STATE OF VERMONT

BEFORE THE PUBLIC SERVICE BOARD

Tariff filing of Central Vermont Public Service Corporation requesting a 7.6% rate increase to take effect December 24, 2000	)	Docket No. 6460
Tariff filing of Central Vermont Public Service Corporation Requesting a 12.9% rate increase to take effect July 27, 1998	)	Docket No. 6120

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE VERMONT DEPARTMENT OF PUBLIC SERVICE

Resource Insight, Inc.

MARCH 9, 2001

TABLE OF CONTENTS

TABLE OF EXHIBITS

I. Identification and Qualifications

Q: State your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts 02139.

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; and the valuation of environmental externalities from energy production and use. My resume is appended to this testimony as Exhibit DPS-PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and eighty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in twenty-five states, New Orleans, the District of Columbia, and Ontario; the Federal Energy Regulatory Commission; the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission; and various siting and environmental regulators. A detailed list of my previous testimony is contained in my resume.

Q: Have you testified previously on utility resource planning?

A: Yes. I have testified on many utility-resource-planning issues, including generation, transmission, and DSM planning, in many jurisdictions in the United States and Canada. My resume details this experience.

Q: Have you testified previously before the Board?

A: Yes. I testified in

- 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 or Central Vermont);

- 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 GMP'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.

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

A: Yes. My other activities have included

- participation in the CVPS and Vermont Gas DSM collaboratives;
- preparation of testimony on the avoided costs of Green Mountain Power (GMP) 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 Electric Department on distributed utility planning;
- assisting the Department and preparing draft testimony in Docket No. 6120, the previous Central Vermont rate proceeding;
- assisting the Department in the statewide collaborative on Distributed Utility Planning.

Q: Are you the author of any publications on utility planning and ratemaking issues?

A: Yes. I am the author of a number of publications on rate design, cost allocation, power-plant cost recovery, conservation-program design and cost-benefit analysis, and other ratemaking issues. These publications are listed in my resume.

II. Introduction

Q: What is the purpose of this testimony?

A: I address three topics related to Central Vermont's purchases of power under Schedules B and C of the Vermont Joint Owners' (VJO) contract with Hydro Québec (HQ), which I will refer to as the HQ-VJO contract or the HQ contract.

- The types of resources that Central Vermont would have acquired had it canceled the HQ-VJO contract.
- The adequacy and effectiveness of Central Vermont's efforts to mitigate the costs of the HQ-VJO contract.
- The excess cost of the HQ-VJO contract, compared to the costs of prudent resources, in the rate years for Docket No. 6120 (calendar 1999) and for Docket No. 6460 (July 1, 2001 through June 30, 2002).

The chronology of major events related to these purchases are described in the Board's order in Docket No. 5701 and 5724.[1] The Company's purchases from HQ under this contract are roughly $50 million annually, out

[1] I use these docket numbers interchangeably in this testimony.

of $290 million of total revenue. The Company expects to spend more than a billion dollars under this contract during 1998–2015.

A. Estimating the Damages due to the Company's Imprudence

Q: What is the normal process for computing the costs incurred due to an imprudent utility action or decision?

A: The general process consists of the following three findings:

- The finding that a particular decision was imprudent.
- The identification of the actions the utility would likely have taken, if it had avoided the imprudent action, and then acted prudently.
- The determination of the cost of the likely prudent course of action.

As I discuss below, the Board has already found Central Vermont's purchase of power under the HQ-VJO contract to be imprudent, and further consideration of that issue has been precluded by the Vermont Supreme Court.

Q: Please describe the process of identifying the subsequent actions the utility would likely have taken, if it had avoided the imprudent action.

A: This task primarily involves positive or predictive analysis, rather than a normative analysis. While the original prudence analysis considers what the utility *should* have done, the identification of subsequent actions primarily concerns what the utility *would* have done, had it avoided the imprudent action.

Since the purpose is to project the utility's decisions in a situation that did not arise, the subsequent-action analysis relies primarily on the utility's standard procedures, adjusted as necessary to reflect the requirement of prudent utility management with due regard for the utility's obligation to ratepayers. Thus, the analyses should be based on the information the utility possessed, as well as any information it should have known but failed to obtain. The subsequent actions should be projected from the utility's normal evaluation, adjusted only as necessary to be consistent with prudent management and the utility's obligation to ratepayers. Specific directives from regulators may establish some assumptions and evaluation methods. Adjustments to the utility's normal decision-making criteria are justified only where those criteria were unreasonable, selected imprudently from the perspective of ratepayers, or would have led to decisions that would not have obtained required approvals from regulators.

Q: Can analysis determine exactly what the utility would have done in the past, had it not taken the imprudent action?

A: No. By their very nature, these historical "what-if" exercises are inexact. The regulators will never be able to know exactly what result the utility would have received, had it bargained hard with potential suppliers. In complicated processes, including utility supply planning, the outcome can be determined by any number of factors, including the order in which parties communicate with one another, their perceptions of one another's bargaining position, the actual and perceived influence of third parties (such as regulators) and the timing of analyses and communications.

Q: How should regulators deal with these uncertainties?

A: That depends to some extent on the range of the uncertainties. In some cases, a single outcome can be identified as being representative, and used for subsequent analysis. In other cases, regulators should examine the range of likely outcomes, and evaluate the damages for a number of those outcomes.

The actions in the same time frame of other, similarly situated, utilities that avoided the imprudent action may provide a guide to the likely actions of the imprudent utility. Using a range of prudent behaviors from other utilities avoids potential problems of dealing with vast numbers of possible actions, as well as the pitfall of assuming a perfect outcome.

In no event should regulators allow the utility to benefit from uncertainties created by the utility's own imprudence. Options that the utility imprudently failed to explore should not be eliminated from the analysis.

Q: Please describe the determination of the cost of imprudence.

A: The cost of imprudence is the difference between the cost of the actual action and the cost of the actions the utility would have taken had it avoided the imprudent action.

This cost may be greater or less than the differential that would have been estimated at the time of the imprudent action. For power-supply decisions, the costs of the alternatives today may differ from previous forecasts due to changes in fuel prices, costs of capital, and other determinants, and due to changes in contractual arrangements (such as the retirement of units that would have served unit contracts). Hence, the costs of imprudence must be determined at the conditions that actually occurred, rather than those anticipated years earlier.

Even actions that were obviously imprudent may have no current cost consequences. For example, a utility that signs an exorbitantly expensive contract for power from a new resource that is never completed, and is subsequently able to obtain replacement power at a cost comparable to that of the prudent alternatives to the original contract, may incur no extra cost. No cost-based prudence disallowance would be appropriate in such a case.[2]

The cost consequences of imprudence may vary over time; an imprudent action may increase costs dramatically for some years, but actually decrease costs in other years. The disallowance for excess costs in the short term should not exceed the total excess cost over time. It is therefore appropriate to look ahead and determine whether the consequences are likely to reverse in the future.

B. Background of this Proceeding

Q: Please describe the regulatory background of the HQ-VJO contract.

A: In October 1990, in Docket No. 5330, the Board approved the overall HQ-VJO purchase. The Order in Docket 5330 also accepted that CVPS was not purchasing more HQ power than its load requirements.

In early 1991, CVPS filed a rate case, Docket No. 5491, in which CVPS disclosed new power-supply offers it had received from Northeast Utilities (NU), and its analyses of those contracts. The cost-effectiveness of the HQ-VO became an issue in that case, including testimony that I filed on July 19, 1991. At that time, the VJO had until November 30, 1991 to decide whether to back out of the contract, or to be locked into it.

On August 28, 1991, the VJO voted in a conference call (scheduled by fax the day before) to waive its rights to terminate the contract and hence locked the member utilities into the contract. Most subsequent litigation regarding the HQ-VJO contract has focussed on this “lock-in” decision.

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[2]Nonetheless, the regulator might well decide to reflect the utility’s poor planning process in some other manner, such as reducing its allowed return.

In Docket No. 5701, CVPS's 1994 rate case, the Board found that CVPS management had erred in inadequately analyzing alternatives prior to the lock-in and in inadequately pursuing reduction in its HQ entitlements after the lock-in. (Order at 111–112, 118–119). The Board reduced CVPS's allowed rate of return by 75 basis points.

In June 1997, Green Mountain Power (GMP) filed for a rate increase, Docket No. 5983, related in large part to the rising costs of the HQ-VJO purchase. The Board found that Green Mountain Power had been imprudent in locking into the HQ-VJO contract, and disallowed 20% of GMP's HQ-VJO contract costs in the rate year, net of the benefits of sellbacks, which brought the net prudence disallowance down to about 4% of GMP's costs.

In September 1997, the Company filed for a rate increase. In that proceeding, Docket No. 6018, I filed testimony on February 11, 1998 regarding CVPS's imprudence in its planning for the HQ-VJO contract. CVPS moved to strike the Department's testimony on the prudence and used-and-useful status of the HQ-VJO contract, and appealed the denial of that motion. Docket No. 6018 has been suspended since that appeal. On February 9, 2001, the Vermont Supreme Court ruled on that appeal and found that the Board's determination of imprudence in the lock-in is final and not subject to further litigation, but that the size of future disallowances remains open.

