PSD-WB-02

ABZ Review of 2012 Vermont Yankee Decommissioning Cost Estimate

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Background

ABZ, Incorporated was engaged by the Vermont Department of Public Service to perform a review of the February 2012 Vermont Yankee (VY) decommissioning cost estimate.[1] The 2012 VY decommissioning cost estimate will be referred to in this report simply as the 2012 estimate.

The ABZ review of the 2012 estimate included consideration of all six decommissioning scenarios presented therein. The ABZ review included evaluation of all cost and schedule assumptions, work activities, craft labor and staffing, period dependent costs, and cost contingency. ABZ also compared the 2012 estimate with the 2007 VY decommissioning estimate.[2] Finally, ABZ performed analysis to quantify the cost and schedule impact of comments generated as part of the review, including evaluation of added contingency or risk margin that might be warranted.

This report documents the ABZ review. The ABZ review was based on the February 2012 TLG cost analysis report, TLG backup data, and publicly available documents. ABZ did not have access to all of the more detailed backup data prepared by TLG.

Review and Findings

Decommissioning as defined by the Nuclear Regulatory Commission (NRC) is limited to the activities necessary to remove radioactive materials from a site such that the NRC license can be terminated and the site can be released for use (with or without further restrictions).[3] However, discussion of decommissioning often is intended to encompass a broader scope, including all post-shutdown activities required to complete NRC-defined decommissioning, to store spent fuel until removed from the site, and to comply with any other federal, state or local requirements necessary for the unrestricted release of the site. These two additional general functions are referred to as spent fuel storage and site restoration. The 2012 estimate scope includes NRC-defined decommissioning, spent fuel storage and site restoration.

The basic parameters defining the decommissioning scenarios evaluated by TLG are plant shutdown date, basic decommissioning approach, and spent fuel removal date. With regard to the plant shutdown date, TLG assumed one of two dates, the original VY license expiration date of 2012, or 2032, representing a 20-year extension of the original VY license.

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[1] "DECOMMISSIONING COST ANALYSIS for the VERMONT YANKEE NUCLEAR POWER STATION," prepared by TLG Services, February, 2012, Document E11-1643-001, Rev. 1 (hereafter referenced as the 2012 estimate).
[2] "DECOMMISSIONING COST ANALYSIS for the VERMONT YANKEE NUCLEAR POWER STATION," prepared by TLG Services, January 2007, Document E11-1559-002, Rev. 0.
[3] 10 CFR 50.2 Definitions.

Estimate Assumptions

Basic Decommissioning Approach

In performing any decommissioning cost estimate, the basic decommissioning approach, either DECON or SAFSTOR, must be chosen.[4] DECON is a decommissioning approach in which the radioactive hazards are removed soon after final shutdown of the facility, allowing termination of the NRC license for the facility. SAFSTOR is an alternative decommissioning approach in which shortly after final shutdown the facility is placed in a safe condition (requiring reduced expense to maintain), stored in this condition for an extended time, and after such storage period, the radioactive hazards are removed, allowing termination of the facility's NRC license.[5]

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[4] The NRC regulations identify ENTOMB as a third option, but this option is no long considered a reasonable assumption for a commercial power reactor.

[5] A DECON approach can have a delay between final shutdown and decontamination. Such an approach is sometimes referred to as delayed DECON. The distinction between delayed DECON and SAFSTOR is for SAFSTOR more effort is initially expended to simplify the requirements and cost for maintaining the plant during the subsequent storage period.

SAFSTOR has no specific length of storage period with the limitation that the NRC requires that absent a showing of a benefit to the health and safety of the public, decommissioning must be complete within 60 years following the final shutdown of the facility.

DECON and SAFSTOR are both acceptable to the NRC. However, both approaches have advantages and disadvantages. These include:

DECON	SAFSTOR
Advantages	
Less risk of regulatory change and associated cost increase	Longer period for possible growth of decommissioning trust fund[6]
Readily available staff, knowledgeable of plant and plant conditions	Decay of radioactive material allowing for potential for greater amount of material to be processed without disposal as radioactive waste and lower personnel exposure[7]
Known availability of radioactive waste disposal sites	Potential for synergy from coordinating decommissioning of plants with common ownership or at a common site
Less uncertainty in cost escalation, including waste disposal costs	Potential to apply lessons learned from earlier decommissioning projects[8]
Less financial risk with respect to decommissioning trust fund	Potential for application of technological advances[9]
Disadvantages	
Less time for decommissioning trust fund to grow	Greater risk of regulatory change and associated cost increases
Higher personnel radiation dose	Need to reduce staff and later, perhaps decades later, re-staff
Less ability to take advantage of lessons learned from other decommissioning projects	Uncertain availability of qualified staff for future decommissioning work
Limited to current technology	Uncertainty of availability of waste disposal sites
	Greater risk of higher than expected increase in waste disposal rates
	Greater risk of higher than expected increase in other costs
	Risk of unfulfilled expectations concerning trust fund earnings

Overall, the DECON option provides greater certainty and less risk, both technically and financially. Conversely, the SAFSTOR option presents the potential for reduced costs and potential greater financial growth, but with greater uncertainty and more risk. Since most of the SAFSTOR advantages are not certain, but are rather potential benefits depending on

[6] As stated, this is true for a facility such as VY that is not collecting or adding funds to the trust fund and thus, the longer SAFSTOR period is only advantageous in this regard if the growth of the fund during the SAFSTOR period exceeds the cost of maintaining the facility and the added cost due to cost escalation.
[7] While allowing time for radioactive decay offers a theoretical advantage, it is not clear that it would have a substantive effect on the scope of waste processing and disposal.
[8] The basic point here is as more decommissioning projects are completed, the greater the knowledge base. The inherent assumption in this SAFSTOR advantage is that others will not choose the SAFSTOR option or that even if they do, they will decommission first.
[9] Technology improvements may turn out to be a disadvantage. For example, the amount of waste disposal and decontamination work estimated is predicated on current radiation detection technology. If more sensitive detectors are developed in the future, consistent with history, then the amount of radioactive waste requiring disposal or the required decontamination actions may be greater. Thus, this potential advantage of SAFSTOR may turn into a disadvantage.

future events, there is the risk that any such potential advantage could turn out to be disadvantageous. For example, the cost to maintain the facility during the SAFSTOR period depends on future regulations and the future performance of trust fund investments, and the SAFSTOR period could result in a net real decrease in available funds for decommissioning and a future shortfall. Similarly, if more sensitive radiation detectors are developed in the future, consistent with history, material that with today's technology could be released without any control because no radiation could be detected may be required to be disposed of in a more controlled fashion, or with other limitations.

Considering the overall balance of advantages and disadvantages for the two decommissioning approaches, the greater certainty (reduced risk) associated with the DECON approach leads to a general conclusion that funding for a DECON approach is more desirable. This conclusion may be different for a large utility if there was a commitment to a coordinated decommissioning plan for multiple plants that would generate synergies and share some risks, thus presenting a cost savings from delaying decommissioning. While such cooperative endeavors are mentioned by TLG, there appears to be no firm commitment to such cooperative endeavors, or quantification of the possible cost savings with respect to the decommissioning of the VY Station.

The VY Station decommissioning cost estimate includes estimates for two DECON scenarios and four SAFSTOR scenarios. The cost estimate does not identify one preferred scenario; however, the SAFSTOR scenarios maximize the length of the non-ISFSI decommissioning, independent of other factors and thus, the specific VY Station scenarios maximize the SAFSTOR risks and uncertainty.

Assumed Start of Spent Fuel Pickup

The six VY scenarios assume three different start dates for Department of Energy (DOE) acceptance of spent fuel:

a. 2020 with first VY spent fuel acceptance in 2021 (scenarios 1, 3 and 5);
b. 2042 first VY spent fuel acceptance (scenarios 4 and 6); and
c. 2058 first VY spent fuel acceptance (scenario 2).

The choice of a 2020 DOE start date for some scenarios represents a bound on the earliest potential start date, but it is unclear there is reason to believe there is any real possibility that DOE acceptance will begin by 2020. The 2012 estimate basis for scenarios with a 2020 DOE start date appears to be 2008 testimony of the Director of the Office of Civilian Waste Management (OCRWM) and the report of the Blue Ribbon Commission on America's Nuclear Future (BRC). The testimony by the Director of OCRWM predated the decision by DOE to discontinue work on Yucca Mountain and thus cannot be seen as a reliable expectation of DOE actions.

The 2012 estimate appears to rely also on the BRC report suggestion that one or more interim storage sites be put in place. The 2012 estimate states Entergy believes one or more Monitored Retrievable Storage (MRS) facilities could be put in place in a reasonable time. It is not clear why Entergy would believe that this recommendation to create one or more MRS facilities would be more successful than prior attempts to do the same thing. Additionally, the Private Fuel Storage (PFS) project was nothing more than a private interim storage facility. PFS was licensed in 2006, but operation has been delayed (now six years) by federal government actions.[10] PFS filed suit against the federal government and prevailed to the extent that the court remanded the actions for reconsideration by the Department of Interior. Nonetheless, the facility has still not accepted fuel six years after being granted an NRC license. While a federal facility may not face government intervention, there would certainly be intervention by others. Given both the DOE experience in attempting to site an MRS and the PFS experience, it is extremely unlikely that DOE could accept spent fuel at an interim facility by 2020. While the scenarios assuming a 2020 DOE start date provide some insight as to how changing the DOE start date changes total costs, any scenario using a 2020 start date assumption should not be viewed as a viable decommissioning scenario.

Date of Last Spent Fuel Pickup

Similarly, the six scenarios assume three different dates for the last pickup of spent fuel from VY. These dates, combined with the assumed start dates, indicate the overall rate of spent fuel acceptance. Three scenarios assume a 2020 DOE start with all fuel being removed by 2045 or 2060. These end dates are based on the assumed start date and the DOE acceptance rate specified in the 2004 Acceptance Priority Ranking and Annual Capacity Report.[11] The third end date is identified as being the latest fuel removal date proposed by the Vermont Department of Public Service, 2082.[12] The Department of Public Service order only specified that the VY spent fuel management plan at a minimum needed to assume spent fuel storage through 2082. While the use of 2082 satisfies the minimum required by the Public Service Board order, it is not conservative for two of the three scenarios where this assumption was used.

In scenarios 4 and 6 there is a more conservative assumption that would satisfy the Public Service Board as well as the NRC requirement for decommissioning to be complete in no more than 60 years after permanent shutdown. Specifically, in each of these cases, given the uncertainty of DOE performance, a date for removal of the last fuel near the end of 2090 could be assumed and still have the decommissioning complete within 60 years of the

[10] The Bureau of Indian Affairs refused to authorize the lease for the land, and the Bureau of Land Management refused to authorize a right-of-way for a rail line needed to move spent fuel to the facility.
[11] "Acceptance Priority Ranking & Annual Capacity Report," DOE/RW-0567, July 2004.
[12] 2012 Estimate page xii of xix cites to State of Vermont Public Service Board Order 7082, April 2006.

assumed shutdown date.[13] Adding about 7.75 years of spent fuel storage would increase the total decommissioning cost by about $54 million.[14]

Low-Level Radioactive Waste

Class A Waste Disposal Rate

The NRC defines four classes of Low-Level Radioactive Waste (LLRW). The classifications are Class A, Class B, Class C, and Greater than Class C (GTCC). The NRC specifies different requirements for the handling and disposal of the different classes of LLRW. The requirements for Class A waste are the least demanding, with the requirements increasing for Class B, then Class C, and finally GTCC. Decommissioning LLRW consists mostly of Class A. Generally, the only Class B, Class C, or GTCC waste generated during decommissioning would be parts of the reactor vessel internals.[15]

The 2012 estimate uses rates for disposal of Class A waste consistent with disposal at the Energy*Solutions* Envirocare facility.[16] The specific rates are based on a current Entergy agreement with Energy*Solutions*. At the same time, the 2012 estimate recognizes that Vermont is a member of the Texas low-level waste compact. The waste disposal facility for the Texas compact has been licensed and recently began accepting waste.

