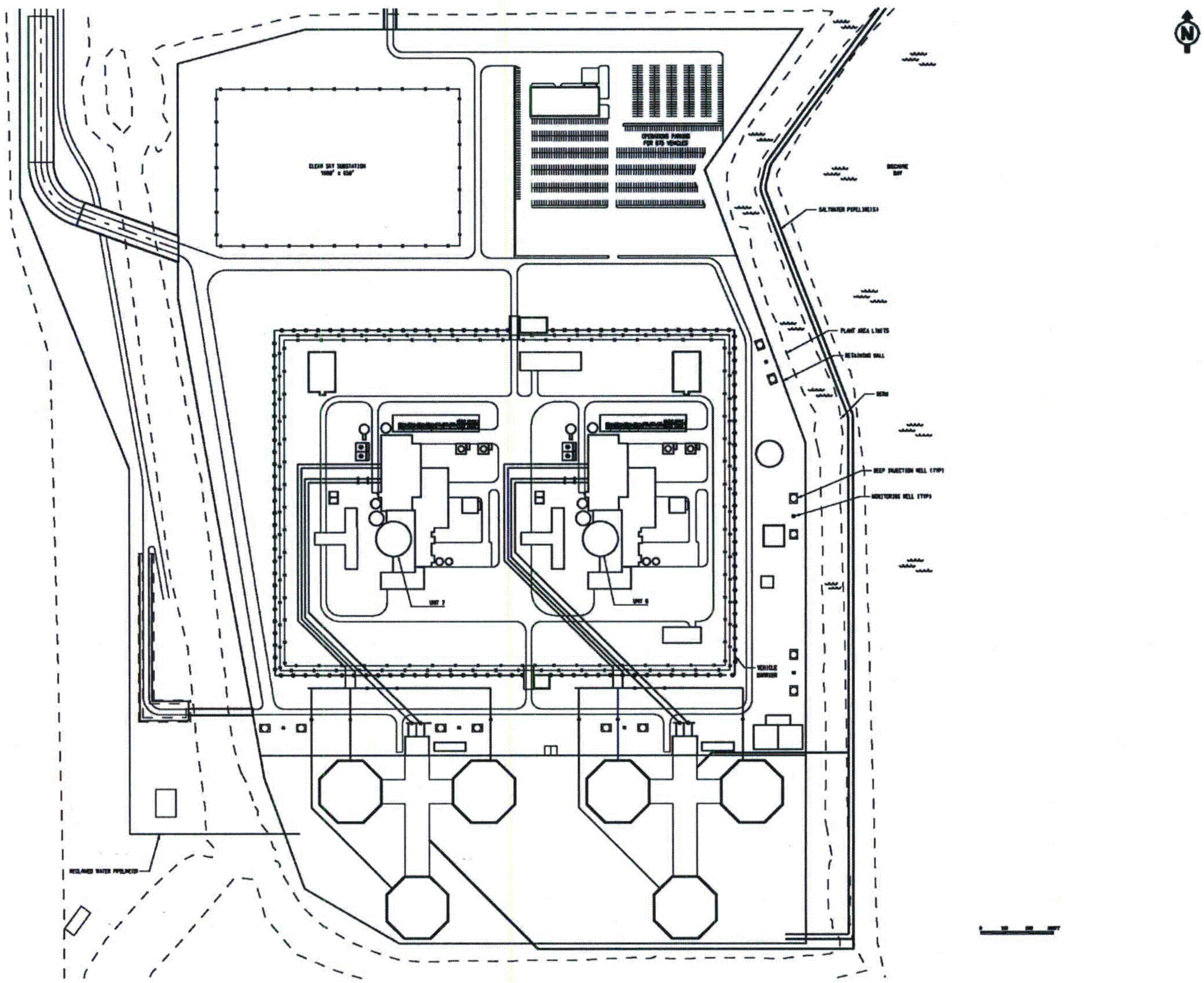

Figure 9.2-202 Deep Injection Well and Dual Zone Monitoring Well Locations

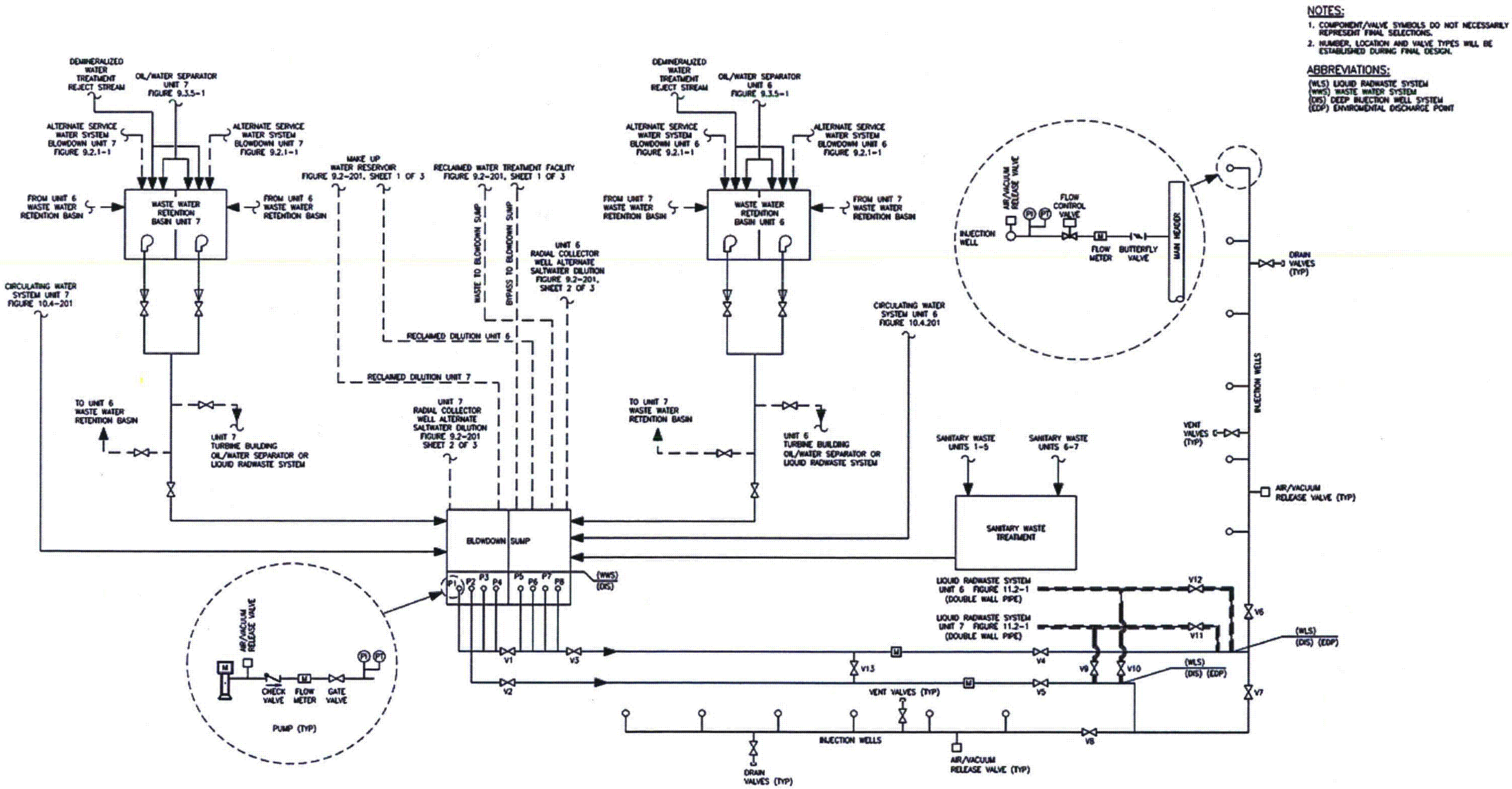

