STATE OF VERMONT

BEFORE THE PUBLIC SERVICE BOARD

Amended Petition of Entergy Nuclear Vermont Yankee, LLC, and Entergy Nuclear Operations, Inc., for amendment of their certificates of public good and other approvals required under 30 V.S.A. sec. 231(a), to continue operation of the Vermont Yankee Nuclear Power Station after March 21, 2012, including the storage of spent-nuclear fuel	)	**Docket No. 7862**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

CONSERVATION LAW FOUNDATION

Resource Insight, Inc.

OCTOBER 22, 2012

Mr. Chernick's testimony provides an evaluation and analysis of certain economic effects of the proposed certificate of public good for operation of Vermont Yankee to assist the Board in determining whether a certificate of public good for Vermont Yankee will "promote the general good of the state" per 30 V.S.A. §231(a). Mr. Chernick's evaluation includes the value to Vermont of the price suppression and of the revenue-sharing provision in Paragraph 4 of the March 3 2002 Memorandum of Understanding, the lack of any direct benefits to Vermont ratepayers in the absence of a power contract, and the risks to Vermont due to the underfunding of the Vermont Yankee decommissioning fund.

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EXHIBITS

I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., Five Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit____PC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in 24 states and three Canadian provinces, and two Federal agencies.

Q: Have you testified previously before the Vermont Public Board?

A: Yes. I testified in the following cases:

- Docket No. 4936, on Millstone 3;
- Docket No. 5270 on DSM cost-benefit test, pre-approval, cost recovery, incentives, and related issues;
- Docket No. 5330, on the conflict between the HQ purchase and DSM;
- Docket No. 5491, on the need for HQ power and the costs of alternative purchases;
- Docket No. 5686, on the avoided costs and water-heater load-control programs of Central Vermont Public Service (CVPS);
- Docket No. 5724, on CVPS avoided costs;
- Docket No. 5835, on design of CVPS load-management rates;
- Docket No. 5980, on electric-industry restructuring and avoided costs;
- Docket No. 5983, on the prudence of Green Mountain Power's decisions regarding the HQ contract, avoided costs, and distributed utility planning;
- Docket No. 6018, on the prudence of CVPS's decisions regarding the HQ contract, avoided costs, and distributed utility planning;
- Docket No. 6107, on the prudence of GMP's decisions regarding the HQ contract and distributed utility planning;

- Dockets Nos. 6120 and 6460, on the prudence of CVPS's decisions regarding the HQ contract;
- Docket No. 6545, on the sale of the Vermont Yankee nuclear power plant to Entergy Nuclear Vermont Yankee (ENVY);
- Docket No. 6596, on the prudence of Citizens Utilities' decisions regarding the HQ contract, including the role of transmission constraints in that decision and its consequences.
- Docket No. 6860, on the use of distributed resources to defer or avoid portions of the Northwest Reliability Project.
- Docket No. 7440, on ENVY's previous petition for authority to continue operation of Vermont Yankee after March 2012.

Most of these appearances were sponsored by the Department of Public Service. My testimony in Dockets Nos. 5330, 5491, 6860, and 7440 were sponsored by the Conservation Law Foundation. In Docket No. 5270 I testified on behalf of a collaborative of the Conservation Law Foundation, the Department of Public Service, and CVPS.

Q: Have you been involved in other aspects of utility planning and regulation in Vermont?

A: Yes, including the following activities:

- participation in the CVPS and Vermont Gas DSM collaboratives;
- preparation of testimony on the avoided costs of Green Mountain Power in Docket No. 5780, not presented due to settlement of the case;
- assisting the Department of Public Service (DPS or the Department) in the power-supply negotiations of the externalities investigation;
- providing consulting support to the Vermont Senate on stranded costs and Vermont Yankee economics;

- assisting the Burlington (Vermont) Electric Department on distributed utility planning;
- assisting the Department in the statewide collaborative on distributed utility planning, and in the Southern Loop and Stratton area-specific distributed utility planning collaboratives;
- assisting the Department and the T&D Component Working Group with updating the transmission and distribution avoided costs used in screening energy-efficiency programs.

II. Introduction and Summary

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Conservation Law Foundation.

Q: What is the purpose of your direct testimony?

A: The purpose of my testimony is to provide the Public Service Board with an evaluation and analysis of certain economic impacts of the proposed continued operation of the Vermont Yankee facility. This evaluation is offered to assist the Board in determining whether continued operation will "promote the general good of the state" 30 V.S.A. § 248(a)(2). My testimony evaluates the proposal presented to the Board and describes the failure of Entergy's proposal to ensure that continued operation of Vermont Yankee will provide benefits to Vermont. My testimony addresses several aspects of the proposal by Entergy Vermont Yankee and its affiliates (collectively "Entergy" or "ENVY") to extend the duration of the certificate of public good for the Vermont Yankee plant, allowing an additional twenty years of plant operation. Specifically, I address the following issues:

- The overestimate of the price effects of Vermont Yankee, in the testimony of ENVY Witness Jeffrey Tranen.
- The likelihood that the revenue-sharing agreement (RSA) between Entergy and the DPS will have no benefit to Vermont ratepayers, in light of current and expected market energy prices and expected escalation in the RSA strike price, the claims of Mr. Tranen notwithstanding.
- The absence of a power-supply contract between ENVY and the Vermont utilities, which would be one way that continued operation might be shown to provide benefits to Vermont and promote the general good of the state.
- The inadequacy of the decommissioning funds for Vermont Yankee (as presented in the testimony of ENVY witness William Cloutier of TLG Services), in light of Entergy's financial status and uncertain costs and investment returns, and the economic risk to Vermont arising from continued operation.

III. Vermont Yankee's Effect on Market Prices

Q: How does Mr. Tranen estimate the effect of Vermont Yankee operation on market prices for electric energy?

A: He estimates the effect on Vermont energy prices by assuming that a MWh of generation from Vermont Yankee would have the same effect on market prices as a MWh of load reduction from an energy-efficiency program. Mr. Tranen used the estimates of price suppression from load reduction that I developed for the AESC 2011 report, which we called DRIPE (demand-reduction-induced price effect). He started with my estimate that a MWh of load reduction in Vermont would reduce the product of the Vermont zonal price times Vermont load by 9%

of the ISO Hub price; multiplied that 9% factor by his estimates of Vermont zonal price and Vermont Yankee output.

As I discuss in Section IV.B, Mr. Tranen's forecast of market prices appears to be too high.

Mr. Tranen's Exhibit EN-JT-9 summarizes his results, which he describes as "maximum potential market savings for Vermont." As Mr. Tranen acknowledges (Direct at 21), most of Vermont's energy is provided by long-term entitlements. In AESC 2011, I reduced the DRIPE effect by the percentage of each state's energy I estimated to be from long-term entitlements. Mr. Tranen did not make any such explicit adjustment.