The use of Envirocare rates rather than the Texas Compact facility appears to ignore the provisions of the Texas Compact. Specifically, it appears that the members of the compact are required to dispose of waste only at the compact facility unless specific permission is otherwise granted by the compact commission.[17] There is no evidence that permission has been granted for Vermont Yankee to dispose of decommissioning radioactive waste at Envirocare rather than the Texas facility. Further, there is no reason to presuppose that

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[13] TLG in scenarios 2, 3, and 4 assumes the decommissioning can be complete within six months of final spent fuel removal. Consistent with this, a date for last fuel removal of about October 2091 would allow completion by March 2092, 60 years after shutdown. ABZ believes six months is too short an interval after final spent fuel removal, and that about two years would be a more reasonable assumption consistent with actual decommissioning experience. Thus, assuming final fuel removal by March to October 2090 would allow completion of decommissioning by March 2092.
[14] The $54 million is based on Table 3.6 of the 2012 estimate and an approximate cost of $6.9 million per year during dry fuel storage prior to 2082.
[15] Some filter media, if not adequately controlled might become higher than Class A waste. Generally, other conditions such as filter differential pressure would require replacement of the filter media before sufficient radioactive material could accumulate to cause the media to be classified as Class B or greater LLRW.
[16] 2012 Estimate, page xii.
[17] Vermont statues, Title 10:Conservation and Development, Chapter 162: TEXAS LOW-LEVEL RADIOACTIVE WASTE DISPOSAL, Article IV, section 4.02 and Article II Section 3.05(7).

such permission could be obtained.[18] Absent such permission or other compelling reason, the Class A disposal rate should be based on the Texas facility.[19]

In the 2012 estimate, it appears that some Class A waste is disposed of at rates that exceed the $150 per cubic foot interim rate published by the Texas Compact for routine non-compactable Class A waste.[20] However, for other material the disposal rate appears to be substantially lower. Changing the estimated costs to reflect the interim Texas Compact disposal rate for all Class A waste adds about $17.4 million to the estimated cost of each scenario.[21]

LLRW Disposal Cost Escalation

Notwithstanding the compact agreement requirements, using Envirocare disposal rates from the current life-of-plant agreement with Entergy may not be appropriate, at least without proper consideration of risks and possible cost escalation rates. Risks associated with the current agreement include:[22]

1. The fixed term of the agreement – it would require renegotiation (once or multiple times) if the VY Station is not decommissioned prior to the expiration of this term. Renegotiation introduces risk, as it could result in unexpected price increases or termination of the agreement.
2. The termination provisions included in the agreement; and
3. The provisions of the agreement allowing for certain price increases.[23]

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[18] The development costs and on-going operating cost for the Texas facility have to be covered by disposal costs. To allow VY to send over 300,000 cubic feet of Class A waste to a different facility would increase the cost for other in-compact disposers. It is unclear what benefit the compact commission would see in granting permission for VY to send the decommissioning waste out of compact.

[19] There is some suggestion in the 2012 estimate that it was preferable to use Envirocare rates because only interim rates had been established for the Texas facility and a formal rate-setting process was to come. However, for Class B and Class C waste, the Texas facility interim rate was used because there is no other facility at present that will accept Class B and Class C waste from Vermont.

[20] TCEQ Executive Director Interim Disposal Rate for the Compact Waste Disposal Facility, August 25, 2011. A subsequent letter from Waste Control Specialists LLC to the Texas Commission on Environmental Quality (TCEQ), November 14, 2011, subject Electronic Version of the Supplemental Application of Waste Control Specialists LLC for Establishment of Initial Maximum Disposal Rates for Compact Waste Disposal Facility requested a slightly higher rate for non-compactible Class A waste. Subsequent action by the TCEQ has recommended lower base rates together with weight and curie surcharges.

[21] The estimated cost was determined by a simple calculation, and as a result the effect may be somewhat larger. The estimate cost was calculated by determining the average rate (dollars per cubic foot) for Class A waste (for all estimate lines that do not also include Class B or higher waste). The total cost for that Class A waste was then multiplied by 150 and divided by that average rate. The difference between this value and the original cost of that waste is the total addition. The difference was calculated using scenario 6. The value stated includes 17 percent contingency consistent with the average contingency in the 2012 estimate. The 2012 estimate does not contain sufficient information to perform a detailed calculation using the 2012 TCEQ rates with curie and weight surcharges.

[22] Energy*Solutions* 2009 Annual Report; Energy*Solutions* Prospectus, July 24, 2008.

[23] Life of Plant Disposal Agreement, General Services Agreement 10160239 dated June 30, 2007, and subsequent amendments.

Absent the Texas Compact agreement, such risks would not prevent the use of rates from the Energy*Solutions* life-of-plant contract in decommissioning estimates. However, the presence of such risks would require consideration of different cost escalation factors for LLRW in decommissioning funding calculations. In either case, the LLRW cost escalation used should account for these risks as well as the historical record of LLRW price increases.

The 2012 estimate, like virtually every other decommissioning estimate, is an "overnight" estimate, expressed in constant year dollars (in this case year of estimate dollars). The specific cost escalation factor used to convert this estimate to year of expenditure dollars does not change the estimate.

Disposal costs for LLRW have escalated over time much more rapidly than other costs. A measure of the rate of escalation of LLRW disposal costs can be determined from the NUREG-1307, "Report on Waste Burial Charges, Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities." Considering only the interval from 2002 to 2010, the NUREG-1307 factors show a cost escalation of about 4.7 percent per year.[24] This is almost double the CPI rate of 2.5 percent per year over this same time period.

The estimate and associated financial planning, including demonstration of adequate funding assurance, cannot be conducted in isolation. The estimate must reflect how the result will be used in planning, and similarly the financial planning must be performed consistent with how the estimate was performed. That is, higher than CPI expected future cost escalation for low-level waste could be accommodated in at least two distinct ways. The first is to base the estimate on a present value of the future LLRW disposal rate rather than current rate. The total cost estimate cash flow could then be escalated using the expected CPI change. The alternative would be to escalate the estimate waste disposal cash flow at a different rate than other costs in the estimate.[25] It does not appear that either of these approaches was used in the 2012 estimate and funding analysis.

LLRW Packaging Density

Both the Texas Compact and Envirocare specify disposal rates in dollars per cubic foot of waste. The detailed calculations in the 2012 estimate, however, calculate disposal cost based on dollars per pound. Because of this conversion from a volume-based price to weight-based price, the accuracy of the total costs is directly dependent on the accuracy of the assumed waste density. For systems and other metallic waste, the calculations assume

[24] NUREG-1307, "Report on Waste Burial Charges, Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities," Rev. 14, November 2010, Table 2-1. To calculate rate of change between 2002 and 2010, the factors for the Atlantic Compact were used. As noted in the footnotes to this table, although the cost indexes are for the Atlantic Compact, the 2010 value assumes 85 percent of the waste is actually disposed of using a waste processor and the Energy*Solutions* Envirocare facility. The escalation rate assuming all direct disposal would be about 5.8 percent per year.

[25] For example, the most recent decommissioning funding ruling for the California nuclear plants (Diablo Canyon and San Onofre) specifies using a cost escalation of about seven percent per year for LLRW costs and about three percent per year for other costs. Decision 10-07-047, Decision on Phase 1 of the Triennial Review of Nuclear Decommissioning Trusts and Related Decommissioning Activities for Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company, July 29, 2010.

a packaged waste density of 80 pounds per cubic foot. Actual decommissioning projects have had difficulty in obtaining a packed waste density of 80 pounds per cubic foot, at least when using larger waste containers. The average waste density, early in the bulk shipment campaign at the Yankee Nuclear Power Station project was about 48 pounds per cubic foot. After efforts to improve this performance, containers having density of about 60 pounds per cubic foot were typical.[26]

Smaller waste containers may make it easier to obtain higher packing densities, but to do so will still require substantial effort and expense. The 2012 estimate assumes rather small containers, about 90 cubic feet or about 43 cubic feet. Even with smaller containers, reaching the assumed density may present a challenge. Consider the detailed waste calculations for RX-BLD-213-2_2. The inventory includes 152 feet of piping with a diameter between 14 and 20 inches. The natural density of such piping is between about 44 pounds per cubic foot and 46 pounds per cubic foot. Even if there were an equal amount of 14 and 20 inch diameter piping, and the piping were packaged with a length of 14-inch pipe nested inside each length of 20-inch piping, the density would only increase to about 67 pounds per cubic foot. Thus, it should be clear that the effort to pack LLRW to achieve a density of 80 pounds per cubic foot would be substantial.

The estimate details also provide calculations of man-hours for waste packaging and waste volumes. Again, based on the calculations for RX-BLD-213-2_2, the average effort for packing a container holding about 90 cubic feet (assumed 7,206 pounds) would be approximately three man-hours. In other words, a single worker is assumed to handle about 7,206 pounds of waste in three hours while placing the waste in a container in an arrangement to obtain a packed density of 80 pounds per cubic foot.

If, for the type of waste discussed here, the density were assumed to be 48 pounds per cubic foot on average, consistent with the early Yankee Nuclear Power Station experience, the cost of waste disposal would increase by $10.9 million for a VY scenario.[27] If this change in assumed density were combined with the change in disposal rate to $150 per cubic foot, the total addition to a VY scenario cost would be about $35 million including contingency.

Aside from the estimate of packing density and labor for packaging being too optimistic, there appears to be no cost for the packaging labor in the calculation of packaging costs.[28] Thus, it appears that the labor for packaging of waste is assumed to be part of the plant

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[26] The densities are based on use of intermodal containers that hold 675 cubic feet, and typical loaded weights of 32,000 pounds (before performance improvements) and 40,000 pounds (after performance improvements).

[27] This was calculated using scenario 6 and considering the system component removal and other line items assuming higher waste density. The DECON value could be slightly different. The values stated include 17 percent contingency consistent with the overall contingency in the 2012 estimate.

[28] One might suggest that the packaging man-hours and associated cost are part of the unit cost factors (UCF). However, this cannot be true because the man-hours per cubic foot for waste going to the processor is about 1/10th that of for waste going to disposal. The same UCFs are used for all the waste in a system, even though part of the waste will go to a processor and part to disposal.

staffing. However, in reviewing the plant staff it is unclear where such personnel are included in the staffing. The type of personnel one would look for to perform such tasks would be laborers and radiation technicians. A group for waste processing is included in the staffing for SAFSTOR, but for two of the decommissioning periods of interest (4a and 4b), only two persons are listed as "Labor Force" in this group, along with one "Waste Supervisor" and one "Waste Packaging RP Supervisor." This is not nearly enough personnel to package the over 600,000 cubic feet of waste for disposal, as well as waste for shipment to the waste processor.