Figure 9.2-203 ~~Deep Well Injection System~~ Liquid Waste Stream Collection and Disposal Schematic (Typical)

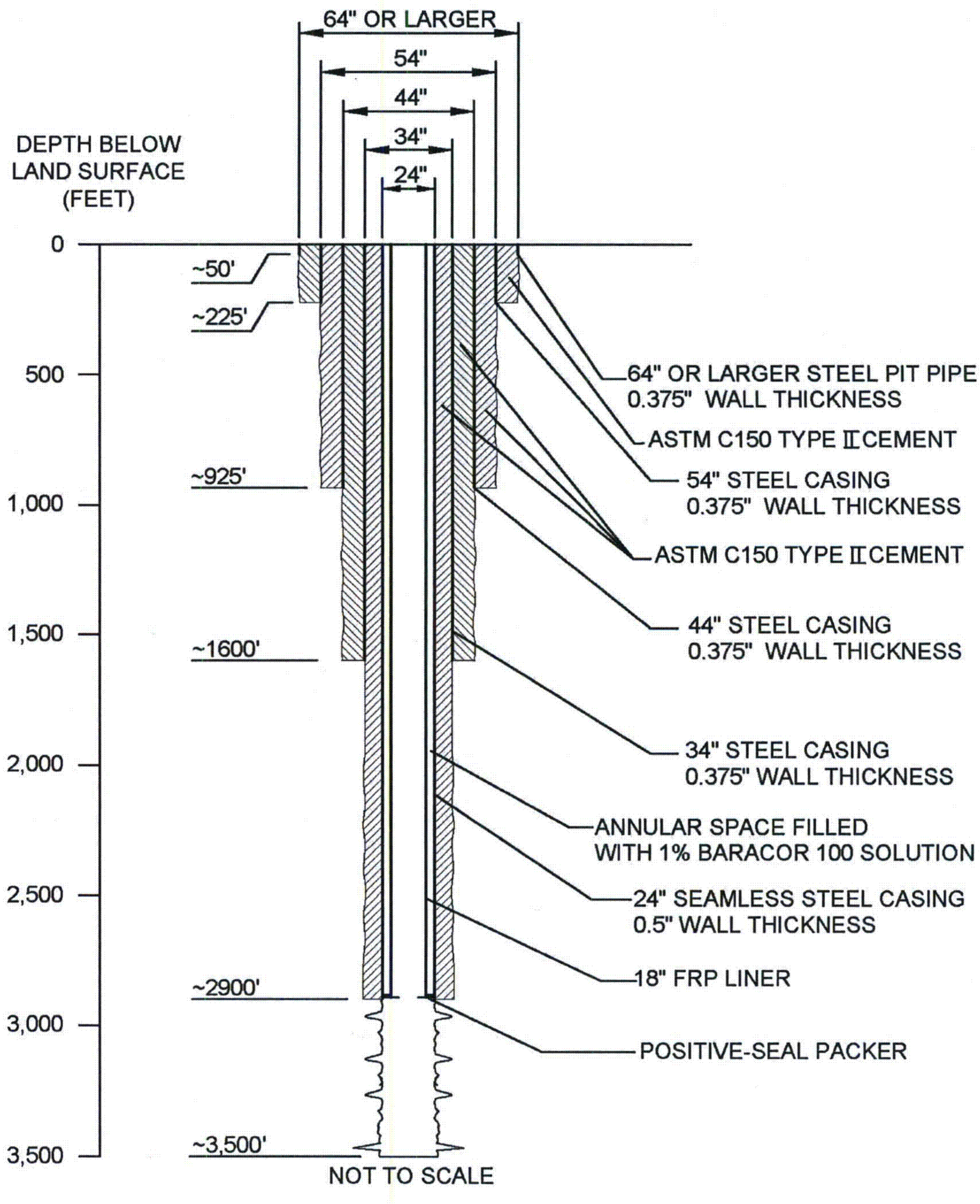

Figure 9.2-204 Deep Injection Well (Typical)