As Mr. Tranen notes (Direct at 10), the Comprehensive Energy Plan (Vermont Department of Public Service, December 2011) "describes a desire for resources that are zero or low emission resources and that have long term affordability and price stability."[1] While I have not found any current comprehensive summary of the status of contracting by the Vermont utilities, Green Mountain Power's IRP indicates that GMP plans to obtain only about 1% of its 2013 energy supply from the short-term market (2011 Integrated Resource Plan, Green Mountain Power, at 37).

In addition, Mr. Tranen does not reflect the decay of the price suppression that I modeled in AESC 2011. In that analysis, I recognized that load reductions would reduce the need for renewables under state renewable-portfolio standards (RPSs); reduce retail prices and thus encourage a small offsetting increase in demand; encourage the derating and retirement of existing capacity; and delay

[1]While Mr. Tranen attributes these characteristics to Vermont Yankee, the page of the Plan that he cites (page 71) describes renewable energy, not nuclear.

the introduction of new generation (AESC 2011, at 6-49–6-50). Table 1 reproduces Exhibit 6-38 from AESC 2011, removing the effect on RPS.

Table 1: Decay of Price Suppression, from AESC 2011

	Demand Elasticity	Existing Generation	New Generation	Remaining Price Suppression
2012	2.5%	1%		97%
2013	3.6%	2%		94%
2014	4.1%	3%		93%
2015	4.3%	4%		92%
2016	4.4%	10%		86%
2017	4.4%	11%		85%
2018	4.4%	12%		84%
2019	4.4%	13%		83%
2020	4.4%	14%	50%	41%
2021	4.5%	15%	60%	32%
2022	4.5%	16%	70%	24%
2023	4.5%	17%	80%	16%
2024	4.5%	18%	90%	8%
2025	4.5%	19%	100%	0%

Source: AESC 2011, Exhibit 6-38

The combination of realistic market prices, the fixed-price resources in Vermont's energy supply, and the decay of price suppression over time will greatly reduce the price-suppression benefits of Vermont Yankee to Vermont ratepayers suggested in Mr. Tranen's Exhibit EN-JT-9. If the resource plan in the Green Mountain Power IRP is typical (1% market purchases in 2013, 11% from 2016 onward), the effect of Vermont Yankee on market prices would be about 5% of Mr. Tranen's estimate. If the Vermont utilities lock in more of their power supply with contracts or utility ownership, the price effect would be even smaller.

IV. The Revenue-Sharing Agreement

Q: Please describe the Vermont Yankee Revenue-Sharing Agreement.

A: The March 3, 2002 Memorandum of Understanding (MOU) in Docket No. 6545, the approval of the sale of Vermont Yankee to ENVY, provides (at ¶4) that ENVY will share 50% of Vermont Yankee's revenue over a strike price with Vermont Yankee Nuclear Power Corporation (VYNPC). The strike price starts at $61/MWh in March 2012 and escalates with a composite inflator. The revenue sharing would continue for just the first ten years of the extended life of Vermont Yankee. The revenue sharing would be computed annually, for fiscal years starting on March 13 of each year from 2012 through 2021.

As Mr. Tranen notes, the allocation of any RSA revenues among Vermont utilities, Vermont ratepayers, and other former owners and customers of Vermont Yankee has not been determined.

> Depending on legal interpretations related to the MOU as to whether the benefits of the RSA are to be received by the sponsors or the shareholders of VYNPC, the share of the benefits for CV and GMP may be either 55% or 100%...." (Tranen Direct at 12)

Q: How would the RSA strike prices be escalated for the RSA years starting with March 2013?

A: The MOU defines the escalator as the sum of the weighted changes from February 2012 to the beginning of later fiscal years of the following three factors:

- 60% on an Employment Cost Index (ECI), defined as "Total compensation for private non-farm workers in the Northeast Region including New York" from the Bureau of Labor Statistics.
- 25% on the Gross Domestic Product Implicit Price Deflator (GDP-IPD) from the Bureau of Economic Analysis.

- 15% on the Nuclear Fuel Market Index, which is itself composed the GDP-IPD and three nuclear fuel indices derived from proprietary sources:
    - 3.9% on the Gross Domestic Product Implicit Price Deflator
    - 3.3% on the Average Uranium Index Adjustment Factor
    - 0.4% on the Average Conversion Index Adjustment Factor
    - 7.4% on the Average Enrichment Index Adjustment Factor.

In effect, then, the escalator is 60% ECI, 28.9% GDP-IPD, and 11.1% various nuclear cost inflators.

Q: Is Vermont likely to receive substantial revenues from the RSA?

A: No. While Mr. Tranen argues that the RSA could provide some revenues to Vermont utilities, his analysis understates escalation of the strike price, overstates the forecast of market price, and ignores other factors that would tend to reduce the probability that any such revenues would be paid.

A. Escalation of the Strike Price

Q: What errors have you identified in Mr. Tranen's forecast of the RSA strike price?

A: Mr. Tranen makes the following assumptions:

- The GDP-IPD inflation rate would be very low, averaging about 1.6% annually.
- The ratio of the ECI to GDP-IPD growth rate would be the same in 2012–2022 as the average of the annual ratios of those rates in 2002–2011 (1.448).
- The nuclear indices would rise at GDP-IPD, even though the price data that he used (EIA data on the spot price of uranium purchased by domestic

nuclear reactors) rose an average of 21% annually from 2001–2011. (xx cite)[2]

Mr. Tranen's first and third assumptions are not reasonable. For the first assumption, the difference between the yields for real and nominal treasury securities for October 12, 2012 indicates that investors expect inflation will be about 2.2% over the next five years, and 2.5% over ten years.[3]

The third assumption is also unreasonable. Mr. Tranen justified exclusion of post-2003 price data by referring to the "drop-off in spot prices after 2007" and the assertion that "the spot market data for 2011 do not reflect the long-term impact of the Fukushima event" on March 2011. This "event" led to at least temporary shutdown of all Japanese nuclear plants and commitment to phase out nuclear power in Japan by 2040 and Germany by 2022 (Tranen Direct at 17). In fact, Mr. Tranen's data show the spot uranium price rising 24% in 2011, reversing the declines in the previous three years.

Q: How does correcting Mr. Tranen's inflation assumption change the strike price?

A: Table 2 compares Mr. Tranen's projection of the strike price to the strike prices that would result from using current inflation expectations.

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[2]U.S. Energy Information Administration. 2012. "Weighted-Average Price of Uranium Purchased by Owners and Operators of U.S. Civilian Nuclear Power Reactors, 1994–2011 Dollars per Pound U_3O_8 Equivalent" Table S1b of "2011 Uranium Marketing Annual Report." Washington: U.S. DOE.