Waste Processing Versus Disposal

The 2012 estimate assumes some LLRW is disposed of at a radioactive waste site, while the remainder is sent to a waste processor. It is assumed that very lightly contaminated waste can be sent to a waste processor. A waste processor uses a variety of means to minimize the amount of material received that must be disposed of as LLRW. The unit cost (per cubic foot or per pound) for waste sent to a waste processor is substantially less than the unit cost for direct disposal of material at a LLRW site.[29]

In the 2012 estimate, a larger fraction of waste is assumed to be sent to a waste processor as compared to direct LLRW disposal for SAFSTOR scenarios compared to DECON scenarios. However, what is not explained in the estimate is labor and cost for determining which waste is sent to the processor and which waste is sent directly to a LLRW disposal site. No such effort or cost appears to be included in the estimate. Such cost would be calculated based on the total waste inventory and there appears to be no such calculation. The cost for this separation of the total waste stream into waste for disposal and waste for processing should be added to the estimate.

In reviewing the detailed calculations of waste disposal and waste processing cost in the 2012 estimate, the method to determine the fraction of waste going to a processor as compared to a waste disposal site is unclear. The assignment appears to be somewhat arbitrary and to make assumptions that are difficult to understand. Consider the details for removal of system RX-BLD-213-2_2 in a DECON scenario. In the inventory, there is a line for one pump and motor set weighing less than 300 pounds. For this pump and motor, the estimate assumes that 35 percent of the waste is sent to processing. Obviously, this implies that the pump and motor are at least partially disassembled so that 35 percent of the material can be sent for processing while the remaining 65 percent is sent for disposal. There are numerous similar examples, including several in this same system inventory.[30] No explanation is provided as to how it is determined what fraction of individual items would qualify for processing rather than disposal. No costs have been included for the

[29] In the detailed calculation of waste costs, $1.45 per pound is used for waste going to a processor and $2.66 per pound for waste going directly to disposal.
[30] Within this system examples are: one valve 4 to 8 inches with 25 percent sent to processing and 75 percent sent for direct disposal; three valves 8 to 14 inches with 50 percent sent to processing; three pump motors 1,000 to 10,000 pounds with 50 percent to processing; one piece of HVAC equipment less than 300 pounds with 75 percent to processing and one piece of HVAC equipment 300 to 1,000 pounds with 75 percent to processing.

equipment dismantlement that would be needed to allow part of a single piece of equipment to be sent for processing with the rest going to disposal. If such divisions are to be part of the cost estimate, the means by which it is determined what percent would go to processing should be documented. Further, the cost for disassembly to achieve such separation of waste streams should be included in the estimate.[31]

The 2007 VY estimate also assumes some waste is sent to a waste processor. The cost for processing is substantially different in that 2007 estimate. In the 2012 estimate, the cost is about $66 per cubic foot.[32] In the 2007 estimate, the cost is about $86 per cubic foot.[33] There is no explanation for why the rate for processing decreased so significantly. Without any cost escalation, using the 2007 rate would add about $9.3 million (including contingency) to the 2012 estimate.[34]

In the 2007 estimate, the split between waste processed and Class A waste is about 50/50 for all scenarios. In the 2012 estimate, for SAFSTOR scenarios, about 18 percent more waste is processed than for the corresponding DECON scenarios. This translates to about 60,000 cubic feet of material, and based on the difference in the rate for processing compared to disposal, if the processing/decon split was not changed for SAFSTOR scenarios, the cost for the SAFSTOR options would increase by about $23 million (including contingency).

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[31] There is no evidence that these specific fractions are based on a high-level assumption that does not require subdividing individual components.
[32] The waste to be processed is assumed to have a packed density of about 40.61 pounds per cubic foot and the cost is $1.45 per pound. The result is about $58.88 per cubic foot. However, if the rate is calculated from the total cost for processing divided by the total volume sent to processing, the cost is about $66 per cubic foot.
[33] Based on the 2007 scenario 8 total processing cost divided by the total volume processed.
[34] Based on the value from 2012 estimate being about $66, since this was determined in the same manner as the $86 per cubic foot for 2012. The estimate asserts that the 2012 processing cost is based on Entergy's existing agreements, but these agreements were not available for review.

Waste

The 2012 estimate states that GTCC waste will be packaged in the same type canisters as spent fuel. The estimate assumes that the cost for disposal of GTCC waste is equivalent to that for spent nuclear fuel. Although, this is a common decommissioning cost estimate assumption, no preliminary or suggested GTCC disposal rate has been published.[35] Also, no proposed methodology for setting the GTCC disposal rate has been published. Thus, the GTCC disposal rate is uncertain.

Additionally, TLG's methodology for calculating the GTCC disposal rate used in the 2012 estimate is unknown. Using the GTCC volume and cost, the disposal rate would be calculated as about $2,760 per cubic foot. Based on the amount of fuel used over a period of several years, the waste fee paid during that time, and the volume of spent fuel casks, the cost would be estimated at between $8,200 and $10,100 per cubic foot of GTCC material. If the rate in the 2012 estimate were based on waste container volume and not the GTCC volume, then the comparison would be closer, but still substantially less than the range of $8,200 to $10,100 per cubic foot. Using a rate consistent with the $8,200 to $10,100 per cubic foot would add about $3.8 million to the cost of GTCC disposal.

Further, the 2012 estimate includes only 15 percent contingency for GTCC waste disposal. This seems too small given the uncertainty in the assumed disposal cost. One can argue that such uncertainty is actually a risk consideration and not within the TLG definition of contingency. However, the 2012 report refers to this cost as an allowance and, as such, it seems appropriate that it be increased to reflect the level of uncertainty. In total, the changes to GTCC disposal would add about $5.8 million.[36]

An inconsistency in GTCC costs also exists. The cost for GTCC disposal includes $500,000 for packaging in scenarios 1, 3, and 4. There is no cost for GTCC packaging in scenarios 2, 5, or 6. Unless a reason can be provided to support not including GTCC packaging costs, the same packaging cost of $500,000 should be included in all scenarios.

Other Potential License Termination Plan (LTP) Compliant Radioactive Waste

The License Termination Plan describes the means, methods, standards and quality controls applied to verifying that decommissioning satisfies NRC regulatory requirements. Those requirements include that residual radioactivity levels assure that post decommissioning radiation exposure is less than the NRC regulatory maximum limit of 25 millirem per year. Part of License Termination Plan effort is the development of radioactive material concentration limits (known as Derived Concentration Guideline Levels or DCGLs) to assure the 25 millirem per year limit is satisfied.

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[35] 2012 estimate, section 3, pages 9 and 10 of 32.

[36] The $5.8 million addition is made of the $3.8 million based on a higher disposal rate and about $2 million to account for the uncertainty of the cost, based on providing a total contingency of 50 percent for GTCC disposal.

The DCGLs must be consistent with the planned use of the site and the planned disposition of site waste materials. For instance, if concrete were to be reused on-site as fill material, the DCGLs would have to be developed in a manner consistent with this expectation. If, alternatively, concrete debris from structure demolition were to be shipped off site for reuse or disposal at other than a licensed radioactive waste disposal site, the DCGLS would have to be consistent with this alternative.

Alternatively, it would be acceptable to demonstrate through radiation survey, sampling and analysis that the decommissioning debris is free of licensed radioactive material by demonstrating compliance with a no detectable activity standard. This involves demonstrating the material contains no licensed radioactive material down to the lower limits of detection of radiation monitoring instruments. If this standard is met, material can be released from the site for disposal or reuse without any radiation based restriction or limit. If it passes this standard it is not licensed radioactive material.

Entergy has committed to removing all site structures to either three feet below grade or bedrock.[37] Entergy has also committed to not reuse concrete rubble from structure demolition for site fill material.[38] As a result, it will be necessary to dispose of the concrete rubble off site. In the 2012 estimate, no cost is included for disposing of this material.[39] Furthermore no cost is included for the necessary surveying and analysis of potential radiological constituents of the concrete rubble to verify it can be released off site to unlicensed recipients.

Based on hard-to-detect nuclide surveys conducted in support of the Yankee Nuclear Power Station decommissioning, some of the Vermont Yankee concrete material is likely to be contaminated with hard-to-detect nuclides such as tritium and carbon-14. Concrete from inside the containment drywell is likely to have at least one of these constituents present. Concrete from structures adjacent to the spent fuel pool and the steam separator and dryer pit, and the volume above the reactor may have volumetric tritium contamination due to leakage of water inventory through defects in the stainless steel liners. In addition, depending on concentrations of tritium in the water vapor within the reactor building over the operating life of the plant, there could also be detectable tritium throughout the volume of the concrete in the reactor building structure. Although the concentrations of tritium and carbon-14 may be low enough to comply with NRC license termination criteria if this material were to remain on site, off-site disposal can be expected to require demonstration of compliance with a no detectable radioactivity standard prior to shipment.

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[37] Entergy VY's Response to WRC's Second Set of Information Requests, October 3, 2012, PSB Docket No. 7862 at 16.

[38] Entergy asserts that $5 million is provided for off-site disposal of clean concrete, but this cost is not readily apparent in the study. Entergy VY's Response to DPS' Second Set of Information Requests, October 3, 2012, PSB Docket No. 7862, at 49.

[39] See, for example, line 3b.1.1.1 in scenario 3 and the associated supporting material, which shows a cost for reactor building demolition, but has no associated disposal cost.

The 2012 estimate does not include costs for procuring the necessary equipment, labor, and other services to perform the surveys and analyses necessary to demonstrate compliance of concrete rubble with a no detectable contamination standard. These surveys are likely to identify contaminated material that must be disposed of as radioactive waste at a licensed facility. Although the 2012 estimate does include an estimate of "monolithic concrete" radioactive waste, the quantity appears far too small to adequately address the various radioactive concrete waste streams expected from the decommissioning, if concrete is not to be re-used on-site as fill material.[40]

Reinforced Concrete Rebar

The 2012 estimate assumes that all steel rebar imbedded in concrete is segregated from the concrete, released from the site, and recycled at no cost to Entergy. This is flawed for the following reasons:

1. A portion of the rebar is expected to have detectable contamination due to proximity to the reactor core and neutron irradiation over the operating life of the plant.[41] This activated material will have to be segregated from un-activated rebar based on radiological survey, sampling, and analysis. The 2012 estimate does not include costs for the disposal of the radioactive portion of the rebar inventory;
2. The 2012 estimate does not include costs for the work necessary to segregate rebar from concrete; and
3. The 2012 estimate does not provide a cost for the necessary radiological surveying, sampling, and analysis to demonstrate that the rebar to be shipped for recycling meets applicable radioactivity standards for uncontrolled off-site release.

Containment Steel, Coatings, and Mixed Waste

Coatings on containment drywell steel and pressure suppression pool steel may include lead or other hazardous materials as a constituent of the coating materials. Containment steel coating used in the construction of the Yankee Nuclear Power Station, for example, was discovered to contain PCBs, a hazardous material that resulted in extensive environmental contamination of the site and nearby environs, and resulted in a large-scale effort to remediate. Unlike the Yankee Nuclear Power Station containment steel, the Vermont Yankee containment steel is located entirely within the Reactor Building and therefore not exposed to the environment. Any hazardous material present in the containment steel coatings would not be expected to present a risk of site environmental contamination provided appropriate controls are applied during decommissioning. Notwithstanding this important plant configuration difference, the potential for hazardous

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[40] The 2012 estimate includes disposition of 287 cubic yards of contaminated monolithic concrete and scabbling of concrete surfaces, but no other disposal of contaminated concrete. ENLRC010876-ENLRC010905, Building Inventory Listing, at ENLRC010904.