In July 1998, CVPS filed another rate case, Docket No. 6120, in which it accepted a temporary disallowance for its HQ-VJO costs modeled on the order in Docket No. 5983, pending resolution of its appeal in Docket No. 6018. That docket has been consolidated into the current proceeding. As a result, this case must consider the costs of the HQ-VJO contract in both the rate years for Docket-No. 6120 (1999) and Docket No. 6460 (2001/02).

Green Mountain Power filed another rate case in May 1998; this became Docket No. 6107. Following filing of direct testimony (including my testimony on the costs of the imprudent lock-in), the parties reached an interim settlement that set temporary rates, pending developments in GMP's efforts to renegotiate the HQ-VJO contract. The failure of those efforts led GMP to reopen Docket No. 6107 in September 2000 with the filing of rebuttal testimony. The Board approved a settlement in that proceeding in January 2001. The Board found that "a prudent mix of resources could have been purchased in 1991–1992 that, in aggregate, would have cost GMP between three and five-and-a-half cents per kWh from 1992 until the mid-2000s" (Docket No. 6107 Order at 44). The Board found (at 49) that disallowing all imprudent costs "would clearly put a significant strain upon GMP's financial viability" and imposed a smaller disallowance to avoid forcing the utility into bankruptcy.

Q: Is prudence an issue in this case?

A: Whether CVPS was prudent in its decision to lock into the HQ-VJO contract is not an issue in the current proceedings. The question is what CVPS would have done if it had acted prudently is very much at issue in this case. Reconstructing prudent actions requires the identification of the information that would have been available to a prudent utility, and the types of analyses that a prudent utility would have performed, both before the premature lock-in and afterwards.

For the most part, I rely on the planning assumptions and methods that CVPS was using in the early 1990s. Where CVPS's approach was not representative of a prudent utility, faced with major resource decisions, I explain why and provide corrections.[3] In all such discussions, my intention is to identify replacement resources and estimate damages, not to reopen arguments over the imprudence of the lock-in. Any references to "prudence" in this testimony relate either to the context (e.g., CVPS's situation if it had *prudently* avoided the HQ-VJO lock in) or the *prudent* choice of inputs and approaches for selecting resources.

C. Summary of Conclusions

Q: Would a prudent analysis in the fall of 1991 have indicated that the HQ-VJO contract was desirable for Central Vermont's ratepayers?

A: No. Had Central Vermont avoided the early lock-in and prudently compared the HQ-VJO contract to the alternatives, it would not have found the economics of the contract to be improving later in 1991.

Q: Would a prudent utility ever have locked into the HQ-VJO contract after August 28, 1991?

A: No. Had Hydro Québec offered a substantially improved contract, Central Vermont might have prudently purchased some long-term resources from Hydro Québec.

Q: What was the Company likely to have done if it had avoided the HQ-VJO lock-in?

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[3]Some of Central Vermont's approaches may have been reasonable for a utility that did not perceive that it had any choice regarding its most important resource commitment. Central Vermont may have believed that it was in that situation, with regard to the HQ-VJO contract. The Board and the Supreme Court have now settled the issue of whether the Company had a choice (it did), and it really does not matter whether CVPS's approach might have been adequate for another utility in another situation.

A: As the Board found with respect to Green Mountain Power in Docket No. 5983, the Company and the rest of the Vermont Joint Owners would have canceled the contract sometime in 1992, as the contract's economics continued to deteriorate (Docket No. 5983, Order at 240). Starting in 1992, the Company would have been looking for replacement power supplies.

Because of the glut of power in the Northeast, the Company would have faced many options for short- and medium-term power purchases, at costs lower than those of new resources. As a result, the Company would probably have replaced the HQ-VJO purchase with a set of contracts covering the period from late 1995 (when CVPS's major purchases from HQ started) until sometime after 2000.[4] These contracts would most likely have included purchases from some combination of NU, UI, NEPCo, and the New York utilities.[5]

It is more difficult to determine when the Company would have signed those contracts, exactly how they would have been structured, with whom they would be, and how much they would cost today. By late 1991, CVPS was not planning to make significant purchases under the HQ-VJO contract until late 1995, and the full contract level would not be reached until late 1996. The cancellation of the HQ-VJO contract in late 1991 would not have required any immediate need for major resources, and Central Vermont

[4]Central Vermont had originally contracted for significant capacity starting in 1991, with further increases in 1996. By late 1991, CVPS had sold back to HQ nearly all of its purchases for 1992 through late 1995.

[5]The Company would probably also have started planning to participate in a utility-owned or NUG combined-cycle plant (and perhaps a combustion turbine, as well) around 2005, but that plant would never have been built, given the change in industry structure.

would have had considerable flexibility about the timing of its purchases. As I discuss below, market prices for multi-year power purchases were falling dramatically in this time period.

The Board will never know exactly what contracts the Company could have negotiated in the 1992–95 period to replace the HQ-VJO contract, since Central Vermont was not actively negotiating to purchase—and indeed was attempting to sell—long-term baseload resources at this time. Few New England utilities were seeking new medium-to-long–term supplies in 1991–1992, due to the glut of resources that contributed to the poor economics of the HQ-VJO contract. By 1993, several smaller utilities started lining up new supplies. In addition, Northeast Utilities offered the Company and other utilities mid-term power sales in 1991, and two New York utilities (New York State Electric and Gas and Niagara Mohawk) offered power to Central Vermont Public Service in 1992.[6]

Due to its failure to reconsider and reject the HQ-VJO contract, the Company never developed a prudent mix of resources in the period from 1992 through the present. Yet it is the excess cost of the HQ-VJO contract in the rate years (2001–02), above the cost of the prudent portfolio, that determines the cost of Central Vermont's imprudence. Hence, the Board must select a proxy for the mix of resources that CVPS would have developed, absent imprudence.

[6]There may have been other offers, but these are the only offers that have been made public. If the HQ-VJO contract had been canceled, HQ would almost certainly have been marketing firm energy to New England, at least enough to use the otherwise idle capacity of the Highgate station.

III. The Prudent Resource Mix Following the Vermont Joint Owners' Refusal to Lock In to the Contract

Q: What would have happened to the HQ-VJO contract had CVPS and the Joint Owners not agreed to the premature August lock-in?

A: That would depend on what actions CVPS, the Joint Owners, and HQ would have taken after August 1991. Had Central Vermont acted prudently, it would not have locked into the HQ-VJO contract by the November 30, 1991 deadline. Either HQ would have granted the Joint Owners an extension of the lock-in date, as it did for New York (which agreed with HQ on a one-year extension at the same time CVPS was agreeing to the lock-in), or the Joint Owners would have canceled the contract prior to November. At that time the utilities faced

- continuing decline in loads and fuel prices forecast, and in market power costs;
- HQ's deteriorating bargaining power in light of the lack of enthusiasm on the part of New York for completing its proposed purchase of HQ power (let alone absorbing any of the VJO sale);
- likely re-examination of the contract by the Board.

These factors would probably have led to either the termination of the HQ-VJO contract, or to steep reductions in the prices, term, size or restrictions in the contract.

In the event of termination, CVPS might conceivably have opted to replace the HQ contract with another long-term single-source contract, but few major long-term power-purchase commitments were made by New England utilities after the end of 1991. I doubt that CVPS would have been able to contract for such a purchase and get it approved before falling market prices rendered it uneconomic. The Company would more likely have purchased power primarily on the short- and medium-term market.

Following the cancellation of the HQ-VJO contract, CVPS would have been in the position of several utilities that were actively seeking power-supply arrangements in 1992. Had Central Vermont acted prudently at that time, it would have diversified its supply sources and contract structures, and contracted for a variety of supplies. It would also have increased its emphasis on energy conservation.

Q: What modifications in the HQ-VJO contract might have made it more attractive?

A: The utilities might have negotiated some combination of the following:

- The purchase of smaller amounts of HQ power, perhaps at the level of Schedule B, to utilize the Highgate interconnection.
- A shorter contract term, to minimize the uncertainties for both the seller and the buyers from the long contract.
- Lower prices, which would have been necessary to bring the costs down to the level of alternatives, as well as to compensate for any reduction in the length of the contract.

Unless the parties and the Board had acted very quickly, or HQ cut prices very dramatically, events would have continued to catch up with the contract. Throughout the early 1990s, fuel prices and fuel-price forecasts continued to fall, the expected costs of new gas-turbine and combined-cycle capacity declined, and capacity and energy surpluses continued to grow. A contract revision that would have looked fine in (for example) October 1991 might well have been unattractive before the Board could complete its review, sometime in 1992. Hydro Québec did not seem inclined to move quickly on any major price reductions, so it was unlikely to work out a major long-term sale to Central Vermont that could pass regulatory review. Had Hydro Québec made major concessions quickly enough, the final contract might well have been comparable to the prices of the offers and contracts I discuss below.

A. The Company's Economic Analyses of Supply Resources in 1991

Q: Can the Board determine what resource mix CVPS would have selected, had it been acting prudently, from the analyses the Company conducted in 1991?

A: No, for a couple of reasons. First, Central Vermont did not leave clear paper trail of its long-term supply analyses in this period, especially with regard to alternatives to the HQ-VJO contract. While CVPS provided some workpapers in its testimony in Docket No. 5701 and numerous boxes of files in discovery in Docket No. 6018, the documentation supporting its analyses of the HQ-VJO contract is incomplete and poorly organized[7], as the Board found in Docket No. 5701 at 107–108. Even in 1995, CVPS was not able to produce much coherent discussion of its 1991 economic analyses of the HQ-VJO contract, even in the form of the internal memos that would be a necessary part of any careful review of results by analysts, managers, or the CVPS Directors.