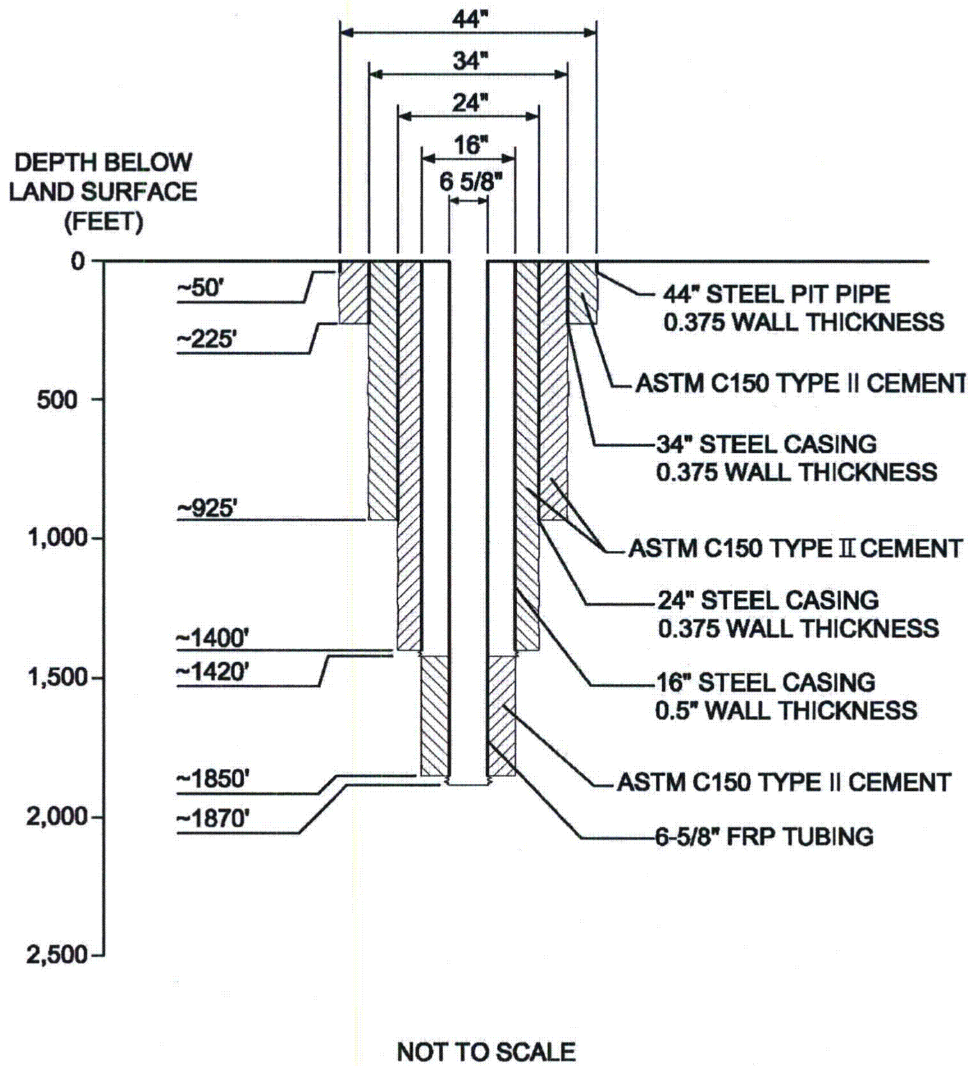

Figure 9.2-205 Dual Zone Monitoring Well (Typical)

The following Subsections were renumbered in COLA revision 5 as shown below:

9.2.13 COMBINED LICENSE INFORMATION

9.2.13.1 Potable Water

9.2.13.2 Wastewater Retention Basins

9.2.14 REFERENCES

FSAR Subsection 10.4.12.3 was revised in COLA revision 5 as shown below:

This COL Item is duplicated in the Subsection 9.2.13.1 COL Item and is addressed as stated in that subsection.

The following paragraph will be added at the end of Subsection 11.2.1.2.4 in a future COLA revision as follows:

The activity concentration of the radwaste portion of the effluent is controlled to 10 CFR Part 20, Appendix B, effluent concentration limits (ECLs) by specifying and maintaining flow rates at the blowdown sump discharge corresponding to at least the minimum dilution factor (DF). The required minimum DF is calculated and applied prior to the release of liquid radwaste (batch is the only release mode anticipated) to ensure the activity concentration of the mixture complies with 10 CFR Part 20, Appendix B, ECLs. Implementation of the liquid radwaste effluent control program is in accordance with the Turkey Point Units 6 & 7 Offsite Dose Calculation Manual (ODCM), an operational program identified in FSAR Table 13.4-201.

The following paragraph will be added at the end of Subsection 11.5.3 in a future COLA revision as follows:

The activity concentration of the radwaste portion of the effluent is controlled to 10 CFR Part 20, Appendix B, effluent concentration limits (ECLs) by specifying and maintaining flow rates at the blowdown sump discharge corresponding to at least the minimum dilution factor (DF). The required minimum DF is calculated and applied prior to the release of liquid radwaste (batch is the only release mode anticipated) to ensure the activity concentration of the mixture complies with 10 CFR Part 20, Appendix B, ECLs. Implementation of the liquid radwaste effluent control program is in accordance with the Turkey Point Units 6 & 7 Offsite Dose Calculation Manual (ODCM), an operational program identified in FSAR Table 13.4-201.

The following Subsection 14.2.9.4.28 was added in COLA revision 5 as shown below. Additional changes designated by differences in font color and style (insertions shown in bold red font and deletions shown as strikethrough) will be made in a future COLA revision as follows:

14.2.9.4.28 Deep Well Injection System (LMA PTN SUP 14.2-1)

Purpose

Deep well injection system testing verifies that the as-installed components **properly perform their specific system function, described in Subsection 9.2.12, of** injecti**ng** effluent from the cooling tower blowdown, radioactive waste system, and wastewater system**.** ~~as described in Subsection 9.2.12.~~

Prerequisites

~~Construction operational conversion testing of the deep well injection system is completed.~~ **Construction of each deep injection well is complete and** ~~T~~**the injection well** components **have been successfully tested.** ~~are operational and the deep injection wells are able to accept effluent.~~ Required support systems, electrical power supplies, and control circuits are operational.

General Test Methods and Acceptance Criteria

The deep well injection system component and ~~integrated~~ system performance is observed to verify that the system functions, as described in Subsection 9.2.12 and in appropriate design specifications. The individual component and integrated system tests include:

a. Operation of the valves is verified. (LMA PTN COL 14.4-5)

b. Operation of the system instrumentation, controls, actuation signals, alarms, and interlocks is verified.

Subsection 14.2.9.4.28 includes provisions for the initial testing of system components, including actuation signals and interlocks. The examples provided are intended to be inclusive of potential system components but do not represent system design finalization. The initial test program description will be revised, as required, to reflect final system design. Figure 9.2-203 does not include any instrumentation, control, actuation signal, alarms, or interlocks.

COLA Part 7 was revised as follows to include FSAR Section 9.2.14 (Note departure is an administrative departure for organization and numbering for the FSAR):

Departure Number: STD DEP 1.1-1

AFFECTED DCD/FSAR SECTIONS:

2.1.1; 2.1.4; 2.2.1; 2.2.4; 2.4.1; 2.4.15; 2.5; 2.5.6; 9.2.11; 9.2.12; 9.2.13; 9.2.14; 9.5.1.8; 9.5.1.9; 13.1; 13.1.4; 13.5; 13.5.3; 13.7; 17.5; 17.6; 17.7; 17.8 (Note the affected sections may vary in subsequent COL Applications, but the departure is standard).

ASSOCIATED ENCLOSURES:

None

NRC RAI Letter No. PTN-RAI-LTR-072 Dated February 20, 2013

SRP Section: 11.02 – Liquid Waste Management Systems

Supplemental Staff RAI to RAI 11.02-1, 11.02-2, 11.02-3, and 11.02-4.