[41] During replacement of its steam generators, the San Onofre site found that rebar in the containment concrete had been activated during reactor operation. Similarly, the Yankee Rowe site found that some of the containment steel was activated during operation.

materials being present in the Vermont Yankee containment steel coatings exists and could present substantial costs not included in the 2012 estimate.

The 2012 estimate assumes the VY containment steel will be recycled with little or no disposal cost to Entergy. This assumption is flawed for the following reasons.

In order to recycle this steel, coatings with radioactive material contamination will have to be removed at least partially and may need to be entirely removed to enable necessary radiological survey activities to occur. Removal of coatings containing hazardous material will require hazardous materials controls, sampling and surveying to assure the safety of workers and the effectiveness of the remediation, in addition to applicable radiological controls for the work. Coating material removed from the steel can be expected to contain both radioactive contamination and any hazardous material constituents of the coatings, thereby constituting a mixed waste (containing hazardous and radioactive material), which must be disposed of at a facility licensed to receive such material.

After the coatings have been removed and the steel has been surveyed for compliance with residual hazardous material acceptance standards, radiological survey, sampling, and analysis will be necessary to demonstrate compliance with a no detectable radioactivity standard for uncontrolled release from the site for recycling. A portion of the containment steel, like the rebar discussed above, is expected to contain radioactive material due to activation from neutron irradiation over the operating life of the plant. This material will have to be segregated by radiological survey, sampling, and analysis, and shipped to a licensed facility for disposal as radioactive waste.

Radiological surveys, sampling, and analysis are likely to identify radioactive material that must be segregated from otherwise recyclable steel and managed on site prior to disposal at a licensed radioactive waste facility. There do not appear to be specific costs included in the 2012 estimate for the necessary survey, segregation and management of containment steel that does not meet radiological criteria for uncontrolled release from the site. In addition, the 2012 estimate does not include the necessary equipment, labor, and services to perform hazardous material removal and verification surveys to prepare the containment steel for uncontrolled release from the site.

Site Restoration

Radiological decommissioning of the Vermont Yankee site to meet the NRC license termination criteria is a subset of the entire scope of effort necessary to eventually release the site for other uses. In addition to the NRC requirements, other federal regulatory, Vermont State, potential other states, and local requirements will have to be satisfied. Detailed information on the nature and scope of the type of additional requirements that can arise and how they were addressed in decommissioning the Yankee Nuclear Power Plant in nearby Rowe, Massachusetts can be found in the site closure documents on the Yankee Rowe web site.

For example, the Yankee Site Closure Project Plan provides an overview of all significant interactions with regulators and stakeholders in support of the decommissioning, site environmental investigation, environmental remediation, site closure, and post closure property transfer considerations. These interactions had significant impact on the scope, schedule, and cost of the Yankee Nuclear Power Station decommissioning and site closure. The site restoration experience at the nearby Yankee plant site should be considered in planning funding for the decommissioning and site restoration work at Vermont Yankee.

On-Site Construction Debris Disposal

During the construction phase of the Yankee Nuclear Power Station, unused construction materials were disposed of in a construction fill site at the southeast section of the Yankee site industrial area (known as the Southeast Construction Fill Area or SCFA). During site closure planning this area was identified, characterized by environmental survey, and a remediation plan developed based on the results of the survey. During execution of the remediation plan, as materials were excavated for sorting and disposition in accordance with the plan, hazardous materials, including asbestos and PCBs, were discovered within the construction fill area inventory. These hazardous materials were not identified during the environmental sampling and survey effort that was part of the development of the remediation plan for the construction fill area. Discovery of the hazardous materials brought remediation of the construction fill area to a halt until hazardous material controls could be established and a hazardous material remediation plan could be developed and approved by state (DEP) and federal (EPA) regulators.

The discovery of hazardous materials in the construction fill area led to a significant expansion of the environmental remediation effort, especially in the remediation of PCB contaminated soils.

The Connecticut Yankee (CY) nuclear power plant decommissioning scope included remediation of a portion of the site found to contain construction related debris. In the remediation efforts both asbestos containing materials and PCB containing coatings were discovered, and were disposed of in accordance with applicable hazardous waste regulations.

The potential for on-site construction debris disposal to have occurred during the construction of the Vermont Yankee plant exists. In light of the Yankee and Connecticut Yankee experiences, the potential also exists for hazardous material requiring regulatory compliant remediation to be discovered during the course of decommissioning the VY site.

Hazardous Material Discovery

Yankee Nuclear Power Station discovered the presence of PCBs in the coating on the containment structure steel. Flaking and washout of this coating material led to widespread contamination of the industrial site and nearby environs through redistribution by wind and rainfall. Redistribution of this material also resulted in contamination of sediments in the adjacent water body and a runoff drainage ditch that required remediation as part of the site closure. Massachusetts DEP and Federal EPA regulatory interaction associated with defining the necessary standards for sampling and remediation of this hazardous material contamination were extensive. During decommissioning the scope of remediation expanded significantly beyond the planned shallow surface decontamination effort expected, due to discovery of deep soil PCB contamination during excavation of below grade structures. This deep contamination was not likely caused by the flaking and washout mechanism, but may have been caused by the nature of coatings handling and application during original construction of the Yankee plant.

In addition to the PCB hazardous material discovered in containment steel coatings at the Yankee plant, asbestos was found to be a constituent of coatings within the turbine building structure and below grade on the intake structure foundation. These discoveries led to significant changes in demolition methods, site work controls as well as waste disposal scope and cost increases.

Other hazardous materials including lead, dioxin, fuel oil and volatile organic compounds were also discovered at various times and locations during the decommissioning and site remediation work. Each discovery required expansion of the scope of planned remediation work, significant regulatory interaction to assure remediation standards were met, and compliant disposal of the hazardous material. The potential for structural coatings to contain hazardous materials that may be redistributed over the course of the operating life of the VY plant, and the potential for hazardous material contamination of soils from coatings application and handling during construction, should be considered in financial planning for decommissioning. In addition, discovery of contamination by hazardous materials is to be expected during decommissioning and site remediation. Such discovery could have a substantial impact on the cost and schedule for completion of decommissioning and site remediation.

Multiple Regulators

The existence of known groundwater contamination and the potential for discovery of hazardous materials during decommissioning activities make it likely that the decommissioning of Vermont Yankee will involve direct EPA regulatory oversight. The 2012 estimate explicitly excludes consideration of costs associated with such dual regulation.[42]

Based on experience with the decommissioning of other sites in New England and compared to the NRC requirements for license termination, the process for demonstrating that the site is safe to release for other uses can be expected to be less well defined and subject to both discovery of conditions during decommissioning and extensive interaction with multiple regulators. In addition, like the Maine Yankee, Connecticut Yankee and Yankee Rowe decommissioning projects in their respective states, the Vermont Yankee

[42] 2012 estimate, Section 1, Page 8 of 8.

project will be the first time regulators will have to deal with a nuclear power plant decommissioning within the state of Vermont.

An example of the type of impact multiple regulators can have on site restoration work from the Yankee Rowe project can be seen in the treatment of below grade foundations. The survey plan for foundations was developed based on limits from the NRC-approved License Termination Plan in accordance with federal regulations and guidelines. While this plan was being implemented the Massachusetts DEP issued its Beneficial Use Determination (BUD) criteria for foundations remaining below grade. The BUD required demonstration of a no detectable plant related radioactivity above background standard for which separate instrument and survey protocols had to be developed, agreed to and implemented.

Allocation of Costs

Allocation of costs refers to the attribution of various decommissioning costs to license termination (NRC-defined decommissioning or 50.75 costs), spent fuel management (50.54(bb) costs), or site restoration costs.[43] With regard to the total decommissioning cost, this allocation has no effect. However, the allocation can be important for reasons related to funding analysis.

First, the NRC regulations only permit decommissioning trust funds to be expended for NRC defined or 50.75 decommissioning costs.[44] In the case of prematurely shut down plants such as Maine Yankee or Yankee Rowe, the NRC has not enforced this restriction, but instead has allowed expending decommissioning trust funds on all three cost categories. It is not clear how the NRC will respond in future decommissioning projects and therefore, care should be taken in allocating costs to the three categories.

Second, based on testimony from Mr. William Cloutier, certain VY decommissioning funding analyses assume spent fuel management costs will be recovered from the DOE. Without commenting at this point on the assumed recovery of spent fuel costs, it is important that the allocation of costs be accurately performed so the assumed recovery is not overstated or understated for the funding analysis.

For some costs, the allocation to license termination, spent fuel storage, or site restoration is essentially a factual matter. For other costs, however, the allocation is a subjective decision with bases for allocation to more than one category. The following discusses the two types of costs separately. The first section discusses costs where it is judged that the allocation is factually incorrect. The second section discusses costs where there is a

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[43] 50.75 refers to 10 CFR 50.75, which is the section of regulations associated with nuclear decommissioning trust funds. Similarly, 50.54(bb) refers to 10 CFR 50.54(bb), which relates to funding for spent fuel management.

[44] Use of NRC-regulated decommissioning funds for any other purpose requires a waiver as identified in 10 CFR 50.82.

reasonable alternative allocation. The allocation reflected in the six scenarios is not consistent in the 2012 estimate and thus, the comments that follow do not apply equally to all scenarios.

NRC Fees

NRC fees are included in all scenarios either as "NRC Fees" or "NRC ISFIS Fees." Such costs are included in all periods, except generally the last period that is assumed to occur after the termination of the NRC license. Further, a given period includes only one of the two designations of NRC fees. NRC fees should include both annual fees (governed by 10 CFR 171) and site-specific for-service fees (governed by 10 CFR 170).

Since 1999, the NRC regulations impose an annual fee on power reactors that are permanently shut down in a decommissioning status, but still have spent fuel on site.[45] Once all spent fuel is gone, the annual fee is no longer charged. Thus, this annual fee is tied to spent fuel management and not license termination.[46]

Because the 10 CFR 171 fee is tied to the presence of spent fuel, one alternative is to allocate all such fees as spent fuel storage costs. This is not what has been done in the 2012 estimate.[47] As an alternative, the allocation could be done on the basis of the applicability of the fee in a hypothetical world where DOE began acceptance of spent fuel in 1998. In such a construct, some spent fuel would remain on site for at least five years after the removal of the last fuel from the reactor. This fact, as well as how spent fuel management costs are treated in the funding analysis, suggests this alternative allocation of such costs. This alternative would allocate all 10 CFR 171 fees as license termination costs through about five years after the final plant shutdown. This also is not what was done in the 2012 estimate.[48] Moreover, the allocation of 10 CFR 171 fees does not appear to be consistent for all the scenarios in the 2012 estimate. The following comments point out inconsistencies and recommend allocations consistent with all 10 CFR 171 fees through about five years after final shutdown being allocated as license termination costs. All 10 CFR 171 fees from about five years after final shut down until all spent fuel has been removed from the site would be allocated as spent fuel management costs.