The Company has produced some materials (mostly spreadsheet print-outs, graphs and handwritten notes) for analyses conducted in February and April of 1991, and a memo with some documentation of its October 1991

[7]The Department reviewed every file in every one of more than 50 boxes that CVPS made available for inspection in Docket No. 6018.

analysis of potential renegotiation of the HQ-VJO contract.[8] The 1991 IRP, issued in September 1991, also provides some insight into the input values that Central Vermont was using at this time.

Q: Please provide a brief description of CVPS's economic analyses of the HQ contract.

A: The Company conducted analyses in February, April, and October 1991, as summarized in Exhibit DPS-PLC-2.[9] These studies compared the HQ base case to cases in which the HQ capacity was replaced with various combinations of the following supply options: short-term purchases, long-term purchases of NU oil-fired capacity, the Sheldon Springs NUG (which was also called Bonneville), generic gas turbines, and intermediate and baseload combined-cycle plants.[10]

The February 1991 analysis compared the HQ contract to two alternative portfolios consisting of a mix of generic new units and short-term purchases, with and without purchases from Sheldon Springs.

The April 1991 study examined several alternative supply portfolios. The lowest-cost expansion plan described in the available documentation consisted of the "oil block" (a 110 MW purchase from the Middletown-4 and Montville-6 oil-fired units of Northeast Utilities), Sheldon Springs, and

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[8]Most of these materials were provided in CVPS Exhibit EMA R-1 in Docket No. 5701, which I refer to herein simply as Exhibit EMA R-1. I have not identified any substantially different analyses in the boxes of files provided on discovery in Docket No. 6018.

[9]Exhibit DPS-PLC-2 is based primarily on Exhibit EMA R-1.

[10]The two types of combined-cycle units represented the same technology, and differed principally in fuel supply. Central Vermont modeled the intermediate combined-cycles as burning a mix of oil and interruptible gas, and modeled the baseload combined-cycle plants as burning firm gas (and hence paying fixed pipeline demand charges).

generic combined-cycle and combustion-turbine units. The analyses in the April study reflect the first sellback.

The April 1991 analyses indicated that the HQ purchase was less expensive than the lowest-cost alternatives modeled by as little as $16 million in present-value terms, and was more expensive than the alternatives through 2012, three years before the end of the contract.

Also in April 1991, CVPS's planning staff met to consider the lock-in. Company planners apparently believed that these results were overstated, and that the present-value benefits of the HQ contract were in the range of $16–$35 million (Exhibit DPS-PLC-3). The second sellback, to which CVPS and HQ had agreed in principle (but had not made final), was expected to reduce the cost of the purchase by $19 million, bringing the range of benefits, under the conditions of the April study, to $35–$54 million (Exhibit DPS-PLC-3). The planners recommended unanimously that the Company not commit to the contract.

The October 1991 analysis was the first Company analysis to use the lower projection of fuel prices that CVPS had developed in July 1991.[11] Of the six cases in the October analysis, five assumed the existence of the HQ-VJO contract, and reflected the benefits of alternative sellback and banking arrangements. The remaining case (Case 6) assumed the cancellation of the HQ-VJO contract, and its replacement with NU's Montville and Middletown units, followed in 1999 by new utility-owned proxy units of unspecified technology. Central Vermont found Case 6 to be $90–100 million more

[11]The analysis is described in a 10/29/91 memo from Amelang, Dodds, and Rochelle to Cater, which is part of Exhibit EMA R-1. It is also contemporaneous with the Company's 1991 IRP, and probably used similar assumptions.

expensive in present value than three cases that included the HQ-VJO contract with the first two sellbacks and various assumptions about banking and other factors. As I discuss below, the Company did not choose appropriate replacement resources for Case 6, and made a number of incorrect assumptions about the cost of new units.

Q: Are the input assumptions in these analyses appropriate for determining the least-cost replacement for the HQ-VJO contract?

A: No, for several reasons. First, Central Vermont does not appear to have sought out the best purchase options to replace the HQ-VJO purchase. Second, the replacement portfolios that CVPS selected were not well calculated to minimize costs. Third, several of the inputs to the analyses were not appropriate.

Q: Please explain why Central Vermont's analyses do not necessarily reflect the best purchase options available at the time.

A: Central Vermont appears to have artificially limited its alternatives, by asking suppliers for a very specific product, which would look like the HQ contract with certain improvements. In a letter of 7/12/91, for example, CVPS asked Northeast Utilities for a bid to supply power from 1996 to 2010, in varying amounts, with options for CVPS to elect additional purchases on short notice. Central Vermont asked that the pricing terms also mirror those in HQ, with energy escalating with GNP inflation throughout the contract and capacity escalating at GNP inflation until the start of each increment of capacity. Central Vermont should have been aware that other utilities in New England were not anticipating excess supply of low-cost power past about 2005;

demanding a purchase of this length, with options, and with the specific HQ escalation provisions, might well have discouraged potential suppliers.[12]

In addition, even though Northeast Utilities had offered to tailor a contract to meet CVPS's needs, there is no evidence that the Company made any serious effort to negotiate with NU, other than the inappropriate request described in the above paragraph.[13]

Q: Please describe the problems with the Company's replacement portfolios.

A: I have identified three such problems.

- The April 1991 analysis assumed that CVPS would purchase more NU capacity than it needed 1995–98, which would overstate the benefits of HQ.
- In February 1991, NU offered CVPS three purchase options: a mix of specific nuclear and oil plants, system power, and the oil block. The available documentation on the nature of the offers is contained in Exhibit DPS-PLC-4. The system-power offer was by far the lowest-cost NU offer, as illustrated in Exhibit DPS-PLC-5. Nevertheless, CVPS decided to exclude this option from its analyses of alternatives to the HQ-VJO contract:

> …CVPS had reservations regarding the basis of the energy rates contained in [the system power option]. The rates appeared to have been simply estimated at 2 cents/kWh and escalated at oil price escalation rates. (EMA Direct in Docket No. 5701 at 70)

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[12]The notes of the 4/17/91 planners meeting similarly indicate a concern that "no other alternatives [are available] to 2015." Clearly, Central Vermont had plenty of time to develop alternatives beyond 2000; the absence of any other proposal for 25 years of sales should not have reduced CVPS's interest in reducing costs in the first decade of the HQ contract.

[13]See the letter from NU to the Department in Exhibit DPS-PLC-4.

Rather than developing greater confidence in the pricing of the NU system power option, CVPS merely assumed for the purposes of the October analysis that the best it could do was the higher-cost 110-MW oil block.

- The October analysis included an NU purchase as a replacement for HQ only until 1999; after that, the analysis constrained the NU purchase to 21 MW, and all additional deficiencies were met with higher-cost new units.
- In the October analysis, CVPS assumed that Sheldon Springs was canceled and no NUG power would be available in either the short or long term. As a result, CVPS assumed that the new units replacing the HQ-VJO contract after 1999 would be generic utility-owned combined-cycle units, which CVPS expected to be significantly more expensive than Sheldon Springs.[14]

Q: Had CVPS been considering major long-term purchases in late 1991 or 1992, what portfolio should CVPS have compared to the HQ-VJO contract, or whatever alternative Hydro Québec would have been offering at that time?

A: Central Vermont should have assembled an efficient low-cost portfolio to use as a benchmark for comparison with the HQ purchase and other planning purposes . That portfolio would comprised the following:

[14]Since Central Vermont acknowledged on discovery (IR 5-42) that other NUGs were offering prices similar to those of Sheldon Springs, that plant's cost could have been used as a proxy for the cost of new NUGs, without requiring any judgement regarding the continued availability of that specific site for development.

- Through about 2005, one or more of the best purchase deals available from the owners of existing capacity. This may have included purchases from NU, UI, NEPCo, NYSEG and/or NiMo. A few other utilities and NUGs with uncommitted capacity might also have been potential suppliers.
- Following the end of the period in which purchases from excess capacity were available, new combined-cycle capacity. With CVPS's cost assumptions, the least-cost option would have been a NUG purchase, at the cost of Sheldon Springs, which CVPS has described as being typical of other options available in the market. Cost inputs more realistic than those used by CVPS would result in similar costs for utility-owned and NUG units.

Q: Can the Board rely on CVPS's 1991 analyses to determine the composition and cost of the least-cost portfolio from a late-1991 or 1992 perspective?

A: Not entirely. Each of CVPS's analyses in 1991 used inputs or selected resources that would have been inappropriate in assembling and evaluating benchmark portfolios in late 1991 and 1992.[15]

Q: Please describe the problems with the inputs to Central Vermont's analyses.

A: I have identified two such problems.

[15] Whether these inputs and assumptions were reasonable at the time they were used is not necessarily relevant to the issues in this case. My interest here is solely in identifying the nature and costs of the resources CVPS should have been considering in deciding how to replace the cancelled HQ-VJO contract.