NRC RAI Number: 11.02-6-7 (eRAI 6985)

[Refer to Attachment 1 for the preamble to this RAI.]

Question 7

While the applicant indicates that liquid effluent discharges will be diluted with a flow rate of 12,500 gpm using reclaimed municipal waste water or 58,000 gpm using seawater, the description does not address the conditions and dilution flow rates when the plant is not operating, such as during extended outages. The applicant is requested to describe in the appropriate FSAR section deep well injection rates under different plant conditions, procedural controls for the disposal of liquid effluents whenever the plant is in an outage mode, sources of dilution flow rates in this operating status, and expected dilution flow rates. The applicant should address whether it will impose in the ODCM and SREC restrictions such that discharges of liquid effluents will not be initiated unless a minimum dilution flow rate is established in demonstrating compliance with effluent concentration limits and unity-rule of 10 CFR Part 20, Appendix B, Table 2, Column 2; dose limits of 10 CFR 20.1301, 20.1302, and 20.1301(e); and numerical guides, design objectives, and ALARA provisions of Appendix I to 10 CFR Part 50 for liquid effluents.

FPL RESPONSE:

Injection from the blowdown sump may be necessary during outage mode operation. If radioactive effluent will be discharged during outage conditions, the required minimum dilution factor to control liquid radwaste (LRW) discharges arising from the release of WLS monitor tank contents will be maintained. The activity concentration of the radwaste portion of the effluent is controlled to ~~a minimum of 6000 gpm dilution flow rate per unit will be maintained to ensure the effluent concentration limits of~~ 10 CFR Part 20, Appendix B effluent concentration limits (ECL) by specifying and maintaining flow rates at the blowdown sump corresponding to at least the minimum dilution factor. ~~are met, as stated in DCD Subsection 11.2.3.3.~~ The alternate dilution water, which is only required when reclaimed water is used as the cooling system makeup water source, will be provided from either the makeup water reservoir, or the radial collector wells. If this dilution water is unavailable, the radioactive effluent can be temporarily stored in tanks onsite. Alternatively, radioactive effluent may be discharged when the dilution flow would yield less than the required dilution factor ~~is less than the DCD~~

~~6000 gpm~~ by reducing the effluent release rate at the dilution point. This will be achieved by calculating and applying a minimum dilution factor through a combination of LRW release and dilution flow rate adjustments.

The dilution requirements to meet 10 CFR Part 20 are prescribed in DCD Subsection 11.2.3.3. Additional dose limits, as prescribed in 10 CFR 20.1301, 10 CFR 20.1302, 10 CFR 20.1301(e), and Appendix I to 10 CFR Part 50 are discussed in the response to eRAI 6985, Questions 11.02-6-1 and 11.02-6-2. FPL will not impose any conditions on Standard Radiological Effluent Controls (SRECs) or discharge restrictions in its Offsite Dose Calculation Manual (ODCM).

FSAR Subsection 9.2.12 will be added to provide deep well injection rates under different plant conditions, procedural controls for the disposal of liquid effluents whenever the plant is in an outage mode, sources of dilution flow rates in this operating status, and expected dilution flow rates. FSAR Subsections 11.2.1.2.4 and 11.5.3 will be added regarding the implementation of the liquid effluent release program in the ODCM. (see ASSOCIATED COLA REVISION section).

This response is PLANT SPECIFIC.

References:

None

ASSOCIATED COLA REVISIONS:

Refer to the response to NRC RAI No. 11.02-6-6 ~~(Attachment 2)~~.

ASSOCIATED ENCLOSURES:

None

NRC RAI Letter No. PTN-RAI-LTR-072 Dated February 20, 2013

SRP Section: 11.02 – Liquid Waste Management Systems

Supplemental Staff RAI to RAI 11.02-1, 11.02-2, 11.02-3, and 11.02-4.

NRC RAI Number: 11.02-6-8 (eRAI 6985)

[Refer to Attachment 1 for the preamble to this RAI.]

Question 8

With respect to system operations and anticipated operational occurrences, the applicant is requested to assess a postulated event involving the failure of some injection equipment, such as injection pipe damaged by a moving vehicle, valve failures, over pressurization, blowout of seals, joint failures, and operator errors. This evaluation would consider programs and procedures used to control radiation exposures and doses to plant workers in responding to accidental spills of the injectate on the site and runoff to unrestricted areas via the site's surface water drainage system. This evaluation should consider the specific design features of the deep well injection system, its location on the applicant's property, engineered and administrative controls used in terminating the injection flow or diverting it to other injection wells.

FPL RESPONSE:

A description of the injectate piping system connecting the pumping station to each injection well, and the wellhead piping of each injection well will assist in providing a response to this question. The deep well injection system (DIS) will be designed to have redundant measures to allow isolation of failed equipment. Pressure rating safety factors will be designed into all injectate piping to prevent damage to injectate piping due to over pressurization, blowout of seals, and operator errors. These items are discussed in the following paragraphs.

The injectate piping system connecting the pump station to the deep injection wells will consist of a main line from the pump station that passes near each injection well and injectate feeder lines that connect the main line to each deep injection well. The piping will be constructed of ~~either high density polyethylene (HDPE) or~~ steel and the pipe diameter from the sump pump discharge to each branch will be of varying diameters, depending on the distance from the blowdown sump. Although the detailed piping layout and design has not been completed, the pipe size will decrease as the distance from the sump increases in each of the branches. The pipe diameter closest to the blowdown sump will be approximately 60-inches in diameter and the pipe diameter at the last well in a branch will be approximately 24-inches in diameter. The

final pipe sizing will be a function of the pipe routing and the design velocities. Redundant isolation valves will be installed on the injectate main line to allow isolation of the main line in the case of damage or failure to this line. Each injectate feeder line will be equipped with redundant isolation valves where the injectate feeder lines connect to the main line to allow for the isolation of each individual injectate feeder line.

Each deep injection well will be located on a curbed concrete containment pad approximately 30-feet by 40-feet. Each deep injection well pad, including where the injectate feeder line exits the ground next to the concrete containment pad, will contain features to protect the piping. These features will include locked protective fencing around the above ground portion at each well and/or closely spaced bollards of steel or concrete to eliminate unauthorized personnel access or vehicle damage to the injection well and associated piping. The injection piping will include appurtenances, such as air/vacuum release valves ~~breakers~~, vent valves, drain valves and access ways, as necessary, for proper operation and maintenance of the piping.