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[45] The fee is part of the annual fee for a reactor licensed under 10 CFR 50.

[46] The exception to this allocation to spent fuel management might be the fee during the first five years after shutdown. Even with DOE performance, all spent fuel would not be removed sooner than five years after final shutdown. Thus, one could argue that the annual fee during that first five years should be categorized as license termination costs. On the other hand, the model plant decommissioning studies prepared for the NRC as part of establishing decommissioning funding regulations assumed at most 90 days of spent fuel storage after shutdown. Thus, one can also argue that allocating the cost of the annual fee as spent fuel management is consistent with the NRC definition of decommissioning and NRC regulations on funding assurance. Spent fuel management costs are not included in the 10 CFR 50.75 decommissioning funding assurance requirements.

[47] The simplest way to verify this is that in Scenario 1 the 10 CFR 171 fee would apply through the end of period 2b (2045), but all NRC fees for periods 1a, 1b, and 1c are allocated as license termination costs.

[48] Using this alternative allocation, all Part 171 fees through period 2a of all the SAFSTOR scenarios would be allocated as license termination costs. In scenario 1, all NRC fees in period 2a are allocated as spent fuel storage costs.

In scenarios 1, 5, and 6, all of the NRC fees are allocated as license termination costs. The annual fee included in these costs should be license termination costs through period 2a and spent fuel management costs thereafter until all spent fuel is removed from the site. Additionally, any 10 CFR 170 fees associated with inspection or licensing related to an ISFSI, wet storage of spent fuel, or transfer of fuel from wet to dry storage should be spent fuel management costs, regardless of period.

In scenarios 3 and 4 (the DECON scenarios), the NRC fees are all allocated as license termination through the end of the prompt decommissioning and as spent fuel management costs from that point until all the spent fuel has been removed from the site. The 10 CFR 171 fees should be license termination costs through period 2b in both of these scenarios (this period ends about 5.5 years after shutdown in both scenarios). Again, any 10 CFR 170 fees associated with inspection or licensing related to an ISFSI, wet storage of spent fuel, or transfer of fuel from wet to dry storage should be spent fuel management costs, regardless of period.

In scenario 2, all NRC fees have been allocated as license termination costs through period 4f (about 60 years after final shutdown). Consistent with the above, the 10 CFR 171 fees should be allocated a license termination costs only through period 2a (about 5.5 years after shutdown) and any 10 CFR 171 fees after that should be allocated as spent fuel management costs. Again, any 10 CFR 170 fees associated with inspection or licensing related to an ISFSI, wet storage of spent fuel, or transfer of fuel from wet to dry storage should be spent fuel management costs, regardless of period.

Security Staff

Even in the absence of radiological materials, there would be some security for an industrial site, such as a power plant, even after it has ceased to operate. This level of security prevents theft as well as intruders being harmed and creating liability for the site owners. This level of security is often referred to as industrial security.

However, with special nuclear material on site, such as spent nuclear fuel, the NRC mandates a higher minimum level of security. The NRC specifies the minimum performance requirements, and each facility develops a security plan to comply with these requirements. Once all fuel is removed from the site, the NRC does not require this higher level of security.[49] For this report, this higher level of security required while fuel is on site will be referred to as nuclear security.

The allocation of security staff costs in the 2012 estimate is not consistent with these facts and not even consistent for all scenarios. The inconsistency between scenarios is evidenced in period 2a of scenarios 1 and 2. For this period in scenario 1, the security staff

[49] As noted above the higher level of security applies to any special nuclear material, not just spent fuel. However, it is unclear why a power plant would have special nuclear material requiring nuclear security once all the spent fuel has been removed.

costs are split about 86 percent as spent fuel management costs and about 14 percent as license termination costs. However, in scenario 2 all the costs are allocated as spent fuel management costs. In both scenarios, fuel is stored wet and dry and the plant is dormant waiting to be dismantled. Thus, there is no reason for such a difference in allocation.

Given the basis for varying levels of security, the following is judged to be a more reasonable allocation of costs than that reflected in the 2012 estimate. For all periods up to and including the termination of the NRC license (except the ISFSI), costs for industrial security should be allocated as license termination costs. For any period during which site restoration is performed (not including the period just dealing with the ISFSI), costs for industrial security should be allocated to site restoration. Any additional security costs during these periods should be allocated as spent fuel management costs. For any periods subsequent to the NRC license termination and site removal (again not including the ISFSI), all security costs should be allocated as spent fuel management costs.

A couple of examples may be useful. For scenario 1, costs equal to industrial security costs would be allocated to license termination for all periods and the added costs for nuclear security would be allocated as spent fuel management costs for periods through 2a. For scenario 3, costs equal to industrial security costs would be allocated to license termination for periods through 2f. Costs for industrial security should be allocated as site costs for period 3b. The added costs for nuclear security should be allocated as spent fuel management costs in all periods.[50]

Of course, this comment does not change the total post-shutdown costs for any scenario, but redistributes costs between the three cost categories. The redistributed costs from the 2012 estimate are:[51]

[50] Because fuel must remain in the spent fuel pool at least five years to qualify as standard fuel under the Standard Contract, one might argue that all security costs during the first five years following shutdown should be license termination costs. The counter to that suggestion is that the NRC decommission funding rules clearly indicate that decommissioning costs do not include fuel management costs and thus, any added costs originating from the presence of fuel would not be a license termination (or decommissioning) cost.
[51] The adjustments were based on evaluating the scenarios to determine a cost of about $1.21 million per year for industrial security. Delayed decommissioning period in scenario 5 and 6 would just be industrial security. The total security cost divided by the duration gives the $1.21 million per year. The industrial security costs which are allocated as license termination costs were calculated. The site restoration security costs were left unchanged, and the spent fuel management cost then adjusted as needed to maintain the total scenario cost unchanged.

2012 Estimate

Scenarios	1	2	3	4	5	6
Cost Categories						
License Termination	$645,773	$610,278	$566,714	$566,714	$653,115	$622,571
Spent Fuel Management	$327,127	$502,979	$230,821	$365,318	$268,976	$397,211
Site Restoration	$47,792	$46,502	$47,887	$47,887	$47,792	$47,792
Total	$1,020,692	$1,159,759	$845,422	$979,919	$969,883	$1,067,574

2012 Estimate with Re-Allocated Security Costs

Scenarios	1	2	3	4	5	6
Cost Categories						
License Termination	$684,973	$657,780	$541,321	$541,321	$691,667	$674,739
Spent Fuel Management	$285,327	$455,299	$256,140	$390,637	$230,424	$345043
Site Restoration	$47,792	$46,680	$47,961	$47,961	$47,792	$47,792
Total	$1,020,692	$1,159,759	$845,422	$979,919	$969,883	$1,067,574

Utility Staff

Utility staff cost allocation can be subjective. In the simplest terms, during periods where the plant is being maintained in a SAFSTOR status or actively decommissioned and spent fuel is being managed, the judgment can be reasonably made that spent fuel management is the primary activity with the necessary staff for fuel storage allocated to spent fuel management and any additional staff being allocated to license termination.[52] Alternatively, one could assume that the primary activity is decommissioning (including SAFSTOR) with the necessary staff for decommissioning allocated to license termination and any additional staff allocated to spent fuel management.

Considering health physics staff can help to explain the two alternatives. Both decommissioning and spent fuel management require health physics activities, although the health physics work just to support spent fuel management is limited. Thus, if decommissioning is primary then there may well be sufficient health physics staff to support spent fuel management, and there would be no spent fuel costs for health physics staff. On the contrary, if spent fuel management is the primary activity, one or two health physics staff would be needed to support fuel management but likely would not be needed full time for these duties. The health physics staff allocated to license termination would be the staff needed in addition to those already there for fuel storage.

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[52] In assuming spent fuel storage is the primary activity, the needed staff would be determined by estimating the needed staff as if no other activity (SAFSTOR or decommissioning) was going on at the site.

In making decisions about cost allocations, the decisions concerning allocations should be applied consistently from one scenario and one period to another unless there are factual differences in the scenarios that suggest the allocations should be different. There are instances in the 2012 estimate that suggest the allocations were not done consistently for all scenarios:

a. Period 2a is the same in terms of spent fuel management and site activities in scenarios 1 and 2. In period 2a of scenario 1, the utility staff cost is split between spent fuel management and license termination. However, in period 2a of scenario 2, all utility staff costs are allocated as spent fuel management costs;
b. Period 2b of scenario 2 includes dry storage of fuel. The utility staff costs are split between license termination and spent fuel management, with nearly one-half of cost going to spent fuel management. Periods 3a and 3b of scenario 1 are restoration from SAFSTOR and D&D preparations both with fuel still stored dry but all staff costs are allocated to license termination. It is unclear the allocation of staff costs would be different from period 2b of scenario 2; and
c. Comparing scenarios 5 and 6, period 2b include the same activities in both scenarios. The difference is that period 2b has a longer duration in scenario 6. In scenario 5, all utility staff costs in period 2b are allocated as spent fuel management costs. In scenario 6, the staff costs in period 2b are split between license termination and spent fuel management costs.

For the 2012 estimate, the suggested allocation assumptions are:

1. For the DECON scenarios, decommissioning is the primary activity through the end of site restoration, not including the ISFSI. The remainder of the time fuel storage would be the primary activity; and[53]
2. Similarly, for the SAFSTOR scenarios, decommissioning and site restoration should be the primary activity with spent fuel management being secondary until the NRC-defined decommissioning activities and site restoration are complete. After that time, spent fuel storage would be the primary activity.[54]

Inconsistent Cost Allocation or Estimation

Tables 6.1 and 6.2 of the 2012 estimate provide the costs for each decommissioning scenario broken down into various categories, including the categories of license termination, spent fuel management, and site restoration. The following concerns are raised by review of the data in these tables:

[53] The duration of decommissioning is consistent with the DECON option and not controlled by spent fuel management.
[54] The reason for considering the SAFSTOR and decommissioning as primary is that the length of the SAFSTOR and delay for decommissioning is not being determined by spent fuel presence, but instead by delaying to allow time for the decommissioning fund to grow. So for example, scenarios 5 and 6 both end a little more than 60 years after shutdown (2092), even though all of the fuel is removed by 2060 in scenario 5 and not until 2082 in scenario 6.

1. Scenarios 4 and 6 both assume that the plant shuts down in 2032, all spent fuel is moved to dry storage about 5.5 years after shutdown, the first spent fuel is removed from the site in 2042, and the last spent fuel is removed from the site in 2082. Given these common assumptions, the spent fuel storage activities and the duration of these activities would be the same for both scenarios. Nevertheless, the spent fuel management costs for scenario 6 is about $32 million greater than for scenario 4. This suggests either an inconsistent allocation of costs or an inconsistent estimate of the component costs.
2. Similarly, scenarios 3 and 5 have consistent assumptions with respect to spent fuel management, so presumably the spent fuel management costs should be the same in the two scenarios. However, the spent fuel management costs for scenario 5 are about $38 million more than for scenario 3.
3. Scenarios 1 and 2 both assume that the plant shuts down in 2012 with the spent fuel pool being emptied about 5.5 years later. However, the period during which spent fuel is stored dry is 37 years longer in scenario 2. The difference in spent fuel management costs for the scenarios should be indicative of the cost for 37 years of dry fuel storage. The calculated annual dry storage cost is about $4.75 million per year.