- The February and April analyses used high fossil fuel prices from WEFA's February 1990 fuel-price forecast. CVPS produced a dramatically lower fuel-price forecast in 7/10/91.[16] The two fuel-price forecasts are summarized in Exhibit DPS-PLC-6. CVPS's 7/91 oil-price forecast for 2005 was almost 30% below the WEFA 2/90 forecast. The Company's 7/91 forecast was much more in line with the assumptions of other utilities in the region.
- Overstating the cost of power from intermediate and baseload combined-cycle units.[17] The avoided-cost inputs specified in the Company's 1991 IRP indicate that CVPS overstated the heat rates, construction costs and pipeline costs for the combined-cycle units and incorrectly modeled the dual-fuel operation of the intermediate combined-cycle units.

Q: Why do you say that CVPS used pipeline costs that were too great?

A: The Company assumed pipeline demand costs of $1.33/MMBtu, or $485/MMBtu-day of pipeline capacity, in 1990 dollars.[18] CVPS assumed that

[16]Company witnesses in Docket 5701 did not reveal the existence of the 7/91 fuel-price forecast in their testimony discussing the costs of alternatives.

[17]The distinction between intermediate combined-cycle and baseload combined-cycle plants, which was often made in New England analyses in the early 1990s, is one of fuel supply. The fixed cost of a baseload combined-cycle includes a pipeline charge, which gives it access to relatively low-cost gas throughout the year. The intermediate combined-cycle fixed costs do not include pipeline charges; without firm pipeline capacity, the plant would burn interruptible gas when regional gas demand is low (i.e., when weather is warm), and much more expensive #2 oil (essentially the same as home heating oil) the rest of the year.

[18]This is $1.33/MMbtu of peak use. At a 75% capacity factor, that would be more like $1.77/MMbtu actually used.

the pipeline costs would escalate at 1% above the general inflation rate to and beyond the in-service date of each combined-cycle unit. This pipeline cost was about half of CVPS's estimate of the total annual fixed costs of a baseload combined-cycle unit. This value was much too high.

The NEPOOL Generation Task Force (GTF), in its "Long-Range Planning Study Assumptions" (April 1991) estimated pipeline fixed charges of $0.65/MMBtu in 1990 dollars, inflated to the in-service date and held constant thereafter. The starting price was half what Central Vermont assumed. In addition, holding pipeline charges constant after the start of deliveries—which would be consistent with common contract and tariff provisions—would significantly reduce the life-cycle costs of a baseload combined-cycle plant.

Q: Were the GTF's 1991 estimates of pipeline costs dramatically different from earlier estimates?

A: No. The GTF in 1989 had projected a pipeline fixed charge of $1/MMbtu, but assumed no escalation, either to the power plant's installation date or afterward.[19] Thus, the 1989 GTF assumptions implied a pipeline charge of $1/MMBtu for a plant entering service in 2006, compared to $1.22/MMBtu for the 1991 GTF assumptions. These are quite similar, compared to CVPS's extraordinary assumption of $2.49/MMBtu in the first year and $3.41/MMBtu by 2014.[20]

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[19]The GTF did not produce an assumption report in 1990.

[20]I used a 4% inflation rate, which was the long-term inflation estimate Central Vermont used in its 1991 IRP.

For comparison, Central Vermont's projection of short-term market prices in this proceeding assumes a charge of $0.64/MMBtu or $232/MMBtu-day.

Q: What is your basis for saying that CVPS overstated the capital costs of the combined-cycle units?

A: Central Vermont used an overnight construction cost of $760/kW (1989$), which with inflation and AFUDC was equivalent to a gross installed cost of $802/kW in 1990 and $1,081/kW in 1996.[21] These estimates were based, at least roughly, on the cost estimate for a 100-MW "conventional" combined-cycle unit from the 1989 GTF report.[22] The GTF reported prices about 10% lower for a 200-MW combined-cycle, and another 10% lower for a 400-MW combined-cycle plant.

Since Central Vermont would need 142 MW to replace the HQ-VJO contract, and could share ownership with other utilities (in Vermont and elsewhere), the choice of a 100-MW unit seems unnecessarily small.[23] Other New England utilities were proposing, with more or less specificity, new combined-cycle units ranging from 100 MW to 300 MW.

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[21]From the 1991 IRP (at Table III.E-3), it appears that CVPS computed plant costs based on winter ratings, and increased the capital cost slightly to reflect the summer derating of the plant.

[22]The base plant cost that CVPS used (in 1989 dollars) is a few percent *greater* than the GTF's estimate (in 1990 dollars), suggesting that CVPS added a year's inflation, rather than subtracting it.

[23]As late as October 1991, Central Vermont anticipated the need for an additional 230 MW of new resources by 2006, even with the HQ-VJO purchase. (at Exhibit 2 of the 10/91 analysis in Exhibit EMA-R1)

The GTF's capital costs were in turn based on a 1987 report from Burns and Roe, and also anticipated much lower costs for advanced combined-cycle designs. Central Vermont should have checked these estimates. As of the early 1990s, there was little recent public information on the costs of building combined-cycle plants. The relatively few existing utility combined-cycle plants were of 1970s vintage, and the combined-cycle plants under construction in the early 1990s were mostly NUGs, which need not publicly report their costs.[24]

There was one readily available data point. In 1990, Virginia Power added the Chesterfield-7 gas combined-cycle unit at a price of $490/kW.[25] That unit had some advantages: it was built at an existing site, and in a less-expensive part of the country (and its reported cost probably did not include its transmission interconnection). A new unit in New England in 1990 would be expected to be somewhat more expensive, but probably not by the 60% difference between CVPS's estimate and the actual cost of Chesterfield 7.

Had CVPS contacted other utilities' planning and construction staffs, it might have also obtained data on the projected costs of plants under or near construction, including the following (all costs are in nominal dollars, winter capacity):

- Chesterfield 8 was completed in 1993 for $546/kW

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[24]It is not clear that NUG cost data from the late 1980s and early 1990s would be applicable to utility-owned plants. For many NUG units, prior to the adoption of competitive bidding, completion of the unit in time to meet contract requirements for a lucrative purchased-power agreement may have been more important than controlling costs.

[25]Chesterfield cost should have been filed in the Virginia Power FERC Form 1 in April 1991. I do not have that document, but Chesterfield's 1990 capital cost is included in the Utility Data Institute database, which is taken primarily from the FERC Form 1.

- Martin 3&4 (Florida P&L), which were completed in 1993 and 1994 for an average cost of $513/kW.
- RM Flynn (a New York Power Authority greenfield plant on Long Island), which was completed in 1994 for $723/kW.
- Hay Road (Delmarva P&L), where the turbines were installed in 1990-91 at less than $300/kW and the combined-cycle was completed in 1993 for an average cost of $469/kW.

More details on these plants are provided in Exhibit DPS-PLC-7.

Q: How did CVPS overstate the heat rates of the combined-cycle units?

A: The Company assumed a full-load heat rate of 8,900 btu/kWh for baseload combined-cycle plants and 9,300 for intermediate combined-cycle units. Since these plants are otherwise treated as being identical (other than their fuel supply), the higher heat rate for the intermediate units would be hard to explain. In fact, combined-cycle units have lower heat rates on oil, and the intermediate units were assumed to burn oil for a large part of the year, so they should have had lower full-load heat rates.[26]

Other sources of heat-rate information at the same time indicated much higher efficiencies:

- Chesterfield's 1990 heat rate was 8,149 BTU/kWh, operating at a 30% capacity factor. Baseload operation should produce a lower heat rate.

[26]Most thermal plants, and especially gas-turbine and combined-cycle units, operate at higher heat rates at part load. The annual heat rates of intermediate units, which spend more of their time a partial load, would therefore typically be higher than those of baseload units of the same design. The difference is modeled directly in UPLAN, which uses different heat rates for different load levels, for the new combined-cycles and for most other thermal plants. The difference in full-load heat rate is in addition to the effects of partial loading.

- The 1989 GTF report listed full-load heat rates for conventional combined-cycles of 200–400 MW as 8,214 Btu/kWh.[27] The IRP indicates that "The Company increased the GTF Assumptions heat rates to allow for slightly lower efficiency" (at III.E-4), but does not explain why CVPS believed that future combined-cycle units would be less efficient than the GTF expected for conventional designs. In any case, a 13% increase in heat rate hardly qualifies as "slight."
- The 1991 GTF slightly increased the estimate of full-load heat rate for conventional combined-cycles, to 8,385 Btu/kWh, still less than CVPS's estimates of 8,900–9,300.

Q: How did CVPS incorrectly model the dual-fuel operation of the intermediate combined-cycle units?

A: In its 1991 IRP, Central Vermont modeled the dual-fueled intermediate combined-cycle plant as operating year-round on a single fuel, which appears to be priced at the average of the prices of #2 oil and interruptible gas. Normal UPLAN modeling would have treated the intermediate combined-cycle as two units: a gas-fired unit with a lower fuel cost that is available only in the summer and an oil-fired unit with a higher fuel cost that is available only in the winter. Had CVPS used this approach, UPLAN would have modeled the unit's dispatch as more frequent in the summer and less

[27]Advanced combined-cycle units were listed as having heat rates around 7,400 Btu/kWh. These might reasonably be thought of as speculative in 1991, although Martin County reported a heat rate under 7,300 for 1994.

frequent in the winter, resulting in a lower-cost fuel mix and a reduction in total energy cost.[28]

The assumption that the intermediate combined-cycle would be burning gas half the year was also very conservative. In 1991, gas was available virtually all year: several New England power plants were burning interruptible gas in January. While supplies might be more limited in some years, the average amount of time that interruptible gas would be available would almost certainly be more than one half.