[3]The inflation-adjusted Treasury securities are inflated by the consumer price index, which appears to track the GDP inflator well over long periods of time, with cumulative GDP inflation equaling 97% of CPI inflation. On 10/12/2012, for instance, the nominal yield on 5-year Treasuries was 0.67% and the real 5-year yield on TIPs was −1.52%. The 2.19% difference expresses investors' expectations of inflation though October of 2017.

Table 2: Revised Strike-Price Projection

	Exhibit EN-JT-7	Revised
2012	$61.00	$61.00
2013	$61.72	$62.30
2014	$62.50	$64.00
2015	$63.66	$65.75
2016	$65.07	$67.54
2017	$66.54	$69.45
2018	$68.02	$71.65
2019	$69.54	$74.04
2020	$71.06	$76.74
2021	$72.62	$79.61
2022	$72.96	$80.24

B. Forecasts of Market Prices

Q: How did ENVY Witness Tranen forecast market prices for the purpose of valuing the RSA?

A: As Mr. Tranen acknowledges, his base projection of market prices for electric energy at Vermont Yankee is below the strike price through the 2020/21 contract year, resulting in RSA payment for only the period January 1 to March 20, 2022 (Exhibit EN-JT-7). Mr. Tranen derived his projected market prices by taking the following steps:

1. starting with avoided electric energy costs for Vermont developed by the regional 2011 Avoided Energy Supply Cost Study Group (AESC),
2. decreasing those AESC 2011 prices by "the ratio of the EIA AEO 2012 reference case price for natural gas at Henry Hub divided by EIA AEO 2011 reference case price,"
3. reducing the above by 2.5% to reflect the difference between prices averaged over the Vermont zone and prices at the Vermont Yankee node.

Q: Is Mr. Tranen's forecast methodology appropriate?

A: No, for two reasons. AESC's avoided energy costs are not an appropriate starting point, and Mr. Tranen's adjustment for gas prices is inadequate, because he starts from the wrong gas price.

Q: Why are the AESC's 2011 avoided energy costs not an appropriate starting point for forecasting Vermont Yankee revenues?

A: There are at least three problems with using AESC's 2011 avoided costs. First, the AESC's 2011 energy prices were not a forecast of market prices that are likely to occur. The AESC process produces an estimate of the market costs of energy that would be avoidable by energy efficiency implemented in 2012 and 2013, without any additional energy efficiency after 2013. In reality, the New England states and utilities are vigorously pursuing energy efficiency in 2012 and 2013. Under existing laws and policies, they are very likely to continue and even expand those programs. With the energy efficiency programs, loads would be lower and (all else equal) market prices would be lower.

Second, AESC's avoided energy costs reflect hypothetical market prices in all hours, while the value of Vermont Yankee sales will be determined by market prices when Vermont Yankee is on line. Energy prices in New England (and especially Vermont) will be somewhat lower when Vermont Yankee is on line than when it is off.[4] AESC's avoided energy costs represent firm power obligations, while Vermont Yankee necessarily sells power on a unit-contingent basis. In Docket No. 7440, ENVY witness Bruce Wiggett estimated (in his Direct at 9) that a unit-contingent Vermont Yankee contract would be priced at 5%

[4]If Vermont Yankee (or any other baseload unit) is permanently retired, the market will gradually adjust and market prices will fall to the level they would have been if the unit had continued operation. For short-term maintenance and forced outages, short-term prices will rise when the unit is off line; these outages are too short for supply and demand adjustments to offset the effect of the outage.

below the firm energy price. It is difficult to be precise about the exact reduction in market value due to the uncertain nature of Vermont Yankee's output, but Mr. Wiggett's estimate is in the reasonable range.

Third, AESC's avoided energy costs represent the value of energy savings distributed over the hours in a period in proportion to load, while Vermont Yankee produces energy whenever it is available. In general, energy prices are higher at time of high load, so load-weighted market prices will generally be higher than flat hourly-weighted prices. The difference between a load-weighted price curve and flat baseload prices would be about 4%.

Q: What is wrong with the gas price forecast that Mr. Tranen adopted as the basis for his price update?

A: The AESC's 2011 avoided energy costs were not based on AEO's 2011 reference-case gas prices, but on a combination of forwards and AEO's 2010 High Shale case, as described in Sections 3.2.2, 3.3, and 3.4 of the AESC 2011 report and summarized in the introduction to Chapter 3:

> The AESC 2011 Base Case forecast is based upon the New York Mercantile Exchange ("NYMEX") gas futures prices for the Henry Hub for the years 2011 to 2014 and the "High Shale Gas" Case forecast from the Energy Information Administration's ("EIA") 2010 Annual Energy Outlook ("AEO 2010") for the years 2015 onward. (AESC 2011, at 3-1)[5]

The AEO 2010 High Shale case prices were much higher than the AEO 2011 reference prices.

Q: Can you quantify the effect of these two errors in Mr. Tranen's analysis?

A: I do not have an easy way to estimate the overstatement in his analysis resulting from the use of the AESC avoided cost as if it were a forecast of market prices,

[5]The AESC 2011 report says almost exactly the same thing at 1-20 and provides a graphic comparison at its Figure 1-16.

except for the 4% downward adjustment for removing the load-weighting of the AESC avoided costs and the 5% downward adjustment for the unit-contingent sale. Determining the effect of the error in identifying the gas prices used in the AESC study is much more straightforward.

Table 3 compares the Henry Hub gas prices for the AEO 2010 High Shale case, the AEO 2011 reference case, and the AEO 2012 reference case. Over 2012–2022, the price reduction from the 2010 High Shale case to the AEO 2012 reference case would be about double to triple the reduction from the AEO 2011 reference case to the AEO 2012 reference case.

Table 3: Comparison of Gas-Price Forecasts

		EIA AEO Henry Hub Prices (Nominal Dollars per MMBtu)			Reductions to 2012 from		
AEO 2011 VT	**avoided cost[a]**	2012 Reference	2011 Reference	2010 High Shale[b]	2011 Reference[c]	2010 High Shale[d]	**Increase in Adj.**
2012	$49.91	$3.70	$4.65	$5.00	20%	26%	27%
2013	$52.65	$4.24	$4.79	$5.31	12%	20%	75%
2014	$55.15	$4.41	$4.89	$5.61	10%	21%	119%
2015	$61.20	$4.62	$5.09	$6.39	9%	28%	202%
2016	$63.60	$4.67	$5.27	$6.55	11%	29%	152%
2017	$65.25	$4.79	$5.41	$6.63	11%	28%	142%
2018	$74.48	$4.93	$5.58	$6.78	12%	27%	135%
2019	$76.99	$5.16	$5.77	$6.94	11%	26%	142%
2020	$78.64	$5.39	$6.10	$7.17	12%	25%	112%
2021	$82.41	$5.77	$6.45	$7.44	11%	23%	112%
2022	$86.38	$6.22	$6.76	$7.71	8%	19%	141%

[a] From work papers for Exhibit EN-JT-7 and 8.
[b] 2012–2014 from March 18, 2011 NYMEX.
[c] Calculated as one minus the ratio of the 2012 reference to the 2011 reference (2012÷2011).
[d] Calculated as one minus the ratio of the 2012 reference to the 2010 high shale (2012÷High Shale).