   In a similar comparison, scenarios 5 and 6 have common characteristics except for the length of dry spent fuel storage. In this comparison, the dry storage period in scenario 6 is 22 years longer than in scenario 5. Again, the difference in spent fuel storage costs for these two scenarios should allow calculation of the annual cost for dry spent fuel storage. The calculated annual cost is about $5.8 million per year.

   If component costs are calculated consistently and allocation of costs is performed consistently, there is no reason that the annual cost for dry fuel storage, when determined by the two comparisons above, should be different by over $1 million per year.

4. Similar to the preceding comparison, if scenarios 3 and 4 are compared the difference in spent fuel management costs represents 22 additional years of dry fuel storage in scenario 4. From this difference an annual cost of dry storage of about $6.1 million per year can be calculated. This value represents a larger difference from the annual costs calculated based on scenarios 1 and 2.

Estimate Details

Staffing

Staffing for nuclear decommissioning typically includes all non-labor personnel involved in decommissioning activities, including areas such as management, quality assurance, engineering, licensing, operations, and health physics. Staffing for decommissioning represents one of the largest cost elements. For the 2012 estimate, staffing cost represents over 40 percent of the total decommissioning cost.

The 2012 estimate assumes that Entergy will manage the decommissioning, supported by a Decommissioning Operations Contractor (DOC) to supervise subcontractors, consultants, and specialty contractors. Estimated costs are based on Entergy salary information. The 2012 estimate does not include severance or retention costs, assuming instead that any reduction in staffing is accommodated through normal staffing processes such as reassignment and outplacement.[55]

Staffing levels are presumed to change dramatically after shutdown, from operating staff levels of approximately 650 personnel to as low as five personnel during site restoration. Consider, for example, the staffing for scenario 6 (2032 shutdown and SAFSTOR), shown in the following table:

Period	Phase	Duration (Days)	Utility Manloading	DOC Manloading
1a	Shutdown through transition	365	203	
1b	Limited DECON activities	92	203	
1c	Preparations for SAFSTOR	93	203	
2a	SAFSTOR dormancy/wet fuel	1457	39.5	
2b	SAFSTOR dormancy/dry fuel	16540	16	
2c	SAFSTOR dormancy/no fuel	1184	8.75	
3a	Reactivate site	365	124	
3b	Preparations for delayed DECON	185	124	56
4a	Large component removal Phase 1	466	125	69
4b	Site decontamination (end wet fuel)	898	118	67
4f	License termination	270	47.5	36.5
5b	Site restoration	548	19.5	34

The changes in staffing levels included in this scenario (and all others) are assumed to occur with virtually no added cost associated with relocation, retraining, severance, retention, or delay in subsequent work activities associated with the time required to establish a large staff.[56]

This method of modeling is simplistic, and fails to recognize limitations inherent in these large staff size changes. A more realistic model would allow staff changes to occur over

[55] 2012 estimate, Section 3, Page 17 of 32.
[56] The estimates include limited relocation expenses (during periods 3b and 4f in the scenario shown) for the DOC staff only. This limited relocation expense is a constant value in the two occasions that it is provided. The value is approximately $21,000 per individual (including contingency).

some reasonable period, with a stepped reduction between different staffing levels. In addition, for large additions to staff, a more realistic model would include costs associated with acquiring new staff members, and training to assure new members have sufficient knowledge of the VY plant design, local requirements, and management decisions and expectations.

In addition to the modeling issues, historical decommissioning staffing costs have been underestimated in decommissioning estimates, resulting in cost overruns (as compared to the estimates) during decommissioning to complete required decommissioning activities. These underestimated staffing costs have generally resulted from several causes, including inadequate consideration of staff needs, and underestimating staff salaries and contractor rates.

Consider, for example, the Humboldt Bay facility being decommissioned by Pacific Gas & Electric (PG&E). In 2006, TLG estimated the cost to decommission this facility. The staff cost estimated by TLG was $107.6 million (escalated to 2010 dollars using CPI).[57] This estimate was performed prior to the start of active decommissioning of that facility.

After the start of active decommissioning, this cost estimate was updated to include $168 million in staff costs (2010 dollars).[58] Nonetheless, even with the updated cost estimate, during execution of decommissioning activities, PG&E incurred significantly higher staffing expenses than estimated by TLG.[59] Similar overruns compared to estimate costs have occurred at other facilities as well.

In addition to unrealistically modeling staff size changes and potentially underestimating costs, there are other concerns with the estimated staff. First, there is no consideration of decommissioning planning costs prior to shutdown. For a planned, end-of-life shutdown, the utility should perform significant planning activities prior to final shutdown, such that the transition from operating to decommissioning can be made as quickly as practical. While these pre-shutdown costs can be paid from operating revenue, there is no indication in the study that such additional revenue was assumed, nor does the study include such costs.

Second, the presumption that staff termination will be handled by reassignment and outplacement with no cost is unlikely. Other decommissioning projects have used substantial retention payments to keep exceptional workers, and provided extensive services to facilitate worker transition to other employment. While estimators can debate the appropriate level of services and costs that will be employed, the simple fact is that zero is not a reasonable estimate.

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[57] PG&E Letter HBL-06-005 from John S. Keenan to U.S. Nuclear Regulatory Commission, March 31, 2006, Decommissioning Funding Report for Humboldt Bay Power Plant Unit 3.
[58] PG&E Letter HBL-11-003 from John T. Conway to U.S. NRC, March 31, 2011, Decommissioning Funding Report for Humboldt Bay Power Plant Unit 3.
[59] October 20, 2011 Advice Letter 3932-E, Subject: Request for Approval of a Disbursement of Funds from the Humboldt Bay Power Plant Unit 3 Nuclear Decommissioning Trusts.

There are common types of personnel included in the utility staff and in the labor included in development of Unit Cost Factors (UCF). However, the labor rates used in the two locations are not consistent:

Labor Type	Rate in Unit Cost Factor	Rate in Staff Costs[60]
HP Tech	$36.57	$54.00
Laborer	$47.52	$38.00
Craft	$61.55	$55.00[61]
Craft Supervisor	$65.29	$57.00

In addition to the rates not being consistent between the UCF development and staff, all of the labor types do not vary in the same way. That is, for the HP Tech, the UCF rate is lower than the staff rate, but for all the other cases, the UCF rate is higher. Unless there is a supportable reason for different rates being applied, consistent rates should be used. In the absence of any data to justify one rate versus the other, the conservative approach of using the highest rate for each labor type in both the UCF and staff costs should be adopted.

Other Period Costs

NRC Annual Fees

The NRC annual fee (10 CFR 171) is discussed above with respect to the allocation of costs. However, there is also a concern about the actual value for such fees included in the 2012 estimate. Specifically, the 2012 estimate assumes an annual fee of $148,000 per year. This fee is the fiscal year 2010 fee. The fiscal year 2011 fee is $241,000 per year. For the 2012 estimate in 2011 dollars, it is unclear why the fiscal year 2010 fee would be the appropriate value to use.

Admittedly, the annual fee amount has changed in an unpredictable way over time. Starting in fiscal year 2010, the fee started at $148,000 per year, increased to $241,000 per year in 2011 and dropped to $211,000 in 2012. In the past, this fee has been over $300,000 per year. The most conservative approach would be to use the maximum of this fee since 1999. To account for the fee variability, a somewhat less conservative, but justifiable methodology would be to use the average fee over some period of time. If the annual fee for fiscal years 2007 to 2011 (5 years) are escalated to 2011 dollars and averaged, the result would be about $161,000 per year. A fee of at least this amount should be assumed. Use of this average value would add about $650,000 to scenarios assuming a 2032 shutdown and 2082 date of fuel removal. Use of the 2011 fee would add about $4.6 million for these same scenarios.

[60] Staff rates are based on the annual burdened cost identified in the staffing information and 2000 hours per year.
[61] Based on mechanical and electrical craft.

10 CFR 170 fees are based on the rate at which NRC personnel time is billed to the utility. The 2012 estimate assumes an hourly rate of $259 per hour. However, the fiscal year 2011 NRC rate is $273 per hour. The 10 CFR 170 fees should be based on $273 per hour.

Energy Costs

The energy costs are not consistent between scenarios. Specifically:

1. Scenario 2 has a total duration of 71 years with 70 years of fuel storage. Scenario 1 has total duration of 61 years with 33 years of fuel storage. Both scenarios are SAFSTOR scenarios. Both scenarios have the same total energy costs ($16.2 million) even though scenario 2 has a 10-year longer total duration and a 37-year longer fuel storage duration;
2. Scenarios 3 and 4 are both DECON scenarios with dismantlement occurring at the same time in both scenarios. However, spent fuel is stored for 22 additional years in scenario 4. Despite the substantial extra storage period in scenario 4, both scenarios have $7.84 million in energy costs. Scenario 4 should clearly have a greater total energy cost; and
3. Scenario 4 has the same total duration and fuel storage length as scenario 6. The difference is that scenario 6 assumes spent fuel storage in parallel with SAFSTOR. Scenario 4 has a similar number of years, but with only spent fuel storage activities. Scenario 4 has a total energy cost of less than half of the scenario 6 energy costs. It is unclear why this difference in activities should result in such a large change in energy costs.

Activity Costs

License Termination Activities

The 2012 estimate contains costs for removal of all plant equipment (contaminated and clean), decontamination of structures, and removal of buildings to three feet below grade.

Reactor Vessel and Reactor Vessel Internals

Several large Pressurized Water Reactors (PWR) have been decommissioned, including segmenting the reactor vessel internals. These projects provide the best data and basis for estimating costs for similar work in future PWR decommissioning projects. This is particularly true for the reactor vessel and reactor vessel internals segmentation and removal. Considering the actual experience for facilities such as the Yankee plants and the Rancho Seco plant, one conclusion is that the actual cost for PWR reactor vessel and internals segmentation has been substantially higher than the cost estimated for that work. For future PWR estimates, the collective actual cost data can be used to adjust the estimated costs to better predict the ultimate costs.

No large commercial Boiling Water Reactors (BWR), like VY, have yet been decommissioned.[62] The reactor vessel internal removal work for a BWR will be very different from that for a PWR. The vessel segmentation work will be similar, but not identical to that for a PWR. Therefore, unlike PWRs, there is no completely applicable experience base to use for benchmarking BWR estimates. However, the cost in the 2012 estimate for SAFSTOR scenarios seems quite low. Despite the PWR/BWR differences, estimates for reactor vessel segmentation alone can be two times the VY total for both the vessel and vessel internals. Based on experience for a small BWR, Humboldt Bay, that has been in SAFSTOR for a long time, the VY estimated costs for DECON scenarios are appropriate for the SAFSTOR scenarios as well. This change would add $20 to $25 million to the total estimated cost for SAFSTOR scenarios.[63]

In addition, there are inconsistencies in the reactor vessel related costs in the 2012 estimate:

1. The waste (including the breakdown of waste into classes) from the reactor vessel and internals is the same for scenario 1 and 2. Further, the work occurs at the same time (absolute time) as well as with regard to time after final plant shutdown. Nonetheless, the packaging cost related to these items in scenario 2 is about $2.3 million ($1.7 million plus cost for GTCC) more than in scenario 1. There appears to be no reason for this inconsistency.
2. The packaging cost for these items is the same in scenarios 5 and 6 as it is in scenario 1. The total amount of radioactive waste is constant over the three scenarios. However, the waste distribution is very different. In scenario 2 there is much more Class B waste than Class C waste, while in scenarios 5 and 6 the amount of Class B and Class C are almost equal. It seems highly unlikely that these two different distributions of waste would result in identical packaging cost.
3. The reactor vessel transportation cost is the same for scenarios 1, 2, 5 and 6. However, the transportation cost for scenarios 3 and 4 is over double the amount in the other scenarios. Again, it is unclear why such a difference should exist.