Had CVPS included an intermediate combined-cycle plant in a resource portfolio, it should have modeled the dual fuel use more realistically than it did in 1991. I avoid this complication by using a baseload combined-cycle (either utility-owned or combined-cycle) rather than an intermediate unit.

B. Available Resources and Other Indicators of Market Prices

1. Excess Capacity in New England

Q: How had the availability of capacity and energy from New England utilities changed between the approval of the HQ-VJO contract in Docket No. 5330 and the post-lock-in period in which CVPS should have been seeking replacement of the HQ-VJO contract?

A: The following factors had changed:

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[28]In a smaller error, CVPS escalated the cost of gas for the baseload combined-cycle, not at the rates assumed for gas in CVPS's fuel forecast, but at the slightly higher escalation rates assumed for #2 oil.

- The economy of Vermont and the region was deteriorating (Docket 5701, Order at 107 and 109).
- The NEPOOL CELT report released on April 1, 1991, dramatically reduced projected load growth in NEPOOL. Combined with the operation of new supply resources, such as Seabrook, the HQ Phase II line, and NUGs, the load reduction moved back the need date for new capacity from 1995 to 2000. (Docket 5701, Order at 108-109)
- NU, the utility generally perceived to have the most excess capacity, was offering power through 2005 or 2006, and its March 1991 System Forecast of Loads and Resources showed adequate reserves through about 2004.
- As the CVPS planners noted at their 4/17/91 meeting, it was a "buyer's market—we are a buyer" (notes reproduced at Exhibit DPS-PLC-3).
- Regional market power prices for the short and medium terms were falling (Docket 5701, Order at 114).

Q: What additional medium or long-run purchase contracts were signed by New England utilities in the early- to mid-1990s?

A: Most New England utilities were not in the market for additional medium or long-run purchases in this period. Most of the larger utilities were selling power, rather than buying. However, some of the smaller utilities obtained power supplies in this period, primarily to replace cancelled supplies. I have identified three cohorts of contracts signed by New England utilities in the early-to-mid 1990s:

- Unitil's acquisitions from its 1991 Request for Proposals.
- A number of purchases by municipal utilities negotiated in 1992 and signed in 1993.

- Purchases negotiated by Burlington Electric Department and New Hampshire Electric Cooperative in 1995.

Q: Please describe the Unitil acquisitions.

A: In late 1991, Unitil selected the winners in its April 1991 RFP. Unitil rejected CVPS's offers of Schedule B at cost through 2015, in favor of purchases from NU, UI, NEES, and MMWEC.[29]

Unitil selected a mix of oil, gas (steam and combined-cycle), coal, and nuclear. This power would come from six utilities, nine plants, and eleven units; and with expiration dates ranging from April 2001 to April 2013. Over half the capacity was in contracts that would expire in 2005–2006. This is a reasonable model for prudent behavior by CVPS a year or so later. Exhibit DPS-PLC-8 shows the 1999 costs of each of Unitil's commitments made in this period, at their actual capacity factors and adjusted to 75% capacity factors, assuming that additional energy would purchased or sold at $25/MWh.[30] Other than the Seabrook contract (which was comparable in price to the HQ-VJO sale), each of the Unitil purchases was less expensive than the HQ-VJO contract, some by a wide margin.

Q: Please describe the municipal power purchases.

A: Exhibit DPS-PLC-9 summarizes the provisions of ten contracts signed by eight New England municipal utilities in 1993 to purchase power over periods of 5–12 years from Boston Edison, NEPCo, or NU.

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[29]The winners were not known in time for the 11/91 issue of *Robertson's Current Competition,* but were listed in the 2/92 issue. At some point, Unitil added a purchase from Great Bay Power, as well.

[30]Unitil's purchase from NEPCo was partially transferred to USGEN when it purchased NEPCo's plants, and some of the component purchases may have been terminated.

I have not included unit power purchases priced at cost-of-service, or contracts that appear to have been continuations of older contracts or resolutions of disputes. The cost projections do not include contracts that are difficult to price or evaluate, such as those based on cost of service. The costs of the NEPCo-Littleton and NEPCo-Braintree contracts include compensation for NEPCo's payment to buy out the Newbay NUG contract; I have reduced the projected capacity cost to reflect pricing without the Newbay payment (about $60/kW-yr, or 1¢/kWh).

The contracts are generally structured as system power purchases, although the prices are sometimes tied to fuel prices at a particular plant and availability of energy is sometimes conditioned on the availability of at least one or two of a group of plants. The inter-utility contracts also generally have greater flexibility in energy take and capacity adjustment than the HQ contract, and have shorter terms as well. If they turn out to be somewhat above market prices, they will not last as long as the HQ contract and will therefore produce much lower damages.

The actual costs (as the resources were dispatched by NEPOOL) generally fell in the range of 3.9–4.5¢/kWh in 1999, for the power-purchase contracts whose prices I have been able to find for that year, compared to 5.8¢/kWh for the HQ purchase.[31] The requirements sale by NU to Madison, Maine cost 4.9¢/kWh, but included reserves, charged the purchaser only for

[31]The average cost reported for the NEPCo-Reading sale, which ended 10/31/99, was 8.6¢/kWh. This contract provided very little energy in 1999 and appears to have operated more like a peaker than a baseload resource. Had the NEPCo-Reading sale operated at a 75% capacity factor, rather than its actual 35% capacity factor, with the same energy charge and the same total demand bill, the price would have been 5.4¢/kWh.

actual load, and allowed the purchaser to change loads as required. Requirements contracts are more valuable, and should generally be priced higher, than firm power sales. The NEPCo-Littleton sale cost 5.6¢/kWh, but I cannot determine how much of that year's price was actually compensation to NEPCo for paying Littleton's cost for buying out the Newbay NUG contract.

Of the seven contracts for which I have been able to project prices for 2001/02, the prices for six of them range from 4.2¢/kWh to 5.7¢/kWh with EVA's current fuel-price forecast.[32] The requirements sale by NU to Madison, Maine would cost 6.7¢/kWh.

Q: Please describe the contract between Northeast Utilities and the Burlington Electric Department.

A: In 1995, the Burlington Electric Department negotiated a contract with NU for purchases from May 1998 through 2009. The contract, signed in March 1996, is described in Exhibit DPS-PLC-10. Burlington would have paid NU $33/MWh in 1999 and $39/MWh during 2001/02, at the 75% capacity factor of the HQ-VJO contract.

This contract provides very flexible power supply. There is no minimum energy take, energy is a majority of the purchase price, and energy prices vary between peak and off-peak. Burlington has the option of changing the capacity of the purchases over a wide range—from 2.5 MW to 7.5 MW—on two months notice. Under these circumstances, the seller cannot count on above-market (or above-cost) prices in one year balancing

[32] The EVA forecast was prepared for the Department. Central Vermont relies on the EVA forecast in its projection of short-term market prices.

below-market prices in another year; the annual prices in the contract must represent a reasonable approximation of the price at which the seller would have been willing to sell in that year, for any length contract.

Q: Please describe the contract between the Company and the New Hampshire Electric Cooperative.

A: On 12/29/94, NHEC issued an RFP to replace its existing contract with CVPS. Central Vermont responded to the request in January 1995, and the contract was made final by April 1995. The contract provides for delivery of 2.75 MW at an annual 54% capacity factor, with specific monthly kW and kWh deliveries, for May 1, 1995 through October 1, 2006. The price for this power is set at $32.40/kW-yr and $14/MWh in 1995, for an all-in price of $23.6/MWh, rising at the general inflation rate.[33] Exhibit DPS-PLC-11 compares the contract price, actual prices through 2000, and CVPS's projection of prices for the rest of the contract term. These prices are less than half the prices of the HQ-VJO contract.

If Central Vermont negotiated the contract with NHEC prudently, these prices should represent the market in 1995. If Central Vermont had not locked into the HQ-VJO contract, it might have been a buyer , rather than a seller, in the 1995 market for medium-term power purchases, and might have wound up paying prices comparable to those in the NHEC contract.

[33]Any additional power would be priced at 10% more than CVPS's short-term marginal costs, with a floor capacity price of $18/kW-yr.

2. *Excess Capacity in New York*

Q: Why is excess capacity in New York relevant to Central Vermont's power-supply planning in the early 1990s?

A: As CVPS's 1991 IRP acknowledges, New York utilities had been, and were expected to remain, significant power suppliers to New England.

This was particularly true in the early 1990s, as New York utilities were projecting large capacity surpluses, no need for capacity until well after 2000, and sharply lower avoided costs. On August 30, 1991, two days after the Vermont Joint owners' early lock-in decision, the New York Power Pool released estimates of long-run avoided costs that were less than those of the HQ contract and other resources CVPS had been considering, through at least 2004,. See Exhibit DPS-PLC-12.[34]

Q: At what prices were New York utilities offering power in the early 1990s?

A: In early 1992, New York State Electric and Gas (NYSEG) and Niagara Mohawk (NiMo) provided CVPS with power offers. These offers are attached as Exhibit DPS-PLC-13 and Exhibit DPS-PLC-14. Each utility made two offers; one of the NYSEG offers is based on a complex definition of marginal energy costs and is difficult to evaluate. The other three offers are priced out in Exhibit DPS-PLC-15.[35] I included transmission charges of $24/kW-yr,

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[34]Due to these conditions, coupled with success of DSM programs, low fuel costs, and the poor economics of the HQ purchase, New York's interest in the HQ purchase was flagging. Agreement on delaying the New York decision from December 1991 to November 1992 was announced in August 1991, the same day as the VJO lock-in decision.