For the years 2012–2014, in which AESC used the NYMEX futures, the corrected downward adjustment is 30%–110% greater than Mr. Tranen's adjustment.

Table 4 shows that properly adjusting from the gas prices used in the AESC 2011 analysis to the AEO 2012 gas prices reduces the adjusted electric prices by an average of more than $10/MWh in 2015–2022. In the earlier years, the reductions are smaller, $3 to $7/MWh, but even Mr. Tranen's price forecast is already far below the strike price in those years.

Table 4: Effect of Correcting Tranen's Gas-Price Update (Dollars per MWh)

	AEO 2011	Reductions to 2012 from[b]		Projected VY Market Energy Price	
	Vermont avoided cost[a]	2011 Reference	2010 High Shale	Tranen[c]	Corrected[d]
	[1]	[2]	[3]	[4]	[5]
2012	$49.91	20%	26%	$38.75	$36.04
2013	$52.65	12%	20%	$45.39	$40.94
2014	$55.15	10%	21%	$48.54	$42.31
2015	$61.20	9%	28%	$54.20	$43.17
2016	$63.60	11%	29%	$54.93	$44.20
2017	$65.25	11%	28%	$56.33	$45.97
2018	$74.48	12%	27%	$64.21	$52.84
2019	$76.99	11%	26%	$67.08	$55.77
2020	$78.64	12%	25%	$67.69	$57.59
2021	$82.41	11%	23%	$71.82	$62.26
2022	$86.38	8%	19%	$77.43	$67.89

[a] From work papers for Exhibit EN-JT-7 and 8

[b] From Table 3

[c] Calculated as the product of the following three values: (1) AEO 2011 Vermont avoided costs, (2) one minus the 2011 reference, and (3) 1 minus 0.025.

[d] Calculated as the product of the following three values: (1) AEO 2011 Vermont avoided costs, (2) one minus 2010 high shale, and (3) 1 minus 0.025. In this case the gas prices are from NYMEX, not AEO.

Even the corrected market price projection is overstated, since it assumes no post-2011 energy-efficiency programs.

Q: How does Mr. Tranen's forecast of forward energy prices compare to current market prices?

A: Table 5 compares Mr. Tranen's forecast, the correction of his forecast to reflect the actual gas prices used in AESC 2011, and current market forwards by calendar year, averaging the NYMEX on- and off-peak energy prices.[6] These Hub prices are about $2–$10/MWh less than Mr. Tranen's forecast of market prices and $18–$20/MWh below his forecast of the strike price.

Table 5: Market Prices and Tranen Forecast (Dollars per MWh)

	Tranen Projections[a]		Forwards 10/9/2012			
	Market Price	Strike Price	ISO Hub[b]	Adjustment to VY[c]	Henry-Hub Gas $/MMBtu[d]	Henry-Hub Gas Escalation[e]
2012	$38.75	$61.00				
2013	$45.39	$61.72	$44.25	$43.40	$3.99	
2014	$48.54	$62.50	$44.89	$44.03	$4.29	7.5%
2015	$54.20	$63.66	$45.42	$44.55	$4.48	4.4%
2016	$54.93	$65.07	$46.09	$45.21	$4.65	4.0%
2017	$56.33	$66.54	$47.04	$46.14	$4.84	4.1%
2018	$64.21	$68.02		$46.74–$48.16	$5.06	4.4%
2019	$67.09	$69.54		$47.49–$50.80	$5.33	5.5%
2020	$67.69	$71.06		$48.26–$53.61	$5.63	5.5%
2021	$71.82	$72.62		$49.05–$56.59	$5.94	5.6%
2022	$77.44	$72.96		$49.86–$59.77	$6.28	5.6%

[a] From Exhibit EN-JT-7.
[b] From NYMEX forwards, October 9 2012.
[c] For 2012–2017, calculated as ISO Hub × 1.06 × (1 − 0.025). For 2018–2022, escalated at 29% of Henry-Hub gas escalation (left) or 100% of Henry-Hub gas escalation (right).
[d] From NYMEX forwards, October 9 2012.
[e] Year-to-year change from Henry Hub gas prices (dollars per MMBtu) in the previous column.

Natural-gas price is generally believed to have been the major driver of changes in New England electric energy prices. In the 2013–2017 period, for which we have forward prices for both New England electric energy and Henry

[6] I weighted the on-peak price 42.9%, added 0.6% for the January 2007–September 2012 average difference between prices at the ISO Hub and the Vermont zone, and subtracted 2.5% for the difference between prices in the Vermont zone and at the Vermont Yankee node.

Hub gas, gas prices rise an average of about 5% annually, while the electric energy prices rise about 1.5% annually, about 29% of the gas escalation. The markets apparently expect that other factors (e.g., downward pressure on market prices from new renewables, energy-efficiency, and imports from Canada) will offset much of the upward pressure from wellhead gas prices.

Table 5 shows the effect of continuing this relationship, escalating electricity prices at 29% of the escalation in Henry Hub prices in 2018 through 2022, or alternatively escalating electricity prices at the escalation in Henry Hub prices. The escalated forward prices in those last five years are $16–$28/MWh less than Mr. Tranen's forecast of market prices, and $20–$24/MWh below the strike price. Unit-contingent sales would garner even lower prices. Unless some other factor significantly increases electric energy prices, the market value of Vermont Yankee energy is likely to stay below the strike price.

C. Capacity Value

Q: Should the RSA computation include any revenues other than energy?

A: Yes, in principle. The MOU (at ¶4) specifies that "VYNPS revenues are based on actual energy and capacity sold by VYNPS," so capacity revenues are relevant to the computation.[7] However, Vermont Yankee's capacity revenues are unlikely to bring its market value above the RSA strike price.

Q: For what years have capacity prices been determined?

A: The ISO has run forward capacity auctions (FCAs) to set the prices to be paid for the first six capacity years, covering one June to the next May, for 2010/11 thorough 2015/16. These auctions and the periods for which they set prices are

[7] It is not clear whether the RSA would include ancillary revenues, but this is a minor issue since Vermont Yankee receives little if any ancillary revenues.

referred to as FCA1 through FCA6.[8] Table 6 lists the prices to be paid to capacity in the Rest of Pool area (i.e., outside Maine) for non-emergency generation in FCA2 and FCA3, as well as the prices Vermont Yankee was awarded in FCA4 and FCA5, and converts those values to $/MWh at the average 93.7% capacity factor assumed by Mr. Tranen in his Exhibits EN-JT-7 and EN-JT-8. Vermont Yankee was allowed higher prices than other New England capacity in FCA4 and FCA5 because it attempted to delist and was refused; Vermont Yankee delisted in FCA6 and will receive no capacity revenue.