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[62] The Big Rock Point BWR has been decommissioned, but it was a very small plant of a very early design with significant dissimilarities to later commercial BWRs. Also, the Shoreham BWR was decommissioned, but that plant was only operated at power levels below five percent for a total duration of about two days. As a result, the Shoreham plant was largely not contaminated and the reactor vessel and internals were not substantially activated. Thus, Shoreham data would not be representative of a BWR that had operated for decades.

[63] As noted, no large BWR has been decommissioned. However, information from a small BWR decommissioning project current underway can be somewhat instructive. The Humboldt Bay BWR is currently being decommissioned. The TLG estimate in 2009 (2008) was about $30.9 million. The Humboldt Bay reactor was much smaller than the VY reactor. Nonetheless, the current total of actual and projected costs for the removal of the Humboldt Bay reactor vessel is almost $49 million. Pacific Gas and Electric Company letter to Public Utilities Commission of the State of California, April 13, 2010, "Request Approval of the Disbursement of Funds from the Humboldt Bay Power Plant Unit 3 Nuclear Decommissioning Trusts," page 2 of attachment 1 identifies cost of 20.1 million through 2011. Pacific Gas and Electric Company letter to Public Utilities Commission of the State of California, October 20, 2011, "Request Approval of the Disbursement of Funds from the Humboldt Bay Power Plant Unit 3 Nuclear Decommissioning Trusts," page 2 identifies costs of $28.7 million for work in 2012 and 2013.

Other Radioactive Systems

There are many large components in a BWR that will be radioactively contaminated, although similar components in a PWR would not be contaminated. These components, such as the turbine, condenser, main steam system, and condensate and feed systems, are located in the steam plant, which is not subjected to radioactive contamination in a PWR, but is in a BWR.[64] These contaminated components include items. Again, since no large commercial BWR has yet been decommissioned, there is no actual decommissioning cost data to use as a benchmark for the estimate. The 2012 estimate removal cost for the turbine and condensers is very low, totaling only about $700,000 to remove over 100,000 cubic feet of waste with a weight of about 4.7 million pounds. This estimated cost is likely to be very low compared to the ultimate cost for this work.

Asbestos

All the VY decommissioning scenarios include costs for asbestos remediation. However, the cost for this remediation is greater for SAFSTOR scenarios than DECON scenarios. There is no reason the asbestos remediation would be more costly in a SAFSTOR approach to decommissioning.

Temporary Facilities

The first bullet in section 2.1.2 of the 2012 estimate discusses construction of temporary facilities as well as modification of existing facilities. Such work would be part of any decommissioning scenario. However, there appears to be no identifiable cost in the 2012 estimate for this work.

Reconfiguration and Modification of Site Structures

The second bullet in section 2.1.2 of the 2012 estimate discusses reconfiguration and modification of site structures. Such work is assumed to be part of all the scenarios. However, the cost for this work cannot be located in the 2012 estimate.

Shielding

The third bullet in 2.1.2 in the 2012 estimate discusses design and fabrication of temporary and permanent shielding. The 2012 estimate assumes such work in all scenarios. The need for permanent shielding is not clear since anything constructed would only be useful for the duration of the decommissioning. More importantly, no costs appear to be included in the 2012 estimate for this work.

[64] In a PWR, the radioactively contaminated reactor coolant is contained within a closed system. The heat from this system is used to generate steam to run the turbines, but the steam never comes in contact with the coolant or radioactively contaminated structures. In a BWR, boiling in the reactor creates steam, and therefore the steam running the turbine will itself be radioactive.

Non-radiological Dismantlement/Site Restoration

Most of the concrete in buildings above three feet below grade is assumed to be clean (not contaminated with licensed radioactive material). In the 2012 estimate, it is assumed that this clean concrete will not be used for on-site fill after the buildings are demolished. However, there does not appear to be any cost for disposal of this clean material. In fact, there does not appear to be any cost for disposal of clean demolition material of any kind.

Rail Upgrade, Repair, and Maintenance

There is a rail line to the VY site although not to the reactor building or ISFSI. It is believed that after plant shutdown the rail line would be desirable for decommissioning activities as well as for ultimately transferring spent fuel to DOE. The decommissioning estimate should include costs for upgrade, repair, and maintenance of a rail spur to the reactor building, the ISFSI, or both.[65]

Funding Analysis

Decommissioning Funding

Decommissioning cost estimates are typically "overnight" estimates. This means it is assumed all activities are performed at the same time (i.e., "overnight"), and thus the estimated costs are not escalated to the time of performance, but rather expressed in constant year dollars. To ensure that adequate funds are collected for decommissioning, these overnight cost estimates are escalated to time of performance using various indices, and then compared to trust fund projections.[66] Different indices are typically used to escalate different parts of the decommissioning costs, such as labor, energy, materials, and waste disposal.

In this process it is critical to use reasonable indices to get an accurate estimate of actual dollars to be expended. One set of such indices is calculated by the NRC and published on a biennial basis.[67] These indices are required to be used by each licensee to periodically demonstrate adequate decommissioning funding (for radiological decommissioning). Review of these factors shows that decommissioning costs have escalated at an annual

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[65] Depending on the location of the ISFSI it may not be necessary to have a rail spur to both the reactor building and the ISFSI. It might be acceptable to have a spur to the reactor building and use other means to bring loaded spent fuel casks to that spur for transfer off-site.

[66] This process is often accomplished by integrating the decommissioning expense cash flow with trust fund projections to determine the actual trust fund balance over time.

[67] The NRC publishes NUREG-1307, "Report on Waste Burial Charges" approximately every two years. This document provides escalation factors (in some cases collected from other sources) for labor, energy, and waste burial.

compound rate of 5.78 percent from 2002 to 2012 (as calculated with the NRC methodology).[68]

Entergy, in its testimony, does not provide an assumed cost escalation rate. Rather it calculates a minimum real rate of return (after-tax trust fund rate of return minus decommissioning cost escalation) required to assure adequate funding. This calculation is performed with two different assumptions for recovery of fuel storage costs from DOE. In both cases, Entergy compares these calculated real rates of return to its estimated historical after-tax trust fund earnings rate and concludes that it has sufficient earnings (without ever discussing projected cost escalation). This approach is flawed for several reasons.

First, as noted above, Entergy does not provide any discussion of decommissioning escalation (which is necessary to determine the real rate of return), but instead simply asserts that the required real rates of return are "very reasonable given its previous fund performance." However, comparing the NRC-calculated escalation rate to the Entergy historical after-tax trust fund earnings rate shows a real rate of return of negative 0.36 percent. Thus, with the NRC-calculated escalation rate, Entergy does not demonstrate adequate funding for any scenario.

Second, Entergy does not consider potential future liability for transfer of fuel to DOE that would have occurred absent DOE's breach. The Courts have held that costs to load DOE-supplied casks had DOE performed under its contract have been deferred.[69] This potential future liability would offset part of the projected recovery from DOE. While Entergy asserts that it believes all of its fuel storage costs should be recovered from DOE, it has not provided any accounting of this deferred cost.

Finally, Entergy does not model its projected portfolio composition in future years to demonstrate that the returns during the 2002 to 2012 period should be representative of future returns. Typically, as utilities approach and perform decommissioning, assets are shifted away from equities, generally reducing volatility and returns. By not analyzing its future portfolio, Entergy has not explained why historical returns have any applicability to its future portfolio management strategy.[70]

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[68] The NRC provides three factors, labor, energy, and waste disposal. These three factors are weighted 65 percent for labor, 13 percent for energy, and 22 percent for waste burial. The 2002 factors for a plant in the northeast using a waste vendor were 1.862, 0.965, and 8.86 for labor, energy, and burial respectively. The composite 2002 factor was 3.285. The 2012 factors were 2.52, 2.795, and 17.083, resulting in a composite factor of 5.76. Together, these two composite factors show an annual escalation of 5.78 percent.

[69] United States Court of Appeals for the Federal Circuit, 2008-5108, Carolina Power & Light Company and Florida Power Corporation v. United States, July 21, 2009.

[70] To the extent that Entergy intends to maintain a large fraction of equities in its portfolio, then it is subject to the same market downturns that occurred in the 2008 time frame. A market downturn just prior to the start of actual dismantlement activities could significantly reduce available funds.

Estimate Uncertainties

Some uncertainties have been discussed in earlier sections of this report. The intent of this section is not to duplicate those discussions, but to address other uncertainties.

Spent Fuel Management

As should be well known, there is no certainty as to when DOE will begin to accept spent fuel, the requirements that may be established, or the plans that may developed as DOE acceptance of spent fuel becomes a reality. There are at least two areas of uncertainty relative to the decommissioning estimate.

First, as noted before, while the 2012 estimate assumes the acceptance of the last fuel by DOE as late as 2082, this is not the latest date that would allow completion of decommissioning within 60 years. By assuming that dismantlement is initiated prior to all fuel being removed from the site, a date of last acceptance as late as about 2090 could be assumed. Based on the annual dry storage costs reflected in the 2012 estimate, extending the date of final acceptance by eight years would add about $54 million to the decommissioning cost.

Second, the 2012 estimate assumes that within 5.5 years after final shutdown, all the fuel in the pool at shutdown will be loaded in to Holtec dry storage casks similar to those already in use at VY. The 2012 estimate further assumes that a second ISFSI pad will be constructed to hold these newly loaded casks, as well as those that will be on the existing ISFSI pad at the time of plant shutdown.

DOE has had two programs for the development of casks for storage, transportation, and disposal of spent fuel. In both instances, the cask being developed would have had a capacity of 44 BWR spent fuel assemblies. If such a cask were ultimately developed, there may be an incentive to use such casks for dry storage of some or all of the spent fuel. The current Holtec casks hold 68 BWR assemblies; so changing to a 44-assembly cask would increase the number of casks (and essentially the size of the ISFSI pad) by approximately 50 percent.

Regulatory Changes

Although identified in the discussion of decommissioning approach, the possibility of changes in regulations (NRC, environmental state or local) presents a risk that additional activities may be required, the method of accomplishing certain activities might be made more difficult, or the criteria for completion could be made more demanding. Regardless of basic decommissioning approach, the risk that regulatory change can increase decommissioning cost cannot be eliminated.

Availability of Labor

The 2012 estimate assumes that specialty contractors and qualified labor will be available at the time the decommissioning is performed. At present, only a few companies can perform reactor vessel and reactor vessel internals segmentation work. As a result, if several decommissioning projects needed this type of contractor at the same time, there may be an insufficient number of qualified contractors available.

Depending on the exact timing relative to other site decommissioning work and the state of the nuclear industry, there may be more demand than available resources. Such a situation could require a change in planning, or delays that could increase costs. Alternatively, the solution could be to pay a premium price for specialty contractors or qualified labor.