There will be multiple valves on each deep injection well to allow isolation in order to prevent upward flow of injected fluid and discharge onto the containment pad due to a damaged injectate feeder line. This valving will consist of an 18-inch diameter gate valve located on the wellhead approximately three feet above where the injection well exits the ground, and an 18-inch diameter butterfly valve located on the horizontal run of surface pipe on the concrete well pad. These valves will provide a redundant system for isolating the injection well. The injectate pipeline system connecting the pump station to the injection wells will be buried from the pump station to the edge of the concrete pad that will surround each injection well. The distance from the point where the piping exits the underground to the injection tubing will be approximately 50-feet. The above ground piping at the injection wells will be accessible for visual inspection to detect any potential leakage from pipe and valve fittings. Air/vacuum release valves ~~Vacuum breakers~~ will be provided at the appropriate location on each branch of the blowdown sump discharge piping. The air/vacuum release valves ~~These vacuum breakers~~ are provided to accommodate situations where pumps may be stopped or started or valves are cycled in branch lines (a water column separation could occur without vacuum valves). This could leave a vapor pocket between the pump or valve and the end of the water column and cause water hammer. The installation of the air/vacuum release valves ~~vacuum breakers~~ will provide assurance of continued integrity of the blowdown lines.

Vent and drain valves will be installed at required locations on each branch line. Vent valves are included to remove air either coming out of solution or air introduced by the air/vacuum release valves ~~breakers~~ in the event that air is not swept out of the blowdown line during system startup. The vent(s) will be located at system high points or where air would be most likely to collect. During normal operation, the vent lines and drain lines will be capped and the ~~vent~~ valves locked closed to prevent inadvertent operation. The vents will be manually operated, as needed, for pump startup. Personnel will be present at the vent valve location to allow air to escape and then close the vent valves when the line fills with water.

The piping, manifolds, valves, controls, and appurtenances are designed to minimize inadvertent or unidentified releases to the environment. Integrity of the injectate piping will be monitored for leakage by performing periodic walkdowns, including the system piping and fittings in the site's routine maintenance program and perform groundwater monitoring, as necessary, as part of the Units 6 & 7 Groundwater Monitoring Program.

The DIS equipment will be designed to minimize the possibility of damage to the injection equipment. These measures will minimize the likelihood of damage by a moving vehicle, over pressurization, blowout of seals, and joint failures.

In the event of a failure of some injection equipment, such as injectate feeder pipe or wellhead surface piping damaged by a moving vehicle or valve failures, valves would be closed to isolate the damaged equipment and minimize the volume of spilled injectate. ~~Electronic remotely isolated valves will isolate the damaged well.~~ The injection well affected by the damage would be removed from service. The damaged piping would then be repaired and pressure tested to confirm a leak-proof repair. One of the redundant injection wells would be ~~temporarily~~ placed into service to make up for the temporarily out-of-service injection well. Upon completion of the repair and pressure testing, the well affected by the damage could be placed back into service.

If the injectate main pipe were damaged, the redundant isolation valves on the main would be closed, isolating the portion of damaged pipe from the pump station. The isolation valves at each of the feeder lines would also be closed, thus isolating the main and preventing injectate from back flowing up the wells and into the main. The damaged main would then be repaired and pressure tested to demonstrate a leak-proof repair prior to opening the isolation valves on the main and feeder lines and resuming normal operations. Injectate spilled and pooled on the ground would be pumped into a tank, transported to the pumping station, and ultimately

pumped down injection wells that remain in service. Soil impacted by the injectate spill would be removed and managed as radioactive waste.

In the event of an accidental spill, isolation valves would be closed to isolate the equipment that allowed the spill to occur to minimize the spill volume. Each injection well will be located on a curbed concrete containment pad to contain any injectate spilled from the injection well or injection well wellhead piping. Pooled injectate off the concrete containment pad would be pumped into a tank, transported to the pump station and ultimately disposed of via the deep well injection system. Any spillage shall be contained and properly managed in accordance with Radiation Protection and ALARA Program requirements. Soil impacted by the injectate spill to the ground would be removed and managed as radioactive waste. Note that the above are proposed FPL procedures.

This response is PLANT SPECIFIC.

References:

None

ASSOCIATED COLA REVISIONS:

~~None.~~Refer to the response to NRC RAI No. 11.02-6-6.

ASSOCIATED ENCLOSURES:

None

NRC RAI Letter No. PTN-RAI-LTR-072 Dated February 20, 2013

SRP Section: 11.02 – Liquid Waste Management Systems

Supplemental Staff RAI to RAI 11.02-1, 11.02-2, 11.02-3, and 11.02-4.

NRC RAI Number: 11.02-6-9 (eRAI 6985)

[Refer to Attachment 1 for the preamble to this RAI.]

Question 9

10 CFR 20.1406 requires that applicants describe how facility design and procedures for operation will minimize, to the extent practicable, contamination of the facility and the environment; facilitate eventual decommissioning; and minimize, to the extent practicable, the generation of radioactive waste. While the NRC recognizes that the proposed disposal method is regulated by FLDEP under EPA provisions, the applicant is requested to discuss and describe the extent to which engineered design features and leakage detection monitoring satisfying the regulatory requirements of FLDEP would also demonstrate compliance with 10 CFR 20.1406 in minimizing the contamination of plant discharge blowdown systems and the environment, including groundwater and surface water. The applicant should identify specific conditions of FLDEP permit and discuss the extent to which such provisions would also address NRC requirements and guidance for routine operational inspections, periodic testing in confirming the mechanical integrity of injection and monitoring wells, and describe system components and their design features that will be used to reduce leakage before pumping into the injection wells and avoid uncontrolled and unmonitored releases of liquid effluents to the environment. Relevant NRC guidance is presented in IE Bulletin 80-10, "Contamination of Nonradioactive System and Resulting Potential for Unmonitored, Uncontrolled Release to Environment," Regulatory Guide (RG) 4.21 "Minimization of Contamination and Radioactive Waste Generation: Life Cycle Planning," and Nuclear Energy Institute (NEI) Topical Report (TP) 08-08A "Generic FSAR Template Guidance for Life Cycle Minimization of Contamination."

FPL RESPONSE:

10 CFR 20.1406 (Minimization of Contamination) summarizes the requirements for applicants to describe how the facility design and procedures for operation will minimize, to the extent practical, contamination of the facility and the environment, facilitate eventual decommissioning, and minimize, to the extent practical, the generation of radioactive waste. Guidance related to 10 CFR 20.1406 is contained in IE Bulletin 80-10, "Contamination of Nonradioactive System and Resulting Potential for Unmonitored, Uncontrolled Release to Environment," Regulatory Guide (RG) 4.21, "Minimization of Contamination and Radioactive

Waste Generation: Life Cycle Planning," and Nuclear Energy Institute (NEI) Topical Report 08-08A "Generic FSAR Template Guidance for Life Cycle Minimization of Contamination."