Table 6: Capacity Prices for Vermont Yankee

FCA	Capacity Year Starting	Regional Price ($/kW-month)	Price for Vermont Yankee $/kW-month	Price for Vermont Yankee $/MWh
2	2011	$3.119	$3.119	$4.56
3	2012	$2.535	$2.535	$3.70
4	2013	$2.516	$3.933	$5.75
5	2014	$2.855	$3.209	$4.69
6	2015	$3.129	Vermont Yankee delisted	

These increments are much smaller than the $20/MWh–$24/MWh differences between the strike price and various estimates of market prices in Table 4 and Table 5. They are far too small to trigger any RSA revenues.

Q: Are the forward-capacity-market prices likely to rise after FCA6?

A: No. The prices in Table 6 are the results of the administrative floor price for each auction, prorated for the excess capacity that cleared at the floor price. The price in FCA7 is likely to be at the floor price, as well, which will be the FCA6 floor price escalated with the Handy-Whitman index. Pending changes in the ISO rules would eliminate the floor price in FCA8, resulting in prices falling still

[8] Conveniently, RSA *n* ends in the year 2010 + *n*.

further. In AESC 2011, my estimate of the ISO forward-capacity-market price incorporated the following assumptions:

- 395 MW of energy-efficiency capacity bid into FCA4 does not exist;
- no new energy-efficiency bid into later auctions;
- The New England ISO would exclude 300 MW of subsidized out-of-market resources (such as generation plants built by municipal utilities or under contract to the Connecticut utilities) that cleared in FCA4 from setting the capacity price;
- about 470 MW of capacity in Maine would be unable to participate in setting the price in the rest of the pool in FCA7, declining to about 230 MW in FCA12, due to transmission constraints;
- Vermont Yankee would retire in March 2012.[9]

In reality, both previously established and new energy-efficiency resources will participate in the FCAs. The draft ISO rules would grandfather in out-of-market resources from FCA4 (and FCA5) and Maine cleared with the rest of the pool in FCA5 and FCA6, adding nearly 800 MW of resources to the regional capacity market in FCA7. Furthermore, any RSA computation must assume the continued operation of Vermont Yankee. Altogether, these adjustments and updates add at least 2,000 MW of resources to the regional capacity market.[10]

[9]The first two assumptions were driven by the purpose of the avoided-cost estimate, while the latter two assumptions reflected the expectations of the AESC project team.

[10]I also assumed the retirement by FCA7 of about 1,150 MW of major generation capacity, in addition to Vermont Yankee and Salem Harbor (which is still committed to retirement by 2014). These retirements comprised Norwalk Harbor 1&2, Middletown 4, and Montville 6. The only retirements or delistings that have occurred in this period so far are AES Thames and West Springfield 3, for a total of about 275 MW.

Even with the much lower resource availability assumed in the AESC report, I estimated that the capacity price would fall to below $2/kW-month in FCA7 and FCA8, and remain below $3 through FCA10 (AESC 2011 Exhibit 6-7). With the additional capacity discussed above, the capacity market would be in surplus through the life of the RSA, and the capacity price would likely remain below $2/kW-month (or even $1/kW-month).

Q: How would the capacity revenues change the revenue-sharing results?

A: With the expected market energy prices, the combined Vermont Yankee market values would result in zero revenue sharing in every year.

D. Effect of Annual Computation of the Revenue-Sharing-Agreement Payment

Q: Would the RSA be computed for the periods Mr. Tranen shows in his Exhibits EN-JT-7 and EN-JT-8?

A: No. Mr. Tranen computes the RSA for the following intervals:

- March 21 2012 to December 31 2012;
- Calendar years 2013, 2014, 2015, 2016, 2017, 2018, 2019, 2020, 2021;
- January 1 to March 20, 2022.

The RSA would actually be computed on an annual basis. While Mr. Tranen's Exhibit EN-JT-7 shows some revenue sharing in the January–March 2022 period, comparing Mr. Tranen's adjustment of the AESC 2011 avoided cost for 2022 ($77.44/MWh) to the projected 2011/12 strike price ($72.96/MWh), and finds that $4.48/MWh would be shared. Under the RSA, the computation would compare the revenues for the 2011/12 period to the strike price for 2011/12. Using Mr. Tranen's assumptions, the 2011/12 revenues would be $73.05/MWh, and the revenue to be shared would be $0.11/MWh, about 2% of

Mr. Tranen's estimate. With more realistic base market prices, the revenue would be zero.

E. *Vermont Yankee Revenues and New England–ISO Market Prices*

Q: Would the RSA be computed from the New England–ISO market prices that are the basis of Mr. Tranen's computations and your corrections in Table 4 through Table 6?

A: No. The revenue sharing will be determined by the actual contract prices that ENVY receives for Vermont Yankee power, not by the nodal ISO-NE prices. There are several ways in which ENVY may sell Vermont Yankee power. The Vermont Yankee price may be depressed if Entergy

- happens to sell power long-term at a low point in the market,[11]
- sells Vermont Yankee power at a low price as part of a bundled contract including higher-priced power from other Entergy plants or contracts, or
- sells Vermont Yankee power to an affiliate below market prices.

Interestingly, the FERC Electric Quarterly Reports indicate that ENVY signed a contract in 2006 to sell all of Vermont Yankee's output to Entergy Nuclear Power Marketing LLC at a price not to exceed $40.61/MWh through March 2014, which includes some of the RSA period and assures that the RSA will not require any revenue sharing in the first two years of the RSA. Entergy Nuclear Power Marketing then resells power to TransAlta under a long-term contract and to ISO-NE at spot prices. Entergy Nuclear Power Marketing also has annual contracts with Entergy Solutions LLC for power to be delivered at Vermont Yankee. I know of nothing that would prohibit ENVY from extending

[11] Conversely, Entergy may sell Vermont Yankee power at a high price, if it happens to find a buyer at a time of high projections of market prices.

the existing contract or signing a new contract with Entergy Nuclear Power Marketing through 2022, keeping the contract price below the RSA strike price.[12]

F. The Effect of Market-Price Volatility

Q: Does Mr. Tranen properly analyze the effect of price volatility on the RSA?

A: No. As I understand his testimony, he finds that twice in the last ten years a price shock has "resulted in…a roughly 30% effect on the annual energy price" (Tranen Direct at 13). He then (at 18–19) "assumed that there will be two major price shocks in the next 10 years [and] calculated the effect of a price shock in each year that raises the annual average price by 30%." He then (at 19) estimates the effect of a price shock in each year and discusses the effect of price shocks in various years.

Q: How do your corrections to Mr. Tranen's estimate of the base market prices and the strike prices affect the volatility analysis he presents in Exhibit EN-JT-8?