Comparison of 2012 and 2007 VY Estimates

Some comparisons were made between the 2007 VY decommissioning estimate and the 2012 estimate. With respect to high-level comparisons, it is important to first establish which scenarios from each study are reasonable to compare. The following were determined to be the appropriate scenarios for comparison:

2007 Study Scenario	2012 Study Scenario	Description
4	4	Scenario 4 in both estimates assumes a 2032 shutdown, DECON, first fuel pickup in 2042, last fuel pickup in 2082.
7	2	Scenario 7 (2007) and scenario 2 (2011) both assume a 2012 shutdown, SAFSTOR, and last fuel pickup in 2082. The one difference is that scenario 7 assumes first fuel pickup in 2057 whereas scenario 2 assumes 2058. This slight difference should not invalidate any high-level comparison.
8	6	Both scenarios assume a 2032 shutdown, SAFSTOR, first fuel pickup in 2042, and last fuel pickup in 2082.

The results of these comparisons are:

1. For all three sets of scenarios, the 2012 total cost is greater than the 2007 total cost escalated based on the change in Consumer Price Index (CPI) from 2007 to 2011.[71]

   There is another way to escalate the 2007 costs to 2011 that could be used. The NRC periodically publishes revisions to NUREG-1307. This document reports on changes in LLRW costs. NUREG-1307 also reiterates the NRC regulatory

[71] The 2007 study has costs in 2006 dollars. Thus, the escalation was based on CPI change from 2006 to 2011. Over this 5-year period, the change in CPI reflects an escalation of about 2.2 percent per year.

requirements for calculating the total cost escalation factor to be used by licensees in demonstrating adequate decommissioning funding assurance per 10 CFR 50.75. Calculating cost escalation NUREG-1307, and using this value to escalate the 2007 costs results in values that are slightly greater than the 2012 costs.[72]

In conclusion, the 2012 total costs are consistent with the 2007 total costs escalated at a rate somewhere between the CPI rate of change and the NUREG-1307 rate of change.

2. The breakdown of costs into license termination, spent fuel management, and site restoration costs was also compared. Unlike the comparison of total costs, the comparison of these categories of cost is troubling.

   The category comparison for scenario 4 from both estimates is similar, with the change in the three category totals being consistent with the change in total cost. However, for the comparison of scenario 7 (2007) and scenario 2 (2012), the individual category costs changed inconsistently. The 2012 license termination costs were about 10 percent higher than the similar 2007 costs escalated consistent with NUREG-1307.[73]

   For spent fuel management costs, the 2012 scenario 2 estimated costs represent a decrease of about 22 percent from 2007 scenario 7 costs escalated in accordance with NUREG-1307. For the comparison of scenario 8 and scenario 6, the spent fuel management costs actually decreased from 2007 to 2012. The 2012 estimated costs represent a decrease of approximately 27 percent from 2007.[74]

   Comparing the site restoration costs in scenario 7 (2007) and scenario 2 (2012), the escalation was less than the change in CPI.

3. Just comparing LLRW related costs (waste disposal and processing) in scenario 7 (2007) and scenario 2 (2012), the 2012 cost is only about 66 percent of what would be expected by escalating the 2007 consistent with NUREG-1307. In fact, the 2012 costs are less than the unadjusted 2007 costs. Thus, the 2012 estimate appears to include some unexplained source of cost reduction.[75] The same situation exists in comparing scenario 8 (2007) to scenario 6 (2012). The waste costs in scenario 4 in

[72] Revisions 12 and 14 were used. These allowed direct calculation of an escalation factor from 2006 (the year dollars of the 2007 estimate) and 2010. To get the factor for 2006 to 2011, the annual rate of change from 2006 to 2010 was calculated and this rate used as the average from 2006 to 2011. This results in an annual rate of escalation of about 4.2 percent.
[73] Compared to the CPI escalation of costs, the 2012 estimated costs have increased about an extra 20 percent.
[74] Based on NUREG-1307, the escalation from the 2007 costs to 2012 costs would be about 22 percent. However, the 2007 scenario 7 costs were essentially the same as the scenario 2 costs or a decrease of about 22 percent.
[75] There is a reduction of waste volume from 2007 to 2012. However, this reduction in volume is not large enough to explain the cost reduction. Further, the basis for the reduction in volume is unknown.

2007 and 2012 are almost the same without adjustment of the 2007 costs. Thus, there is a cost reduction in real terms between 2007 and 2012.

4. Other costs such as transportation, packaging, corporate A&G, and surveys have increased at 2 to 3 times the rate expected based on NUREG-1307.

Additional Comments

Lessons Learned

Mr. Cloutier testified that VY would benefit from decommissioning other Entergy plants. Mr. Cloutier appears to be stating that the only question is the magnitude of the benefit that will be gained.

In particular, Mr. Cloutier states this benefit will come from experience decommissioning the Fitzpatrick and Pilgrim plants (both BWRs similar to VY). With license extension, Pilgrim will permanently shutdown in 2032 (the same year as VY with license extension) and Fitzpatrick will shut down two years later, in 2034. While experience from prior decommissioning work can result in benefits to later projects, the assertion that VY will benefit is dependent on significant assumptions that may prove untrue.

Unless the decommissioning activities are conducted reasonably closely in time, the experience may not be preserved in a way that allows any substantive benefit. For example, assume that the other two plants are decommissioned promptly after shutdown, but that VY uses a decommissioning approach similar to scenario 5. Fitzpatrick and Pilgrim would perform the radiological decommissioning in the 2030s, but VY would not perform this work until about 50 years later in the 2080s. Any experience that was and could be retained in records could only be useful 50 years later if the existence and repository of such information was known. Further, even if the knowledge were retrievable, it may be of little or no value because of changes in technology or regulations. Any experience not recorded, but that might be obtained from the personnel involved in the earlier work, would likely not be available half a century after the fact.

Second, who is to say that VY would not be the first plant decommissioned? If this were true, then Pilgrim or Fitzpatrick rather than VY would gain the benefit of any experience in decommissioning. If Entergy undertook a plan to sequence the decommissioning of these three plants to maximize the benefit of experience, the specific location of each plant in the sequence would not only effect how that plant would benefit from lessons learned, but the sequencing would likely change the funding analysis for that plant. The actual benefit would only be known once both effects were evaluated. Also, a decision would have to be made as to which facility would reap the benefits. Aside from the rather direct assessment of how to minimize total cost for all three plants, there would also be consideration as to the ultimate disposition of any excess money in the decommissioning trust funds. Depending on the agreements related to each plant, there would be competing interests of maximizing the financial interests of Entergy and maximizing the financial interests of Vermont, New York, or Massachusetts.

Mr. Cloutier identifies that one of the areas in which benefit of lessons learned may be realized is spent fuel management. While experience might produce benefits in this area, suggesting that this may somehow reduce the VY cost of decommissioning is inconsistent with other testimony. Specifically, Mr. Cloutier testifies that he expects the spent fuel management costs to be ultimately borne by DOE. If this later point becomes true, then experience that reduces spent fuel management costs will not reduce Entergy's cost for VY decommissioning, but instead would simply reduce the cost borne by DOE.

Overall, while there may be decommissioning savings possible from lessons learned based on coordinated efforts, there are reasons why such savings may never materialize, and there is a possibility for a given plant that the coordinated plan may be financially detrimental. As a result, while possible ways to reduce the cost of decommissioning should be pursued, no positive or negative credit should be assumed until the details of such a plan are made specific and definite.

Fleet Operation of Long Term Fuel Storage

Mr. Cloutier has testified there could be financial advantage to Entergy fleet management of long-term fuel storage "once decommissioning has been completed." Storage of spent fuel after decommissioning is complete only applies to three of the six 2012 estimate scenarios. The benefit suggested has no applicability to the other scenarios.

Additionally, as noted above, Mr. Cloutier believes spent fuel storage costs will be recovered from the DOE. If correct, there would be no reduction in Entergy's costs even in three of the scenarios where the posited situation exists.

Maturation of DOE Plans

Mr. Cloutier has testified that an additional 20-year period of operation of VY will provide additional time for maturation of the DOE spent fuel program plans and this would provide greater assurance that the decommissioning of VY can be achieved in a timely and cost effective manner. The nature of the benefit being suggested by Mr. Cloutier is unclear.

The start of decommissioning is not dictated by progress in DOE planning. While it is important that spent fuel be removed from the spent fuel pool to begin significant decommissioning work, starting such work is not dependent on the beginning of DOE spent fuel acceptance. Further, the completion of the NRC-defined decommissioning, which represents the majority of the estimated costs, can be completed (except for the ISFSI dismantlement) independent of the start of DOE acceptance. Based on Mr. Cloutier's testimony that he expects all spent fuel management costs to be recovered from DOE, any benefit gained with regard to spent fuel management would not benefit Entergy or Vermont.

It is possible that maturation of DOE plans could influence the type of storage system used to move fuel to dry storage after final shutdown. As noted above, this could result in different spent fuel management costs. However, once again, consistent with an assumption that all spent fuel management costs will be borne by DOE, such an effect would not alter the decommissioning cost to Entergy.

Recovery of Spent Fuel Management Costs

As noted several times, Mr. Cloutier testifies that he expects VY to recover all spent fuel management costs from DOE. Such an assumption does not affect the 2012 estimate, but rather the funding analysis. To the extent the amount assumed to be recovered is based on the allocation of costs in the 2012 estimate, it is only as reasonable and reliable as the allocation of costs in the estimate.

Aside from the issue of cost allocation, and identifying what costs constitute spent fuel management costs that might be recoverable, there is a separate specific reason to believe that not all spent fuel management costs will be recovered. Entergy has referred to court rulings in litigation with the DOE as basis for assuming recovery of spent fuel costs, but Entergy has not identified or properly evaluated all of the circumstances with those rulings.

First, recovery of any costs to date, aside from those utilities that have settled with DOE, have been delayed for many years after those costs were originally incurred. For example, in 1998 Yankee Rowe sued for costs incurred through 2001, yet recovery of those costs was delayed in excess of ten years. Other utilities have faced similar delays in recovery of costs.

Second, even when costs have been recovered, it has not always been on a dollar-for-dollar basis. Courts have disallowed recovery for costs that it deems the utility would have had to perform even if DOE had met its obligations to remove spent fuel under its contracts.

Finally, Entergy has not explained the significance of the ruling by the Court of Appeals for the Federal Circuit with regard to spent fuel loading costs. Specifically, the Court ruled that the cost of loading fuel for transfer to a DOE facility that the utility would have incurred had DOE performed was not an avoided cost, but a deferred cost. The Court also stated that these deferred loading costs would have to be paid by the utility at the time DOE does perform.[76] Although the value of these deferred responsibilities will be established in the future, the cost could be as much as the dry cask loading cost. This deferred obligation to DOE could be on the order of $10 to $20 million at the VY Station.[77]

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[76] United States Court of Appeals for the Federal Circuit, 2008-5108, Carolina Power & Light Company and Florida Power Corporation v. United States, July 21, 2009.

[77] This estimate is based on the projected VY ISFSI size of 84 casks and two estimates for cask loading: a lower estimate of about $120,000 per cask, and a higher estimate of $240,000 per cask. Entergy has estimated cask loading costs, based on experience with Holtec cask, and could readily estimate the magnitude of this potential liability.