The sections of the ~~Florida Administrative Code (~~F.A.C.~~)~~ relevant to the deep well injection system (DIS), including operational and monitoring requirements, are summarized in the discussion below. In addition to these requirements, FPL's proposed design, operation, and monitoring of the DIS is discussed in order to show compliance with 10 CFR 20.1406, specifically design, operation, and monitoring items *that will minimize, to the extent practical, contamination of the facility and the environment*. By design, DIS components will transport radioactive material in fractional ECL average concentrations; thus it is anticipated that these components will retain residual amounts of previously licensed radioactive material after operations cease. Because of the low average concentrations transported with limited opportunity for re-concentration, the nature and extent of residual radioactivity present in DIS components during decommissioning is expected to be of small concern. Minor or no remediation and institutional controls are anticipated to satisfy the 10 CFR 20 Subpart E radiological criteria for license termination applied to the decommissioned end state of the DIS. ~~The deep injection well system will not generate radioactive waste – it is only used as a means of disposal. The potential for radioactive components of the deep injection well system that may have an impact during facility decommissioning is not known at this time. However, residual radioactivity in the deep injection well system is anticipated to be of low potential due to the required dilution to meet 10 CFR Part 20 requirements and the methodology of deep injection and dual zone monitoring well abandonment.~~ In addition to the adherence to FDEP requirements, a discussion of DIS design features and system monitoring, particularly in the context of waste minimization, is also provided in the discussion below.

Rule 62-528.415, F.A.C., (Operation Requirements for Class I and III Wells) stipulates FDEP requirements for the operation of the DIS. Item (3) of this Code addresses Operation and Maintenance, which is summarized below:

(3) Operation and Maintenance Manual.

(a) An operation and maintenance manual(s) for injection well disposal facilities, or portions thereof, shall be prepared for the use of operators, maintenance personnel, technicians, laboratory personnel, and others as appropriate, and shall consist of:

1. Written instructions provided to the injection system operators which specify:
    a. Procedures for the safe reliable operation of the system; and
    b. Procedures to be used in the event of an emergency.
2. Records of the basic engineering design and equipment description; and
3. A program to assure proper maintenance of the system.

Rule 62-528.300, F.A.C., (Underground Injection Control: General Provisions) stipulates FDEP requirements for mechanical integrity testing. The relevant items of this code (Item 6) applicable to the DIS are summarized below:

(6) Mechanical Integrity.
- (a) An injection well has mechanical integrity if:
  1. There is no leak in the casing, tubing or packer; and
  2. There is no fluid movement into an underground source of drinking water through channels adjacent to the injection well bore.
- (b) One of the following tests shall be used to evaluate the absence of leaks under subparagraph (a) 1. of this subsection.
  1. Monitoring of the tubing-casing annulus pressure with sufficient frequency to be representative, as determined by the Department, while maintaining an annulus pressure different from atmospheric pressure measured at the surface, after an initial pressure test pursuant to subparagraph 2. and paragraph (e) of this subsection; or
  2. Pressure test of inner casing or tubing.
- (e) A pressure test required under paragraph (b) above shall be conducted with a liquid at a minimum pressure of 1.5 times the maximum pressure at which the well is to be permitted, or 50 PSI, whichever is higher, for at least one hour. Internal mechanical integrity under subparagraph (a)1. above is demonstrated if there is no more than a five-percent pressure change over the one-hour test period. The pressure used to test wells constructed using tubing and packer shall not exceed the design specifications of the tubing or packer.

Finally, Rule 62-528.425, F.A.C., (Monitoring Requirements for Class I and III Wells) stipulates FDEP requirements for monitoring of the DIS. The relevant items of this code (Item g) applicable to the DIS are summarized below:

- (1) (g) The Department shall require monitor wells above the injection zone near the injection well, field or project.
  1. The permittee shall be able to monitor the following:
     a. The absence of fluid movement adjacent to the well bore, and
     b. The long-term effectiveness of the confining zone.
  2. Monitor wells used to meet the requirements of subparagraph 1. above shall be sampled periodically. The frequency of sampling and constituents to be analyzed

shall be specified in the permit and shall be representative of the monitored activity.

3. Monitor wells used to meet the requirements of 1.a. above shall be located within 150 feet of the injection well unless the applicant can demonstrate, through a hydrogeologic study, that a monitor well located at a greater distance will be capable of adequately monitoring fluid movement adjacent to the borehole.
4. The permittee shall monitor a zone below the base of the underground source of drinking water, if a zone is available, and at least one zone within, and near the base of, the underground source of drinking water.
5. The Department shall also require any of the following when needed to provide reasonable assurance that the requirements of 1. above are being met:
   a. Continuous monitoring for pressure changes in the first aquifer overlying the confining zone.
   b. Continuous monitoring for pressure changes in any monitor well constructed.
   c. Periodic monitoring of ground water quality in the first aquifer overlying the injection zone.
   d. Periodic monitoring of ground water quality in the lowermost underground source of drinking water.
   e. Periodic additional monitoring to determine whether fluid movement caused by underground injection activity is occurring into or between underground sources of drinking water.

Based on the requirements of the current FDEP deep injection well DIW-1 permit, sampling of each monitoring zone and the injection wastestream is required to take place on a weekly basis during the first six months of operation of the injection well and associated monitoring well. Following the first six months of weekly sampling, it is anticipated that a request to reduce sampling frequency from weekly to monthly will be submitted to the FDEP. If FDEP's review of the monitoring data gives no indication of migration of injected fluids, it is anticipated that the request for increasing the monitoring interval would be approved. FDEP regulations also require that mechanical integrity testing be performed at least once every five years.

FPL's design, operation, and monitoring of the DIS will adhere to the relevant requirements of the F.A.C., as summarized in part above. The monitoring of the DIS in the context of waste minimization in the environment, through use of the dual zone monitoring wells, was previously discussed in the response to eRAI 6985 Question 11.02-6-10. The current conceptual design and operational approach of the DIS, relevant to waste minimization, leak detection and the monitoring of leakage before pumping into the injection wells, and the avoidance of uncontrolled and unmonitored releases of liquid effluents to the environment is discussed in the paragraphs below. It should be noted that these are anticipated to be requirements imposed by FPL.