A: Reducing the base market prices and increasing the strike prices both reduce the probability that revenues will rise enough to produce revenue sharing. Table 7 shows my correction of the annual strike prices and the extrapolation of market energy from the AESC 2011 prices, plus my projection of market energy prices from current forward prices. For each projection of market prices, Table 7

[12] Mr. Tranen says that "Entergy VY has agreements for the bilateral sale of 250 megawatts of energy through the end of 2013 [below] the RSA strike prices. The remainder of its energy is assumed to be sold to the ISO-NE spot market." (Tranen Direct, note 14) As noted above, ENVY has sold its output in 2006 through March 2014 to Entergy Nuclear Power Marketing LLC, which has been selling some of the output to Entergy Solutions LLC as "requirements service." The RSA does not address the treatment of resales of Vermont Yankee power by Entergy subsidiaries other than ENVY.

shows the increase in the market energy price necessary to generate any RSA revenues. Exceeding the strike price would require that the projected market energy price increase by 40% to 70% in most years over the market energy prices in Table 4 and Table 5. Capacity revenue might increase the market price by $1/MWh to $2/MWh in the later years, or about 2%–5%. The 30% historical price shocks that Mr. Tranen identified in his analysis (Tranen Direct at 13) would not be sufficient to produce any RSA revenues, even supplemented by capacity revenue.

Table 7: Rate-Shock Analysis with Corrected Projections

	Fiscal Year Revised Strike Price[a]	Calendar-year Market Prices: From AESC 2011[b]	Calendar-year Market Prices: From Forwards[c]	Shock Needed for Revenue Sharing: From AESC 2011[d]	Shock Needed for Revenue Sharing: From Forwards[e]
2012	$61.00				
2013	$62.30	$37.40	$41.23	65%	51%
2014	$64.00	$38.64	$41.83	65%	53%
2015	$65.75	$39.44	$42.32	66%	55%
2016	$67.54	$40.37	$42.95	66%	56%
2017	$69.45	$41.99	$43.83	59%	58%
2018	$71.65	$48.27	$44.40	46%	61%
2019	$74.04	$50.95	$45.11	44%	63%
2020	$76.74	$52.60	$45.85	43%	67%
2021	$79.61	$56.87	$46.60	37%	70%
2022		$62.02	$47.37		

[a] From Table 2.
[b] From Table 4, reduced for loads and shapes.
[c] From Table 5, reduced for contingency.
[d] The ratio of the revised strike price (first column) to market prices estimated from AESC 2011 (second column) ((price ÷ AESC)-1).
[e] The ratio of the revised strike price (first column) to low-escalation forward market prices (third column) (price ÷ (forwards)-1).

Hence, price shocks far beyond the 30% shocks in the historical record would be needed to generate any revenue sharing. Even accounting for price shocks, revenue sharing is most likely to be zero.

Q: Does the manner in which ENVY sells power affect the likelihood that any RSA revenues will be paid to VYNPC?

A: Yes. Mr. Tranen "assumed that Entergy VY revenues for purposes of estimating the benefits of the RSA come from the ISO-NE spot market" (Tranen Direct at 13). If Vermont Yankee sells power in contracts spanning multiple years (even just a few years), the sort of price spike that Mr. Tranen considers may occur in the middle of the contract, so that revenue never exceeds the sharing threshold. Longer-term contracts, even if they were at market prices, would further reduce the probability of a price spike showing up in Vermont Yankee's revenue and triggering revenue sharing.

V. Assuring Benefits to Vermont

Q: In the previous sections of your testimony, you have explained why the Vermont ratepayer benefits that ENVY claims for the RSA and price suppression are overstated. How else has ENVY claimed that the operation of Vermont Yankee might benefit Vermont ratepayers?

A: Mr. Tranen suggests,

> the VY Station also provides a valuable opportunity to Vermont electricity providers to purchase power in the future from a resource with…zero or low emission[s] and…long term affordability and price stability to provide some protection against the highly uncertain New England wholesale market prices. (Tranen Direct at 10)

He goes on to assert (at 10) that the Vermont utilities

> have had portfolios of resources over time that incorporated these types of resources. This has led to a more stable price for electricity in Vermont than for the rest of New England. As long as the VY Station is allowed to continue to operate, electricity providers in Vermont will have the opportunity to sign contracts with Entergy VY for power from the VY Station in the future that would have these attributes.

Q: Does ENVY have in place a long-term contract to supply power to Vermont utilities?

A: No. A hypothetical future contract, with hypothetical pricing terms, cannot be argued to demonstrate that the operation of Vermont Yankee would benefit ratepayers and promote the general good of the state. Mr. Tranen does not even assert that ENVY has offered the Vermont utilities a contract at affordable and stable prices.[13]

Q: Is Vermont Yankee uniquely qualified to provide a power contract with low emissions and stable prices?

A: No. Green Mountain Power and the Vermont Electric Coop have signed contracts with NextEra for substantial purchases of power from the Seabrook nuclear plant (GMP 2012 IRP at 35; VEC 2012 IRP at 5-2).[14] Similar contracts may be available from the Millstone and Pilgrim nuclear plants in New England, the Point Lepreau plant in New Brunswick (which recently returned to service after a four-year refurbishment outage), and four nuclear plants in New York.

Other low-emission sources that could be stably priced would include the large New England and Québec hydro plants, wind projects and potentially other renewables in New England, New York and Canada.[15] Depending on the definition of "low-emission," the category could also include a tolling agreement with a combined-cycle plant, combined with a long-term gas contract.

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[13]The contract, were it to be unit-contingent, would need to be priced at least 5% below the current forward market prices.

[14]The Coop reports the "contract price was set at a levelized $50/MWh for all market products received" (Vermont Electric Cooperative 2012 Integrated Resource Plan at 5-12).

[15]While the total cost of wind projects is likely to be higher than market prices for some time to come, the revenues from renewable energy credits would bring the net wind costs down to levels comparable with other market resources.

Vermont is in an unusually favorable situation as a long-term power purchaser, since most New England and New York utilities have been restructured and cannot enter into long-term purchases. A generator seeking to sell power for more than a few years into the future has few other potential customers.

Q: Would a contract with Vermont Yankee be more "affordable" than other resources?

A: No. If Vermont Yankee continues to operate, the Entergy subsidiaries responsible for marketing its output (such as Entergy Nuclear Power Marketing LLC, Entergy Solutions LLC) would sell the power for market prices, which would be very similar to the price of power from other sources, adjusted for the pattern and flexibility of energy delivery.[16]

VI. Economic Risk to Vermont of Continued Operation

Q: What economic risk does continued operation of Vermont Yankee pose for Vermont?

A: The continued operation of Vermont Yankee creates a set of interconnected economic and financial risks for Vermont, including (at least) the following:

- The decommissioning fund for Vermont Yankee is not currently sufficient to decommission the plant.
- Past trends of decades' duration indicate that the Vermont Yankee decommissioning fund will not be sufficient for either a near-term or delayed shutdown.
- The value of the decommissioning fund fluctuates with market returns, which can stagnate or turn negative.