[35]I used NiMo's estimate of its marginal energy costs in evaluating NiMo A.

based on the charges in NYSEG's offer. The costs of these offers were considerably below the costs of the HQ-VJO contract.

In 1995, the Burlington Electric Department negotiated a contract with New York State Electric and Gas for purchases from May 1998 through 2009, respectively. The contract, signed in March 1996, is described in Exhibit DPS-PLC-16. The prices for 1999 and 2001/02 are equivalent to \$37/MWh and \$41/MWh at the 75% capacity factor of the HQ-VJO contract. As with the NU-Burlington contract, this purchase is very flexible. Burlington has the option of changing the purchase from 2.5 MW to 7.5 MW, on two months notice.

3. *Availability of Transmission from New York*

Q: Was transmission from New York available to CVPS in 1991 and 1992?

A: Yes. The transfer capability across the interface was allocated by agreement between the three NEPOOL participants that owned lines connecting to New York: VELCo, NU, and NEPCo. Vermont had access to 14% of the transfer capability, which was usually approximately 220 MW, but could fall to 170 MW when critical transmission elements were unavailable (IR DPS 5-30 at 1–2).

In addition, capacity on the interface could be purchased from the other two owners. The NY-NEPOOL tie was used largely for economy purchases, over which a firm purchase would take priority.

Capacity on the interface was not heavily used. In April 1991, R. M. Mallary of VELCo wrote to Central Vermont's R. deR. Stein and others: "With the recent decrease in power demand, the commissioning of Seabrook, the construction of Phase II and the acceleration of DSM efforts, the demand for transmission from New York has largely evaporated."[36] D. James, NEPOOL's Manager of Transmission Planning, wrote that during 1992–93, "New York to NE transfers greater than 1,000 MW have rarely occurred in recent years (e.g., 8 hours in the past two years)."[37]

While New York and NEPOOL transmission planners in this period prudently attempted to foresee and avoid inter-regional transmission constraints due to the construction of new plants, the concerns they identified were generally limited by such qualifiers as "improbable risks," "rare circumstances," and "certain severe and improbable conditions." Transmission constraints arose periodically on the NEPOOL side of the interface; these were mitigated in the short term by the control of generation dispatch, and were relieved within a year or two by reinforcement of the transmission system.

Q: Was NYPP-NEPOOL transmission capacity expensive in the early 1990s?

A: No. NYSEG estimated a cost of $24/kW-yr in 1992 (Exhibit DPS-PLC-13), which would be about $4/MWh. Green Mountain Power paid about $3/MWh for NYPA to wheel power from Ontario Hydro in 1990 through 1993, and also reserved 50 MW of NU's transfer capability for its purchase from RG&E, through 1997 (although the contract was cancelled earlier). Green Mountain

[36] "VELCo's Study of the New York to Vermont Interface," April 12, 1991, at 2, ¶2. Exhibit GMP-RJB-2 of the testimony of Richard Bolbrock, Docket 5983,1/9/98.

[37] Letter to M. DeLaura, Chairman, Task Force on System Studies, New York Power Authority, "Re: TFSS Review of the Potential InterArea Effects of the Saranac Energy NUG," September 1, 1993, at 1, ¶4. Exhibit GMP-RJB-1 of the testimony of Richard Bolbrock, Docket 5983, 1/9/98.

Power paid about $16/kW-yr for NU transmission capacity in 1990, and much less (under $1.5/kW-yr) in 1991 and 1992 (GMP's FERC Forms 1 for various years at 332).

Q: Were the New York utilities concerned that NUG construction might restrict their ability to sell their excess capacity into NEPOOL?

A: No. Niagara Mohawk, which was a major seller of power to New England with every reason to keep transmission capacity open, reported in its September 1991 IRP (at 6-15) that the NYPP-NEPOOL Interface "is currently limited by lines in New England which may be upgraded in the future…. Subject to specific study, new [NUG] resources in Eastern NY are not anticipated to be detrimental to the NYPP-NEPOOL Interface and, unless shown to be detrimental to Central-East requirements, should not be discouraged."

Q: Were imports from New York generally assumed to be available to New England utilities in the early 1990s?

A: Yes. For example, in 1994, Boston Edison filed testimony purporting to demonstrate that it could count on as much as 750 MW of capacity from New York, even if it did not reserve capacity or transmission in advance. An excerpt of that testimony is attached as Exhibit DPS-PLC-17.

4. New Plants

Q: What types of new plants would have been considered as replacements for the HQ-VJO contracts?

A: During the period of excess capacity in New England and New York, no new plant could compete with the cost of existing plants.[38] Once demand and supply converged, sometime after 2000, CVPS would have two basic choices: a purchase from a NUG, or participation (as owner, co-owner, or purchaser) in a utility-owned plant. As a replacement for the baseload HQ-VJO purchase, both the NUG and the utility plant would be expected to be gas-fired combined-cycle units.

Q: Would CVPS have needed to commit itself to a specific new unit in the early 1990s?

A: No. The Company would have used a proxy unit in its economic analyses. Since that unit would not be needed until 2005 or beyond, CVPS would not have expected to need to make any specific commitments until about 2000.

Q: What would be an appropriate proxy for a NUG purchase?

A: Based on the documentation CVPS provided in previous dockets, the NUG with which it was most familiar was Sheldon Springs. The Company describes Sheldon Springs as typical of IPP's proposed in the early 1990s (IR DPS 5-42).

Q: What cost assumptions would have been appropriate for a utility-owned combined-cycle plant?

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[38] In the 1991 IRP, CVPS indicated that the Sheldon Springs project was unlikely to be completed, because "of the declining need for power in Vermont and the Northeast due to the economic downturn" and because "a preliminary Department of Public Service analysis indicates that the need for power has declined" (1991 IRP at VI-5). In other words, given the low cost of oil and the plentiful power supply, Sheldon Springs (and most other NUGs) were not least-cost options in the near term.

A: The Company's 1991 IRP provides most of the input data required for the combined-cycle unit. As described above, the estimates CVPS used for capital cost should have been reduced somewhat, to reflect the costs of plants actually constructed in that period. For both heat rate and the cost of gas transportation from the Gulf, CVPS should have used values similar to those of the NEPOOL GTF, rather than its own higher values (for which it has not been able to produce any documentation).

C. Comparison of the HQ-VJO Contract to Other Alternatives

Q: How would Central Vermont have compared resource alternatives in the early 1990s, had it been prudently seeking resources to replace the canceled HQ-VJO contract?

A: I assume that CVPS would have taken the basic approach it used in its 1991 IRP. As I describe above, certain of CVPS's input assumptions would need to be revised.

Q: Have you performed such a comparison?

A: Yes. Exhibit DPS-PLC-18 shows my comparison of the HQ-VJO contract to the NU system proposal through 2006, followed by a NUG purchase modeled on Sheldon Springs. I use the input assumptions of the 1991 IRP and CVPS's October 1991 HQ analyses, except for

- recognizing the first and second sellbacks, by deleting all HQ costs and benefits through 1994
- using the NU system purchase through 2006, with the energy price CVPS assumed in its analyses ($22.7/MWh in 1990, escalating with #6 oil price).

- using Sheldon Springs, instead of an over-priced generic combined-cycle, as the post-2006 replacement. I escalated the Sheldon Springs variable costs at CVPS's projected escalation in gas prices, and the fixed charges at CVPS's projected construction inflation to the contract start date. After the plant's start-up, I follow EMA's assumption that the fixed costs will increase at 1.1% annually.

Q: What is the result of this analysis?

A: The replacement resources have a lifetime present value that is $78 million (or 17%) less expensive than the HQ-VJO contract.

Q: Does this result depend on the use of Sheldon Springs as a proxy for the long-run replacement?

A: No. If CVPS believed that utility-owned plants were inherently more expensive than NUGs, it should have used a NUG proxy for the later years in its resource portfolio. A utility combined-cycle unit with more-realistic, but not aggressive, projections of capital cost, heat rate, and pipeline charges would have costs comparable to the NUG proxy; see Exhibit DPS-PLC-18.

Q: Is your conclusion that the HQ-VJO contract was more expensive than alternatives dependent on the pricing of the NU system purchase?

A: No. The HQ-VJO contract would also have been predicted in 1991 to be more expensive than a portfolio including the NU Oil Block; see Exhibit DPS-PLC-18.

Q: Had CVPS considered the environmental costs and benefits of purchases from HQ contract in comparing resource alternatives, how might that have affected its analyses?

A: For its own planning purposes, in the 1991 IRP and for several years thereafter, CVPS quantified environmental costs only in the calculation of avoided costs for DSM, as required by Docket No. 5270. The Company sometimes displayed tradeoffs between costs and environmental effects, but I have not been able to identify any situations in which CVPS selected resources with higher costs, to reduce environmental externalities.

For example, with respect to supply resources, the 1991 IRP highlights environmental issues only in terms of the risks related to future environmental compliance costs, and then only in the last point in twelve-bullet list (at III.C-9). Similarly, in the 1994 CVEC LCIP, Central Vermont found that adding new clean generation ahead of need would reduce air emissions, but took no action toward achieving such additions.