There will be multiple valves on each deep injection well to allow isolation in order to prevent upward flow of injected fluid and discharge onto the containment pad due to a damaged injectate feeder line. The above ground piping at the injection wells will be accessible for visual inspection to detect any potential leakage from pipe and valve fittings. Air/vacuum release valves ~~breakers~~, which will provide assurance of continued integrity of the blowdown lines, will be provided at the appropriate location on each branch of the blowdown sump discharge piping and at each deep injection well.

The piping, manifolds, valves, controls, and appurtenances are designed to minimize inadvertent or unidentified releases to the environment. Integrity of the injectate piping will be monitored for leakage by performing periodic walkdowns, including the system piping and fittings in the site's routine maintenance program.

If the injectate main pipe were damaged, the redundant isolation valves on the main would be closed, isolating the portion of damaged pipe from the pump station. The isolation valves at each of the feeder lines would also be closed, thus isolating the main and preventing injectate from back flowing up the wells and into the main. The damaged main would then be repaired and pressure tested to demonstrate a leak-proof repair prior to opening the isolation valves on the main and feeder lines and resuming normal operations. Injectate spilled and pooled on the ground would be pumped into a tank, transported to the pumping station and ultimately pumped down injection wells that remain in service.

In the event of an accidental spill, isolation valves would be closed to isolate the equipment that allowed the spill to occur to minimize the spill volume. Each injection well will be located on a curbed concrete containment pad to contain any injectate spilled from the injection well or injection well wellhead piping. Pooled injectate off the concrete containment pad would be pumped into a tank, transported to the pump station and ultimately disposed of via the DIS.

FPL must adhere to the requirements of Rule 62-528, F.A.C., relevant to the DIS, as discussed above. FPL must also adhere to the project specific requirements of any UIC permit FDEP issues to FPL for the DIS, which requirements will be imposed to ensure that the injected fluid cannot move into any underground source of drinking water. FPL is also proposing a design and operational approach that will adequately minimize contamination to the environment and provide for minimization and monitoring of potential unplanned system leakage and/or contamination. Therefore, FPL believes the requirements of 10 CFR 20.1406 (Minimization of Contamination) have been addressed.

This response is PLANT SPECIFIC.

References:

None

ASSOCIATED COLA REVISIONS:

~~None.~~Refer to the response to NRC RAI No. 11.02-6-6.

ASSOCIATED ENCLOSURES:

None

NRC RAI Letter No. PTN-RAI-LTR-072 Dated February 20, 2013

SRP Section: 11.02 – Liquid Waste Management Systems

Supplemental Staff RAI to RAI 11.02-1, 11.02-2, 11.02-3, and 11.02-4.

NRC RAI Number: 11.02-6-10 (eRAI 6985)

[Refer to Attachment 1 for the preamble to this RAI.]

Question 10

With respect to environmental radiological monitoring, the applicant is requested to describe sampling locations and elevations above the Boulder Zone, sampling frequency, and analytical program in detecting the presence of long-lived and environmentally mobile radionuclides. The applicant should identify specific conditions of FLDEP permit on environmental monitoring and discuss the extent to which such provisions would also address NRC requirements of the radiological environmental monitoring program (REMP). The environmental radiological monitoring program should also acknowledge, given the information presented in FSAR Rev. 4, Section 2.4.12.2.1.2, that the sampling and analysis program will include the evaluation of water samples from Upper Floridan aquifer production wells that are used to supply cooling and process water for the operation of FPL Units 1, 2 and 5 and protective actions that will be taken if radioactive materials are detected.

FPL RESPONSE:

The Florida Department of Environmental Protection (FDEP) regulates deep injection well through its Underground Injection Control (UIC) program. As part of this program, FPL has proposed radiological monitoring to assess the operation of the deep injection wells that includes gross alpha and combined radium-226/radium-228 which will be initially performed on a monthly sampling frequency. This proposed sampling frequency will be reduced to a quarterly frequency once the underground injection system operational testing phase is complete.

In addition to this state regulated program, FPL is proposing additional background and operational system monitoring to specifically monitor for injection well failure/confining unit layer breakthrough. This additional proposed monitoring is discussed below.

A dual zone monitoring well will be installed for each pair of deep injection wells in accordance with FDEP requirements which states, in part, that the monitoring wells will be no farther than 150 feet from the injection well. The location of these wells is depicted on

FSAR Figure 1.1-201. The monitoring intervals for the dual zone monitoring wells will also be in accordance with FDEP requirements - it is anticipated that the upper zone will be located at a depth of approximately 1450 to 1500 feet below ground surface (bgs) and the lower zone will be located at a depth of approximately 1850 to 1900 feet bgs. The upper monitoring zone corresponds to the base of the Underground Source of Drinking Water (USDW) and the lower zone is located immediately above the Middle Floridan Confining Unit. While these are the approximate depths of the monitoring intervals, the monitoring intervals of each monitoring well will be determined based on data collected during the construction of each dual zone monitoring well and are subject to FDEP approval (~~Florida Administrative Code~~ Rule 62-528.420 F.A.C.; Monitoring Well Construction Standards for Class I and III Wells). The Boulder Zone, where the deep injection wells will inject, is located below a depth of approximately 3000 feet bgs. This depth will be verified at each well site during construction.

The AP1000 liquid effluent activities per reactor, as summarized in DCD Table 11.2-7, indicate that tritium (H-3) is the highest contributor to the amount of curies released per year per reactor. Tritium also may serve as a subsurface tracer since it does not adsorb onto solid particles and therefore its spatial extent would represent the furthest extent of dissolved radioactivity. Therefore, tritium will be monitored on a monthly basis at the dual zone monitoring wells to serve as ~~an~~ the sentinel indicator of deep injection well failure/confining unit layer breakthrough. Other radionuclides (e.g., those identified in DCD Table 11.2-7, monitor tank sample results, and dilution water supply sample results) will be considered for inclusion in the monitoring program based on their half-life, mobility, and detectability. This sampling schedule will be reduced to quarterly once an adequate baseline is established during deep well injection system (DIS) testing. Gamma isotopic and Gross Beta will also be monitored on an initial monthly sampling frequency, which will also be reduced to quarterly once the underground injection system operational testing phase is complete. Analytical testing will be in accordance with the Environmental Protection Agency (EPA) methods presented in 40 CFR 141.25, modified (if necessary) to accommodate measurement interferences posed by high (greater than 500 mg/L) solids content sample matrices. ~~Due to the construction sequencing, the deep injection wells and dual zone monitoring wells may not all be operational with the commercial operation date of Unit 6. The available dual zone monitoring wells will be monitored as they become operational.~~ All of the injection wells and associated dual-zone monitor wells (6 injection and 3 dual zone monitoring wells) needed for Unit 6 operation will be constructed and operational prior to the commercial operation date of Unit 6. The injection wells and associated monitor wells (12 injection and 6 monitoring wells) needed for operation of Unit 6 & Unit 7 will be constructed prior to the commercial operation date of Unit 7. As a

result of the construction sequence it is possible that not all of the wells needed for Unit 7 will have received approval to begin operation prior to the commercial operation date of Unit 6.