[16] Pilgrim and two of the New York nuclear stations are owned by Entergy, which is unlikely to contract with a Vermont utility until the fate of Vermont Yankee is determined.

- An accident at Vermont Yankee, even one with little or no off-site radiological consequences, could result in permanent shutdown of the plant and significantly increase the cost of decommissioning.
- The ability of the State of Vermont to pursue contributions to decommissioning from ENVY'S parent company (the Entergy Corporation) will vary over time. Entergy is currently solvent and has a barely investment-quality rating of Baa3,[17] which is Moody's minimum investment-grade rating. At this point, Entergy might be held responsible for paying for at least some the shortfall in decommissioning funding, but there is no guarantee that Entergy will continue to be solvent over the next twenty years. In particular, the factors that would tend to lead to early shutdown of Vermont Yankee and/or higher decommissioning costs (another nuclear accident, especially at Vermont Yankee, and low costs of power alternatives) would also tend to stress Entergy's finances, given its exposure to merchant nuclear operations.[18]

A. *Decommissioning Funding*

Q: Do you have concerns about the adequacy of the decommissioning funds for Vermont Yankee?

A: Yes. The estimated cost of decommissioning continues to rise much faster than inflation. In Docket No. 7440, ENVY reported an average 3.2% annual escalation in its decommissioning costs from 2001 to 2006 (Docket No. 7440, Attachment CLF/VPIRG:EN.S2-1). As shown in Table 8, the decommissioning costs for

[17] "Rating Action: Moody's Affirms Entergy with Stable Outlook; Assigns Prime-3 Rating to New Commercial Paper Program" Moody's Global Credit Research, 10 August 2012.

[18] Entergy also owns, through other subsidiaries, the Pilgrim, Indian Point 2 and 3, Fitzpatrick, and Palisades nuclear units.

various decommissioning dates and methods have escalated 2.7% to 6.2% annually from 2007 to 2012.

Table 8: Vermont Yankee Decommissioning Cost Estimates, 2007 and 2011

2012 Scenario	Shutdown	Option	Spent Fuel Assembly Pickup First	Spent Fuel Assembly Pickup Last	Cost million 2011$	Best 2007 Match	Spent Fuel Assembly Pickup First	Spent Fuel Assembly Pickup Last	Cost million 2011$	Escalation
1	2012	SAFSTOR	2021	2045	$1,020.7	5	2017	2042	$803.7	4.9%
2	2012	SAFSTOR	2058	2082	$1,159.8	7	2057	2082	$991.1	3.2%
3	2032	DECON	2021	2060	$845.4	2	2017	2057	$655.5	5.2%
4	2032	DECON	2042	2082	$979.9	4	2042	2082	$815.3	3.7%
5	2032	SAFSTOR	2021	2060	$969.9	6	2017	2057	$717.4	6.2%
6	2032	SAFSTOR	2042	2082	$1,067.6	8	2042	2082	$932.4	2.7%

Source: Cloutier Direct at 15; Docket No. 7440 Cloutier Direct at 7.

The estimates with the slowest escalation rates are those that have the latest spent-fuel removal, suggesting that the other costs, for which there is no prospect of Federal reimbursement, are growing even faster than the average escalation rates shown. Indeed, the escalation rates for the costs that Mr. Cloutier describes as "License Termination" (excluding spent-fuel storage and site restoration) range from 3.9% to 7.5%; see Table 9.

Table 9: Vermont Yankee License-Termination Cost Estimates, 2007 and 2012

2012 Scenario	Shutdown	Option	Spent Fuel Assembly Pickup First	Spent Fuel Assembly Pickup Last	Cost million 2011$	Best 2007 Match	Spent Fuel Assembly Pickup First	Spent Fuel Assembly Pickup Last	Cost million 2011$	Escalation
1	2012	SAFSTOR	2021	2045	$645.8	5	2017	2042	$457.5	7.1%
2	2012	SAFSTOR	2058	2082	$610.3	7	2057	2082	$450.1	6.3%
3	2032	DECON	2021	2060	$566.7	2	2017	2057	$469.0	3.9%
4	2032	DECON	2042	2082	$566.7	4	2042	2082	$469.0	3.9%
5	2032	SAFSTOR	2021	2060	$653.1	6	2017	2057	$455.4	7.5%
6	2032	SAFSTOR	2042	2082	$622.6	8	2042	2082	$469.1	5.8%

Source: Exhibit TLG-2 at xvii–xix; Docket No. 7440 Exhibit EN-TLG-2 at xvi–xvii.

The high end of these escalation rates exceeds ENVY'S return to date on the decommissioning fund; see Table 10. Interest rates are now at record low levels, increasing the difficulty of earning historical returns on a dependable basis. I am not aware of any plans for ENVY to contribute additional decommissioning funds from operations or from parent-company equity.[19]

Table 10: Return on ENVY Decommissioning Fund

Date	Fund Balance	Return since July 2002
31-Jul-02	$310.7 M	
31-Dec-06	$416.5 M	6.9%
31-Dec-07	$439.6 M	6.6%
31-Dec-08	$372.0 M	2.8%
31-Dec-09	$428.4 M	4.4%
31-Dec-10	$474.2 M	5.1%
31-Dec-11	$497.7 M	5.1%
30-Jun-12	$523.5 M	5.4%

Source: CLF EN 2-2; Docket No. 7440 Chernick Direct at 9

Mr. Cloutier estimates that ENVY will need a return 0.4% higher than inflation for SAFESTOR and 0.8% higher than inflation for DECON for the decommissioning fund to cover the cost of decommissioning for a 2032 shutdown, even assuming that all spent-fuel storage costs are reimbursed by the Federal government.[20] Assuming that the escalation in decommissioning cost estimates continues at the rate reported by Mr. Cloutier for 2006–2011 and the

[19]Given the low market power prices and the low prices that ENVY receives from Entergy Nuclear Power Marketing LLC, it is not clear that ENVY could afford additional contributions to the decommissioning fund. Indeed, ENVY convinced ISO-NE that Vermont Yankee would be uneconomical to operate with capacity payments lower than $3.91 and $3.21/kW-month in FCA4 and FCA5, respectively. But Vermont Yankee will receive no capacity revenues in FCA6 and little capacity revenue beyond FCA7, and projected energy prices are likely to remain low.

[20]It is not clear that DOE will pay all the costs of spent nuclear fuel storage and handling, even under current law. Considering the magnitude of concerns over the Federal budget deficit, Congress may decide at some point to eliminate DOE's obligation (under the Nuclear Waste Policy Act of 1982) to take additional spent fuel and other high-level waste or to pay damages.

fund continues its past average performance, the fund will not be able to cover the cost of SAFESTOR and will keep barely ahead of inflation for DECON.