Q: Let us suppose that CVPS had decided to include some consideration of environmental externalities in deciding whether to sign a new contract with HQ, similar to the HQ-VJO contract, or purchase surplus power in New England or New York. How might a prudent Vermont utility have proceeded, given the Board precedent?

A: In considering the environmental effects of the HQ purchase, Central Vermont might have started with the Board's review of those effects in Docket No. 5330. In the order of October 12, 1990, the Board stated:

- "[T]his contract is, compared to other available choices, an environmentally attractive supply source for Vermont" (Order at 29). This statement appears to be based on the conclusion that "large-scale hydroelectric facilities can have significant, negative environmental effects, but we believe that these effects, properly controlled and mitigated, are *less* damaging that the alternative supply sources" (Ibid.).

- "[W]e do not accept the argument that approval of this contract should 'cause' the construction of major new facilities on the Hydro-Québec system" (Ibid. at 28). The Board found that the combination of the 323 MW of expiring sales from Hydro Québec to Vermont, 3,500 MW of planned generation additions (including 2,510 under construction), and 4,000 MW of planned efficiency programs would meet the HQ-VJO sale without new construction. (The order elaborates on some of these issues at 171–177.)
- "[I]t is reasonable to expect that Hydro Québec will attempt to sell the power elsewhere so that its projected export sales targets will be met and its construction schedule will not be delayed.…it is also probable that over the longer term, even if the contract is rejected, Hydro Québec will continue to develop surplus hydroelectric capacity for sale to other utilities that could also be used to replace fossil fuel fired generation with similar air quality benefits." (Order at 167–168, note 45).
- Of the three environmental scenarios that the DPS developed, the Board rejected the one in which one-third of the power displaced coal generation in Ontario, because of Mr. Winter's testimony that Ontario's dispatch of its oil plants would not be affected by purchases from Hydro Québec (Order at 167).[39] This was the only DPS scenario in which 100% of the HQ-VJO energy was resold.

[39]Mr. Winter actually testified that purchases from Hydro Québec might cause Ontario Hydro to reduce its coal-fired generation, and hence its carbon emissions, but not its production of acid gases (SO_2 and NOx), since HQ purchases would allow Ontario Hydro to defer retrofits or burn higher-sulfur coal. Alternatively, he testified, Ontario Hydro might reduce generation at its oil-fired units, or increase sales to other utilities, either of which would have effects similar to direct HQ sales into the Northeast US.

- If none of the HQ-VJO energy would be resold after a cancellation, the environmental benefits of the purchase were greater than if ⅔ of the energy were resold (Order at 167, finding 212.) The Board did not express an opinion about the amount of power that would be resold in the short term, but indicated that all of it would be resold in the longer term. (Order at footnote 45).
- The Department's scenarios in which less than 100% of the HQ-VJO power is resold assume that incremental hydroelectric development is delayed by the cancellation. (Order at 186–187, footnote 49)

The Board's conclusions on the environmental effect of the HQ-VJO contract are complex. On the one hand, the Board finds that the contract is "environmentally attractive" because large hydro is "less damaging that the alternative." On the other hand, the Board finds that Hydro Québec's construction of large hydro is likely to be the same, with or without the contract. At least in the long term, the Board finds that Hydro Québec's off-system sales and resulting environmental effects would be the same with or without the contract. In the short term, the Board suggests that Hydro Québec might sell less energy off-system were the contract cancelled, but also suggests that the reduction in sales would only result from a delay in HQ's hydro construction schedule, which the Board does not believe will occur.[40] The Company did neither believed in 1991 nor believes today that cancellation of

[40]Logically, the energy that would have been freed up in the short term by the cancellation of the HQ-VJO contract could have been used in other ways, such as filling the new reservoirs faster, which would provide more energy to be sold off-system in the long term, or reducing the operation of Hydro Québec's own high-sulfur oil plant. Each of these alternatives has environmental benefits.

the HQ-VJO contract would have changed Hydro Québec's expansion plans (IR DPS 8-17).

In short, the Order in Docket No. 5330 suggested that the environmental benefits of HQ-VJO contract are limited to the extent to which Hydro Québec would choose not to resell the energy if the contract were cancelled, and that whatever effects occurred would be limited to the short term. While the Board found the environmental effects of the purchase to be smaller than the environmental effects of alternatives, the differences must be rather small.

Q: If Central Vermont had decided to extrapolate an environmental valuation of an HQ purchase from Board precedent, how might it have proceeded?

A: The logical starting point for that extrapolation would be the 5% externality adder that the Board adopted for DSM in the order in Docket No. 5270. Unlike energy saved through DSM, which does not require the operation and/or construction of power plants, the energy (or the vast majority of it) from the HQ purchase results in the operation of fossil power plants. Those may be existing plants, including HQ's own Tracey oil plant, or plants that would otherwise be backed down in New England, New York, New Brunswick or adjacent areas, due to HQ's sales to other utilities.

Some of these plants would have higher emissions than the resources that would replace the HQ-VJO contract in CVPS's resource plan. Some of the additional generation due to the HQ-VJO contract, in the longer term, would be from new plants that have been, or will be, built in Québec or neighboring regions, but that would have been displaced had additional power been available from HQ's existing units. Only a delay in development of new dams would lead HQ not to resell power. These dams "can have significant, negative environmental effects" and should not receive a zero environmental valuation. So the HQ adder that the CVPS might have tried to derive from the order in Docket No. 5270 would have to be substantially smaller than the 5% adder for DSM.

Depending on how one interprets the order in Docket No. 5330, it could be read as supporting a range of estimates of externality adders, from zero to perhaps 2% or so. For example, suppose the following:

- Two thirds of the HQ energy freed up by cancellation of the HQ-VJO contract would otherwise have backed down the same types of fossil resources that would have operated due to CVPS's replacement of the HQ energy (so only one third is any cleaner than the replacement). At least this level of resales is implied by the discussion of the resale of Hydro Québec power in the Order in Docket No. 5330.
- The remaining third, which requires earlier installation of large hydro plants, has externalities per kWh that are a third of the externalities of CVPS's replacements. The Order in Docket No. 5330 source suggests that hydro development has "significant, negative environmental effects," but that these effects are "*less* damaging that the alternative supply sources." For this example, I have assumed that significant, but less damaging, means something like one-third as damaging as the alternatives.

In this example, the HQ adder could be extrapolated from the DSM adder as the DSM adder times

[(the fraction of power that would have been resold) ×
(the benefit of using the power that would have been resold)] +
[(the fraction of power that would not have been resold) ×
(the benefit of deferring construction of HQ's large hydro)]

or

$5\% \times (\frac{2}{3} \times 0 + \frac{1}{3} \times \frac{2}{3}) = 1.1\%$. ⅔

Q: Would an adder of this magnitude have affected a prudent utility's decision as to whether to commit to the HQ-VJO contract (or a later equivalent) or purchases from existing plants, followed by construction of new gas-fired combined-cycle plants?

A: No.

Q: Did the HQ-VJO contract have significant benefits in reducing cost risks to CVPS's ratepayers?

A: No. While the contract had some advantages, it was a very large fixed obligation, which added to CVPS's existing fixed obligations. The independence of the HQ-VJO contract from fuel prices would have been desirable to diversify the portfolio of a utility with primarily oil- and gas-fired supply resources, but that description does not fit CVPS.

The Board's Order in Docket No. 6107 (at 47) recognizes that the HQ-VJO contract does not have the characteristics for which the Board assigned a risk credit to DSM.

Q: Did CVPS understand the risks posed by the HQ contract and how to deal with those risks?

A: At least one senior manager understood this issue earlier in the HQ purchase process. In a September 1988 document entitled "Key Assumptions:

Economics of Schedule C Analysis," Bob Stein explained why CVPS should be careful to avoid excessive purchases from HQ (Exhibit DPS-PLC-19):

- Under a situation of uncertainty, CVPS should avoid making large long-term commitments unless the economics are highly favorable:

> Uncertainty increases through time and flexible, balanced planning suggests that post 1995 commitments be made on a more conservative basis. Strong weight should be given to a low load growth, high NUG, high penetration of DSM scenario. Over the next few years we will learn much more about our needs for the mid 1990's and beyond. While HQ now appears to be the most economic resource, over-commitment is expensive and embarrassing.... Moral, *there's always another train coming*. (emphasis added)

- "We should not plan on everlasting strong market for capacity."
- "Cost should not be the only criterion…. We should consider splitting our eggs between HQ and resources with other price drivers."
- "Like any good portfolio manager, we should divide our investments up and leave room for unknown future good deals. Undercommitting will also give us the future flexibility to see how our DSM efforts have faired and to understand where NUGs really are going. Lastly, undercommitting will cause us to purchase capacity at whatever cost and would be defendable in a rate case whereas over-commitment would be at risk in rates."

In early 1990s, CVPS should have been aware of these risks and avoided excessive commitment to this single source.

IV. The Effectiveness of Central Vermont's Efforts to Mitigate the Costs of the HQ-VJO Contract

Q: Did CVPS achieve any mitigation of the HQ-VJO contract costs since the Board's Order in Dockets Nos. 5701 and 5724?

A: No. Mr. Boyle's testimony in this case describes CVPS's efforts to reduce the costs of the contract, but acknowledges that those efforts were fruitless.