Cooling water for Unit 5 and process water for Units 1, 2, and 5 are obtained from the Upper Floridan aquifer production wells (PW-1, PW-3, and PW-4). The top of the Upper Floridan aquifer elevation is located at a depth of approximately 1000 feet bgs. The closest Unit 5 production well is approximately 3500 feet from the nearest proposed Unit 6 & 7 injection well. If operational/radiochemical monitoring of the deep injection wells or the dual zone monitoring wells indicate the presence of plant effluent, through the use of tritium as ~~a~~ the sentinel tracer, the production wells PW-1, PW-3, and PW-4 will be sampled on a monthly basis for tritium and ~~radiation (e.g. beta gamma)~~ gross alpha/beta radioactivity to monitor potential movement of any constituents to the Upper Floridan aquifer. If sampling of these wells indicates the presence of tritium due to Units 6 & 7 operation, FPL's mitigative action will include removal of the applicable water supply well(s) from operation and investigation of the DIS for determination of injection well failure/confining unit layer breakthrough.

The middle confining unit failure with injectate travel into the Unit 5 Upper Floridan Aquifer water supply wells was a highly improbable scenario evaluated in the DIS performance assessment. Additional response actions are to include, as appropriate, confirmatory monitoring, removal of affected DIS components from service, and other actions protective of members of the public and plant workers. The DIS off-normal operations prompt detection and mitigative strategies program will be part of the Turkey Point Units 6 & 7 ODCM/REMP (FSAR Table 13.4-201). ODCM/REMP development will consider regulatory and industry guidance, including Regulatory Guides 1.21, 4.1 and 4.15 and NUREG-1301.

FPL believes the groundwater monitoring proposed to satisfy FDEP requirements and the additional monitoring discussed in this response satisfies the objectives of a REMP as discussed in NRC RG 4.1, Radiological Environmental Monitoring for Nuclear Power Plants. Specifically, FPL is proposing the following:

- Baseline groundwater monitoring prior to the start of reactor operations
- Monitoring of groundwater at the plant during reactor operations
- Determination, through tritium sampling, whether any radioactivity in groundwater is attributable to plant operations and whether this radioactivity is commensurate with radioactive effluents and plant design objectives
- Reporting of results in the Annual Radiological Environmental Operating Report

The proposed monitoring discussed is applicable to the plant site. Additionally offsite sampling, based on exposure pathways and annual land use census results, will be proposed as necessary during plant operations.

The REMP will be modified to address the UIC program groundwater monitoring. The modified REMP would be conducted in accordance with RG 4.15, Quality Assurance for Radiological Monitoring Programs (Inception Through Normal Operations to License Termination) - Effluent Streams and the Environment, Revision 2, 2007.

This response is PLANT SPECIFIC.

References:

None

ASSOCIATED COLA REVISIONS:

~~The COLA will be revised to incorporate the response to this RAI in a future revision. This revision will be provided with the response to NRC RAI No. 11.02-6-1, 11.02-6-2, 11.02-6-3, and/or 11.02-6-4 (eRAI 6985).~~ Refer to the response to NRC RAI No. 11.02-6-6.

ASSOCIATED ENCLOSURES:

None

NRC RAI Letter No. PTN-RAI-LTR-072 Dated February 20, 2013

SRP Section: 11.02 – Liquid Waste Management Systems

Supplemental Staff RAI to RAI 11.02-1, 11.02-2, 11.02-3, and 11.02-4.

NRC RAI Number: 11.02-6-11 (eRAI 6985)

[Refer to Attachment 1 for the preamble to this RAI.]

Question 11

As part of the REMP, the applicant should also address the presence of naturally occurring radioactivity in the Upper and Lower Floridan aquifers. For example, a December 1996 article published in the Florida Water Resources Journal notes that gross alpha activity concentrations of 90 and 375 pCi/L were noted in the Upper and Lower Floridan aquifers, respectively. These concentrations are associated with the presence of U, Ra and Th and their respective decay products and K-40. The applicant should include in its operational monitoring program the means to assess the variability of the concentrations of naturally occurring radioactivity over an appropriate time period. A baseline should be established before the operation of injection and monitoring wells since the presence of alpha radioactivity in environmental samples could be later erroneously attributed to fuel failures.

FPL RESPONSE:

The Florida Department of Environmental Protection (FDEP) regulates deep injection well through its Underground Injection Control (UIC) program. As part of this program, FPL has proposed radiological monitoring to assess the operation of the deep injection wells that includes gross alpha and combined radium-226/radium-228 which will be initially performed on a monthly sampling frequency. This proposed sampling frequency will be reduced to a quarterly frequency once the underground injection system operational testing phase is complete.

In addition to this state regulated program, FPL is proposing additional background and operational system monitoring to specifically monitor for injection well failure/confining unit layer breakthrough. This additional proposed monitoring is discussed below.

As discussed previously, tritium will serve as the primary indicator of deep injection well failure/confining unit layer breakthrough at the site. Prior to deep well injection system startup, baseline radiochemical sampling events will be conducted at the dual zone monitoring wells and the three Upper Floridan production wells for parameters specified in the FDEP UIC well permit: gross alpha/beta radioactivity, gamma isotopic, and tritium. The dual zone monitoring wells will be sampled as they are completed and become operational. FPL proposes a minimum of six months of weekly sampling at the available dual zone monitoring wells prior to plant operation. FPL does not believe that continual background monitoring of naturally occurring radioactivity is warranted, since tritium monitoring will serve as an indicator of injection well failure/confining unit layer breakthrough at the site and background levels of tritium are not anticipated to be present in the Upper Floridan aquifer. Nonetheless, this portion of the preoperational monitoring program will be conducted over a time period sufficient to detect analyte variability such that the average and range of results are reliably representative.

This response is PLANT SPECIFIC.

References:

None

ASSOCIATED COLA REVISIONS:

~~The COLA will be revised to incorporate the response to this RAI in a future revision. This revision will be provided with the response to NRC RAI No. 11.02-6-1, 11.02-6-2, 11.02-6-3, and/or 11.02-6-4 (eRAI 6985).~~ Refer to the response to NRC RAI No. 11.02-6-6.

ASSOCIATED ENCLOSURES:

None