Anything that further increases the cost of the decommissioning would exacerbate this situation.

Q: What factors contribute to uncertainty in the cost of decommissioning?

A: Any of the cost items in the decommissioning estimate may change, due to changes in input costs, regulatory changes, and other factors. Regulation can affect the labor and equipment costs of SAFSTOR and decommissioning, as well as the costs of transportation and disposal.

Q: How do ENVY's current decommissioning-cost estimates reflect these uncertainties?

A: The decommissioning-cost estimates include allowances for contingencies, which are costs that are expected in aggregate but not identifiable in detail. The estimates do not include future increases in the prices for the inputs to the decommissioning process, any safety factor, or any unexpected cost, as Mr. Cloutier clearly states in "Decommissioning Cost Analysis for the Vermont Yankee Nuclear Power Station" (Exhibit TLG-2):

> The cost elements in the estimates are based on ideal conditions; therefore, the types of unforeseeable events that are almost certain to occur in decommissioning, based on industry experience, are addressed through a percentage contingency applied on a line-item basis. This contingency factor is a nearly universal element in all large-scale construction and demolition projects. It should be noted that contingency, as used in this estimate, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the unit.
>
> The use and role of contingency within decommissioning estimates is not a safety factor issue. Safety factors provide additional security and address situations that may never occur. Contingency funds, by contrast, are expected to be fully expended throughout the program. Inclusion of contingency is necessary to provide assurance that sufficient funding will be available to accomplish the intended tasks. (Exhibit TLG-2 at xi)

The Decommissioning Cost Analysis goes into some detail in describing some of the costs that are excluded from the estimate:

> In addition to the routine uncertainties addressed by contingency, another cost element that is sometimes necessary to consider when bounding decommissioning costs relates to uncertainty, or risk. Examples can include changes in work scope, pricing, job performance, and other variations that could conceivably, but not necessarily, occur. Consideration is sometimes necessary to generate a level of confidence in the estimate, within a range of probabilities. TLG considers these types of costs under the broad term "financial risk." Included within the category of financial risk are:
>
> - Transition activities and costs: ancillary expenses associated with eliminating 50% to 80% of the site labor force shortly after the cessation of plant operations, added cost for worker separation packages throughout the decommissioning program, national or company-mandated retraining, and retention incentives for key personnel.
> - Delays in approval of the decommissioning plan due to intervention, legal challenges, and national and local hearings.
> - Changes in the project work scope from the baseline estimate, involving the discovery of unexpected levels of contaminants, contamination in places not previously expected, contaminated soil previously undiscovered (either radioactive or hazardous material contamination), variations in plant inventory or configuration not indicated by the as-built drawings.
> - Regulatory changes (e.g., affecting worker health and safety, site release criteria, waste transportation, and disposal).
> - Policy decisions altering national commitments (e.g., in the ability to accommodate certain waste forms for disposition, or in the timetable for such, or the start and rate of acceptance of spent fuel by the DOE).
> - Pricing changes for basic inputs, such as labor, energy, materials, and waste disposal.

While TLG calls these "financial" risks, none of them are financial in nature. TLG continues:

> This cost study does not add any additional costs to the estimates for financial risk, since there is insufficient historical data from which to project future liabilities. Consequently, the areas of uncertainty or risk are revisited periodically and addressed through repeated revisions or updates of the base estimates. (Exhibit TLG-2 at 3-5–3-6)

The decommissioning-cost analysis filed in Docket No. 7440 was even more explicit, acknowledging that TLG's decommissioning analyses are usually understated:

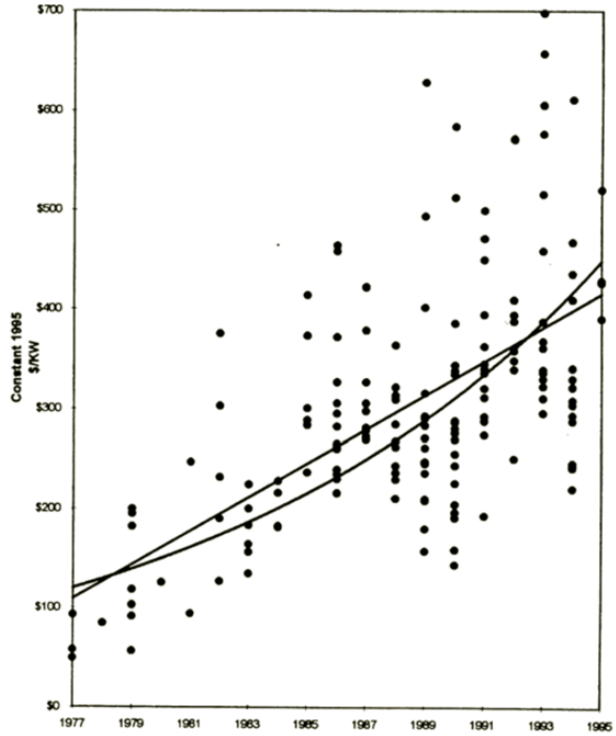
> It has been TLG's experience that the results of a risk analysis, when compared with the base case estimate for decommissioning, indicate that the chances of the base decommissioning estimate's being too high is a low probability, and the chances that the estimate is too low is a higher probability. This is mostly due to the pricing uncertainty for low-level radioactive waste burial, and to a lesser extent due to schedule increases from changes in plant conditions and to pricing variations in the cost of labor (both craft and staff). (Docket No. 7440, Exhibit TLG-2, Section 3, at 6)

Q: How stable have been the decommissioning-cost estimates by TLG Services?

A: My experience with TLG's earlier decommissioning estimates indicates that those estimates have been subject to dramatic escalation. For example, a trend analysis of TLG estimates from 1977 through 1995 showed a four-fold increase in inflation-adjusted cost estimates.[21] The data and regression lines from that analysis are shown in Figure 1. As I show in Table 8 and Table 9, the escalation in Vermont Yankee decommissioning cost estimates continues. TLG's current decommissioning estimates for Vermont Yankee acknowledge the exclusion of a range of potential cost drivers, which could result in large increases from the current estimates to actual decommissioning costs.

[21] Biewald, Bruce. 1996. "Electric Industry Restructuring and Environmental Sustainability." Proceedings USAEE 17th Annual North American Conference 116–124.

Figure 1: Nuclear Plant Decommissioning Cost Estimates by Year of Estimate
(180 Estimates by TLG Engineering 1977–1995)



Source: Biewald 1996 at 120.

Q: What are the implications of decommissioning funding for this proceeding?

A: The continued operation of Vermont Yankee increases Vermont's exposure to the risks that (1) decommissioning costs will exceed the value of ENVY's decommissioning fund and (2) Entergy Corporation will not be a source of supplemental funding at a future critical point.

Q: Does this conclude your testimony?

A: Yes.