Q: Then what are all the benefits that Mr. Boyle claims in his testimony?

A: At page 81, Mr. Boyle claims savings from CVPS's four sellback arrangements with HQ.[41] These sellbacks occurred prior to Docket No. 5701, and hence are not the subject of this testimony.

At pages 82–85, Mr. Boyle reports on the difference between the costs of the HQ-VJO contract projected in 1990, and the actual costs to date and projected for the 2001/02 rate year. These savings are due to lower inflation rates and costs of capital, rather than CVPS's skill in negotiation.

Q: Are these cost reductions reflected in your analysis?

A: Yes. I use the actual and projected costs of the HQ-VJO project in the relevant test years.

Q: Does it matter whether CVPS's unsuccessful efforts were undertaken prudently?

A: No. In Docket No. 5701, the Board offered CVPS the opportunity to reduce the penalty by demonstrating, "through tangible results, that it has eliminated the excessive power costs imposed on customers by ineffective and

[41]He acknowledges that those benefits will be offset to some extent by costs that are not fully estimated.

improvident management decisions, or that it is on a reasonable and equitable path towards doing so" (Order at 172). Mr. Boyle's testimony does not make either of these demonstrations.

How hard CVPS tried to negotiate a better deal with HQ is not relevant to this docket. Even assuming that CVPS has done nothing else wrong since 1994, the costs of its prior imprudence have increased and the probability of CVPS being able to correct the problem has decreased.

V. Excess Rate-Year Costs of the HQ-VJO Contract

Q: How much would CVPS have paid to replacing the HQ-VJO contract in the Docket-No.-6120 rate year had CVPS prudently managed its power supply in the early 1990s?

A: Depending on the exact mix of base, intermediate, and peaking resources; the duration of each contracts; and the details of contract pricing that CVPS could have negotiated, prices of individual contracts in 1999 would have been between 3¢/kWh and 5¢/kWh.

As enumerated in Exhibit DPS-PLC-20,

- Unitil's purchases that that resulted from its 1991 RFP cost $41.90/MWh.
- The NU offers to CVPS would have cost about $40/MWh for either the Montville-Middletown Oil Block or system power.
- Offer A from NYSEG would have cost $49/MWh.

- The municipal utilities for which we have actual 1999 prices paid $40–54/MWh under their early-1990s market-based contracts.[42] The contracts for which I can backcast prices (adjusted for the Newbay charges), all cluster around $40/MWh.
- Burlington's purchases from NU and NYSEG cost about $33/MWh and $37/MWh, respectively.
- The New Hampshire Electric Coop's contract with CVPS cost $27/MWh.

Q: How do those prices compare to what Central Vermont paid for HQ power in 1999?

A: Central Vermont's spreadsheet HQ_HIST.wk4 indicates that purchases under the contract in 1999 averaged $58.3/MWh, for a total cost of $53.5 million for 917 GWh.[43]

Q: What portion of the 1999 power cost was due to CVPS's imprudence?

A: had CVPS paid an average of $40/MWh (a mid-range price for the purchases I list above), it would have been paying 31%, or $16.8 million, less than the actual cost of the HQ-VJO contract.

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[42]This range excludes the sale from NEPCo to Littleton, which includes an undetermined about of Newbay buyout charges in 1991, and brings the NEPCo-Reading sale up to 75% capacity factor using the contract energy price. Other than these two contracts and the requirements contracts, the highest price was $44/MWh.

[43]These values are consistent with the net purchases and sales reported in Central Vermont's 1999 FERC Form 1, pp. 310 and 326. Central Vermont reports higher prices and lower energy purchases in HQ_sav_90_vs_01.wk4, the workpapers for Mr. Boyle's Exhibit FJB-30.

Q: How would Central Vermont have paid for replacing the HQ-VJO contract in the Docket No. 6460 rate year if CVPS had prudently managed its power supply in the early 1990s?

A: From the same exhibits, using CVPS's projection of near-term oil prices, I project that prices in 2001/02 would have been between 3¢/kWh and 5.7¢/kWh.

As shown in Exhibit DPS-PLC-21, for the 2001/02 rate year,

- The NU offers to CVPS would cost $54/MWh for the Montville-Middletown Oil Block and $52/MWh for system power. Central Vermont would have replaced some of the expensive energy in the Oil Block with off-peak energy purchases.
- Offer A from NYSEG to CVPS would have cost $54/MWh.
- The municipal-utility power-supply contracts for which I can project a price for 2001/02 will cost $42–57/MWh.
- Burlington's purchases from NU and NYSEG will cost about $39/MWh and $41/MWh, respectively.
- The take-or-pay portion of NHEC's contract with CVPS will cost about $25/MWh. Supplementing the contract with CVPS's incremental energy to bring it to a 75% capacity factor would raise the price to about $29/MWh.[44]

Q: How do those prices compare to what Central Vermont will be paying for power under the HQ-VJO contract in the rate year?

[44]Generally, a higher capacity factor resource would have a lower price. This situation is reversed for the CVPS-NHEC contract in 2001/02, partly due to the increase in fuel prices since the contract was signed.

A: Central Vermont projects that it will be paying $63.89/MWh in 2001 and $64.54 in 2002, for an average rate-year cost of $64.21/MWh and a total cost of $60.2 million for 938 GWh.[45]

Q: What portion of the cost was due to CVPS's imprudence?

A: If the average cost of CVPS's alternative portfolio was $45/MWh (again, in the middle of the range), the Company would be paying 30%, or $18 million, less than for the HQ-VJO contract.

Q: Are the costs of imprudence that you have estimated the same as the uneconomic costs estimated by Mr. Biewald?

A: No. Mr. Biewald's testimony concerns the long-run economic usefulness of the HQ-VJO contract using today's information about the rate year and beyond. My analysis is concerned with what CVPS would be paying if it had been prudent in 1991–1995, while Mr. Biewald's analysis is concerned with what CVPS would pay if it were to replace the HQ-VJO contract on a forward-going basis, at current expectations. Mr. Biewald therefore compares the cost of the contract to a current market-price forecast, appropriately including actual NEPOOL market-clearing prices for 1999 and current prices for power to be delivered in 2001 and 2002. The prices he reports for those years are different from the costs of resources that CVPS could have acquired in the early 1990s.

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[45]These values are from Central Vermont's spreadsheet HQ_FORC.wk4. For comparison, Mr. Boyle's Exhibit FJB-1 projects an average cost of $63.86/MWh for the twelve months ended 10/31/01, and the workpapers for that Exhibit project $64.50/MWh for the year ending 10/31/02. The rate year includes four months from the year ending 10/31/01 and eight months from the year ending 10/31/02, for an average cost of $64.29/MWh, which agrees well with the $64.21/MWh I quote in the text.

Actual market prices were very low in 1999, and many prudent contracts from the early 1990s exceeded the market price in 1999. Hence, the uneconomic portion of the contract cost in 1999 was larger than the imprudent portion. For 2001/02, the situation is reversed; market prices are expected to be higher that the costs of prudent contracts signed in 1991–95, so the uneconomic portion of the contract is less than the imprudent portion.

Q: Are these excess costs in the rate year likely to be offset by benefits in later years?

A: No. Mr. Biewald reviews the projected costs of the HQ-VJO contract in his testimony.

Q: Does this conclude your testimony?

A: Yes.

Exhibit DPS-PLC-1

Professional Qualifications of Paul Chernick

Exhibit DPS-PLC-2

Memos and Notes Describing 4/17/91 CVPS Planners Meeting on HQ Contract

Exhibit DPS-PLC-3

Summary of CVPS HQ Analyses

Exhibit DPS-PLC-4

NU Offers to CVPS

Exhibit DPS-PLC-5

EMA's Comparisons of Busbar Costs of Longterm Power Resources

Exhibit DPS-PLC-6

Comparison of CVPS Fuel-Price Forecasts: February 1990 and July 1991

Exhibit DPS-PLC-7

Capital Costs of Combined-Cycle Units Completed in the Early 1990s

Exhibit DPS-PLC-8

Cost of Unitil Purchases from Late 1991

Exhibit DPS-PLC-9

New England Municipal Power Contracts Signed in 1993

Exhibit DPS-PLC-10

System Power Sales Agreement: Northeast Utilities to Burlington Electric Department, 3/8/96

Exhibit DPS-PLC-11

CVPS-NHEC Contract and Prices

Exhibit DPS-PLC-12

Excerpts from NYPP Avoided-Cost Filing, August 30, 1991

Exhibit DPS-PLC-13

NYSEG 1992 Offer to CVPS

Exhibit DPS-PLC-14

NiMo 1992 Offer to CVPS

Exhibit DPS-PLC-15

Costs of New York Utility Offers to CVPS

Exhibit DPS-PLC-16

NYSEG/BED Letter Agreement for an Installed Capacity and Associated Energy Transaction 2/14/96

Exhibit DPS-PLC-17

Boston Edison 1994 Filing on New York Power Supply

Exhibit DPS-PLC-18

Comparison of HQ-VJO Contract to Lower-Cost Alternatives

Exhibit DPS-PLC-19

“Key Assumptions: Economics of Schedule C Analysis,” R. Stein, 7/88

Exhibit DPS-PLC-20

Summary of Costs of Alternatives in 1999

Exhibit DPS-PLC-21

Summary of Costs of Alternatives in 2001/02